ASSESSING UNCERTAINTIES AND MANAGING RISKS IN SHALE GAS PROJECTS

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ABSTRACT

ASSESSING UNCERTAINTIES AND MANAGING RISKS IN SHALE GAS PROJECTS

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New millennium's oil industry met the production from shale oil and shale gas formations as a revolution, a game changer which certainly have taken attention of most investors. However, shale oil and shale gas projects generally have marginal economics, hence should be carefully analyzed from the economic standpoint.

To analyze the economics of a shale oil or shale gas play, generating an economically recoverable resource (ERR) probability function showing the full uncertainty range is highly important. Furthermore, the net present value (NPV) of the project together with the uncertainties inherent in it should be revealed so that the primary decision of entering a shale oil or shale gas project will be determined. As progressing through the project phases, judicious go/no-go decisions should be given at several decision gates.

In this study, a methodology to evaluate shale oil and shale gas projects at any project maturity stage via a fully probabilistic approach is developed. Moreover, a new user-friendly software with graphical user interface is developed to make our methodology applicable.

Considering the available input parameters at each of the three different project phases; exploration, appraisal and development phases, specific probabilistic reserves estimation methodologies are designed to reveal the effect of uncertainties in input parameters on the ERR probability ranges. Moreover, by utilizing the economical parameters such as market prices, tax rates and various expenditures, NPV probability ranges and hence firm go/no-go decisions at the decision gates can be attained. The main objective is to develop a methodology to obtain firm decisions at any project stage while considering the uncertainties in the input parameters and to evaluate the risks in the monetary level. Finally, the developed methodology is verified via the data obtained from a real field and utilizing the developed software.

Keywords: Shale Gas, Shale Oil, Risk Management, Uncertainty Assessment, Probabilistic Methods, Monte Carlo

ÖZ

ŞEYL GAZI PROJELERİNDE BELİRSİZLİKLERİN TAYİNİ VE RİSKLERİN YÖNETİMİ

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Petrol ve gaz endüstrisi bu milenyumun başlarında şeyl formasyonlarından petrol ve gaz üretimiyle tanıştı ve bu gelişmeyi bir devrim, bir oyun değiştirici olarak gördü. Doğal olarak bu gelişme birçok yatırımcının ilgisini çekti. Ne var ki, şeyl petrolü ve şey gazı projeleri marjinal ekonomilere sahiptir ve ekonomik açıdan dikkatle analiz edilmelidir.

Ekonomik analizleri gerçekleştirebilmek için en başta ekonomik üretilebilir kaynak miktarını belirten bir olasılık fonksiyonu elde edilmelidir, böylelikle kaynak miktarındaki tüm belirsizlikler ortaya serilebilir. Buna ek olarak, projenin net bugünkü değeri belirsizlikleriyle birlikte ortaya koyulmalı ve bir şeyl petrolü veya şeyl gazı projesine başlama kararı bu iki parametre göz önüne alınarak değerlendirilmelidir. Ayrıca proje içinde ilerlerken geçilen çeşitli karar noktalarında isabetli devam et veya dur kararları verilmesi gerekmektedir.

Bu çalışmada, şeyl petrolü ve şeyl gazı projelerini, herhangi bir proje olgunluk safhasında, tamamen olasılıklı yaklaşım vasıtasıyla değerlendiren bir yöntem geliştirilmesine odaklanılmıştır. Ayrıca, bu yöntemi uygulanabilir kılmak amacıyla yeni, kullanıcı dostu ve grafiksel kullanıcı arayüzlü bir yazılım geliştirilmiştir.

Girdi parametrelerindeki belirsizliklerin ekonomik üretilebilir kaynak miktarı olasılık aralığına etkilerini bulabilmek için, üç farklı proje safhasının; arama, değerlendirme ve geliştirme safhalarının her birinde ulaşılabilir olan girdi parametreleri göz önüne alınarak, özgül olasılıklı rezerv tahmin yöntemleri tasarlanmıştır. Buna ek olarak, piyasa fiyatları, vergi oranları ve çeşitli giderler gibi ekonomik değişkenler tanıtılarak, net bugünkü değer olasılık aralığı ve dolayısıyla karar noktalarında güvenilir devam et veya dur kararları elde edilebilecektir. En temel amacımız, girdi parametrelerindeki belirsizlikleri göz önünde bulundurarak bir projenin herhangi bir safhasında sağlıklı bir karar sunabilecek ve parasal riskleri değerlendirebilecek bir yöntem geliştirmektir. Son olarak, geliştirdiğimiz yöntem gerçek bir sahanın verileri vasıtasıyla geliştirilen yazılım kullanılarak doğrulanmıştır.

Anahtar Kelimeler: Şeyl Gazı, Şeyl Petrolü, Risk Yönetimi, Belirsizlik Tayini, Olasılıklı Yöntemler, Monte Carlo

To Dr. Esra Nur Tuğan

Hoping to inspire a promising academician

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The main motivation behind this work is my belief in lifelong learning. Every person we met, every moment we live is a nominee to teach us life. I, a humble lifelong student, will always know the value of a moment and try to make differences wherever I am. Many years of study brought this dissertation to life and during this challenging period, many people encouraged and supported me strongly.

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NOMENCLATURE

A	Area
$\boldsymbol{A_0}$	Original cross sectional area
$\boldsymbol{A_t}$	Annual non-discounted cash balance at year t
AGIP	Average German import price)
ANN	Artificial Neural Network
API	American Petroleum Institute
ASF	Alternating Sequence Fracturing
AUPM	Analytic Uncertainty Propagation Method
b	Constant related to decline type, decline exponent
$\boldsymbol{B_g}$	Gas formation volume factor
$\boldsymbol{B_o}$	Initial formation volume factor
bbl	Barrels
Bbbl	Billion barrels
Bcm	Billion cubic meter
Bcf	Billion cubic feet
BCGA	Basin centered gas accumulations
Bcm	Billion cubic meter
BDF	Boundary Dominated Flow
boe	Barrels of oil equivalent
BOPD	Barrels of oil per day
BI	Brittleness index
C	Present value of all capital investments per well after income tax

C_b	Cost of a bit
C_f	Drilling cost per unit depth
C_r	Fixed operating cost of the rig per unit time
C_R	Royalty rate
C_T	Tax rate
c_0	Leasing cost per area
CAPEX	Capital Expenditures
CBM	Coal bed methane
CTU	Coiled Tubing Unit
D	Decline Rate
D_{min}	Minimum decline rate
D_i	Initial nominal decline rate
D_∞	Decline constant at "infinite time"
D&RA	Decision and Risk Analysis
d	Diameter (Pore diameter)
df	Discount factor
D	Yearly production decline rate
D_i	Initial nominal decline rate.
D_∞	Decline constant at infinite time
D_{dep}	Depreciation rate of CAPEX
DCA	Decline Curve Analysis
DCF	Discounted Cash Flow
DFIT	Diagnostic Fracture Injection Test
DFN	Discrete Fracture Network
DG	Decision Gate
E	Young's modulus

E&P	Exploration and Production
EPV	Effectively Propped Volume
ERR	Economically Recoverable Resources
EUR	Estimated Ultimate Recovery
EUR_D	Dimensionless Estimated Ultimate Recovery
F&DC	Finding and Development Costs
FID	Final Investment Decision
F	*F*orce
G_a	Adsorbed gas storage capacity
G_f	Free gas storage capacity
G_{sL}	Langmuir volume
G_{so}	Dissolved gas-in-oil storage capacity
G_{st}	Total gas storage capacity
G_{sw}	Dissolved gas-in-water storage capacity
GIP	Gas in Place
GIIP	Gas Initially in Place
$GIIP_{ad}$	Adsorbed gas initially in place
$GIIP_{free}$	Free gas initially in place
$GIIP_{tot}$	Total gas initially in place
GUI	Graphical User Interface
HH	Henry Hub
HI	Hydrogen Index
h_{net}	Net thickness
i	Interest rate or discount rate
IOR	Improved Oil Recovery

IOC	International Oil Companies
IP	Initial Production
IP30	Average daily rate after 30 days
IP60	Average daily rate after 60 days
IP90	Average daily rate after 90 days
IRR	Internal Rate of Return
ISIP	Initial Shut-in Pressure
K_n	Knudsen number
k_B	Boltzmann constant
L_0	Original length of the object
LNG	Liquefied Natural Gas
LOE	Lease Operating Expenditure
mD	Milli Darcy
m_{ad}	Air-dry gas volume
$\dot{\hat{M}}$	Apparent natural-gas molecular weight
MCM	Monte Carlo Method
MM	Million
Mcf	Thousand cubic feet
MMBTU	Million British Thermal Units
MMcfd	Million cubic feet per day
MFO	Mini Fall Off
MSS	Mechanical Shifting Sleeves
MTI	Moment Tensor Inversion
MZF	Modified Zipper Frac
NBP	National Balance Point

NPV	Net Present Value
NPV0	Undiscounted net cash flow
NPV (W)	NPV as a function of the number of wells
N_p	Cumulative oil production during project, EUR
n	Exponent parameter
OHCIP	Original Hydrocarbon in Place
OI	Oxygen Index
OPEC	Organization of Petroleum Exporting Countries
OPEX	Operating Expenditures
p	Original reservoir pressure
p_L	Langmuir pressure
P	Price of hydrocarbon
P_n	Well-head hydrocarbon price at year n
P_1	Well-head hydrocarbon price at year 1
P&A	Plug and Abandonment
P10	10% Probability
P50	50% Probability
P90	90% Probability
PA	Production Analysis
PD	Proved Developed
PI	Profitability Index or Production Index
PIR	Profitability Investment Ratio
PL	Plateau Life
PSA	Production Sharing Agreement
PSC	Production Sharing Contract

PR_C	Poisson's Ratio Composite
PTA	Pressure Transient Analysis
PUD	Proved Undeveloped
PV	Present Value
PV (N_p)	Present Value (*PV*) of reserves
Q	Production output, cumulative production
q_t	Daily oil production rate per well at time t
q_i	Initial daily oil production rate per well
QD	Dimensionless cumulative production
q(t)	Oil production rate at time t
q_i	Initial oil production rate
qD	Dimensionless production rate
R/T	Royalty/Tax
RCP	Resin Coated Proppant
RF	Recovery Factor
RTT	Resource Triangle Theory
Ro	Vitrinite reflectance
r_{inf}	Annual inflation rate effecting the hydrocarbon price
rp	Recovery potential
spf	Shot per foot
S_o	Oil saturation
S_w	Water saturation
Sw_T	Total initial water saturation
SEDP	Stretched Exponential Decline Model
SRA	Stimulated Reservoir Area

SRV	Stimulated Rock/Reservoir Volume
STOIIP	Stock Tank Oil Initially in Place
$\mathbf{STOIIP_{Tot}}$	Total oil initially in place
$\boldsymbol{T}$	*T*emperature
Tcm	Trillion cubic meter
Tcf	Trillion cubic feet
TOC	Total Organic Content
TRR	Technically Recoverable Resources
TVD	True Vertical Depth
$\boldsymbol{t}$	time, number of time periods
$\boldsymbol{t_b}$	Rotating time during bit run
$\boldsymbol{t_c}$	Non-rotating time during the bit run
$\boldsymbol{t_t}$	Trip time
UR	Ultimate Recovery
XL	Cross Linked
$\boldsymbol{V}$	Oil price netted back to the well after income tax
V_c	Volume of crushed gas
V_l	Volume of lost gas
$\boldsymbol{V_L}$	Langmuir volume
$\boldsymbol{V_m}$	Volume of measured gas
$\boldsymbol{V_{ker}}$	Kerogen volume
W	Number of wells
$\mathbf{W_o}$	Optimum well number for maximum economic return
$\mathbf{W_m}$	Minimum number of wells for maximum oil extraction
WTI	West Texas Intermediate

YMS_C	Young's Modulus Composite
$\boldsymbol{Z}$	PV of other investments after income tax
$\mathbf{\Delta D}$	Total time required to drill at final depth
$\mathbf{\Delta_0}$	The well spacing
$\boldsymbol{\varepsilon}$	*S*train
$\boldsymbol{\varepsilon_{trans}}$	Transverse strain
$\boldsymbol{\varepsilon_{axial}}$	Axial strain
$\boldsymbol{v}$	Poisson's ratio
$\boldsymbol{\tau}$	Characteristic number of periods
$\boldsymbol{\lambda}$	Elastic modulus
$\boldsymbol{\rho_b}$	Rock/formation density
$\boldsymbol{\rho_{ker}}$	Kerogen density
$\boldsymbol{\rho_o}$	Oil density
$\boldsymbol{\rho_s}$	Sorbed-phase density
$\boldsymbol{\sigma}$	*S*tress
δ	Collision diameter of the molecule
Φ	Total porosity fraction
Φ_a	Porosity consumed by adsorbed gas
$\mathbf{\sigma_{Hmin}}$	Minimum principle stress
$\mathbf{\sigma_{Hmax}}$	Intermediate principle stress
$\mathbf{\sigma_{overburden}}$	Overburden stress

CHAPTER 1

INTRODUCTION

As today's hydrocarbon reserves decline day by day, emerging technologies introduce new opportunities to develop new reserves economically those are formerly somewhat unattainable and used to be called as "Unconventional Resources". Due to their global potential, especially shale oil and shale gas have taken attention of most investors and become a lifesaver for world's declining hydrocarbon potential. However, shale oil and shale gas projects generally have marginal economics, hence should be carefully analyzed.

There are many unconventional issues in unconventional reservoirs. Extremely low permeability, exotic diffusion effects, stress dependent permeability and porosity, molecular adsorption/desorption and horizontal wells with complex fracture network are a few examples. These entire phenomena combined with poor data make the results of any estimation highly uncertain (Houze 2013, Clarkson *et al.* 2011).

As for an unconventional play, original hydrocarbon in place (OHCIP), technically recoverable resources (TRR), economically recoverable resources (ERR) and the determination of the ERR to be classified as reserves, i.e. estimated ultimate recovery (EUR) are all functions of the former ones and should be calculated independently with the uncertainties inherent in each one (Weijermars 2015). However, reliable determination of these values is highly difficult and needs rigorous investigation.

Moreover, different resource estimation methodologies are applicable at different project maturity stages, since data available at each stage evolves. The project maturity stages are categorized into three in this PhD study as exploration, appraisal and development stages in chronological order and three decision gates are placed at the end of each stage.

Exploration stage aims to prove the existence of producible hydrocarbons, appraisal stage aims to determine the profitability of the opportunity and development stage aims to meet production targets, i.e. to prove economic producibility of future horizontal wells (Giles *et al.* 2012).

As of today, although there is not any industry standard in the evaluation of shale oil and shale gas reserves, two most widely used reserves estimation methodologies are generally utilized for the evaluation of shale formations, after having some modifications to handle the above-mentioned unconventional issues.

The first reserves estimation methodology is the volumetric estimation method with some modifications to include adsorption phenomena, which is basically like that applied for conventional reservoirs (Ambrose *et al.* 2010). However, deterministic application of this method would certainly bring high uncertainties to evaluation of shale formations.

Second reserves estimation methodology is the production data analysis method, which can only be used again with the necessary modifications and whenever enough data are available. Throughout the last decade, several authors modified the well-known Arps' equation for better representation of the flow mechanisms special to shales (Ilk *et al.* 2008b, Valko 2009, Duong 2010, and Giles *et al.* 2012). However, the application of this method is performed by estimating a mean estimated ultimate recovery (EUR) and a single production decline trend for the entire play (Chen *et al.* 2015). As will be discussed in this study, the traditional methodology would naturally involve a high degree of uncertainty due to the high degree of heterogeneity and consequently productivity variation across the area.

In this study, we develop a methodology to probabilistically evaluate a shale oil or shale gas project at any project maturity stage while considering the uncertainties in input parameters. In our methodology, we utilized several reserves estimation methods in a fully probabilistic fashion, according to the maturity stage of a project. For exploration phase, a specially developed analogy method; for appraisal phase, a modified version of volumetric method and for the development phase, a special type of production data analysis method is used.

All three reserves estimation methods are extensively modified to better suit to the shale gas formation characteristics. Moreover, these methods can be easily modified for shale oil formations whenever the reliable reservoir, fluid, rock properties data together with production data are available.

To make our methodology applicable, we have also developed a new user-friendly software with GUI (Graphical User Interface), which can estimate OHCIP, TRR and ERR, systematically and reveal the uncertainties in all outputs. Lastly, the economical parameters are also required as input to present a Net Present Value (NPV) probability range and hence clear go/no-go decision for the project can be obtained as the outcome.

As is the case of today, there is no economic shale oil or shale gas production outside of North America. Our study also examines the barriers of achieving economic shale oil and shale gas projects anywhere in the globe. Moreover, via the developed software, investors would be able to evaluate the economics of any shale play, determine the weak points to be strengthen, optimize their investments and develop de-risking strategies at any phase of their project. This study stays in the core of the shale oil and shale gas project management and involves the evaluation of the projects both from technical and economical point of views.

The reader will find an extensive number of pages of literature survey in this dissertation, since a wide technical background from exploration to completion and production, together with the basic concepts of project risk and uncertainty analysis, decision-making, financial analysis and so on are necessary to compose such a study. All the presented information pile in the manuscript have strong connections to this study, directly or indirectly. On the other hand, although this study includes a powerful and highly challenging programming background, any theory about computer programming language was not given in the manuscript.

The software developed together with this study fundamentally aims to provide investors and executives a user-friendly GUI environment to calculate the risk of failure and the uncertainty in success at any stage of the shale gas projects. In words of one syllable, the software provides a firm decision-making utility from the touch of the bit to the abandonment of the field.

Finally, robustness of the methodology and the software developed in this study are corroborated by benchmarking with the selected real fields. In other words, the TRR/ERR results calculated at each tab of the software representing separate decision gates are highly consistent with the foreknown values of the real fields used in these case studies.

CHAPTER 2

UNCONVENTIONAL RESOURCES PRELIMINARIES

Unconventional term for oil industry is a dynamic term, which changes with time and even location. For example, until the first oil well drilled by Edwin L. Drake in August 1859, the conventional method of oil production was collecting natural oil seeps and open pit excavations. At those times, drilling with a rig was considered as unconventional. From that day on, offshore drilling, horizontal wells, hydraulic fracturing and IOR (Improved Oil Recovery) methods are all examples of the change of the projects referred as "unconventional" to "conventional" in time. Today, some of the so-called unconventional resources, such as shale oil and shale gas, Coal Bed Methane (CBM) and tight gas are seen as routine by some part of the oil industry (Vassilellis 2009). Global hydrocarbon production entered a new era with so-called "unconventional resources", which today can be called as "previously overlooked" (Reeves *et al.* 2007).

Unconventional Resources are generally spread throughout a large areal extent and significantly not affected by hydrodynamic influences. They need unconventional (specialized) extraction or process techniques (Chan *et al.* 2010).

As can be seen from Figure 1, according to final products, unconventional resources can be divided into two categories; *gas sources* (tight gas sands, basin centered gas, coalbed methane, shale gas and methane hydrates) and *oil sources* (heavy oil, extra heavy oil, bitumen and oil shales).

As suggested in the Resource Triangle Theory (RTT) of Masters (1979), all natural resources (gold, silver, gas, oil) are distributed log-normally in nature, i.e. the highest grade of the deposits found will be only a small portion of the whole resource.

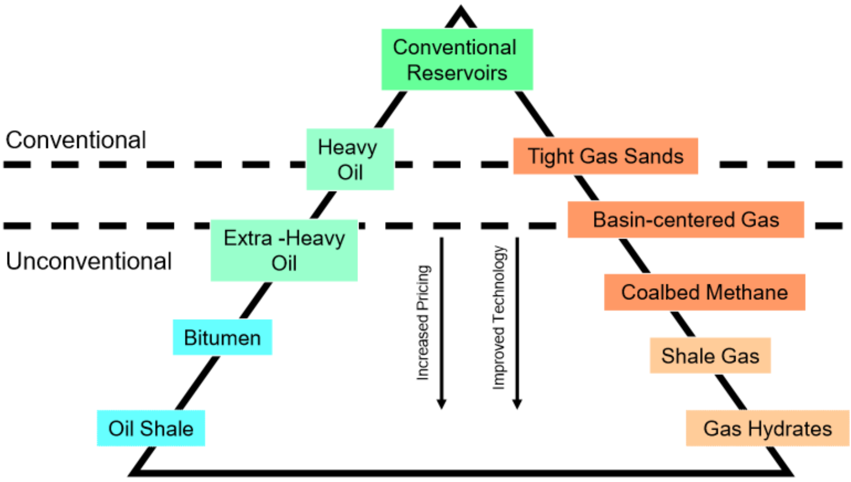


Figure 1 – Classification of unconventional resources (after Chan *et al.* 2010)

The larger portion, lower grade resources need improved technology and increased investment. In short, the exploitation of resources is highly sensitive to both technology and commodity prices (Masters 1979). The log-normality tendency of many natural phenomena can be explained as most of them has a lower boundary, namely zero, but no upper boundary (Jarlsby 2007).

Higher commodity prices inherently bring new technologies, hence development of lower grade resources. In other words, higher market prices of the products encourage developing the resources at the bottom part of the resource triangle in Figure 1, which in turn bring increased drilling and boosted production (Flores *et al.* 2011).

The oil and gas resources called as "conventional" constitute the high-grade portion of the whole resource and "unconventional" consists of the remaining huge portion, which requires improved technology and adequate oil and gas prices (Gouveia and Citron 2009).

This PhD study is limited to shale oil and shale gas resources, which are defined as the oil and gas resources in shale formations that are thermally mature enough and has sufficient and economic hydrocarbon content (SLB Oilfield Glossary 2015a).

Although, tight gas sands and basin centered gas accumulations (BCGA) are different from a geological perspective, they show similar production trends and need similar development strategies, hence economic characters.

Tight gas sands are low-permeability gas reservoirs with conventional trapping mechanism (reservoir rock) (Figure 2), typically having sandstone texture (Holditch 2006) and *BCGA* is defined as a regionally pervasive unconventional natural gas accumulation having low permeability, abnormal pressure (over-pressure or under-pressure) and high gas saturation without a gas-water contact (SPE-PRMS 2007).

BCGA's range from a few feet thick single reservoirs to several thousand feet thick multiple, stacked reservoirs (AAPG Wiki 2017, Law 2002).

To summarize, where both tight gas sands and BCGA's are types of tight gas reservoirs (unconventional resources); tight gas sands show conventional accumulation or trapping characteristics whereas BCGA show unconventional characteristics. There are two types of BCGAs; direct BCGAs consist of gas prone kerogen and the pressure mechanism is hydrocarbon generation whereas indirect BCGAs consist of liquid prone kerogens and the pressure mechanism is cracking of liquid hydrocarbons to gas (Law 2000, 2002). Masters (1979) was the first to define this type of accumulation and called it as "deep basin gas".

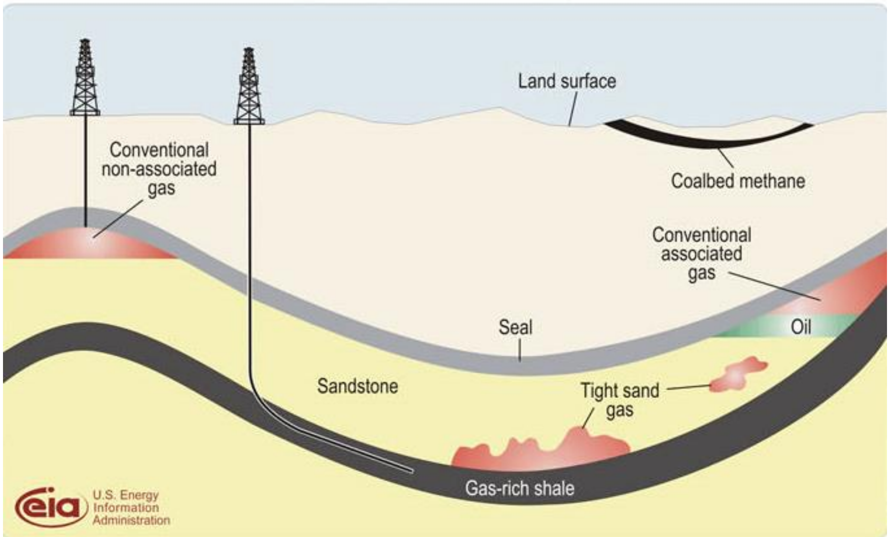


Figure 2 – Classification of gas resources (after EIA 2011a)

Although some authors draw a permeability cut-off of "0.1 mD" to distinguish unconventional and conventional reservoirs, this designation do not have a scientific background (Boyer et al. 2011). Actually, *economy* would be a more meaningful criterion that draws the border for unconventional term.

Holditch (2006) makes the neatest definition of an unconventional gas reservoir (tight gas reservoir) by emphasizing economy as “a reservoir that cannot be produced at *economic* flow rates nor recover *economic* volumes of natural gas unless the well is stimulated by a large hydraulic fracture treatment or produced by use of a horizontal wellbore or multilateral wellbores”.

On the other hand, the need for drilling more and complex wells together with massive stimulation operations leads to invest more in unconventional plays, which in turn bring higher economic risks (Madani and Holditch 2011).

Moreover, uncertainties arise at the exploration stage and ranges from “does the play exist” to “what is the lifecycle profitability”. Range of uncertainties becomes narrower as the play is developed, however they remain until the abandonment of the field (Giles *et al.* 2012). While areal extents of shale plays are much larger, they involve much uncertainty. Moreover, geological complexity, petrophysical and geomechanical factors, together with high investment requirement bring even more uncertainty. Considering the many parameters each involving uncertainties, a multi-disciplinary approach is necessary (Harding 2008). Despite the huge uncertainties inherent in shale play evaluations, assessment and quantification of uncertainties would provide asset owners valuable insight into potential of their assets and allow them more accurate categorization of their reserves (Lee and Sidle 2010). To obtain the uncertainty range and analyze the risk, stochastic approach should be utilized, rather than a single point outcome. Stochastic analysis not only assesses the risk of failure, but also provides a statistical distribution for all possible outcomes (Harding 2008).

To evaluate the risk in developing an unconventional play, two concepts should be examined carefully. The first one is the **technically recoverable resources (TRR)**, which is the proportion of **gas/oil initially in place (GIIP/STOIIP)** that can be technically produced using current technology disregarding the economical parameters. The second one is **economically recoverable resources (ERR)**, which is the portion of TRR within favorable economic conditions and incentives, i.e. the portion having profit potential. **Finding and development costs (F&DC)**, **lease operating expenses (LOE)** and commodity prices are the most important parameters in determination of ERR (EIA 2013).

Since unconventional oil and gas projects have marginal economics, their profitability is highly sensitive to recovery efficiency and F&DC, which are driven mainly by technology and political-economic conditions, respectively (Flores *et al.* 2011).

To prevent any confusion, it would be suitable to define estimated ultimate recovery (EUR) as the portion of ERR to be classified as reserves, i.e. economically recoverable volume, at the current technology and market prices (Weijermars 2015)

In this dissertation, the relationships between GIIP/STOIIP, TRR, ERR and EUR of shale oil and shale gas plays are mostly concentrated. A methodology and a software is developed to evaluate the economics concurrently assessing the uncertainties and mitigating the risk in any maturity stage of a resource development project. In short, clear go/no-go decisions can be rendered at all stages, namely from exploration to production, using the developed software.

2.1. Shale Gas and Shale Oil Reservoirs

Shales are very fine-grained sedimentary rocks that contain clay, quartz and other minerals. They are of ultra-low permeability and conventionally behave as a natural barrier to the migration of oil and gas (Boyer *et al.* 2006, Passey *et al.* 2010). Shales are the most abundant rocks in sedimentary basins worldwide (Ahmed and Meehan 2016).

Shale Gas and Shale Oil Formations are organic-rich rocks containing kerogen that matured due to overburden pressure and temperature, and ultimately yield hydrocarbons. These are briefly layers of shales and layers of silt and/or carbonates and while deposition, fine-grained organic materials deposited concurrently with the silt, mud and clay. Generally, source rocks expulse some portion of the hydrocarbons they generate which will be trapped in conventional reservoirs. However, the remaining portion, which is very large comparing to expulsed portion, may provoke the formation to show shale oil and/or shale gas resource characteristics according to its kerogen type and level of total organic content (TOC). In other words, oil and gas shale formations are known as the source rock for conventional oil and gas reservoirs until recent extraction techniques evolved them to economically producing shale oil and shale gas reservoirs. In these rocks, hydrocarbons are stored mostly in limited pore spaces and partly adsorbed to the organic material of these rocks (Cipolla *et al.* 2009a, Glorioso and Rattia 2012, Ahmed and Meehan 2016).

In addition to proximity of source rocks to conventional reservoirs, they exist in a broader area where conventional reservoir rocks are unavailable for permeation of hydrocarbons (WEC 2010).

Hydraulic fracturing was the first enabling technology for producing commercial quantities of hydrocarbons from shale formations, which creates additional permeability in rocks those having very low permeability and little natural fractures. Although fracturing vertical wells in shale formations produce high volumes initially, they exhibit a sharp decline after a short time. To overcome this issue, drilling of extended reach horizontal wells with multistage fracturing to create more reservoir contact came into concern. These two key enabling technologies, horizontal drilling and multistage hydraulic fracturing, unlocked the potential of economic production from shale gas and shale oil formations (Zhang *et al.* 2009, Boyer *et al.* 2011).

2.1.1. Shale Formation Producibility and Sweet Spots

Sweet spot concept is one of the most important factor controlling the productivity of shale formations because of the regional heterogeneity. Sweet spot refers to the points where reservoir quality parameters; such as permeability, porosity, net thickness or formation pressure are much superior comparing to the rest of the area (Chan *et al.* 2010). Moreover, Giles and Tennant (2014) defined sweet spots as portion of the play that has top quartile estimated ultimate recovery (EUR). Every author may define sweet spot term to the parameter of his or her interest. In one way or another, sweet spot refers to a preferable part of a play (Giles and Tennant 2014). Some definitions may be:

1) Most economic portion of the play,
2) Best producing portion of the play,
3) Shallowest producing portion (cheapest wells),
4) Closest to infrastructure (easily developable),
5) Optimum thermal maturity range for gas/liquids,
6) Other factors such as highest TOC, pressure, thickness; or optimum stress.

While moving away from the sweet spots, geological degradation occurs and extraction costs increases. Hence, these changes should be considered while classification and categorization of the resource (Chan *et al.* 2010). Locating the sweet spots would make a huge difference in the economics of the play or provide pace in proving the commerciality of a play (Giles and Tennant 2014, Chen *et al.* 2015). On the other hand, Haskett (2014) clearly reveals that pursuing sweet spots at the exploration phase may lead to fail in determination of the *true economic potential* of an unconventional opportunity. Since the true value is the aggregated value of the entire developed area, sweet spot exploration oriented programs may lead to overvaluing of the opportunity, i.e. exaggerated/over-estimated results and misleading of the investors. According to Haskett (2014), rather than exploring the sweet spots, a fair assessment of the entire opportunity is the quickest and lowest risk pathway into an unconventional opportunity. The initial wells should provide confidence that the overall productivity is greater than the project execution threshold, i.e. what you have should be higher or equal to what you need to have to sustain a viable project.

Haskett (2014) also denotes the disparity of unconventional resource project management as: “Our conventional mindset of striving in the exploration phase to drill the target in the best location is contaminating our unconventional business decision-making. The primary exploration target and intent should be the identification of an area of productivity of sufficient magnitude and areal extent to support a business decision to develop”.

Nevertheless, in the development phase prioritizing the sweet spots significantly increases the operational efficiency and value of the entire opportunity (Haskett 2014). Sweet spots can be detected via the existing wells by the help of cuttings, mudlogging, well tests and well logs. Moreover, seismic or geological modeling tools help to determine the areal or lateral continuity of the sweet spots (Glorioso and Rattia 2012).

To evaluate the **producibility** of a play, evaluation of the source rock potential would be the initial step. It is performed primarily by geochemical analysis of shale samples together with offset well logs. The samples should be rich in organic material and capable of generating hydrocarbons (Boyer *et al.* 2006).

Moreover, there is a consensus on the crucial role of fractures in the shale oil and shale gas resource producibility. The more natural and induced fracture permeability, the more transport conduits, hence producibility. The extent of the propped fractures in the complex fracture network determines the **stimulated rock volume (SRV)**, from where exactly the production comes into the wellbore (Mayerhofer *et al.* 2010). Moreover, **natural fractures** are also indispensable for shale production either because they interact with hydraulic fracture treatments and contribute directly to storage or permeability. Hence, a good understanding of natural fractures and SRV is important to predict the production potential and model the system.

There are 4 key parameters that determine the production potential of a shale formation and they are explained below in details (van Gijtenbeek 2012). The first two, organic matter richness (TOC) and hydrocarbon generation potential (thermal maturity) determine the source rock potential, where the latter two, complexity and stimulation potential, determine the suitability of the formation to be developed as economic oil/gas resource.

Total Organic Content (TOC)

TOC is the amount of carbon bound to organic contents of the rock. Basically, it represents the amount of organic material in kerogen, bitumen, liquid hydrocarbons and measured by weight percent of organic carbon (van Gijtenbeek 2012). As a consensus, from the producibility point of view, minimum required average TOC of a shale prospect is 2% (EIA 2013).

Kerogen, which literally means “producer of wax”, is a mixture of organic compounds (algae and woody plants), generally occurs in source rocks. Prior to burial, microbial activity converts some organic material into biogenic gas. Furthermore, while depth of burial increases due to sedimentation, temperature and pressure increases. Hence, the remaining organic matter – primarily lipids from animals and plant matter or lignin from plant cells – slowly cooks and transformed into various kerogen types (Boyer *et al.* 2006). Some types of kerogen (Type I, II and III) can release crude oil or natural gas upon intense heating due to further burial. The process of kerogen alteration explained above is called **maturation**. Kerogen is insoluble in normal organic solvents (e.g. in carbon bisulfide). On the other hand, soluble elements are known as "**bitumen**" which forms from kerogen during petroleum generation. Asphalt and mineral wax are forms of bitumen (Glorioso and Rattia 2012, SLB Oilfield Glossary 2015b).

Kerogen has typically low density, which is close to water, hence decreases grain density in shale when comparing to kerogen free shales. Generally, kerogen has very small pore sizes; either micropores or nanopores and considered as hydrophobic (Glorioso and Rattia 2012, SLB Oilfield Glossary 2015c). Shale regions close to kerogen show oil-wet characteristic, whereas regions away from kerogen show water-wet characteristic (Boyer *et al.* 2006).

Kerogen has the role of creating pore space and providing hydrocarbon storage, hence there is a strong correlation between kerogen content and total porosity, hydrocarbon saturation and permeability. In short, kerogen content or TOC values are directly related with the overall reservoir quality (Neville and Donald 2012).

Generally, TOC and kerogen terms are used interchangeably, however, TOC represents all the carbons including the hydrocarbons that kerogen generated. Hence, while kerogen matures and produces gas and oil, its amount decreases; however, TOC remains constant until the generated products are expelled to other reservoirs (Glorioso and Rattia 2012).

Although, TOC and kerogen are closely associated with shales and silt-rich claystone, they may be present in many carbonates (Glorioso and Rattia 2012).

TOC evaluation is traditionally performed by indirect measurement, which will be explained below in details. However, the development of new generation spectroscopy measurement tools (e.g. Litho Scanner – a high-definition spectroscopy logging tool – a trademark of Schlumberger) are worth mentioning briefly here (SLB 2017). The tool enables the direct continuous measurement of carbon together with other major rock forming elements. While mineralogy and TOC are determined, one can estimate porosity and adsorbed gas content easily (Neville and Donald 2012).

Traditionally, TOC is determined either by measuring CO or CO_2 emission after combustion of 1 g of pulverized rock sample or subjection of sample to controlled heating in inert gas (no oxygen) to the point of hydrocarbon generation which is called as “**pyrolysis”** (SLB Oilfield Glossary 2015d, Glorioso and Rattia 2012).

Pyrolysis is briefly controlled thermochemical break down **(cracking)** of large hydrocarbon molecules into smaller ones and a very useful instrument in evaluating shale oil and gas plays (SLB Oilfield Glossary 2015e, Glorioso and Rattia 2012).

Pyrolysis is used to assess the quality of source rock, the abundance and thermal maturity of organic material and the quality of hydrocarbons to be generated. Researchers from IFP (Institut Français du Petrole) developed a methodology for pyrolysis, which become an industry norm (Espitalie *et al.* 1977). This method requires 50-100 mg of pulverized rock and performed in 20 minutes. Sample is heated in controlled stages. First stage is heating the sample to 300 °C at which free hydrocarbons are released from the matrix, i.e. inter-particle pore network. The sample continues to be heated up to 550 °C in the second stage where volatile hydrocarbons formed by thermal cracking are released.

In addition, kerogen yields CO_2 between temperatures 300 °C to 390 °C. A flame-ionization detector measures released organic compounds through the first and second stage and a sample results chart is given in Figure 3. The peaks in the chart reveals the relative abundance of hydrogen, carbon and oxygen in the kerogen, hence the kerogen type and its potential of hydrocarbon generation (Espitalie *et al.* 1977, Boyer *et al.* 2006).

As can be seen in Figure 3 below, **S1** peak represents the milligram of hydrocarbons (oil + gas) that can be thermally distilled (volatilized) during the first stage (below 300 °C) per gram of rock. **S2** peak represents the milligram of hydrocarbons generated by thermal cracking of kerogen during second stage (up to 550 °C) per gram of rock, i.e. residual hydrocarbon potential of the rock if the burial and maturation continues. **S3** peak represents the milligram of CO_2 produced by kerogen as it is heated per gram of rock. Lastly, $\mathbf{T_{max}}$ represents the temperature at which the maximum volume of hydrocarbons are released, corresponds to the tip of S2 peak. T_{max} value determines the thermal maturity of the source rock (Boyer *et al.* 2006; Espitalie *et al.* 1977).

Calculation formulas for **Production Index**, **Hydrogen Index**, **Oxygen Index** and their meanings can be seen in Figure 3, as well.

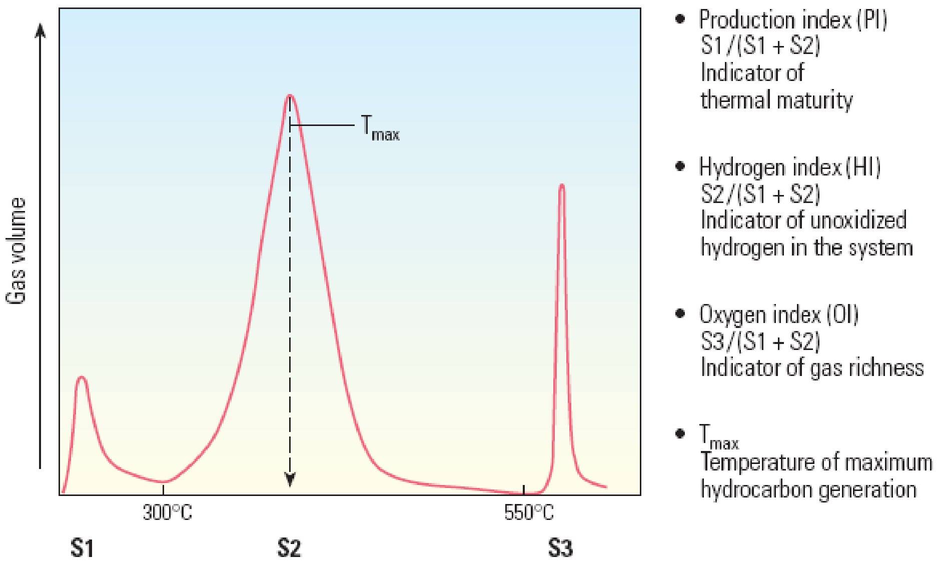


Figure 3 – Results of pyrolysis using flame-ionization detector (after Boyer *et al.* 2006)

TOC is used to estimate the adsorbed gas and is a property of the rock. A conversion factor (generally $k \approx 1.2$) or a direct relationship factor ($f \approx 2 - 2.5$) (Passey *et al.* 2010) could be utilized to estimate TOC from kerogen which include additional certain elements (e.g. hydrogen, oxygen, nitrogen and sulphur). TOC can be obtained from the % of kerogen or can be measured in laboratory (Glorioso and Rattia 2012).

To clarify the direct relationship factor mentioned above, we should state that, the grain density of organic matter (1.1 - 1.4 g/cc) is much smaller than the inorganic rock forming minerals (2.6 – 2.8 g/cc). Hence, kerogen occupies much larger volume percent (vol %) than is indicated by the weight percent (wt. %) (Passey *et al.* 2010).

Due to lack of sample availability, correlations between TOC and other parameters are also developed. For example, current rock density (ρ_b) measured in laboratory and using the density logs, log TOC could be estimated relying on the fact that kerogen reduces the rock density (Glorioso and Rattia 2012).

$$TOC = \frac{V_{ker} \times \rho_{ker}}{\rho_b \times k} \quad \textbf{(1)}$$

$$Kerogen(volume\%) = TOC\ (weight\%) \times f \quad \textbf{(2)}$$

where, TOC : total organic content (lbf/lbf); V_{ker} : kerogen volume (vol/vol); ρ_{ker} : kerogen density (g/cc); ρ_b : formation density (g/cc); k : conversion factor (~1.2), f : direct relationship factor (~2 - 2.5).

Van Krevelen diagram in Figure 4 shows the classification of kerogen types according to hydrogen index (HI) and oxygen index (OI), besides the corresponding maturity windows and Table 1 presents the generated hydrocarbon products after maturation.

Basically, thermal generation of hydrocarbon from kerogen starts with generation of non-hydrocarbon gases (CO_2 and H_2O) by losing oxygen primarily. Later, as kerogen continues with losing more hydrogen; it yields oil, wet gas and dry gas, respectively (Glorioso and Rattia 2012, Espitalie *et al.* 1977). Since oil is rich in hydrogen, more oil is generated in hydrogen rich kerogen. Following the depletion of hydrogen in kerogen, generation stops regardless of the availability of carbon (Baskin 1997).

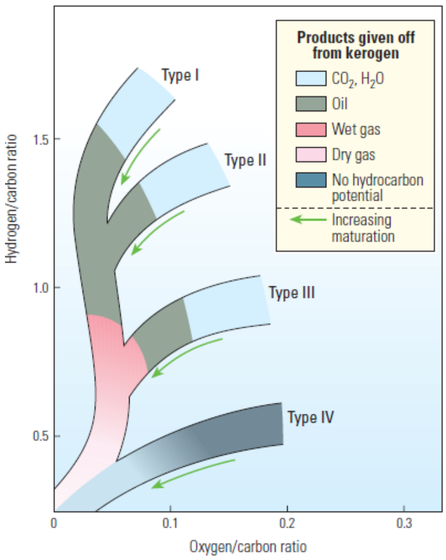


Figure 4 – Modified version of Van Krevelen Diagram showing the evolution of kerogen types by increasing heat and burial, i.e. maturation (after Boyer *et al.* 2006)

Although, as presented in Table 2, TOC percentage determines the kerogen quality of source rocks, some authors argue that too much kerogen may fill the pore spaces that would otherwise be occupied by hydrocarbons.

Table 1 – Kerogen types and generated hydrocarbon products after maturation (after Glorioso and Rattia 2012, Van Gijtenbeek 2012)

Kerogen Type	Depositional Environment	Constituents	Hydrocarbon Product	
I	Lacustrine	Algae and amorphous organic matter	Very H/C rich	Oil
II	Marine, Reducing Conditions	Algae and herbaceous matter	H/C rich	Oil & Gas
III	Marine, Oxidizing Conditions	Wood and humic matter	H/C poor	Gas, Coal (CBM)
IV	Marine, Oxidizing Conditions	Decomposed organic matter	Very H/C poor	Inert

As for shale gas to be thermogenically generated, Type III found as the most preferential. However, Type II may also generate shale gas in post maturity stages.

In gas accumulations of biogenic origin, organic matter has not been subjected to enough geothermal gradients to generate hydrocarbons. Instead, there has been enough bacterial action to generate biogenic gas that has been adsorbed by organic matter. TOC levels are helpful to differentiate thermogenic shale from biogenic shale. Due to conversion of kerogen to hydrocarbons in thermogenic shale, TOC levels are relatively low (< 2 wt. %) (Glorioso and Rattia 2012).

Table 2 – Evaluation and classification of source rock potential according to various authors (after Boyer *et al.* 2006, Baskin 1979, Glorioso and Rattia 2012)

Total Organic Content Weight (%)	Boyer *et al*. (2006)	Baskin (1979) Glorioso and Rattia (2012)
< 0.5	Very Poor	Poor
0.5 - 1.0	Poor	Fair
1 - 2	Fair	Good
2 - 4	Good	Very Good
4 - 12	Very Good	Excellent
> 12	Excellent	

Thermal Maturity

Thermal maturity is a measure of the maximum temperature that the kerogen was exposed. The kerogen content gradually lessens during the maturity process. However, as discussed, TOC lessens merely when the hydrocarbons are expelled from the rock (Figure 5). Gas storage capacity increases with the increase in Thermal Maturity. The thermal transformation of kerogen to different hydrocarbon types with increasing depth and temperature is illustrated in Figure 6 (Glorioso and Rattia 2012).

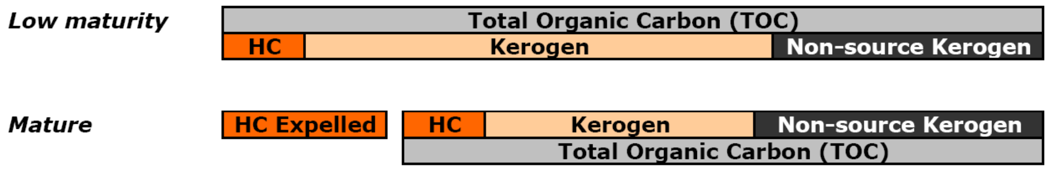


Figure 5 – Reduction in kerogen and TOC due to maturity and expulsion, respectively (after Glorioso and Rattia 2012, adapted from Mr. Daniel Jarvie)

Upon evolution of sedimentary rocks due to increasing burial and temperature, S1 peak (free hydrocarbons present) increases and S2 peak (hydrocarbon generated by cracking) decreases. Consequently, PI (Production Index) value (details given in Figure 3) increases with depth (Espitalie *et al.* 1977). Thermal maturity can be measured by Pyrolysis Method or Vitrinite Reflectance (Ro). Since the former was mentioned in the above, details of Vitrinite Reflectance will be given in this part.

Vitrinite is a shiny substance that constitutes a key component of kerogen, hence generally there is a positive correlation between kerogen density and Vitrinite reflectance (Bratovich 2012). Vitrinite is formed through alteration of lignin and cellulose in plant cell wall and undergoes complex, irreversible aromatization reactions with increasing temperature, consequently its reflectance increases. Reflectance measurements, the percentage of light reflected in oil, are done by special microscopes and equipment. The Ro values corresponding to the generated hydrocarbon types are given in Table 3. It is worth noting that, where HI and OI are utilized to classify the kerogen types, thermal maturity is utilized to indicate the potential of hydrocarbon generation. To illustrate the generation of oil and gas from organic content, Figure 7 will be very helpful (Jarvie *et al.* 2007), which presents the thermal maturation behavior of a Barnett Shale specimen.

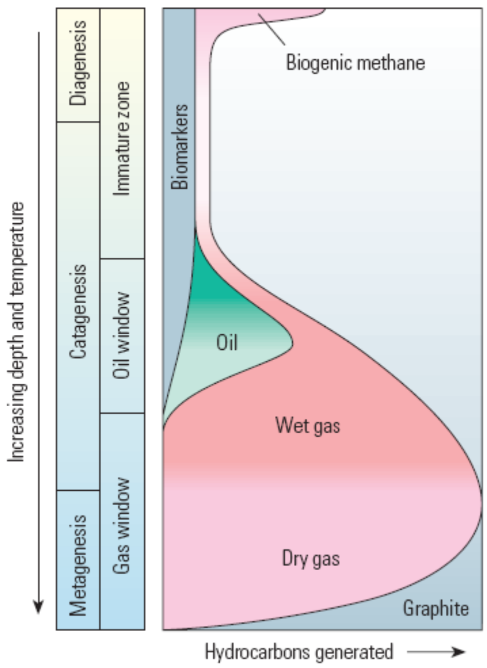


Figure 6 – Thermal transformation of kerogen (after Boyer *et al.* 2006)

Table 3 – Vitrinite reflectance (Ro) and the resulting hydrocarbon type (after Van Gijtenbeek 2012, Boyer *et al.* 2006)

Ro %	Hydrocarbon Type
0 - 0.55	onset of oil generation
0.55 - 0.9	peak oil production
0.9 - 1.1	wet gas
1.1 - 1.4	dry and wet gas
1.4 - 2.1	dry gas only
> 2.1	CO_2

Firstly, a part of the original TOC (TOC_o), which was 6.41 wt.%, is converted to hydrocarbons C_c, where also the other part remains as hydrogen poor component C_R. After thermal maturation, approximately 60% of carbon in generated hydrocarbons is expelled (C_{cex}) and a portion of carbon is not expelled (C_{cnex}), most of which will further cracked to gas and retained in the shale. Additional dead carbon is formed from this secondary cracking of oil (C_{Roc}), yielding a high thermal maturity Carbon (C_R).

As seen in this example only 0.59 wt% carbon is retained in the Barnett Shale as gas where original TOC was 6.41 wt%, however in volumetrics this corresponds to a huge amount (911 × 10^3 ft^3/acre-ft of gas content).

To prevent any possible confusion, it is worthwhile to categorize oil sources in shales according to their extraction methodologies as per below.

Firstly, **Shale Oil** is in-situ produced oil from shale rocks rich in organic matter and not expulsed to the reservoir rock. In other words, it is the remaining portion of the hydrocarbons generated by kerogen in source rocks (Glorioso and Rattia 2012).

Secondly, "**Oil Shales**" are the inorganic, non-porous, kerogen rich shales with insufficient thermal maturity, hence can only yield hydrocarbons with special process techniques and high temperature exposure (i.e. artificial maturation of kerogen). Oil shales can be produced either by mining or by means of in-situ processing. Rich shale may contain up to 40 % of kerogen (which is 1% in oil source rock) and yields 50 gal of oil per ton when heated to 350 - 400 °C. Two third of world's reserves are in USA and the largest resource potential belong to Green River shale deposits in Wyoming, Colorado and Utah. However, Estonia, China and Brazil are the leaders of utilizing oil shales. (Glorioso and Rattia 2012, SPE-PRMS 2007, Radovic 2003, Wikipedia 2015a).

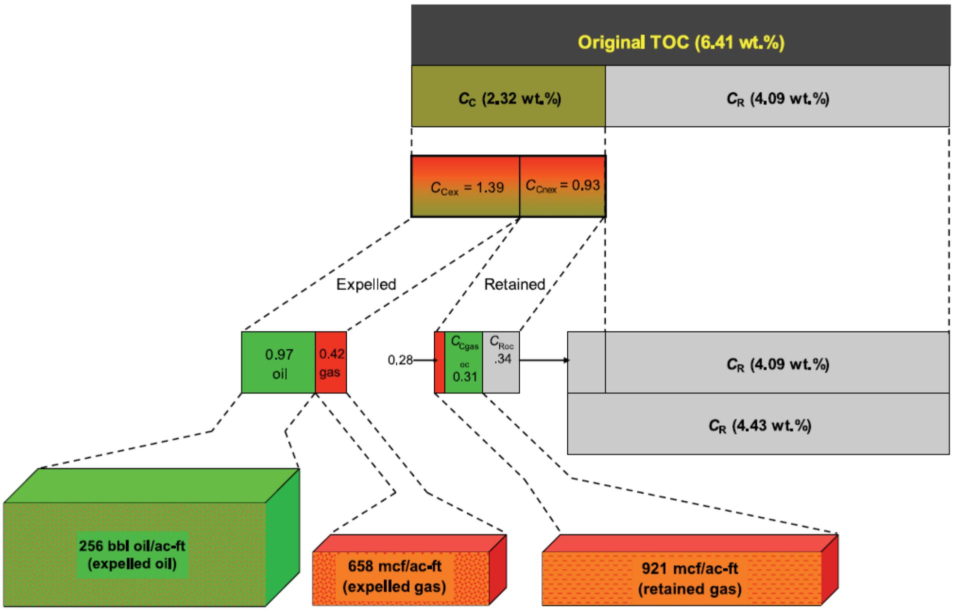


Figure 7 – Illustration of TOC components and values result from thermal maturation of organic matter in Barnett Shale specimen (after Jarvie *et al.* 2007).

Lastly, it is suitable to define the "**Oil Sands**" here as the sand deposits highly saturated with **natural bitumen**, which are also called as "**Tar Sands**" or "**Bituminous Sands**" (SPE-PRMS 2007, Wikipedia 2015b). Basically, oil sands are porous rock layers with a mixture of sand (sometimes carbonate), clay, water and bitumen. Both in-situ recovery and mining methods (for shallow depths of less than 100 m) are utilized to produce this heavy oil with a gravity of less than 10°API (SLB Oilfield Glossary 2015b). Tar sands contain 10-15% bitumen and by heating above 500 °C, 70% of the bitumen is converted to a **synthetic crude oil**. Venezuela and Canada are the leaders for oil sand resources and the largest oil sands deposit is the Athabasca oil sands in the McMurray Formation, Fort McMurray, Alberta, Canada and outcrops for 50 km (Wikipedia 2015b).

The main difference between oil shales and tar sands is that the former has never been buried deep enough to convert the kerogen in them into liquid oil, i.e. heat and pressure have not (yet) transformed the kerogen into petroleum. On the other hand, tar sands originate from the biodegradation of oil (Wikipedia 2015b, Radovic 2003).

Complexity

Thickness and extent of the deposit, fracturing/faulting and bedding layer complexity all contributes to the geologic complexity (Van Gijtenbeek 2012). The complex geologic features usually hinder shale oil and shale gas recovery efficiency. For example, extensive fault systems in a prospective area may limit the productive horizontal length, hence the recovery. Another example is the vertically extensive fault systems crossing organic rich shale formations, which probably bring water into the shale matrix, reduce relative permeability and flow capacity. They may also compartmentalize the reservoir and increase reservoir stresses, which makes fracturing difficult. Lastly, compressional tectonic features like thrust faults and up-thrusted faults show high lateral stress, which in turn result in reduced permeability and flow capacity. Faults also bring significant problems for horizontal wells crossing them, such as wellbore stability and pursuing the reservoir zone (EIA 2013, Haskett and Jenkins 2009). Moreover, geologic complexity brings difficulty in understanding of the shale systems and more importantly the determination of sweet spots (Kennedy *et al.* 2016).

In addition, complex geomechanical properties along the vertical direction may hinder the propagation of induced fractures in the vertical axis due to varying rock strength, hence may prevent adequate fracturing and propping of the full net interval. Moreover, understanding of the lateral heterogeneity in rock mechanics and in reservoir quality is essential to put fracturing stages in the right places and optimize the fracturing design along the lateral.

Since it is one of the strongest parameters determining the producibility of shale prospects, it is thought to be suitable to categorize and discuss formation **depth** under complexity title. As a consensus favorable depth for shale formations range from 3,300 ft to 16,500 ft (EIA 2013, Ashayeri and Ershaghi 2015). EIA (2013) reports that prospects deeper than 16,500 ft brings reduced permeability and higher drilling and development costs. Moreover, Ashayeri and Ershaghi (2015) warn that even depths below 10,000 ft may bring technical and financial challenges. On the other hand, prospects shallower than 3300 ft have low reservoir pressure hence lower driving forces for oil and gas recovery, together with high water content risk in the natural fracture system.

Stimulation Potential

The typical characteristics of productive shales are summarized below and illustrated in Figure 8 (Van Gijtenbeek 2012):

- Thickness (h_{net} > 100 ft),
- Well Bounded,
- Maturation (Ro = 1.1 to 1.4),
- Good Gas Content (> 100 scf/ton),
- High Total Organic Content (TOC > 3%),
- Low Hydrogen content,
- Moderate Clay content (< 40%),
- Highly brittle shale (Low Poisson's Ratio & High Young's Modulus).

As clearly illustrated in Figure 8, stimulation potential (brittleness) is one of the main parameters determining the producibility of a shale formation. In-situ stress regime together with the rock mineralogy determine the response of the rock to the hydraulic fracturing, i.e. the stimulation potential.

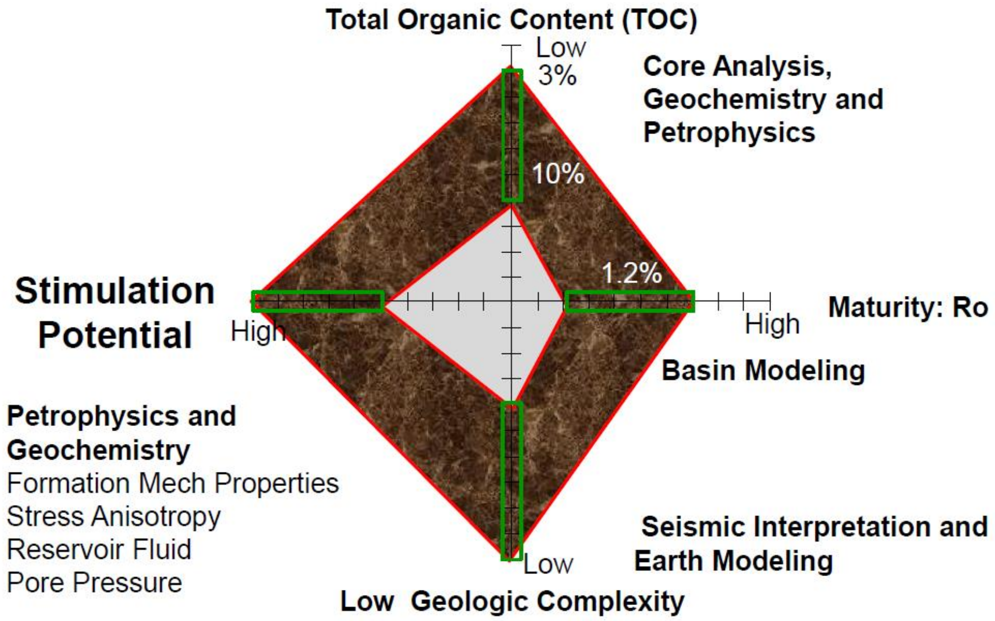


Figure 8 – Parameters determining the productivity of a shale formation (Van Gijtenbeek 2012)

Mineralogy

The mineralogical content of the formation is highly important in evaluation of any formation, and especially important in shale formations in determining their stimulation potential. Identification of quartz, calcite, dolomite, type of clay, heavy minerals like pyrites, and kerogen is the backbone of mineralogical analysis.

The zones in a formation can be classified relying on their compositions as one of the five categories: Sand, Shale, Coal, Carbonate, or Evaporite. Also, these general categories can be branched into sub-categories. To illustrate, carbonates can be classified as calcite or dolomite according to their Ca and Mg ingredients (Pemper *et al.* 2006).

Depositional environment can help in identifying the mineralogy. For instance, marine deposition environments create mineralogy in favor of fracturing, i.e. they have lower clay content and higher brittle minerals like quartz, feldspar and carbonates (Glorioso and Rattia 2012, Ashayeri and Ershaghi 2015, EIA 2013). On the other hand, shales deposited in non-marine environment do not respond well to hydraulic fracturing due to their ductile behaviors resulting mainly from their high clay content (EIA 2013).

Moreover, transgression systems in marine environment have high TOC values, hence show high hydrocarbon potential (Ahmed and Meehan 2016).

The common sedimentary lithologies of the formations can be determined via ternary diagrams of rock chemistry as illustrated in Figure 9. As can be seen, carbonates and siliciclastic sediments are distinguished by the ratio of SiO_2 to CaO. Dolomite is distinguished from limestone by the increase in ratio of MgO instead of CaO. Mg has another importance in identifying various clay types. Clay rich shales lie along the SiO_2 and MgO axes and distinguished from quartz-rich sandstones by the increment in Mg-bearing clay minerals. Moreover, additional general lithologies may be identified using element ratios together with other specific diagrams (Bratovich and Walles 2016, Pemper *et al.* 2006).

High-vertical-resolution well logs and borehole image logs play an important role in characterizing the lithologies in shale formations (Passey *et al.* 2012). Moreover, core and cutting analyses (XRD & XRF) and wireline elemental spectroscopy logging may significantly contribute to the shale formation evaluation (Bratovich and Walles 2016).

Shale reservoirs can be categorized into three types according to their lithologies: siliceous mudrocks, calcareous mudrocks and argillaceous mudrocks, which can be determined using a ternary diagram with the axes of clay, carbonate and quartz & feldspars. It should also be noted that, the mineralogy has a notable effect on mechanical properties of these source rocks such as Young's modulus, Poisson's ratio, unconfined compressive strength and minimum horizontal stress. These mechanical properties play a highly important role in the success of shale formation stimulation (Bratovich and Walles 2016). Figure 10 shows the varying mineral composition for selected shale reservoirs globally.

It is reported that formations with lower clay content and higher quartz or carbonate content show higher hydraulic fracture efficiencies, i.e. higher brittleness index (BI). Although, there is no universal equation for BI, it can be defined as a function of Young's modulus and Poisson's ratio. BI increases with high Young's modulus and low Poisson's ratio (Bratovich 2012).

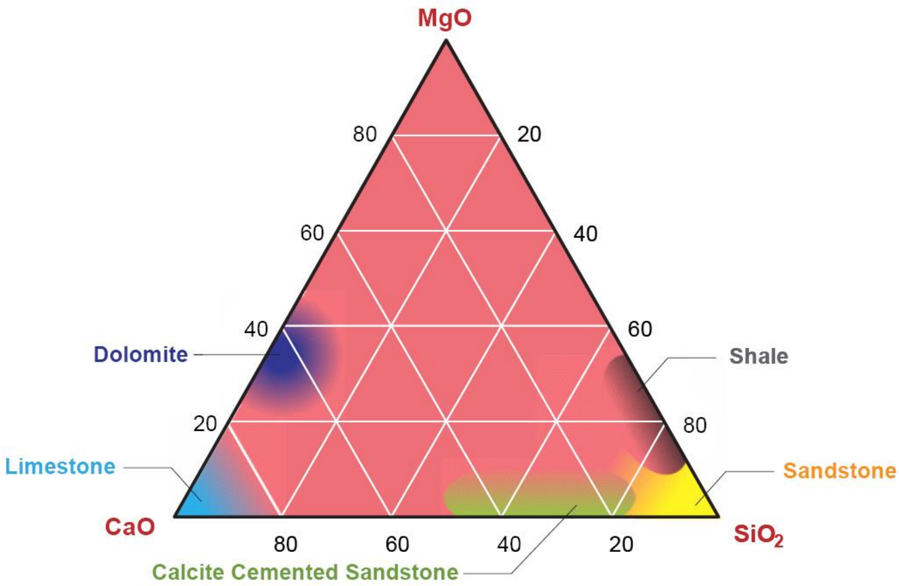


Figure 9 – Ternary diagram to identify lithologies (after Pemper *et al.* 2006)

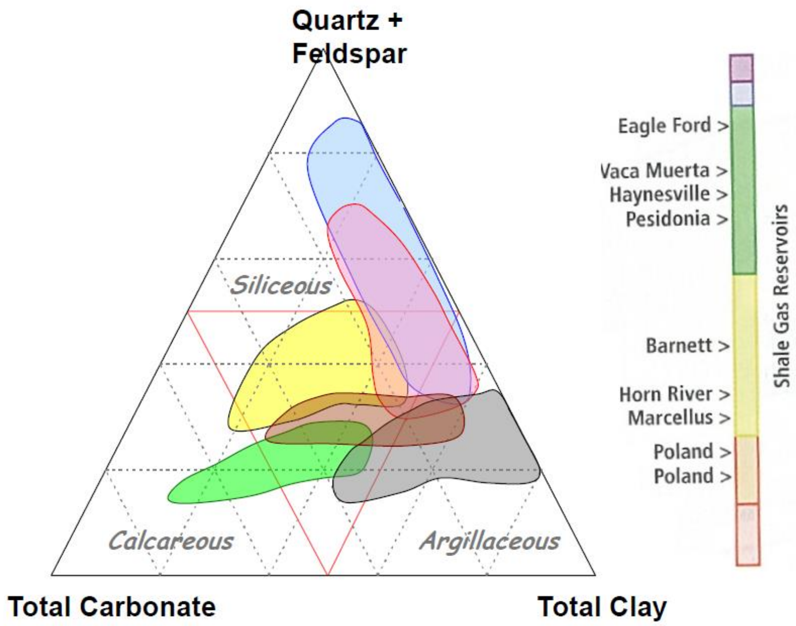


Figure 10 – Varying mineral composition for selected shales (after Bratovich and Walles 2016, modified from Passey et al. 2012).

A brief information on the modulus of elasticity is given below to go further into the brittleness vs. ductility discussion. Together with the basic elastic modulus definition, the two most widely used measurement of it; Young's modulus and Poisson's ratio are presented below.

Elastic Modulus (Modulus of Elasticity) measures an object's tendency to be deformed elastically, i.e. non-permanently, when a force is applied to it. It is defined as the slope of its stress–strain curve in the elastic deformation region. Young’s modulus and Poisson’s ratio are the two most widely used elastic moduli for shale formations, which are fundamentally, stress per strain (Glorioso and Rattia 2012, Wikipedia 2015c). Those two can be calculated from shear and compressional data estimated from dipole-sonic log response (Beard 2011).

$$\lambda = \frac{\sigma}{\varepsilon} \qquad \textbf{(3)}$$

where, λ : elastic modulus (Pa, psi), σ *:* stress (Pa, psi), ε *:* strain (ratio).

Young’s modulus (Tensile modulus) is a measure that characterizes the behavior of an elastic material on the direction in which a force is applied. Fundamentally, it measures the force (per unit area) that is needed to stretch (or compress) a material. (Figure 11a) (Glorioso and Rattia 2012, Wikipedia 2015d).

$$E = \frac{\sigma}{\varepsilon} = \frac{F / A_0}{\Delta L / L_0} \qquad \textbf{(4)}$$

where, E *:* Young’s modulus (Pa, psi), σ *:* tensile stress (Pa, psi), ε *:* extensional strain (ratio), F *:* force exerted on an object under tension (Newton, pounds), A_0 *:* original cross sectional area (m^2, in^2), ΔL *:* length change of the object (m, in), L_0 : original length of the object (m, in).

Poisson’s ratio is a measure for cross-sectional stretching of an isotropic or linear elastic material when it stretches lengthwise and contracts perpendicularly to the stretching (Figure 11b) (Glorioso and Rattia 2012, Wikipedia 2015e).

$$v = \frac{\sigma}{\varepsilon} = -\frac{d\varepsilon_{trans}}{d\varepsilon_{axial}} \qquad \textbf{(5)}$$

where, v : Poisson’s ratio (ratio), ε_{trans} : transverse strain (m), ε_{axial} : axial strain (m).

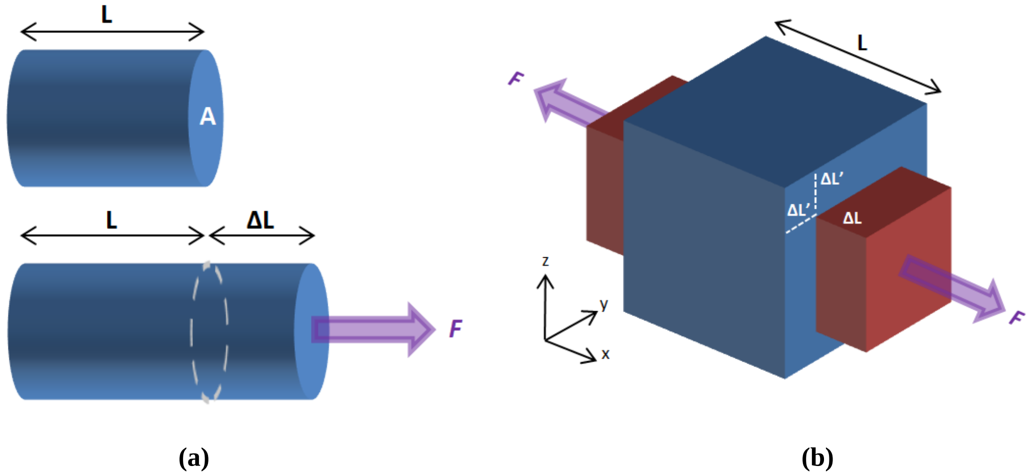


Figure 11 – (a) Young's modulus, stress, strain (b) Poisson's ratio, transverse and axial strains.

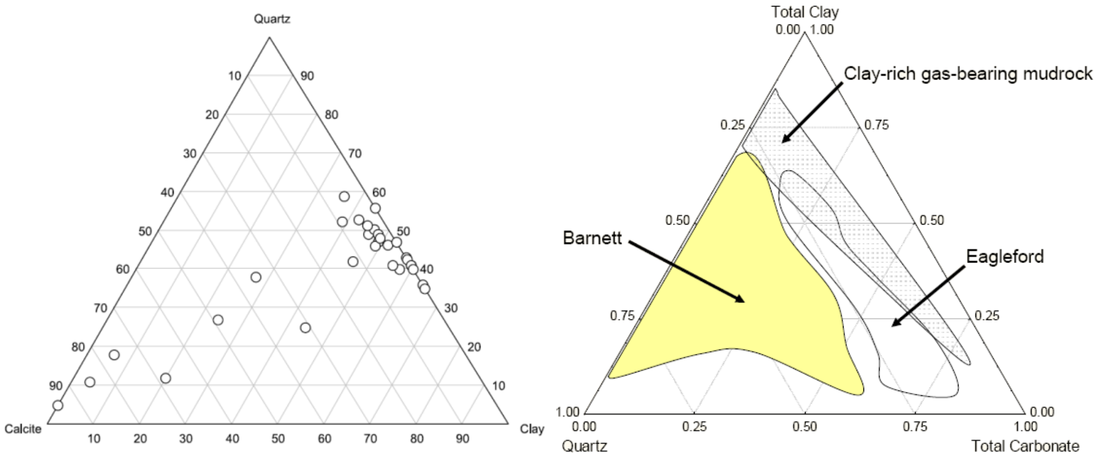
As the carbonate and quartz content of the rock becomes higher, its brittleness become higher, hence the fraccability. On the contrary, clay-rich lithological components result in low brittleness index. (Glorioso and Rattia 2012). Since Poisson's ratio are low (0.10 to 0.30) for most sandstones and carbonates, these rocks fracture relatively easily. On the contrary, shale, very shaly sandstone, and coal, which have high Poisson's ratio (0.35 to 0.45) are more elastic, hence harder to fracture. Shales are often the upper and lower barrier to the height of a fracture in conventional sandstone (CPH 2015a).

The lateral extent of a fracture is primarily determined by Young's modulus. Stiffer rocks, i.e. rocks with low clay, high silica volumes, have higher Young's modulus and are easier to fracture (CPH 2015a, Miller *et al.* 2011). Lastly, essential rock mechanics parameters, Poisson's ratio, dynamic and static Young's modulus and Brittleness Index can be easily derived from the sonic logs (Pitcher 2013).

As a real-life field example, Figure 12a shows the mineralogical distribution for a Barnett Shale specimen. This specimen shows a high amount of quartz, which indicates high brittleness, hence high fracture efficiency (Jarvie *et al.* 2007).

The mineral compositions of various shale plays are given in Figure 12b, which clearly shows that these plays have clay contents below 50%. Moreover, zones with quartz or carbonate content above 50% are more brittle; hence respond to hydraulic fracturing much better (Passey *et al.* 2010).

Since the mineralogical distribution would be highly variable, even within a horizontal well as in Barnett, the brittleness throughout the well will be different. This brings heterogeneous stimulation efficiencies, i.e. some zones will be fractured less efficiently than others will, hence their contribution to production would be much lower (Jarvie *et al.* 2007).



(a) **(b)**

Figure 12 – (a) Mineralogical distribution of quartz, calcite and clay in the Barnett Shale (data taken from Gas Research Institute's Report No. 5086 in Jarvie *et al.* 2007), (b) Mineral composition of different shale plays (Passey *et al.* 2010)

Figure 13 below shows the basic methodology to distinguish brittle and ductile formations by considering their mechanical properties. Since the units of the two axes of the figure is very different, the brittleness caused by each component unitized and then averaged to end up with a brittleness as percentage. While going right in the x-axis, Poisson's ratio "increases" and while going upward in the y-axis Young's modulus "decreases".

The top right portion (green dots) shows increasing ductility and the bottom left portion (red dots) shows increasing brittleness. The green-to-red line in Figure 13 below is only a legend, showing the brittleness in color code.

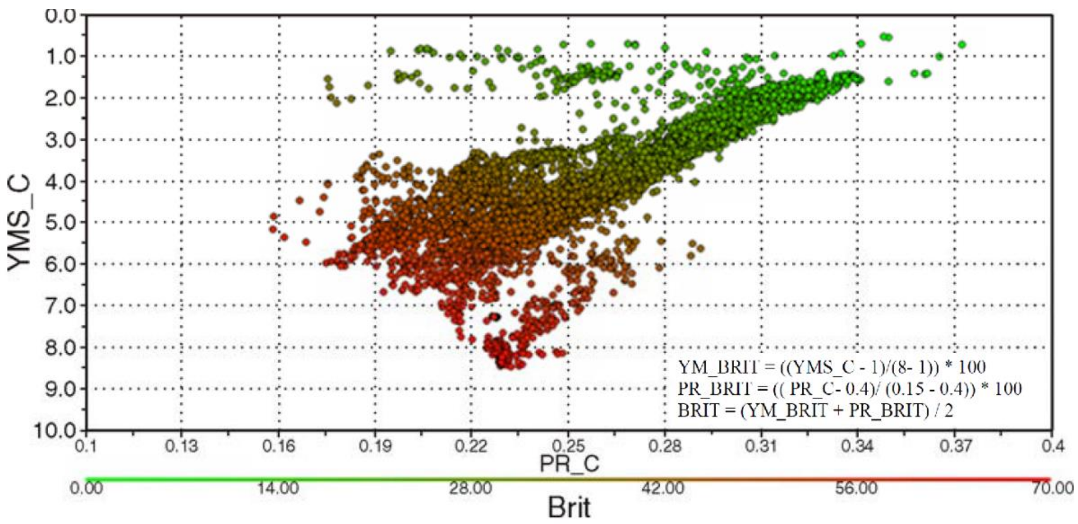


Figure 13 – Brittleness / Ductility evaluation from crossplot of Young's modulus and Poisson's ratio (after Rickman *et al.* 2008)

YMS_C denotes the composite determination of Young's modulus and PR_C denotes the composite determination of Poisson's ratio. The equations at the bottom right of the Figure 13 can be used to determine brittleness coefficient as percentage (Rickman *et al.* 2008).

It should be emphasized that, while brittleness of the rock increases, assuming the stress differences are low, and the complexity of the fracture network increases which brings higher recoveries. On the contrary, ductile formations behave more plastic and absorb more energy. This will in turn bring the requirement of more fracturing pressure, hence more horsepower while fracturing. However, in ductile formations, the fractures tend to be in single bi-wing geometry; hence less complex fracture network develops. As discussed above, briefly, the lower the Poisson's ratio and higher the Young's modulus, the more brittle the rock (Mohamed *et al.* 2016). Rock's ability to fail under stress is determined by Poisson's Ratio and its capability of maintaining the fracture is determined by Young's Modulus (Rickman *et al.* 2008).

Before a stimulation treatment begins, a wide knowledge about the formation properties should be gathered. All shale formations are unique and all need special treatment design. The items to be known prior to a fracturing job can be classified into two main categories as geomechanical and geochemical considerations and detailed in Table 4, together with why the item is important for and how it can be determined.

Table 4 – Necessary information for stimulation treatment (after Rickman *et al.* 2008)

Geomechanical Considerations	Important For	Determined By
How brittle is the shale?	Fluid type selection	Petrophysical model
What is the closure pressure?	Proppant type selection	Petrophysical model
What proppant size and volume?	Avoid screen-outs	Petrophysical model/Experience
Where the frac should be initiated?	Avoid screen-outs	Petrophysical model/Experience
Geochemical Considerations	**Important For**	**Determined By**
What is the mineralogy?	Fluid selection	XRD/LIBS/Petrophysical model
Fluid water sensitivity?	Base fluid salinity	CST/BHN/Immersion Test
Can acid be used if necessary?	Initiation issues, etching	Acid Solubility Test
Does proppant or shale flow back?	Production issues	Historical knowledge
Are surfactants beneficial?	Conductivity endurance	Flow test/Experience

Finally, minimum values of petrophysical parameters of a source rock to be able to viable as a hydrocarbon producing formation are proposed by Boyer *et al.* (2006) as presented in Table 5 below.

Table 5 – Minimum limits of reservoir parameters for a viable shale-gas resource (Boyer *et al.* 2006)

Parameter	Minimum Value
Porosity	>4%
Water saturation	<45%
Oil saturation	<5%
Permeability	>100 nanodarcies
Total organic content	>2%

2.1.2. Worldwide Shale Plays

As of today (October 2017), there is no commercial shale gas and oil production outside of North America. However, taking into consideration the hard work all over the world, this situation may change soon. Explorations are ongoing in South America, Africa, Australia, Europe and Asia (Boyer *et al.* 2011) and many countries are working hard to transfer the shale success in North America (Ashayeri and Ershaghi 2015).

In the USA, where this revolution kicked-off, Barnett, Marcellus, Haynesville, Fayetteville, Woodford are the biggest five shale plays in the US, which estimated to have totally 3,760 Tcf GIIP and 475 Tcf ERR (WEC 2010). Together with the Eagle Ford, all the above shales are called as the Big Six. Moreover, Utica Shale, Wolfcamp Shale, Monterey Shale, Niobrara Shale, Bakken tight oil reservoir can be counted as the preceding plays showing high hydrocarbon potential in the USA (see Figure 14). In the preceding paragraphs, detailed information on the Big Six shales of USA are given (Kennedy *et al.* 2016).

Barnett Shale consists of two sections; the Upper and Lower Barnett, separated by the Forestburg Limestone. The Lower Barnett contributes to 70-80 % of most Barnett wells' production, which is thicker than the Upper Barnett. The Marble Falls overlies the Barnett Shale and acts as the barrier for upward hydraulic fracture growth. The Viola Limestone, which show good reservoir characteristics and the Ellenburger Limestone, which includes some water (hence should be stand apart) are the lower boundaries for Barnett Shale. The lithology of Barnett Shale is siliceous shale with approximately 40% silica, 13% carbonate and 23% clay, which makes Barnett Shale highly brittle, hence responds well to hydraulic fracturing. Average initial productions (IP's) are around 2.5 MMcfd and average EUR's are around 1.6 Bcf/well (Kennedy *et al.* 2016).

Marcellus Shale is the second shale formation came into production (in 2005), which includes also some wet gas areas. A thick layer of siltstones and shales overlies the Marcellus as upper barrier. Formation lithology is siliceous shale with approximately 10-60% silica, 3-50% carbonate and 10-35% clay, which brings brittleness to Marcellus, also. Marcellus wells' initial productions are generally higher than the

Barnett wells' with an average of 3.5 MMcfd and average EUR's are around 4.5 Bcf/well (Kennedy *et al.* 2016).

Fayetteville started production in 2006 and can be called as siliceous shale. 20-60 % of the formations consist of silica, together with smaller amount of carbonate and clay. This lithological structure brings fair brittleness to the Fayetteville formation. The IP's are around 2.8 MMcfd and EUR's are around 2.1 Bcf/well (Kennedy *et al.* 2016).

Woodford Shale is not a basic dry gas resource. This shale formation also contains some liquid hydrocarbons. Its lithology includes 50-65% silica and have a high brittleness. The average values for IP's are 3.6 MMcfd and for the EUR's are 2.1 Bcf. The main distinctness of this formation is its high organic content with a TOC value of up to 9.8%, which makes Woodford a good source rock (Kennedy *et al.* 2016).

Haynesville Shale began its production in 2008 with its significantly high TRR. This shale is relatively deeper and consequently have higher initial pressures. Moreover, this formation has high porosity values. All these superiorities bring this formation the potential of higher IP's (> 14 MMcfd) and higher EUR's (~6.5 Bcf/well), comparing to previous four shale plays. Meanwhile, contrary to common belief about the equivalency of the Haynesville and Bossier Shales, Bossier occurs generally as a separate section above the Haynesville. The lithology of Haynesville is called as siliceous marl and consists of 25-45% silica, 15-40% carbonate and 30-45% clay, which makes Haynesville rather ductile. Hence, the Haynesville do not respond to hydraulic fracturing as much as other shale formations (Kennedy *et al.* 2016).

Eagle Ford Shale is basically the source rock underneath the Austin Chalk and Edwards Formation. Its major lithology consists of 10-25% silica, 60-80% carbonate, and 10-20% clay, which makes this formation brittle; hence respond well to hydraulic fracturing. IP's of Eagle Ford wells range up to 8 MMcfd and most of the wells bring considerable amount of condensate to the surface. Eagle Ford has three hydrocarbon windows extending across a large area. Some Eagle Ford wells are producing oil and the IP's may go up to 2500 BOPD. Both gas and oil wells in Eagle Ford have high EUR values, consequently this play is one of the most active shale play in US with a considerable number of running rigs (Kennedy *et al.* 2016).

As for Canada, the Horn River Basin and Utica Shales are promising with their estimated 1,380 Tcf GIIP and 240 Tcf ERR (Chan *et al.* 2010, WEC 2010). Cordova Embayment, the Laird Basin, the Deep Basin, the Colorado Group, Montney Shale and Duvernay Shale are also showing significant shale gas potential (Boyer *et al.* 2011, Kuuskraa *et al.* 2011).

The Horn River Basin of Canada together with the above mentioned Big Six U.S. shales, constitutes the so-called North American's magnificent seven (Kennedy *et al.* 2016). Figure 14 below presents the largest shale plays of North America.

Figure 14 – North America shale plays (after EIA 2011b)

In Mexico, potential shale plays were used to serve as the source rock for some of Mexico's largest conventional reservoirs. The five basins of high potential are Burgos, Sabinas, Tampico, Tuxpan and Veracruz which totally have an estimated resource of 2,366 Tcf GIIP and 681 Tcf TRR. First two basins are the extension of Eagle Ford Shale in USA which produces both gas and oil, hence show high potential (Boyer *et al.* 2011, Kuuskraa *et al.* 2011).

As for South America, Argentina leads the shale gas potential with 2,732 Tcf GIIP and 774 Tcf TRR. Brazil follows with 906 Tcf GIIP and 226 Tcf TRR. Where Chile, Paraguay and Bolivia have sizeable potentials, Uruguay, Colombia and Venezuela have limited potentials (Boyer *et al.* 2011, Kuuskraa *et al.* 2011).

Europe is also looking for economic shale gas reserves in where the geologic setting is much different comparing to the North America. Shale formations are much deeper (1,5 times deeper), more complex and they cover much smaller areas than the big fields in the US. In addition to geological difference, economical aspects bring another major difficulty to development of European shale formations. For instance, the well costs are estimated to be twice of the well costs in US. Moreover, due to strict safety and environmental regulations, intensive hence costlier precautions should be taken (Hausberger, Högn and Soliman 2012, Geny 2011). Although the continent has substantial amount of estimated resources, most countries have bans or imposed moratoriums on hydraulic fracturing (see Figure 15) together with discouraging regulations and tax regimes (Bauerova 2015).

Hereby, The European Commission (2014) published a "recommendations" document (2014/70/EU) for the member states to specify the minimum principles for the exploration and production of hydrocarbons using high-volume hydraulic fracturing. Its basic aim is to safeguard public health, climate and environment while ensuring efficient use of resources and alleviate public concerns and possible oppositions.

Moreover, to build a synergy, consequently cost efficiency, there should be enough number of activities, which will in turn bring equipment and workforce to the continent. However, such a revolution seems not possible soon (Bauerova 2015).

On the other hand, to reach less carbon emission goals, reduce energy import costs and provide the energy security, Europe must keep going on exploring shale gas resources, where it is a little early to obtain these aspects with renewables (Kosc 2014).

Considering the potential of shale resources only, self-sufficiency is not a possible issue for Europe; however, any molecule of shale hydrocarbon production will certainly reduce energy dependency of the continent (Cremonese *et al.* 2015). The possible future steps in shale exploitation for Europe will be discussed in Section 2.1.5.

Poland is the most active explorer country in Europe due to her appearance of leading potential. Baltic, Lublin and Podlasie basin constitutes the most promising shales in Poland. The initial estimates of total resource potential for all three basins are 792 Tcf GIIP and 187 Tcf (5.3 Tcm) TRR according to EIA (2011d) (Boyer *et al.* 2011, Kuuskraa *et al.* 2011). However, after less than a year, Polish Geological Institute (2012) estimates the TRR of shale gas in Poland as 346 - 768 Bcm, which corresponds to one-tenth of the EIA estimates (Marocchi and Fedirko 2013, Buckley 2015). Considering the high coal proportion in her primary energy supply and her strong dependency on gas imports (mainly from Russia), shale resources are highly promising for Poland (Weijermars 2013a, Stephenson 2016). As of the date of this study, Polish exploration only ended up with a series of failed attempts, which cause investors to leave the country without any returning signals despite the government's enormous support (Kosc and Snyder 2013). More than 70 wells were tested and a total investment reached 2 Billion USD (Buckley 2015). Only a few wells proved economic production considering the high well costs. The main problems encountered are the low flow rates and high lateral variety of reservoir quality and productivity. However, to obtain a wide understanding of Poland potential, approximately another 1 billion USD should be invested, hence the role of regulatory and fiscal regime becomes more important (Poprowa 2013).

France follows with her 720 Tcf GIIP and 180 Tcf TRR in the Paris basin and Southeast basin (EIA 2011d). In Paris basin, explorations are especially directed at shale oil. However, there is a government ban acted in June 2011 on hydraulic fracturing, which is the key for shale gas and oil production (Boyer *et al.* 2011, Kuuskraa *et al.* 2011). Weijermanrs (2013) argues that nuclear power lobby may be the driving force behind local opposition towards the shale resources, which are strong alternatives of nuclear power.

In the North Sea-German basin, which extends along the North Sea from Belgium and across Netherlands to Germany's eastern border, there exist formations with shale gas potential. The formations with potential are the Posidonia with 26 Tcf GIIP and 7 Tcf TRR, the Wealden with 9 Tcf GIIP and 2 Tcf TRR and the Carboniferous Namurian Shales with 64 Tcf GIIP and 16 Tcf TRR (Boyer *et al.* 2011, Kuuskraa *et al.* 2011).

Alum Shale extending along Norway, Sweden and Denmark show a resource potential of 589 Tcf GIIP and 147 Tcf TRR (Boyer *et al.* 2011, Kuuskraa *et al.* 2011). Due to conventional resource abundance in continental shelf of Norway, the development of shale resources in this region, which need higher development costs, may be slower (Weijermanrs 2013).

The Pannonian-Transylvanian basin extending along Hungary, Romania and Slovakia is believed to be the source of many conventional reservoirs in Hungary. However, the early stages of exploration was discouraging (Boyer *et al.* 2011, Kuuskraa *et al.* 2011).

Ukraine is another country in Europe pressing ahead with its large gas potential, which may be enough to make her a self-sufficient country for gas (Kosc and Snyder 2013, Stephenson 2016). The resource estimates are naturally uncertain however, reported values are 42 Tcf TRR (EIA 2011d) and 247 Tcf GIIP (Marocchi and Fedirko 2013).

Russia, the home for huge conventional natural gas resources, naturally show good potential for shale hydrocarbons. Bazhenov Shale, which is highly organic and siliceous and the source rock for the conventional gas and oil produced from West Siberian basin, naturally become the most prominent candidate for shale hydrocarbon production. Bazhenov Shale’s potential is estimated as 1,243 Billion bbl of oil as STOIIP, which corresponds to 74,6 Billion bbl of oil as TRR. Moreover, Bazhenov Shale is estimated to have 920 Tcf of gas as GIIP, which corresponds to 285 Tcf of gas as TRR (EIA 2013, Kennedy *et al.* 2016).

As for UK and Ireland, the Carboniferous northern petroleum system and Mesozoic southern petroleum system contain several basins. After lifting of government action in December 2012, which restricts shale exploration since May 2011, activities gained pace in both systems despite the anti-fracking protests (Boyer *et al.* 2011, Kuuskraa *et al.* 2011). Due to production declines in North Sea, the import dependency of UK is increasing and hence energy security is becoming a main issue (Stephenson 2016). However, the economics of shale resource production is still a problem together with public pressure. Bloomberg New Energy Finance reported the production cost of UK gas would be as twice of US gas (Kosc and Snyder 2013, Reuters 2012).

In addition to numerous shale deposits across Europe, lastly Mikulov Shale in Austria worth mentioning here as a potential shale gas resource (WEC 2010).

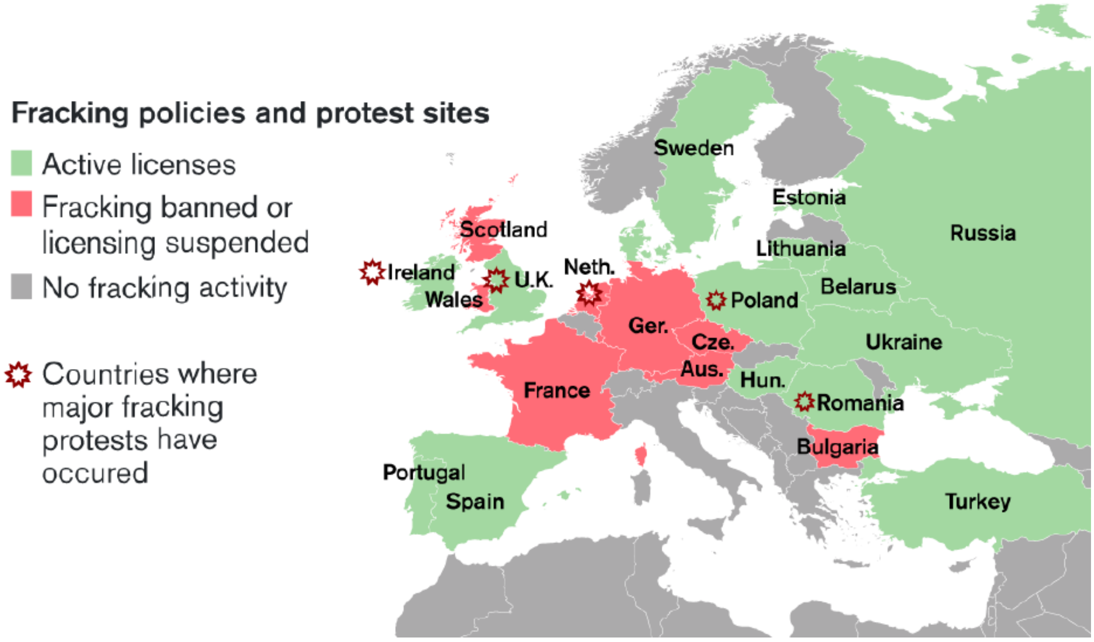


Figure 15 – Active licenses and fracking bans throughout Europe (after Gilblom and Patel 2014)

In Africa, there supposed to be numerous shale basins with hydrocarbon potential. However, in North Africa (Algeria, Tunisia and Libya), where considerable amount of conventional hydrocarbon reserves exist, shale oil and shale gas exploration have little importance and economic consideration. Unlike the above three countries, Morocco has little conventional reserves hence exploration activities in shale deposits are ongoing namely in the Tindouf basin and Tadla basin with a total estimated resource of 266 Tcf GIIP and 53 Tcf TRR. As for South Africa, the Karoo basin containing Ecca Shale Group has a significant volume of 1,834 Tcf GIIP and 486 Tcf of TRR. In short, much of the Africa remains unexplored (Boyer *et al.* 2011, Kuuskraa *et al.* 2011).

India and Pakistan also have organic-rich shales with total resource potential of 496 Tcf and 114 Tcf of TRR, respectively. However, due to tectonic activities, these basins are geologically complex. Where, the Cambay basin, the Krishna-Godawari basin, the Cauvery basin and the Damodar Valley basin are promising for India, Southern Indus basin is promising for Pakistan (Boyer *et al.* 2011).

China, not surprisingly, has an estimated resource potential comparable to that of North America with 5,101 Tcf GIIP and 1,275 Tcf TRR. The two considerable basins, the Sichuan basin and the Tarim basin have thick, organic-rich shale deposits with large areal extensions and good reservoir characteristics. Sichuan basin take great interest due to gas production in tests of exploration wells. Moreover, its low clay content makes them easy to stimulate. However, its high structural complexity with extensive folding and faulting brings risk for future development. As for Tarim basin, which served as the source rock for conventional carbonate reservoirs of the region, promise great potential. However, due to arid conditions being beneath the Taklimakan Desert, sourcing water for fracturing will be difficult (Boyer *et al.* 2011, Reuters 2010).

Australia has been producing her tight gas and CBM resources for a long time, which has highly similar development procedures (equipment, techniques, etc) with shale resources and hence, she possesses the experience for shale development. Canning, Cooper, Perth and Maryborough basins are estimated to hold 1,381 Tcf GIIP and 396 Tcf TRR. Beetaloo basin and Georgina basins are also promising (Boyer *et al.* 2011, Kennedy *et al.* 2016).

Figure 16 and Table 6 below are excerpted from EIA (2013) and presents the worldwide shale gas and shale oil basins and the TRR volumes, respectively. Unfortunately, due to lack of exploration or published data outside North America, evaluation of these resources contain very high uncertainties (Boyer *et al.* 2011).

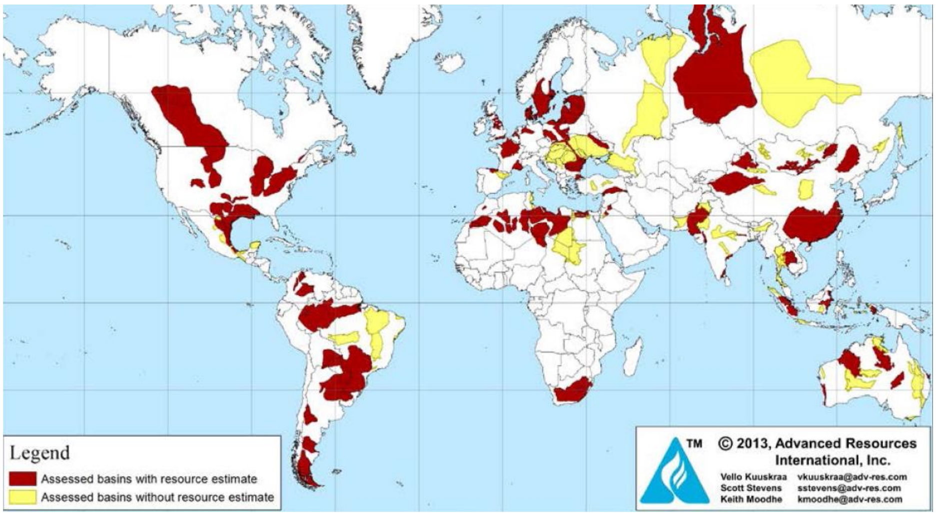


Figure 16 – Global assessed shale gas and shale oil basins (after EIA 2013)

Table 6 – Assessed world shale gas and shale oil resources (after EIA 2013)

	Technically Recoverable Shale Gas Resources (Tcf)		Technically Recoverable Shale Oil Resources (Billion Barrels)	
1	U.S.	1161	Russia	75
2	China	1115	U.S.	48
3	Argentina	802	China	32
4	Algeria	707	Argentina	27
5	Canada	573	Libya	26
6	Mexico	545	Australia	18
7	Australia	437	Venezuela	13
8	South Africa	390	Mexico	13
9	Russia	285	Pakistan	9
10	Brazil	245	Canada	9
11	Others	1535	Others	65
	Total	**7795**	**Total**	**335**

Last but not the least, contrary to all these countries investing in unconventional resource exploration, OPEC (Organization of Petroleum Exporting Countries) members, home of giant conventional hydrocarbon reservoirs, have not turn their attention to unconventional resources yet. Although there is little information and data about unconventional resources of this region, theory suggests the existence of huge shale resources due to the natural proximity of source rock resources to conventional reservoirs (Ashayeri and Ershaghi 2015). As stated in their website (OPEC 2016), the main objective of OPEC is "to co-ordinate and unify petroleum policies among Member Countries in order to secure fair and stable prices for petroleum producers; an efficient, economic and regular supply of petroleum to consuming nations; and a fair return on capital to those investing in the industry". Hence, OPEC must keep the oil prices at an optimum level to prevent rapid exhaustion of these non-renewable resources, provide a stable revenue to net exporters whose economics are mostly rely on oil exports, while keeping an economic and regular supply to importing countries (Ashayeri and Ershaghi 2015). Considering the 7-fold increment in oil consumption of OPEC countries in the last four decades (Gately *et al.* 2013), investment in technology and mostly in shale resources is compulsory for OPEC countries soon.

Hereby, it would be beneficial to briefly mention about the global market share war, which will clearly illustrate the effect of shale oil and shale gas on the global oil and gas prices and the market share. After October 2014, the peak date of shale oil boom, global output was hovering higher than the global supply; hence, this oversupply caused a market share competition between producers, and especially between conventional and unconventional producers. Consequently, oil and gas prices lowered and started to cruise at low levels, around $40/bbl, for the specified period of time. At first OPEC did not want to cut their supply in order not to lose their market share. According to The Economist (2014), Saudis wanted to push high-cost producers, especially shale oil and shale gas producers in USA, out of the business. This would in turn supposed to reduce the global supply and cause prices to increase again. Moreover, due to sharp production decline nature of shale formations, any reduction in investments will directly lead to production collapse. As it was expected, many shale oil and gas companies filed bankruptcy; however, Saudi Arabia also could not afford to keep market prices at such low levels for a long term due to high negative impact on her budget. In addition to these, other OPEC members, whose income mostly consist of oil exports, were in a similar situation. At last, OPEC had to decide reducing the output by January 1, 2017 and afterwards market prices started to rise above $50/bbl. This increment in market prices in turn encouraged shale oil producers, who improved production efficiency and reduced breakeven prices, increase their activities and ramp up their production (Hussein 2016).

As a consequence, the balance between prices and the activities, hence hydrocarbon output has been provided. For a relatively remarkable time, oil price has been hovering around $50/bbl (at least at the time of writing this dissertation, i.e. 3rd quarter of 2017).

2.1.3. Factors Preventing Replication of Shale Success of North America

The nullity of shale formation production out of North America is most probably related to the unfavorable economic conditions rather than the absence of productive shale basin. Although European shales are much deeper and have more complex geologic character, these phenomena do not make these shales non-productive, they only bring higher costs. In addition to economics, which is the main differentiating factor of North American success from rest of the globe, the remaining favorable factors of North America are listed below by combining the thoughts of Giles *et al.* (2012) and Kefferpütz (2010):

1) *Landowners' share in minerals rights in USA, contrary to the most of the globe*
   Outside of the US; residents experience the troubles, but do not get much benefits. Hence, public support on shale resource development is hindered.
2) *Low drilling and completion costs in North America*
   The most costly part, drilling and completion is 3 times higher in Europe. Moreover, especially labor costs is much higher in Europe.
3) *Availability of equipment and the supporting supply chain*
   Where US has more than 2000 drilling rigs, Europe has only around 50. Hydraulic fracturing fleet shortage is more severe than drilling rigs.
4) *Knowledge and experience built in North America*
   Most of the globe lacks reliable geologic data and have very little shale experience.
5) *New opportunity de-risking is carried by multiple small independent companies*
   They learn, innovate and share successful practices. Moreover, small companies are fast in decision-making and they are more risk-tolerant.
6) *Population density, competition for water resources, emerging public concern*
   These are powerful barriers for the rest of the globe especially in Europe. It can also be argued that environmental awareness is higher in Europe than in the US. Moreover, Europe is 3-times more densely populated than the US (Gilblom and Patel 2014).

The 2nd and 3rd items are directly related to the highly-competitive, well developed, high-tech oilfield service sector in the USA (Cui *et al.* 2014). A large work commitment in Europe may help to relocate suitable equipment and skilled labor force to the continent (Ernst & Young 2013).

As for the 5th item, Meisenhelder (2013) states that there is not much place having tolerance for failure outside the US. There would be very few national or international operators willing to drill hundreds of expensive wells before achieving economic production.

In North America, generally third-party companies invest for the infrastructure, contrary to the rest of the globe. Since, infrastructure burden for global unconventional resource development means much larger materiality requirement, this issue become another significant reason lies behind North American success (Giles *et al.* 2012).

For the 6th item, environmental concerns, Heinz (2013) argues that most of these concerns are caused by misperceptions. For example, chemicals, groundwater pollution, seismic activation or uncontrolled methane release to the surface are only perceived risks, i.e. there is not any physical support for these phenomena to be happen in Europe, where the real risks are transportation (traffic risks), water management or land usage risks, for which the impact minimization cautions should be taken carefully.

As a complement to 6th item, the population density near shale prospects is not entirely a coincidence since the shale layers are related to the coal measures as in Bowland-Hodder Shale. Since coal fueled the whole 19th century and the industrial revolution, proximity to coal deposits encouraged the human settlement (Stephenson 2016).

Lastly, it is worth mentioning that mainly shale oil and shale gas production is most attractive for two types of countries. The first type are those highly dependent on hydrocarbon imports and have a rich hydrocarbon infrastructure (e.g. France, Poland, Turkey, Ukraine, South Africa, Morocco and Chile). The second type are those having large shale oil and shale gas reserves together with infrastructure (e.g. Canada, Mexico, China, Australia, Libya, Algeria, Argentina and Brazil) (EIA 2011d).

2.1.4. Turkey's Shale Oil and Shale Gas Potential

Lease acquisition is highly different in Turkey than it is in North America. Turkish government owns all the minerals, hence to pick up a block, a company has to either farm in to another company's block or make an acquisition. Access to rig, land, and water resources is another challenge in Turkey. On the other hand, Turkey's vast usage of natural gas brings high quality and broad range of infrastructure, hence easiness of transportation issues (Taylor 2010).

According to an article investigating unconventional resources in Turkey by Taylor (2010), TransAtlantic Petroleum Ltd. expresses their intention of applying North American shale know-how to Turkey's unconventional resources. TransAtlantic's CEO Mr. Matthew McCann evaluates Turkey as one of the best reserve yield per dollar invested as for unconventional resources (Taylor 2010). He summarizes their plan as utilization of the company's success proved strategy of vertical integration and the western technology in Turkey. TransAtlantic's target is not only the shale oil and gas. They also focus on improvement of recovery factors in conventional reserves in countries having stable fiscal regimes and net importers of hydrocarbons. This also makes Turkey as one of the promising countries for an oil and gas company.

Moreover, a vertically integrated company has the advantage of utilizing their own equipment in drilling and stimulation operations, which brings pace and cost reduction (Taylor 2010).

According to reports of EIA (2013) the Dadas Shale in Southeastern Anatolia Basin and the Hamitabat Shale in Thrace Basin are the two most promising areas for shale resources. Moreover, Sivas and Salt Lake Basins are the preceding ones, which lack much exploration data. The Hamitabat and the Dadas Formations are estimated to have a total of 24 Tcf of gas and 4.7 Billion bbl of oil as TRR. Details for the potential and reservoir parameters of both basins specifically for shale gas and shale oil are given in Table 7 and Table 8, respectively. Lastly, the geographical location map for the prospective basins of Turkey is given in Figure 17.

Table 7 – Shale gas reservoir properties and resources of Turkey (after EIA 2013)

Basic Data	Basin/Gross Area		SE Anatolian (32,100 mi^2)		Thrace (6,500 mi^2)		
	Shale Formation		Dadas		Hamitabat		
	Geologic Age		Silurian-Devonian		M. - L. Eocene		
	Depositional Environment		Marine		Marine		
Physical Extent	Prospective Area (mi^2)		3,540	500	150	210	680
	Thickness (ft)	Organically Rich	394	377	500	500	500
		Net	216	207	250	250	250
	Depth (ft)	Interval	6,000 - 11,500	5,500 - 13,000	10,000 - 13,000	13,000 - 16,400	14,000 - 16,400
		Average	9,000	9,500	11,500	14,500	15,000
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.
	Average TOC (wt. %)		3.6%	3.6%	2.0%	2.0%	2.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%	1.15%	2.00%
	Clay Content		Med./High	Med./High	Medium	Medium	Medium
Resource	Gas Phase		Assoc. Gas	Wet Gas	Assoc. Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		48.2	91.4	34.7	81.8	104.1
	Risked GIP (Tcf)		102.4	27.4	1.9	6.2	25.5
	Risked Recoverable (Tcf)		10.2	6.9	0.1	1.2	5.1

Table 8 – Shale oil reservoir properties and resources of Turkey (after EIA 2013)

Basic Data	Basin/Gross Area		SE Anatolian (32,100 mi^2)		Thrace (6,500 mi^2)	
	Shale Formation		Dadas		Hamitabat	
	Geologic Age		Silurian-Devonian		M. - L. Eocene	
	Depositional Environment		Marine		Marine	
Physical Extent	Prospective Area (mi^2)		3,540	500	150	210
	Thickness (ft)	Organically Rich	394	377	500	500
		Net	216	207	250	250
	Depth (ft)	Interval	6,000 - 11,500	5,500 - 13,000	10,000 - 13,000	13,000 - 16,400
		Average	9,000	9,500	11,500	14,500
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.
	Average TOC (wt. %)		3.6%	3.6%	2.0%	2.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%	1.15%
	Clay Content		Med./High	Med./High	Medium	Medium
Resource	Oil Phase		Oil	Condensate	Oil	Condensate
	OIP Concentration (MMbbl/mi^2)		41.0	14.2	33.8	8.0
	Risked OIP (B bbl)		87.1	4.2	1.8	0.6
	Risked Recoverable (B bbl)		4.36	0.21	0.07	0.02

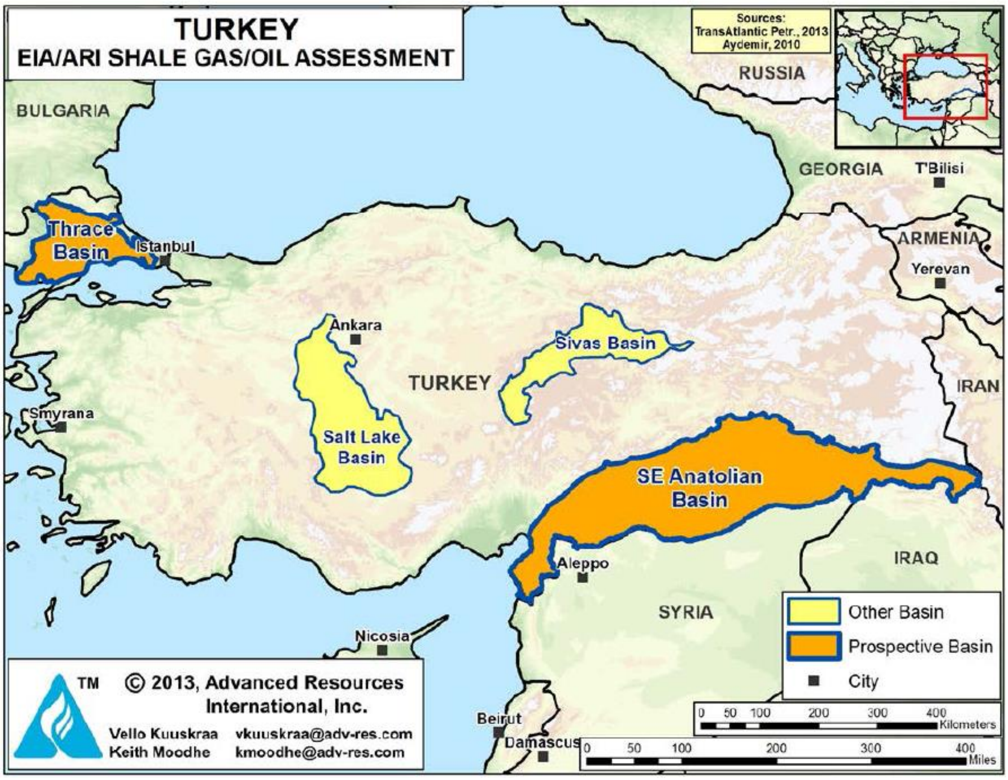


Figure 17 – Major shale basins of Turkey (after EIA 2013, prepared by ARI)

Hereby, it is suitable to mention about Topçu (2013)'s study in one paragraph, which probabilistically evaluated the Dadas Shale in Southeast Anatolian Basin of Turkey as can be seen in Figure 17. He reached GIIP estimate of 88.6 Tcf as P50 value, which corresponds to 13.3 Tcf of TRR according to his assumption of 15% recovery factor. He proposes to drill 5,189 wells throughout the Dadas Shale, which extends through approximately 1,264,000 acres. Although, his GIIP estimate is consistent with EIA (2013) estimates (Table 8), the assumption of 15% recovery factor is unrealistically high for shale oil resources. EIA (2013) quotes extreme values for recovery factors of shale oil resources as 1-10% relying on their US experience.

2.1.5. What is Next for Europe and Turkey?

Europe, including Turkey is a very large integrated hydrocarbon market with rising demand and having an established vast infrastructure. The replication of US shale revolution in Europe is desired by both the European countries to decline their energy import dependency and large oil companies, which were surpassed by small companies in US shale market. However, the economic factors together with demographic, political, regulatory and environmental factors inhibit Europe's unconventional adventure (Kefferpütz 2010).

At this point, it would be beneficial to elaborate on economic factors a little bit more. Basically, there is not much tolerance to failure in Europe, i.e. no one will be willing to drill 100+ wells without any economic hydrocarbon. Hence, a more scientific approach together with a sophisticated project management should be utilized in Europe. Meisenhelder (2013) proposes a new approach in the name of Shale 2.0, an *effective reservoir centric* strategy integrating geological, geophysical, petrophysical and geomechanical data together with simulation models would provide deeper understanding of variations in reservoir and completion quality in a proposed lateral or throughout the play. Hence, learning curve could be built much earlier, even though every shale play is structurally, compositionally and geomechanically unique. To illustrate, engineers may analyze and optimize any proposed lateral or they may group perforation clusters into stages that would be fractured similarly, hence efficiently. Consequently, all these would result in an increase in production. Moreover, with the increased effectiveness far more production would be obtained in less time and from fewer wells. The resulting increments in EUR and Internal Rate of Return (IRR) from the proposed engineered approach may change the economic conditions and help unlock the Europe's and Turkey's shale oil and shale gas resources.

In addition to these, relying on the US experience, European countries should propose incentives for investors since shale exploration needs high up-front capital investments and investors need to mitigate their risks. Tax regimes revised for shale oil and shale gas production may be the first step for encouraging investors (Kus and Kilian 2013).

2.2. Shale Formation Characteristics

2.2.1. Heterogeneity in Shale Formations

Shale formations are highly heterogeneous and well productivity strictly depends on reservoir properties together with completion and stimulation efficiency. To reduce the uncertainty in petrophysical interpretations, which in turn used in formation evaluation, sample density must be kept as high as possible (Glorioso and Rattia 2012). It also worth mentioning that, as discussed above the shale formations show great heterogeneity on a local scale, whereas a significant homogeneity lies in group of wells in segments of a play (Chan *et al.* 2010).

Formation characterization is necessary to evaluate the production performance of shale plays. Matrix quality, natural fractures, net gas porosity are the most important controlling factors of production performance (Ramakrishnan *et al.* 2011). Moreover, the fracture flow capability can be increased by stimulation since existing natural fractures are activated and consequently contact area increases (Zhang *et al.* 2009).

Figure 18 presents the sensitivity study results of Zhang *et al.* (2009) which shows the impact of the reservoir parameters on the production performance. The hydraulic fracture parameters such as spacing (300 ft), conductivity (5 md-ft), height (200 ft) and half-length (300 ft) were assumed as fixed. As presented, most influential reservoir parameters on cumulative production are the stimulated fracture network permeability and matrix-fracture sigma factor (the connection factor between rock matrix and fractures).

Figure 18 (a) shows the sensitivity on stimulated fracture network permeability ranging from 0.0001 and 0.001 mD. Figure 18 (b) shows the sensitivity on matrix-fracture sigma factor ranging from 12 to 1.2×10^{-5}. As for the porosity, variations were taken to be 0.2% – 0.8%. Lastly, Figure 18 (c) shows the influence of all reservoir parameters on cumulative production, comparatively (Zhang *et al.* 2009).

Moreover, the impact of stimulated fracture network permeability on the drainage area can be seen in Figure 19. As the stimulated fracture network permeability increases, the drainage area becomes larger around the well (Zhang *et al.* 2009).

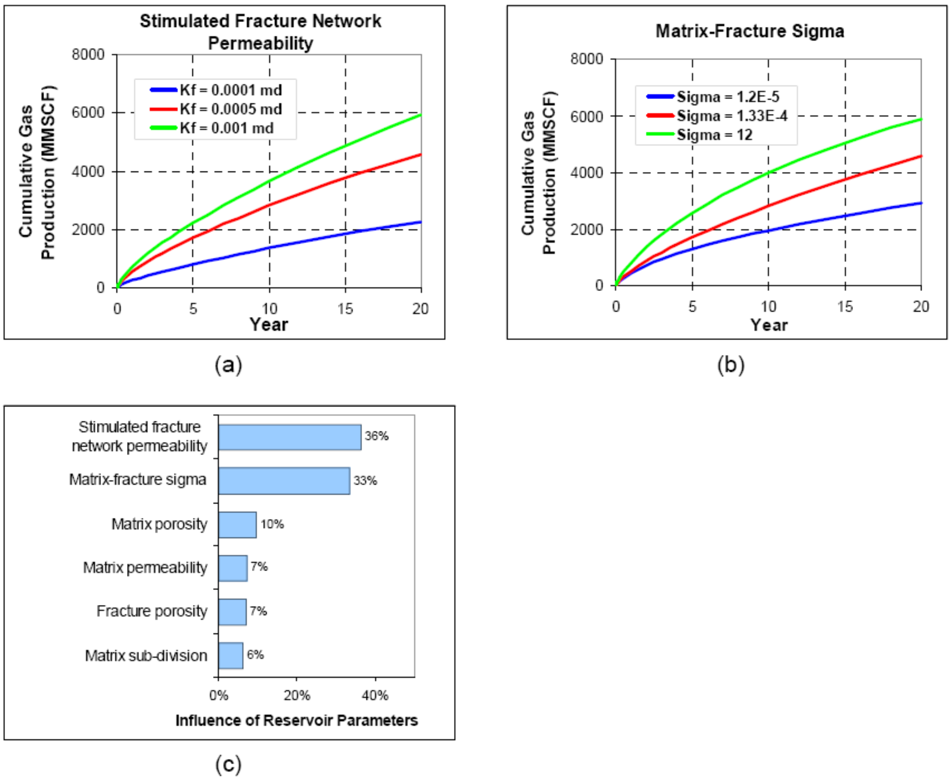


Figure 18 – Impact of reservoir parameters on cumulative gas production (after Zhang et al. 2009)

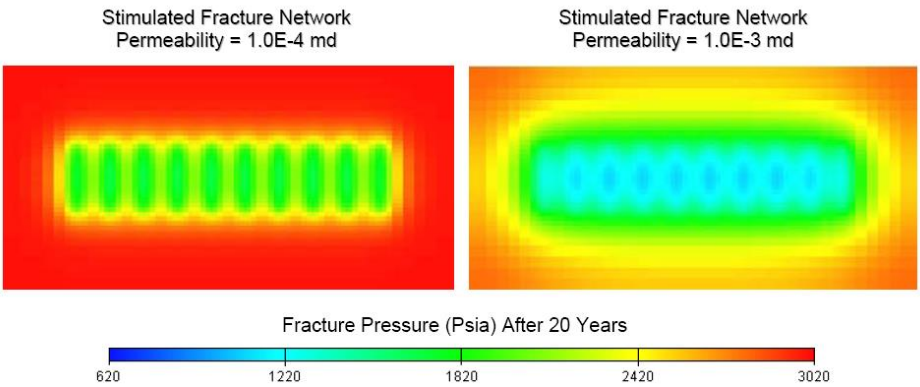


Figure 19 – Impact of stimulated fracture network permeability on the drainage area (after Zhang *et al.* 2009)

Zhang *et al.* (2009) also studied the impact of other parameters on cumulative production by keeping all reservoir and hydraulic fracture parameters fixed and the results are presented in Figure 20. As can be deduced from Figure 20 (a), rock compaction has a significant negative effect on the production performance. Lastly, Figure 20 (b) and (c) show that non-Darcy flow and gas content has minor effects on cumulative production.

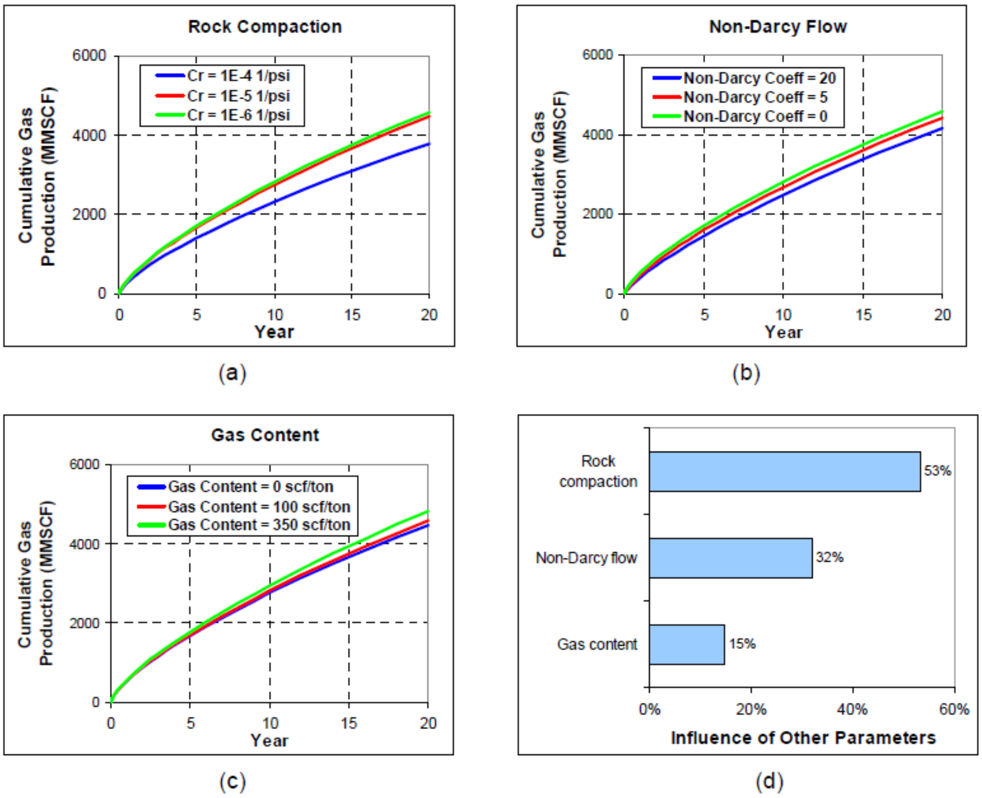


Figure 20 – Impact of other parameters on the cumulative production (after Zhang et al. 2009)

As a continuum, Zhang *et al.* (2009) studied the impact of hydraulic fracture parameters on cumulative production and the results are discussed in Section 2.3.1.

In conclusion, the most influential parameters are the stimulated fracture network permeability and the matrix-fracture sigma factor. Moreover, primary hydraulic fracture spacing, conductivity, and half-length also have significant influences.

2.2.2. Hydrocarbon Saturation

Generally, shale reservoirs produce little or no free water and hence it is assumed that the water saturation in the pores is at irreducible level. Water saturation is generally estimated as in the conventional reservoirs. As for hydrocarbon saturation, a combination of laboratory analyses, Dean-Stark or retort analyses, are used (Bratovich and Walles 2016).

According to the US experience published in EIA (2013) reports, the production of shale oil needs at least 15 - 25% of gas saturation in pore spaces to meet the pressure support needed to drive the oil to the wellbore via the expansion of the gas.

2.2.3. Porosity

Due to various organic and inorganic materials inherent in shale formations, there exist various sources of porosity in these rocks. Where pores within organic matter are formed during thermal maturation, i.e. results of hydrocarbon generation, pores within inorganic matter are formed by mechanical and chemical diagenesis. Inorganic matter pores can be classified into two as; interparticle pores which occur between grains and crystals and intraparticle pores, which occur within boundaries of grains. Pore networks dominated by interparticle and organic matter pores have better connectivity, hence higher permeabilities (Loucks *et al.* 2010).

Pores are important for storativity and transmissibility of hydrocarbons and other fluids. Free gas in-situ and adsorbed gas in-situ consist the total gas in-situ (which can be measured from log). Free gas occupies the pores of kerogen and matrix, together with the open natural fractures. On the other hand, water would be present as adsorbed by clay that is called as clay bound water, which is immobile (irreducible) and hard to quantify and differentiate. Lastly, water may occupy the pores of inorganic matrix due to capillary effects abbreviated as Pc bound in Table 9 (Glorioso and Rattia 2012, Passey *et al.* 2010).

Table 9 – Sources of porosity and the associated fluids (after Glorioso and Rattia 2012)

Matrix	Fluid	
Kerogen	Free	Gas
	Adsorbed	Gas
Inorganic Matrix	Free	Gas
	Pc bound	Water
	Clay bound	Water

Irrespective of their total porosity, unconventional reservoirs generally exhibit extremely low permeability due to their small average pore sizes and grain sizes; moreover they generally show absolute water wet surface character (Lakatos *et al.* 2011). Moreover, as a natural consequence of small pore and grain sizes, shales have low pore throat sizes, which lead to low permeability values, hence, productivities.

2.2.4. Permeability

Although it is admitted that the original permeabilities of shale formations are very low, the feasibility of maintaining long-term production is determined by the magnitude of the matrix permeability, i.e. matrix-to-fracture hydrocarbon support rate.

Research show that permeabilities below 100 nanodarcies define the lower limit for a shale gas play to produce economically since the greatest limit to gas production is the pore throats of the source rock (see Figure 21). Moreover, this limiting value is independent of completion quality and gas content (Boyer *et al.* 2006).

In such ultra-low permeability medium, natural fractures become highly important for project economy. To take most out of the natural fractures and increase the likelihood to cross them, industry utilized horizontal drilling perpendicular to the maximum horizontal stress direction (Boyer *et al.* 2006).

Generally, determination of in-situ permeabilities of nanoscale is highly challenging since core samples are generally subjected coring induced or stress release fractures. This will in turn bring greatly overstated permeability values (Javadpour *et al.* 2007). Moreover, due to stress-sensitive characteristic of shale permeability, recreation of accurate in-situ stress conditions during measurement is highly critical (Clarkson *et al.* 2011).

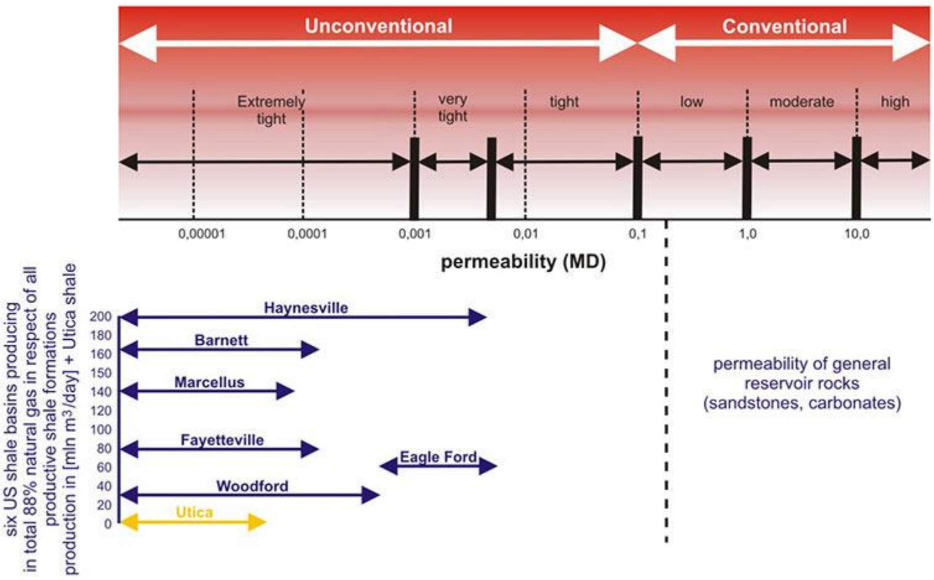


Figure 21 – Permeabilities for conventional and unconventional reservoirs (after PGI 2017)

2.2.5. Resource Thickness

Resource thickness, together with areal extent are the two most important parameters determining the net rock volume due to the high uncertainty they embrace. Identification of top and base limits is rather easier comparing to net thickness determination. Porosity, water saturation cut-offs come into concern in the latter, however, many operator companies do not use any cut-offs in their estimations. Net thickness is determined by analyzing several factors, such as kerogen & TOC content, hydrogen index, hydrocarbon saturation, permeability, porosity and fracture porosity, rock density, lithology and brittleness index (BI), most of which are difficult to precisely determine in shale formations (Glorioso and Rattia 2012).

All shale formation characteristics can vary sharply in vertical and horizontal directions, hence the net thickness. Reservoir-quality shales may expand or pinch-out laterally within short distances, while gross shale thickness remains the same (Boyer *et al.* 2006).

2.2.6. Area

Tight gas reservoirs, which have conventional trapping mechanisms, are generally bounded by the areal extent of the reservoir, hence in the volumetric estimations; area has a high degree of importance and uncertainty (Lee and Sidle 2010).

On the other hand, since shale oil, shale gas and BCGA resources are continuous-type deposits, i.e. the assets are generally bounded by lease boundaries instead of the formation extends (Figure 22), it may sometimes be meaningless to assign uncertainty to the area as an input of recoverable volume analysis. As stated by Haskett and Brown (2005), many evaluators may be forced by their companies "mistakenly" to include area uncertainty within the confines of their acreage holdings.

Details of areal extent and the location of wells also become very important in categorizing reserves as proved, probable and possible. Moreover, categorization as contingent resources is directly related to the proximity of the producing wells and the reservoir property similarities to the area that encloses the producing wells (Seager 2016).

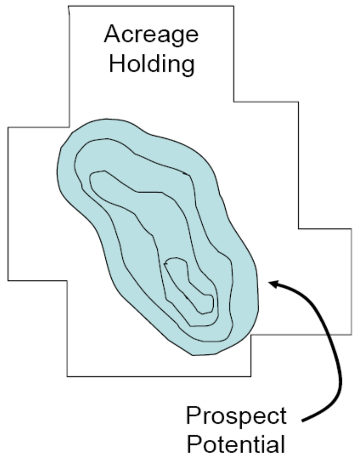


Figure 22 – Unconventional resource potential may extend beyond the limits of the area being assessed, hence traditional approaches changed (after Haskett and Brown 2005)

To categorize any reservoir in proved category, it should firstly stay in the proved area. Proved area indicates firstly the area identified by drilling as either proved developed (PD) or proved developed non-producing (PDNP). Secondly, it indicates the adjacent undrilled area with reasonable certainty of producing economically producible oil or gas in the current geological and engineering knowledge that is classified as proved undeveloped (PUD). This approach is called as "concentric rings" by some authors (see Figure 23) and offers the assignment of higher confidence to potential well locations closer to the producing wells and lower confidence to the locations farther away. Moreover, timing constraints should be considered while evaluating PUD reserves, which means new PUD wells on undrilled acreage must be drilled within a specified time frame, which is 5 years in SEC (2008) rules (Abdelmawla and Hegazy 2015, Henry 2015, Seager 2016).

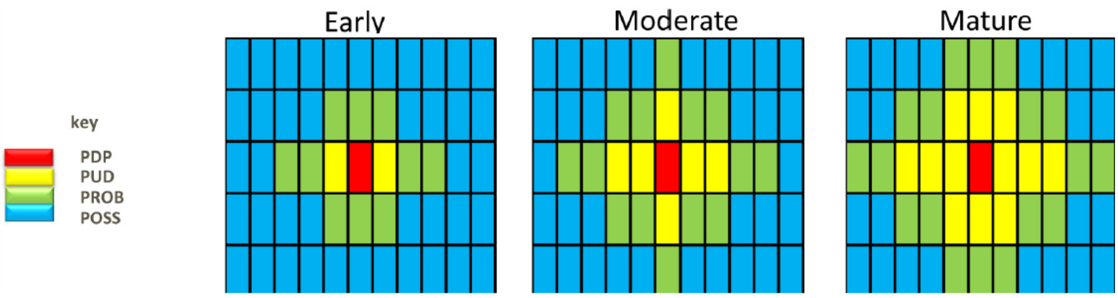


Figure 23 – Reserve categorization methodology according to property maturation - PDP: Proved developed, PUD: Proved undeveloped, PROB: Probable, POSS: Possible (after Abdelmawla and Hegazy 2015, modified from Guidelines for Application of PRMS 2011).

2.3. Hydraulic Fracturing Design

As discussed earlier, **Hydraulic Fracturing** (Hydraulic Stimulation) is the second of the two key technologies; those unlock the unconventional hydrocarbon potentials (Novlesky *et al.* 2011). To hydraulically fracturing the formation, water enriched with various chemicals are pumped into the formation with pressures exceeding the fracture pressure and afterwards proppants are placed into these fractures to keep them open. As a result, the formation's ability to produce hydrocarbon increases by creating man-made fracture network in the formation that effectively connect huge reservoir surface area to the wellbore, i.e. the contact area controlling the fluid flow is increased (Cipolla *et al.* 2009b, Cipolla 2009, Nolen-Hoeksema 2013).

To obtain economic production rates from these ultra-tight shale formations with a matrix permeability range of 10^{-4} to 10^{-5} mD (10 to 100 nanodarcies), a very complex fracture network should be created by stimulation treatments (Cipolla *et al.* 2009b). To obtain such complexity, a successful design of the hydraulic fracturing is prerequisite. The major objective of all fracturing jobs, both in conventional and unconventional wells is to create fractures in the reservoir rock while keeping them outside of the unwanted zones. Induced fractures grow up and down until they are faced with a barrier to stop growing vertically (Holditch 2006). In such fracturing operations, careful consideration of cost effectiveness that minimizes operation time and material usage is very important (CPH 2015a).

To optimize completions of horizontal wells, firstly determining distribution and orientation of both natural and drilling-induced fractures are crucial and these data can be obtained basically by image logs. Especially, characterizing drilling-induced fractures are useful in determining the stress variation and mechanical property changes along the length of the lateral wellbore (Boyer *et al.* 2006, Waters *et al.* 2006). Moreover, an extensive understanding of hydraulic fracture complexity, interference between fractures and fracture height growth are also crucial, in which *micro-seismic* would be a useful tool (see Section 2.3.6). Finally, understanding of perforation cluster and stimulation stage contribution to the well's total production is essential and usage of repeatable production logging would provide such vital information (Ramakrishnan 2011).

A "rule of thumb" developed by industry up to date is that production from a hydraulically fractured stage in a horizontal well may be assumed equivalent to gas production of a vertical well (Chan *et al.* 2010). Moreover, 6 - 8 horizontal wells drilled from one well pad can access as much reservoir volume as 16 vertical wells and using multi-well pads would significantly reduce the environmental footprint (DOE 2009).

2.3.1. Unconventional Hydraulic Fracturing

The state of the art of hydraulically fracturing of unconventional formations is very different from fracturing of conventional formations. Since conventional hydraulic fracturing treatments target planar fractures, i.e. low complexity fracture network; high viscosity fracturing fluids (gels) are used and high concentration of large proppant placement is essential. On the other hand, hydraulically fracturing of shale formations needs large volumes of low viscosity fluid, i.e. slickwater, to promote fracture complexity (Figure 24) and low concentration of small proppants are to be placed (Cipolla *et al.* 2009a). Slickwater is basically composed of water and friction reducing additives, which certainly result in low viscosity and low density.

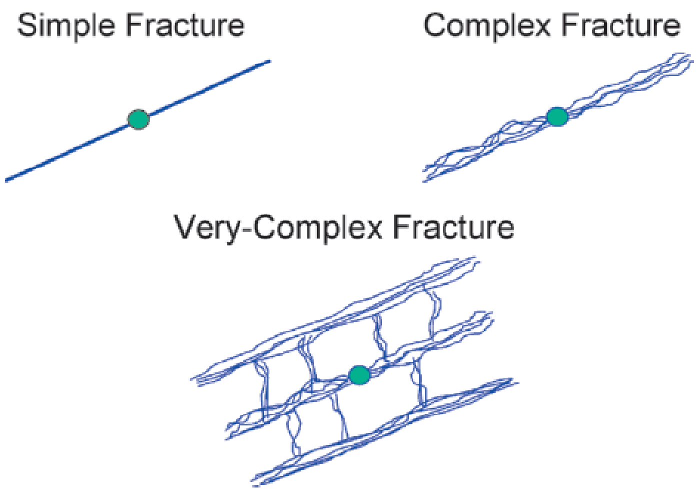


Figure 24 – Complex fracture network (after Fisher *et al.* 2005)

The created complex fracture network encompasses 50 acres (~0.2 km^2) or more and hydrocarbon production is directly related to the number and complexity of fractures, conductivity of created fractures and matrix permeability (Cipolla 2009).

Typical hydraulic fracturing of a stage in a horizontal well needs more than half million gallons of water and up to half million pounds of proppant which are pumped at rates of 75-150 bpm (DOE 2009, Fredd *et al.* 2015). The multistage fracture stimulation equipment consists of 10-20 each 2,000 Hp pumps, a blender, 2-4 each sand storage bins, a hydration unit, a chemical truck and 20-30 workers (Beard 2011).

There are 3 key parameters affecting the flow capacity of a hydraulically fractured reservoir:

1) The locations of the proppants placed effectively,
2) Conductivity of the propped fracture network,
3) Conductivity of the un-propped fracture network.

Research shows that a large percentage of perforation clusters in the lateral are not effectively being stimulated and hence over 30% of them resulted in zero contribution to the production (Schorn 2014, Meisenhelder 2013, Miller *et al.* 2011, Fredd *et al.* 2015). An operator in Marcellus Shale play also reported that 2 of 11 fracture stages contribute 70% of well's production (Neville and Donald 2012). Miller *et al.* (2011) interpreted production logs of 100+ horizontal shale wells and concluded that in some basins 2/3 of the production comes from 1/3 of the perforation clusters. While evaluating all basins 1/3 of all perforation clusters are not contributing at all. Moreover, Schorn (2014) and Fredd *et al.* (2015) notes that 40% of the unconventional wells drilled are not economical.

One of the primary reasons of inadequate stimulation of perforations is the variation of fracture initiation pressures across the perforated intervals, which leads to uneven stimulation among the perforation clusters (Kraemer *et al.* 2014). Production logs interpreted by Miller *et al.* (2011) showed that 20-30% of the perforations in fractured horizontal wells in US shale basins do not contribute to production due to this issue.

To overcome uneven stimulation, Kraemer *et al.* (2014) propose usage of degradable diverting agents together with sequenced fracturing technique, which basically block the previously stimulated perforations for a secondary fracturing job. In other words, the flow to the least resistance path would be blocked by some chemical pills and fracturing fluid is diverted into the unstimulated perforations.

Zhang *et al.* (2009) studied the impact of hydraulic fracturing parameters on cumulative production by assigning values in reasonable ranges to the fracturing parameters and checking the sensitivity of the results. The study showed that fracture half-length is the most influential hydraulic fracturing parameter. Fracture spacing is the second, fracture height is the third and the fracture conductivity is at the fourth place. It is worth mentioning that, in the study, fixed reservoir properties are used. The studied parameters and their impact on drainage area can be seen in Figure 25.

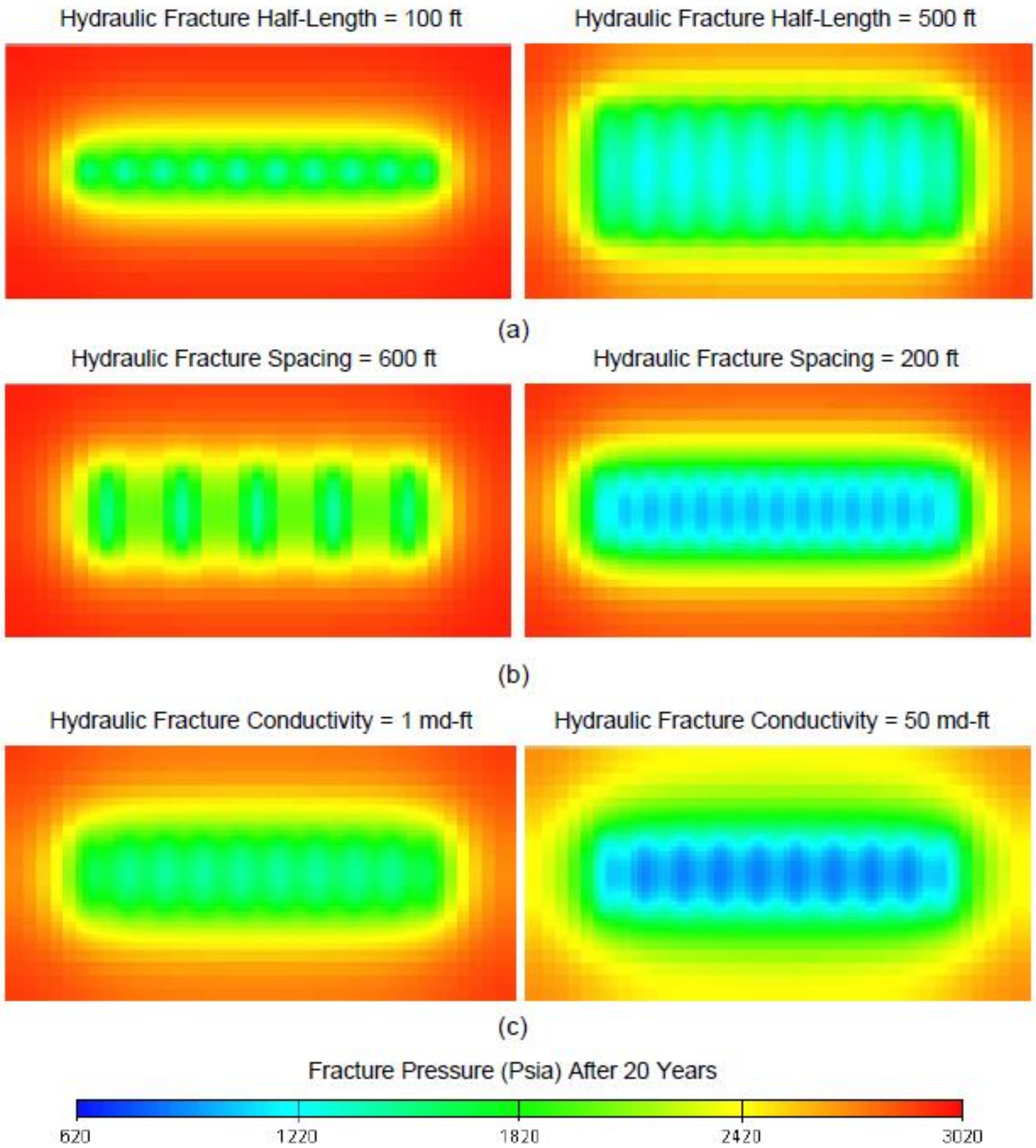


Figure 25 – Impact of hydraulic fracture parameters on the drainage area (after Zhang *et al.* 2009).

2.3.2. In-Situ Stress Field

The extent and orientation of the fractures created and the pressure needed for hydraulic fracturing are all controlled by **in-situ stress field**, which can be defined by three principal compressive stresses perpendicular to each other. These are maximum, intermediate and minimum principle stresses. In-situ stress field is a function of tectonic regime, depth, pore pressure and rock properties, which in turn determine stress transmission and distribution among the formation (Nolen-Hoeksema 2013).

The maximum principal stress is the **overburden stress (principle vertical stress - $\sigma_{overburden}$),** which caused by the weight of the overlying rock (see Figure 26). Since hydraulic fractures are tensile fractures, they open in the direction of least resistance, which is **minimum principle stress (σ_{Hmin})** and propagate in the plane of the maximum and **intermediate principal stress (σ_{Hmax})** direction. It should be noted that "σ_{Hmax}" is sometimes called as maximum horizontal stress, hence denoted as **"σ_{max}"**.

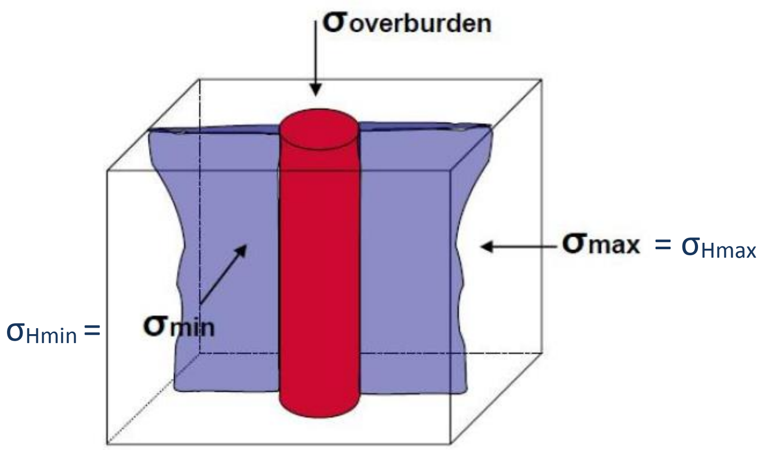


Figure 26 – Overburden stress, maximum and minimum horizontal stresses (after WTF 2009).

In other words, because of the in-situ stress field of the earth, in a horizontal well drilled perpendicular to maximum principle stress, fractures are created vertically and propagate parallel to the maximum horizontal stress (intermediate principle stress) when pressure exerted exceeds the minimum horizontal stress (minimum principle stress). Naturally, fractures propagate in the direction of maximum principle stress since they preferentially open against the minimum principle stress (see Figure 27). All these bring maximum amount of transverse fractures hence maximum production (Beard 2011).

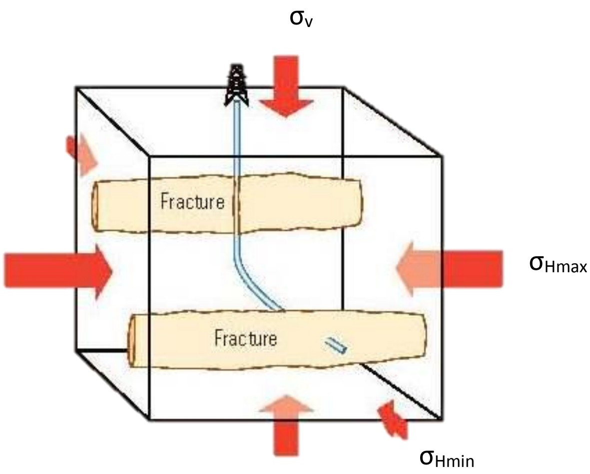


Figure 27 – In situ stresses and hydraulic fracture propagation (after Nolen-Hoeksema 2013)

All three principle stresses increase with depth and this rate of increase is defined as **vertical gradient (lithostatic gradient)**. Vertical gradients are mainly controlled by local and regional stresses generally through tectonics, which cause a variation with respect to basin and lithology (Nolen-Hoeksema 2013).

Another concept helpful to understand the stress regime is the in-situ **pore pressure**, which is caused by the overlying fluid inside the pore spaces, and the vertical gradient of pore pressure is called the **hydrostatic gradient.** When the pore pressure within a formation is less or greater than the normal pressure, it is called under-pressured or over-pressured, respectively (SLB Oilfield Glossary 2015f). An increase in pore pressure through injection of fluids will cause the rock matrix to experience a tension and the increase of this tension beyond certain limits will cause initiation of fractures in the rock matrix.

Rock strength and the pressure difference between rock and the fracturing pressure determine the extensions of hydraulic fractures, i.e. fracture height, fracture half-length and aperture (width or opening) (CPH 2015a). The fracture height is especially determined by the stress difference throughout the vertical direction. If there is not much closure stress difference, the fracture grows much higher (Mohamed *et al.* 2016)

The concepts which determine the induced fracture orientation and dimensions are presented in the below paragraphs. A careful knowledge on these concepts is required for an efficient hydraulic fracturing job.

2.3.3. Fracture Pressure and Rock Strength

Fracture pressure, also called as **formation breakdown pressure** or **fracture initiation pressure**, is briefly the pressure at which rocks breakdown and fracture is created. To break the rock, the fracture initiation pressure must exceed the sum of the minimum principal stress plus the tensile strength of the rock (Nolen-Hoeksema 2013).

Fracture pressure is the pressure needed to create a fracture in a rock while drilling in open hole. Whereas, the **closure stress** is the pressure needed to fracture a rock through perforations in well-cemented cased hole, which is lower than fracture pressure. However, sometimes they are used interchangeably or ambiguously. Both values are function of the overburden pressure, pore pressure, Poisson’s Ratio, porosity, tectonic stresses and anisotropy. **Breakdown pressure** is the sum of the closure stress and the friction loss during the delivery of fracturing fluids from the surface to the formation. Breakdown pressure can be considerably higher than closure stress (CPH 2015a).

Closure stress can also be defined as the pressure at which the fracture closes after the fracturing pressure is relaxed, which usually corresponds to 80-90% of breakdown pressure. Higher closure stress leads to difficulties in fracturing, i.e. need for more horsepower. An example of high closure stress rocks is shallow shaly sands, which have high Poisson’s ratio (CPH 2015a).

In-situ stress tests (injection fall-off test or injection flowback test) is conducted by injecting small volumes of fluid at small injection rates (mini-frac tests). The aim is to pump fluid at a rate sufficient to create a small fracture. Afterwards, the pumps are shut down to determine the pressure at which fracture closes that shows fracture closure pressure, i.e. the minimum in-situ stress (see Figure 28) (Petrowiki 2016a, Valko 2005). The naming changes according to service supplier; DFIT (Diagnostic Fracture Injection Test) by Halliburton, MFO (Mini Fall-Off) by Schlumberger (Halliburton 2017). Hereby, Instantaneous Shut-in Pressure (ISIP) is also another important parameter obtained by the analysis of special plots of pressures obtained from DFIT tests. It can basically be explained as the difference between final injection pressure and the final pressure drop due to friction (Fekete 2012).

These concepts can be clearly determined in the pressure regime chart of a fracturing process. Pressure continously increased while pumping at a prescribed rate and at the **fracture initiation pressure**, formation is cracked and fluid flow started into the formation through fractures. Afterwards, pumps are shut-down and the resulting pressure drop at a certain level indicates **fracture closure pressure**. While repressurizing the formation, previously cracked fractures starts to reopen at the **fracture reopening pressure,** which is higher than the closure stress. Both closing and reopening pressures are controlled by the minimum principal compressive stress (Nolen-Hoeksema 2013).

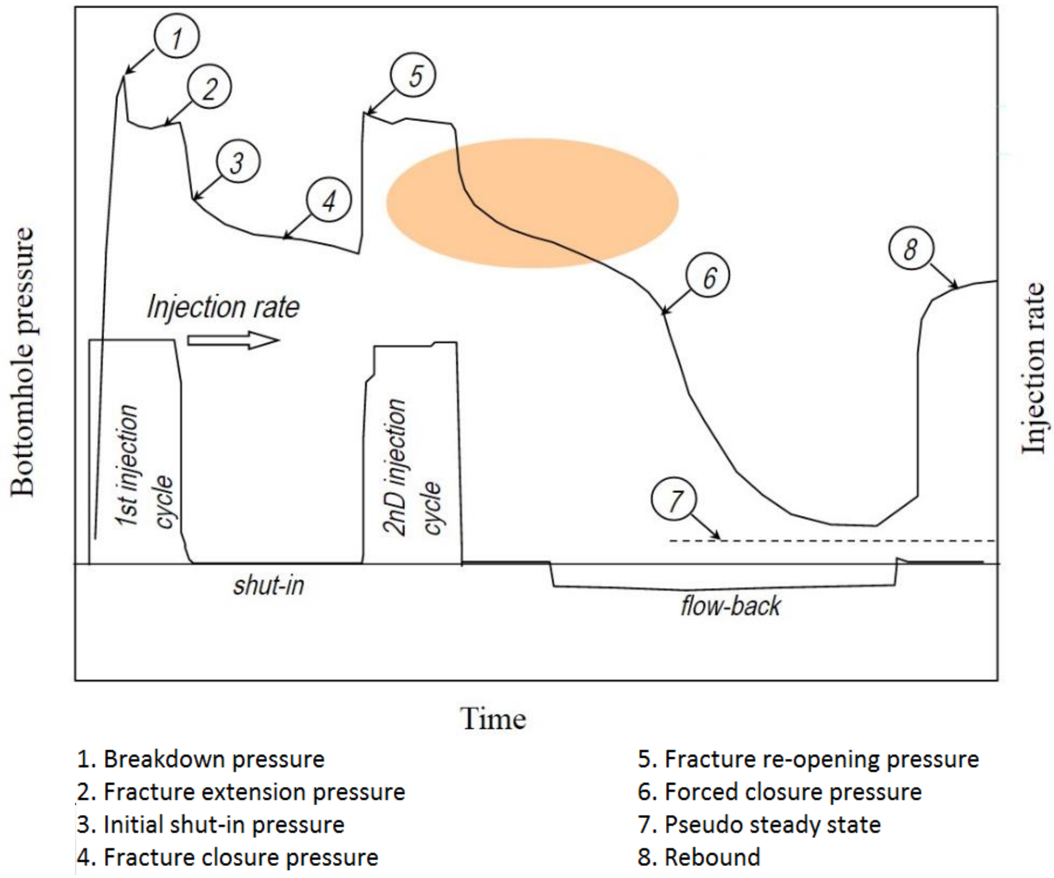


Figure 28 – In-situ stress test (mini-frac test in cased hole or leak-off test in open hole) data (modified from Valko 2005)

To keep the induced fractures open and to extend the fracture length, the downhole pressures should be kept above the minimum principal stress, which is the **fracture propagation pressure**. This will also assure that the pressure is to be kept above the fracture closure pressure, and the difference between them is the **net pressure** which represents the sum of the frictional pressure drop and the fracture-tip resistance to propagation. Net pressure is the energy to propagate the fracture and can be calculated by the difference between ISIP and the closure stress (Nolen-Hoeksema 2013, Fekete 2012).

The net pressure keeps the fracture open and allows the fracturing fluid and proppants, i.e. **fracturing slurry,** to enter into the fractures. The **proppants** are the solid materials, typically sand or man-made particles, used to keep the fractures open after pumping is stopped (Figure 29). In carbonate reservoirs, acid can be used as the final slurry to etch the formation, hence create artificial roughness (Nolen-Hoeksema 2013).

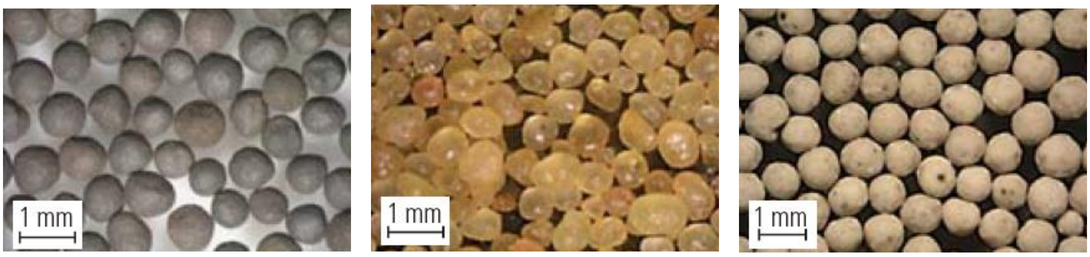


Figure 29 – High-strength bauxite (left), resin-coated silica (middle) and lightweight ceramic (right), are pumped into fractures to maintain open fractures for enhanced hydrocarbon production (after Nolen-Hoeksema 2013).

After the pumps stop, the fluid inside the fractures either flows back into the wellbore or leaks away into the reservoir rock (see Section 2.3.4).

Sometimes, the treatment should be stopped due to a phenomenon called **screenout**, which is warned by a sudden rise in pressures and caused by bridging of proppants across the fracture width and restricts the fluid flow into the induced fracture. If the pumping was not terminated immediately, this phenomenon ends up with the accumulation of proppants in the wellbore. Hence, only remedy will be the clean-up of the wellbore by a **coiled tubing unit (CTU)** or workover rig. In order to reduce the screenout risks, some volume of clean fluid, called as **pad**, is pumped before proppant addition into the slurry.

At this stage, hydraulic **fracture design** comes into concern to obtain a desired length of induced fractures and to optimize the fracture height that would keep the fractures in the reservoir and prevent growth into the risky zones. While designing the fracturing operations; pumping rates, treatment pressures, fracturing fluid and proppant properties should be carefully optimized to achieve the targeted fracture geometry and propagation (Nolen-Hoeksema 2013).

Rock Strength

Breakdown pressures during stimulation is directly proportional to stress region around the perforations. Sometimes high stress near-wellbore region around perforations causes high breakdown pressures and even if they are broken down, conductivity may remain very low. Post-stimulation production logging results performed from individual perforation clusters showed that there is strong correlation between minimum in-situ stress at the perforation cluster and hydrocarbon production (Ramakrishnan *et al.* 2011).

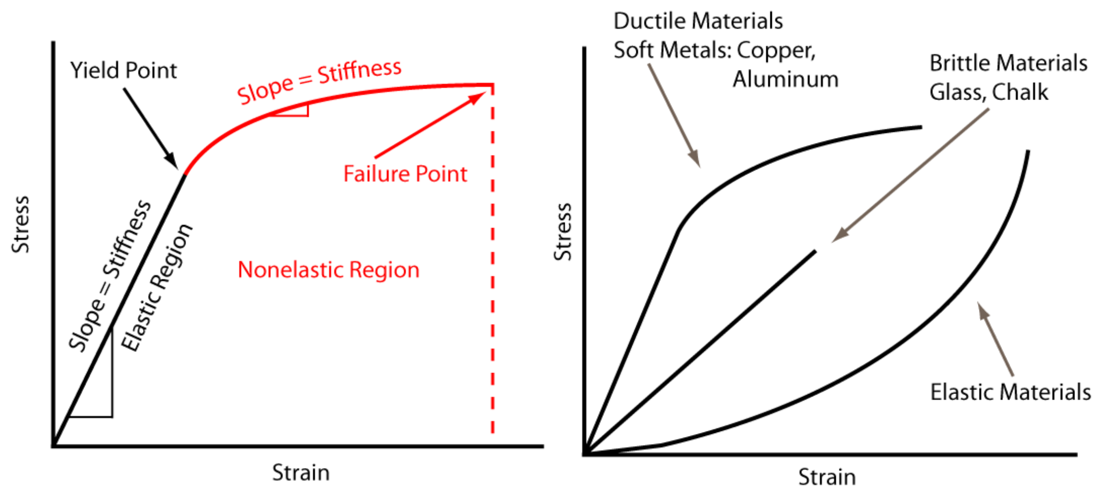


Figure 30 – Stress vs. strain relationship, elastic and ductile materials (after Ricard 2015)

Static moduli measurements are performed on cores whereas dynamic moduli measurements are either performed on cores or using data obtained from well logging. The geomechanical data determine the stress vs. strain relationship (Figure 30) which in turn reveal the elasticity, brittleness or ductility of the rock. All these are the key parameters of fracture design, i.e. determination of the resulting fracture propagation, closure of fractures and the geometry of drainage area of fractures (Glorioso and Rattia 2012).

2.3.4. Fracturing Fluids

Traditionally, CO_2 or N_2 foam treatments was the common practice for shale formation (Barnett Shale) fracturing until 1980's, which is today continued to be used in shallower shales or in low pressure formations. After 1980's, operators began utilizing massive fracturing treatments in shale formations using huge amounts of cross-linked gels and sand proppants. Despite the considerable increase in EURs, this practice brings high costs and marginal economics. After 1997, with Mitchell Energy, slickwater started to be used as fracturing fluids with pumping approximately twice of the volume of jellified fluids, but using only 10 % of the proppant volume. While well performances slightly increased, costs reduced by approximately 65% (Boyer *et al.* 2006; Waters *et al.* 2006).

Replacement of slickwater by jellified fluids allowed the fractures to become longer and more complex. Moreover, usage of slickwater caused less damage to the formation since no gel residue or filter cake is left behind (Fisher *et al.* 2005). Slickwater frac fluid can easily enter into micro-cracks and enlarges them. Slickwater is environmentally friendly since it contains very few chemicals, however much more water is needed (WEC 2010).

One possible drawback of slickwater usage is the reduction in proppant transport ability due to settlement of dense proppants. Hence, many small cracks away from the well likely remain un-propped (see Section 2.3.5). One solution is to use smaller sized proppants, (e.g. 40-70 mesh) with slickwater to transport the proppants away from the wellbore (Mohamed *et al.* 2016). This settlement problem was the case for some plays other than the Barnett, and operators found another solution. Commercial agents can be used (e.g. Schlumberger's ClearFRAC, FiberFRAC) to keep the proppants suspended for extended time periods and keep them in the fractures until they are closed down (Boyer *et al.* 2006).

Lastly, the efficiency of slickwater in shales was proved by re-fracturing practice. Mitchell Energy begin re-fracturing their wells and the success ratio in wells initially fractured with gelled fluids are much higher than the wells initially fractured with slickwater (Boyer *et al.* 2006).

On the other hand, more gels may be utilized at the end of a stage to transport higher sand concentrations allowing higher fracture conductivity in some cases or to promote greater conductivity in liquid rich wells (Beard 2011).

Fracturing Fluid Recovery

After the fracturing operation, the injected fracturing fluid used to create the fractures should be recovered at the surface facilities. This operation is called as "**flowback**".

The recovery of the fluids used during the fracturing process, i.e. the flowback of fracturing fluids via gas produced from fractured formation, is another important aspect affecting the formation conductivity. Pagels *et al.* (2012) stated that less than 25% of fracturing fluids are recovered back during flowback operations. The non-recovered fluids can be trapped in the complex fracture network and/or leak into the tight rock matrix (Parmar *et al.* 2014). Because of non-recovered fracturing fluid; economic, technical and environmental problems come into concern (Makhanov *et al.* 2014).

Fracturing fluid recovery is adversely affected by three basic parameters (Parmar *et al.* 2014): the first one is *capillary force*, which depends on the interfacial tension between the fluids (fluids and gas) and the wettability of the proppants used. The second one is *viscous force* that depends on the displacement velocity and the mobility ratio, i.e. increasing the viscosity of fracturing fluids reduces the fluid recovery. Finally, the last but the most powerful one is *gravity force,* which depends on the density difference and the drainage direction with respect to the gravity direction.

According to the work of Parmar *et al.* (2014), a considerable amount of fracturing fluid remains in the below part of the vertical fractures induced through the horizontal wells since recovery needs upward vertical displacement of fracturing fluids against the gravity by produced gas. As for multi-stage fractured wells, the toe-side stages cannot clean up as efficiently as heel-side due to commingled flow back. Hence, many operators drill the laterals with slight incline to improve toe-side clean up (Warpinski 2008).

Low recovery of fracturing fluid, i.e. non-recovered fracturing fluid in turn leads to loss in fracture conductivity and fracture face damage. To overcome this severe problem, Parmar *et al.* (2014) recommended use of surfactants together with fracturing fluids or hydrophobic propping agents during fracturing operations. They also showed that, usage of surfactants increased the ultimate frac-fluid recovery by 30% and usage of hydrophobic proppants instead of hydrophilic doubled the water recovery.

2.3.5. Proppants

Various issues in fracturing jobs were solved with the development of several types of proppants, which also improved final conductivities in formation. The pyramid in Figure 31 shows the conductivity hierarchy, in which conductivity increases by going upward while costs are also increased. The crucial point in proppant type selection is again the economic feasibility. The higher the strength, uniformness and thermal resistance of the proppant, the higher the productivity of the well. In the conductivity hierarchy pyramid, Tier 1 presents the ceramics, Tier 2 presents the resin-coated sands and Tier 3 presents uncoated sands (Gallagher 2011).

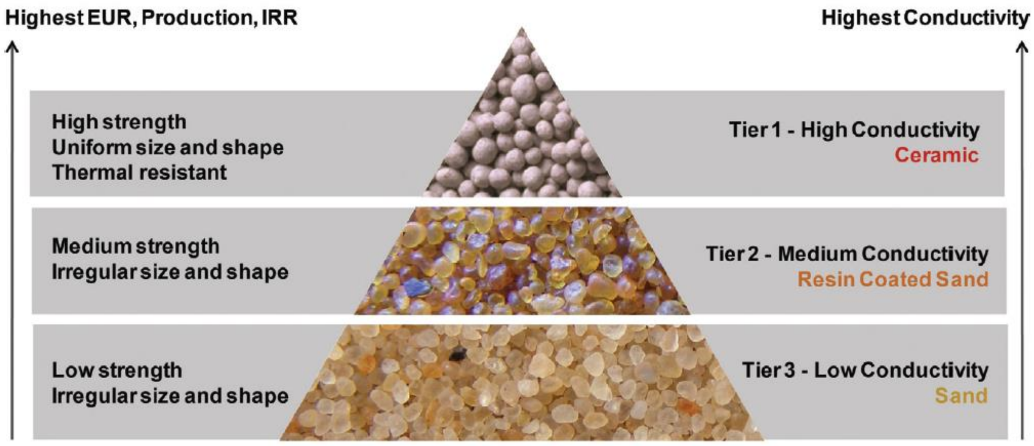


Figure 31 – Conductivity hierarchy pyramid for proppants (after Gallagher 2011).

Coating the silica sand with resin (Tier 2) brings higher strength to the sand and keeps together the small particles after a possible crushing, which will prevent migration of proppant fines. Moreover, resin coated proppants (RCP) have a lower tendency of moving during flow-back, hence are used at the end of the treatment (Beckwith 2011, Beard 2011).

Proppants manufactured from a type of ceramic material (bauxite or kaolin clay) can be engineered to reach superior properties (Tier 1) such as high strength (especially after undergoing a molecular structure changing process called sintering) and more uniform roundness, sphericity and size (Beckwith 2011).

In addition to proppant types, the proppant size, generally referred as mesh size, is also an important parameter in fracturing design. The smaller the number representing mesh size, the coarser the grain, since mesh size number represents the number of holes in one inch-sq. of mesh (Beckwith 2011).

Different sizes can be used in various stages of a job according to needs. Coarser proppants allow higher flow capacity, however may breakdown or crush at lower stresses due to lower grain-to-grain contact points. Moreover, as for coarser proppants, placement into the fractures is more difficult due to their size and higher settlement rates. As for industry practice, 100-mesh sand is the early portion propping agent to provide enhanced distance and height and to prop/plug the natural fractures. 40/70 or 40/80 proppants are the predominant agents used in gas shales and 30/50 or 20/40 proppants are used to enhance fracture conductivity, especially in liquids rich plays (Beard 2011).

Un-propped fractures participate to production only at the initial times of production. However, with decreasing reservoir pressure, earth stresses close these fractures and production ceases (WEC 2010). A possible remedy for this phenomenon is usage of low-gravity proppants. In Figure 32, one can see the variation of conductivity in fractures when they are un-propped or partially propped with different strength proppants. Bottom curve (black curve) shows the un-propped fractures in which two fracture faces are aligned upon closing. As can be seen, above 3000 psi of closure stress, typical to most shale formations, conductivity vanishes. As for 0.1 lbm/ft^2 of sand (blue curve), conductivity increases for low closure stresses, however, decrease would be dramatic with increasing closure stress due to crushing of sands. Lastly, for high strength proppants (orange curve), such as sintered bauxite, fracture conductivity increases significantly and this high conductivity is preserved regardless of closure stress increments (Cipolla 2009).

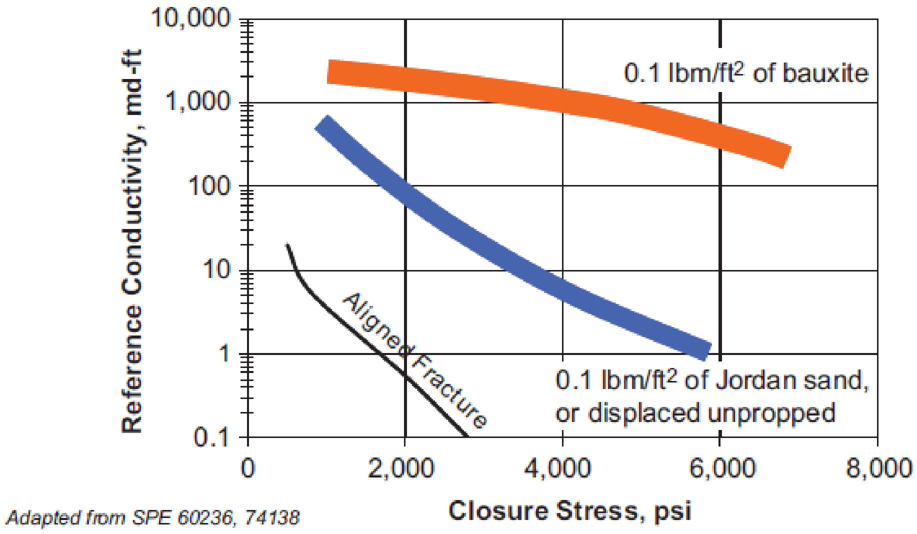


Figure 32 – Un-propped and partially propped fractures (after Fredd *et al.* 2001, Cipolla 2009).

2.3.6. Fracture Mapping (Micro-seismic)

Micro-seismic refers to determination of very small seismic events, triggered during hydraulic fracturing. Evaluation of the output data help engineers to determine the fracture growth and complexity. While observing the fracture growth direction, the fracture can be kept in the desired zones, i.e., fractures can be oriented and located within the reservoir, by adjusting the fracturing parameters. In an extreme case, fracturing can be terminated before entering into an unintended zone. Micro-seismic is performed by running highly sensitive listening devices (geophones or accelerometers) into the offset wellbore in a vertical array (Figure 33 and Figure 34) (Nolen-Hoeksema 2013, Fisher *et al.* 2005).

The micro-seismic event pattern, which shows the rock brake-down locations by hundreds of dots, is developed as fracturing continues and as a result, fracture azimuth and dimensions are revealed. Figure 35 presents an example for micro-seismic event pattern for two cases from Barnett Shale fracturing jobs. The first one belongs to usage of cross-linked (XL) gel frac and the second one belongs to water-frac re-frac. A simple comparison of both cases clearly shows the superiority of water as fracturing fluid if the complex fracture network is the primary objective (Warpinski *et al.* 2005, Cipolla *et al.* 2009a).

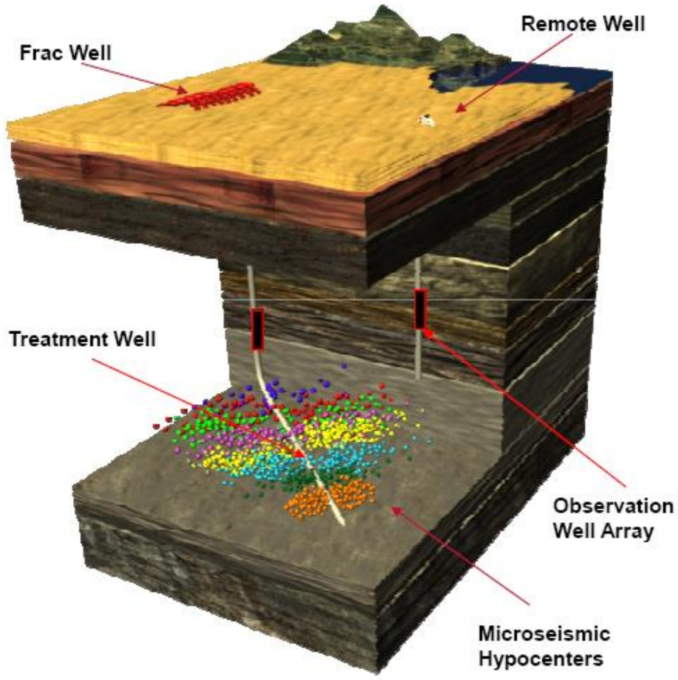


Figure 33 – Micro-seismic operation field schematic (after Martinez 2012).

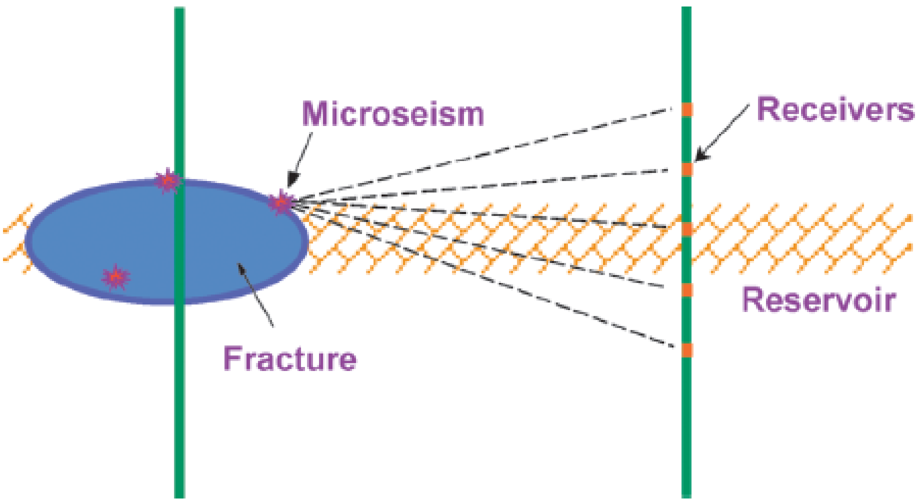


Figure 34 – Micro-seismic-event location (after Fisher *et al.* 2005).

In this example, the SRV of XL gel frac is 430 million cuft, where it is 1450 million cuft in water-frac re-frac and this difference in SRV resulted in twice the production rates in water-frac comparing to XL gel frac. Generally, in shale formations, larger and more complex micro-seismic event patterns show better production profiles (Mayerhofer *et al.* 2010, Cipolla *et al.* 2009a).

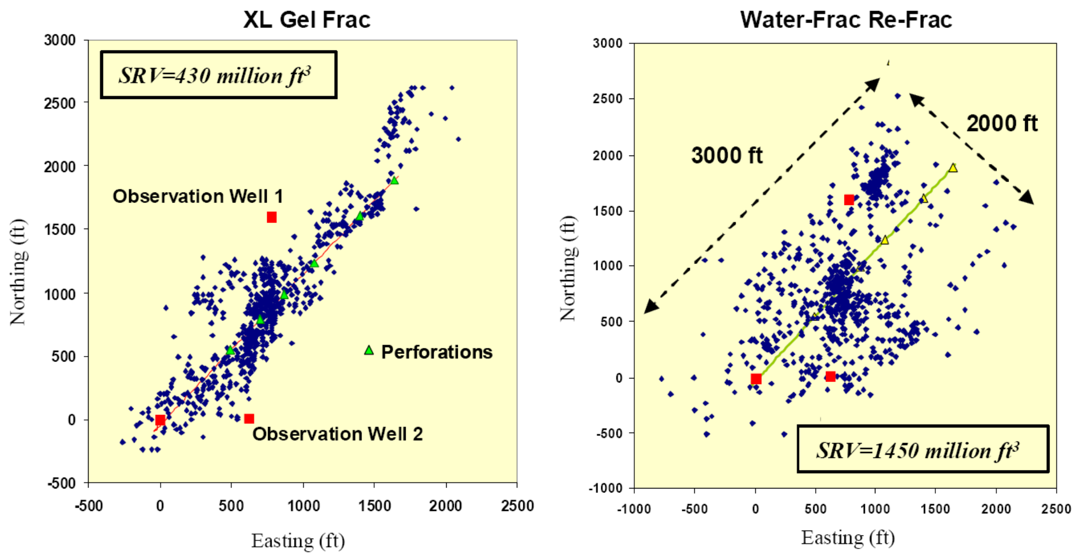


Figure 35 – Micro-seismic event pattern comparison of XL gel frac and water-frac re-frac treatment in a horizontal Barnett Shale well (after Warpinski *et al.* 2005, Cipolla *et al.* 2009a)

It is worth noting that, while micro-seismic determines the initiated fractures and fracture geometry, overall effectiveness of the fracturing cannot be anticipated since location of the proppant and distribution of conductivity within natural or induced fractures cannot be measured (Cipolla 2009, Clarkson *et al.* 2011).

Moreover, understanding the created-fracture geometry is essential to improve the future treatments and drilling programs. Recently, **surface-tilt** and **downhole-tilt** fracture mapping technologies are also used to characterize the created fracture geometry by analyzing the measured deformations at the surface and dislocations in the subsurface during fracturing. Figure 36 represents the usage of these highly sensitive devices to determine the fracture network (Fisher *et al.* 2005).

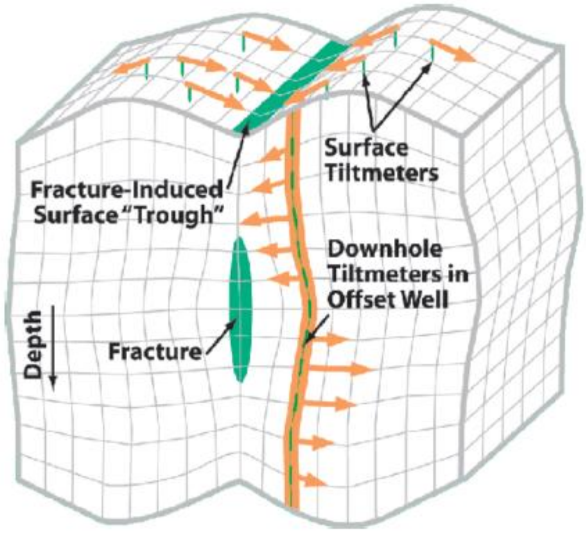


Figure 36 – Deformation pattern resulting from hydraulic fracturing (after Fisher *et al.* 2005)

At this point, another concept called EPV (Effectively Propped Volume) comes into concern, which is the fraction of SRV that has been effectively propped open and capable of flow. Micro-seismic records locations of every micro-seismic event during stimulation, however does not identifies the type of rock movement. In detail, while micro-seismic signals indicate both tensile deformation (fracture faces move away from each other) and shear deformation (fracture faces slide past each other), only tensile deformation brings an open space for fluids and proppants flow-in and hydrocarbon flow-out. To quantify EPV, hence estimate reservoir drainage, moment tensor inversion (MTI), which is an advanced seismic signal processing technique differentiating the components of geomechanical deformation, should be used together with geomechanical fracture modeling. In summary, a more careful estimation of EPV provides a better understanding of fractured volume, which is propped and capable of flow. This will in turn brings the optimization of well spacing, maximization of production and hence maximum investment return (Maxwell 2013).

CHAPTER 3

CONVERTING UNCONVENTIONAL PROSPECTS TO RESERVES

3.1. Special Characteristics of Shale Formations

Extremely low permeability (nanodarcies) which results in non-linearities in equations, ultra-fine matrix pore structure (nanopores), exotic diffusion effects, stress dependent permeability and porosity, molecular adsorption/desorption and horizontal wells with complex fracture network are the most eminent issues those make unconventional plays really unconventional (Houze 2013; Clarkson *et al.* 2011).

3.1.1. Adsorption and Desorption

Adsorption refers to the gas accumulation at the walls of a solid which results in a molecular or atomic film on the walls. Not to be confused, **absorption** is the trapping of a substance within another substance (Glorioso and Rattia 2012). Absorbed molecules are taken up by the volume, not by the surface as in the adsorption (Wikipedia 2016a). **Desorption** is the reverse of both process, i.e. expulsion of gas (Wikipedia 2016b).

Fistly, Irwin Langmuir (1918) published an equation to measure adsorbed gases in solids. Today industry uses the Langmuir Isotherm to measure adsorbed methane gas content by the surface of kerogen. The general form of the Langmuir isotherm can be represented by the following equation:

$$g_c = \frac{V_L \times P}{P + P_L} \qquad \textbf{(6)}$$

where, g_c : adsorbed gas content (scf/ton), P : original reservoir pressure (psia), V_L : Langmuir volume (scf/ton), P_L : Langmuir pressure (psia).

Langmuir volume (V_L) is the volume of gas adsorbed to infinite pressure, which is a function of organic richness and thermal maturity of the shale. Langmuir pressure (P_L) is the pressure at which one-half of the Langmuir volume can be adsorbed. In other words, it shows how readily the adsorbed gas is released as a function of decrease in pressure. The Langmuir isotherm curve in Figure 37 describes the free gas and adsorbed gas equilibrium as a function of reservoir pressure at the isotherm temperature. This isotherm is measured at a set temperature and TOC level; hence, corrections should be applied for temperature variations and different TOC's (Glorioso and Rattia 2012, Dong *et al.* 2013, EIA 2013).

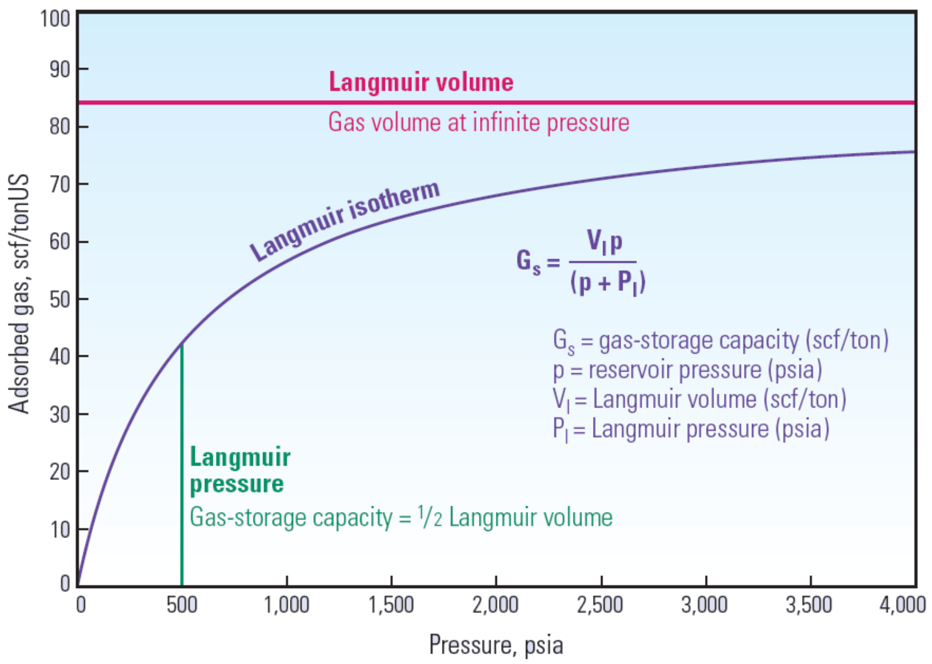


Figure 37 – Langmuir isotherm used to estimate adsorbed gas content (after Boyer *et al.* 2006).

Since more gas is stored in the matrix porosity at high pressures, free gas production contributes much more than the desorbed gas at early producing times. Moreover, in ultra-low permeability formations like shale, it may be very difficult to capture adsorbed gas even if there is a considerable amount of adsorbed gas as in-place. This phenomenon is a result of adsorption equilibrium (Sun *et al.* 2015).

Core analysis experiences showed that mature, thermogenic shales are predominantly saturated by interstitial gas and adsorbed gas constitutes a volume of 50 to 10%. On the contrary, immature, biogenic shales are predominantly saturated by adsorbed gas with smaller amounts of interstitial gas (Boyer *et al.* 2006).

Although, gas desorption does not bring too much volume to the ultimate recovery in shale gas formations, it should be reflected to the production forecasts or should be defined to the model to match the real production behavior. In today's commercial simulators, shale gas modules are included. Hence, by providing the Langmuir Isotherm of the formation to the software, desorption issue can be simulated with high confidence.

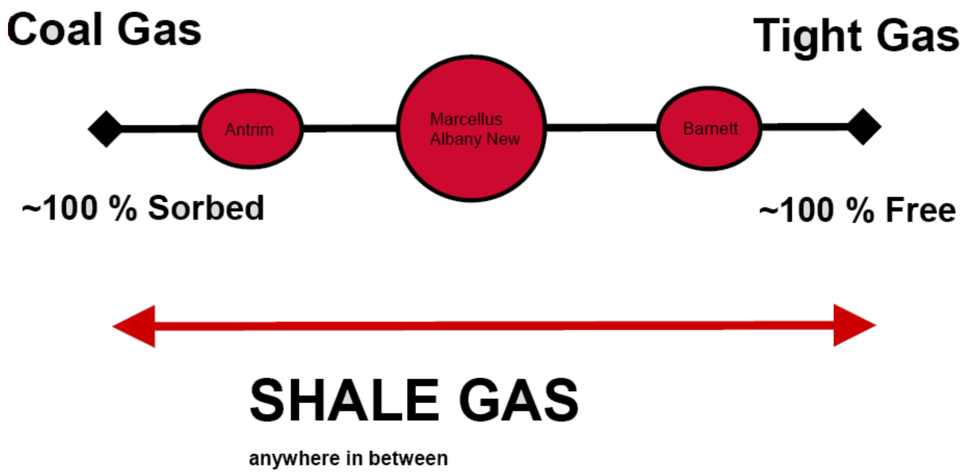


Figure 38 – Sorption isotherm for different unconventional gas sources (after Van Gijtenbeek 2012)

Adsorbed gas is relatively important in shallow and highly organically rich shales whereas free gas becomes more important in deeper, high clastic content shales (Kuuskraa *et al.* 2011). The sorption amount for different shales and the comparison with CBM and Tight Gas are illustrated in Figure 38.

Lastly, due to its late-time contribution to the production, adsorbed gas amount has minimal impact on shale play economics; however, it has considerable impact on GIP calculations (Ahmed and Meehan 2016).

3.1.2. Stress Dependent Conductivity

Although all materials deform less or more under stress, stress dependent conductivity becomes meaningful only for stress sensitive rocks like unconventional reservoirs in which pore-throat sizes are especially low. As reservoir pressure declines, i.e. hydrocarbons are produced; porosity and permeability of the rock reduces. The stress sensitivity of the rock directly proportional to the permeability of the rock in concern, again due to low pore-throat sizes (Holditch 2006).

Figure 39 below shows the effect of net over burden (NOB) pressure on permeability values by comparing the permeabilities of various core plugs at NOB pressure (y-axis) and at ambient pressure (x-axis). As can be seen, lower permeability rocks are more stress sensitive due to their smaller pore-throat diameters (Holditch 2006).

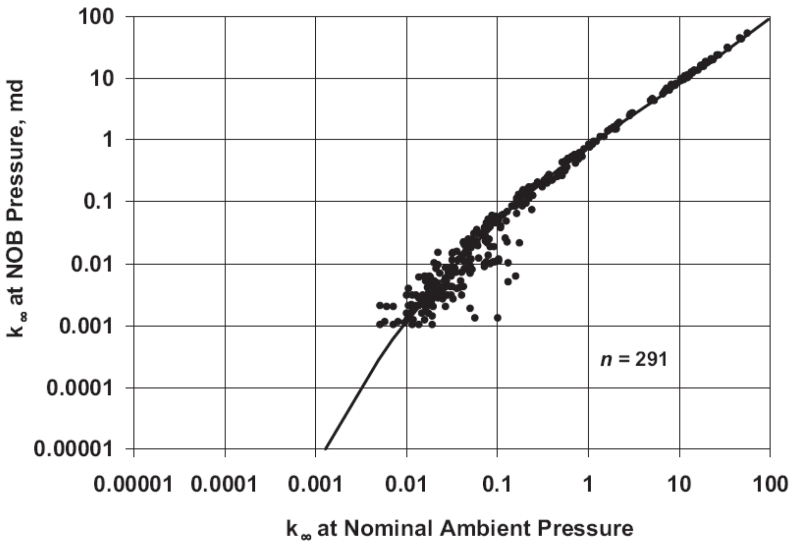


Figure 39 – Gas permeability at NOB pressure vs. gas permeability at ambient pressure for Howell No. 5 and SFE No. 2 Travis Peak cores (after Holditch 2006)

As expected, un-propped network conductivity is highly dependent on stress variation, and the sensitivity to stress is highly inversely proportional with Young's modulus. In other words, especially with low Young's modulus formations (softer rocks), stress dependent fracture conductivity results in reduces ultimate gas recovery. Figure 40 clearly presents effect of closure stress and Young's modulus for different rock types (different Young's modulus). The dramatic decrease in un-propped fracture conductivity can be seen in the softest rock.

According to Cipolla *et al.* (2009a), with lower Young's modulus, the reduction in fracture conductivity becomes significant as drawdown in the fracture network increases with production time. Hence, the drainage of tight matrix rock, i.e. ultimate gas recovery, significantly lowers. On the other hand, initial well performances are not affected from stress dependency. A potential side effect of this phenomenon would be optimistic gas recovery forecasts while they are performed with initial well performance data (1-2 years).

Both gas desorption and stress dependent network fracture conductivity affect the late life performance of the formation.

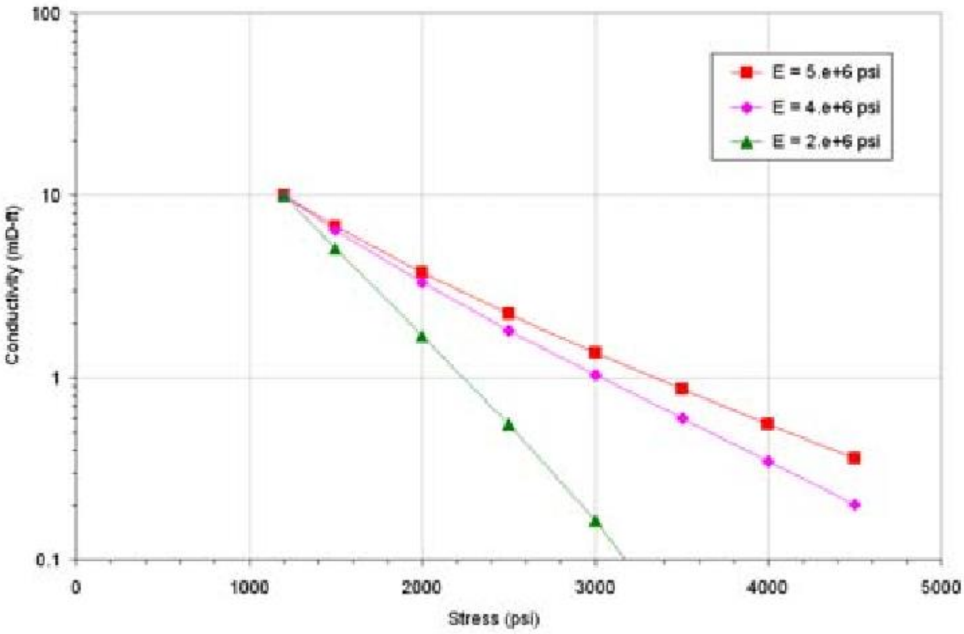


Figure 40 – Effect of closure stress and Young's Modulus on un-propped fracture conductivity (after Cipolla *et al.* 2009a)

3.1.3. Nanopore Concept

Shale reservoirs form within the fine grained sedimentary rocks, called as shale or mudstone, which are rich in organic material. As stated, these rocks have very small pore sizes, thus have very low permeability. As a consequence of this ultra-low permeability and adsorption phenomena, gas cannot migrate to a more permeable reservoir. Hence, shale formation plays all the roles itself, namely the source rock, the seal and the reservoir (Sun *et al.* 2015).

Contrary to conventional sandstone and carbonate formations with pore sizes in micrometer range, shale formations have much smaller pore sizes in the nanometer range in both organic and inorganic medium as illustrated in Figure 41 and Figure 42 (Javadpour *et al.* 2007, Sun *et al.* 2015, Ozkan 2012).

Since the methane molecules with sizes of 0.38 nm flow in the 5-15 nm sized nanopores (Loucks *et al.* 2009) (Figure 41), a good understanding of molecule transfer through nanopores in both organic and inorganic medium is essential to model the overall hydrocarbon flow mechanism in shale formations (Sun *et al.* 2015, Ozkan 2015).

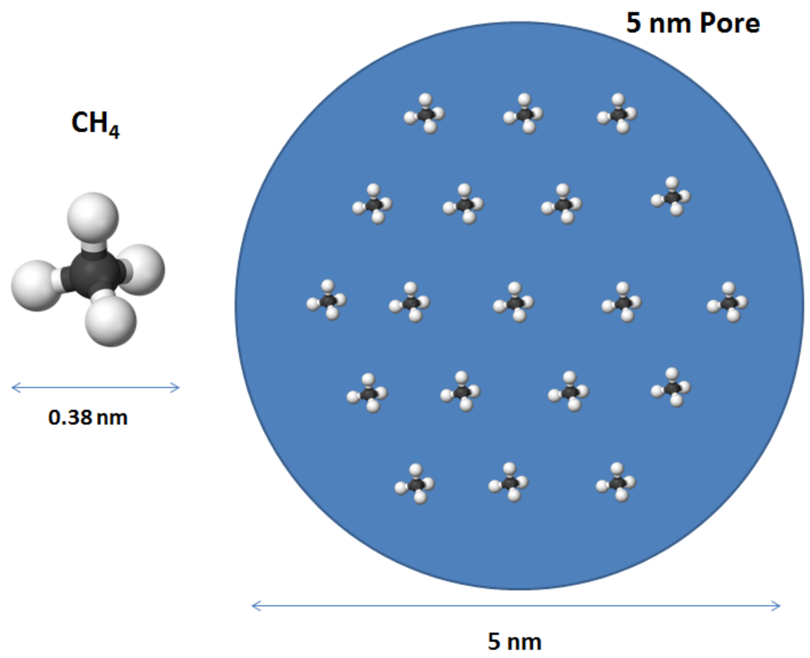


Figure 41 – Methane molecule in nanometer world (modified from Loucks *et al.* 2009)

Nanopores of shale formations bring special flow characteristics by playing two different roles. Firstly, for the same pore volume, the surface area would be much larger than in micropores, since surface area is proportional to “4 / d (pore diameter)”. Because of this large exposed area, large volumes of gas desorption can occur. Secondly, slip flow dominates the flow behavior, which will be discussed in the following section in details (Javadpour *et al.* 2007).

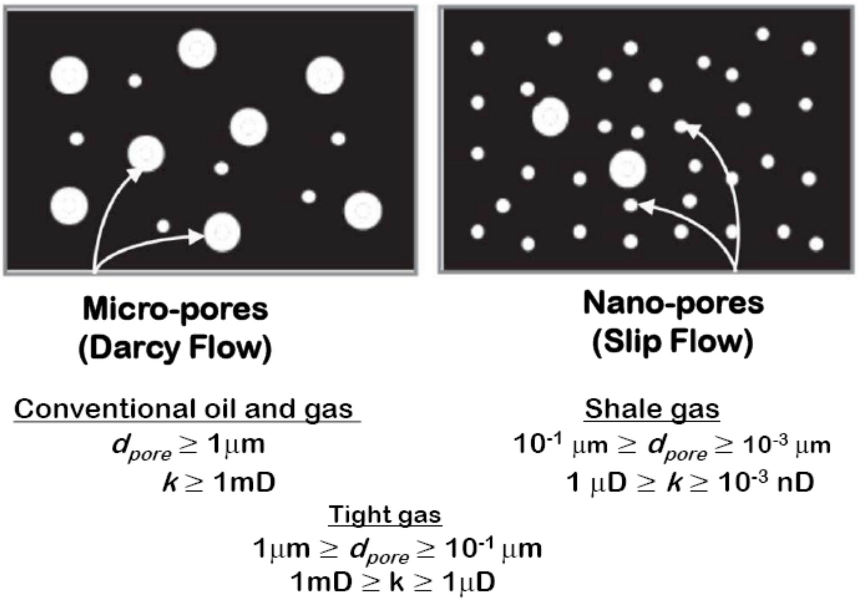


Figure 42 – Porosity and permeability ranges (after Javadpour *et al.* 2007, modified by Ozkan 2012)

Gas molecules stored in the pores in three different ways start to flow by disturbing the equilibrium, i.e. opening the well. Although there are overlaps, the order of the stored gas to contribute to the flow is as follows: Firstly, the freely compressed gas in the pores. Secondly, desorption of the molecules on the surface of the kerogen walls. Thirdly, diffusion of the dissolved gas in the kerogen materials to the kerogen surface (this is different from Knudsen diffusion) due to resulting difference in the concentration between the bulk of the kerogen and its surface (Javadpour 2009). Moreover, Javadpour *et al.* 2007 well illustrates their view on the flow in different pore scales as in Figure 43.

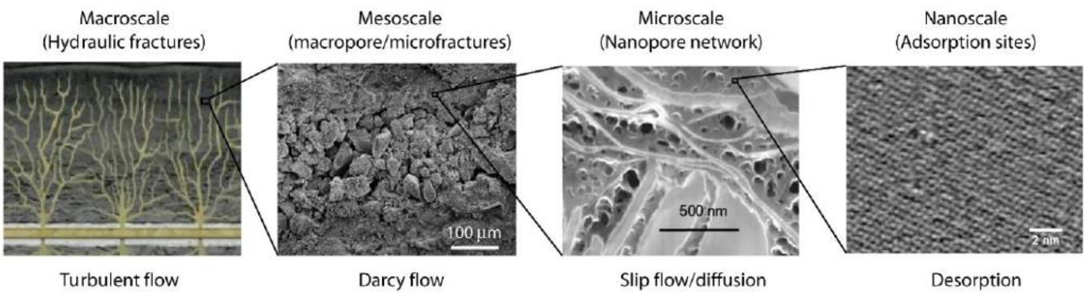


Figure 43 – Different pore scales and gas flow in shales (after Euzen 2011, Javadpour *et al.* 2007)

3.1.4. Special Flow Behaviors

Contrary to **Darcy Flow** (No-Slip Flow) in conventional reservoirs, **Slip Flow** is dominant in nanoporous structure of the shale formations (see Figure 44). Since the mean free path of the methane molecules is smaller than the nanometer scale pore radius, gas molecules collide along the wall of nanopores during transport (Albo *et al.* 2006). CH_4 molecules form a dense, liquid like adsorption layer with a thickness equal to molecule diameter (0.38 nm) and covers the internal surface of the nanopore walls. Moreover, a less dense and more mobile phase transition layer occupies remaining space in the nanopores still under the influence of the wall. This thickness of the transition layer is twice the molecular diameter. Hence, mass transport through the nanopores occur with three CH_4 molecule thickness (1.14 nm). At this point, **Knudsen diffusion** comes into concern to define this gas transport enhancement phenomenon under the influence of the wall. This phenomenon cannot be modeled by conventional constant permeability convection model, i.e. no-slip boundary in the continuum flow regime is not valid in the nanopores (Sun *et al.* 2015, Javadpour *et al.* 2007, Clarkson *et al.* 2011).

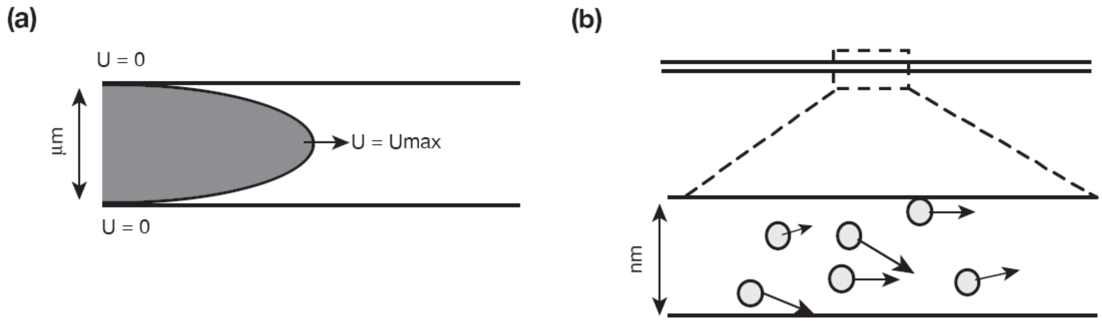


Figure 44 – (a) Darcy flow (no-slip flow) in micropores and (b) Gas flow in nanopores (slip flow) (after Javadpour *et al.* 2007)

Knudsen number (K_n) is a dimensionless parameter that determines the degree of invalidity of the continuum model, which is basically defined as the ratio of the mean-free path of molecules "λ" and the pore diameter "d" (Javadpour *et al.* 2007).

$$K_n = \frac{\lambda}{d} \tag{7}$$

$$\lambda = \frac{k_B.T}{\sqrt{2\pi\delta^2 P}} \tag{8}$$

where, λ : mean-free path of molecules, d : pore diameter, k_B : Boltzmann constant (1.3805 x 10^{-23} J/K), T : temperature (°K), P : pressure (Pa), δ : collision diameter of the molecule.

As can be depicted from Eqn. 8, the average mean free path, hence Knudsen number is inversely proportional with pressure and directly proportional with temperature. Moreover, Knudsen number is smaller at larger pores (Javadpour *et al.* 2007).

At low Knudsen numbers (K_n < 0.001), the no-slip boundary condition in the continuum flow is valid, however, at high Knudsen numbers (0.001 < K_n < 0.1), the continuum approach becomes invalid (Javadpour *et al.* 2007). Figure 45 presents the dominating flow regimes for different Knudsen numbers.

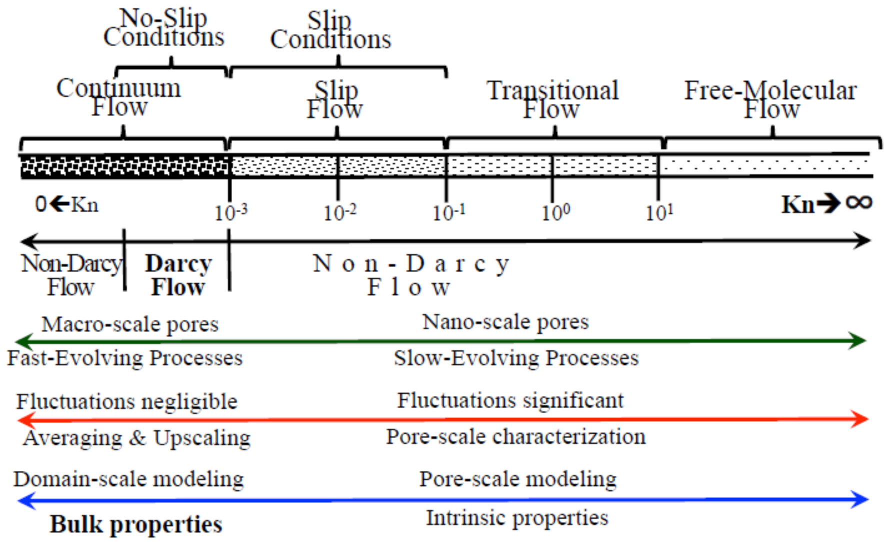


Figure 45 – Knudsen number shows where Knudsen diffusion starts (after Ozkan 2015)

Multiple flow mechanisms are valid for different pore scales. For larger pores (≥ µm), influence of pore surface becomes negligible and the dominating flow mechanisms will be convection due to pressure gradient and molecular diffusion due to mole fraction gradient. On the other hand, as pore sizes reduces below 100 nm, deviation from Darcy flow becomes obvious. Contribution of Knudsen diffusion to flow increases as pore sizes becomes smaller (Javadpour 2009).

As for molecular diffusion, mass transport is assumed to take place only between the fluid molecules in the same phase.

Sun *et al.* (2015) summarizes properties of the medium in shale formations that flow occurs as triple porosity system (organic nanopores, inorganic nanopores to micropores, and micrometer scale aperture fractures) and double permeability system (organic-to-inorganic material and inorganic material-to-fracture) (Figure 46).

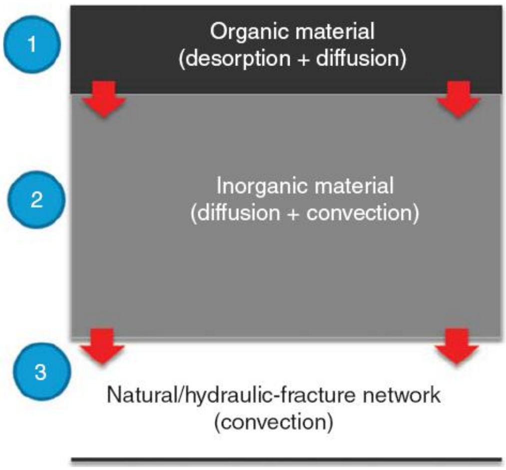


Figure 46 – Conceptual multi-mechanistic model for shale gas systems (after Sun *et al.* 2015).

3.2. Hydraulic Fracturing Optimization

Optimization of hydraulic fractures at the early stages of field development will reduce the number of wells required to exploit the full potential of the reservoir, hence strengthen the economics of the project (Carboceramics.com 2017a). An optimum fracture design should (Beard 2011):

1) Frac the total pay interval,
2) Create sufficiently conductive propped half-length,
3) Create optimum perforations cluster spacing with some overlap,
4) Minimize the well interference,
5) Achieve largest SRV and highest EUR.

In the light of foregoing, fracture length and height are the two main parameters of fracture modeling, which can be optimized through a fracture modeling software (e.g. FracPro, Gohfer, Stimplan). The sophisticated design software help in understanding of proppant placement, conductivity improvements and fracture dimensions.

Especially, keeping the fractures in the zone of interest is one of the main consideration of a fracture design that can be handled by utilizing design software. Hence, production can be maximized and waste of frac energy and costs are prevented (Beard 2011, Carboceramics.com 2017b).

Another target of fracture design is to properly create high conductive adequately propped fractures. Reservoir simulations showed that to obtain high production performances, higher primary fracture conductivity is required (Cipolla 2009b, Beard 2011).

As discussed earlier, multistage fracturing in horizontal wells is one of the key points in unlocking production from shales. At this point, placement of fractures in the lateral brings another optimization parameter (Ajayi *et al.* 2013).

The most basic approach to placement of fractures is to use a standard template, *the geometric method*, which practice dividing the lateral wellbore evenly into the number of planned fracturing stages. This approach ignores the vertical and horizontal heterogeneity and anisotropy of petrophysical and geomechanical characteristics of rocks. Hence, this approach generally ends up with poor well performances, namely about 1/3 of the perforations has zero contribution to production (Ajayi *et al.* 2013).

A more sophisticated approach is grouping the perforations with similar rock characteristics for a fracturing stage and concentrating the stages on the much prospective points. This is called as *engineered stimulation method*, which bring more success and can be done by help of stimulation design software by assembling geologic, core, production log, micro-seismic, logging while drilling (LWD) data in a 3D earth model. One of a kind of software is Schlumberger's Mangrove as a plug-in for Petrel. After designing of where to place stages and perforation clusters by using this type of software, engineers use hydraulic fracture simulators to design the stimulation treatments (Ajayi *et al.* 2013).

Utilization of this second method, engineered stimulation method, firstly brings higher initial production rates, which is stated in Ajayi *et al.* (2013)'s study as 106% higher initial cumulative production per foot of stimulated wellbore length in Marcellus Shale comparing to adjacent wells stimulated using geometrical method. Secondly, in the same study Ajayi *et al.* (2013) investigated another operator's work in Marcellus Shale and compared three wellbores drilled from a single pad. Two of them were stimulated using engineered design and one of them was stimulated using geometric design. According to their comparison using real-time micro-seismic monitoring, 35% of the perforations in well with geometric completion do not contribute to the stimulated reservoir volume, whereas only 20% of the perforations in wells with engineered completions made little to zero contribution to the stimulated reservoir volume. The last example of Ajayi *et al.* (2013) about success of engineered completion is from a tight oil sandstone from China. The operator reported that initial production rates increased three to fourfold comparing to previous horizontal wells. After three months, stabilized production rates of wells with engineered completion are 50% higher than any other horizontal well in the formation.

In addition to designing of fractures ordered from toe to heel in a horizontal well, fracturing in an alternating order (going back and forth) in a horizontal well or fracturing of two-horizontal wells concurrently worth mentioning here. These emerging techniques are developed to wisely utilizing the increased stress perturbation around the surrounding area of previous fractures and consequently to have a better stimulation efficiency. Moreover, these recently developed methodologies may also be utilized to overcome some specific drawbacks to be discussed (Rafiee *et al.* 2012, East *et al.* 2010).

Fundamentally, due to a single fracture, the change in minimum horizontal stress is greater than the change in other two principle stresses hence the stress anisotropy reduces. This in turn helps in activating the planes of weakness (fissures and natural fractures) which are also called as secondary fractures. Secondary fractures are highly important in creating a complex fracture network. The 3D visualization and the plan view of a fracture presented below (Figure 47) show the change in minimum horizontal stress (in psi) after placement of a single fracture. Moreover, significant favorable shear stress changes occur near the tip of the fractures, which will cause activation of plane of weakness and hence complexity in the far fields. Emerging fracturing methodologies utilize this theory as background and try to increase the efficiency of treatments (Rafiee *et al.* 2012, Soliman et al. 2010).

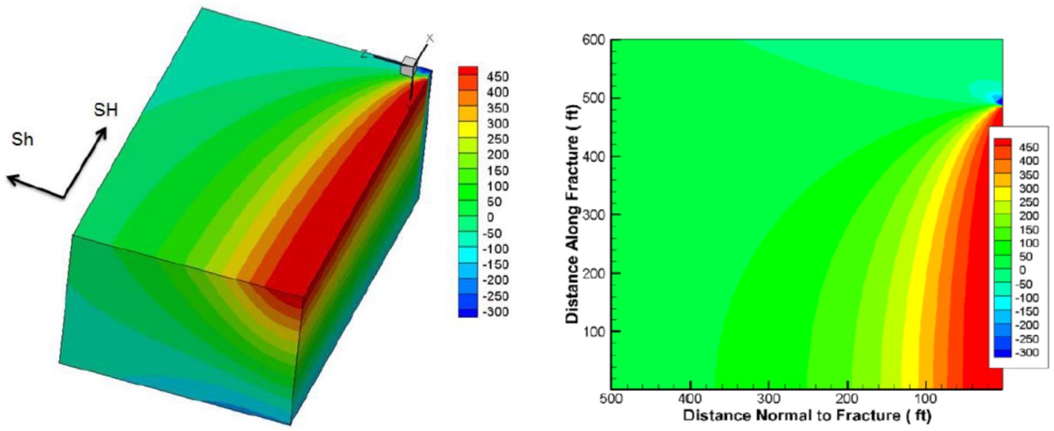


Figure 47 – 3D visualization and plan view of stress change in minimum horizontal stress – in psi (after Rafiee *et al.* 2012)

For example, **Alternating Sequence Fracturing (ASF)** technique (also called as *Texas Two-Step Fracturing* after the popular dance in Texas) is proposed to increase far field complexity. Fracturing treatments are performed in an alternating manner, i.e. after treating first and second stages; a third stage is placed between the first two stages. Stress alteration occurs in the area between fractures, i.e. the minimum horizontal stress changes. The initial two fractures are supposed to neutralize the stress contrast in the area between them. Consequently, fracturing of the middle area activates the stress-relieved fractures (planes of weakness) and increase the complexity of the fracture network. The connection between the secondary fractures and the main fractures by the middle fracture treatment can be seen in Figure 48. The red lines show the fractures grow after the treatment of the middle stage (third stage), whereas black lines represent the fractures grow with the treatment of the first and second stages. Subsequent fractures throughout the horizontal wellbore will be treated using the same procedure. If this technique is designed and applied properly, propping of both induced fractures and secondary fractures is possible. Although, the sliding sleeve technology (mechanical shifting of sleeves – MSS) made alternating fracturing technique available for the industry, it is very difficult to apply as a field practice. Lastly, the creation of longitudinal fractures due to stress reversal near wellbore is a risk of poorly designed ASF treatment (Rafiee *et al.* 2012, East *et al.* 2010, Soliman *et al.* 2010).

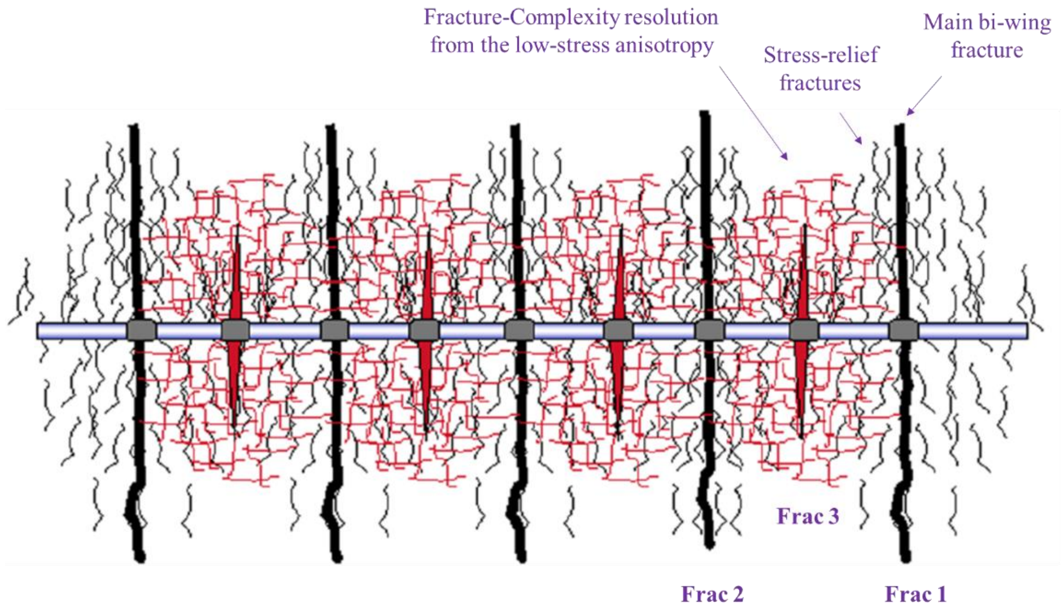


Figure 48 – Texas Two-Step fracturing (Alternating Sequence Fracturing - ASF) in a horizontal well (after East *et al.* 2010, Soliman et al. 2010).

Another widely used technique is the **Zipper Frac** (also named as SimulFrac after simultaneous fracturing) (Figure 49). Fundamentally, this treatment technique is performed in two parallel horizontal wells simultaneously from toe to heel. Maximization of stress disturbance near the tips of the fractures, result in the increase of the far field complexity. This can be explained as the fractures propagate perpendicular to the lateral wellbore due to occurrence of interference between the tips of the fractures when opposite fractures propagate towards each other. However, a possible change in direction of the fractures occurs when the opposite fractures get very close and this may result in unwanted well communication (Rafiee *et al.* 2012, East *et al.* 2010, Waters *et al.* 2009).

Lastly, another alternative is so-called **Modified Zipper Frac (MZF)**, in which stages are performed alternatingly, i.e. a stage in one well is performed just after a stage performed in the other well in an offset perforation (Figure 49). This explains why this methodology is called after the teeth of a zipper. Another specific advantage of this technique is that, while waiting on wireline to set plugs and perforate new intervals in one well, another fracturing stage can be performed in the other well; hence a considerable amount of time is saved (Rafiee *et al.* 2012, East *et al.* 2010, Waters *et al.* 2009).

Hereby, *Commuter-Fracturing* technique and use of CT (Coiled Tubing) for fracturing are also worth mentioning lastly. The basic principle behind commuter fracturing is to place heavier proppants into the well-developed fractures to plug the passage from these large fractures, hence the fluid slug is forced to find an alternative pathway. This method is a variation of so-called *tip screen-out* method, in which treating pressure is forced to go higher to open natural fractures or break the planes of weakness. In addition, use of CT in fracturing and especially in commuter-fracturing enables controlling the proppant and fluid properties at the downhole on-demand and on-the-fly (thanks to smaller diameter of the coiled tubing, no need for waiting the entire casing volume). This will in turn reduce treatment risks, especially the screen-outs, increase efficiency and help in placement of proppants more aggressively into the reservoir and into the near well bore (East *et al.* 2010, Soliman *et al.* 2010).

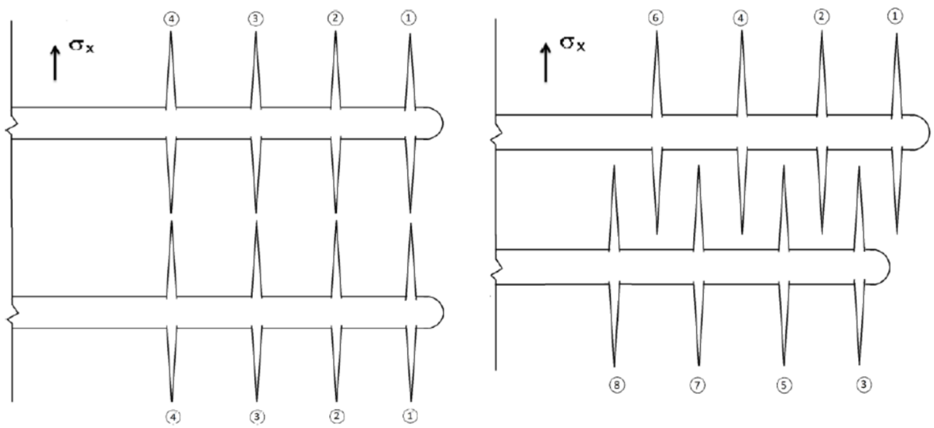


Figure 49 – Fracture placement in Zipper Frac technique (left) and Modified Zipper Frac (MZF) technique (right) (after Rafiee *et al.* 2012)

Perforation Clusters and Stage Spacing

It is clearly stated by several authors (Cipolla *et al.* 2009b, Beard 2011, Miller *et al.* 2011, Cheng 2012, Xiong 2017, etc.) that optimization of fracture and cluster spacing plays highly critical role in the well performances and project economics. Both parameters affect short- and long-term production performance of horizontal wells. At this point, proper reservoir characterization such as understanding of reservoir matrix permeability, geomechanical properties, and existing natural fracture networks is vital.

As an industry practice, in a horizontal well to be fractured, each perforation cluster is about 1 m of perforation generally with 6 spf. Neighboring 4-6 perforation clusters make up a stage. Fracturing stages for a horizontal well may go up to 12-16 stages (Figure 50).

The perforation cluster per stage and the spacing of stages (stage spacing) are the two important parameters to be designed for a stimulation job of a shale well (Figure 50).

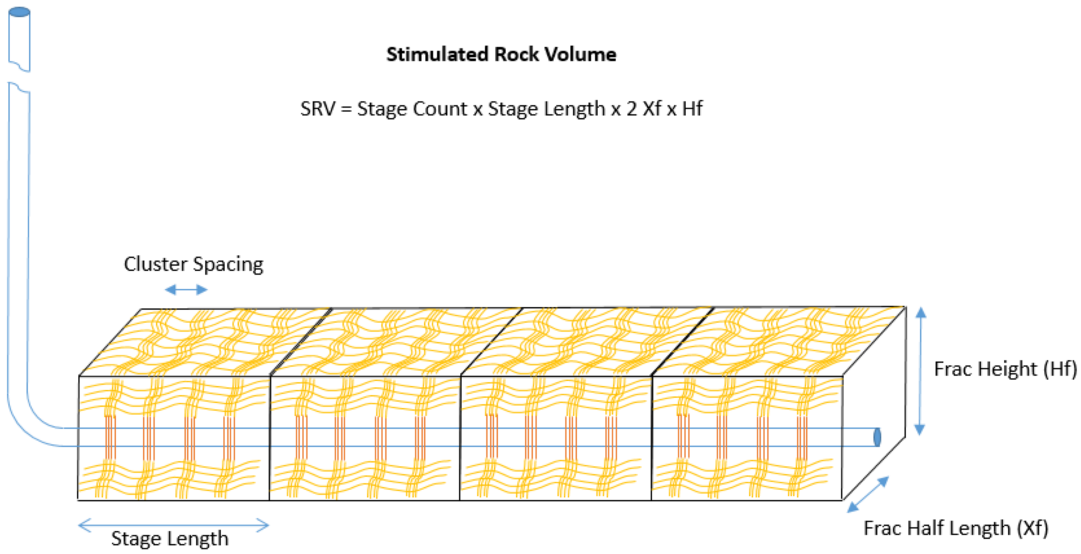


Figure 50 – Stage length, cluster spacing and SRV

Firstly, perforation clusters are typically placed 50 – 100 ft apart (Beard 2011), which can differ upon several parameters. Miller *et al.* (2011) recommends a cluster spacing of 75 – 175 ft in their study. The design of cluster spacing is primarily function of several factors, such as type of reservoir fluid, permeability, fracture conductivity, proppant distribution and associated stresses (Sierra and Mayerhofer 2013). Beard (2011) also summarized the controlling parameters for selection of greater or lower cluster spacing as follows:

Greater cluster spacing is used for:

- Higher permeability and porosity,

- More naturally fractured formations,

- Lower stress anisotropy.

Lower cluster spacing is needed for:

- More ductile shales,

- Liquid-rich plays.

As stated above, very low permeability reservoirs need tighter cluster spacing, however, geomechanical property changes and stress interference between fractures may prevent tighter placement of fractures. At this specific situation, zipper frac method comes into concern and provides an option to place fractures tighter, hence to obtain more complex fracture network, greater reservoir contact, productivity and recovery efficiency (Rafiee *et al.* 2012, Sierra and Mayerhofer 2013, Waters *et al.* 2009).

According to Miller *et al.* (2011)'s study on the US shales, closer cluster spacing does not bring extra productivity to Barnett wells since a wide, complex fracture system generally is obtained during stimulation of Barnett Wells. On the contrary, as for Woodford, Haynesville, Marcellus and Eagle Ford Shales, closer spacing is more beneficial.

While the number of perforation clusters is increased, the chance to adequately stimulate each cluster is lowered (Beard 2011). The main motivation behind tighter cluster spacing is to have higher Inıtial Productions (IPs), however, Cheng (2012) claims that, increasing the perforation clusters in one stage does not necessarily increase the IPs. Perforations placed too close to each other can induce fracture interference, which in turn result in higher fracturing pressures and prevent creation of dominant fractures due to uneven distribution of fracturing fluids (Miller *et al.* 2011).

Moreover, bringing perforation clusters closer would result in strong stress concentrations (**stress shadowing**) around the inner fractures and hence ineffective fractures. Narrower fracture widths are also possible results of closer cluster spacing, which in turn cause problems in proppant transportation (Cheng 2012). Stress shadowing can be explained as while stimulating the closely spaced hydraulic fractures, stress accumulates and consequently increases the minimum horizontal stress in the target zone. This will in turn gradually reduce the stress contrast between the target zone and the natural barrier zones. While stimulation of subsequent stages, fractures will grow upward (or rarely downward), hence out of the zone (Figure 51 - Stage #3 to #5). While stress accumulates in the area above or below the target zone, fractures again start to grow in the target zone (Figure 51 - Stage #6) (Dohmen *et al.* 2014).

Stress concentration reaches the maximum at the time of fracturing treatment and supposed to decay till fracture closure as pressure reduction due to fluid leak off into the matrix. However, the pressure reduction may take extended duration due to slow leak off and high stress may last at considerable amounts at the time of the next fracturing stage. The industry needs to optimize the cluster spacing while maximizing the number of fractures and minimizing the impact of stress concentrations. Current industry practice is determined as the cluster spacing should be less than 1.5 times the fracture height, even at this ratio the stress concentration is not negligible (Cheng 2012).

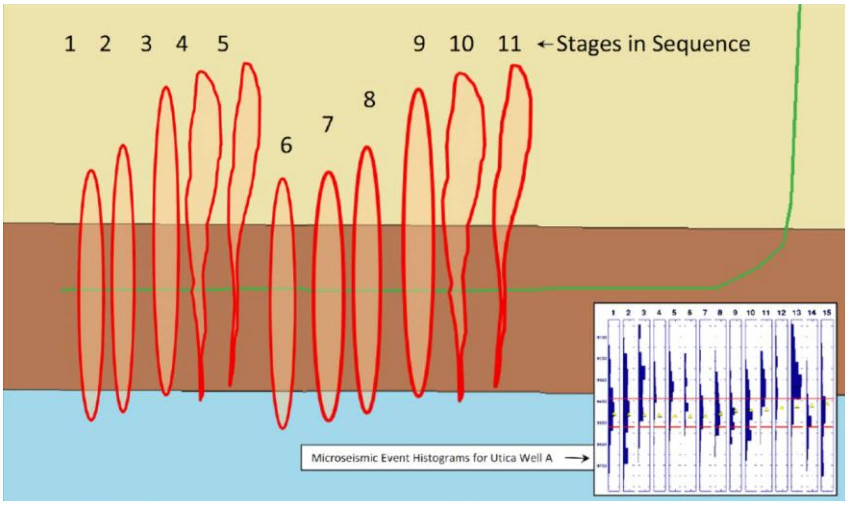


Figure 51 – Stress shadowing causes out of zone fractures (after Dohmen *et al.* 2014)

In each lateral length, although reducing the cluster spacing will increase the number of fractures in the design, this will not necessarily result in improved well performances. In other words, ineffective fractures caused by smaller cluster spacing may lead to lower gas rates and lower EUR (Cheng 2012, Javadi 2015, Dohmen *et al.* 2014).

Secondly, stage spacing typically correlates with perforation cluster spacing and typical stage length is around 250 – 500 ft (Beard 2011). Miller *et al.* (2011) concluded their study with a stage length recommendation of 300 - 400 ft.

Average perforation cluster spacing and perforation clusters per stages for six major US shale basins studied by Miller *et al.* (2011) are given in Table 10.

Figure 52 presents the increment in the number of fracturing stages contribute highly positively to the well productivity. Moreover, one can see that the correlation with average lateral length and productivity is weaker comparing to number of fracturing stages.

Table 10 – Average perforation cluster spacing and perforation clusters per stage for six major shale basins studied by the authors (after Miller et al. 2011)

Basin	Perforation Cluster Spacing (ft)	Perforation Clusters per Stage
Woodford	130	4.2
Barnett	183	3.3
Fayetteville	120	4.3
Eagle Ford	72	2.8
Haynesville	87	4.5
Marcellus	50	5.2

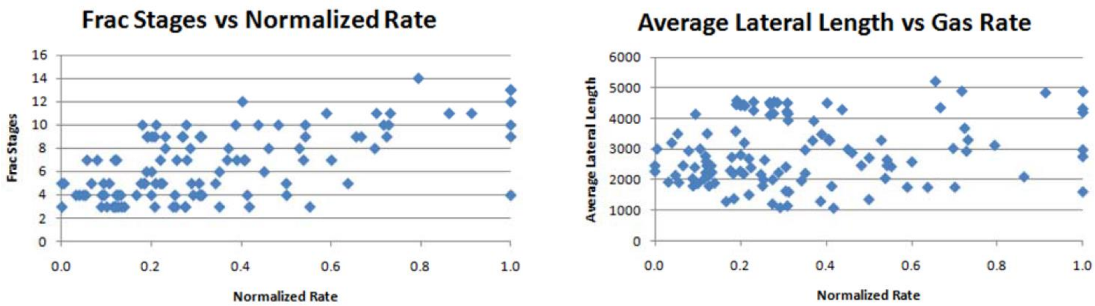


Figure 52 – Average number of frac stages and lateral length vs rates (after Miller et al. 2011)

The study of Javadi and Mohagheg (2015) on 164 Marcellus wells also claims that, longer lateral lengths and shorter cluster spacing can result in higher EURs, however, increasing the lateral length with same cluster spacing does not necessarily have positive effect on EUR (Figure 53). Hereby, it is also worth mentioning that the placed proppant amount and the volume of fluid injected have a tremendous importance in the EUR. It is clearly presented in Figure 54 and Figure 55 that, increase in both parameters leads to increase in 10-year-EUR. To be more specific, EUR is more sensitive to placed proppant amount.

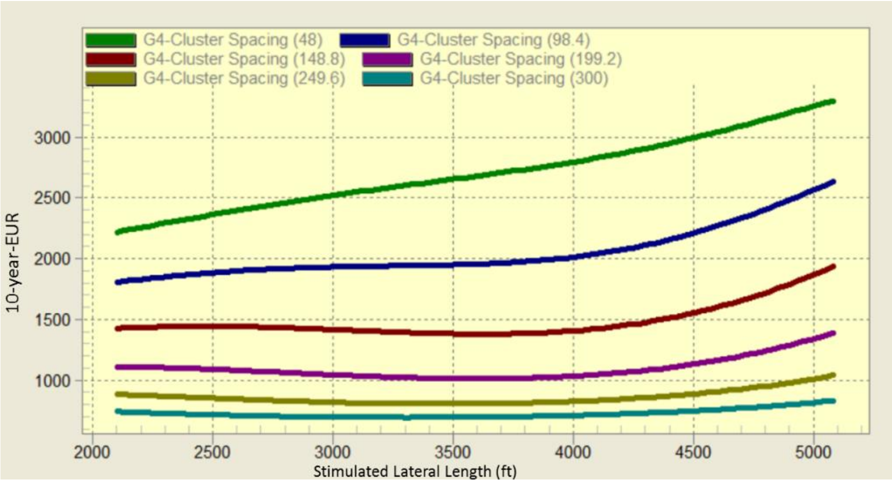


Figure 53 – EUR as a function of cluster spacing (after Javadi and Mohagheg 2015)

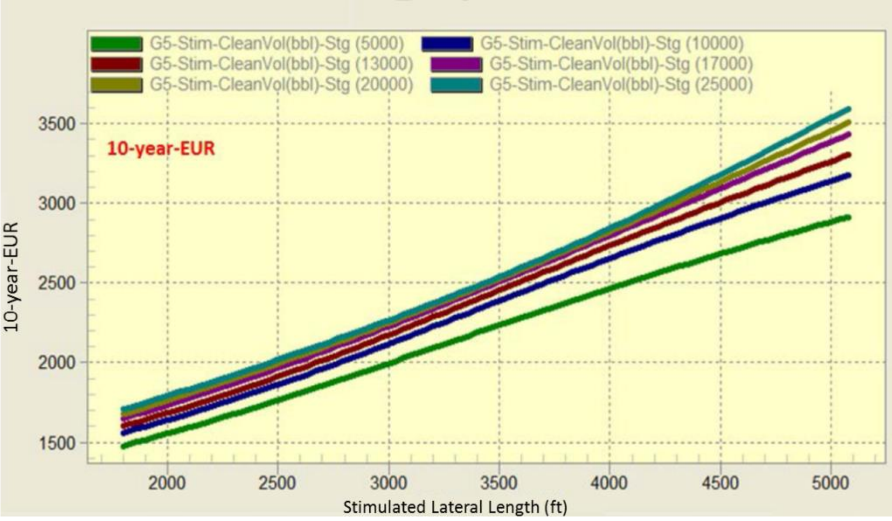


Figure 54 – EUR as a function of injected fluid volume (after Javadi and Mohagheg 2015)

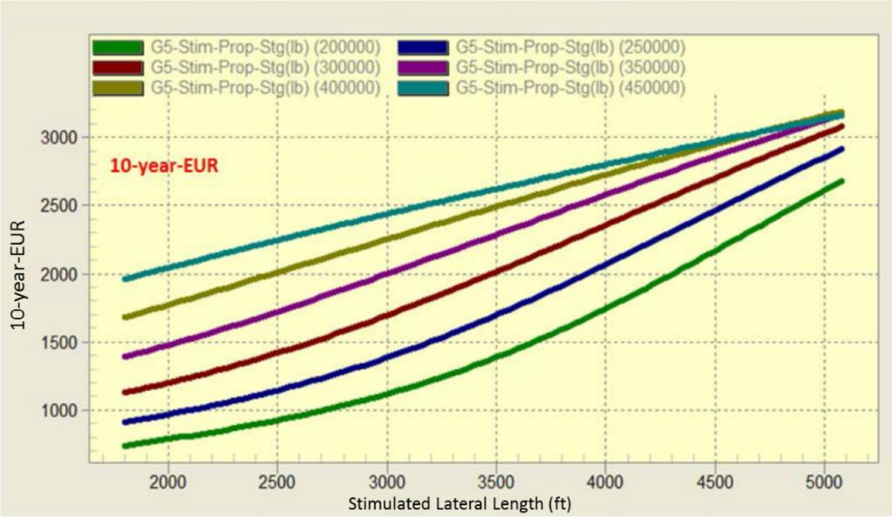


Figure 55 – EUR as a function of injected proppant amount (after Javadi and Mohagheg 2015)

3.3. Well Design and Geometry

Each play type needs a special well design and one type does not fit all. Careful well design considering well spacing, well geometry and optimum tubular selection is crucial. Tubular selection includes the determination of suitable sizes and metallurgy considering many parameters such as maximum treating pressures and rates, fracture staging, flowback, clean-up, re-stimulation, well life span, liquid loading and lifting, corrosion and future abandonment. Meanwhile, keeping the costs as low as possible to sustain the economic feasibility is the core of well design (Miskimins 2008).

As for well geometry, the first step is identifying the maximum and minimum horizontal stress directions, which can be estimated through wireline logs performed in a pilot hole. As discussed earlier, wells in shale formations should be drilled perpendicular to maximum horizontal stress to obtain a complex transverse fracture network.

The lateral length is the second step of the well geometry to be determined. It is primarily driven by economics together with drilling costs, completion efficiency and wellbore failure risk (Beard 2011). In the U.S. shale plays, the average lateral lengths for gas wells are 3,000 to 5,000 ft and for oil wells are 6,000 to 10,000 ft (Kennedy *et al.* 2016). Hereby, the lateral length in turn determines the number of stimulation stages and stimulation parameters. In Table 11, the average lateral length and stage information by basin are given for Big Six US shale basins.

Table 11 – Average lateral length and stimulation stage details by basin (after Miller et al. 2011)

Basin	Lateral Length (ft)	Number of Stimulation Stages	Stage Length (ft)	Distance Between Stages (ft)
Woodford	3090	6.1	528	166
Barnett	2422	5.6	476	217
Fayetteville	2903	7.1	412	111
Eagle Ford	2176	11.8	180	100
Haynesville	4025	10.2	394	83
Marcellus	3115	10.0	308	66

3.4. Well Spacing and Drainage Area

One of the primary constituent of field development costs is well cost, which could be minimized by determination of optimum number of wells, i.e. optimum well spacing without impairing net present value. However, this optimization process is highly complicated and controversial (John and Onyekonwu 2010). Muskat (1949) defines the reservoir engineering as the exploiting hydrocarbon reservoirs with maximum efficiency, i.e. maximum recovery of hydrocarbons at a minimum cost.

Theoretically; for a homogeneous, uniform and continuous reservoir, the ultimate primary recovery is independent of well spacing (Corrie 2001, Craze and Buckley 1945). Muskat (1949) evaluated this problem in two different perspective: the physical ultimate recovery and the economic ultimate recovery.

From the physical standpoint, increasing the well number beyond a minimum number of wells (W_m) to achieve maximum recovery would not increase ultimate primary extraction. As for the economic standpoint, there is an optimum well number (W_o) to be determined which yields maximum economic return (Corrie 2001, Muskat 1949).

Traditionally, to determine a preliminary optimum well number in conventional reservoirs, plots of economic return versus well spacing or net present value versus well number are used (Muskat 1949). Corrie (2001) proposed an analytical approach to solve this problem directly by using the independent variables; reserves, initial production rate per well, oil price, total present value cost per well and interest rate. This approach is based on two assumptions, firstly the well's initial production rate will decline over the life of the reservoir and secondly the ultimate primary recovery is independent of well spacing. Well spacing options with different densities are presented in Figure 56.

Corrie (2001) proposed an analytical solution using Muskat (1949)'s simplified economic model and relying on exponential production decline, which end up with the number of wells required to develop a field. The **net present value** (*NPV*) of a field development project is represented by Eqn. 9. Using mid-step equations (Eqns. 10 to 15) optimum number of wells (Eqn. 16) could be reached.

$$NPV(W) = df \times N_p \times V - C \cdot W - Z \tag{9}$$

Several assumptions lies behind this approximation;

- Reserves remains constant,
- Present net value is after income tax,
- All investments are incurred at year zero,
- All wells have same initial production rate and decline at the same rate,
- Oil price is netted back to the wellhead.

Nomenclatures for all equations (Eqns. 9 to 16) are presented below.

NPV (W)	NPV as a function of the number of wells, $
df	Discount factor
N_p	Cumulative oil production during project (EUR), bbls
V	Oil price netted back to the well after income tax, $/bbl
C	PV of all capital investments per well after income tax, $
W	number of wells
Z	PV of other investments after income tax, $
$PV(N_p)$	Present Value (*PV*) of reserves, bbls
i	Interest rate or discount rate, fraction (p.a.)
D	Yearly production decline rate, fraction (p.a.)
q_t	Daily oil production rate per well at time t, bbls/day
q_i	Initial daily oil production rate per well, bbls/day
W_o	Optimum number of wells for maximum economic return
W_m	Minimum number of wells for maximum oil extraction

Where the discount factor (*df*) could be estimated by:

$$df = PV(N_p) / N_p \tag{10}$$

Basically, cumulative production (N_p) can be thought as:

$$N_p = \int 365 \cdot q_t \cdot dt \qquad \textbf{(11)}$$

Where, production rate at a particular time (q_t) can be represented as:

$$q_t = q_i \cdot (1 - D)^t \qquad \textbf{(12)}$$

Replacing Eqn. 12 in Eqn. 11 and neglecting q_t at economic limit, the cumulative oil production (N_p) from a number of wells (W) is:

$$N_p = \frac{365 \cdot W \cdot q_i}{-\ln(1 - D)} \qquad \textbf{(13)}$$

Hence, present value of N_p at interest rate "i" is:

$$PV(N_P) = \frac{365 \cdot W \cdot q_i}{-\ln\left[(1 - D)/(1 + i)\right]} \qquad \textbf{(14)}$$

Firstly, a new "*df*" representation will be created by replacing Eqn. 13 and Eqn. 14 into Eqn. 10. Secondly, replacing "$-\ln(1-D)$" with "$365 \cdot W \cdot q_i / N_p$" in the new representation and replacing this in Eqn. 9, the following Eqn. 15 will be obtained.

$$NPV(W) = \left\{ \frac{365 \cdot W \cdot q_i \cdot V}{\left[\left(365 \cdot W \cdot q_i / N_p\right) + \ln(1 + i)\right]} \right\} - C.W - Z \qquad \textbf{(15)}$$

To find the maximum value of *NPV (W)*; its derivative with respect to number of wells (*W)* should be taken and equalized to zero $\left(d\,NPV(W) \big/ d\,W = 0 \right)$.

Then solving the resulting quadratic equation for *W*, optimum number of wells can be defined by:

$$W_o = \frac{N_p \left\{ \ln(1 + i) \cdot C - \left[365 \cdot q \cdot V \cdot C \cdot \ln(1 + i)\right]^{0.5} \right\}}{(-365 \cdot q \cdot C)} \qquad \textbf{(16)}$$

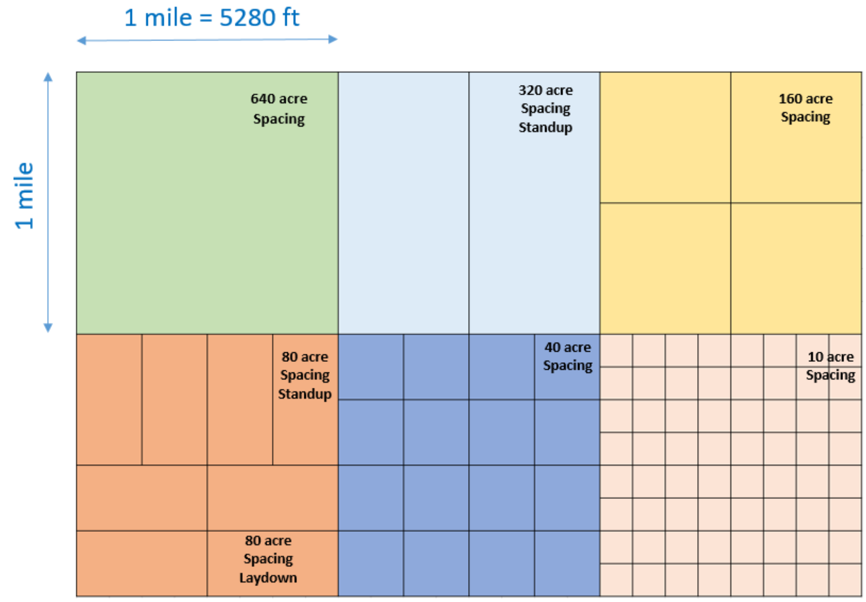


Figure 56 – Well spacing representation

Edwards *et al.* (2011) studied well spacing in a series of hydraulically fractured horizontal wells of Marcellus Shale. They monitored 500 ft and 1000 ft offset wells during completion with micro-seismic, radioactive tracers, chemical tracers, and pressure gauges. Moreover, they evaluated the post-flowback well performance to define the interaction among natural fractures and induced fractures, which in turn helped to identify the actual impact and effectiveness of the hydraulic fractures. The study revealed that, although a communication is observed during fracturing of the 500 ft wells, there is no difference in performance between 500 ft spaced wells and 1000 ft spaced wells.

In these Marcellus Shale wells, radius of influence is found to be greater than 1000 ft according to micro-seismic data. However, the analysis of 6-months of production data using a nodal analysis software suggests less than half of this value as the effective frac-half-length. In the offset wells with 500 ft spacing, there occurs greater communication during fracturing operations; however, it ceases after the well is put on flow-back. This communication is consistent with the micro-seismic data, which yields 1000 ft radius for SRV. The termination of this communication is apparently due to closing of induced fractures in these ultra-tight reservoirs. The production analysis shows no interference during production with an effective frac half-length of 150-200 ft, which is much less than SRV (Edwards *et al.* 2011).

The effect of the well spacing should also be considered for evaluating the pressure data, since a closer spacing of wells would bring interference between wells and lessens the transient period, i.e. decline steepens. Hence, as advised by some authors (e.g. by Dr. Tom Blasingame as discussed in Haskett and Jenkins 2009), extrapolating early time data in closely spaced wells may bring overestimation of reserves (Haskett and Jenkins 2009).

Moreover, according to a study on Haynesville Shale by Pope *et al.* (2010), micro-seismic mapping gives the SRV; however, it does not define the effective fracture half-length and conductivity. To reach this information, post-fracture well performance analysis is necessary. Effective fracture lengths are generally shorter due to several reasons such as: the proppant placement was not effective due to embedment, spalling of proppants, gel damage, lower proppant concentrations than modeled, over displacement of proppants, inadequate coverage of perforation clusters limiting the contribution of fractures.

At this point, it would be beneficial to mention a little more on SRV estimation approaches to give a better understanding of this concept, and consequently to use in reserves estimations. SRV can be estimated by means of micro-seismic, fracture distribution models or simulation models (Heckman *et al.* 2013).

One major side effect arose after reducing the well spacing by infill drilling is called as the *Fracture Hits (Frac Hits),* which is basically occur when the fractures created in one wellbore during treatment hit another offset wellbore, i.e. the occurrence of cross-well communication caused by fracture treatment of one well. This phenomenon brings early decline in the wells' oil and gas production. Moreover, it can be strong enough to damage production tubing, casing, and even wellheads. Besides, they may affect several wells on a pad or nearby pads. Regulators in various states adopting rules that mandates companies to notify other operators in nearby areas for an upcoming fracturing operation, moreover, usage of high-pressure wellhead equipment entailed to prevent any risk of blowout due to frac hit. On the other hand, very rare cases showed a production increment in the affected wells (Jacobs 2017). Fracture hits can be handy in determination of propped half-length, hence, the spacing of subsequent wells can be optimized (Carboceramics 2017a).

CHAPTER 4

TECHNICALLY RECOVERABLE RESOURCES

Technically recoverable resources (TRR) are the hydrocarbon accumulations that are certain to exist together with the required technology to extract it. However, this certain accumulation cannot be booked as reserves until the wells are drilled and reservoirs are developed (Holditch 2006).

Marginal economics of unconventional reservoirs need reliable reserves estimations for successful decision making, which are on the knife-edge (Kabir and Lake 2011). Until today, industry do not have a consensus for how to evaluate the reserves potential of shale oil and shale gas fields. Since these accumulations are not affected from hydrodynamic influences, they exist in comparatively very large areas, i.e. they are continuous-type deposits (SPE-PRMS 2007). Since, the resulting heterogeneity is too high, sampling density becomes highly important for characterizing these shale zones.

SPEE (2010) includes an important criterion (as one of the four essential criterion) to the definition of resource plays: "Wells exhibit a repeatable statistical distribution of estimated ultimate recovery (EURs)". This sentence is the backbone of the basis behind the common resource evaluation methodologies, as of today (Seager 2016). Interestingly, these reservoirs are heterogeneous on a local scale, whereas groups of wells in segments of the play show significant homogeneity. Hence, if the drainage area of typical wells could be estimated, the required number of additional wells to fully develop the reservoir could be projected. After determining the areal extent (or using the fixed lease boundary), one can estimate the overall hydrocarbon potential.

As is well known from conventional reservoirs, the principal techniques for EUR determination are material balance method, numerical reservoir simulation, decline curve analysis (DCA) and volumetric analysis. While unconventional reservoirs in concern, the robustness of these techniques are questionable.

There exists also analogy method, which is estimating reserves and future production by analogy to existing reservoirs or wells, as one of the estimation methods. It is also a useful tool to use either for conventional and unconventional resource estimations. However, one can use analogy method only to have an initial insight and guess some initial parameters when there is not enough data. The key point of this method is finding truly appropriate analogies, i.e. analog should be at a more advanced development stage, completion techniques must be the same, parameters controlling recovery factor should be similar (Lee and Sidle 2010, SEC 2008).

Material balance method is a very useful tool for conventional reservoirs, especially for volumetric gas reservoirs (Tuğan and Onur 2015). There are two main assumptions behind this method; unchanging drainage volume and stabilized (boundary-dominated) flow. However, due to very long shut-in time requirement of a stabilized drainage volume in ultra-tight shale formations, material balance method will not be useful. In other words, since obtaining a single reliable reservoir pressure from an individual well to represent the reservoir as a tank is nearly impossible, using the material balance method to calculate the volume of a shale formation is unpractical or any attempt will result in too low volume estimates (Lee and Sidle 2010).

As for the volumetric methods, there exists a huge uncertainty in recovery factor parameter and the actual drainage area (Baihly *et al.* 2010). Shale plays generally have low geologic risk contrary to their high commercial risk. Moreover, large uncertainties exist in geologic and engineering data, hence in the results of estimations using these data (Dong *et al.* 2013). As stated by Tuğan and Onur (2015), uncertainty should be assessed carefully by utilizing probabilistic approach, especially when unconventional plays are in concern. Probabilistic approach could either be performed via random selection of each parameter to calculate outcomes, known as Monte Carlo Method (MCM) or via an analytic method called Analytic Uncertainty Propagation Method

(AUPM). Details for uncertainty assessment methods can be found in the appendix part of this dissertation (Onur 2010).

Numerical reservoir simulation has proved itself, especially for data rich fields. Future well productions are estimated fair enough, where the physics of shale gas production mechanism is well-known (Baihly *et al.* 2010).

On the other hand, Duong (2010) argues that, although pressure initialization in simulation modeling is based on an equilibrium state with the fluid gradient, field data show a disequilibrium state for pressure transition through a shale gas zone.

Last but not the least, **decline curve analysis (DCA)** is a reliable indicator of estimated ultimate recovery (EUR) as it is in the conventional reservoirs. Moreover, its simplicity in application made it the most frequently used production-forecasting tool for shale formations. Naturally, reliable production data are vital to utilize DCA. However, DCA applied for conventional reservoirs, i.e. Arps' method, is insufficient to represent the flow behavior of shale formations and they have certain shortcomings. Above all, Arps' method is applicable for boundary-dominated flow period, however, wells producing in shale formations exhibit transient flow period, which can last for the first several years. Moreover, these wells have bi-linear and linear flow regimes that may dominate their entire production life. However, these flow regimes are absent in conventional wells (Freeborn and Russell 2012).

Several authors (Ilk et al. 2008, Valko et al. 2009, Duong 2010) propose more-recent empirical methods to overcome these shortcomings. However, the utilization of these emerging methods came short due to complex equations to be solved and hence these methods implemented in some commercial software (e.g. IHS Markit DeclinePlus) (IHS 2017). In this dissertation, both Arps' method and these emerging empirical methods will be discussed and their strengths and weaknesses will be addressed. Moreover, another method to forecast future production in shale formations, proposed by Mr. Hampton Roach, so-called "3-Segment Decline Curve Analysis" (Giles *et al.* 2012) will be introduced in Section 4.2.

Regardless of the estimation methodology listed above, drainage area should be estimated carefully to determine the well spacing, hence the well numbers that will be used in estimations. In addition, the total surface area suitable for drilling should also be determined carefully, i.e. terrain conditions, infrastructure (roads), forests, national parks, critical water resources and population density should be taken into account (Giles *et al.* 2012). Finally, one of the most important issues in reserves estimations and production forecasts is to establish a range of results including the probability distribution (Lee and Sidle 2010).

4.1. Volumetric Estimations

This estimation methodology basically relies on the determination of hydrocarbon in place in the volume under consideration (e.g. drainage volume of an individual well, or volume of a segment, or a reservoir), together with a fraction of these in-place hydrocarbons that are likely to be recovered, i.e. recovery factor (Lee and Sidle 2010). Estimations using this method especially become useful when it is supported by appropriate analogy from more mature nearby wells (Glorioso and Rattia 2012) and volumetric estimates at least can be used as credibility check for other estimation methodologies (Lee and Sidle 2010).

As discussed earlier, unconventional gas reservoirs have different accumulation types and each has specific problems at in-place volume determination procedures. For shale gas resources, although gas volumes stored in pore spaces account the most of the in-place volume, estimation of in-place adsorbed gas is also important. As for tight gas reservoirs, which have conventional trapping mechanisms, areal extent determination, i.e. boundary determination, becomes the main difficulty. Besides, the estimation of other reservoir properties to be used as input (e.g. net pay thickness) may include high uncertainties in tight gas reservoirs (Lee and Sidle 2010).

Most importantly, in both accumulation types recovery factor determination is very difficult, hence will be highly uncertain. Due to very low permeabilities, the area to be drained by a well will strongly be influenced by the number and size of the stimulation treatments on the wells; hence, the reservoir volume beyond SRV would remain undrained until abandonment.

Various other difficulties specific to volumetric estimates of shale gas resources are also listed below (Lee and Sidle 2010):

- Gas saturation cannot be determined directly or indirectly via well-log data,
- Free vs. adsorbed gas ratio may not be determined easily,
- Anomalous gas contents may occur due to complex burial or fluid migration.

While performing in place calculations for shales, several sources for hydrocarbon should be considered (Merey 2013). For example, Ambrose *et al.* (2010) suggested the following formula to estimate the gas content in a shale gas formation:

$$G_{st} = G_f + G_a + G_{so} + G_{sw} \quad \textbf{(17)}$$

where, G_{st} : total gas storage capacity, scf/ton, G_f : free gas storage capacity, scf/ton, G_a : adsorbed gas storage capacity, scf/ton, G_{so} : dissolved gas-in-oil storage capacity, scf/ton, G_{sw} : dissolved gas-in-water storage capacity, scf/ton. As for industry practice, G_{so} and G_{sw} are omitted and following equations can be used to estimate G_f and G_a:

$$G_f = 32.0368 \frac{\emptyset(1-S_w-S_o)}{\rho_b B_g} \quad \textbf{(18)}$$

$$G_a = G_{sL} \frac{P}{P+P_L} \quad \textbf{(19)}$$

where, P : pressure, psia, P_L : Langmuir pressure, psi, G_{sL} : Langmuir volume, scf/ton, S_w : water saturation, dimensionless, S_o : oil saturation, dimensionless, B_g : gas formation volume factor, rcf/scf, ρ_b : bulk rock density, g/cc, ρ_s : sorbed-phase density, g/cc, $\emptyset$: total porosity fraction, dimensionless.

However, Ambrose *et al.* (2010) suggest a new method, which recommends the subtraction of the gas occupied by adsorbed gas from the free gas volume, i.e. a volume correction for free gas (Figure 57). In the case of organic-rich shales with nanopores, adsorbed phase occupies a significant pore volume and reduce porosity available for free gas storage.

Ambrose *et al.* (2010) also showed that unless the correction proposed in their study is not utilized, overestimation of free-gas, hence total gas is inevitable. The proposed equation for the corrected free gas storage capacity is as follows:

$$G_f = 32.0368 \frac{\emptyset(1 - S_w - S_o) - \emptyset_a}{\rho_b B_g} \quad \textbf{(20)}$$

where, $\emptyset_a$ is the porosity consumed by adsorbed gas volume in shale gas reservoir and can be written for a single-component fluid system as:

$$\emptyset_a = 1.318 \times 10^{-6} \dot{\hat{M}} \frac{\rho_b}{\rho_s} G_a \quad \textbf{(21)}$$

Hence, the total gas storage capacity equation becomes:

$$G_{st} = \frac{32.0368}{B_g} \left[\frac{\emptyset(1 - S_w)}{\rho_b} - \frac{1.318 \times 10^{-6} \dot{\hat{M}}}{\rho_s} \left(G_{sL} \frac{P}{P + P_L} \right) \right] + \left[G_{sL} \frac{P}{P + P_L} \right] \quad \textbf{(22)}$$

where, $\dot{\hat{M}}$: apparent natural-gas molecular weight, lbm/lbmole, P : pressure, psia, P_L : Langmuir pressure, psi, G_{sL} : Langmuir volume, scf/ton, S_w : water saturation, dimensionless, ρ_b : bulk rock density, g/cc, ρ_s : sorbed phase density, g/cc, $\emptyset$: total porosity fraction, dimensionaless, $\emptyset_a$: sorbed phase porosity fraction, dimensionless.

Adsorbed gas density estimation requires thorough studies (Belyadi *et al.* 2017), however, as stated in Ambrose *et al.* (2010) according to molecular modeling and simulation of methane adsorption in organic silt-pores, sorbed phase density (ρ_s) of methane can be taken as 0.37 g/cm^3, disregarding major deviations caused by pore size differences and minor deviations caused by temperature differences.

Moreover, for practical purposes, apparent natural-gas molecular weight ($\dot{\hat{M}}$) can be taken as 20 lb/lb-mole, bulk rock density (ρ_b) can be taken as 2.5 g/cm^3 (Ambrose *et al.* 2010). In addition, it should be noted that molecular weight of pure methane is 16.04 lb/lb-mole.

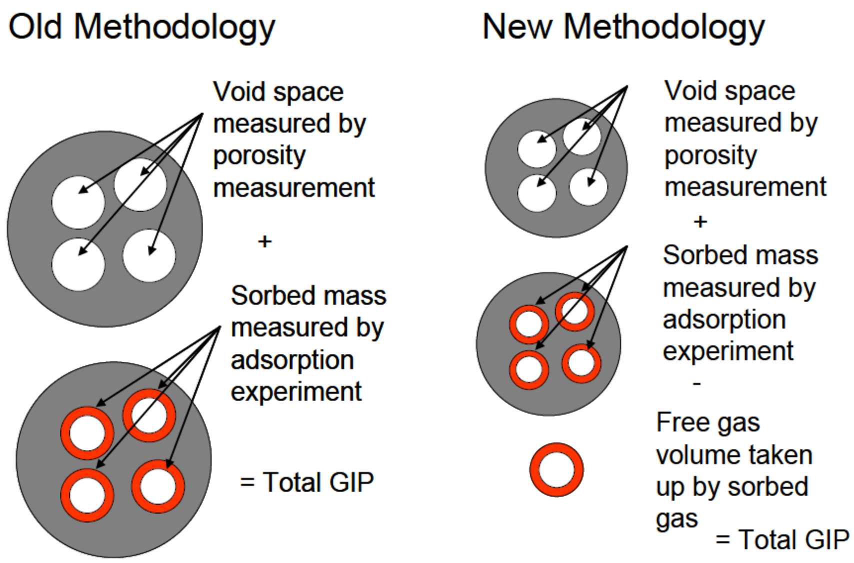


Figure 57 – New methodology in predicting shale gas in place (after Ambrose *et al.* 2010)

While utilizing volumetric methods, gas content of the formation samples can be measured by direct method or indirect method.

4.1.1. Adsorbed Gas Estimation (Indirect Method)

To estimate the adsorbed gas initially in place ($GIIP_{ad}$) with Langmuir isotherms, CBM industry developed the following equation (Glorioso and Rattia 2012):

$$GIIP_{ad} = g_c x \rho_b x A x h x C \qquad \textbf{(23)}$$

where, $GIIP_{ad}$: adsorbed gas initially in place (Bcf), g_c : adsorbed gas content (scf/ton), from Langmuir isotherm equation, ρ_b : average formation density in h (g/cc), A : area (acres), h : average usable depth (ft), C : units conversion factor (1.3597×10^{-6}).

It should be noted that, both inorganic matrix (clay, silt, carbonates etc.) and the organic matter can be porous; hence, organic matter contains free gas as well as adsorbed gas.

4.1.2. Total Gas Estimation (Direct Method)

Utilization of canister desorption analysis in laboratory provides direct measurement of total gas in formation samples complying with the following formula. Moreover, by replacing g_c in Eqn. 23 by G_{st} obtained from Eqn. 24, $GIIP_{tot}$ (Total GIIP) can be estimated (Glorioso and Rattia 2012):

$$G_{st} = 32.0368 \times \frac{V_l + V_m + V_c}{m_{ad}} \tag{24}$$

where, G_{st}: Total gas content (scf/ton), V_l : volume of lost gas (cc), V_m : volume of measured gas (cc), V_c : volume of crushed gas (cc), m_{ad} : air-dry gas volume (g).

Canister desorption provides only the total gas content, not proportions of desorbed or free gas, neither the pressure dependence of them (Boyer et al. 2006).

4.1.3. GIIP and Gas Reserves Estimation

Total gas in-place, based on log interpretation can be calculated by following equation (Glorioso and Rattia 2012):

$$GIIP_{Tot} = 43560 \times A \times h \times \phi_T \times (1 - Sw_T) \times \left(\frac{1}{B_g} \right) \times 10^{-9} \tag{25}$$

where, $GIIP_{Tot}$: total gas initially in place (Bcf), *A:* area (acres), *h*: average net thickness (ft), ϕ_T : total initial porosity (%), Sw_T : total initial water saturation (%), B_g: initial formation volume factor. Hence, the volume of free gas in place can be calculated by the difference of gas in-place total and gas in-place adsorbed (Figure 58) (Glorioso and Rattia 2012):

$$GIIP_{free} = GIIP_{Tot} - GIIP_{ad} \tag{26}$$

where, $GIIP_{free}$: free gas initially in place (Bcf), $GIIP_{Tot}$: total gas initially in place (Bcf), $GIIP_{ad}$: adsorbed gas initially in place (Bcf).

Some authors prefer to work with effective porosity and effective water saturation to estimate free gas. On the contrary, Glorioso and Rattia (2012) argue that using effective values will bring more uncertainty, since logs basically read total values.

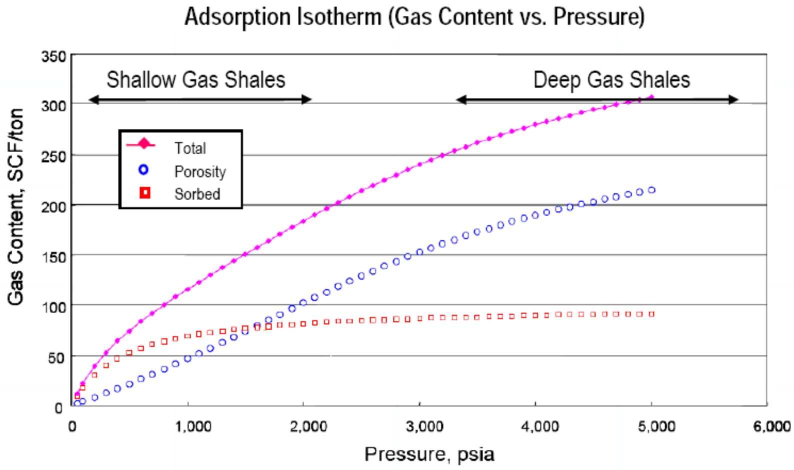


Figure 58 – Combining free and adsorbed gas for total gas in-place (after EIA 2013)

4.1.4. STOIIP and Oil Reserves Estimation

In-place oil estimations using geochemical testing can be performed using the equation below (Glorioso and Rattia 2012):

$$STOIIP_{S1yl} = \left(0.001 \times \frac{S1_{yl}}{\rho_o}\right) \times \rho_b \times A \times h \times C \tag{27}$$

where, $STOIIP_{S1yl}$: oil initially in-place (Mbbl), $S1_{yl}$: oil content (mg/g), P_o : oil density (g/cc), ρ_b : average formation density in h (g/cc), A : area (acres), h : average net thickness (ft), C : units conversion factor (7.758).

In addition, in-place oil estimation using logs can be performed by the following equation (Glorioso and Rattia 2012):

$$STOIIP_{Tot} = 7.758 \times A \times h \times \phi_T \times (1 - Sw_T) \times \left(\frac{1}{B_o}\right) \tag{28}$$

where, $STOIIP_{Tot}$: total oil initially in place (Mbbl). A: area (acres), h: average net thickness (ft), ϕ_T : total initial porosity (%), Sw_T : total initial water saturation (%), B_o : initial formation volume factor.

4.1.5. Recovery Factor (RF)

According to reports of EIA (2013), shale production experience of the US show that the recoverable amount of in place gas volumes, i.e. shale gas RF range between 20% - 30%, where extreme values like 15% as lowest and 35% as highest can be observed. On the other hand, recovery factor for shale oil range between 3% - 7%, where extreme values like 1% and 10% can be observed. The reason that shale oil recovery factors are much lower comparing to shale gas is the relatively higher viscosity of oil and capillary forces, which prevents oil to flow through fractures as easily as natural gas. EIA (2013) presents TRR of 41 countries outside the US by using a production forecast of 30 years, which brings RF calculations according to a well life of 30 years.

RF’s can be approximated considering a set of properties such as the mineralogy, i.e. fraccability of the rocks, presence of micro-fractures, state of stress for the shale formation, reservoir overpressure and absence of unfavorable faulting. RF’s may be assumed as following, considering the criterion associated with them (EIA 2013):

Favorable Hydrocarbon Recovery: RF’s of 6% for oil and 25% for gas can be assumed for prospects having low clay content, low-moderate geologic complexity and favorable reservoir properties, i.e. over-pressured shale formation and high oil-filled porosity.

Average Hydrocarbon Recovery: RF’s of 4-5% for oil and 20% for gas can be assumed for prospects having medium clay content, moderate geologic complexity and average reservoir properties (reservoir pressure).

Less Favorable Hydrocarbon Recovery: RF’s of 3% for oil and 15% for gas can be assumed for prospects having medium-high clay content, moderate-high geologic complexity and below average reservoir properties (reservoir pressure).

RF estimations are subject to change in time. For instance, utilizing closer well spacing, improving well designs, i.e. longer laterals and more frac stages, completion of more vertical net pay and development of lower zones may change the ratio of recoverable resources to in-place resources (EIA 2013).

4.2. Production Data Analysis

Conventional reservoirs initially exhibit transient flow, in which the reservoir pressure at the boundaries remain constant and flow boundary approaches to reservoir boundary. This period is characterized by high decline rates. After reaching an actual reservoir boundary or interference of another well, the reservoir pressure starts to decline and boundary dominated (BDF) flow begins. Actually, in the BDF period, traditional production data analysis methods come into rescue to analytically model the flow behavior (IHS 2016).

The most basic production data analysis method, Decline Curve Analysis (DCA) is an empirical method offered by Arps (1945) assuming boundary dominated flow at constant bottom-hole pressure. As can be deduced from its name, this method relies on the analysis of production rate declines and starts with matching the historical rate data on an analytical formulation by regressing the decline parameters and forecasting the future production rates. Presenting some basic definitions prior to starting the derivations would be useful, however, the intermediate steps in derivation of equations are omitted here. Details for the derivations can be found in Blasingame and Rushing (2005) and Onur (2015).

Definition of Loss Ratio (Decline Rate) "*D*" can be represented by:

$$D = -\frac{dq/dt}{q} \quad \text{or} \quad \frac{1}{D} = -\frac{q}{dq/dt} \tag{29}$$

Derivative of the Loss Ratio (Decline Exponent) "*b*" can be represented by:

$$b = \frac{d}{dt}\frac{1}{D} = -\frac{d}{dt}\left[\frac{q}{dq/dt}\right] \tag{30}$$

When considering D = constant, exponential decline will be reached which will represent pseudo-steady state (or BDF) flow in a closed reservoir for a constant compressibility liquid at a constant well-bore flowing pressure (Ilk *et al.* 2008b).

Omitting the intermediate steps, **exponential rate decline** equation will be:

$$q(t) = q_i . e^{-D_i . t} \tag{31}$$

The formulation for the **hyperbolic rate decline** equation can be represented as below:

$$q(t) = \frac{q_i}{(1 + b \cdot D_i \cdot t)^{1/b}} \tag{32}$$

Lastly, it would be handy to present an intermediate equation, which come out in the derivation process of hyperbolic equation by Blasingame and Rushing (2005).

$$D = \frac{1}{\frac{1}{D_i} + b \cdot t} \tag{33}$$

The variables and units for the equations above is as follows: q or $q(t)$: oil production rate at time t, q_i : initial oil production rate, b: constant related to decline type, D_i: initial nominal decline rate.

Arps' equations have always been considered as empirical, i.e. do not rely on any physical law of fluid flow, until Fetkovich and others place DCA on a fundamental basis using the constant wellbore pressure analytical solution and combinations of material balance equations and pseudo-steady-state rate equations to derive rate/time decline equations (Fetkovich 1996).

Utilizing the mathematical background with the specified assumptions below, Fetkovich (1996) showed that decline constant "b" varies between 0 and 1.

- Stabilized (boundary-dominated) flow,
- Constant bottom hole pressure,
- Unchanging drainage area and,
- Fixed skin factor.

The simplified forms of Eqn. 32 according to various "*b*" values are given in Table 12.

Table 12 – Forms of Arps' decline equation for different "b" values

Exponential	Hyperbolic	Harmonic
$b = 0$	$0 < b < 1$	$b = 1$
$q(t) = q_i.e^{-D_i t}$	$q(t) = q_i.(1 + b \cdot D_i \cdot t)^{-1/b}$	$q(t) = \dfrac{q_i}{(1 + D_i.t)}$

Although, the assumptions above may be valid for most of the conventional reservoirs in certain time periods, it is very difficult to satisfy these conditions in ultra-tight unconventional reservoirs. Hydraulically fractured shale gas and tight gas wells may remain in transient flow for several years (Giles *et al.* 2012, IHS 2016). As for these tight formations, boundary-dominated flow (assumed in Arps' method) cannot be reached in a reasonable time frame, hence parameters assumed for production analysis of conventional formations would lead to optimistic results (Ilk *et al.* 2008b, Dong *et al.* 2013). Moreover, analysts are obliged to forecast future production and estimate reserves relying only on transient period data (Cheng *et al.* 2008).

Roberts *et al.* (1991) modeled the transient gas flow in a horizontal well with multiple fractures as follows. The wells' drainage area starts with near wellbore and continues to grow with time (several days) beyond the wellbore and hydraulic fractures. No-flow boundaries in unconventional plays are function of well density and pattern, i.e. the no-flow boundary is defined by the maximum area it can drain given offset drainage areas of surrounding wells.

Consequently, to match early historical production data in horizontal and vertical wells during transient inflow, using decline parameters outside the normal range ($b \geq 1$) works well (Giles *et al.* 2012; Roberts *et al.* 1991). Valko and Lee (2010) applied Valko (2009)'s stretched exponential production decline method (to be discussed below) to analyze 14,687 wells, which is the largest analyzed dataset to date in Barnett Shale, instead of individual subjective curve matching. This study proved that, for tight gas wells, the decline exponent stays larger than unity ($b > 1$) for the transient period.

However, using $b \geq 1$ also leads to optimistic EURs with unreasonably long well lives (Maley 1985, Lee and Sidle 2010). Following equations show how cumulative production "Q" converges to infinity, in the conditions of "$b \geq 1$" in Arps' equation (Eqn. 32).

$$Q = \int_0^t q(t).dt \tag{34}$$

For b = 0 (exponential decline), Q converges to a finite and realistic value:

$$Q = \int_0^t q_i.e^{-D_i.t}.dt \Rightarrow \mathrm{Q} = \lim_{t\to\infty}\left(\frac{q_i.e^{-D_i.t}}{-D_i} - \frac{q_i.e^{-D_i.0}}{-D_i}\right) = \frac{q_i - q}{D_i} \tag{35}$$

$$t \to \infty,\ Q \to \frac{q_i}{D_i}$$

For 0 < b < 1 (hyperbolic decline), Q converges to a finite and realistic value:

$$\begin{gathered} Q = \int_0^t q_i.(1 + b \cdot D_i \cdot t)^{1/b}.dt \Rightarrow \\ \mathrm{Q} = \lim_{t\to\infty}\left(\frac{q_i}{D_i.(b-1)}(1 + b.D_i.t)^{1-\frac{1}{b}} - \frac{q_i}{D_i.(b-1)}\right) \end{gathered} \tag{36}$$

$$\mathrm{Q} = \lim_{t\to\infty}\left(\frac{q_i}{D_i.(1-b)}\left(1 - (1 + b.D_i.t)^{1-\frac{1}{b}}\right)\right) \Rightarrow t \to \infty,\ Q \to \frac{q_i}{D_i.(1-b)} \tag{37}$$

For b = 1 (harmonic decline), Q converges to infinity, i.e. unrealistic results:

$$Q = \int_0^t \frac{q_i}{(1 + D_i.t)}.dt \Rightarrow \mathrm{Q} = \lim_{t\to\infty} \frac{q_i}{D_i}.\ln(1 + D_i.t) \tag{38}$$

$$t \to \infty,\ Q \to \infty$$

For b > 1, Q increases without bound; i.e. converges to infinity:

$$Q = \int_0^t q_i.(1 + b \cdot D_i \cdot t)^{1/b}.dt \Rightarrow \mathrm{Q} = \lim_{t\to\infty}\left(\frac{q_i}{D_i.(1-b)}\left(1 - (1 + b.D_i.t)^{1-\frac{1}{b}}\right)\right) \tag{39}$$

$$t \to \infty,\ Q \to \infty$$

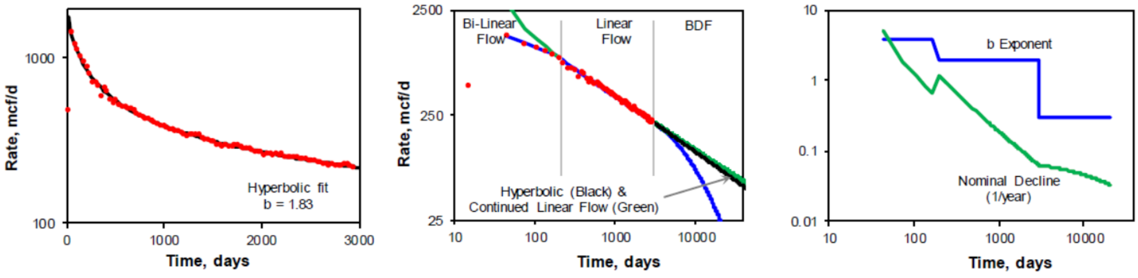
Thus, values of $b \geq 1$ will end up with a cumulative production of infinity, hence beyond realistic values, i.e. physically unreasonable. On the other hand, rapidly declining rate data are characteristics of low-permeability stimulated wells and those show apparent values of $b > 1$, which is also called as super hyperbolic. However, better fit of some data with values of $b \geq 1$ mean that the data are taken from the transient-flow regime. Hence, usage of b values obtained from transient portion of a decline data for the entire analysis would result in overly optimistic forecasts (Fetkovich *et al.* 1987, Freeborn and Russell 2012).

An approach to overcome the infinite cumulative production problem while using $b \geq 1$ is limiting the decline rate by a minimum value "D_{min}" based on analogy or intuition. In other words, introducing a terminal condition using a constant D_{min} and utilizing exponential decline for the remaining production life after decline rate reduces to D_{min} (Lee and Sidle 2010, Vassilellis *et al.* 2016). This minimum decline rate is usually 5 – 10 percent per year (AbdelMawla and Hegazy 2015). However, this approach do not rely on any physical background. After Rushing et al. (2007) introduced hybrid decline schemes (varying b values while producing) for shale plays, they started to be used widely, however, the determination of minimum decline rate and other decline parameters are arbitrary, hence needs experience in the formation in concern (Vassilellis *et al.* 2016).

Blasingame and Rushing (2005) and Rushing *et al*. (2007) observed that as more data become available, i.e. increasing production time, best-fit value of b tends to decrease. This assures us that, if we have enough production to see stabilized (boundary-dominated) flow, we would have b values smaller than unity. At this very point, the so-called stretched exponential equations, in fact empirical models to predict future production of shale reservoirs, came into concern. Several authors (Ilk et al. 2008, Valko 2009, Duong 2010 and Giles et al. 2011) developed several versions of this approach to well represent the flow, i.e. honor the changing "b" exponents (Freeborn and Russell 2012).

In Figure 59a hyperbolic decline with $b = 1.83$ matches with the early production data, namely 8 years, gathered from a Barnett well. Decline exponent "b" can be observed as $b = 4$ for bi-linear flow, $b = 2$ for linear flow and $b \leq 1$ for BDF as presented in

Figure 59b. Moreover, it can be deduced that, like most unconventional wells, this well stays in linear flow regime for the first 8 years without reaching BDF (Freeborn and Russell 2012).



(a) (b) (c)

Figure 59 – Stretched exponential concept (after Freeborn and Russell 2012)

Figure 59c shows the step-changes of b values according to flow regime. For this example, it was assumed that b = 0.3 for the BDF and to make the changes smooth, final nominal decline of linear flow regime is assumed as the initial nominal decline for the BDF regime. Generally, after a predetermined nominal decline rate, exponential equations are utilized instead of hyperbolic equations, which represents the point of linear flow to BDF. Instead of changing the equations used from hyperbolic to exponential, stretched exponential equations family was developed (Table 13) to provide changing of "*b*" exponent with time (Freeborn and Russell 2012).

Table 13 – Decline trend formulations for various methods (after Vassilellis *et al.* 2016)

Decline Method	Formulation	Introduced by
Exponential	$q = q_i e^{(-Dt)}$	Arps, 1944
Hyperbolic	$q = q_i \frac{1}{(1 + bD_i t)^{(1/b)}}$	Arps, 1944
Linear flow	$q = q_i t^{-n}$	Bangall and Ryan, 1976
Power law	$q = q_i e^{(-D_\infty t - D_i t^n)}$	Ilk et al., 2008
Stretched exponential	$q = q_i e^{\left[-\left(\frac{t}{\tau}\right)^n\right]}$	Valkó et al., 2009
Duong	$\frac{q}{G_p} = a t^{-m}$ or $q = q_i e^{\left[\frac{a}{1-m}\left(t^{(1-m)} - 1\right)\right]}$	Duong, 2010

Valko (2009) proposed a production forecasting method different than Arps' method referred as "Stretched Exponential Decline Model (SEPD)". Its main characteristics are; (1) a finite (realistic) EUR prediction as production time increases, (2) applicable in both transient and stabilized flow regimes and (3) a limited number of parameters to be determined. The proposed rate equation is:

$$q = \hat{q}_i . \exp\left[-\left(\frac{t}{\tau} \right)^n \right] \tag{40}$$

Where, $\hat{q}_i$: initial production rate (not necessarily the first rate data, since generally rate peaks after a period, hence largest observed monthly production data should be used), t: number of time periods, dimensionless, τ : characteristic number of periods (or characteristic time parameter, which is median of the characteristic time constants), n : exponent parameter (dimensionless model parameter).

Valko's method relies on working equations and a graphical technique and it uses observed cumulative production and theoretical cumulative production derived from the integral of rate equation. The model works for the production data taken evenly; hence, this is why the time used in the equation is the number of periods. Moreover, evaluation of one- and two-parameter Gamma function is required, which was handled via a software called Mathematica v.6 by Valko (2009).

As for illustration, Figure 60 taken from Valko (2009) shows a type-curve family at n = 0.5 for various τ parameters. Although, each stem corresponds to a certain τ parameter, the label shows a dimensionless EUR (EUR_D) approximation. The steps in using such plots to reach at a EUR_D is explained just after Figure 60. Dimensionless parameters can be thought as that parameter divided by the rate at certain time (q_t).

Good news is that to eliminate the complex mathematical background Valko also developed a software. Determination of τ is not required and n is calculated by an iterative technique (Lee and Sidle 2010, Valko 2009, Valko and Lee 2010). It should be noted that, Valko did not try to develop a rate-time analysis relation; instead, he developed a statistical identity to analyze a database of production data (Ilk *et al.* 2008b).

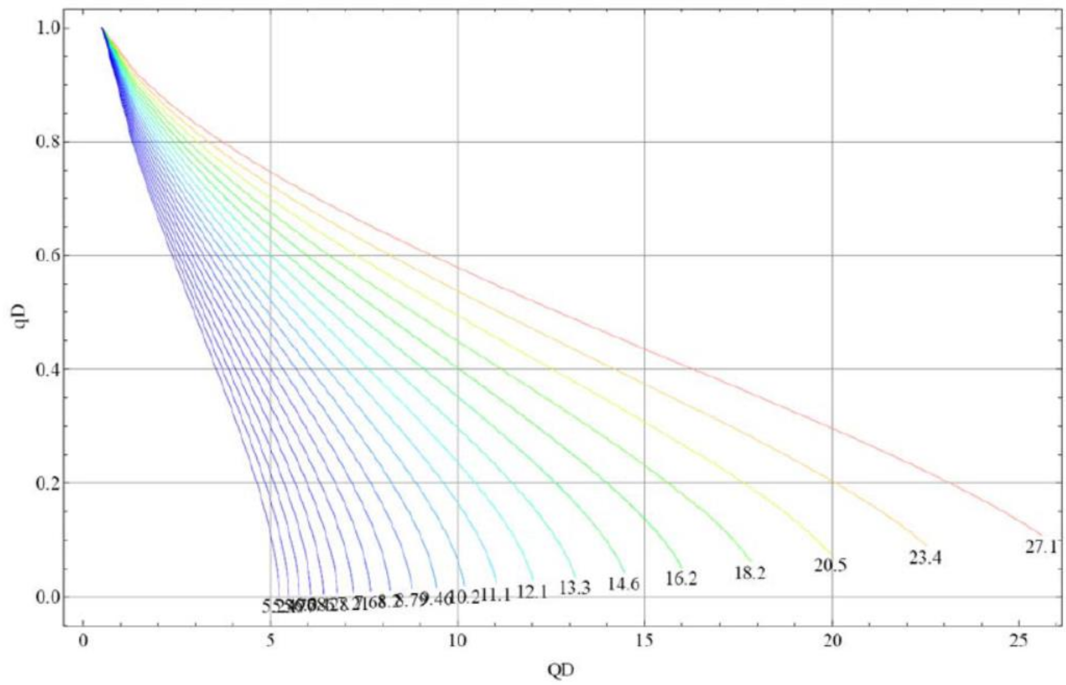


Figure 60 – Dimensionless rate vs. cumulative production stems for various τ parameters at n = 0.5. Each stem has a corresponding EUR value (after Ilk *et al.* 2008b).

The usage of the Figure 60 and the decline analysis steps are as follows (Valko 2009):

1) Determine from the real data that what is the maximum production rate (q_i),
2) Create a series for "qD" (dimensionless production rate) and "QD" (dimensionless cumulative production),
3) Assume an exponent parameter "n" and prepare a type-curve family plot as given in Figure 60, Determination of "n" value can be performed by another iterative graphical approach which relies on recovery potential concept (below paragraph).
4) Plot the points on the type-curve family,
5) Determine the most appropriate stem and hence the dimensionless EUR.

One last advantage of this method is that, it also helps in determining a so-called recovery potential (rp), which is actually one minus recovery factor. Moreover, a plot of rp vs. QD yields straight-line and help in determining the "n" exponent. When correct "n" exponent is reached, the y-intercept should give 1 and x-intercept should give EUR. The detailed procedures for such an analysis can be found in the original reference (Valko 2009).

Ilk *et al.* (2008a) proposed independently a similar model, referred as "Power-Law Exponential Decline":

$$q = \hat{q}_i . \exp\left[-D_\infty . t - \hat{\hat{D}}_i . t^n \right] \tag{41}$$

where, $\hat{q}_i$: Rate "intercept" [i.e. *q(t=0)*]; *t*: time, days; D_∞: Decline constant at "infinite time" [i.e. $D(t=\infty)$]; $\hat{\hat{D}}_i$: Decline constant, *n* : time exponent.

The physical background of Eqn. 41 is the loss ratio "*D*" is being approximated by a decaying power law function with a constant behavior at large times (D_∞ = constant), which yields an exponential decay in the rates, i.e. "D_∞" is dominant at late times. This may provide a lower bound for reserves estimates. At early times, i.e. at transient and transition flow periods, "t^n" dominates the flow regime. This model is highly flexible that a reasonable match can be obtained for transient, transition and boundary-dominated flow data (Ilk *et al.* 2008b). As "*n*" becomes smaller, the rate-time relation has greater downward curvature as increasing "*b*" exponent in hyperbolic equation (Freeborn and Russell 2012).

Figure 61 given below to present the hyperbolic and power law exponential prototype models for rate decline and loss ratio. As can be deduced, for hyperbolic relation *D*-parameter is nearly constant at early times and decays with a unit slope. On the other hand, power law loss ratio exhibits a power law decay from transient to transition flow and continues with a constant value (i.e. D_∞) at large times (Ilk *et al.* 2008b).

The strength of this equation is its suitability of high initial gas flow rates, which is typical in unconventional wells, on the other hand, this method needs a long period of BDF to correctly model the switch from linear flow to BDF (Freeborn and Russell 2012).

Basic difference between Valko's and Ilk *et al.*'s methods is that $D_\infty = 0$ in the former method. Ilk *et al.* suggest that inclusion of D_∞ term provides better fit and forecast of long-term data. Note that; when $D_\infty . t \gg \hat{\hat{D}}_i . t^n$ at large times, the model becomes exponential decline (Lee and Sidle 2010).

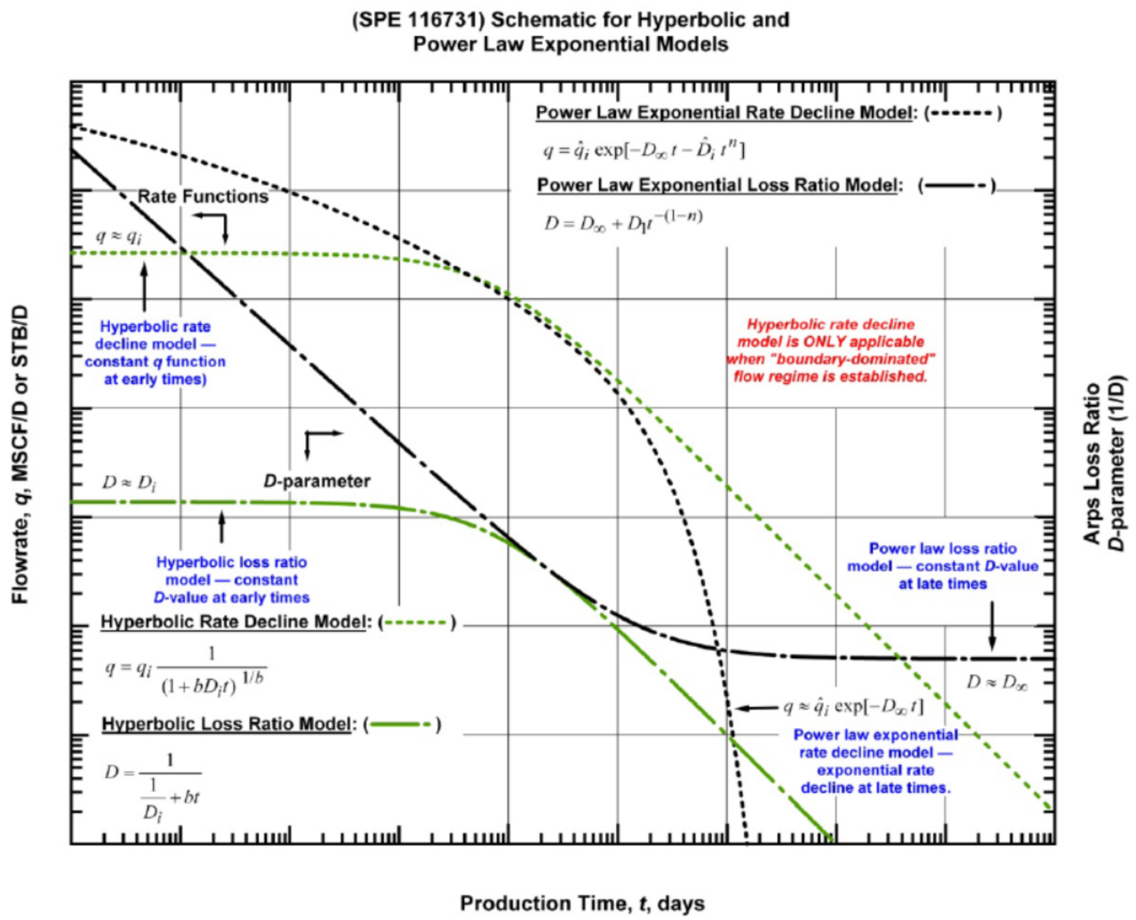


Figure 61 – Schematic log-log plot for comparison of Hyperbolic and Power Law Exponential models of rate decline and loss ratio (after Ilk *et al.* 2008b).

Duong (2010) offers another approach, which uses an empirically derived decline model based on a long-term linear flow in a vast number of wells. Field data show that a log-log plot of rate over cumulative production (q / G_p) vs. time in days would give a straight line for sometimes over 5 years whose slope is "m" (a negative slope is obtained, hence "- m" is also used) and has an intercept "a". These two parameters are related to reservoir rock and stimulation characteristics, besides operational conditions and liquid content.

$$\frac{q}{G_p} = a.t^{-m} \tag{42}$$

$$G_p = \frac{q_1}{a}.e^{\frac{a}{1-m}.(t^{1-m}-1)} \tag{43}$$

where, m : slope defined by Eqn. 42, a : intercept defined by Eqn. 42 with slope m.

Moreover, "*a*" and "*m*" are related variables and a correlation is reached using the data of various gas plays. Duong (2010) presented a plot and equation for this correlation and consequently built type-curves for "q/q_1" vs "t" for "$m > 1$" (which is valid for all shale gas wells). In short, he argues that, if q_1 is known, reserve evaluation can be established.

It should be noted that, the reciprocal of Eqn. 42 yields "G_p / q" on the left-hand side which also named as Material Balance Time (MBT) and the exponent of right hand side becomes "+ m" instead of "- m". Hence a plot of MBT vs. time yields a straight line with slope *m*.

To summarize this method in steps: firstly, rate vs. time is plotted log-log for data validation and correction. Second step is the log-log plot of "q / G_p" vs. time to determine "*a*" and "*m*" parameters. Third step will be the determination of "q_1" parameter, which is the flow rate at day one. However, for considering the current wellbore conditions, some equations and plots are proposed by Duong (2010). As for the last step, Eqn. 43 is used to reach reserves estimation.

The drawback of this method is that it is valid for one single flow regime, hence makes it a poor EUR estimator, however, it can be used to forecast rates for a specified flow regime (Freeborn and Russell 2012).

Freeborn and Russell (2012) compare the three methods above and end up with the following remarks. Ilk *et al.*'s Power Law method yields better solutions relative to Valko's Stretched Exponential method, which is generally more conservative. However, it sometimes fails to yield a result, hence at those times, the latter should be preferred. All three have troubles in switching from linear flow regime to BDF regime. Hence, if the BDF is reached and provided data for a long duration enough, Arps' equation should be preferred instead of these. All these three methods require complex equations to be solved and not appropriate for simple calculators or even for spreadsheets. They bring TRR rather than ERR since both estimate future recovery at zero withdrawal rates, i.e. average reservoir pressure is equal to the wellbore pressure. Hence to estimate ERR, one should estimate the volume producible between economic limit and terminal zero rate and subtract it from TRR (Lee and Sidle 2010).

Three-Segment Decline Curve Analysis

Last but not the least, breaking DCA into segments to represent initial transient flow period followed by a boundary-dominated flow period is another method to be used in shale gas and oil rate decline analysis. Giles *et al.* (2012) proposes a **three-segment decline curve analysis** method (multi-segment DCA) to obtain better fits for all the periods and originally developed by a reservoir engineer named Mr. Hampton Roach.

As stated above, decline exponent changes with producing time in tight reservoirs and this phenomenon is more severe in hydraulically fractured shale oil and shale gas reservoirs, Starting with $b > 1$ for transient region, and as flow regime turns to boundary-dominated, "*b*" values reduces below 1 and hence the decline should be represented with different "*b*" values in several segments. The decline parameters "*b*" and "*D*" for the proposed 3-segments are as follows and illustrated in Figure 62 (Giles *et al.* 2012):

Segment 1: transient flow, hyperbolic decline, $b_1 > 1$ and $D_1 = D_i$ (Maley 1985).

Segment 2: boundary-dominated, hyperbolic decline, $0 < b_2 \leq 1$ (Cheng *et al.*, 2008).

Segment 3: late-life, exponential decline, $b = 0$ and D_{min} (Maley 1985).

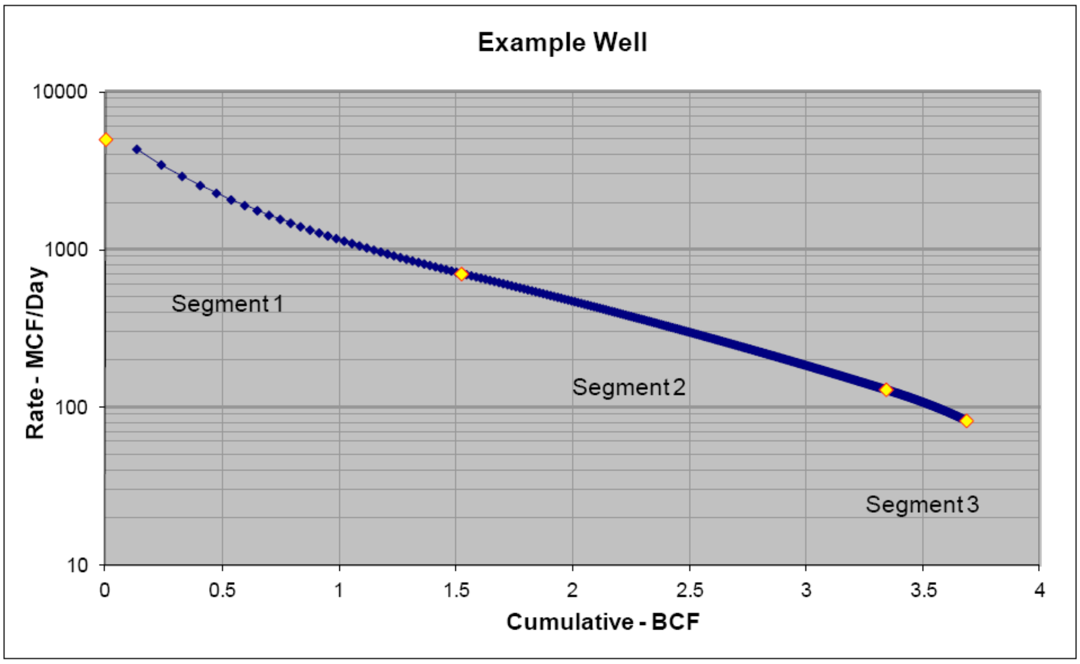


Figure 62 – Three-segment DCA example by Mr. Hampton Roach (after Giles *et al.* 2012).

As for three-segment DCA, Segment-1 parameters (q_i, D_i, b_1) can be estimated by matching historical profile. Segment-2 parameters (b_2, t_2) may be estimated by Production Data Analysis and Segment-3 parameters (D_{min}, q_{min}, maximum well life) may be estimated based on analogues (Giles *et al.* 2012).

The main difficulty behind this method is determination of the starting point of BDF period and the decline exponent "*b*" for that period. In Giles *et al.* (2012)'s example, they determined "q_i", "D_i" and "b_1" by fitting a wells' 6+ months production.

Pour *et al.* (2015) used 3-segment decline curve to analyze the production rate decline of Canadian Deep Basin wells. Figure 63 below presents the distinctions of the flow regimes belonging to their example well.

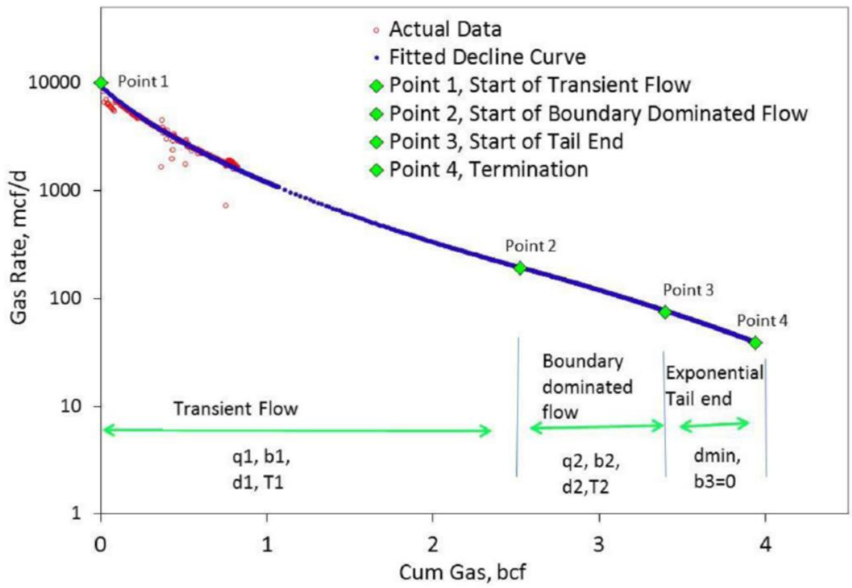


Figure 63 – Another illustration for 3-segment decline curve analysis (after Pour *et al.* 2015).

Pour *et al.* (2015) also suggested that Rate Transient Analysis (RTA) data may be used to tune the parameters of DCA; moreover, they applied this idea to their analysis of Canadian Deep Basin wells (Figure 64). Generally, data in public domain is insufficient to use RTA alone to evaluate the reservoir; however, it is adequate to calibrate the DCA parameters. Moreover, these calibrated DCA parameters can be used in the analysis of wells those do not have RTA data via the help of technical judgement to average the parameters while keeping the reflection of general behavior.

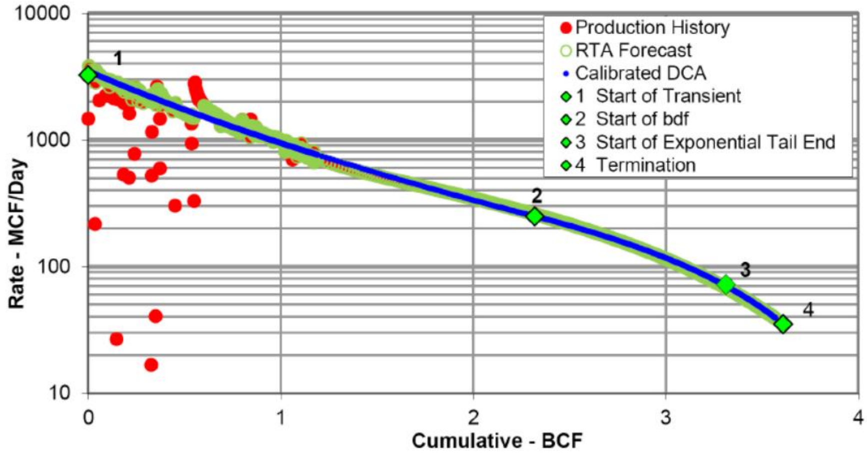


Figure 64 – RTA data (green hollow circles) used to calibrate DCA parameters (blue filled circles) (after Pour *et al.* 2015).

According to Pour *et al.* (2015)'s observations on horizontal wells, transient period lasts for 5-10 years on average. During the Segment-1 (transient period) $b_1 > 1$ and annual nominal decline rate "D_i" is between 0.5 and 0.8. As for the Segment-2 (BDF period represented by hyperbolic decline), b_2 would be between 0.4 and 0.8. It should be noted that the lower the b_2, the lower the EUR, i.e. lower *b* values lead to more conservative EUR results. Decline rate for the Segment-2 "D_2" is a function of the decline parameters of the Segment-1 as such (Pour *et al.* 2015):

$$D_2 = \frac{D_1}{(1+b_1.d_1.t_1)} \tag{44}$$

This period elongates more than 20 years and hence many wells stay in the BDF until they reach the terminal rate (q_{min}). Provided that "D_{min}" is observed before reaching "q_{min}" in Segment-2, Segment-3 starts with the governing equations of exponential decline and b exponent becomes zero. Generally, "D_{min}" is assumed around 5-10% or determined according to experience in the field. This segment do not have a true physical background, instead it is used to prevent unrealistically long tail production (Pour *et al.* 2015).

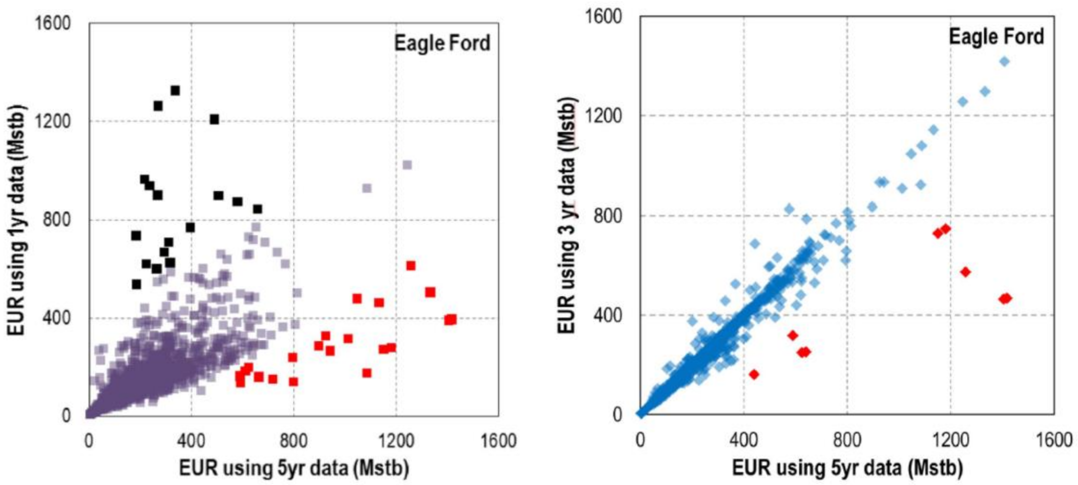
Jeyachandra *et al.* (2016) claim that visual observation of the decline curves for the slope change points may give the time of change of the flow regimes, only if the operating conditions are not changed or no interference effects. Hereby, RTA would help to identify the flow regimes by using diagnostic plots.

As discussed, transient linear flow is the initial flow period, which is characterized by a half-slope on the log-log plot of gas rate vs. time or by a straight line on a square root of time plot. Moreover, when inverse of flow rate (1/*q*) vs. superposition times ($t^{1/4}$, $t^{1/2}$, log t and t) are plotted, the deviation from straight line points reveal the flow regime changes at very early, early, middle and late times, respectively. However, regression for "b" exponent is necessary to name the flow regime for those periods (Jeyachandra *et al.* 2016).

Lastly, different from Giles *et al.* (2012), Jeyachandra *et al.* (2016) suggest usage of "b" exponent between 0.2 and 1 for Segment-2 and between 0 and 0.2 for Segment-3.

Darugar *et al.* (2016) investigated 1594 Eagle Ford and 2350 Bakken wells by utilizing multi-segment decline curve approach. The wells having at least 5 years of production history and peak production above 200 bopd were selected to enable the comparison of EUR estimations using 1, 3 and 5 years of production history data.

The results for the benchmarking via using Eagle Ford data show that when using 1-year data, 10% of the EURs are within ±10% consistency range with EURs estimated using 5-years data, i.e. EURs are underestimated significantly (Figure 65a). On the other hand, when 3-years data is used, 90% of the EURs estimated are within ±10% consistency range with EURs using 5-years data (Figure 65b).



(a) **(b)**

Figure 65 – (a) EUR comparisons between 1 vs. 5-years of data (left) and (b) between 3- vs. 5-years of data (right) using multi-segment decline curve analysis (after Darugar *et al.* 2016).

It should be noted that, red data points in both Figure 65a and Figure 65b represents the outliers resulting from the re-stimulations performed in the later life of the well.

The authors also studied the Bakken Shale with the same methodology and using multi-segment decline curve analysis. While using 3-years of production data of Bakken wells, 80% of the EURs are within ±10% consistency range with EURs estimated using 5-years of production data (Figure 66). Although it was not presented in a graphical form, they noted that 1-year of data did not give any reliable EUR estimations.

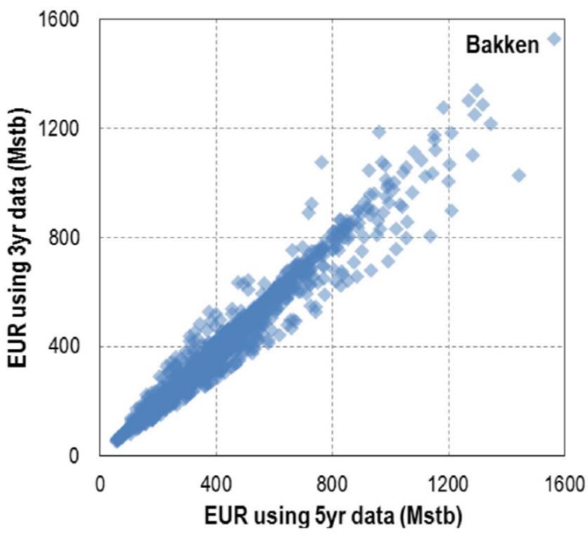


Figure 66 – EUR comparisons between 3 vs. 5-years of data using multi-segment decline curve analysis (after Darugar *et al.* 2016).

This benchmarking study assures that 3-years of production data is sufficient to obtain a reliable EUR estimate when using multi-segment decline curve.

Further, the stretched exponential decline model (SEPD) was used to compare the results with multi-segment decline curve estimations. Again, 3-years and 5-years of historical production data were used to estimate EURs as presented in Figure 67. The results of Darugar *et al.* (2016)'s study showed that SEPD is not as reliable EUR estimator as multi-segment decline curve method.

Moreover, Arps' traditional decline curve yielded more scattered results, namely only about 40% of the EURs lie within the ±10% consistency range.

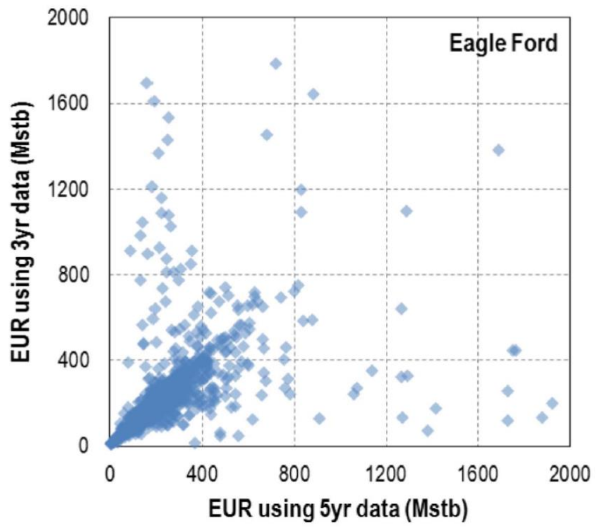


Figure 67 – EUR comparisons between 5- vs. 3-years data using SEPD (after Darugar *et al.* 2016)

Giles *et al.* (2012) state that, to reach a reasonable EUR from production data analysis, approximately 6-months of historical production data with low back-pressure is needed. Moreover, Pour *et al.* (2015) also quote the same duration, 6-months of production data, to reach a reasonable RTA model. On the other side, Gonzalez *et al.* (2012) warn about the bias problem when production data of 18 months or less is matched.

Figure 68 illustrates the variation of *b* values in 6 wells with producing time. The arrow in the figure shows the average *b* value determinations for these 6 wells for several segments. Segment-1 ends after 3 years with b_1=1.5 and Segment-2 begins at starting time of boundary dominated flow (t_2), with a decline constant b_2 = 0.4. Finally, the average values for "b_1" and "b_2" obtained from the analysis of a set of wells can be used in the 3-Segment decline curve analysis of other wells in the field (Giles *et al.* 2012).

In the literature, several authors show that "*b*" exponent changes with production time in very low permeability reservoirs. Giles et al. (2012) presented analysis of 6 wells by Mr. Okouma, in which one can clearly see that with production time, *b* reduces until a constant value below one. All these newly developed methods are taking into consideration the changing nature of b exponent with time for production data of shale formations (Freeborn and Russell 2012).

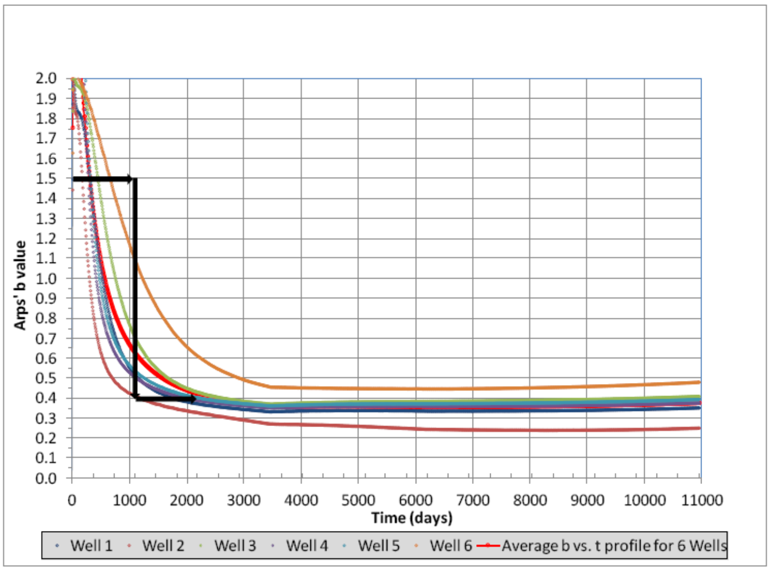


Figure 68 – Average b vs. time for 6 wells by Viannet Okouma (after Giles *et al.* 2012).

Moreover, Rushing *et al.* (2007) built a numerical model as in Figure 69 below for a fractured well in a tight gas reservoir (dry gas reservoir with 4 layers) to study the effect of various reservoir and fracture parameters on "*b*" exponent. This study showed that, the superficial application of the Arps' equation in the transient or transition periods lead to high production forecast errors, in which "*b*" exponent is greater than unity. After boundary-dominated flow is reached, "*b*" exponent generally stabilizes somewhere between 0.5 and 1 (Ilk *et al.* 2008a).

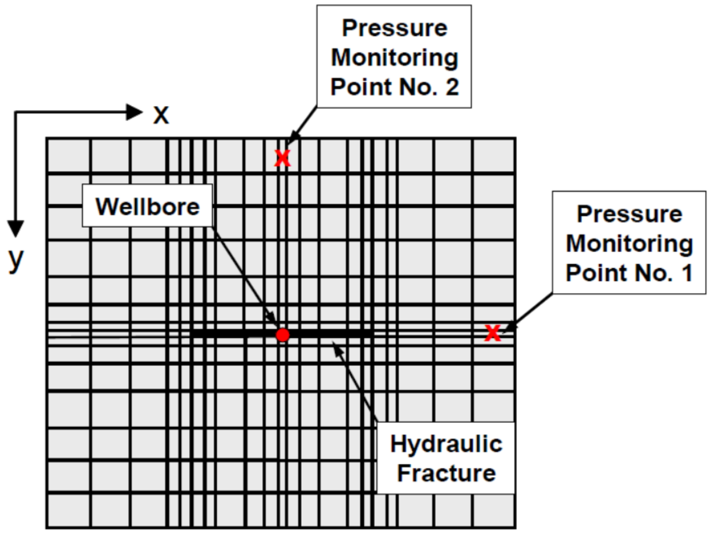


Figure 69 – Model built to present the hydraulically fractured well behavior in a tight gas reservoir (after Rushing *et al.* 2007).

To illustrate, the effective (propped) fracture half-length is taken as a variable (50, 100, 300, 500 ft) and the effect of this parameter on production decline behavior is given in Figure 70. As expected, the shorter half-lengths result in steeper initial production declines followed by flatter profiles, vice versa is valid for the longer half-lengths.

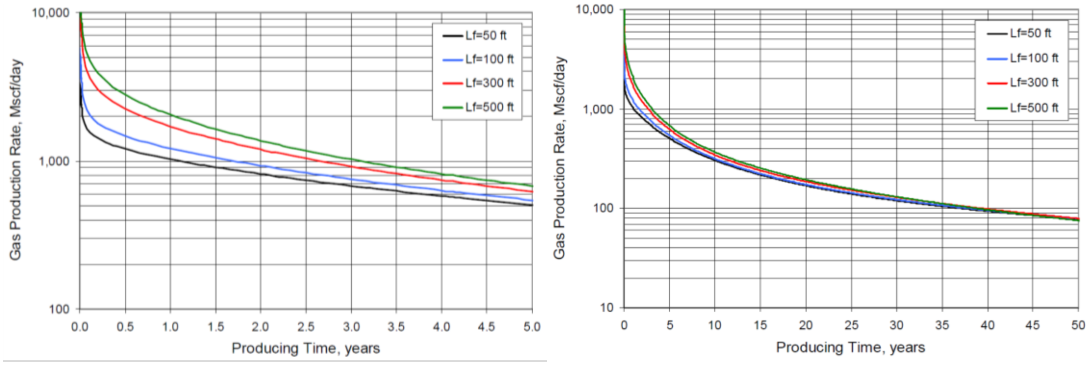


Figure 70 – Simulated short-term (left) and long-term (right) production decline behaviors for various fracture half-lengths L_f = 50, 100, 300, 500 ft (after Rushing *et al.* 2007).

The main objective of including this study here is presenting the change in "*b*" exponent with producing time. Figure 71 shows that, at the initial periods of production "*b*" exponent hovers between 1.5 and 4, according to fracture half-length. However, with the increment in producing time, "*b*" exponent decreases. Specific to this example, the reason for having "*b*" exponent values above unity after some producing time is that the model was built as 4-layers. In the same reference, authors studied the effect of layering and permeability contrast among layers on the "*b*" exponent and they end up with "*b*" exponents considerably below unity after some producing time (Rushing *et al.* 2007).

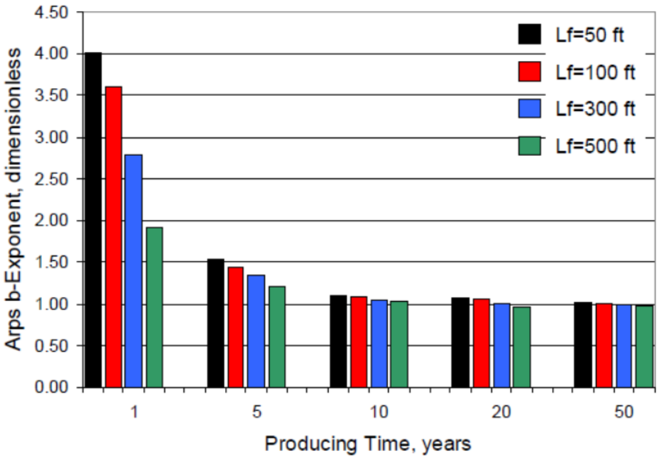


Figure 71 – Variation of b values with time and fracture half-length (after Rushing *et al.* 2007).

As can be seen, uncertainty ranges are quite high in using DCA analysis for low permeability reservoirs especially having unreliable or early time data. As the production life increases, i.e. amount of the production data matched, the uncertainty in production forecasts will decrease. However, always failure in uncertainty quantification of production forecasts and reserves estimations would result in suboptimal development and erroneous economic analysis of shale assets. Reliable quantification of uncertainty will naturally support the success of decisions and to quantify the uncertainty, probabilistic approach should be utilized (Cheng *et al*. 2005, Gonzalez *et al.* 2012).

According to Chan *et al.* (2010), although neighboring wells may show totally different initial rates and EURs, group of wells generally have meaningful distribution and individual well EURs can be converted to a full reserves EUR using analogy technique. The assumptions behind their proposal are:

i. Shale formations generally starts with an extended period of transient flow. Following the rapid decline of initial high rates, the “tail” may extend over decades until economic limit,
ii. There is a reasonable correlation between peak rate and EUR,
iii. Within analogous subgroups, the distribution of EURs is repeatable,
iv. The reservoir within the study area is sufficiently homogeneous and the completion practices are similar to support this analogy approach.

It is important to consider the Central Limit Theorem (CLT) in item (iii), which assures that, if sufficiently large number of EUR distributions are added (individual well EUR distribution), the resulting aggregate will tend to be normal distribution. Hence, P90 and P10 will converge on the mean, which is the most likely outcome to happen (Chan *et al.* 2010; Tuğan and Onur 2015, Jarlsby 2007).

It is worth noting that SPE-PRMS (2007) recommends usage of probabilistic assessment methods and probabilistic aggregation up to the field, property, or project level. As for higher level aggregations, simple arithmetic summation of individual reserves categories should be utilized, which will give conservative proved and optimistic possible resource values (Chan *et al.* 2010, SPE/AAPG/WPC/SPEE/SEG 2011).

Lastly, here it is worth mentioning that maintaining production from unconventional reservoirs is more challenging. The steep decline of the production rates and fluctuating fluid characteristics (gas content changing from 15% to 100% during production) are two major difficulties to artificial lifting of the produced oil in unconventional wells with extreme lateral length and designs (Brenner 2013).

Lakatos *et al.* (2011) presents a good example of phase variation in the reservoir from Eagle Ford Shale as one the many reasons of sharp decline of production rates in unconventional reservoirs. As in Eagle Ford Shale, Basin Centered Gas Accumulations (BCGA) may contain both light hydrocarbons (C_1 – C_{10}), CO_2, H_2S and water, and their boiling points and critical parameters are highly different (Figure 72). Considering these specific parameters of each component at the typical BCGA reservoir conditions (T = 260 °C and p = 1000 Bar assumed in Lakatos *et al.*), the components can be divided into two subgroups. Hence, the first group (C_1 – C_6), together with CO_2 and H_2S may exist in “supercritical state” and C7+ and water may exist in “two-phase state”. Moreover, one can deduce that, with decreasing pressure, i.e. with production time, the phase ratio changes continuously and “liquid domains” in supercritical fluid gradually transform to gas phase. Hence, density of the complex fluid decreases.

All these phenomena also contribute to the sharp decline in production rates special to unconventional reservoirs, especially in BCGA’s. Certain part of the stored gas is liquid and low mobility fluid under reservoir condition. The gas influx drops since the mass transportation of fluid is hindered by the low mobility liquid phases and the diffusion controlled character of gas phases. Hence, the drainage area in low permeability unconventional formations are much less than the conventional high permeability formations (Lakatos *et al.* 2011).

In short, Eagle Ford Shale exhibit different fluid characteristics throughout the large reservoir (Figure 73). All three phase windows exist in Eagle Ford and this shale formation does not have natural fractures due to its high carbonate (as high as 70 %) and lower clay content, Eagle Ford Shale is highly brittle, i.e. easy to frac (Dong *et al.* 2013). Typical fracture half-length is 350 ft, with 8-10 fracture stages (Kennedy 2010).

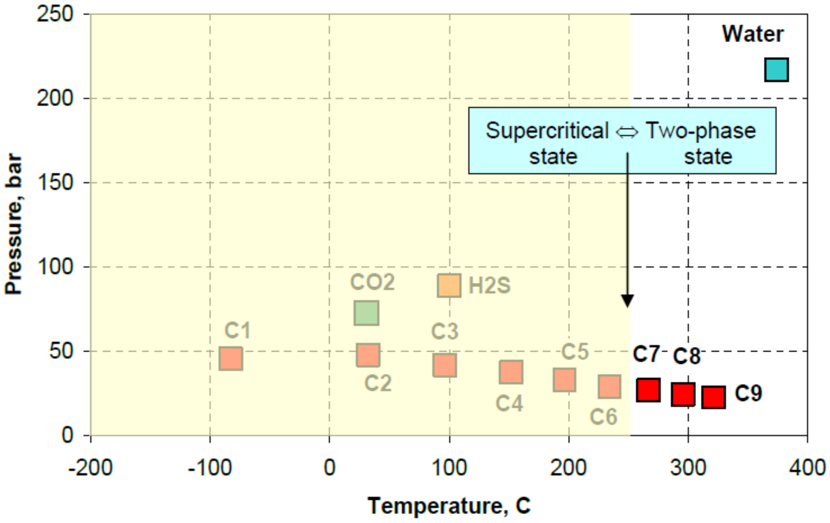


Figure 72 – State of different gases at assumed BCGA conditions - T = 260 °C and P = 1000 bar (after Lakatos *et al.* 2011).

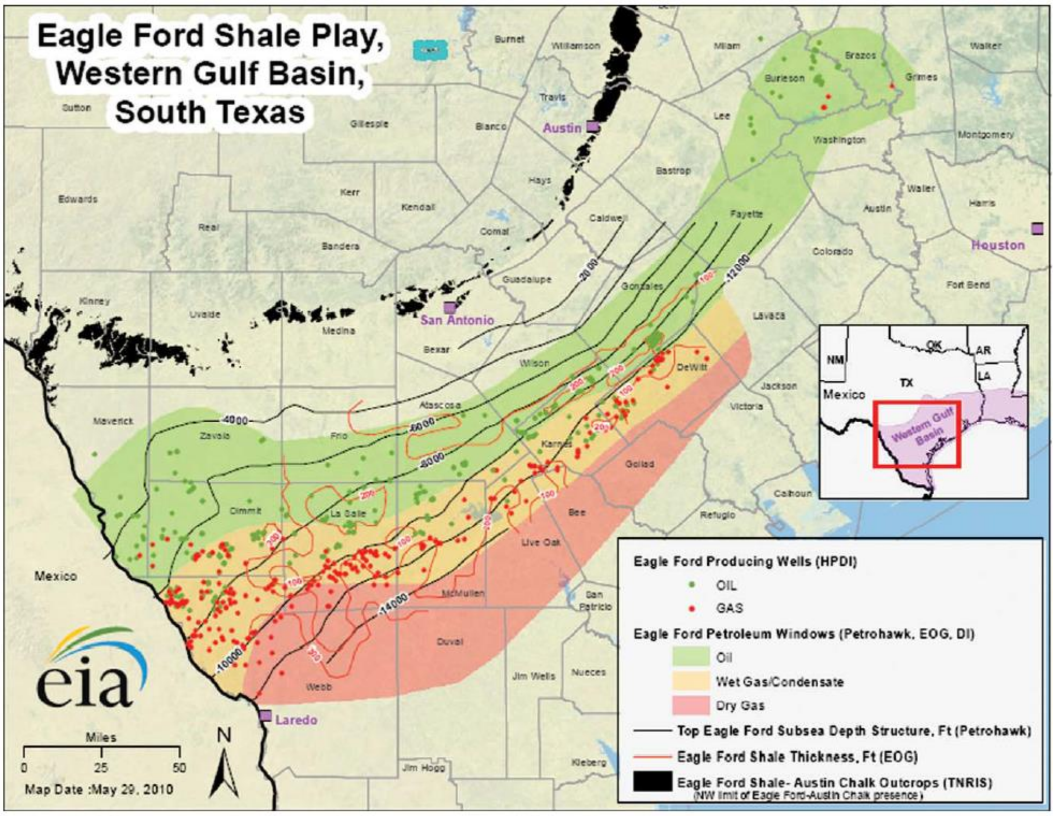


Figure 73 – Eagle Ford Exhibits all 3 Phases; up-dip oil, mid-dip condensate and down-dip gas (after EIA 2014, Dong *et al.* 2013).

4.3. Numerical Reservoir Modeling

Modeling of shale gas and shale oil reservoirs is a continuing challenge for the industry. Thanks to today's high computing power, detailed shale reservoir models consisting of shale matrix, primary fractures and complex fracture network become attainable. However, due to uncertainties in characterization of the complex fracture network and highly heterogeneous formation properties, static models suffer representing the real reservoir behavior. As for the dynamic modeling part, inadequacy of flow solutions is the main struggle in simulating the shale formations.

4.3.1. Static Modeling of Shale Reservoirs

Some authors (Dong *et al.* 2013) argue that shale reservoirs behave as a transient dual-porosity system. The matrix behaves as the secondary porosity system and contributes to the system consisting of created fracture network and natural fractures (primary porosity system). These transient dual-porosity systems are traditionally used to model naturally fractured reservoirs (Figure 74) (Warren and Root 1963, Kazemi 1969 and Swaan 1976).

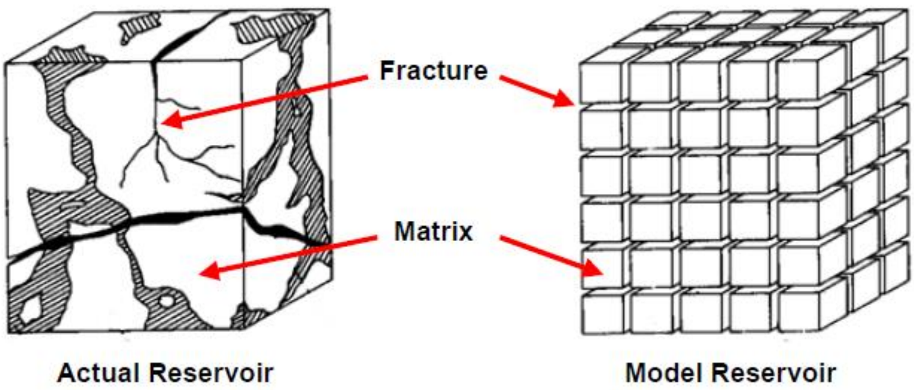


Figure 74 – Dual-porosity idealization (after Warren and Root 1963)

Traditional dual porosity models assume that the matrix to fracture flow is in pseudo steady state, however, in shale reservoirs, the transient behavior in the matrix becomes important. A discretized matrix model allows simulator to predict transient behavior by sub-dividing of each matrix cell into a series of nested sub-cells. The complex fracture network can be characterized rigorously using **discrete fracture network (DFN)** model. Especially, utilization of micro-seismic mapping would be a useful tool to model the complex fractures using DFN and afterwards upscaling can be applied to model the reservoir as a dual porosity system (Figure 75) (Zhang *et al.* 2009).

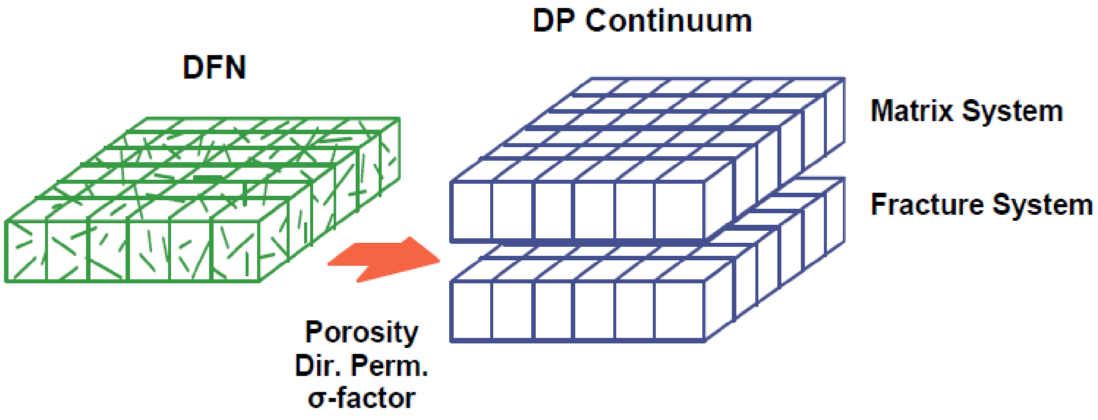


Figure 75 – Upscaling of properties from the DFN model to dual porosity system (after Zhang *et al.* 2009; Golder Associates)

According to Cipolla *et al.* (2009a), the most rigorous method to model shale reservoirs, envisaging the increase in computational time, is to discretely gridding the entire reservoir together with natural fractures, hydraulic fractures, matrix blocks and un-stimulated areas. With the recent advances in computing power, much more complex models can be efficiently utilized.

Houze (2013) defines the modeling technology of shale oil and gas reservoirs in 3 levels starting with level zero.

Level 0 - absolutely no modeling

- Matching of transient data with final decline
- Production Analysis with Arps or modified versions

Level 1 – SRV compatible models

- Specialized analyses
- Firstly simple, then complex analytical and numerical models

Level 2 – Discrete Fractures Network

Grid Orientation

Grid orientation affects the flow in these ultra-tight shale reservoirs, as much as it does in conventional reservoir models. Hence, tectonic history and stress regime should be understood clearly. In practice, grids of shale reservoir models are preferred to be oriented to have cells with one side parallel to the maximum horizontal stress azimuth and the other side is quasi parallel to the horizontal well path (see Figure 76) (Ramakrishnan 2011).

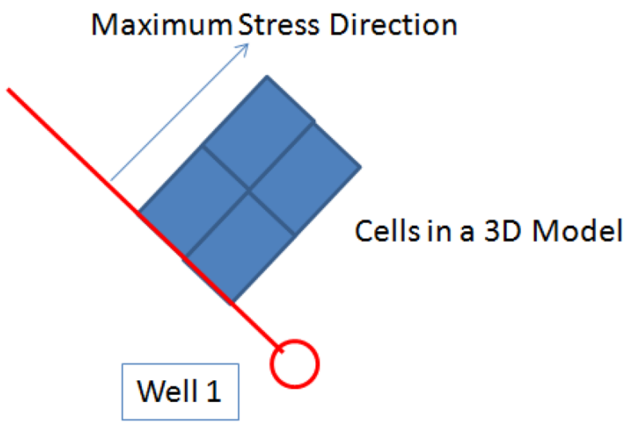


Figure 76 – Grid orientation according to maximum stress direction and horizontal well path (after Ramakrishnan *et al.* 2011).

Modeling of Natural and Induced Fractures

The knowledge of natural and induced fracture distribution and orientation will provide better decisions on perforation design, staging, landing depths and well locations (Javadi and Mohaghegh 2011).

Since their crucial role in production efficiency of shale formations, all fractures should be carefully characterized and implement into the model to represent the flow behavior in the reservoir simulation. As discussed in the above section, **Discrete Fracture Network (DFN)** modeling is a rigorous tool where image interpretation make up the basis for DFN modeling. The needed calibration can be done using core data, seismic attributes, and micro-seismic events where available (Ramakrishnan 2011).

Cipolla *et al.* (2009a) evaluated several options to determine the best "grid design" and "porosity model" to efficiently and accurately model the transient, non-Darcy flow from hydraulically fractured horizontal wells in shale formations. They ended up with the superiority of dual permeability method to represent all network fractures in both the un-stimulated and stimulated volumes together with the utilization of locally refined, logarithmically spaced grid design in the stimulated volumes. This method is referred as "DK-LS-LGR method" (dual permeability, logarithmically spaced, locally refined grid).

Understanding the relationship between fracture network, fracture spacing, proppant distribution and fracture conductivity is critical to understand the flow behavior of a shale reservoir. Cipolla *et al.* (2009b) summarizes their study on the effect of each parameter on the flow behavior as: "[…] achieving adequate primary fracture conductivity (~50 to 200 mD-ft) can significantly increase gas recovery and initial production rates, while minimizing the impact of un-propped network fracture conductivity, and primary fracture spacing (i.e. distance between perforations). In all cases, horizontal well performance is improved when network fracture spacing is smaller (more complex network with larger surface area), and when network fracture spacing is small (~50 ft) the impact of matrix permeability is reduced". Relatively higher primary fracture conductivity (~200 mD-ft) will significantly improve ultimate gas recovery and initial rates, while the need for the number of treatment stages reduces. Moreover, when the network fracture spacing is lowered (~50 ft), impact of matrix permeability is reduced significantly (Cipolla *et al.* 2009b).

To obtain more effective fracture network and higher drainage efficiency from the fracturing treatment, pumping of larger proppants at the latter stages to efficiently prop primary fractures, hence improve conductivity of the primary fractures is recommended (Cipolla *et al.* 2009b).

Lastly, Javadi and Mohaghegh (2015) present the more the injected proppant and clean volume the more the EUR obtained from shale wells.

4.3.2. Dynamic Modeling of Shale Reservoirs

Analytical methods provide exact solutions to simplified problems, whereas numerical methods yield approximate solutions to exact problems. Discretization is the process of converting the partial differential equations (PDE's) into algebraic equations to obtain values at discrete points in the reservoir and the most widely used discretization method in oil industry is finite-difference method (Ertekin *et al.* 2001). To solve the fluid flow in the reservoir, dynamic modeling, which utilizes finite difference approach is used. Although dynamic modeling is a widely used approach in conventional reservoirs, due to complex pore systems each having distinct physical properties, using this approach in shale formations needs some modifications.

Analytical solutions for fluid flow in naturally fractured reservoirs were published by Warren and Root (1963) and Kazemi (1969) long time ago. Moreover, semi-analytical solutions were published by Medeiros *et al.* (2007). However, they lack the ability to capture the very long transient behavior in the ultra-tight matrix blocks exist in shale formations. Also, run-time vs. precisely modeling the gas transport in different medium of shale formations is a continuing challenge. Although, analytical solutions improve run-time in numerical simulations, they are insufficient for shale reservoirs (Sun *et al.* 2015).

For the time being, the flow mechanism under these multi-porosity (organic materials, inorganic materials, and fractures) and multi-permeability systems are not well understood, hence implementing the equations representing the flow is not an easy task. Dominant transport mechanisms differ from diffusion, convection and desorption according to the medium of the formation; i.e. different flow mechanisms dominate flow behaviors in **organic matter**, **inorganic matter** and **fractures**. Hence a so-called multi-mechanistic model is advised by Sun *et al.* (2015) for representing different flow mechanisms namely; concentration driven **diffusion** (matrix nanopores), pressure driven **convection** (in pores or natural fractures) and **desorption** of multicomponent gas from the organic material's surface (also summarized in Ozkan 2014). Hudson *et al.* (2012) also emphasizes the necessity to separate representation of slow gas transport in organic material and quicker gas transport in inorganic material in the system.

As for heavier hydrocarbons, which exist as tight liquid reservoirs, concentration driven diffusion comes into concern and phase behavior becomes a function of pore size when dealing with the nanometer pores. In other words, there occur different liquid pressures at bubble point as a function of pore size and this phenomenon creates concentration driven diffusion in nanopores. However, small pore throat sizes (at the scale of the membrane pores) prevent passage of heavier hydrocarbons with large molecules and this will cause osmosis-like behavior and act counter-currently to diffusion (Figure 77) (Ozkan 2015).

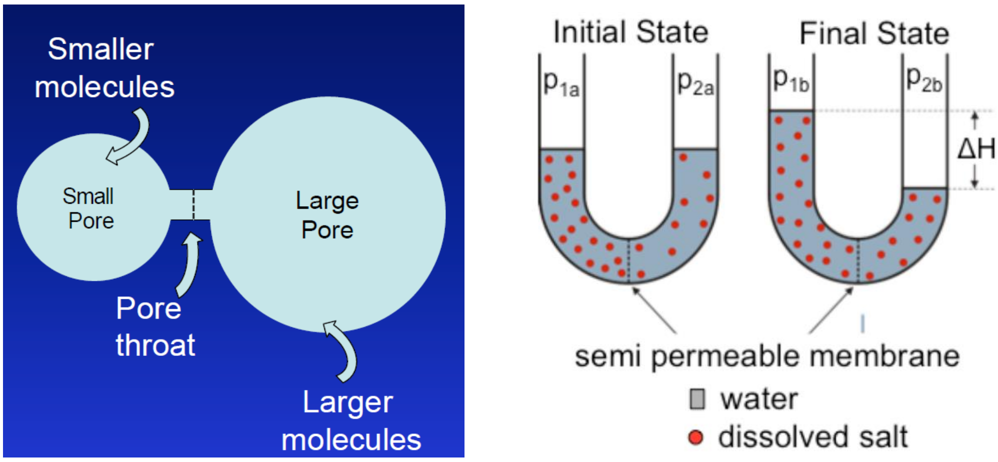


Figure 77 – Shale as a membrane due to pore size difference (after Ozkan 2015)

Different authors studied the flow mechanisms and performed benchmarking to match the real data obtained either from the field or from laboratory. Sun *et al.* (2015), strongly states that dual porosity, dual permeability (DPDP) model with Knudsen diffusion is adequate to model the shale formation production behavior after comparing triple porosity dual permeability, DPDP and single porosity single permeability models.

While performing simulation for an unconventional reservoir, the following alternatives should be considered and most efficient ones should be selected:

- Simulation Software (Eclipse, Rubis),
- Simulator Type (E100, E300),
- Fluid Model (Single-phase, Compositional),
- Porosity Model (Dual-porosity),
- Additional options (Langmuir Isotherm).

CHAPTER 5

ECONOMICALLY RECOVERABLE RESOURCES

Regardless of the difficulties in forecasting production and estimating reserves in shale oil and shale gas reservoirs, owners should know these values to manage their assets properly. Moreover, generally they should also report these values to regulatory agencies and stakeholders. Hence, these estimations should be done anyhow and doing these estimations with more certainty or having the uncertainty range is highly crucial.

Under SEC (2008) guidelines, reserves estimates are to be based on “reliable technology” to establish appropriate levels of certainty for the reserves volumes disclosed. Moreover, reserves estimation procedures should be repeatable and consistent (Lee and Sidle 2010).

ERR is the portion of a gas/oil resource where extraction costs are low enough and market prices are high enough that the companies make profit (Madani and Holditch 2011). Higher market prices due to increased demand (or decreased supply), lower drilling, completion, fracking, production costs or favorable taxation policies converges ERR to TRR, i.e. more TRR become economical and on the contrary depressed economic conditions increases the gap (Figure 78) (Weijermars 2015).

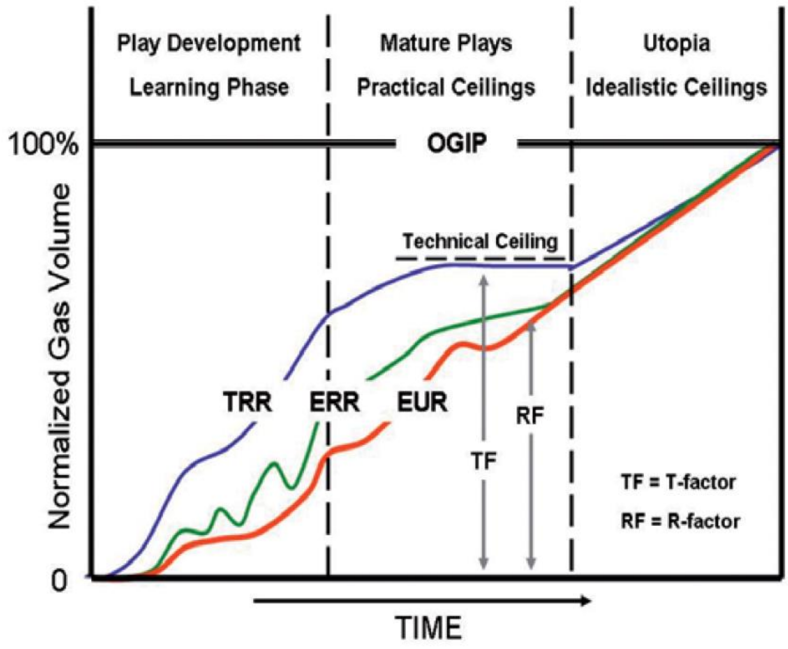


Figure 78 – TRR, ERR and EUR Relation (after Madani and Holditch 2011, Weijermars 2015)

5.1. Economic Yardsticks and Time Value of Money

At this point, it would be beneficial to define shortly the financial terms to be used in the following sections. Firstly, **gross revenue** is the product of price times the quantity. In oil industry, wellhead price of hydrocarbon (P) times the production output (Q) gives the gross revenue (P * Q). **CAPEX** is the capital expenditures including drilling, well completion, tie-in, land acquisition costs, where **OPEX** is the operating expenditures and can be assumed as a portion of CAPEX (generally 5% in conventional oil and gas projects) or indexed to the well performance (Weijermars 2013a).

In the light of the foregoing, non-discounted cash flow (A) can be explained by:

$$A = (P * Q) - CAPEX - OPEX - (C_R * P * Q) - (C_T * Income) \quad \textbf{(45)}$$

where, C_R is the royalty rate and C_T is the tax rate. Introducing D_{dep} as the depreciation rate of CAPEX, income can be calculated by the following Eqn. 46:

$$Income = (P * Q) * (1 - C_R) - OPEX - D_{dep}.(CAPEX) \quad \textbf{(46)}$$

As it is well known, money has also a time value (e.g. inflation or bank interest), hence cash flows should be estimated at a specific time. Generally, **Discounted Cash Flow (DCF)** analysis is used to calculate the **Present Values (PV)** of all future cash flows by discounting them according to a specific discount rate, which includes the interest rates and compensation of risk. In project economics, time value of money should also include the risks of the project. The sum of all these discounted future cash flows gives **Net Present Value (NPV)** (Chen *et al.* 2015, Jarlsby 2007).

Following Eqn. 47 demonstrates NPV where *i* denotes discount factor and t denotes the project time. To calculate NPV non-discounted, *i* = 0 should be used (Weijermars 2013a):

$$NPV = \sum[A_t/(1+i)^t] \quad \textbf{(47)}$$

NPV analysis measures the full value and size of a project, assigns higher weight to early cash flow, allows usage of different discount rates during the project life, and lastly can be used to evaluate different combination of projects, i.e. NPV analysis is additive. On the other hand, it does not consider the size of initial investment (Warren 2014).

Another parameter to evaluate project economics is the **Internal Rate of Return (IRR),** which is the average rate of return over the lifecycle of the project and corresponds to a specific discount rate at which NPV equals zero (Weijermars 2013a).

IRR measures the relative attractiveness of a project regardless of its size and includes the time value of money. It is independent to cash flow and easy to evaluate by management. However, IRR analysis have many weaknesses. such as, it is sensitive to errors in the early cash flows due to higher weight assigned to them, incorporation of risk and uncertainty is not possible, cannot be used for all positive or negative cash flows, does not measure the actual size of the profit and lastly a delay in project will not affect IRR (Warren 2014).

Other project economic indicators that can be used to compare several projects are; firstly **Profitability Index (PI)** or sometimes referred as Profitability Ratio, which is the ratio of the net present value to the original investment (present value of all negative net cash flows). PI has the strength of revealing profitability per unit investment and accounts for the size of the investment. Secondly, **payback time**, which is the time to recover the original investment as cumulative cash flow and thirdly **maximum exposure**, which shows the largest cumulative cash flow early in the project (Jarlsby 2007, Warren 2014, Tordo 2007, Wright 2008).

NPV is an absolute measure, which presents the net worth of the project. However, IRR and PI are relative measures that are used to rank projects from financial perspective (Tordo 2007).

The economics of a project is a subjective concept. For example, some authors call projects having PV10 (present value at 10% annual discount rate) values greater than zero as economic project. On the other hand some authors define the economics according to predetermined values of Payout Time and Internal Rate of Return (IRR).

Madani (2010) proposes economic wells to pay out its Finding and Development Costs (F&DC) in 5 years or less and makes at least 20% IRR during a typical well life of 25 years. Meanwhile, well life has only minor effect since tail-end productivity contributes only little to EUR and NPV. However, re-stimulation may be effective for increasing the production in late times (Weijermars and van der Linden 2012).

5.2. Economic Evaluation of Shale Oil and Shale Gas Projects

The economics of unconventional gas and unconventional oil projects depend on several factors (Giles et al. 2012, Madani 2010, Madani and Holditch 2011):

1) TRR per well,
2) Market prices of gas & oil,
3) Finding and development costs (F&DC),
4) Lease operating expenditures (LOE).

As stated by Lee and Sidle (2010), we have little chance to characterize the inaccuracies in future price forecasts; however, we can characterize the inaccuracies, i.e. quantify the uncertainties, in our engineering calculations. Moreover, the total recoverable volumes per well, besides the probability of achieving these volumes are the keystones of analyzing the economics and the profitability of the projects (Giles *et al.* 2012). Hence, this PhD study will mostly concentrate on uncertainties in resource estimations and production forecasts together with their economic determinants, i.e. the factors draw the line between TRR and ERR, rather than market price, cost or condition uncertainties.

However, this PhD study does not undervalue the importance of market prices and conscious of the determinant power of average long term market prices on the economic cut-off for the future production forecasts. In other words, the distinction between TRR and ERR is mainly determined by market prices (Weijermars 2012). TRR calculations together with the uncertainties are discussed in detail in previous section and this section is devoted to determination of the distinction between TRR and ERR and building probabilistic EUR estimations and the associated charts.

The main parameter bringing economic risk to shale hydrocarbon fields is the highly uncertain EUR values. Moreover, per well reserves estimations vary widely throughout the fields (Weijermars 2012, Weijermars 2013b). As the future production forecast and reserves estimation ability of industry for shale plays advances; financial forecasts, asset values and accuracy of reserves will all be positively affected (Lee and Sidle 2010). Lastly, well rollout delays also bring further uncertainty to NPV. Optimization of well rollout scenarios is highly important in reducing the maximum exposure (Weijermars 2013b).

To improve well economics, or more precisely the recovery factor, stimulation treatment optimization and optimal well placement are the two major contributors. Both concepts directly affect stimulated reservoir volume (SRV) which is a unique indicator of well productivity (Sedillos *et al.* 2010). In addition, density and direction of natural and induced fractures together with their interaction strongly determines the well placement (Ahmed and Meehan 2016).

Economics of shale oil and shale gas projects are generally run on individual well basis, i.e. decisions are given according to these singular, isolated evaluations. However, development of an unconventional reservoir should be investigated by looking at the overall picture. Overall well placement optimization, together with individual well stimulation optimization play crucial role in the EUR, hence in the project economics (Sedillos *et al.* 2010). Fredd *et al.* (2015) states in their study that, even in North America with her favorable economic conditions, 40% of unconventional wells are uneconomic.

Learning curve has a tremendous effect on the economic viability of unconventional projects. Fredd *et al.* (2015) extensively studied the effect of learning curve using a retrospective assessment method, which reveals the savings in investments or in other resources to produce same amount of hydrocarbon. According to Fredd *et al.* (2015)'s study, in Barnett Shale (gas window), $23 Billion could be saved if today's efficient and effective techniques are utilized from the beginning of the development of this resource. This number arises as $18 Billion for Eagle Ford Shale (oil window). Moreover, for Barnett Shale, the other savings can reach up to 11,700 fewer wells, 20 billion gallons of water, 21 billion pounds of proppants while still delivering the same 15 Tcf of gas. As for Eagle Ford Shale, savings can reach up to 4,000 fewer wells, 20 billion gallons of water, 40 billion pounds of proppants while still delivering the same 1 billion barrels of oil.

All these lessons took more than 30 years to be learned. Fortunately, today's investors are not obliged to pass from the tedious roads of the past operators thanks to this learning curve. Most of the lessons learned can be applied to other plays globally (horizontal drilling, multistage fracturing, pad drilling, fracturing technologies, integrated workflows), however, each play require its own learning curve after some point due to the uniqueness of the formations (Fredd *et al.* 2015).

5.2.1. Probabilistic EUR Envelope

Uncertainty arises where there is an estimation with uncertain parameters. Naturally, due to our reserves estimations, we must deal with a wide range of uncertainties.

Assessing single well uncertainties sometimes requires a good understanding of the uncertainties in multi-well or field wise estimations and vice versa. Furthermore, utilization of well base estimations in evaluation of the projects requires special care. In fact, aggregation of means of a probabilistically generated production profile would end up with an over estimation of the value of an opportunity (Haskett 2011).

Relying on 14,000 wells' production data analysis in Barnett Shale, Madani and Holditch (2011) found that EURs are log-normally distributed as expected. Moreover, there is a so-called 80/20 ratio, which states that 80% of the production comes from 20% or less of the wells. Consequently, EUR/well should be represented by the asymmetry of the lognormal distribution, rather than normal or uniform distributions (Gouveia and Citron 2009). P10, P50, P90 markers for Barnett's EUR/well are found as 0.25 Bcf, 1.5 Bcf and 4.0 Bcf, respectively (Madani and Holditch 2011).

Because of natural human behavior on decision making, people tend to focus on "outstanding" wells and ignore poorer wells, however due to log-normal tendency of natural resources, the mean is higher than the P50 value, i.e. most of the wells exhibit lower performances than average. This phenomenon should be firmly addressed while estimating likely outcomes for further wells to be drilled (Hall 2007). Wright (2008) also points out the importance of the careful examination of this skewness in well performance statistics since wells with top 5% EUR significantly determines economic viability of the projects.

EUR envelope approach can be used to convert field size distributions to individual well distribution. As can be seen in Figure 79, every point on a field size distribution (see Figure 80) comes from distribution of individual wells. Two distributions should be generated for EUR envelope, which represents the range of distribution of outcomes. In general, EUR envelope bounds may meet but never cross. Moreover, bounds can be well represented by a lognormal distribution between P10 and P90 (Haskett and Brown 2005).

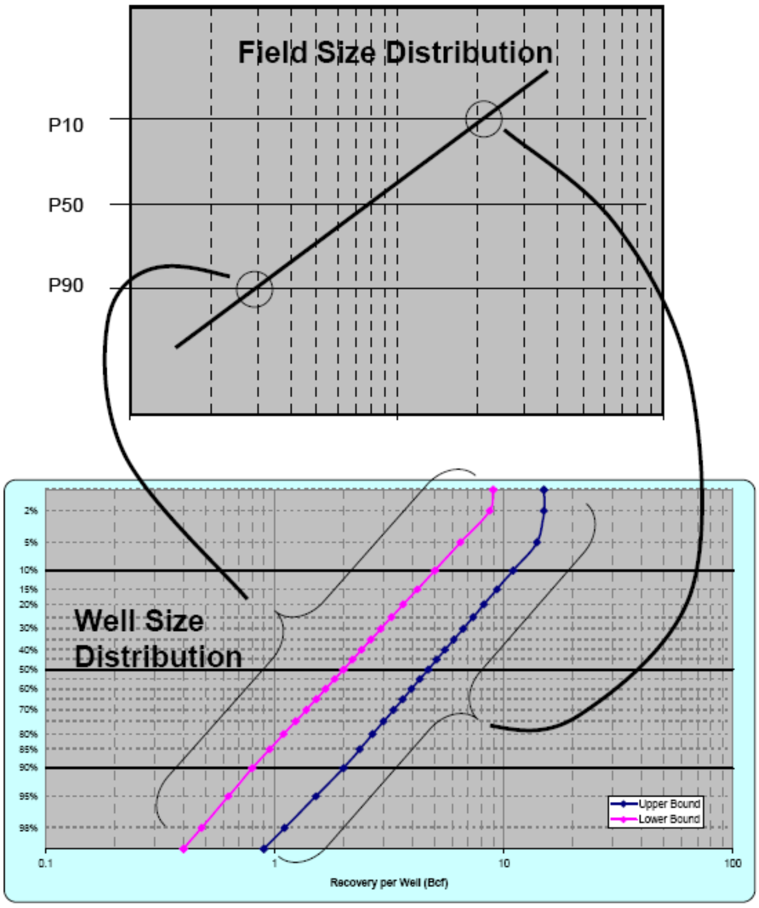


Figure 79 – Each point on a field size distribution is the result of an aggregation of individual wells (after Haskett and Brown 2005)

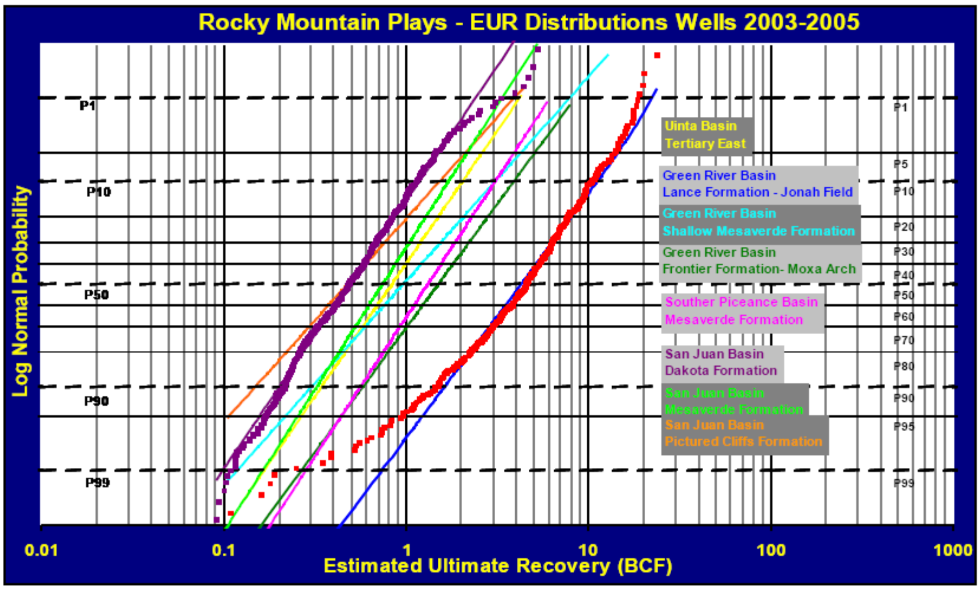


Figure 80 – Typical distribution of EUR for tight gas plays (after Giles *et al.* 2012)

5.2.2. ERR and TRR Distinction

Constitutively, a seesaw determines the relationship between ERR and TRR. F&DC and LOE sit on one side and market prices of products sit on the other side. However, it should be noted that this relation is also dynamic. Even with fixed market prices, ERR can change with increasing technology since costs will decrease and recovery per wells may increase.

Weijermars (2015) notes in his study that technology improvement has a very powerful impact, even comparable to market prices, on shale project economics (markers such as NPV and IRR), due to reduction in drilling, completion and fracturing costs.

Fundamentally, supply and demand relation of hydrocarbons determines the market prices (Madani 2010). However, there are tens of reasons that affect this balance such as political reasons, speculations, regional instabilities, technical developments and so on. In the oil price history, the peaks in oil prices generally supported unconventional projects, which require special techniques to produce (Wilson 2012).

Figure 81 shows the historical West Texas Intermediate (WTI) crude oil prices and Henry Hub natural gas prices (as barrels of oil equivalent). One can easily see that after 2009, the gap between oil and gas prices increased apparently (since the source is dated back to 2014, data after 2014 should be considered as predictive values).

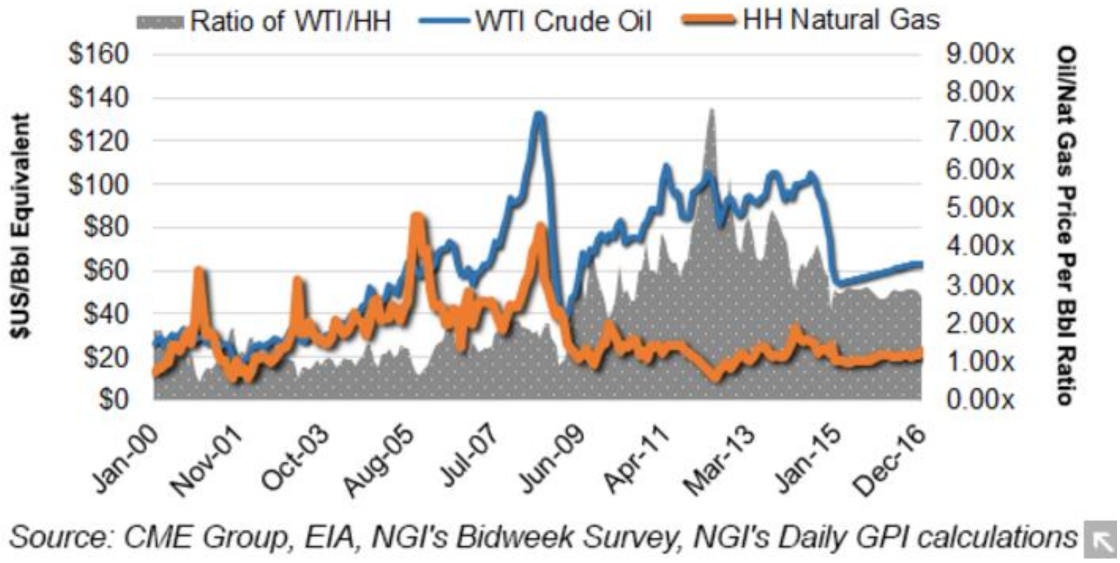


Figure 81 – Monthly WTI crude oil and Henry Hub gas prices (after NGI 2014)

Especially, the US gas market is dominated by short-term delivery contracts, which leads to the quick response of gas prices to economic changes (Weijermars 2012). The US gas market is highly liquid thanks to spot gas trade market called *Henry Hub*, which has a strong effect on gas prices in the US. Moreover, UK has a gas trade market with high liquidity *NBP* (National Balance Point), in which spot gas prices accounts short and medium-term gas contracts together with rarely oil-indexed long-term contracts. On the contrary, European gas prices are state controlled (e.g. *AGIP* - average German import price) and mostly determined with long-term contracts, generally oil-indexed, which brings higher gas prices than US and UK (see Figure 82). Consequently, European spot gas prices are far from true liquidity, however, more liberalization of European gas prices is inevitable soon. As from gas producers' point of view, the higher gas prices in Europe propose more opportunity in this region (Weijermars and McCredie 2011b).

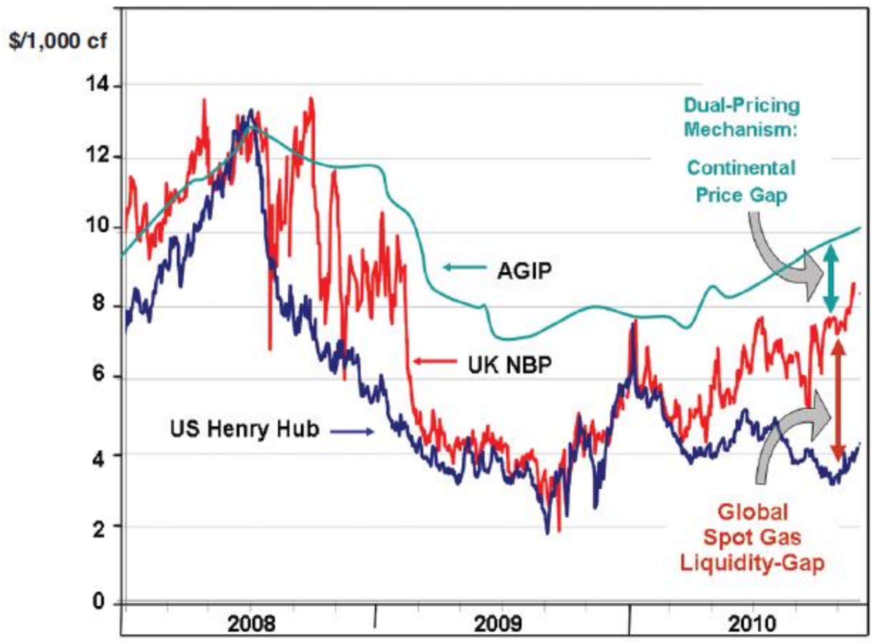


Figure 82 – Gas prices at US-UK spot prices and AGIP (average German import price) (after Weijermars 2011)

5.2.3. Relation between Economics and Activities

Market prices of hydrocarbons strongly determine the activities in unconventional projects, those having knife-edge economics. For example, the strong downturn of gas prices, due to high domestic production of independent shale companies after 2008, diverted capital investments into oil projects, whose prices have recovered better. Figure 83 showing yearly rig counts assigned to oil or gas projects, clearly shows the increasing interest in oil projects after 2008 (Weijermars 2011b, Weijermars and McCredie 2011a).

Comparing the gas projects with the oil projects, due to high transportation costs, the cost per unit energy of gas is higher. The lower heat content –high volume, low value nature- of gas also bring another burden on cost per unit energy. Moreover, the flexibility of transportation and trade is much lower for gas due to limitations of gas transportation to pipeline or Liquefied Natural Gas (LNG). The transportation limitations make the gas market regional rather than being global. All these in turn shrinks the profit margin for gas market. In addition, due to high up-front cost requirements and the strict adherence of seller and buyer, since pipelines have fixed ends, gas business call for long-term contracts. Lastly, as for the cost structure, gas market requires very high fixed costs contrary to the requirement of much lower variable costs, which in turn brings the requirement of full capacity operation of equipment to increase economic feasibility (Stevens 2010, Amorim 2014).

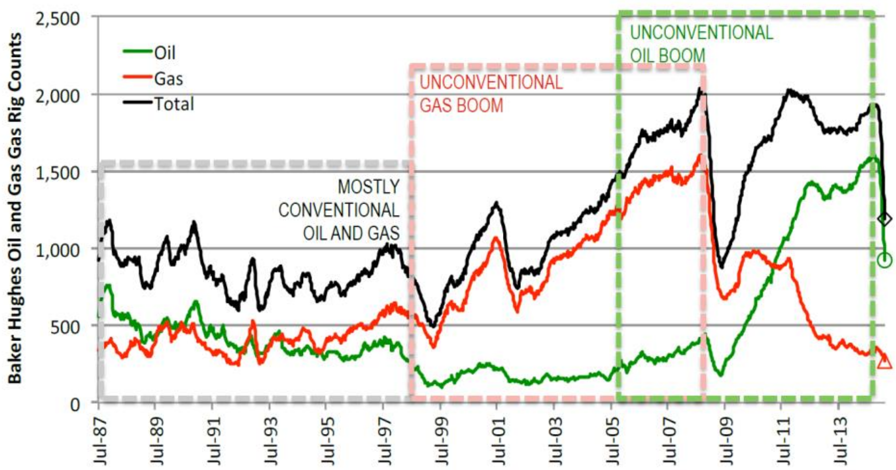


Figure 83 – US rig counts, oil-directed, gas directed and total (after Flaharty and Waheed 2015, modified from Baker Hughes Data)

Although, gas production from shales started much earlier than 1998, this date may be assumed the start of shale gas boom with the intense horizontal drilling and massive stimulation treatment activities in the Barnett in Texas. On the other hand, the intense development of shale oil plays, i.e. shale oil boom, started with the Bakken only after 2005. From 2005 to 2008, industry lived the boom in both unconventional gas and unconventional oil drilling. The activities in natural gas drilling peaked in September 2008 with 1606 gas-directed rigs and after this date, low gas prices were become unable to support unconventional gas developments and hence activities directed to oil or liquid-rich plays. The oil-directed rig count reached a peak of 1609 in October 2014 and the decline began due to the collapse of oil prices (Flaharty and Waheed 2015).

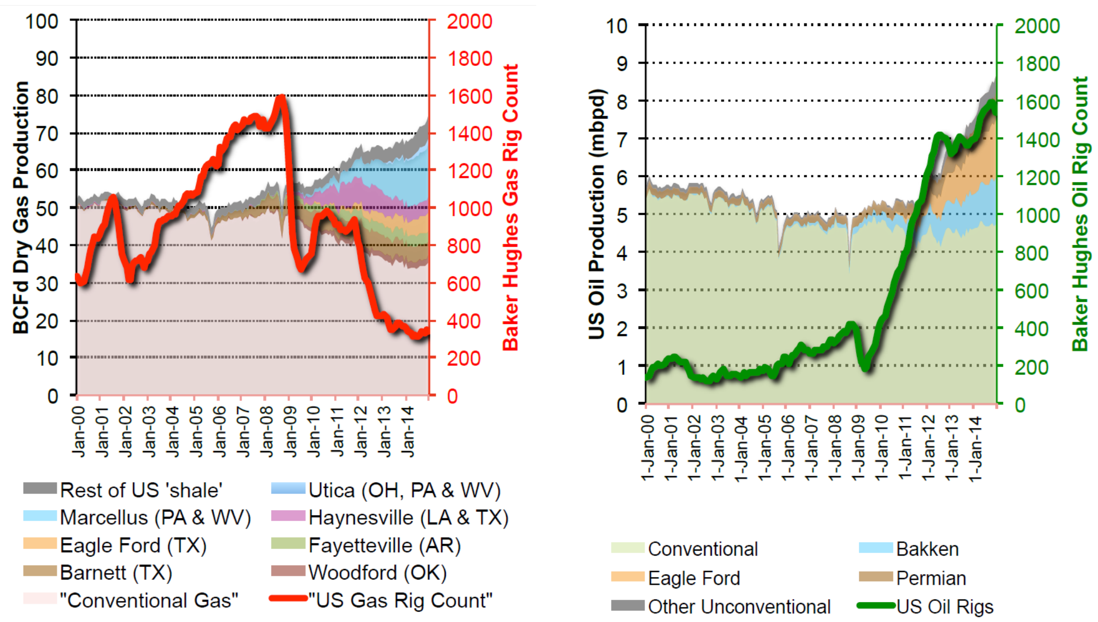


Figure 84 – US gas-directed rig count and gas production (Left), US oil-directed rig count and oil production (Right) (after Flaharty and Waheed 2015, modified from Baker Hughes Data)

Despite the decline in drilling activities as the date of this study, oil and gas production is still increasing due to efficiency improvement and the lag between drilling and production Figure 84. The price collapse was the inevitable consequence of increased supply of oil since the production increment of US alone exceeded the increment in global oil demand. Hence, OPEC gave up its swing producer role in order not to lose its market share, i.e. did not choke back its production and let the prices fall (Flaharty and Waheed 2015).

Soon, if OPEC would not be willing to play the swing producer role, it may be played by high-cost US shale producers by adjusting their activities (the active rig counts) and consequently increasing or decreasing their productions according to global oil prices (Flaharty and Waheed 2015). This issue was discussed detailly in Section 2.1.2.

The operating margins, i.e. the leftover of the revenue after paying the variable cost of production for shale gas companies are generally close to zero or negative, contrary to integrated oil and gas majors having high margins even with low gas prices (Investopedia.com 2017). Since unconventional gas companies are in a business with high CAPEX demand and tight cash flow, they can only survive if they can create shareholder value. Generally, cash flow is maintained by equity and debt financing, i.e. companies sell their assets to meet maturing debt payment schedules. However, this method is not sustainable for long term and makes the business highly volatile. Consequently, the assets become illiquid, i.e. cannot be sold easily. Figure 85 compares the retained earnings (net profit retained by the company after payment of taxes, interest and shareholder dividends) of Exxon, the largest conventional gas producer and Chesapeake, the largest unconventional gas producer in USA. As is well known, retained earnings are necessary to buy new assets and for investing in ongoing projects which bring future profit. To bring a solution to this phenomenon, technological innovations are needed to increase the operating efficiency, i.e. increase recovery rates and reduce costs (Figure 86) (Weijermars and Watson 2011a, 2011b, Weijermars 2011b, Weijermars 2015, Weijermars and van der Linden 2012).

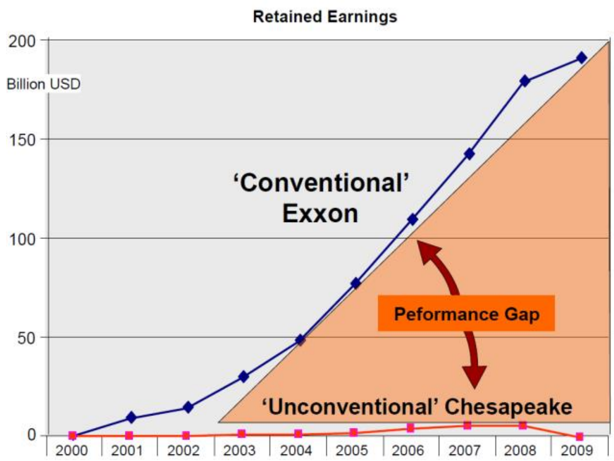


Figure 85 – Retained earnings comparison between Exxon – largest conventional gas producer - and Chesapeake – largest unconventional gas producer (after Weijermars and Watson 2011b)

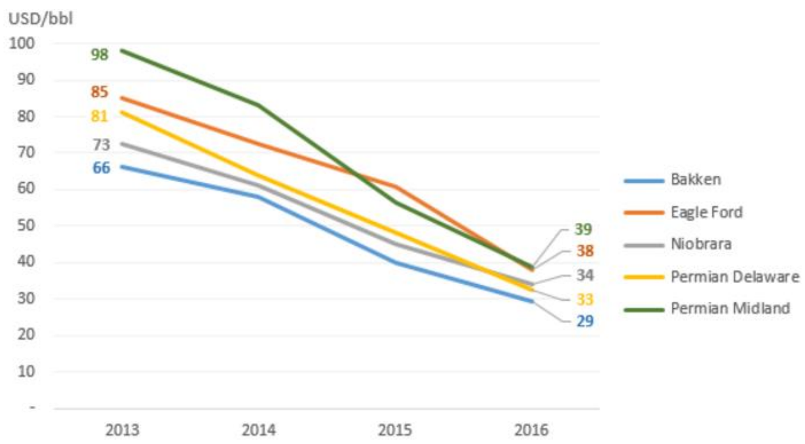


Figure 86 – Reduction in wellhead breakeven prices for oil plays (after Rystad Energy 2017)

In the last few years, the oil and gas industry has experienced an interest of International Oil Companies (IOC's) in independent unconventional gas companies, which is driven by the intention of gaining a strategic advantage. Firstly, IOC's assume conventional gas plays are not promising anymore, secondly, they want to buy the skills and competencies together with the technology required to develop unconventional plays, thirdly, they see the unprecedented reserves growth of unconventional as an opportunity to increase their reserves replacement ratios which is close to unity. IOCs' acquired nearly all acreage in China, India, Australia, South Africa and Europe to ensure future access when a probable economic production commences. Especially, tight gas plays come with little problem, hence are good opportunities (Weijermars and Watson 2011a, 2011b, Weijermars 2011b).

Here, it should be noted that after with the increment in drilling and fracturing activities after 2011, there occurred a shortage of service items hence increment in service costs. To combat these, some operators become more vertically integrated and developed their field services and supply capacities, i.e. some operator companies bought or developed sand mines, water treatment facilities, gas processing plants or drilling rigs so that to ensure reach of services and lower those costs (EIA 2016).

Last but not the least, a quotation from Weijermars and van der Linden (2012) states well the need for studies of this kind (this dissertation) for the sustainability of shale resource development as: "A renewed effort to quantify the risks and uncertainties of shale project economics is crucial for the success of emergent shale gas plays".

5.2.4. Costs Throughout the Lifecycle of Projects

One of the most significant differences in economics of unconventional and conventional projects is the loading of costs through the lifecycle. Due to the high heterogeneity and low connectivity between wells, unconventional projects need capital investments for longer periods to drill new wells, even may be for the whole plateau production period. On the contrary, conventional projects need most of the investments to be done up-front to explore and develop the field and enjoy the production period with low operating costs (Amorim 2014). Details about the costs regarding the upstream projects are investigated in detail below to give a better insight into the project economics.

F&DC (Finding and Development Costs) are the capital expenditures including the costs of leases obtaining, acquiring land, seismic data acquisition, processing and interpretation, well drilling and completion and field development (Madani 2010, Geny 2011).

The details of the capital expenditures (CAPEX) can be listed as follows (EIA 2016):

- Drilling, which comprises 30-40% of the total well costs and include casing, liner costs as tangible costs and drill bits, rig hiring fees, logging, cementing, drilling fluid and fuel costs as intangible costs. Average horizontal well drilling costs range from $1.8 MM to $2.6 MM.
- Completion, which comprises 55-70% of total well costs and include liners, tubing, christmas tree and packers as tangible costs and perforation equipment, fracturing equipment, proppant, fluids, chemicals, water and all fees for fracturing and perforation crew as intangible costs. Average completion costs range from $2.9 MM to $5.6 MM.
- Facilities, which comprise 7-8% of total well costs and include road construction and site preparation, surface equipment such as tanks, separators, dehydrators and artificial lift installations. Facilities will cost a few hundred thousand dollars and several wells can be tied into one facility to benefit from economics-of-scale.

LOE (Lease Operating Expenditures) are basically the costs incurred from gas or oil production after the well has been drilled and completed, which includes hydrocarbon production costs from the reservoir to a central facility, maintaining oil and gas properties and operating equipment on a producing lease. These include costs of labor, supplies, taxes, insurance, transportation and other similar expenses (Madani 2010, Geny 2011).

The details of the operating expenditures (OPEX) can be listed as follows (EIA 2016):

- Fixed lease costs, includes artificial lift, well maintenance and minor workover operations. These costs are reported as $/boe and ranges from $2 - 14.5 /boe including water disposal. While artificial lift costs only accounts for oil plays and constitutes a large portion, gas plays have other various operating costs.
- Variable operating costs represents the costs for delivery of oil and natural gas to a purchase point or pricing hub. These costs include gathering, processing, transport and gas compression and measured in $/MMcf or $/bbl. Dry gas, which requires little processing have the lowest variable operating cost nearly $0.35/Mcf. On the other hand, oil or condensate have greater variable operating costs of $0.25 - 1.5/bbl for pipelines and $2 - 3.5/bbl for trucking.

The production costs for the US shale gas are estimated in the range of $3 - 7 /Mcf, whereas European shale gas production costs are guessed to be in the range of $8 – 12 /Mcf, where these costs exclude the lease or land acquisition (Ernst & Young 2013). As for benchmarking purposes, Barnett OPEX can be assumed as $1/Mcf and for general and accounting cost $0.5/Mcf can be added (Madani and Holditch 2011, Weijermars 2013a).

According to EIA (2016)'s report on oil and gas upstream costs, an additional $1.0 million to $3.5 million can be added for a 20-year well life cycle for fixed lease costs and nearly the same amount should be considered for variable operating costs.

According to Deutche Bank analysis in 2009 for 20 North American unconventional-gas companies, the average breakeven cost is $6.5 /Mcf for new acreage with 10% discount rate (Weijermars and Watson 2011a).

Moreover, Bloomberg & Credit analyzed major US plays and presented breakeven prices as in Figure 87 (Weijermars 2013b). The well cost, royalty, operating cost and breakeven price data for US shales are presented in Table 14.

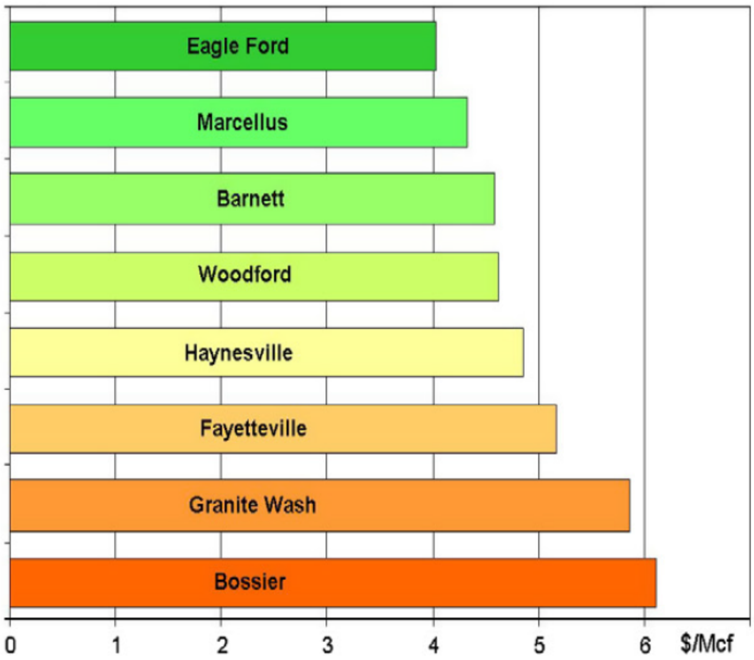


Figure 87 – Breakeven marginal prices for major US gas plays (after Weijermars 2013b, data: Bloomberg & Credit Suisse)

It should lastly be noted that, for pricing some authors or institutions use $/MMBtu ($/million BTU) which nearly equals to $/Mcf ($/thousand cubic feet) (Weijermars 2015).

Table 14 – Breakeven prices together with well and operating costs and EUR /well statistics for biggest five US shale plays (Baihly *et al.* 2010)

Play	Well Cost	Royalty	Operating Cost	EUR	Breakeven Price
	$ MM	(%)	$ / Mcf	Bcf / well	$ / Mcf
Barnett	3	22	0.7	2.87	3.74
Fayetteville	2.8	17	1.1	3.4	3.2
Woodford	6.7	19	1.15	3.39	6.22
Haynesville	8	25	2.5	6.09	6.1
Eagle Ford	5.8	25	1.5	3.79	6.24

One of the most recent studies performed belongs to Federal Reserve Bank of Dallas (Dallas Fed). The fed asked 62 E&P companies a single question “What WTI oil price does your firm need to profitably drill a new well?” in mid-March 2017. After the results show that oil price seems to be hovering around break evens for new wells, however, this prices do not force companies to shut in production any time soon. Hence, the fed also asked these companies, “What WTI oil price does your firm need to cover operating expenses for existing wells?” (Oilprice.com 2017). Figure 88 below clearly presents the results of their research. The black line shows the means and the bars show the range of responses by different companies.

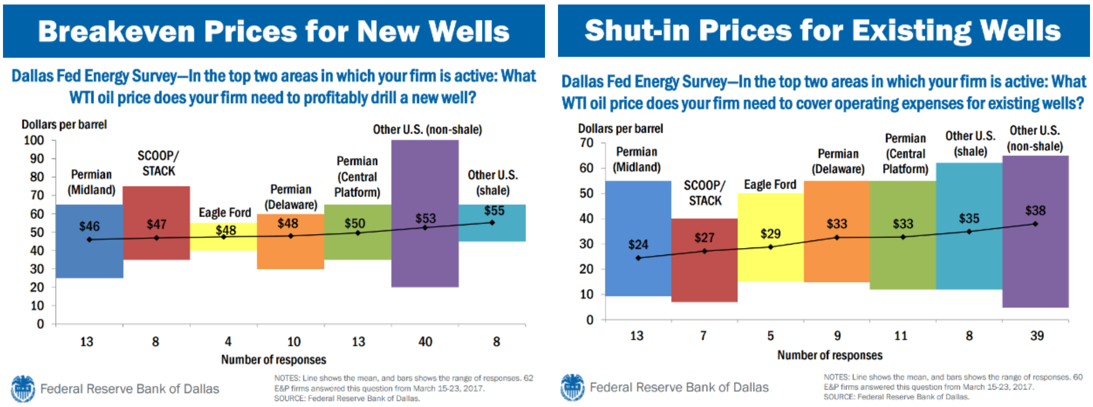


Figure 88 – Breakeven prices for new wells and existing wells (after Dallas Fed 2017)

5.2.5. Valuation of Shale Oil and Shale Gas Projects

In this study, as recommended by Giles *et al.* (2012), opportunity valuation by analyzing the EUR/well necessary to support the project economics and the probabilities associated with those volumes will be the first step. Wright (2008) illustrates the strong correlation between EUR and undiscounted net cash flow (NPV0) by analyzing the economics of more than three hundred Barnett wells. Moreover, having the production profile if possible would give a stronger insight in the economical evaluation of the opportunity.

Haskett and Brown (2005), proposed generating so-called NPV swarm plots by which a balance point (breakeven EUR) for EUR/well where full project NPV corresponds to zero can be determined. Moreover, to have a better illustration, they generated a cumulative probability curve by plotting “1-probability” vs. NPV.

These plots provide an insight at the point that recoverable amount per well will be enough to support the project continuity.

Giles *et al.* (2012) started their journey by creating a set of probabilistic simulation results, where only the EUR/well estimation involves uncertainty. As shown in the Figure 89, while field average EUR/well probabilities are plotted versus NPV, a clear distinction arises between favorable and unfavorable outcomes above and below a particular EUR/well threshold, namely 2.9 Bcf/well in this figure. This EUR/well threshold (vertical blue line) is called "*breakeven EUR*" which is created assuming only uncertain parameter is EUR and below this value, the project should be cancelled.

Meanwhile, in the two figures below, the evaluation results of a development program with a thousand wells are presented. The y-axis are the Post-FID NPV given in *million* $, which refers to project NPV after Final Investment Decision (FID), and the x-axis is the Field Average Ultimate Recovery (UR) per well in billion cubic feet (Bcf).

In this dissertation, we built the same NPV swarm plot for analysis of a single well by introducing uncertainty to nearly every parameter in calculation of NPV and EUR/well. A superiority in our methodology is that, we calculated the NPV values considering the time value of money, i.e. considering the production profiles, contrary to the previous works in which NPV values are generated according to a single monetary value of a total recoverable amount (EUR) per well.

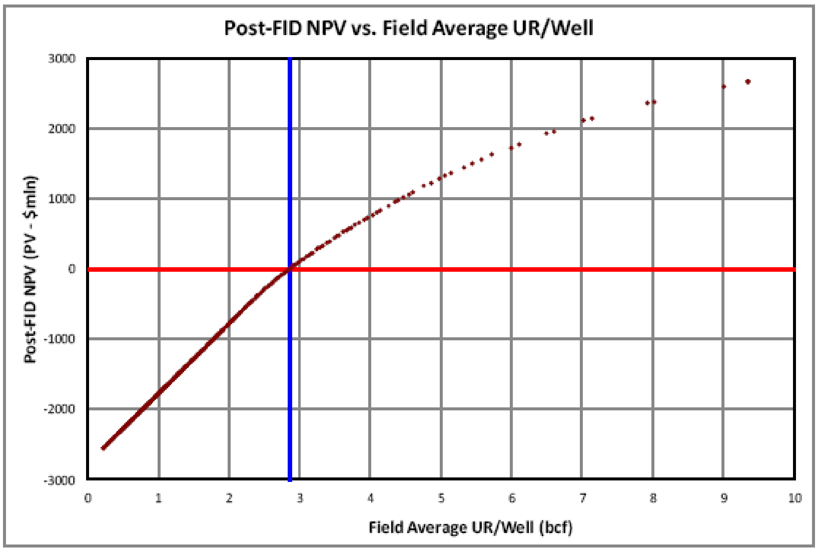


Figure 89 – Determining EUR/well required for economic development (after Giles *et al.* 2012)

To be more realistic, additional uncertainties affecting NPV may be introduced which will complicate the simple plot of EUR/well vs. NPV. Giles *et al.* (2012) also studied this case and came up with another plot (see Figure 90) that shows the probabilistic simulation results with uncertainties in both EUR/well and NPV. This figure, contrary to the previous one, does not reveal a unique result for "breakeven EUR". Instead, a range of "breakeven EUR" can be deduced, which is between 2.2 Bcf/well representing the upper boundary for all negative NPV line and 5.4 Bcf/well representing the lower boundary for all positive NPV line in this example. Hence, the decision of go/no-go will be a question of ***risk tolerance***.

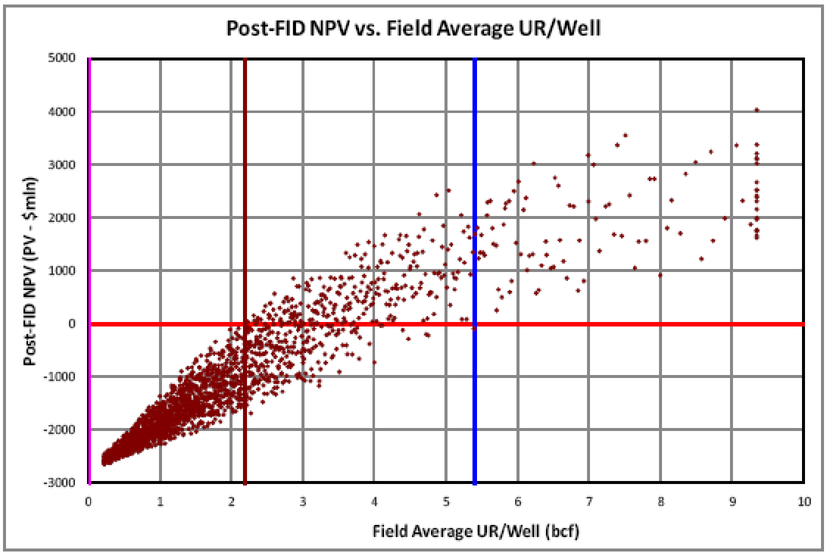


Figure 90 – Determining EUR/well range required for economic development with uncertainties both in EUR/well and in NPV (after Giles *et al.* 2012)

5.2.6. Risk, Uncertainty and Decision Making

Risk is fundamentally the possibility of loss and hence the *project risks* are the potential factors that may affect the success of a project. *Project risk management* is the practice of identifying, assigning, and responding to risks throughout the life of the project to improve the project success. The primary goal of risk management is to minimize potential risks and maximize the potential opportunities. *Risk quantification* is the process of evaluating risks and provides possible outcomes, i.e. determination of the risk's probability of occurrence and its final impacts (CDU-SIT n.d.).

It would also be beneficial to explain the *Decision and Risk Analysis (D&RA)* concept, which refers to a philosophy designed to help make better decisions. Understanding the uncertainties in the problem by approaching in a probabilistic fashion and using mathematical tools to bring simplicity to complicated scenarios is the basis of D&RA. While the project progresses, uncertainty reduces due to increase in information. D&RA is basically used to identify the most important uncertainties for the project success and allow decision makers to concentrate on these uncertainties and invest more to reduce those. Tornado diagrams help to present the uncertainties by ranking them according to their potential impact to the decision criteria. Any item ranked low in a Tornado diagram does not mean it is not an important parameter; this situation is only an indication of the uncertainty in that parameter is not large enough to make a difference in the results (Mao-Jones 2012).

The risk of an opportunity can be evaluated by looking at the **expected value**, which is the differentiation of "the probability of success times the value of the success" and "the probability of failure times the cost of the failure" (Giles *et al.* 2012).

Expected value analysis can be performed by the help of Decision Trees. As is well known, making a decision in a deterministic model is easy, however, while utilizing probabilistic approach, i.e. making a decision under uncertainty is much more difficult. At this point, probabilistic modeling of the range of outcomes with the aid of calculus would help to end up with a decision. A decision tree example is given in Figure 91, in which the circles represent chance nodes and squares, represents the choice nodes. Moreover, as can be seen from the illustration, the probability of the outcomes for a particular project must always sum up to unity (Lozano-Pérez and Kaelbling 2002).

It should be noted that, expected value is only a decision criteria, which helps in decision-making and best works for "risk-neutral" decision maker, and expected value does not mean the prediction of the outcome, even it may not be a possible outcome. The most likely outcome is denoted by the mode, i.e. best prediction of outcome (Begg 2013).

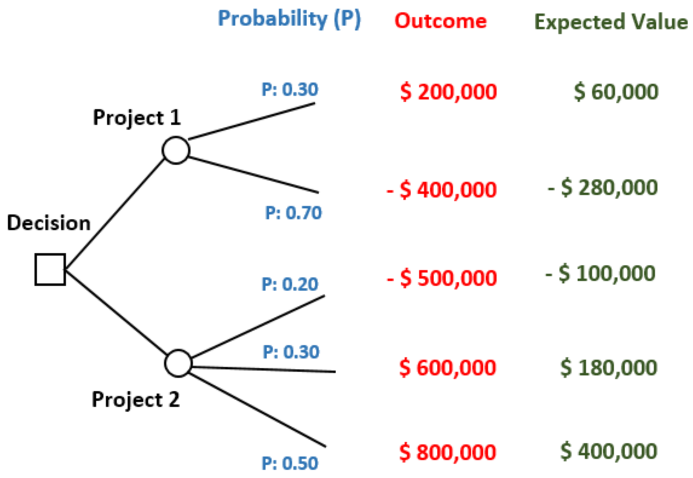


Figure 91 – An illustration for decision tree analysis and calculation of expected values

Several decision-making processes are utilized by different organizations. Some adapt nested structures, which can be explained as, individuals make the decisions and pass to the upper one in the hierarchy and the upper levels make their own decision by approving or disapproving. Another decision-making process is the team decision making, which is more compatible to oil and gas industry due to the highly complex nature of the industry. The decision makers, i.e. team leaders must combine and integrate different recommendations from diverse specialty team members and end up with a final decision to be approved by the organization. The following linear process describes the individual or core decision-making process (Mackie *et al.* 2010):

- Determine the aim,
- Take time to frame the problem,
- Determine objectives and the relative weights,
- Seek alternatives,
- Check other possible solutions,
- Make the decision.

Fleckenstein and Zimmermann (2013) strictly emphasize the importance of quantifying the uncertainties before investment decision making of an opportunity. Moreover, value creation is highly important both on resource and shareholder level, i.e. the optimal path for project development should be selected to please the shareholders and remaining within the capital financial constraints.

Immediate and continuous feedback for decisions made in oil and gas industry is nearly impossible, because the judgement of the final results generally occur as late as many decades later. A solid example for this phenomenon may be the judgement of a decision relying on recoverable reserves, which can hardly be verified after many years. Moreover, in oil and gas industry, the size of the outcome, e.g. the reserves amount of a hydrocarbon discovery, is extremely important since success must be evaluated from a commercial viewpoint. A decision may be technically successful, but economically a failure (Mackie *et al.* 2010).

Profitability Investment Ratio (PIR), the ratio of present value of future cash flows to initial investment, can be converted to a plot of EUR/well vs. average well-cost and helpful in valuation of a project. An illustrative example is given in Figure 92. By utilizing the PIR, a rigorous de-risking program may be undertaken by operator by minimizing the capital costs while determining the success or failure of a case (Giles *et al.* 2012).

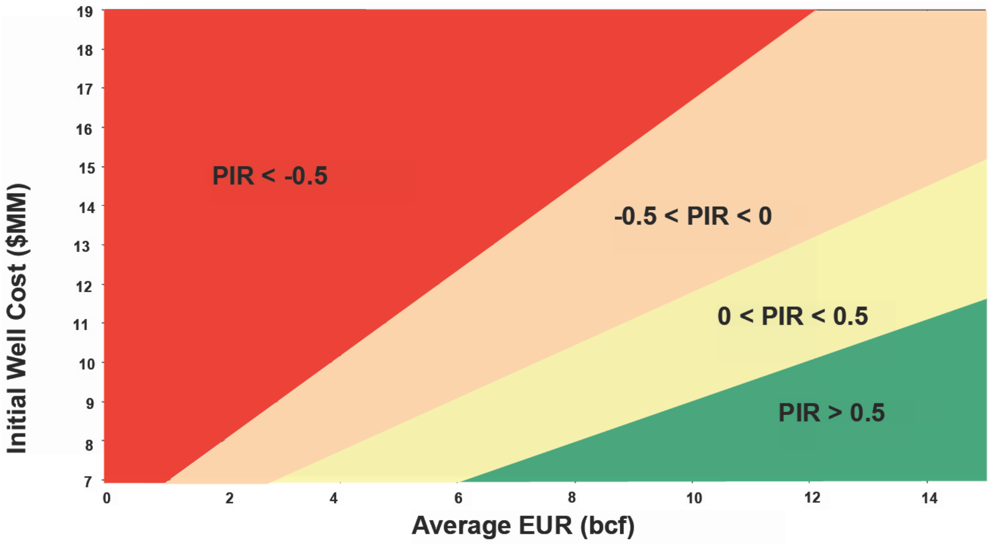


Figure 92 – Relationship between initial well cost, average EUR and PIR for a typical unconventional project with fixed infrastructure cost (after Giles *et al.* 2012)

There is a certain risk on well level due to reservoir heterogeneity that leads to no economical production even after stimulation. Moreover, there is also mechanical risk on well level (Haskett and Brown 2005).

However, on play level, there is very little probability of not producing hydrocarbons (Figure 93). The primary focus of unconventional resource evaluation should be the uncertainties associated with the volumes and the rate through time. These uncertainties are caused by uncertainties in reservoir parameters such as hydrocarbon saturation, formation volume factor, recovery efficiency, porosity, net thickness and area (Haskett and Brown 2005).

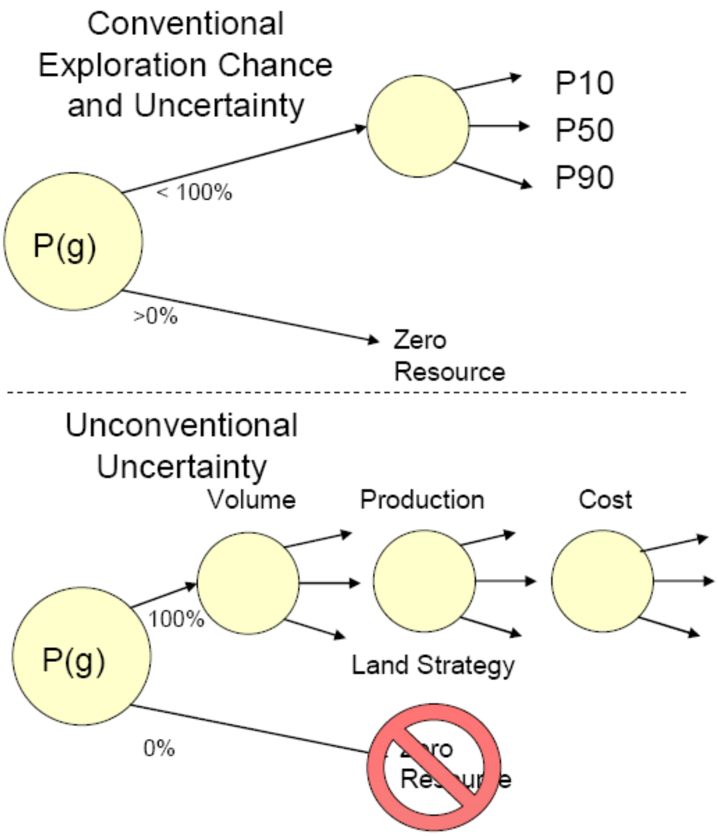


Figure 93 – Comparison of conventional and unconventional risk and uncertainties (after Haskett and Brown 2005)

Volumetric success is the primary key for economic viability; however, it is not the single source of uncertainty. Production profile, cost, program timing, land strategy all contribute to uncertainty of profitability. Hence, a valid evaluation of an unconventional project should consider all these major uncertainties (Haskett and Brown 2005).

5.2.7. Reserves Classification for Shale Oil and Shale Gas Resources

Hereby, it may be appropriate to mention about the reserves/resource classification in the context of shale oil and shale gas resources to build a common language for this study. SPE-PRMS (2007) is a practical reserves management framework for operators where SEC (2008) basically aim to protect investors by regulating how companies report oil and gas reserves and UNFC (2009) is a complementary framework especially useful for national oil companies, which includes also the mineral resource classification. All three frameworks mainly aim to de-risk the assets and reduce the volatility in volumes and economic producibility. For example, SEC (2008) updated its rules to make proved reserves less sensitive to short-term price fluctuation and hence make energy investments less volatile by changing the prices in concern to be determined by 12-month average rather than the year-end price (Weijermars 2012, Weijermars and McCredie 2011a).

Traditionally, growth of reserves in the portfolio is normally a slow and costly process, which can either be realized by success in exploration of new prospects (organic growth) or by the purchasing assets and proved reserves from other companies (non-organic growth). With the emergence of hydrocarbon production from shales, infill-drilling programs become able to add new reserves without acquiring new acreage or exploring new prospects. Because of advances in shale oil and shale gas production, need for a revision in regulations arose (Weijermars and McCredie 2011a, Weijermars 2012). SEC (2008) clearly states the intent of amendments is "to modernize and update the oil and gas disclosure requirements to align them with current practices and changes in technology". Hence, a more comprehensive understanding of oil and gas reserves and comparison between companies are ensured (Henry 2015).

Typically, shale projects require high up-front costs that provoke negative cumulative cash flow at the early times of the project. Besides, investors generally interest in "proved" reserves comparing to "unproved", "contingent" or "prospective" resources. The amendments in SEC (2008) make unconventional resources more attractive for investors by changing the criterion for "proved reserves" in undrilled locations from "certainty" to "reasonable certainty", hence more proved undeveloped reserves could be disclosed (SEC 2008, Lee 2012).

Moreover, SEC changed its rules-making philosophy from “rules-based” to “principles-based”, which leads to a wide variety of procedures in obtaining results would get acceptability. In short, if operators develop a methodology in predicting with “reasonable certainty”, that certain volumes of hydrocarbons in undrilled locations will ultimately be produced, and then they are accepted as proved reserves according to SEC (Figure 94). To prevent potential abuses at this situation, SEC restricted the time period of development projects to be accounted as proved undeveloped reserves for 5 years, i.e. reserves with wells in 5 years approved development plan satisfies SEC rules. Although unconventional resources generally extend in huge acreages that cannot be fully developed in 5 years, regulators force resources to be drilled beyond this period to be placed in lower certainty reserves category (Lee 2012).

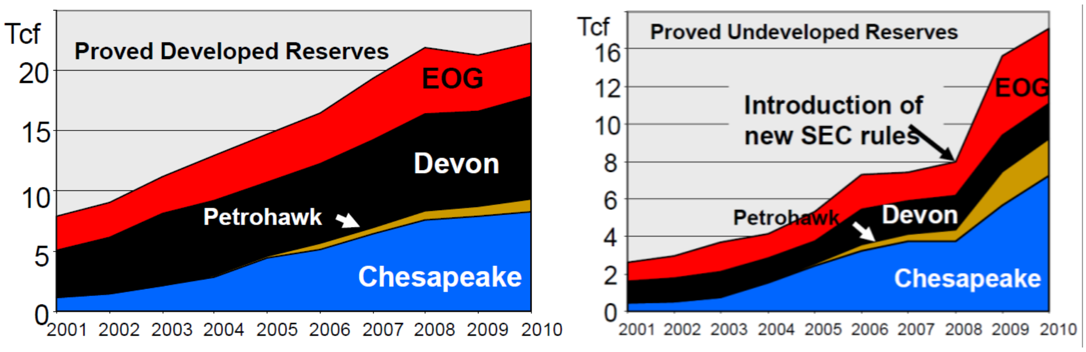


Figure 94 – Proved developed (PD) and proved undeveloped (PUD) gas reserves for US Independents showing the steep rise in PUD mainly caused by the introduction of new SEC rules for undeveloped reserves (after Weijermars 2011a, 2012)

The words “amount of economically recoverable hydrocarbon” in the basic definition of reserves and clearly indicates that flow rates are as important as the total recoverable volumes from economical perspective. As a matter of fact, volume and rate are strongly linked to each other. In fact, economic outcome is generally more sensitive to production profile than EUR. Hence, being volumetrically right do not always mean being economically right (Haskett 2005). The next section elaborates the importance of production profiles on shale project economics and presents the parameters those may bring uncertainties to the evaluation of the unconventional projects.

5.3. Production Profile

Uncertainty ranged approach to production profile will provide better assessment of the true potential and downside possibilities, which is a combination of 4 major uncertainties; initial production (IP), plateau life (PL), total production (EUR) and decline rate (*D*) as illustrated in Figure 95 (Haskett 2005). Different values of decline parameters lead to various shapes of P10, P50 and P90 profiles. IP (initial production) is partly dependent on reservoir character and GIIP, whereas "*D*" is inversely dependent on reservoir quality and GIIP. Lastly, "*b*" is dependent on the reservoirs' ability to recharge near well-bore vicinity – except the exponential declines – (Haskett and Brown 2010). While generating production profile of an asset, Haskett (2005) recommends aggregation of well level profiles for consideration of ramp-up, early production possibilities prior to full development of the asset, facility or pipeline constraints and production efficiency.

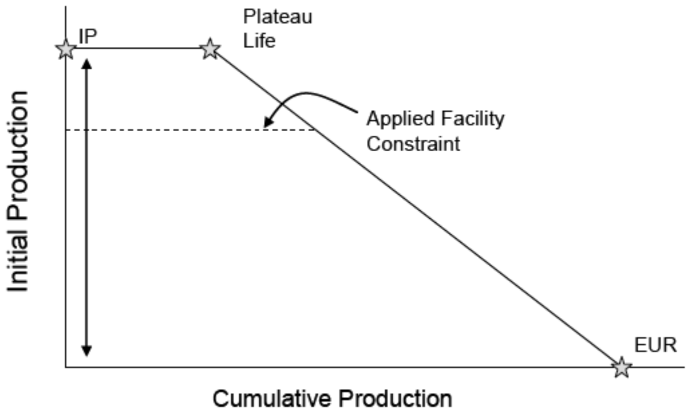


Figure 95 – Four major uncertainty source for exponential decline based production profile (after Haskett 2005)

While quantification of resource potential and volume-based chance of success are crucial in economic evaluation of an opportunity, the primary uncertainty comes from the uncertainty of production profile. Namely, two thirds of the NPV uncertainty of shale plays are related to production profile. Moreover, as presented in Figure 96, approximately 18% is related to Capital Expenditure (CAPEX) and only 15% is related to resource volume. Hence, depending only on a volumetric assessment associated with a deterministic production profile result in an overestimation of the production potential and value (Haskett 2009, Haskett and Brown 2010).

Hence, an integrated operational and business approach, which starts with a probabilistic production potential and resource assessment, is necessary to maximize the value (Haskett and Jenkins 2009).

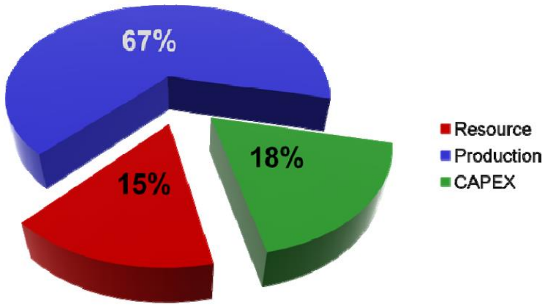


Figure 96 – Contribution to NPV uncertainty of principal elements of a typical gas shale project (after Haskett and Brown 2010).

5.3.1. Pathways vs. Aggregates

Production profiles have two axes with uncertainty; time and rate. Production profile distribution differs from the volumetric estimation by being a time series as are cash flow, capital requirement and revenue, hence analysts should be aware of the complexities in the interpretation of the time series. Uncertainty through time is different from the uncertainty at a time (Haskett 2011). There are two configurations of time series, pathways and aggregates, which have different usages (Haskett 2005).

Haskett (2005) defines the two configurations as quoted: "Pathways are case specific. They are string of results that occur together and represent a viable output path through time. The individual 10-50-90 outputs may cross. The 10^{th} percentile pathway may end earlier than the 90^{th} percentile pathway, but may have had a higher IP. The ranking parameter to determine the 10-50-90 is total production or another non-rate based parameter, though usually it is NPV. Production pathways should be used when the ranking parameter is not rate related.

Aggregations are time series plots showing successive 10-50-90 results by time. Aggregations are year-by-year distributions. Typically, they are used as the final output from a portion of a project that then can be used as uncertainty input to the next portion. Aggregations should be used when the ranking parameter is production rate based".

According to Haskett (2011), the ranking parameter to determine 10-50-90 from eyes of an academician may be EUR, however from eyes of a businessperson, value (specifically NPV), would be the ranking parameter. The ideal case is assessment of stochastic full value-chain, which deliver average profile and profile for average value.

When ranges of aggregate outcomes are presented, errors are inevitable due to nature of the time series. In details, the case generating P10 at time t_1 may be different from the case in time t_2. Hence, using P10 outcomes through time to obtain P10 pathway may be invalid (Figure 97 and Table 15). The use of this invalid pathway in economic analysis would lead to over estimation of the opportunity (Haskett and Brown 2010). Pathways and aggregate outputs have different uses in different viewpoints as summarized in Table 15. In short, while aggregate output is used for facility system assessments, pathways are used for defining the success case economic viability (Haskett 2005).

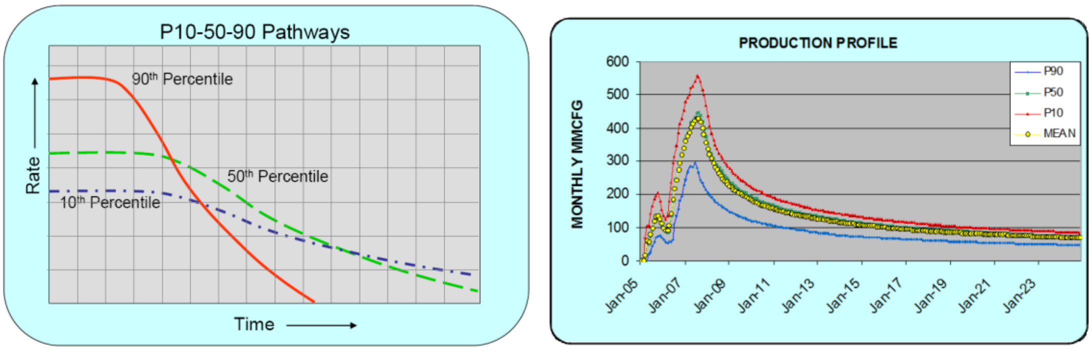


Figure 97 – (a) Production profile pathways, coherent valid possible production rates through time. (b) The Aggregate profile – valid uncertainty for any particular point in time but invalid through time (after Haskett and Brown 2010)

Table 15 – Uses of pathway and aggregate outputs (after Haskett and Brown 2010, Haskett 2005)

Pathways	Aggregates
Valid through Time (horizontally)	Valid within a particular Time point (vertically)
Used to define production components of other rankings	Used to define production component of production ranking
Defines throughput paths for economics	Defines post production utilization (facility throughput, pipeline capacity, de-bottlenecking)

5.3.2. Initial Production (IP)

Initial production rates of the wells in any specific resource play have a significant correlation with well EUR's of the play. Hall (2007) examined 92 horizontal Barnett gas wells and draw peak monthly rate (Mcf/month) vs. estimated EUR. He ends up with the correlation coefficient of 0.75 as shown in Figure 98a. It can be deduced that IP is a good predictor of reserves in resource plays. Moreover, Figure 98b shows the variation of IP's throughout the reservoir examining 361 horizontal Barnett gas wells.

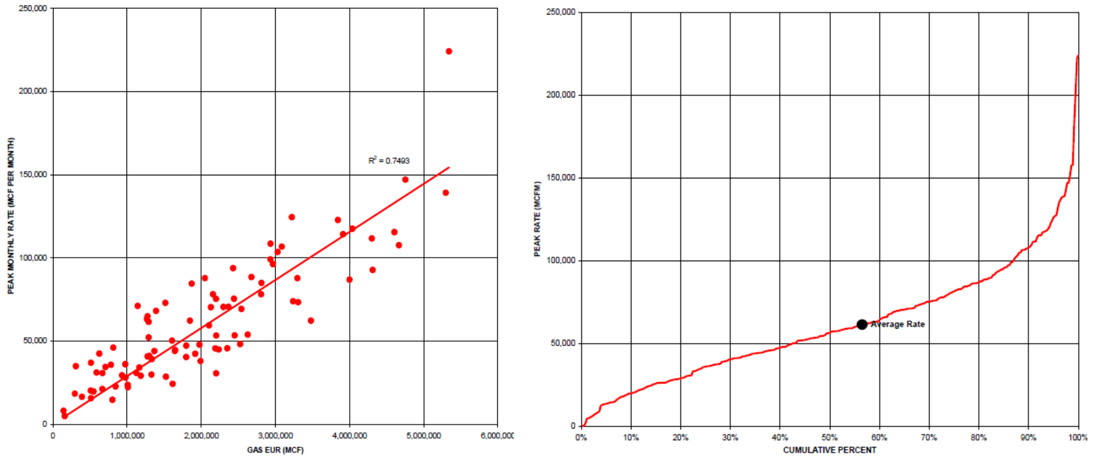


Figure 98 – (a) EUR's and IP's of 92 wells in Barnett Shale, (b) Cumulative percentage for IP's of 361 horizontal Barnett wells (after Hall 2007)

It is also worth noting that initial rates are also recommended to be modeled by a clipped lognormal distribution as shown in Figure 99 (Gouveia and Citron 2009).

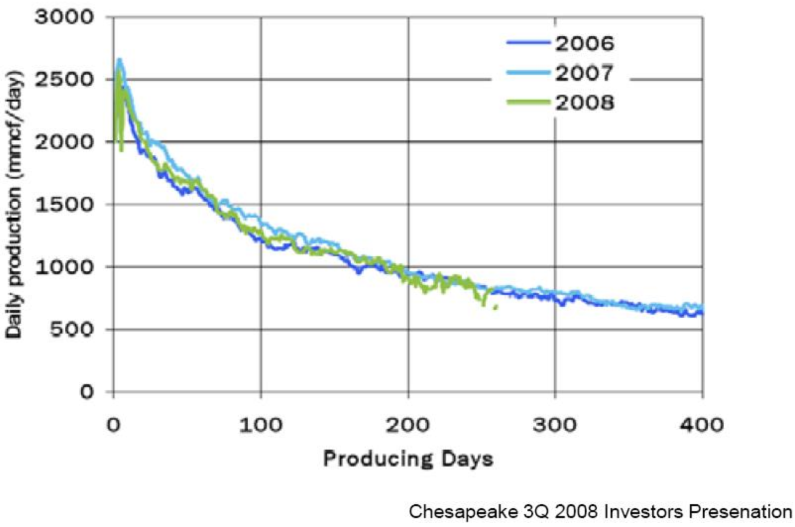


Figure 99 – Barnett Shale normalized production type curves (after Gouveia and Citron 2009)

Haskett (2011) draw attention to the uncertainty in IPs to be used in production analysis. They strongly warn that day 1 productions are not representative of IPs; instead, at least 30-day stabilized rate should be used. Here, IP30, IP60, IP90 terms come in handy, which show the average daily rate when the well produced for the specified number of days. The numbers after "IP" abbreviation show the number of production days. This number is converted to hours of production and downtimes are excluded, hence the elapsed time to reach any IPxx (xx denotes the number of days) varies from well to well (Verdazo.com 2015).

Initial production rates for horizontal shale gas wells range between 2 to 10 MMcfd and for shale oil wells, the oil rate ranges between 250 to 2000 BOPD as for various shale plays. Moreover, it should be noted that, the initial production is a strong function of reservoir pressure. The higher the reservoir pressure, the higher the initial production rates and in turn the higher the EUR (Ahmed and Meehan 2016). The comparison of the initial production rates of various fields, their decline profiles, and hence their EURs are also discussed in detail in Section 5.2 (Baihly *et al.* 2010, 2011).

5.3.3. Economic Limit

Economic limit is defined in SPE-PRMS (2007) as "the production rate, beyond which the net operating cash flows from a project (after royalties or share of production owing to others), which may be an individual well, lease, or entire field, are negative, a point in time that defines the project's economic life". Net operating cash flow represents the direct operating costs subtracted from net revenue and the costs considered here are those that can be eliminated after the production is terminated (SPE/AAPG/WPC/SPEE/SEG 2011).

According to Ahmed and Meehan (2016) the economic minimum limit for a shale gas well is 100 Mcf/d. Browning *et al.* (2013) assumed an economic limit for Barnett gas wells as 50 Mcf/d. As for high-BTU gas wells, since liquid revenue helps to improve economics, 29 Mcf/d was assumed as the economic limit in Browning *et al.* (2013)'s study.

5.4. Well Costs

Through the starting of economic production of shales by Mitchell way back 20 years and hundreds of wells; drilling and completion costs are reduced considerably. Numerically this cost reduction has reached 50 % in many places by application of new technologies, efficient project management and supply chain negotiations (Meisenhelder 2013). Even in a given project, due to learning curve, drilling and completion costs reduce with increasing number of wells (Gray *et al.* 2007).

Figure 100 from EIA (2016) presents that the well costs are reduced by 25-30% from 2012 to 2015 due to learning curve. In details, the period of 2006 – 2012 represents the ramp up trend of the drilling and services activities, which brought capacity increments. After 2012, not only activities reduced, but also the efficiency of drilling, completion and well designs increased and put the trend downward. Moreover, the report foresees a continued downward trajectory in costs in dollars per barrel of oil-equivalent ($/boe) including the earnings from efficiency increments in drilling and completion operations and designs.

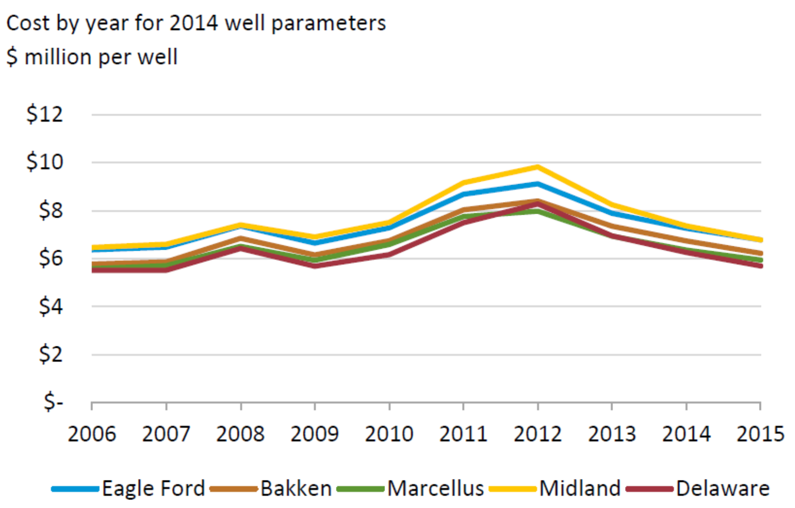


Figure 100 – Average well drilling and completion costs (after EIA 2016, IHS's Cost Study)

The report (EIA 2016) focuses on 5 onshore regions Eagle Ford, Bakken, Marcellus, Midland and Delaware and gives the total capital costs per well in these plays as $4.9 million to $8.3 million, including average completion costs range between $2.9 million to $5.9 million per well. The following pie chart in Figure 101 presents the constituents of total well costs in percentage.

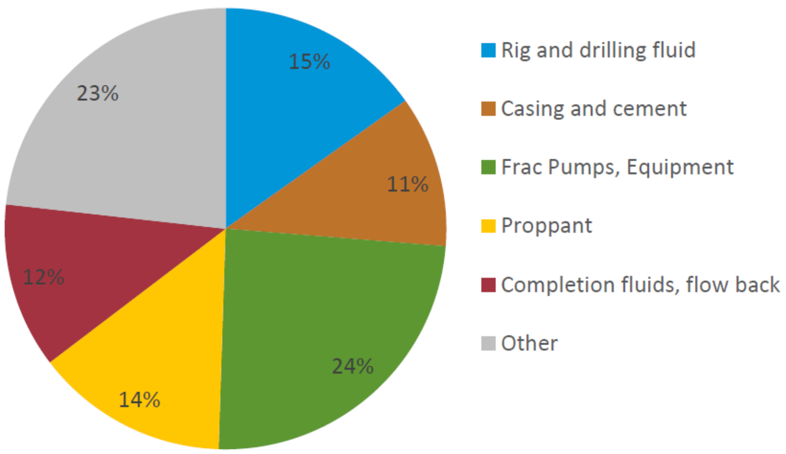


Figure 101 – Cost share percentages for U.S. onshore plays (after EIA 2016, from IHS's Cost Study)

There is a strong correlation between well size, complexity and costs. The key drivers above have several sub-parameters, which constitute these costs and can be listed as:

- Rig and drilling fluids: TVD, lateral length and drilling penetration rate,
- Casing and cement: TVD, lateral length, number of casing strings,
- Frac pumps and equipment: injection rates, breakdown pressures, stages,
- Proppant: Amount of proppant, cost per amount of proppant
- Completion/frac fluids: amount of fluid, amount of gel, chemicals.

Figure 102 present cost per year charts showing the variation in drilling costs per total depth and completion costs (stimulation included) per lateral length. Especially, the reductions in both drilling and completion costs after 2012 are remarkable.

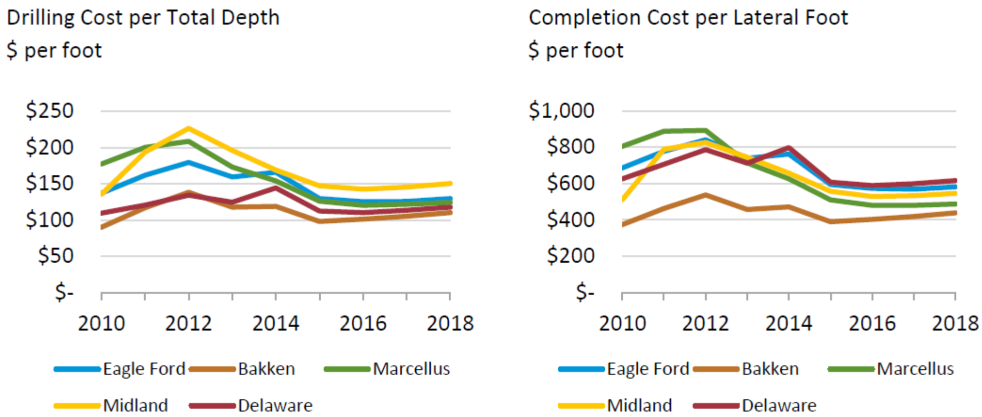


Figure 102 – Drilling and completion cost variations (after EIA 2016, from IHS's Cost Study)

Drilling cost prediction is essential for a reliable project economic analysis. Moreover, being the backbone of unconventional wells, lateral sections bring higher costs together with higher economic uncertainty to horizontal wells.

Factors effecting costs can be categorized in two primarily parameters: the location of the well and the depth of the well. Moreover, drilling costs can be categorized into three: fixed (wellheads, site preparation, tubulars, cementing, packers), daily (rig time, tool rental, salaries, fuel, lubricators, consumables) and unit costs (unit prices for consumed commodities; barites, bentonite) (Bourgoyne *et al.* 1991, Craig 2014).

Drilling cost per unit depth, "C_f" can be defined by Eqn. 47 (Bourgoyne et al. 1991):

$$C_f = \frac{C_b + C_r.(t_b + t_c + t_t)}{\Delta D} \quad \textbf{(47)}$$

where, ΔD is the total time required to drill at final depth which is the sum of total rotating time during the bit run "t_b", non-rotating time during the bit run "t_c" and the trip time "t_t". "C_b" is the cost of a bit and "C_r" is the fixed operating cost of the rig per unit time.

While looking from a wide angle, depth vs. cost plots for real case studies reveal that depth and cost are in an exponential relation, that is, costs increase exponentially while drilling depth increases. Total drilling cost can be estimated via Eqn. 48 below (Bourgoyne *et al.* 1991, Craig 2014):

$$C = a.\mathrm{e}^{b.D} \quad \textbf{(48)}$$

Where, "*C*" is the cost of drilling the well ($), "*a*" and "*b*" are the constants to be used according to the location of the well in units of $ and ft^{-1} respectively, and finally "*D*" represents the depth of the well (ft). The data of historical wells can be used to determine "*a*" and "*b*" constants via curve fitting methods.

It should be noted that, for wildcat/exploration wells, costs are much higher than development wells since the project is at an earlier point in the learning curve. Moreover, a contingency factor should be applied to address the uncertainties, which can be as lump sum or percentage of the total cost (Craig 2014).

Bourgoyne *et al.* (1991) studied data of nearly two thousand completed wells below 7500 ft in South Louisiana and utilized least-square curve fit (Figure 103). They determined the constants in Eqn. 48 as “a = 1 x 10^5 \$” and “b = 2 x 10^{-4} ft^{-1}” for that specific field.

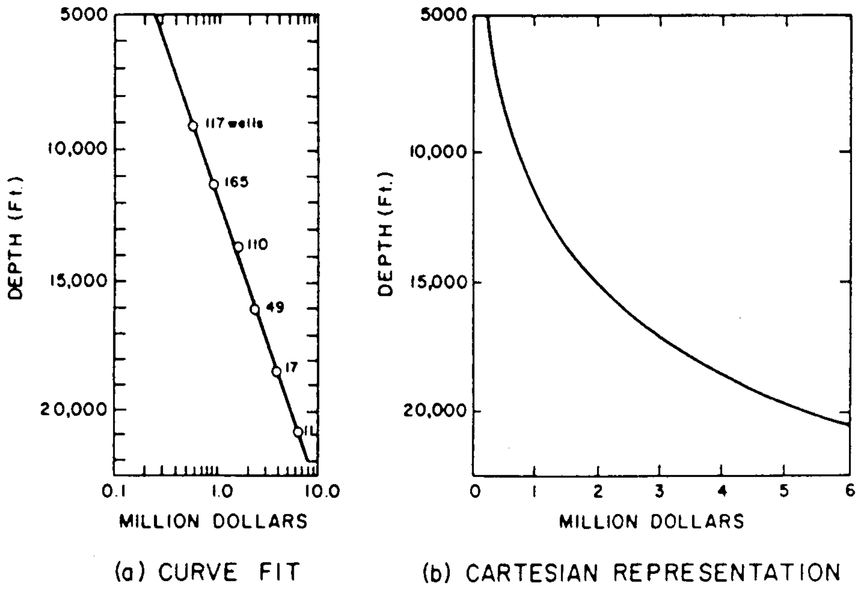


Figure 103 – Exponential increment in drilling costs with depth (after Bourgoyne *et al.* 1991)

These above mentioned costs are related to vertical wells. Since wells with shale formation targets are drilled with horizontal sections, both vertical and horizontal drilling costs should be evaluated separately. Darugar *et al.* (2016) assumed drilling unit costs of \$70/ft for vertical section and \$110/ft for the horizontal in their evaluation of Eagle Ford wells and Bakken wells.

Completion costs are the costs of tubular goods that are run in hole for the vertical depth. Darugar *et al.* (2016) reached a unit cost of \$160/ft by examining the reports (Spears and Associates) revealing total tubular costs for Eagle Ford wells. Although, well completion term includes well stimulation in general, mentioned authors evaluated the stimulation costs in another title as per below.

Stimulation costs contains the perforating and hydraulic fracturing costs. The total number varies according to the stage count together with the proppant and fluid type and amount used in these stages (Darugar *et al.* 2016). \$100,000 to \$200,000 is the common range for a stimulation job of only one stage.

Leasing of mineral rights is another CAPEX to be covered for development of oil/gas resources. In countries like USA, where mineral rights belong to the landowner, this procedure is handled by payment of a signing bonus per area by the operator company. Hence, the leasing cost of mineral rights corresponding to one single well can be formulated as (Darugar *et al.* 2016):

$$Leasing\ Cost = c_0.\Delta_0 \quad \textbf{(49)}$$

where, c_0 : the leasing cost per area ($/acre) and Δ_0 : the well spacing (acre/well).

In study of Darugar *et al.* (2016), the leasing cost for Eagle Ford and Bakken Shales are found as $15,000/acre and $2000/acre, respectively. As can be deduced, leasing cost can change considerably between locations.

Site construction costs also contributes to the CAPEX, which includes all costs for preparing the wellsite such as: leveling the terrain, creating the pad and constructing the roads. This cost is also highly variable according to the location. Darugar *et al.* (2016) has taken this cost as fixed, namely $400,000/well for both Eagle Ford and Bakken.

Plug and Abandonment (P&A) is naturally a part of field development, even it may be performed years later. Darugar *et al.* (2016) reached an approximate value of $30,000/well from reports, which may be negligible comparing to all other CAPEX.

Production cost includes lifting costs ($2.5/bbl - $5/bbl), water management costs (around $4 /bbl), hydrocarbon transportation costs ($10/bbl for rail, $2.5/bbl for tanker) and other costs related to production. It should be again noted that unit production cost highly differs between locations (Darugar *et al.* 2016).

As a concluding remark of Darugar et al (2016)'s study, the lifecycle cost per well is calculated as $7.4 million and $8.7 million on average for Eagle Ford and Bakken Shales, respectively. The resulting breakeven price according to this study is $69/bbl for Eagle Ford and $63/bbl for Bakken Shale. All these above-mentioned costs are valid for both conventional and unconventional projects; however, unit costs differ between those two. It may also be helpful to remind that, CAPEX and OPEX concepts together with their contributing items are mentioned in detail in Section 5.2.4.

An illustrative study to present the cost difference of conventional and unconventional wells comes from Cui *et al.* (2014) who compare a typical Eagle Ford unconventional well and a typical Austin Chalk conventional well since these two plays have geological proximity, similar reservoir fluids as light oil and similar well designs with 3500 – 4500 ft lateral lengths. The result of their research showed that while Eagle Ford well recovers twice of the Austin Chalk well, it also costs about twice of the latter ($8 million vs. $4 million). Hence the unit cost of production ($/boe) is nearly the same for both.

Although, Eagle Ford well is slightly deeper than Austin Chalk well, it does not bring too much cost burden, namely only 10 % more. However, there is a huge difference in the completion cost, which results in twice well cost of a conventional horizontal well as presented in Figure 104 (Cui *et al.* 2014).

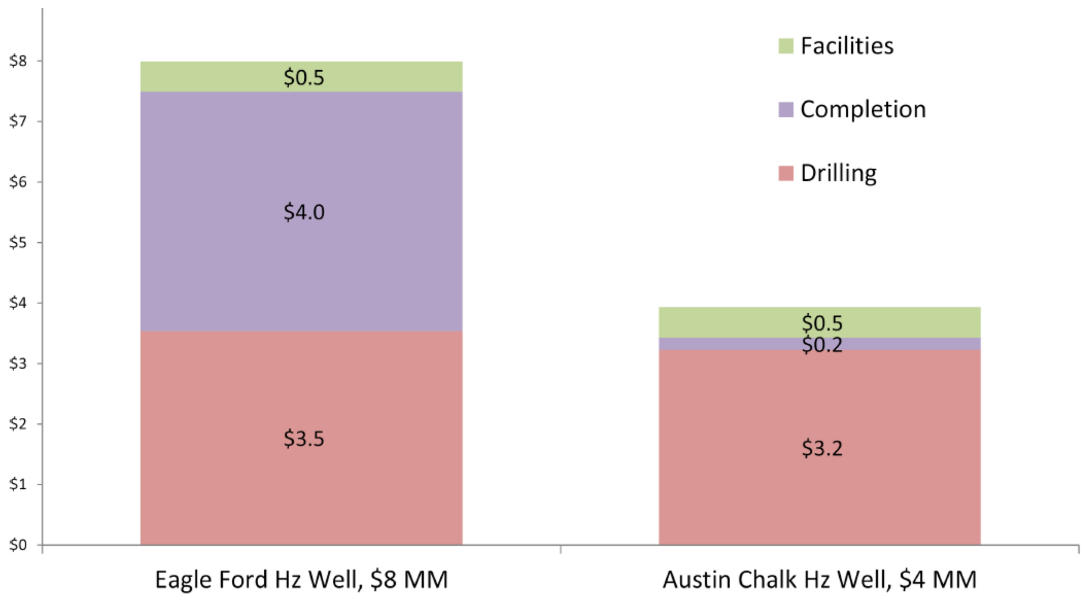


Figure 104 – Eagle Ford and Austin Chalk well CAPEX comparison (after Cui et al. 2014)

Cui *et al.* (2014) also considered the 20-year EUR/well in both plays and they calculated Net Present Values with 90 % confidence and 10 % discount rate. They ended up with NPV10 of $5.3 million for Eagle Ford well and NPV10 of $2.2 million for Austin Chalk well, due to the higher overall EUR/well of the former. Another contribution of higher NPV10 came from the higher initial production of Eagle Ford well (Figure 105).

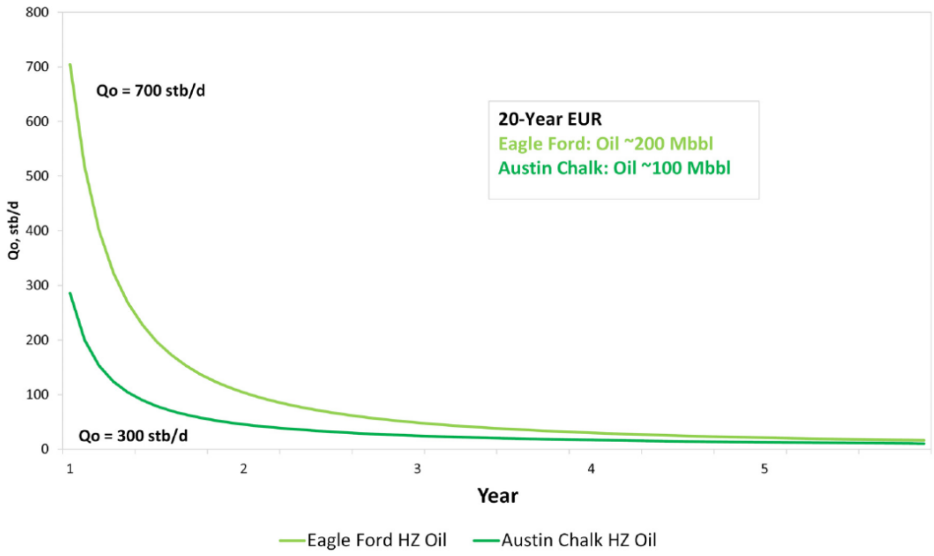


Figure 105 – Eagle Ford and Austin Chalk well type curves (after Cui et al. 2014)

From single well perspective, while Eagle Ford well cash flow becomes positive in a few months, Austin Chalk well reaches breakeven only after a couple of years (Figure 106).

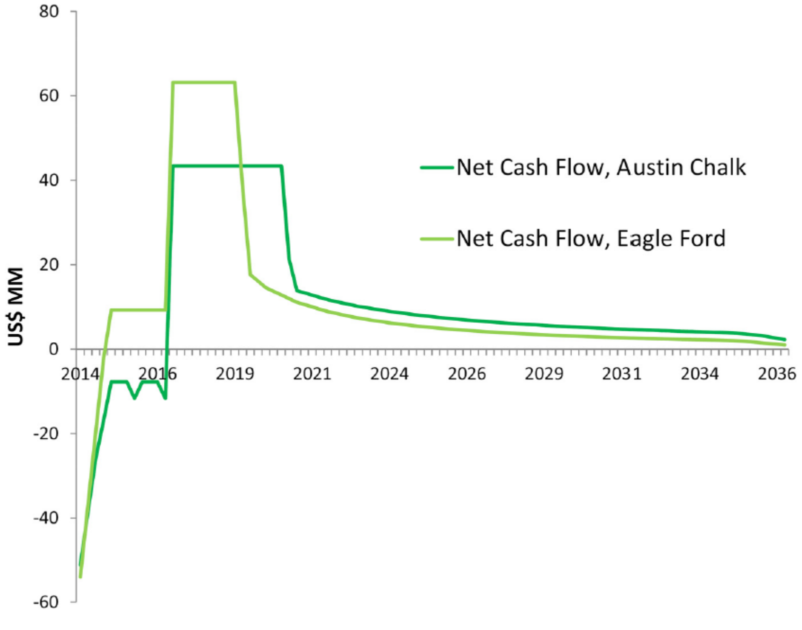


Figure 106 – Eagle Ford and Austin Chalk well cash flow comparison (after Cui et al. 2014)

It should be noted that, these analyses are based on single well case, however, in multiple well development plans, project economics change significantly. Since fully developing an unconventional play requires drilling of thousands of wells; the overall investment would look much more like those of a deepwater offshore project. To equalize an offshore Gulf of Mexico (GoM) well EUR with an Eagle Ford project, 80 wells should be drilled. This would in turn reduce Eagle Ford projects' IRR significantly. Below, CAPEX (Figure 107) and type curve comparisons (Figure 108) for an Eagle Ford well and GoM offshore well are presented (Cui *et al*. 2014).

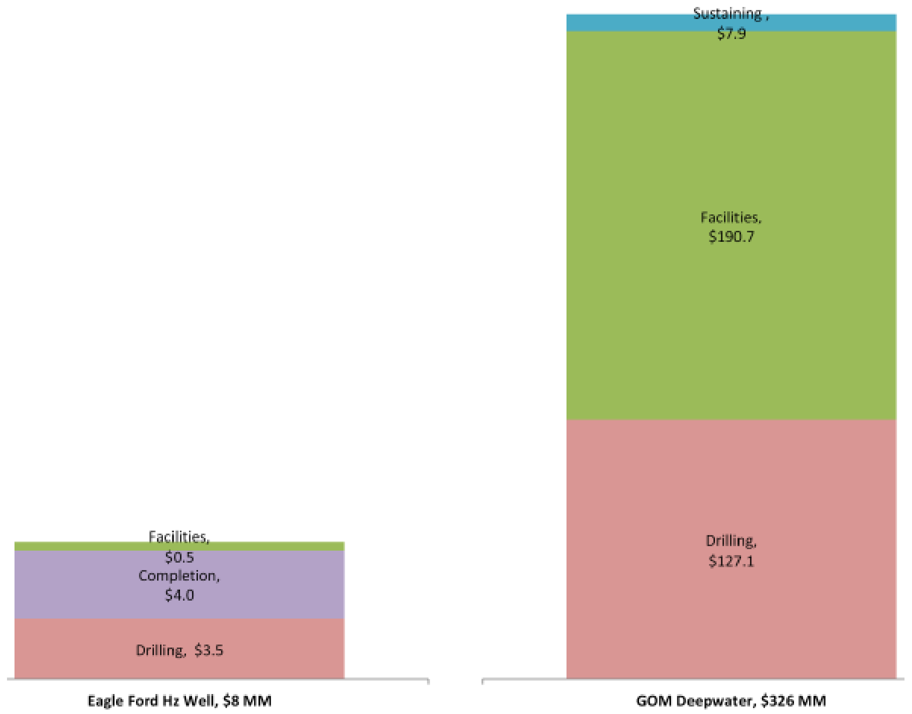


Figure 107 – Eagle Ford and GoM deepwater well CAPEX comparison (after Cui *et al.* 2014)

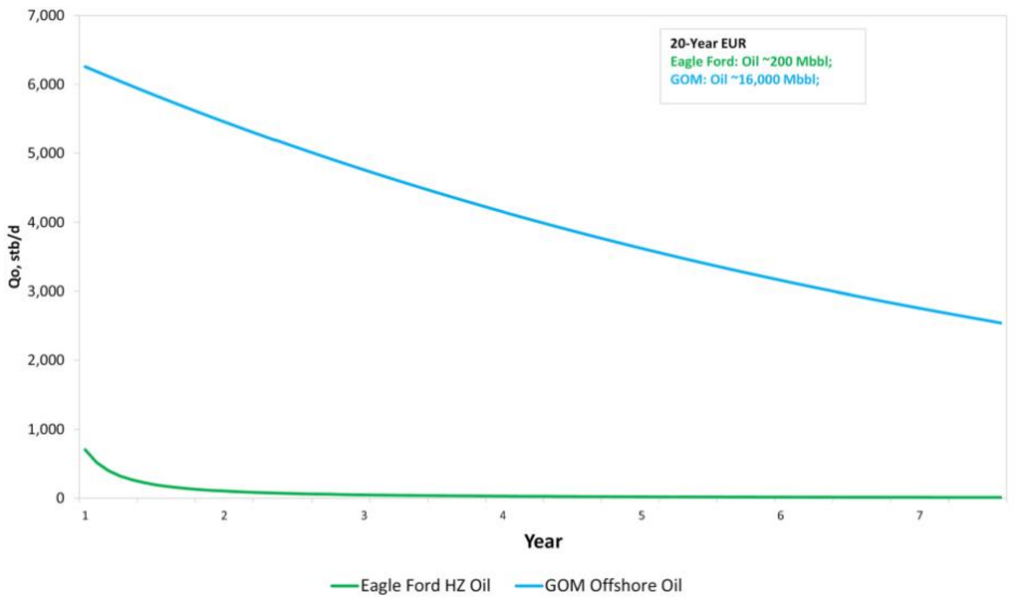


Figure 108 – Eagle Ford and GoM deepwater well type curves (after Cui *et al.* 2014)

5.5. Average Market Prices

Although companies do the reserves reporting according to historical prices, e.g. 12-month average for the previous year in SEC (2008), market value of the projects, i.e. future revenue/expenditure estimations should be done according to future prices of oil and gas. Consequently, the future prices of hydrocarbons are one of the major uncertainty factor affecting revenue and economics of the project. There are several organizations publishing different scenarios or models for future trends, however, it is very difficult to end up with a correct forecast. In oil industry, NYMEX (New York Mercantile Exchange) future prices are one of the most widely used scenarios for market valuation. Moreover, hydrocarbon price functions can be used as fixed (no change), linear (steady change), exponential (late hydrocarbon price riser) or logarithmic (early price riser). Linear price function (simple inflation function) proposes an initial price for the starting time and a forward correction for inflation. The equation representing this model is:

$$P_n = P_1.\left(1 + r_{inf}\right)^n \quad \textbf{(50)}$$

where P_n is the well-head hydrocarbon price in year n, P_1 is the well-head hydrocarbon price in year 1, r_{inf} is the annual inflation rate affecting the hydrocarbon price, and n is the number of years of production (Weijermars 2013a, Chen *et al.* 2015, Henry 2015). However, in our study, we used a fixed price scenario since the price of hydrocarbon is mostly affected by socio-politic motives instead of a technical or economic ground (see Figure 109); hence, the prices are not necessarily going upward. Moreover, as stated previously, this study only focuses on the uncertainties in technical level.

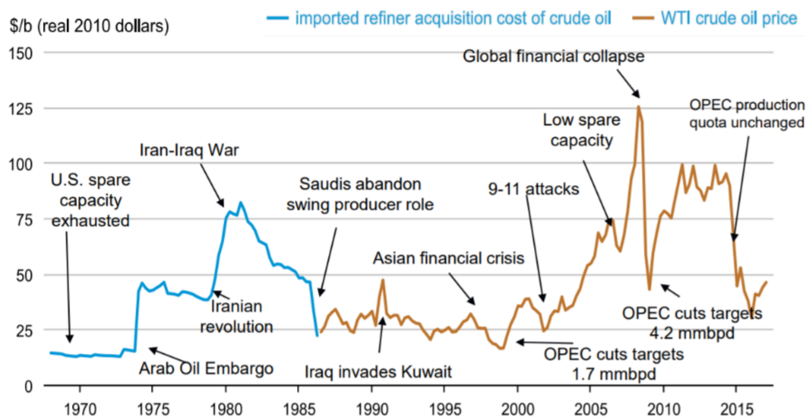


Figure 109 – Historical oil and gas prices affected by socio-political events (after EIA 2017).

5.6. Regulations, Terms and Conditions

Unconventional gas and oil business is highly dynamic and not a simple task of acquiring acreage, drilling a horizontal well and applying multistage fracturing. Regulations and politics are the two other highly important factors besides economics those determine the destiny of an unconventional play (Lee 2012).

A host country government should propose a dynamic, efficient and stable fiscal arrangement together with high geologic prospectivity to attract investors/operator companies. Investors show interest in regions only if they have a balance between risks and rewards, i.e. have a rational fiscal arrangement (Iledare 2014). Governments must set up a rational fiscal regime that will maximize the benefits of its citizens while keeping the country an attractive place for oil and gas investments (Christiansen 2016).

Fiscal regimes applied to regulate the economic relations of the host country (state/government) and the operator company (contractor/investor) in the oil industry can be classified into two. The first one is c**oncessionary system**, which is also referred as R/T (Royalt/Tax) regime and the second one is **contractual system**, which embraces several sub-systems such as; PSC's (Production Sharing Contract), service contracts, buyback contracts and technical assistance contracts. Figure 110 presents the categorization of petroleum fiscal regimes (Zweidler 2012, Tordo 2007, Johnston 1994).

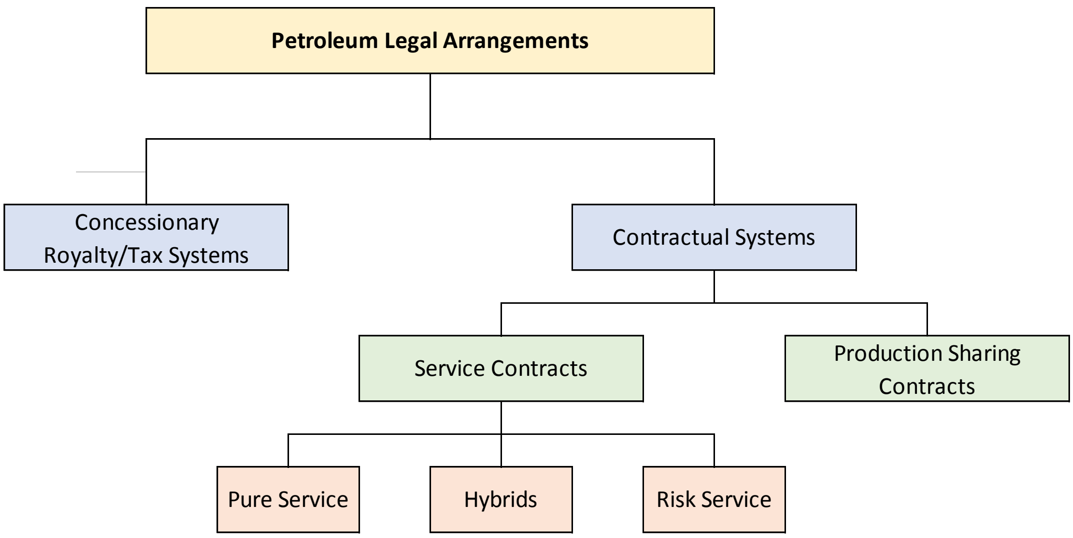


Figure 110 – Oil and gas fiscal regimes (modified after Tordo 2007, Johnston 1994).

In **R/T regimes**, operator company holds the title to all products at wellhead for a fixed time and pays royalties, taxes and bonuses. Firstly, royalties are deducted on gross production (gross revenues), which corresponds to net revenue. Afterwards, costs, which include operating costs, depreciation, depletion and amortization costs (DD&A) and intangible drilling costs, are deducted and finally the remaining portion (taxable income) is subjected to taxation and contractor's take (company's share) is obtained (Figure 111). Concessionary systems are considered as more liberal systems, however have some drawbacks. Firstly, with application of high royalty rates, the government's future take of the total profit become lesser by reduction in costs by time. Secondly, the determined royalty rate is independent of the profitability of the project. R/T regime is common in US and Western European countries like UK, Norway, Turkey etc. (World Bank 2007a, Zweidler 2012, Christiansen 2016, Tordo 2007, Cui *et al.* 2014, CEE n.d.).

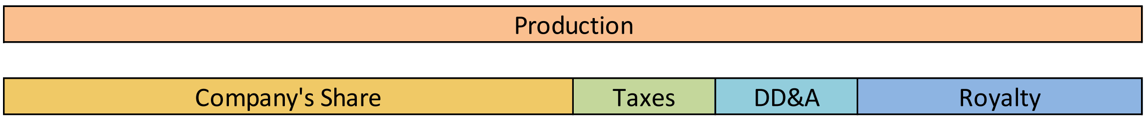


Figure 111 – Revenue sharing according to concessionary agreements (modified after CEE n.d).

As for contractual regimes, **PSC** or sometimes referred as PSA (Production Sharing Agreement) is the most widely adopted regime and mainly relies on sharing of products rather than profits. The main practical difference is PSCs' limiting power on cost recoveries, which increases the early revenue of the country, while postponing the breakeven for the operator company. After royalty and cost recovery portion deducted, the remaining portion is shared between government and the company. Unlike R/T regimes, different conditions can be applied within the country according to the negotiation between the government and the companies. The government transfers the title to a portion of the product to the company at an agreed delivery point. PSC's offer the government more control over her resources (World Bank 2007a, Zweidler 2012, Christiansen 2016).

Another sub-system of contractual regime is service contracts, which prescribes assigning a fixed or variable fee to the contractor for a unit of produced hydrocarbon. The products all belong to the government. This agreement leads to high government takes, hence preferred by oil-rich countries that have high success rates and low costs. Through the eyes of the companies, this system comes with low costs and offers low risks (World Bank 2007a, Zweidler 2012, Christiansen 2016, Tordo 2007).

Host countries design their fiscal systems according to their resource potential and aim to optimize their revenue without losing the interest of the investors. Early revenue may be provided to the government, which would increase the risk of operator company. On the contrary, government may provide incentives to investors to increase attractiveness of their projects especially for marginal fields or during low oil price times The main objective in setting up of an effective fiscal regime is the judgement of reasonable terms for both government and the investors (World Bank 2007b). A firm fiscal regime should be firstly flexible, providing government an adequate share under varying profitability conditions, secondly neutral, neither encouraging over-investment, nor discourage potential investments and lastly stable, would last for a longer time-frame or changes are predictable. Moreover, a simpler model is generally better due to administrative and audit purposes (Tordo 2007).

In most fiscal agreements, operator company, i.e. investor undertakes the whole risk since he makes all the expenditure and there will be no reimbursement if no commercial discovery is made (World Bank 2007a).

Fiscal terms may be either progressive or regressive according to their attitude in time, where the former one provides increment in rate of revenue to the government with increasing income and both require trade-offs. Progressive fiscal terms provide reasonable return to investors especially when oil prices are low, but limits the amount of profit in good times. Regressive fiscal terms provide early revenue to company and ensure minimal revenues in bad times however deter investments especially in marginal fields and also lead to early abandonment of fields. (World Bank 2007a, 2008).

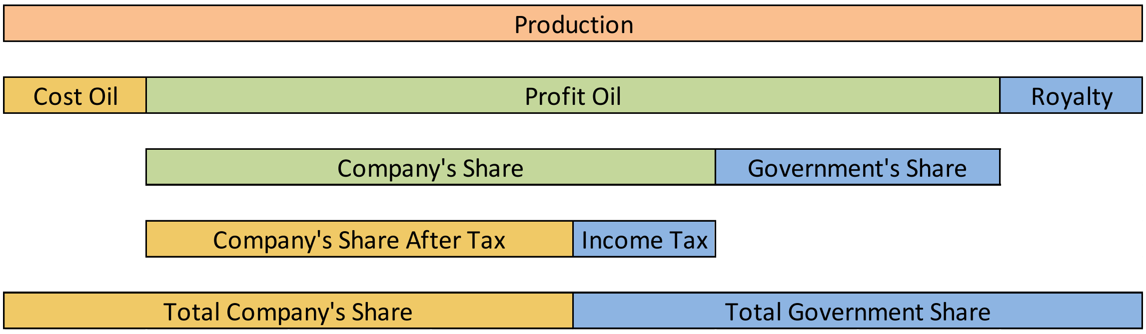


Figure 112 – Production sharing revenue distribution (after World Bank 2007b).

Here, it would be beneficial to mention about the terms used in fiscal systems and shown in Figure 112. **Royalty** is the portion that paid to host government as soon as commercial production begins and can be paid in cash or in kind. **Cost oil** refers to the amount retained by the company in response to expenditures made during exploration, development and production; it is also referred as cost recovery. Hereby, PSA's may limit the amount of cost oil for a given accounting period and the unrecovered amount is *carried forward* and recovered later. Bonuses, royalties, interests and such are not eligible for cost recovery. Lastly, **profit oil** is the portion of production remained after the royalty is paid and cost oil is retained (World Bank 2007b, CEE n.d.).

In US, standard corporate tax rate is applied as 35 % to all production projects. Onshore Texas plays are subject to 20 % royalty rate (Cui *et al.* 2014).

Cui *et al.* (2014) observed in their study that, as for unconventional projects, if PSC regime is used instead of R/T regime, the operator would receive a higher IRR due to cost recovery, but a lower NPV due to profit sharing of future project revenue. Figure 113 presents the waterfall charts for comparison of fiscal regimes for 80+ Eagle Ford wells and Figure 114 presents cash flow comparison of R/T and PSC fiscal analysis of an Eagle Ford project.

It is worth noting here that, in public documents, unconventional well IRR's are generally reported to be over 100%, which is a natural result of high initial production and highly liquid US hydrocarbon market (Cui *et al.* 2014).

Last but not the least, relying on all these analysis, Cui *et al*. (2014) found that fiscal regimes outside North America, i.e. a shift to PSC regimes, is not a major obstacle for the development of unconventional resources.

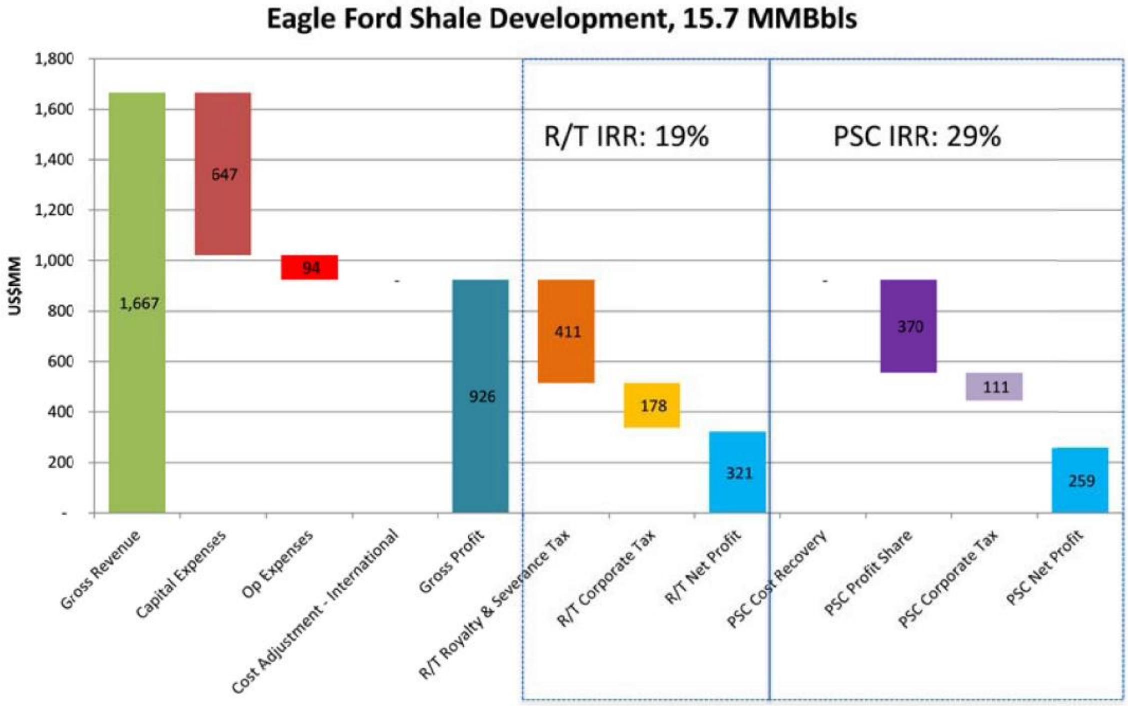


Figure 113 – Fiscal Regime Comparison for Eagle Ford (> 80 wells) (after Cui *et al.* 2014)

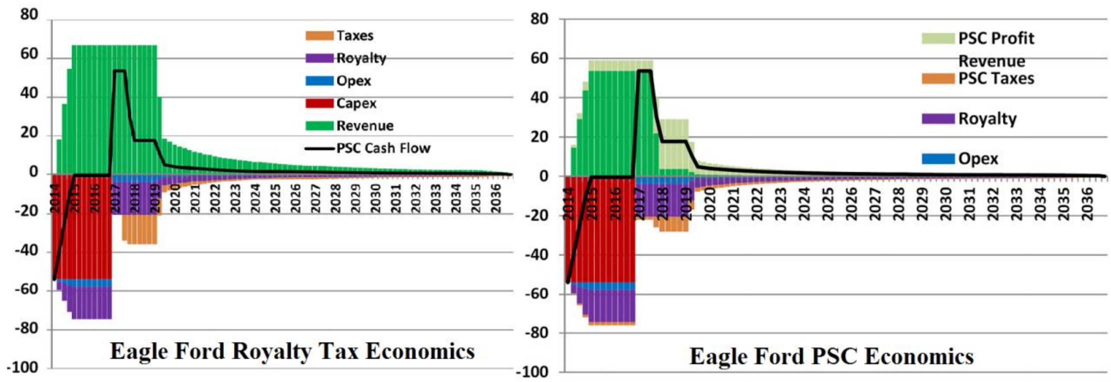


Figure 114 – Economic Comparison of R/T and PSC regimes for Eagle Ford (after Cui et al. 2014)

CHAPTER 6

STATEMENT OF PROBLEM

While progressing through different stages of the project, investments grind on and due to knife-edge economics of shale oil and shale gas projects, rigorous investigation of the project economics is crucial. To build a de-risking strategy, so-called decision gates (DGs) should be set at the transition points of the project stages. In other words, these DGs provide investors the chance to decide whether project should be carried to the next stage or should be abandoned to hinder further losses. To make firm decisions at DGs, successful project planning and phasing, and evaluation of each phase through a robust methodology are essential.

For this very reason, we designated the core of this study as developing a methodology to be capable of evaluating each phase of a shale oil or shale gas project in a fully probabilistic fashion. To that end, we also developed a software to assess uncertainties in all input parameters at each stage, calculate outputs by considering these uncertainties and present the results in a probabilistic fashion while addressing the possible risks.

Moreover, since the reserves estimation methods available in the literature for shale oil and shale gas formations are modified versions of the methods developed for conventional formations, we investigated all reserves estimation methods. We determined the strengths and weaknesses of them together with the necessary input parameters and their possible confidence intervals. We decided which one would be most applicable for each project stage, hence at each DG. Moreover, we modified these reserves estimation methods to be utilized in a fully probabilistic fashion while concerning the economic parameters specific to the field in concern.

CHAPTER 7

DEVELOPMENT OF METHODOLOGY AND SOFTWARE

The core of this study is developing a methodology that can probabilistically evaluate a shale oil or shale gas project at any project maturity stage while considering the uncertainties in input parameters. The novelty behind our methodology is its capability of melting the economic and technical calculations in the same pot in a fully probabilistic fashion from the touch of the bit to the abandonment of the field. The economical evaluation is necessary to present a Net Present Value (NPV) probability range and hence to obtain clear go/no-go decisions for the project.

Moreover, in our methodology, we utilized different reserves estimation methods again in a fully probabilistic fashion, for different maturity stages of a project. The selection of the most appropriate reserves estimation method is performed by analyzing the strength and weaknesses of each method and matching the required input data to the possible data generated at each project phase. Moreover, these reserves estimation methods are extensively modified to better suit to the shale formation characteristics.

Firstly, uncertainty assessment is one of the two key features addressed through our methodology. As discussed by Harding (2008), uncertainties associated with each parameter varies for different stages of the project. For instance, at early stages of the project, high uncertainty may be inherent in operating costs, which reduces towards the later stages of the project. This phenomenon obliges projects to be phased and uncertainty related to each phase to be considered to achieve reliability and to lower investment risks (Haskett and Jenkins 2009). Besides, it should be noted that, the effect of learning curve on the assessment of uncertainties in input parameters is highly dominant.

The second key feature to be addressed in our methodology is the risk management. Oil companies aim risk hedging prior to and during a single project. Moreover, they try to reduce their overall company risk by diversifying their portfolio or farming out their assets to multiple partners (Tordo 2007).

As for unconventional projects, distinctive risks should be concerned which can be classified into three as geological, financial and political risks. After discovery, geological risk vanishes, where political and financial risks increase (Tordo 2007).

Each project stage in unconventional projects involves unique risks, i.e. risks change along the field life. For example, exploration phase involves reservoir risks such as thickness, permeability, IP, hydrocarbon composition, land capture. Upon well testing of the exploration wells, appraisal stage starts and the primary risks evolve to be wellbore control, completion success, rate behavior and areal extent. As for development stage, areal delineation, development costs, market access and political and environmental issues involves the highest risks (Harding 2008).

As discussed at the prologue of this chapter, careful planning of DGs provide a good risk management methodology or **“de-risking program”** for unconventional projects. They can be thought as off-ramps of the project appearing at the end of a particular stage. The predetermined project stages ending with DGs are explained in Figure 115.

Our methodology offers three principle *decision gates* (DGs), at which firm go/no-go decisions should be given after completing the requirements of the associated stage. Our study envisions an unconventional project as consisting of four stages: Exploration, Appraisal/Pilot, Development and Production. Actions at each stage are explained in details in the following paragraphs, together with the criteria to proceed to the next stage.

To be more precise, naming of the project stages each ends with a DG, the main objective of that project stage and the requirements to pass through the associated DG are presented in Table 16 and Figure 116. The skeletons for project phasing and associated DGs proposed by Giles *et al.* (2012) and in this study are also presented.

To be noted that, we merged appraisal and pilot stages into one project stage, which was separately discussed in Giles *et al.* (2012).

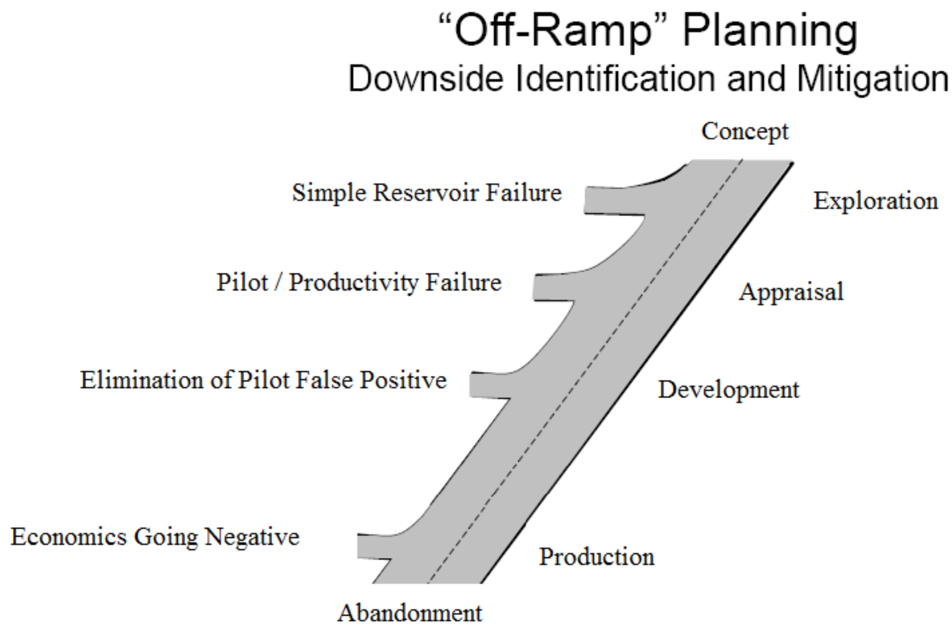


Figure 115 – Stages together with the decision gates (modified after Haskett and Brown 2010)

In summary, as stated by Haskett and Brown (2005), multi-stage risk management is crucial to prevent or mitigate loss and optimize the decisions. Following pages firstly aim to discuss the phasing of an unconventional project, the decision gates to manage risks and the questions to be answered to check if the criteria described in the literature to pass the associated decision gate are met. Secondly, our methodology to evaluate each decision gate will be explained after discussing the main features of the project phase in concern. To express our point of view further, the distinctions we put in understanding of project phasing, the variations in evaluating each project phase and our prebuilt questions to be answered at each phase will be discussed.

Although, the software developed as a byproduct of this study and is only a tool to implement our methodology, we will present screenshots from each step from the evaluation of a real shale gas play (Eagle Ford Shale) via our methodology and our software.

Table 16 – Requirements to proceed at each Decision Gate

Project Stage Decision Gate	Main Objective	Requirement to Proceed	
		Giles *et al.* (2012)	This Study
Exploration Stage DG-1	Prove the presence of producible hydrocarbon	Produce at least 100 Mscf/d	Meet the minimum criteria for basic parameters (Table 5) & Have a positive result in Undiscounted monetary value analysis
Appraisal/Pilot Stage DG-2	Initial prediction of EUR/well	Prove 2 Bcf/well & % 5 porosity from 5 wells' cores	Estimate 2 Bcf/well as P90 reserves & Have a positive result in Undiscounted monetary value analysis
Development Stage DG-3	Analyzing field wide economic producibility	-	Estimate NPV > 0 & IRR > 10 % as P50 Reserves
Production Stage		-	

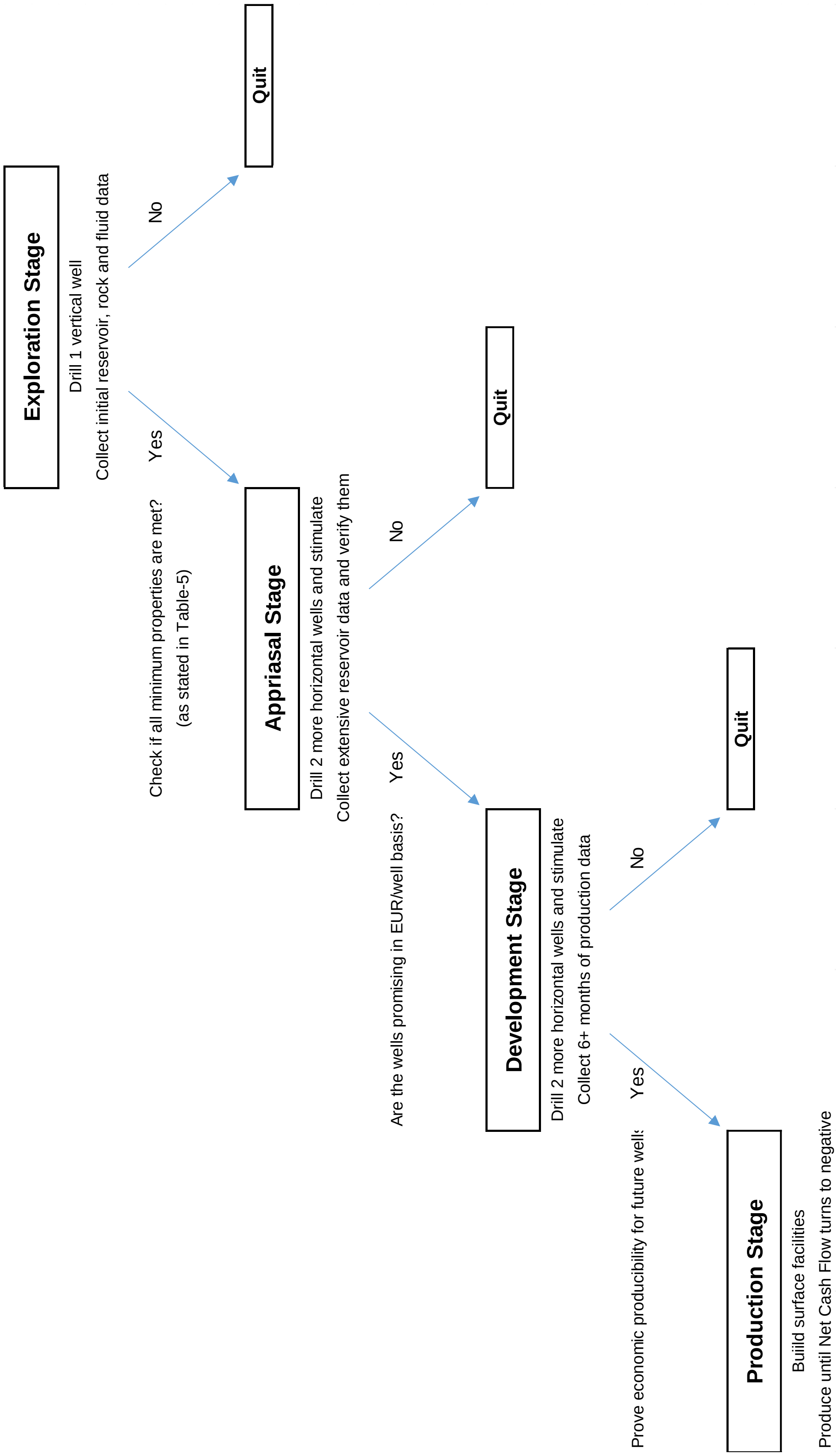


Figure 116 – Fundamental algorithm of the developed software

7.1. Decision Gate-1 (Exploration Stage):

Purpose of exploration stage is to prove the existence of producible hydrocarbons and improve the geological understanding of the play (Giles *et al.* 2012). A play without well carries a high degree of play risk, which is shared by all potential locations. In other words, only after a necessary number of wells are drilled to identify the shared risk element (geological or technical failure), a firm decision could be given. If all other locations share the similar failures, play should be abandoned (Haskett and Brown 2005). As stated by Weijermars (2011a), the exploration process is not a gamble, but a cost-conscious program with many decision stages aimed to identify profitable resources.

According to Stabell (2005), exploration starts with sweet spot identification (pre-pilot investigation) to obtain the acreage and continues with pilot well drilling to test the sweet spot performance by a pilot production. However, we are in favor of Haskett (2014) about sweet spots prioritization, which suggests utilizing of them in the development phase, rather than in exploration or pilot phases (see Section 2.1.1). Still, the first well may be drilled in the most advantageous point to prove the hydrocarbon existence.

Commonly, at first vertical wells are drilled to evaluate resource properties and collect samples (CSUG 2016). After the play is proved to have potential of commercial hydrocarbon production, horizontal wells are placed and multi-stage fractures are placed.

Hereby, the fundamental question that DG-1 expected to answer in yes/no fashion is: "Does the initial data collected from the vertical well met the minimum requirements of a play to be a commercial hydrocarbon producer?" If the answer is "yes", i.e. the decision is "go" for the project, drilling of horizontal wells commences. The initial data not only provide a simple go/no-go decision, but also give clues about the reservoir quality and the suitability of formation for effective stimulation. These two parameters constitute the basis for producibility, hence using analogy method, i.e. comparison with known fields, EUR can be estimated within a tolerable uncertainty range.

In the literature, many authors used well, completion and rock properties to forecast EUR of shale formations without production data. Proposed solutions of two different authors are presented below to forecast producibility of shale formations using only the initial data collected.

Javadi and Mohaghegh (2015) used Artificial Neural Network (ANN) to condition rock properties, well and completion parameters (totally 18) such as matrix porosity, net thickness, water saturation, TOC, proppant per stage, cluster spacing, depth, Young's Modulus, Langmuir parameters and so on, to forecast EUR of Marcellus Shale wells. EURs of 164 Marcellus Shale wells are calculated using a modified decline curve approach (Combined Decline Curve) and 80 % of these data (132 wells) used to train the neural network and the rest is used for calibration and checking purposes. Their model has given an R-square value of 96 % between predicted and actual 10-year EUR estimations. This method claims to estimate the EUR without production data or even drill the well and find the relationship between different parameters and EUR. On the other hand, the method proved itself for wells in the same shale formation with a considerable high number of produced wells. The authors do not offer any solution to predict EUR for a new shale prospect with limited data that is offered in this study.

Zhang *et al.* (2016) analyzed the effect of seventeen main parameters of shale formations, including petro-physical parameters, hydraulic fracturing parameters, etc. on the shale gas production performance. They built a correlation between these parameters and the recovery efficiency of shale formations by using so called grey relational grade (based on a new analysis technique called Grey Relational Analysis proposed in Gray system theory) using the data collected from fourteen shale formations in the USA. Their technique not only quantitatively estimates the potential of prospects but also reveals the impact ranking of the parameters. The impact ranking of these parameters on shale productivity from most important to less important is matrix permeability, fracture conductivity, fracture density of hydraulic fractures, reservoir pressure, TOC, fracture half-length, adsorbed gas, reservoir thickness, reservoir depth and clay content. The authors briefly claim that, their technique can be applied to evaluate the exploitation potential of shale gas reservoirs.

The main drawback of this technique is that it needs a vast number of parameters and to obtain all these parameters, a great amount of investment should be placed. Moreover, this technique does not utilize a probabilistic point of view and uses single input values.

At this point, it would be suitable to present our methodology, which is designed as an initial approach to evaluate the resource potential of a shale formation.

The superiority behind our methodology is the fully probabilistic platform it provides, by which all uncertainties in input parameters can be reflected at the results. Moreover, it is very suitable to be used at the very early stages of project since it needs only 6 main parameters of a shale formation. The methodology presented here should be thought as an aid to make a firm decision at DG-1, which is just after the drilling of one single vertical data well. After obtaining further information by drilling of horizontal wells, together with fracturing and testing of them, subsequent stages of our software should be used.

In this part of our methodology, which constitutes the first stage of our software, briefly a comparison method or a sort of analogy method is utilized. Our methodology offers a linear equation with four basic parameters in normalized forms (the equation used for normalization is given in Eqn. 52 and the normalization procedure will be discussed in the next paragraphs): hydrocarbon-in-place (gas-in-place) per unit area (GIP/area)’, permeability (k)’, total organic content (TOC)’ and reservoir pressure (p_r)’, together with their “weight terms” as ***a***, ***b***, ***c*** and ***d***, respectively (the calculation of weight terms will also be discussed). The assumed linear equation can be presented as following:

$$Shale\ Value = \boldsymbol{a} * \left(\frac{GIP}{area}\right)' + \boldsymbol{b} * (k)' + \boldsymbol{c} * (TOC)' + \boldsymbol{d} * (p_r)' \qquad \textbf{(51)}$$

Considering the “value of a shale” is basically the producibility of the shale, i.e. recovery per well; by using the “EUR/well” data of today’s producing shale formations, the “weight terms” for each parameter can be estimated provided that enough number of reliable data in hand.

As of today (September 2017), only the big six US shale gas formations' "EUR/well" data are accessible to us and all of those were used in the estimation process. A database of real producing shale fields is generated consisting of minimum, maximum and average values for porosity, water saturation, thickness, permeability, TOC, reservoir pressure and EUR/well data. The generated database is presented in Table 20 and the references where all these data collected are also presented in the same table.

In this database, the "GIP/area" parameters were generated by multiplying porosity, gas saturation and thickness, by ourselves.

The four parameters are normalized to be used in the same linear equation (Eqn. 51). The normalization process is done for each parameter as such, minimum observed values (min) quoted from the literature representing the currently producing shale formations is assumed to have "0" normalized value and the maximum observed value (max) is assumed to have "100" normalized value.

Then, to obtain a "multiplier" to be used in the normalization of a parameter, the maximum normalized value "100" is divided by the full range of observed values (max - min) exist in the literature. Lastly, the difference between the parameter's value (x) and the minimum observed value (min) is multiplied by the calculated multiplier [100 / (max – min)]. The equation for the normalized valuation of any parameter is:

$$normalized\ value\ of\ parameter = (x - \min) \times \left(\frac{100}{\max - \min} \right) \qquad \textbf{(52)}$$

It should be noted that, as for any outlier data that may be obtained from any new wells in currently producing fields or created in a totally newly discovered field, the "normalized value of parameter" will be truncated to stay between 0 and 100. In other words, if the new parameter is outside the bounds of the assumed minimum or maximum, either 0 or 100 will be assigned to that value, respectively.

Hereby, to enhance the understanding, we can give a brief example for the cases in which a parameter is assigned 0 or 100 as a value. Taking the permeability as the parameter in concern, Haynesville has the maximum permeability value quoted in the literature which is 650 mD. Hence, the value assigned for the permeability of any field having 650 mD or more would be assigned as 100. On the worst case, some wells in Barnett has the lowest permeability value quoted in the literature, which is 10. Hence, the value assigned for the permeability of any field having 10 mD or less would be assigned as 0.

It is time to reach a single value, which we call “value of shale”. Here, each “normalized value of parameter” is multiplied by its “weight term” (***a***, ***b***, ***c*** and ***d***) and results are summed to obtain a single “value of shale”. If the “weight terms” are calculated correctly, the calculated “value of shale” and real “EUR/well” data of those shales are expected to have a fair correlation (Table 17). Consequently, a plot of “value of shale” vs. “EUR/well” should yield a straight line with correlation coefficient of approximately unity.

To have maximum correlation coefficient between “value of shale” and “EUR/well” of any field, Microsoft Excel’s (version 2016) Solver Add-in is used, which provided a regression analysis to determine the “weight terms”.

Table 17 – Value of shale from this study and EUR/well from literature

Fields	Value of Shale	EUR/well (Bcf/well)
Marcellus	15,71	3,5
Eagle Ford	24,25	5,5
Fayetteville	7,91	1,7
Woodford (Western)	14,33	4,0
Haynesville	29,67	6,5
Barnett	16,23	3,5

In details, by using the “CORREL” function of MS Excel 2016 and selecting the “value of shale” column and “EUR/well” column as inputs, the correlation coefficient is obtained. Afterwards, correlation coefficient forced to converge at maximum, which is “1.0”, by changing the “weight terms” ***a***, ***b***, ***c*** and ***d*** within the boundaries of 0.01 and 0.9. Meanwhile, the sum of ***a***, ***b***, ***c*** and ***d*** is limited to unity.

The resulting values for ***a***, ***b***, ***c*** and ***d*** “weight terms”, for GIP/area, permeability, TOC and reservoir pressure, respectively are given in Table 18 and the output for CORREL function has given a result of 0.9786 (Figure 117).

Table 18 – Obtained multipliers, weights for each parameter to obtain value of shale

Parameter		Weight / Multiplier
GIP/area	a	0,815880
Permeability	b	0,106784
TOC	c	0,063796
Pressure	d	0,013540

Calculating the normalized value for all other parameters, multiplying with the corresponding weights/multipliers and finally summing them up, the value of shale offered in this study is reached.

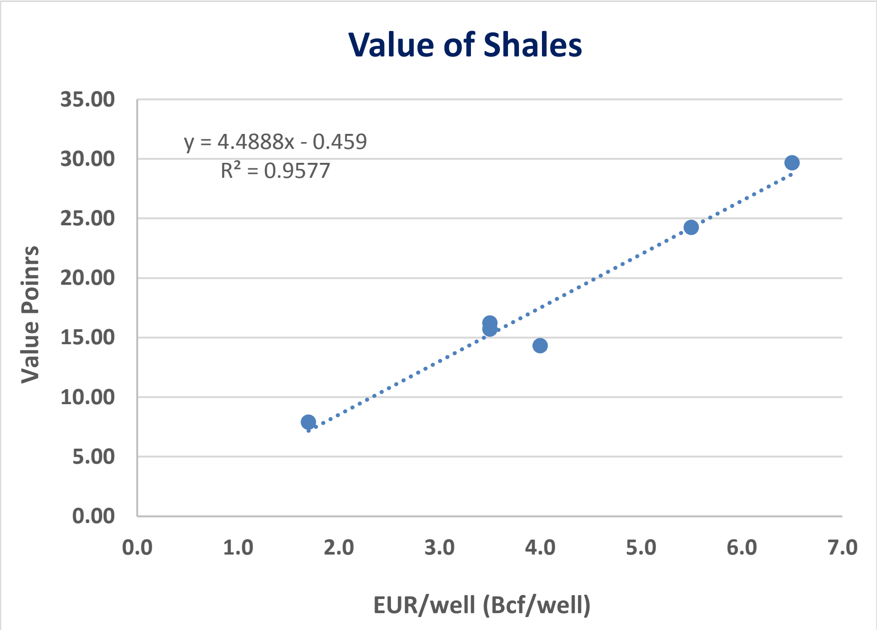


Figure 117 – The correlation between "value of shale" and "EUR/well".

By utilizing the methodology above, which is summarized in Figure 118, one can calculate the value of any shale and compare that with the big six US producing shale gas formations in terms of producibility. Finally, by using the equation for the best line in Figure 117, "EUR/well" can be guessed with a considerable amount of uncertainty.

As this study strongly defends, uncertainties should be assessed and quantified to have a better understanding in the engineering calculations. In our software, minimum and maximum values for each parameter are requested as inputs.

By utilizing Monte Carlo method, 10,000 iterations for Eqn. 51 are performed by randomly picking values (i.e. generating random numbers) for each input parameter within the range introduced based on a uniform distribution. In other words, when the user imposes ranges for the 6 parameters mentioned above, software randomly assigns a value for these 6 parameter within the ranges imposed. Afterwards, using Eqn. 52, each values are normalized and using Eqn. 51 all these values are multiplied by their weight terms and converted into a single "*shale value*". This procedure is performed for 10,000 times. Hence, a range of outcome is obtained and presented via a histogram, in which 6 producing formations are also marked. Moreover, P10, P50 and P90 markers for EUR/well are also presented, which represents 10^{th}, 50^{th} and 90^{th} percentiles.

It should be noted that, this approach provides only an initial insight and assumes the data collected from the literature for producing shale formations represent average "EUR/well" values for wells, which have optimum stimulation treatments, optimum well geometry, optimum lateral lengths and no interference.

In other words, the "EUR/well" values are basically the average EUR value of wells those have optimum lateral length, stage number and stimulation efficiency. Hence, the results only represent wells with such optimum properties.

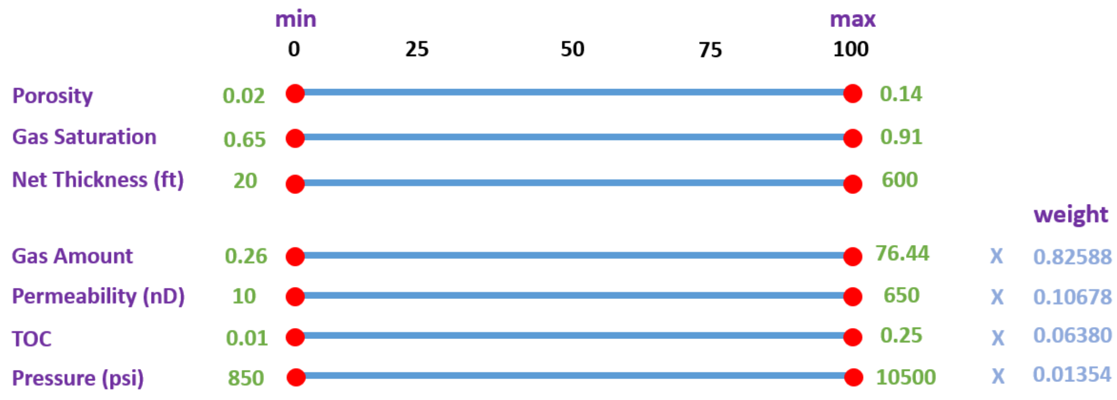


Figure 118 – The normalization procedure of parameters and the associated weight terms

7.2. Decision Gate-2 (Appraisal/Pilot Stage):

Giles *et al.* (2012) put separate decision gates for appraisal and pilot stages; however, combination of these two decision gates as DG-2 is also acceptable, since both aims to determine the profitability of the opportunity. The primary aim of the appraisal and pilot stages are to enable the prediction of "EUR/well" representative for the whole field and the secondary aim is increasing well productivities and decreasing well costs via the lessons learned (Giles *et al.* 2012). This stage starts with the drilling of the horizontal wells and continues with production tests (CSUG 2016).

The success of stimulation programs could only be determined after pilot wells. Hence, if the sufficient number of the pilot wells show insufficient rates or recovery profiles, play should be abandoned. The more wells drilled in the pilot stage, the more pilot results would converge to the program result. First few wells reveal the highest knowledge in the pilot stage; hence, determination of sufficient number of wells, i.e. optimal pilot well number, is important for pilot stage and mitigate downside risk (Haskett and Brown 2005).

Since every activity requires cost and time, failures result in loss of both. Thanks to learning curve, while costs and time-spent decrease with increasing number of wells, well productivities increase (Stabell 2005).

The results of the pilot wells should also be verified with engagement of new wells, since results from pilots may also be deceptive. The four possible outcomes that could be obtained from pilot programs; namely true positive, true negative, false positive and false negative, are presented in Figure 119. The pilot effectiveness is the sum of probabilities of True Positive and True Negative. Moreover, a pilot program is successful whenever it delivers a correct information, regardless of the information. A true negative pilot would probably mitigate risk in investing a bad project. Appraisal/Pilot Stage is the most costly off-ramp, if a false decision is given (Haskett and Brown 2005). As emphasized by Haskett (2014), "Pilots are not meant to tell you what you have. Their purpose is to give you confidence that what you appear to have is greater than what you think you need". Moreover, he defines the **pilot effectiveness** as "the truth-telling ability of the pilot program".

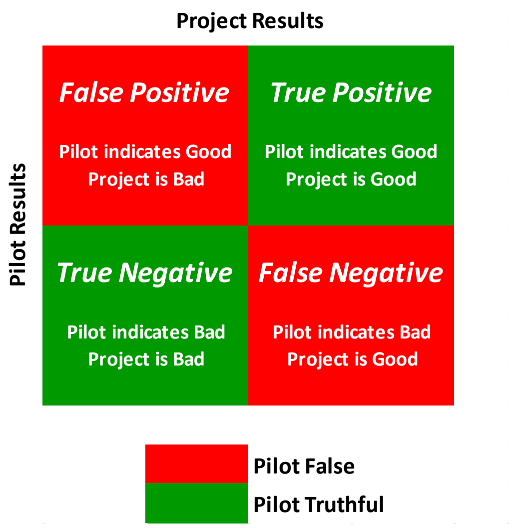


Figure 119 – The probability that the pilot will be truthful (modified after Haskett and Brown 2005)

The major question to be asked at DG-2 is “Are the drilled horizontal wells promising in EUR per well basis?” Answering this question is not an easy task and requires a careful investigation of the drilled wells and all data collected through them.

Between DG-1 and DG-2, we strongly suggest collecting core, cutting and fluid samples to commence particular tests and analyses, well log analyses and seismic process revisions if needed to obtain and calibrate necessary parameters to perform a more reliable and sophisticated analysis. Moreover, specialized tools for unconventional resources (e.g. micro-seismic mapping) can be utilized to reach some other specific data (e.g. SRV, induced fracture properties), hence easier optimization can be implemented. Procedures and instruments to reach these parameters are presented in Table 19.

Table 19 – Particular tests and analysis to obtain required parameters

Test / Analysis	Parameters Belong to	Obtained Parameters
Adsorption Tests	Langmuir Isotherm	p_l, V_L, G_{ads}
Basic Core Analysis	Reservoir Properties	Φ, S_g, ρ_b
PVT Analysis	Fluid Properties	B_g
Well Log Analysis	Reservoir Properties	h, Φ, S_g
Micro-seismic Mapping	Induced Fracture Properties	SRV

Our methodology offers a sort of probabilistic volumetric analysis method to answer the questions asked at DG-2, since there would not be enough production data yet. DG-2 is designed to be exactly after completion and hydraulically fracturing of 2 horizontal wells besides the initial vertical well. There would not be any long-term production data; hence, the analyzer would have only an initial insight into the production performance of the horizontal wells. As the details were discussed in Section 4.2, Giles *et al.* (2012) and Pour *et al.* (2015) declare that there should be at least 6-months of production data in hand to perform a reliable production decline analysis or history matching.

At this stage, one can only estimate “EUR/well” for the drilled horizontal wells and check if the calculated “EUR/well” is adequate for the play to be assumed as a material opportunity. Hence, sophisticated economic analysis is not the concern of DG-2.

Volumetric analysis method we offer at this stage is the probabilistic version of Ambrose *et al.* (2010)’s suggested method, which recommends the subtraction of the gas occupied by adsorbed gas from the free gas volume. The required input parameters are exactly the ones mentioned in Table 19; and hence at DG-2, all of them are available to the analyzer.

If recoverable volume is in concern, i.e. TRR is to be calculated besides the in-place volumes, a Recovery Factor (RF) for a given formation should also be determined. At this point, analogy to similar formations comes in handy. Moreover, as discussed in Section 4.1.5, EIA (2013) provided RF values for various formation types and hence a range for RF can easily be attributed.

The probabilistic platform behind our methodology is built via utilization of both MCM and AUPM. A minimum and maximum value for each parameter in calculation of free and adsorbed gas contents are required as input. Afterwards, a value in the range imposed is picked and via MCM, the results are calculated repeatedly for 10,000 times. The textboxes showing minimum and maximum values for free and adsorbed gas contents show 90^{th} and 10^{th} percentiles for the results of 10,000 iterations via MCM sorted in the descending order. In other words, 1000^{th} value is selected as the maximum value and 9000^{th} value is selected as the minimum value.

Total gas content, which is the summation of free and adsorbed gas contents, is calculated at each iteration, i.e. calculated for 10,000 times and the minimum, mode and maximum results represents the 90^{h}, 50^{th} and 10^{th} percentiles when the results of MCM is sorted in descending order.

Stimulated reservoir area (SRA) is also calculated at this gate via multiplying twice of the fracture half-length with the horizontal length. There is not any direct way for determination of fracture half-length; however, micro-seismic results would give highly accurate results. Moreover, PTA or PA may give an insight into the magnitude of the fracture half-length. Fracture design software may also give an estimation for the supposed half-length, assuming that the whole operation performed on the field is exactly as in the software, together with the assumption of absolute accuracy of input parameters. Hence, we designed our methodology to include a confidence interval for the frac half-length, so that minimum and maximum range for this parameter could be estimated. However, the result of GIIP is highly sensitive to SRA, since it is directly calculated by multiplication of area with other reservoir related parameters. Consequently, the uncertain nature of frac half-length bring high uncertainties to GIIP.

The calculation of net thickness is rather easy, since it can be conducted via well logs, together with the assumption of perfect stimulation job in which the fracture covers entire net interval. However, the net thickness of the formation changes considerably along the horizontal axis in shale formations those cover huge areas. The bulk rock density is the last input parameter for GIIP calculation, which was thoroughly mentioned in Volumetric Estimation methodology, Section 4.1.

Finally, using all these input parameters together with their uncertainty range, probabilistic estimation of GIIP can be performed via AUPM. The details and the superiority behind this method can be found in the appendix part of this dissertation and also in Tuğan (2010) and Tuğan and Onur (2015).

To estimate TRR, recovery factor (RF) should be introduced to the estimation process and this value includes high uncertainties. At this point, industry experience or real field data published in researches of foundations (e.g. EIA 2013) can be referred for determination of analog formations and associated RF values.

7.3. Decision Gate-3: (Development/Delineation Stage)

The main goal of this stage is to evaluate whether the wells will meet the production targets or not (Giles *et al.* 2012), i.e. proving the economic producibility of future horizontal wells. As stated by Gouveia and Citron (2009), the main issue in shale oil and shale gas projects is not the existence of hydrocarbons, but if hydrocarbons can be converted to reserves, i.e. economically recoverable resources.

The question to be asked at DG-3 is "Will the play promise economic producibility if the development moves forward?" The answer for this question requires a future forecast, which have to be performed by investigating the past and present production performances. The questions for DG-1 and DG-2 are about volumes alone, whereas question for DG-3 addresses performance and economic issues (Giles *et al.* 2010). As the number of development wells increase, the probability that the forecasts to converge real value increases. Exactly at this point, the "value of information" concept comes into concern, which assures that after a certain point, the information obtained through further investments would not significantly improve the decisions.

Haskett (2014) divides development wells into three groups, learning wells, recovery wells and profit wells. **Learning wells**, which are drilled at the beginning of development phase and teaches the operator the science, completions and operational efficiency. These are investments for future profit. **Recovery wells** are drilled profitably and provide company to recover learning expenses. Exactly at this stage, sweet spots exploitation gains high importance. **Profit wells** make the significant portion of the revenue. The extent of the play or acreage determines the number of profit wells. Actually, learned operational efficiency may change the destiny of the previously sub-economic areas, giving them the chance to be developed profitably.

As from the risk point of view, Development stage has the lowest ***risk tolerance***, comparing to exploration or appraisal stages. Companies are comfortable with failed exploration wells, but not with failed development wells. Moreover, due to ***portfolio effect***, which represents the change in the value of a portfolio in response to a change in the value of one of the assets, risk tolerance should be applied at the portfolio level, not the project level. In other words, the real value will converge on the sum of the mean values of the projects, providing that enough projects are performed (Leach 2010).

Oil industry has a high level of uncertainty in its nature, both in reservoir behavior and even more in market behavior (Leach 2010). Due to unavoidable uncertainties, decision makers of oil industry have a strong desire of bad outcome avoidance, which results in application of ***risk threshold,*** i.e. putting strict limits to the acceptable risk amount, on development decisions. Risk threshold is the amount of risk acceptable to a particular organization (Justgetpmp.com 2015). Generally, in the long run, a ***risk neutral*** approach to development projects would result in outperformance comparing to ***risk averse*** approach (Leach 2010, Investopedia.com 2016). Whitfield (2016) quotes Dr. Steve Beggs's statement in an SPE meeting as "… company that is biased toward risk aversion or risk seeking behaviors faces a worse long-term outcome than companies that take a risk-neutral, or an expected value approach to decision making… Uncertainty is not the problem, it is bias". The key point is looking at the collection of decisions and their outcomes (Figure 120), instead of looking at an individual event and its outcome (Whitfield 2016).

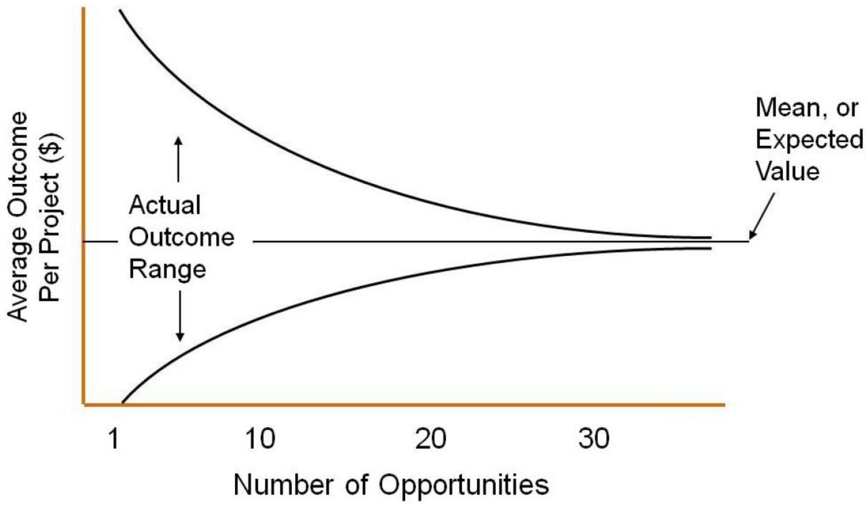


Figure 120 – The convergence on the mean with multiple opportunities (after Leach 2010).

A cross plot of project NPV vs. expected average EUR/well, which is referred as NPV swarm plot, is a very useful tool to provide a go/no-go decision (Haskett and Brown 2005).

This title constitutes the most complex part of our methodology and our software, which provides the evaluation of development phase and reveals the answer for the question of “Should we fully develop this prospect?” At this gate, both well performances and project economics have to be evaluated simultaneously in a probabilistic fashion.

The aim of this part of the methodology is to analyze the decision of go/no-go from an economical viewpoint considering mainly the time value of money. Hence, a production profile is required to account the time dimension into our analysis. We utilized 3-segment decline curve approach (discussed thoroughly in Section 4.2) to analyze the performance of the shale wells, i.e. forecast the future production.

One of the most influential parameter on the economics of shale wells, Initial Production Rate, is the primary input in our methodology, hence minimum and maximum values are required from the analyst. Since shale wells have marginal economics, time value of money have also a clear effect on the project economics. Hence, early produced hydrocarbons, i.e. early return of investments considerably affects project NPV. Consequently, high initial productions, which lasts the first few months or years, bring considerably positive contribution to the NPV, together with its favorable effect on EUR.

However, this early high production period continues with a steep decline. To represent this early period and distinct the production behavior from the middle and late times, the first segment of the decline analysis is introduced to the methodology. A yearly decline rate with a minimum and maximum range, decline exponent with a minimum and maximum range and the duration for this period are required from the analyst. The duration was thought as free of uncertainty since it can be determined from specialized plot and have minor effect on the results.

The second segment do not require any decline rate, since it inherits that value from the last time step of the first segment. Actually, in our methodology we recommend continuing the calculations for one more time step after the termination decision of the first segment, in order to obtain the first decline rate of the second-time step. Hence, the decline rate continues to reduce in its own trend at the transition of the segments.

The second segment requires only two input parameters. The first one is the decline exponent with uncertainty range. As discussed before in Section 4.2, this segment represent the boundary dominated flow and the decline exponent to be used will be between 0 and 1 theoretically and in practice it would be between 0.5 and 1. The second input parameter is the minimum decline rate to terminate this second segment. After reaching this minimum decline rate, third segment comes into concern.

The type of the decline curve at the third segment is exponential, hence no decline exponent is required. However, the minimum decline rate is required as input and used as constant throughout this segment until one of the termination criterion; either minimum economical rate or maximum field/well life, is met.

Until this point, generation process of the production profile is discussed. Now, it is time to explain conversion of the production profile into monetary value as a function of time. We propose to place CAPEX at the very first-time step, i.e. at the time zero, as a negative cash flow, representing the total of drilling, completion, stimulation and other costs. Since, we designed our methodology for economic analysis per well basis, all these values should be thought as the cost of a development well, instead of an exploration well's, to have a credible insight into the economics of the project development. Starting from the first time step, average daily rates for each month is calculated via the 3-segment DCA and by multiplying with average number of days in a month, namely 30.5, monthly produced volumes are reached. The multiplication of these monthly productions by the market price of a unit of commodity will give the monthly income/revenue. As is well known, royalty tax is deduced directly from the produced amount, i.e. the revenue. After applying the royalty tax, OPEX for a unit of commodity produced multiplied by monthly production should be introduced as negative cash flow. Lastly, corporate tax is applied to the remaining portion of the monthly cash flow and net cash flow for that month will be left. To reach the cumulative cash flow, monthly cash flows are summed. To introduce the time value of money, discount rate is applied to normalize the cash flow corresponding to each month and hence all these monthly discounted net cash flows are summed to reach NPV of the project.

7.4. Details of the Developed Software

To make our methodology applicable, we also developed a new user-friendly software with Graphical User Interface (GUI), for the evaluation of shale gas projects whatever the phase they are in and with an entirely probabilistic platform. Briefly, it can present a probability range for OHCIP, TRR and ERR, since it works in fully probabilistic fashion and hence reveal the uncertainties in all outputs. Moreover, via melting the input parameters concerning economics and the outputs concerning the technical reserves evaluation in the same pot, Net Present Value (NPV) probability range and hence clear go/no-go decision for the project can be obtained as the outcome.

It is worth noting that, the current version of the software (URES v.1.17) is designed for the evaluation of only shale gas formations, since there is not enough field data for shale oil formations. Especially, more real-life field EUR/well data and long term production data are needed to put the shale oil evaluation into a reliable basis. However, the methodology/algorithm developed for shale gas reservoirs can readily be extended for the analysis of shale oil formations just after enough data are created in these formations.

The coding of the software is performed in C++ programming language and the Graphical User Interface (GUI) is designed in Microsoft Visual Studio Community 2017. Through the coding and designing process, online help documents mostly from msdn.microsoft.com, videos from YouTube.com and the book of Mastar and Eriş (2012) are used extensively.

The software is named as ***URES*** after "Unconventional Resources Evaluation Software". The version number is given in a format "*URES v.x.yy*", such that the initial number before the dot (represented with x) shows the number of previous releases including the version in concern and the numbers after the dot (represented with yy) shows the last digits of the year at which the version in hand is released.

The case study part below is presented in a considerably detailed fashion to compensate a user manual for the software. Many screenshots are provided so that one can easily follow the same route as a tutorial and learn how to use the software.

The main window of the software consists of four tabs, which are named as Economics, Exploration, Appraisal and Development, respectively. The sorting of the tabs are designed after the chronological order of project phases. Hence, the user would not get lost in the dozens of input boxes and will start to enter the inputs in a clearly stated order.

The first tab is designed to collect preliminary economical inputs, as can be deducted from its name. This tab also calculates one of the main parameter in economical evaluation, CAPEX and presents as an output. These inputs and outputs are used at the background while other three tabs, are processing their analysis. CAPEX is calculated via the well, completion and stimulation design parameters imposed by the user and the unit costs associated with them. Moreover, tax rates and discount rates are required as inputs at this tab, which can change according to the locations or fiscal regimes.

The latter three tabs are named after the stage of the project evaluated. Exploration tab requires basic reservoir, rock and fluid data namely porosity, water saturation, thickness, permeability, TOC and pressure. By performing a sort of analogy technique, in other words, comparing these parameters of the formation in concern, with the well-known U.S. Big Six shale formations, a probability range for EUR per well values is extracted. As for the Appraisal tab, parameters necessary to calculate adsorbed and free gas content are required as input. Moreover, basic measures about formation extensions are also required and finally probability markers for GIIP and TRR are revealed. The last tab, development tab represents the final exit before the full field development. This tab performs a production decline analysis based on multi-segment decline curves and requires input parameters such as IP, decline rates, decline exponents and durations for each segment, which can be obtained via production tests.

The probability markers for ERR, IRR or NPV are not the only outputs obtained through our software. A serious number of sophisticated markers and charts presenting specific data can be reached via the top menu items, namely Data Analysis and Risk Analysis. The top menu is designed to make the software more user-friendly by File, Edit and Help menu items and handier in reaching more sophisticated outputs by Data Analysis and Risk Analysis menu items.

CHAPTER 8

A CASE STUDY

To test and demonstrate our software developed in this study, a real-field case study is performed which involve the evaluation of a field, Eagle Ford Shale, at all three DGs to demonstrate a feasible shale formation.

The input parameters are collected from a wide range of resources and most of them are already referred in the literature survey part and presented in Table 20. Naturally, data from different resources sometimes do not overlap. However, this is not a misfortune; on the contrary, this phenomenon may be an opportunity to reflect the uncertainties in the inputs and their effects on the results. Through the evaluation process, we will discuss on the details about the inputs, the uncertainty range in those, their ultimate effects on the outputs and thoroughly all the calculation steps, Moreover, the results will also be examined in depth to provide an insight into the reliability and practicality of the software developed.

The case study is performed via using the data of a well-known U.S. shale formation, Eagle Ford Shale, which is producing all three phases, namely oil, condensate and dry gas, for a long duration (Figure 73). However, in this study, only the dry gas portion of the field is evaluated. The main motivation behind selection of Eagle Ford Shale is the abundance of data in all aspects. We evaluated the prospect at three different DGs those corresponding to the end of three chronological project phases, namely exploration, appraisal and development phases.

Hereby, it would be suitable to introduce the software briefly. The top menu consists of five menu items which are namely, File, Edit, Help, Data Analysis and Risk Analysis.

Especially, firstly entering into the "Help" menu item will ease the usage of the software. The first option in Help menu item is the "Units", which shows the units system to be used in each input textbox and a screenshot is given in Figure 121.

Moreover, all input textboxes are designed to show the units to be used, just after hovering the mouse cursor on the textbox.

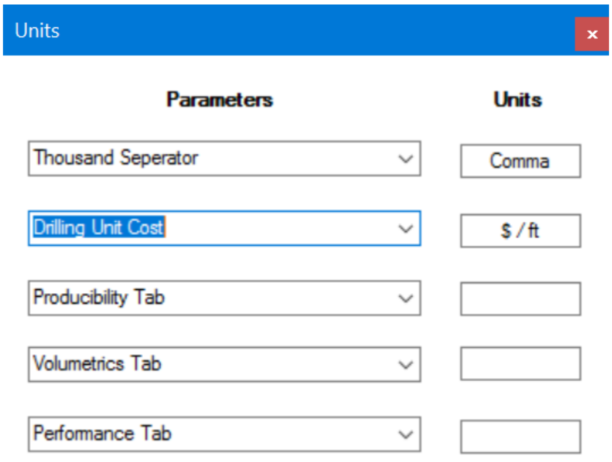


Figure 121 – "Units" window from URES v.1.17.

The second option in "Help" menu item is "***Help Me***" option, which introduces the software and briefly explains the working principle behind it. A screenshot from this window is given in Figure 122.

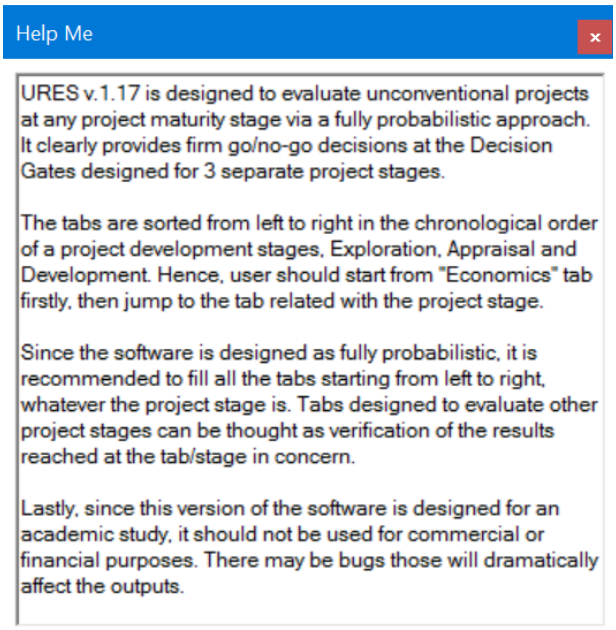


Figure 122 – "Help Me" window from URES v.1.17.

The third option in "Help" menu item is "***About Us***" option, which placed to introduce the designer of the software and reserved to present the version information. A screenshot from this window is given in Figure 123.

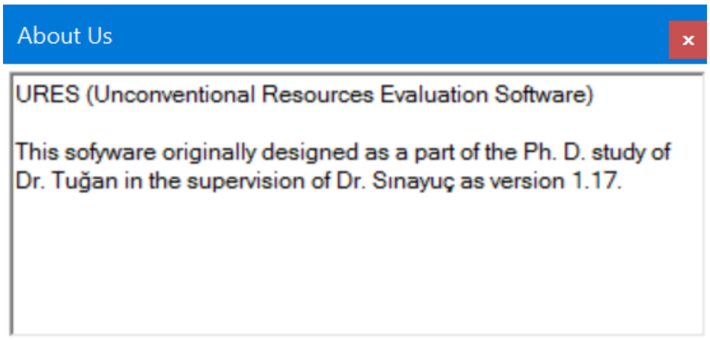


Figure 123 – "About Us" window from URES v.1.17.

Prior to starting an analysis, some initial parameters should be determined or predicted for evaluation of the prospect, which are displayed in Figure 124 captured from URES v.1.17. This first tab, "***Economics***" tab, is reserved for fundamental input parameters to be used throughout the software at the background. The relatively larger textboxes are reserved for the average values for input parameters, which are in fact an approximate value or an initial guess for a parameter. The shorter textboxes are reserved for the confidence intervals associated with the input parameter by assigning an uncertainty range in percentage, which enables software to calculate a minimum and maximum range for the possible values of that certain parameter.

Left side of the *Economics* tab is devoted for the unit costs ($/ft, $/stage or $/unit) for drilling, completion, stimulation, site construction and leasing rental. Moreover, two other key parameters affecting project economy, namely hydraulic fracture stage spacing (ft) and well spacing (acres/well) parameters are placed on this side. The top-right side of the *Economics* tab is devoted for the well design parameters such as vertical and horizontal well lengths and approximated fracture half-length. The middle-right portion is devoted for the inputs concerning fiscal policies of the country, namely royalty and corporate taxes and the ultimate economical parameter, the discount rate. Finally, the bottom-right part includes the market price for the commodity, the operating expenditure (OPEX) for a unit of commodity production.

Last but not the least, the most bottom-right parameter denotes the total capital expenditures (CAPEX) calculated by using the other input parameters on this tab. Market price, OPEX and the CAPEX will all be used as input for the future calculations, hence in summary this tab involves the fundamental inputs (Figure 124).

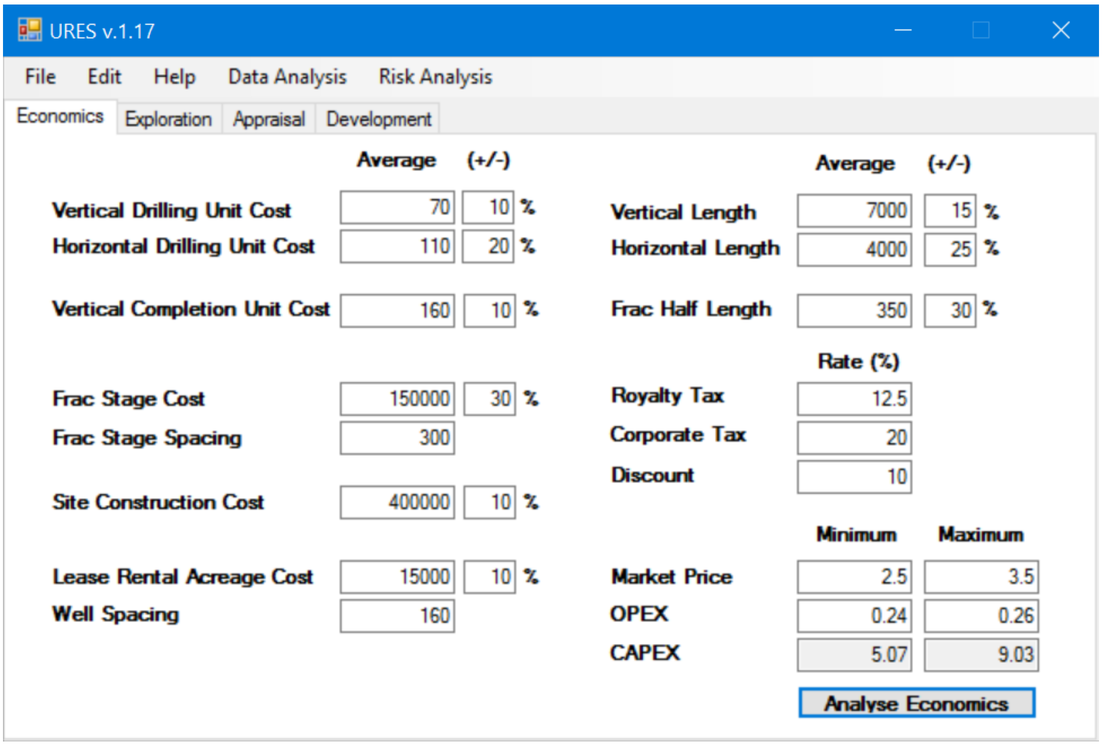


Figure 124 – Economics tab from URES v.1.17.

Moreover, detailed outputs regarding the fundamental economic analysis performed through *Economics* tab can be reached via the Top Menu. The possible ranges for well design parameters such as the number of frac stages, vertical length and horizontal length can be reached via the Top Menu "***Data Analysis/Economics/Detailed Data***". The range for the number of frac stages can be estimated by dividing the minimum and maximum horizontal length by the stage spacing. Moreover, the possible ranges for drilling, completion, stimulation and other costs, which constitutes well CAPEX are presented in the same window. A sample screen shot captured from the window presenting Economic details for the Eagle Ford well is given in Figure 125.

The first DG is designed to evaluate the project just after the first vertical well in the field is drilled and basic reservoir data is obtained while bearing in mind that there are considerable amount of heterogeneity in the formation.

To evaluate the prospect, a sort of analogy method is being used to compare the fundamental formation and rock properties collected via well logs, cores, wireline testers and well tests, with the well-known Big-Six US shale gas fields.

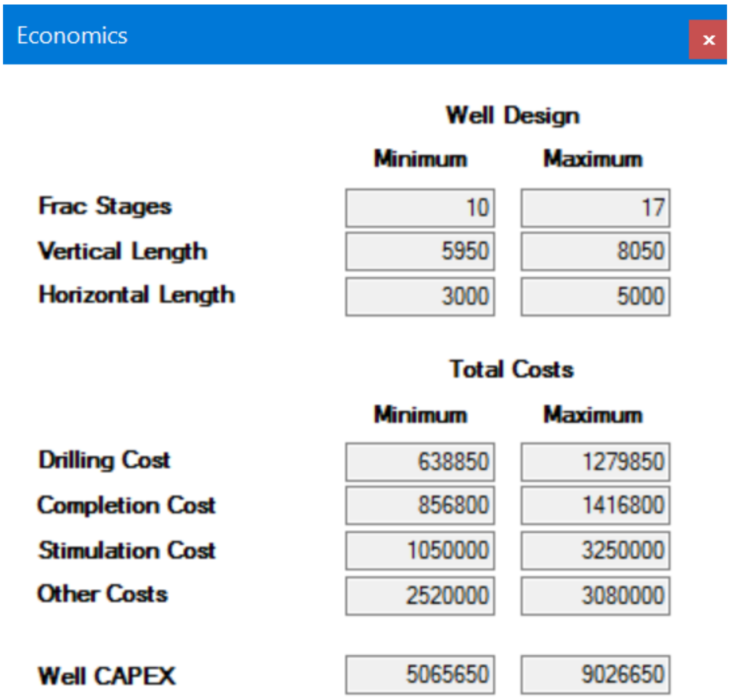


Figure 125 – Detailed data for Economics tab from URES v.1.17.

In the second tab, "***Exploration***" tab, data belong to exploration well, is evaluated through our methodology whose details are mentioned in Section 7.1.

Data collected from the field would have some degree of uncertainty due to various reasons, such as vertical/horizontal heterogeneity, measurement errors or analyst bias. Hence, a range for each input parameter, i.e. a minimum and a maximum possible value, will be assigned based on our claim of fully probabilistic methodology. Through utilization of MCM, a value for each input parameter is picked randomly and via our proposed linear equation in our methodology (Eqn. 51), a so-called Shale Value Point is created for each set of data. Relying on MCM, this process repeated for 10,000 times and at each loop, the obtained Shale Value Point is converted to EUR/well via the correlation obtained through our methodology and the investigation of Bix-Six U.S. Shales. The results for EUR/well at the 10th, 50th and 90th percentile of 10,000 realizations are displayed in the textboxes reserved for output (Figure 126).

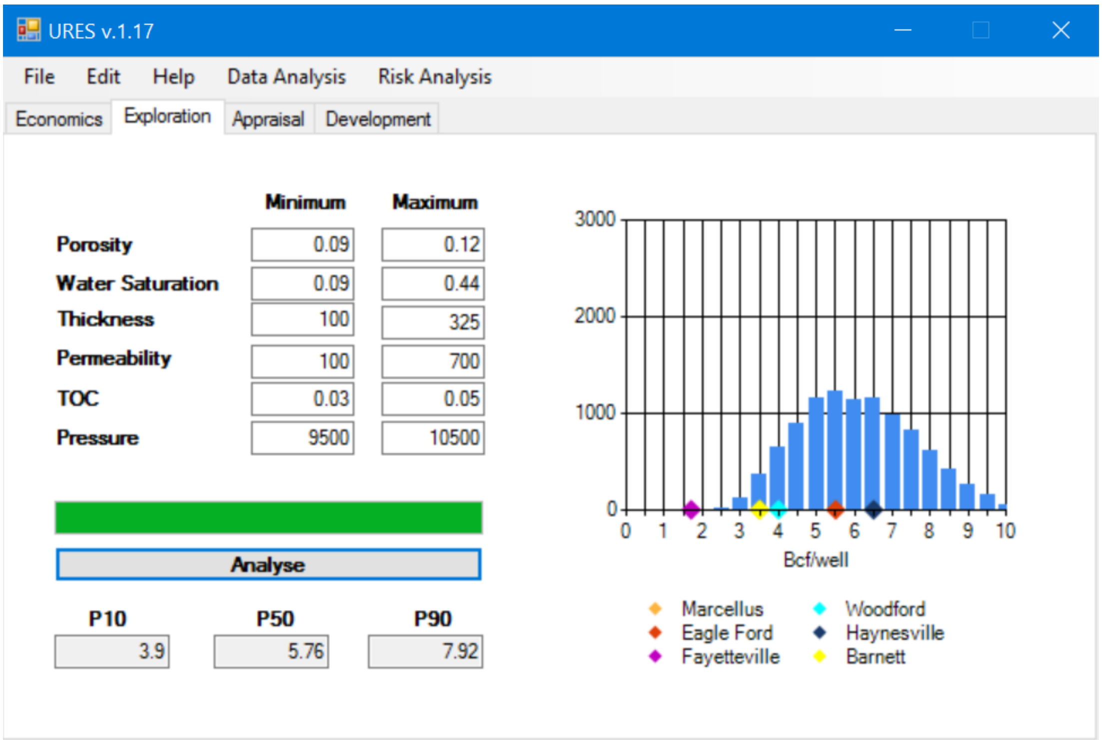


Figure 126 – Exploration tab from URES v.1.17.

The illustration for the conversion of all 10,000 Shale Value Point data to EUR/well is given in the left side of Figure 127. Moreover, in the spreadsheets given on the right side of the figure, 10,000 shale value point realization, corresponding EUR/well and sorting of EUR/well in the descending order is presented.

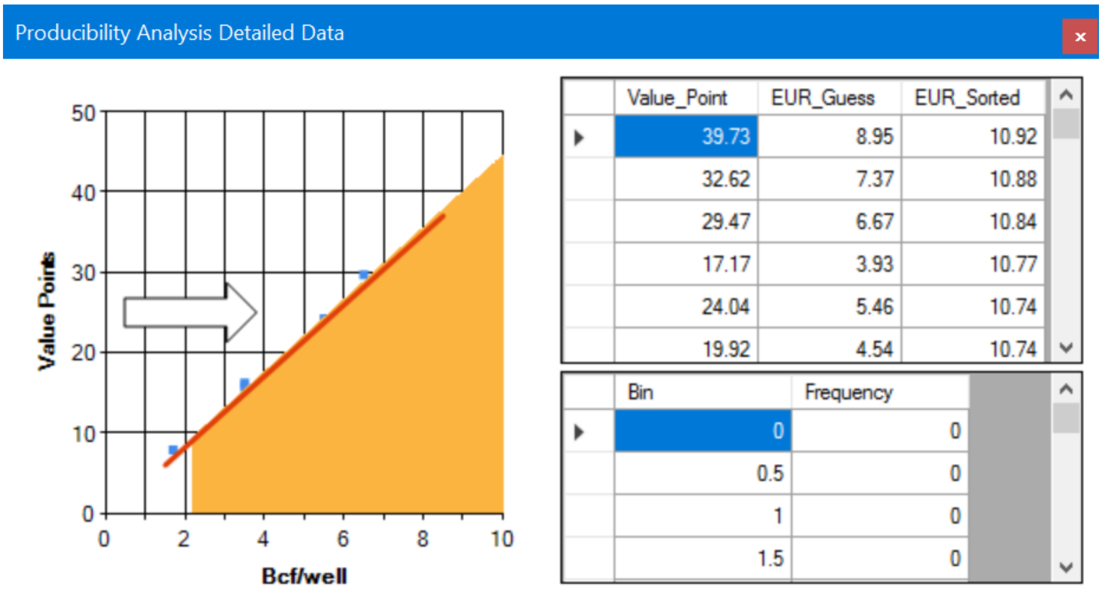


Figure 127 – Detailed data for Exploration tab from URES v.1.17.

Moreover, just below that, the bin and the associated frequency for EUR/well data to generate the histogram is tabulated. The histogram on the right side of the Producibility tab worth paying attention, which shows the realizations for EUR/well (Bcf/well) values as a result of our methodology (Figure 126).

The second DG is designed to be just after completion and stimulation of 2 horizontal wells, in addition to the first vertical well. In this third tab, namely "***Appraisal***" tab, analyze of the second DG will be performed and the resource potential of the prospect is calculated again in a fully probabilistic fashion.

The top-left portion is designed to calculate the free gas content per mass of rock and requires porosity, gas saturation and gas formation volume factor data. Moreover, since a porosity correction is also designed, the output of bottom-left portion, adsorbed gas content per mass of rock is also used in the calculation for the free gas content.

To calculate adsorbed gas content, adsorption tests should be conducted in rock or cutting samples, so that Langmuir pressure (p_L) and Langmuir volume (V_L) be determined. Lastly, by utilizing the reservoir pressure (p_r) and the Langmuir parameters in MC simulation, minimum and maximum values for adsorbed gas content can be determined.

Free and adsorbed gas contents sum up to the total gas content. It should be noted that the minimum and maximum values for the free and adsorbed gas contents presented in this tab represents the 10^{th} and 90^{th} percentiles for the results of 10,000 iteration via Monte Carlo simulation, sorted in the descending order.

In the top-right portion of the tab, the first line represents minimum, maximum and mode values, i.e. 10^{th}, 50^{th} and 90^{th} percentiles for the MC simulation results of total gas content. The second line, SRA (Stimulated Reservoir Area) is calculated via multiplying the twice of the fracture half-length entered in the "*Economics*" tab with the horizontal length of the wellbore. Specifically for the calculation of minimum, maximum and mode values of this parameter, a direct multiplication of the worst possible values, the best possible values and average values are performed, respectively. The third line represents the net thickness of the reservoir, which may be obtained from hydraulic fracturing design or any result from micro-seismic.

The fourth line, which is the last input parameter for in-place volume calculation is the density of the rock and the minimum, maximum and mode values can easily be determined through laboratory measurements (Figure 128).

However, the adventure of calculating recoverable resources does not end with calculation of in-place volumes. Hence, a recovery factor obtained from literature (EIA 2013) or through analog formations should be introduced to end up with recoverable volumes.

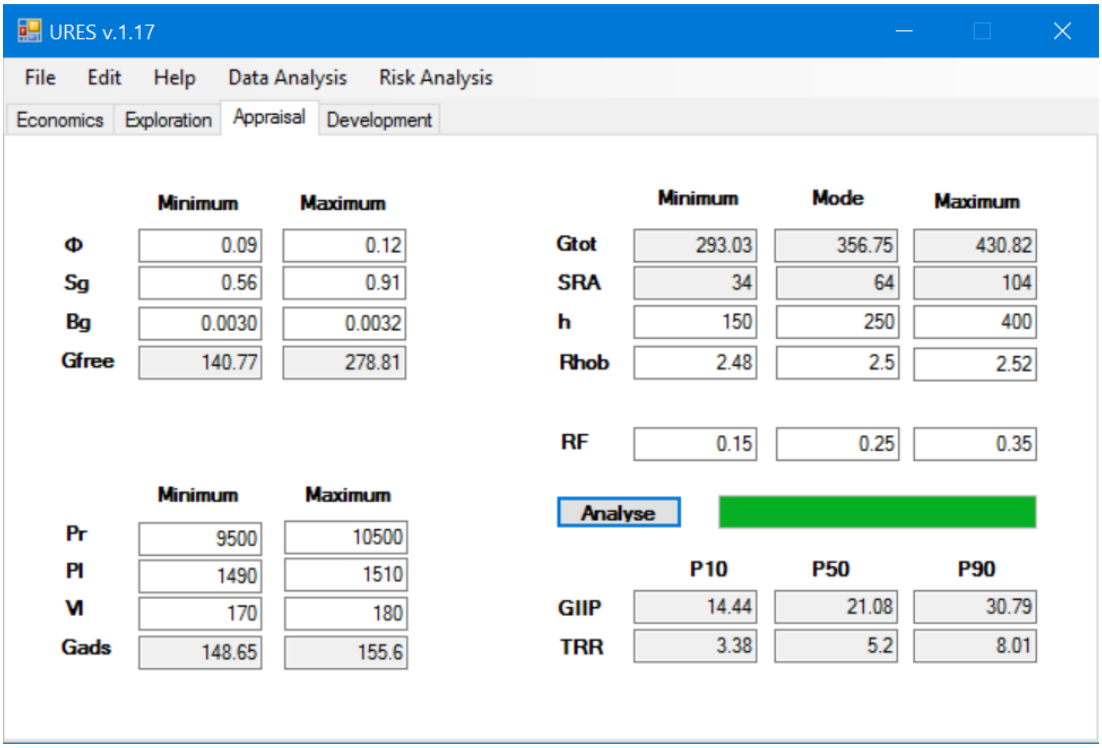


Figure 128 – Appraisal tab from URES v.1.17.

The last DG is designed to analyze the production data through 3-segment DCA in a probabilistic fashion. Other tabs could only evaluate the ultimate recoverable volumes, however, do not include any time dimension into the function. Hence, time value of money could not be included in the decision making process. The fourth tab, the "***Development***" tab, provides user a tool to analyze performance of the well in time. Consequently, monthly cash flow can be calculated and NPV and IRR markers, which are function of time are revealed.

The left side of this tab is reserved for performance parameters those will be used as input of the 3-segment DCA. As discussed the economics of shale fields are mainly determined in the first few years, where both the production and the time value of the money earned are relatively higher. The first line is devoted to the most influential parameter, IP, to the EUR and NPV results. Later, first segment, which generally lasts for a few years and again affects NPV considerably, precedes the IP input. At this period of the flow, yearly decline rate and decline exponents are thought as uncertain parameters. However, uncertainty is not adhered to duration of this period since this duration can be calculated through special plots discussed in Section 4.2 provided that enough historical data is produced. The second segment starts with a pre-calculated decline rate, which was calculated using the decline rate at the last time step (last month of Segment-1 in our case). Hence only decline exponent is required as input with a minimum and maximum range. Minimum decline rate to terminate this period is again thought as free of uncertainty since industry/literature has a consensus on the value of this parameter ($D_{\min}$ = 0.05). The third segment inputs determine the termination of the production period, which are minimum economical rate and field life. Again, these two parameters are thought as free of uncertainty deliberately since there is an industry consensus on these two parameters.

On the top-right portion of this tab, a plot showing the theoretical minimum and maximum production profiles is placed. These profiles are not realistic, since they show the most conservative case and most speculative case, which will assure the user that the real profile will be inside of this envelope (Figure 129).

The economic parameters provided in the "*Economics*" tab are widely used in the probabilistic evaluation of the project at this last DG. Since the results of production data analysis give time dependent outputs, time value of money comes into concern to have a better insight into the monetary valuation. For example, on the bottom-right corner, NPV and IRR markers are provided at their 10th, 50th and 90th percentiles of MC simulation, in addition to ERR markers.

This tab is a perfect example of accommodation of fully probabilistic approach by melting the time dependent economical inputs gathered in “Economics” tab and the time dependent production rates calculated in the “Development” tab, in the same pot.

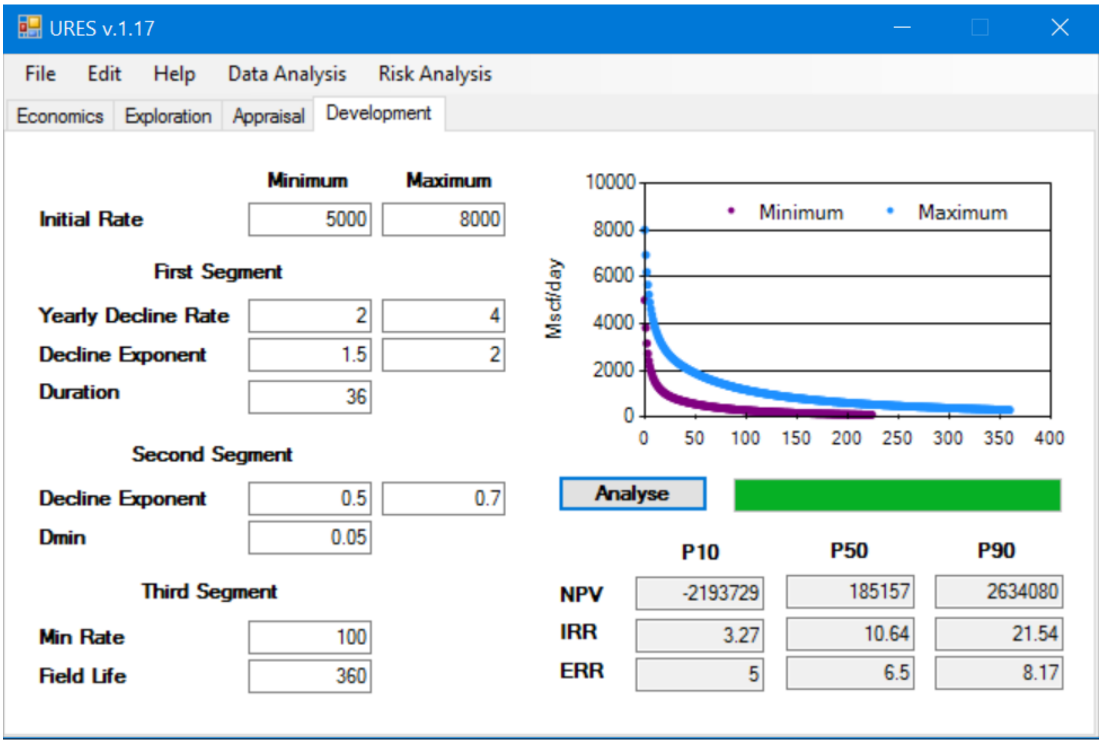


Figure 129 – Development tab from URES v.1.17.

Accurate analysis of the results is as important as reaching reliable outputs. Hence, some specially designed plots are implemented into our software, which can be reached via the top menu “***Data Analysis***” menu item.

One of the most useful one is the NPV Swarm Plot, which can be reached via “***Data Analysis/Development/NPV Swarm Plot***” option. This is a plot of NPV vs. EUR/well data generated with MC simulation. While the number of points corresponding to positive values of NPV increase, entering into or persisting in the project become more logical (Figure 130). Another informative plot for economic evaluation is the cash flow plot, which can be reached via “***Data Analysis/Development/Cash Flow Analysis***” option and shows the monthly cash flow and cumulative cash flow chart for both conservative and speculative cases. By the help of this plot, the payback time and the maximum exposure could easily be determined.

As for the conservative case, all the parameters used represent the worst case and the as for the speculative case, all the parameters used represent the best case (Figure 131).

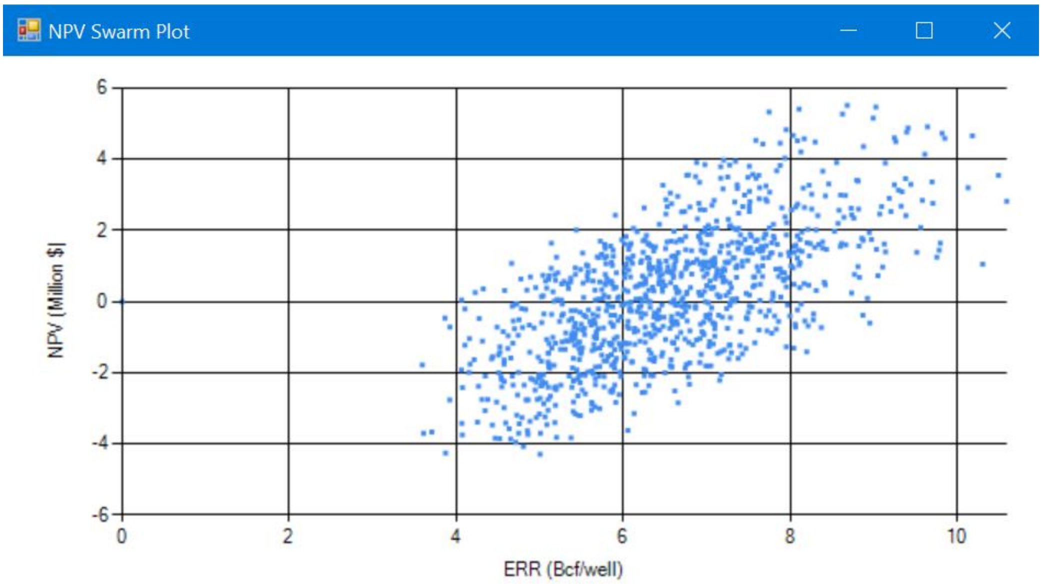


Figure 130 – NPV Swarm Plot from URES v.1.17.

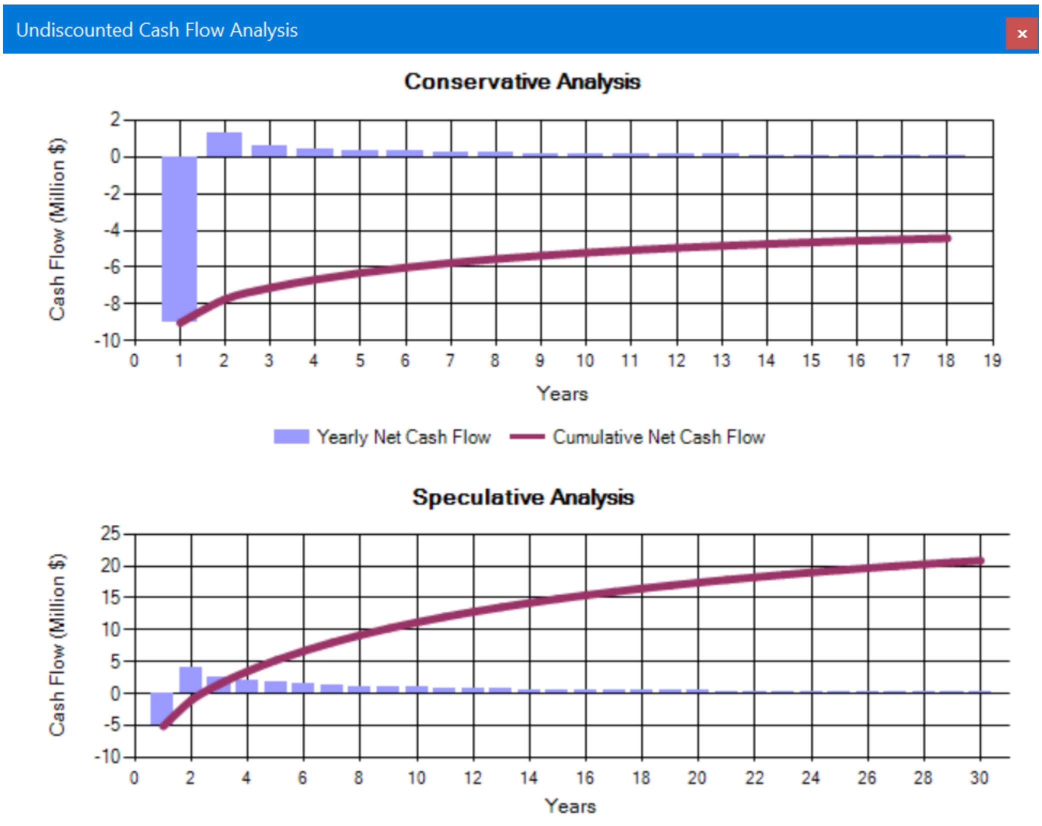


Figure 131 – Undiscounted Cash Flow Analysis from URES v.1.17.

Moreover, data associated with these two plots can be reached via the Top Menu with the path: "***Data Analysis/Development/Minimum-Maximum***" as in Figure 132 and the results of 1000 loops can be reached via the Top Menu with the path: "***Data Analysis/Development/Financial Realizations***" as in Figure 133.

Financial Realizations

NPV	ERR	IRR	NPV_Sorted	ERR_Sorted	IRR_Sorted
2476143.98	7379848	19.92	5497554.76	10590859	44.97
1585213.75	7002819	16.49	5459000	10491015	42.76
1665934.35	6632148	16.62	5395116.29	10302092	41.12
-1864317.31	5392781	4.17	5319139.35	10179279	40.79
-906104.61	5425568	6.77	5260142.49	10127061	37.44
-477585.54	6421930	8.32	5142909.66	9847884	37.08
-1666899.44	5801723	4.26	4902216.32	9815546	36.77
-2319866.59	6791245	3.67	4871935.25	9793365	36.67
-2557452.35	6227015	2.43	4823988.86	9782255	36.36

Figure 132 – Financial realizations from URES v.1.17.

Maximum & Minimum Bounds

Conservative Projection

Months	Average Rate (Mscf/day)	Monthly Production (Mscf)	Cumulative Production (Mscf)	Investments ($)	Income ($)	Royalty Tax ($)
0	5000	0	0	-9026650	0	
1	3816	134440	134440	0	336100	-
2	3150	106224	240664	0	265560	-
3	2714	89429	330093	0	223572	-
4	2404	78052	408145	0	195130	-
5	2169	69734	477879	0	174335	-

Speculative Projection

Months	Average Rate (Mscf/day)	Monthly Production (Mscf)	Cumulative Production (Mscf)	Investments ($)	Income ($)	Royalty Tax ($)
0	8000	0	0	-5065650	0	
1	6928	227655	227655	0	796792	-
2	6197	200156	427811	0	700546	-
3	5657	180768	608579	0	632688	-
4	5237	166135	774714	0	581472	-
5	4899	154577	929291	0	541020	-

Figure 133 – Maximum and Minimum Bounds window for cash flow from URES v.1.17.

Since our aim is the development of a methodology and a software, which will evaluate shale oil and shale gas formations in all phases and provide firm go/no-go decisions, a "***Risk Analysis***" part is put in the top menu as a tool to provide go/no-go decisions by looking at either undiscounted monetary values or NPVs. Moreover, the variation in investors' risk attitude have an important effect on the decision making process, hence we included an option for the user to select his/her risk attitude. If the investor is risk seeking, i.e. can tolerate more risk, we selected the low case value or P10 probability value as the determinant of go/no-go decision. As for a risk neutral investor, mid case or P50 value is the determinant. Lastly, for a risk seeking investor, who wants an absolute profit, the determinant would be the high case or P90 value.

As for the decision window for DG-1 (Figure 134), which appears after Exploration phase, undiscounted monetary value analysis is selected as the main parameter for decision-making. After selection of the risk attitude of the investor, one of the low, mid or high case value becomes the determinant and software checks if the undiscounted monetary value in the selected case is greater than zero or not. If the result is a positive value, software recommends go decision for the project. Moreover, in this window, we also analyze the fundamental reservoir, rock and fluid parameters whether they are above minimum criteria or not. This part is not a determinant for decision making, however, user can see if any of the criteria is below the minimum limit or not.

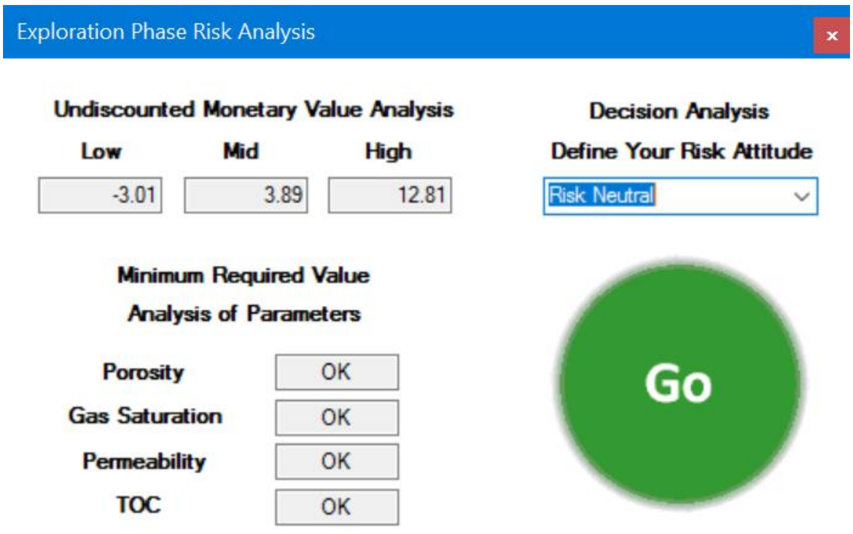


Figure 134 – Decision-Making window for DG-1 from URES v.1.17.

As for the decision window for DG-2 (Figure 135), which appears after Appraisal phase, again undiscounted monetary value analysis is selected as the main parameter for decision-making and the rest of the procedure is the same as above.

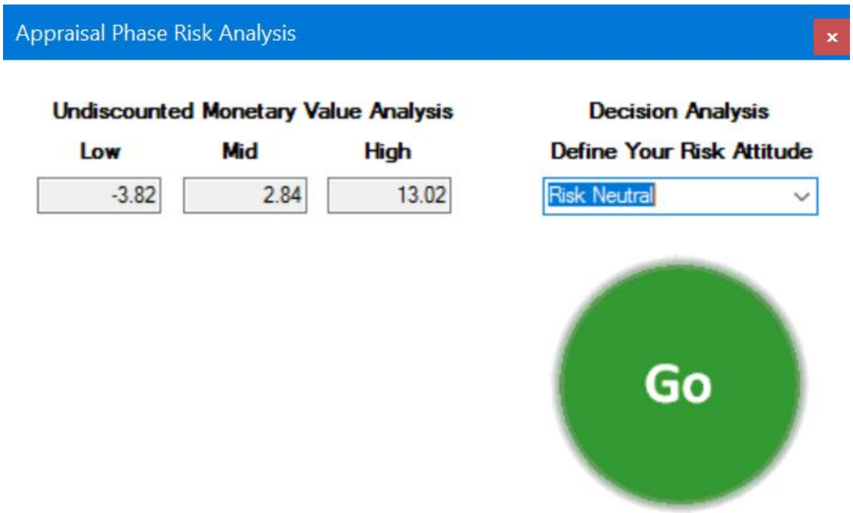


Figure 135 – Decision-Making window for DG-2 from URES v.1.17.

Lastly, the decision window for DG-3 (Figure 136), which appears at early Development phase, is more detailed than the other two decision-making window. Since time value of money is in concern at this stage, results of NPV Analysis become the determinant for this DG. The initial procedure is the same with other two decision-making windows. After selection of the risk attitude of the investor, one of the P10, P50 or P90 value becomes the determinant and software checks if the NPV in the selected probability marker is greater than zero or not. If the result is a positive value, software recommends go decision for the project. We also included undiscounted monetary value analysis in this window for checking purposes with the other DGs. The number of positive NPV values in the 1000 NPV realizations, i.e. the number of positive values in NPV Swarm Plot in Figure 130, is also calculated and presented as "***Positive NPV Probability***" value in the left-middle part of this window. Below that line, one can see "***NPV Cumulative Probability Chart***" and "***ERR Cumulative Probability Chart***" buttons, whose functions can be deduced from their naming and the plots generated through them are given in Figure 137 and Figure 138.

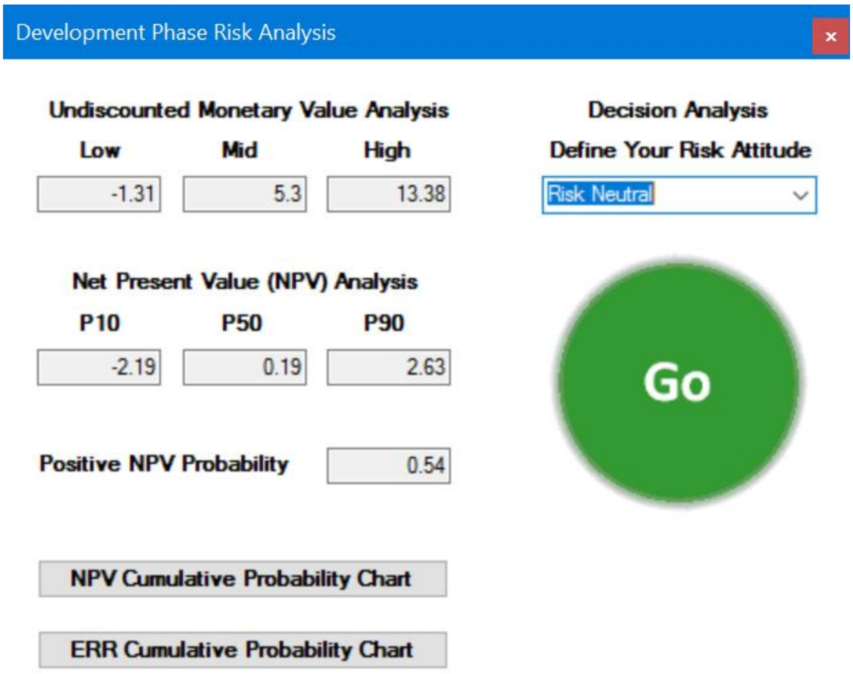


Figure 136 – Decision-Making window for DG-3 from URES v.1.17.

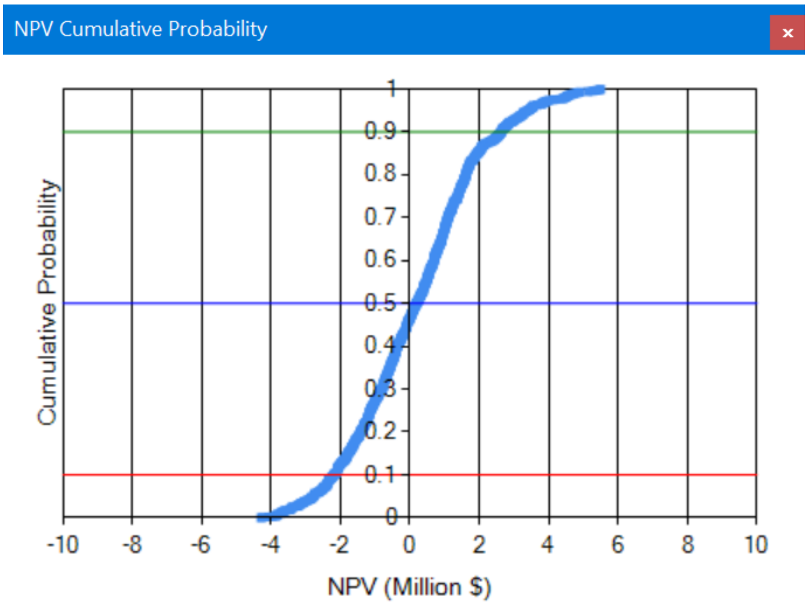


Figure 137 – NPV Cumulative Probability Plot window generated in DG-3 from URES v.1.17.

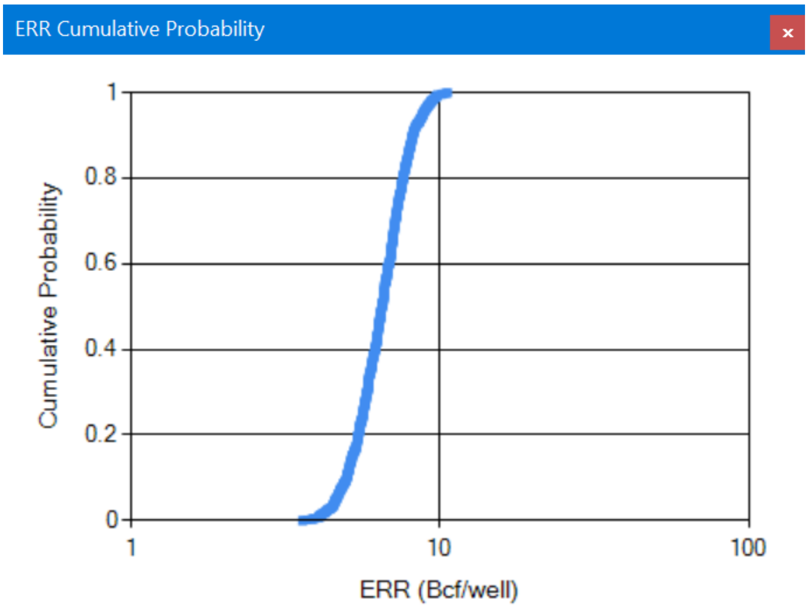


Figure 138 – ERR Cumulative Probability Plot window generated in DG-3 from URES v.1.17.

As can be seen from the results generated above, a risk neutral investor would like to invest in Eagle Ford Shale. Firstly, he/she analyses the results obtained from first vertical well through the Exploration tab given in Figure 126 and the P50 TRR value appears as 5.8 Bcf/well. While looking at the literature, Dong *et al.* (2013) quotes the minimum and maximum EUR per well for Eagle Ford Shale as 2.3 Bcf/well and 8.5 Bcf/well, respectively. Moreover, EIA (2011) quotes the average value for EUR per well as 5.5 Bcf/well. All these data together with other fields are presented in Table 20. Hence, the result of the analysis in DG-1 is highly consistent with the real field values.

After getting a “go” decision in DG-1, investor would proceed to drill two new horizontal wells and stimulate them to see stimulation efficiencies. After getting the required information from these the two horizontal wells, together with the initial vertical well, investor enters into Appraisal tab, i.e. DG-2, where the volumetric analysis will be handled for decision-making. The results of this window is given in Figure 128 and the P50 TRR value appears as 5.2 Bcf/well, which is also highly consistent with the real field data.

Since the investor got a “go” decision from DG-2, he/she proceeds with drilling of two more horizontal wells, stimulate them and collect production data from wells for at least 6 months. The production data collected will be evaluated via Development tab and our final decision gate, DG-3 appears exactly at this point, just before proceeding to full field development, aggressively drilling and stimulation of horizontal wells and building larger surface process facilities.

In our case study, the P50 ERR value appears as 6.5 Bcf/well, and the corresponding NPV for a single-well appears as 0.19 Million $ for a wells’ entire life. The chance of having a positive NPV value from an Eagle Ford well is calculated as 54 % as can be seen in Figure 136. The possible NPV values can go more than 2.63 Million $, which is P90 value of the analysis and can go less than -2.19 Million $, which is P10 value of the analysis.

Hence, the reliability of the proposed methodology is proved through this real field case study. Especially, while considering today’s market prices are on the limits for profit making in U.S. shales wells, reaching a slightly positive NPV value more or less reflects the real world. As mentioned in the literature review part, most of the shale companies today make losses rather than profits.

Table 20 – Reservoir properties of shale gas formations in the US

	Marcellus			Antrim			Haynesville			Eagle Ford			Fayetteville		
	Min	Max	Average	Min	Max	Average	Min	Max	Average	Min	Max	Average	Min	Max	Average
Porosity (fraction)		0.1	0.08			0.09	0.08	0.09	0.085	0.09	0.12	0.09	0.02	0.08	0.05
1-Sw (fraction)	0.68	0.80	0.75						0.82	0.56	0.91	0.82			0.75
h (ft)	50	200	125	70	120	95	200	300	250	3	326	200	20	200	110
Perm (nano-Darcy)	160	350	255						650	100	700	400			120
TOC (fraction)	0.03	0.12	0.12	0.01	0.2	0.11	0.05	0.04	0.0225	0.03	0.05	0.0425	0.04	0.098	0.069
EUR (bcf/well)			3.5			0.28	4	10	6.5	2.3	8.5	5.5			1.7
IP (MMcf/d)												7			
Well Cost (million $)			4			0.5									3
Depth (ft)	4000	8500	6750	600	2200	1400	10500	13500	12000			7000	1000	7000	4000
Lateral Length (ft)															
Gas Content (scf/ton)	60	100		40	100		100	330		7	118	82	60	220	
Pressure (psi)			7600						2850			10500			3500

	Western Woodford			Central Woodford			New Albany			Barnett			Horn River, BC		
	Min	Max	Average	Min	Max	Average	Min	Max	Average	Min	Max	Average	Min	Max	Average
Porosity (fraction)	0.03	0.09	0.07			0.06	0.1	0.14	0.12	0.04	0.05	0.05	0.03	0.06	0.045
1-Sw (fraction)			0.78						0.6	0.57	0.75	0.7			0.75
h (ft)			150			250	100	300	200	100	600	300			450
Perm (nano-Darcy)			250						8	10	5000	250			230
TOC (fraction)	0.01	0.14	0.065			0.04	0.01	0.25	0.13	0.024	0.051	0.045	0.01	0.05	0.025
EUR (bcf/well)			4			1			1.1	1.1	10	3.5			7.5
IP (MMcf/d)												4			7.3
Well Cost (million $)						7			1			3			7
Depth (ft)	6000	11000	9500			5000	1000	4500	2750	6500	8500	7500	6230	10170	8800
Lateral Length (ft)										3500	5000				
Gas Content (scf/ton)				200	300		40	80		300	350				
Pressure (psi)			3500			3500			850			3200			4800

Table 21 – Reservoir properties of shale gas formations in US (cont'd)

	Big Sandy			Niobrara			Utica / Point Pleasant			Turkey, Dadas			Turkey, Hamitabat		
	Min	Max	Average	Min	Max	Average	Min	Max	Average	Min	Max	Average	Min	Max	Average
Porosity (fraction)			0.1			0.08			0.05	0.06	0.07	0.07			
1-Sw (fraction)						0.65			0.82						
h (ft)			175			313			150			200			250
Perm (nano-Darcy)						500			22.5						
TOC (fraction)			0.0375			0.055			0.0205	0.02	0.07	0.036	0.01	0.04	0.02
EUR (bcf/well)			0.325												
IP (MMcf/d)															
Well Cost (million $)															
Depth (ft)			3800			7500			6500	6000	13000	9000	14000	16400	
Lateral Length (ft)						4250			6500						
Gas Content (scf/ton)															
Pressure (psi)						5000			3250						

Colour Code for References

EIA (2011)

EIA (2013)

DOE (2009)

Waldo (2012)

Dong *et al.* (2013)

Zhang *et al.* (2016)

CHAPTER 9

CONCLUSIONS

Firstly, selection of the right shale oil or shale gas play opportunity is the gate number zero to be passed while deciding to involve in an unconventional project. As clearly stated in the text, the main issue in unconventional resource development is the economics, i.e. conversion of resources to reserves, rather than the existence of the resource.

After deciding on the most promising play, the project should be carefully phased to generate a robust de-risking strategy. During the whole life of the project, starting from the exploration to appraisal and development, it is highly crucial to give correct go/no-go decision at every decision gate.

Since the shale oil and shale gas formations are highly heterogenic in the vertical and lateral axis, a reliable evaluation of these formations needs probabilistic approach. Hence, the risk of reaching erroneous results is much higher than the analysts think. Including the knife-edge economics of these projects, ending up with financial losses is quite likely. Utilization of the developed methodology and the software in this study provides a robust de-risking strategy, reliable risk analysis and decision-making tools. Hence, it is much likely to prevent possible financial losses.

Moreover, the developed software aids in determination of the necessary parameters to evaluate the project reliably in each maturity phase. It also provides a well performing benchmarking tool to compare the project in hand with the international shale projects. The case study presented in this dissertation also verifies the robustness of the methodology and the software developed, since the outputs related to volumetric and monetary analysis both comply with the real values of the field in concern.

CHAPTER 10

RECOMMENDATIONS

The most important recommendation for possible future studies is the extending the software developed in this dissertation for shale oil formations. Main obstacle in front of the development of the software for shale oil projects is the lack of public data. Personal communication with operator companies may help in overcoming this issue.

Moreover, to create value for the home country, the gas potential of the Hamitabat Shale in Turkey can be evaluated through the methodology and the software developed in this dissertation. Moreover, after modifying the software for shale oil projects, Dadaş Shale in Turkey can also be evaluated.

To verify the results of this study, artificial intelligence may be utilized after the collection of enough data with time for training, testing and validation.

While performing random selection from the range imposed by the user, the distribution types for input parameters are assumed to be uniform. Hereby, it is also recommended to extend the proposed methodology so that different distribution types can be used while random selection of input parameters from an imposed range.

Lastly, production decline data of currently producing shale plays can be studied to generate confidence intervals for the decline parameters used in multi-segment decline curve method. Hence, more reliable EUR values can be obtained.

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APPENDIX

UNCERTAINTY ASSESSMENT METHODS

This appendix part of the dissertation is taken from the author's Master's Thesis (Tuğan 2010) written in the supervision of Dr. Onur. The purpose is to present the uncertainty assessment methods discussed in this dissertation. To make good decisions, one must be able to accurately assess and manage the uncertainties and risks. Hence, it is vital to quantify the uncertainty in estimates of oil and gas reserves.

This part is limited with uncertainty assessment for volumetric methods, but the methodology given here is general and can be applied to any other methods different from the volumetric methods that can be used for reserve estimation.

One can use both Monte Carlo (MC) and the analytic uncertainty propagation (AUP) methods for characterizing and quantifying uncertainty in reserves estimated from volumetric methods. As to be discussed in the next sections, Monte Carlo is the most general approach to assess the uncertainty. However, there is a simple and fast alternative method – which we refer to it as the analytic uncertainty propagation method (AUPM) – to the MCM for characterizing uncertainty. The validity of the AUPM for accurately characterizing uncertainty results from the fact the distributions of reserves for a zone, well, or field to be computed from the volumetric method tend to be log-normal. This result simply follows from the fundamental theorem of statistics and probability – the Central Limit Theorem (CLT) (e.g., see Parzen 1962). As a consequence of this theorem and the functional relationship of the volumetric method which involves a product/quotient of several independent random variables for computing oil and gas reserves, the resulting distribution of oil and gas reserves is to be nearly log-normal. This result is in fact valid no matter what form of uncertainty the input variables assume. The same findings have been reported previously for the assessment of uncertainty in oil or gas reserves computed from the volumetric methods by Capen (1996).

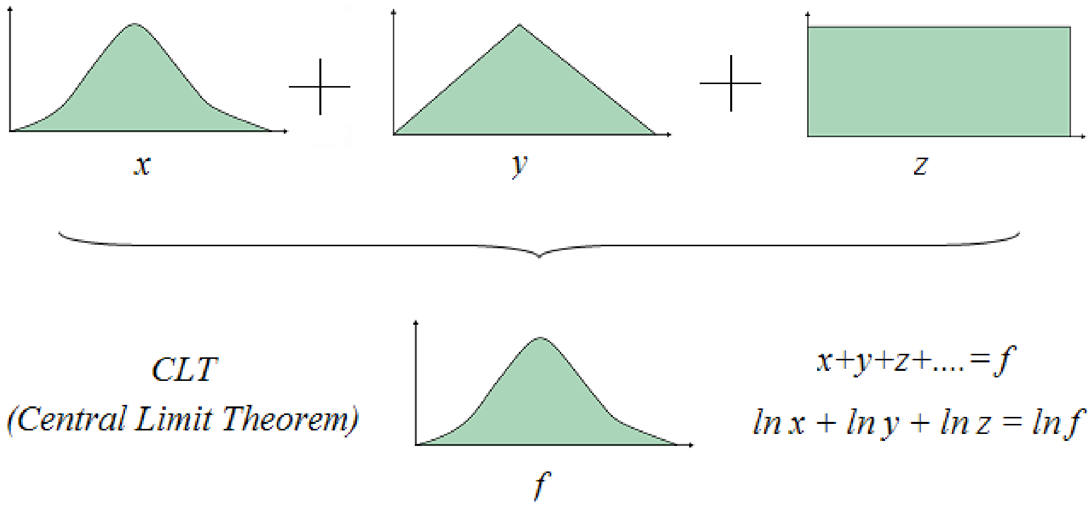

Figure 139 – Regardless of the Distribution Types of the Inputs, Summation Tends to be Normal as a Consequence of CLT (Tuğan 2010)

Central Limit Theorem (CLT): This theorem states that the sum of a sufficiently large number of identically distributed independent random variables each with finite mean and variance will be approximately normally distributed (Rice, 1995). The explanation of this theorem can be found in the following equation series:

$$a + b = (a + b) \tag{A.1}$$

Considering, a and b are some random variables with uniform distribution; then *(a + b)* summation should have a normal distribution according to CLT.

In light of the foregoing; taking natural logarithm of a and b separately and adding them together gives a result with normal distribution according to CLT:

$$\ln(a) + \ln(b) = \ln(a \cdot b) \tag{A.2}$$

Since, *ln (a.b)* have a normal distribution; *(a.b)* will have a log-normal distribution

Finally, let us turn again to our topic, which is Volumetric Method for Estimating Reserves, with the information about CLT in mind. One can see that the resulting distribution of the volumetric estimation equations, which involve product and quotient of several independent random variables, should be log-normal providing the number of input random variables are sufficiently large.

The equations for Volumetric Method with natural logarithm are following;

$$\ln(ROIP) = \ln A + \ln h + \ln\phi + \ln(1 - S_{wc}) + \ln R_F - \ln(5.615 \cdot B_o) \quad \textbf{(A.3)}$$

$$\ln(RGIP) = \ln A + \ln h + \ln\phi + \ln(1 - S_{wc}) + \ln R_F - \ln(B_g) \quad \textbf{(A.4)}$$

By the help of Central Limit Theorem and considering that all the inputs above are independent random variables, the resulting distributions for *ln(ROIP)* and *ln(RGIP)* will tend to be normal. Hence, the distributions of *ROIP* and *RGIP* become log-normal.

A spreadsheet analysis identifying the relationships among variables is generally useful in modeling the uncertainty, i.e., preparing a spreadsheet that includes the result in terms of variables in the equational form. However, conventional spreadsheets allow the user to enter one single value for each variable instead of a range of values for a correct uncertainty analysis. In order to have a probability distribution for resulting estimate, user should manually change the variables in spreadsheet in a time-consuming manner. This situation is the point where uncertainty quantification methods come in handy (Goldman 2000).

It is worth mentioning that, quantifying of uncertainty process is totally subjective because the selection of the values of input parameter and their ranges depend on the data in hand which are generally inadequate and the expertise of the interpreter.

Moreover, neglecting the correlation among input parameters may lead to large errors in quantifying uncertainty (see Chapter 4.3 in Tuğan 2010).

Monte Carlo Method (MCM)

Monte Carlo Method is generally referred as the Monte Carlo Simulation. Literally, “simulation” means an imitation of real-life. Likewise, Monte Carlo Simulation is an imitation of a real-life system for generating outcomes by using randomly chosen values from a distribution model as input variables and calculating the results over and over. Hence, the model is simulated and a probability distribution is derived for output values. Without such a simulation, the spreadsheet model only reveals a single outcome. However, by using “Monte Carlo Simulation” add-in for spreadsheets, a range of possible outcomes with their possibility of occurrence can be obtained.

Crystall Ball^{TM}, @Risk^{TM} are examples for spreadsheet based Monte Carlo applications.

Explaining where the name of MC Simulation comes from may help to understand the idea under this method. MC Simulation was named after the gambling paradise Monte Carlo, Monaco. That is, where the primary attractions are the casinos, so the games of chance. Dice, slot, roulette wheels are all exhibit random behavior, just as MC Simulation exhibits to select variable values.

In all MC spreadsheets, the user is supposed to define a probability distribution for each input variable. Normal, triangular, log-normal and uniform distribution types may be familiar, however, there exist many less-familiar types such as, beta, gamma, Weibull and Pareto. At this point, three main sources come into rescue to determine the distribution model, which are: fundamental principles, expert opinion and historical data (Murtha 1993).

On the other hand, MC simulation has some drawbacks. Murtha (1993) classifies these drawbacks in three main parts; firstly, the price of the software and users need to learn software, secondly the language of probability and statistics should be well known and thirdly the results are only as good as the model and the input assumptions. First two drawbacks are easy to overcome, however, the third should be dismissed or minimized by carefully selecting models and input parameters.

Monte Carlo Simulation can be used in any type of calculation that includes inputs with some uncertainty. Hence, MC Simulation can be used within all estimation methods. For example, in DCA, both the initial productivity, and the decline rate, can be run in MC simulation as random variables. As a consequence, the production forecast becomes a band of uncertainty, rather than a single curve.

In short, by running a MC Simulation, the input variables are repeatedly sampled from the distributions and used in the final equation to calculate scenarios and at last multiple scenarios are obtained. Lastly, modeling all these scenarios will give the user a probability distribution for the result, i.e. a histogram showing the occurrence frequency of all scenarios.

Analytic Uncertainty Propagation Method (AUPM)

Analytic Uncertainty Propagation Method (AUPM) is another way of assessing the uncertainties in output values by estimating the variance of the function defined by several random variables. In other words; the function is the result of some products and quotients of random variables which are independent or correlated. Onur *et al*. (2009) define AUPM in their work as: “It is based on a Taylor series approximation of the function around the mean values of the variables up to first derivatives with respect to each of the input variables.”

The main superiority of AUPM on MCM is that it does not assume a specific type of distribution for the input variables (variables does not need to be in uniform, normal or any type of distribution), only those statistical properties of the distribution for each random variable specifically the mean, variance (or standard deviation) and covariance (or correlation coefficient) among variable pairs if the random variables are correlated are required in the AUPM (Onur *et al.* 2009).

There exist three different approaches of AUPM for uncertainty assessment. In this part, only the easiest and the most accurate method will be discussed which uses the equations in natural logarithm base.

Let us start to illustrate AUPM method with transforming the basic equations to natural logarithm base. For example, take in hand the RGIP equation:

$$RGIP = \frac{A \times h \times \phi \times (1 - S_{wc})}{B_g} \times R_F \qquad \textbf{(A.5)}$$

$$\ln RGIP = \ln A + \ln h + \ln \phi + \ln(1 - S_{wc}) + \ln R_F - \ln Bg \qquad \textbf{(A.6)}$$

Let $\ln f = \ln RGIP$, and the number of random variables be M and they are $\ln X_1$, $\ln X_2$,……, $\ln X_M$. The Taylor series expansion will be:

$$\ln f = \mu_{\ln f} + \sum_{i=1}^{M} (\ln X_i - \mu_{\ln X_i}) \cdot \frac{\partial \ln f}{\partial \ln X_i} \qquad \textbf{(A.7)}$$

$$\mu_{\ln RGIP} = \mu \ln_A + \mu \ln_h + \mu \ln_\phi + \mu \ln_{(1-Swc)} + \mu \ln_{RF} - \mu \ln_{Bg} \qquad \textbf{(A.8)}$$

Then, variance calculated using AUPM:

$$\sigma^2_{\ln f} = \sum_{i=1}^{M} \sigma^2_{\ln Xi} + 2\sum_{i=1}^{M-1} \sum_{j=i+1}^{M} \rho_{\ln Xi.\ln xj} \cdot \sigma_{\ln xi} \cdot \sigma_{\ln xj} \quad \textbf{(A.9)}$$

where, the term after the plus sign stands for the correlation between input pairs. As for the special case without correlation between inputs:

$$\sigma^2_{\ln f} = \sum_{i=1}^{M} \sigma^2_{\ln Xi} \quad \textbf{(A.10)}$$

By looking at the above equations, only mean (μ) and variance (σ^2) values needed to apply AUPM method, contrary to the MCM, in which probability distribution type also needed. Three common probability density function (PDF) types are given in Figure 140.

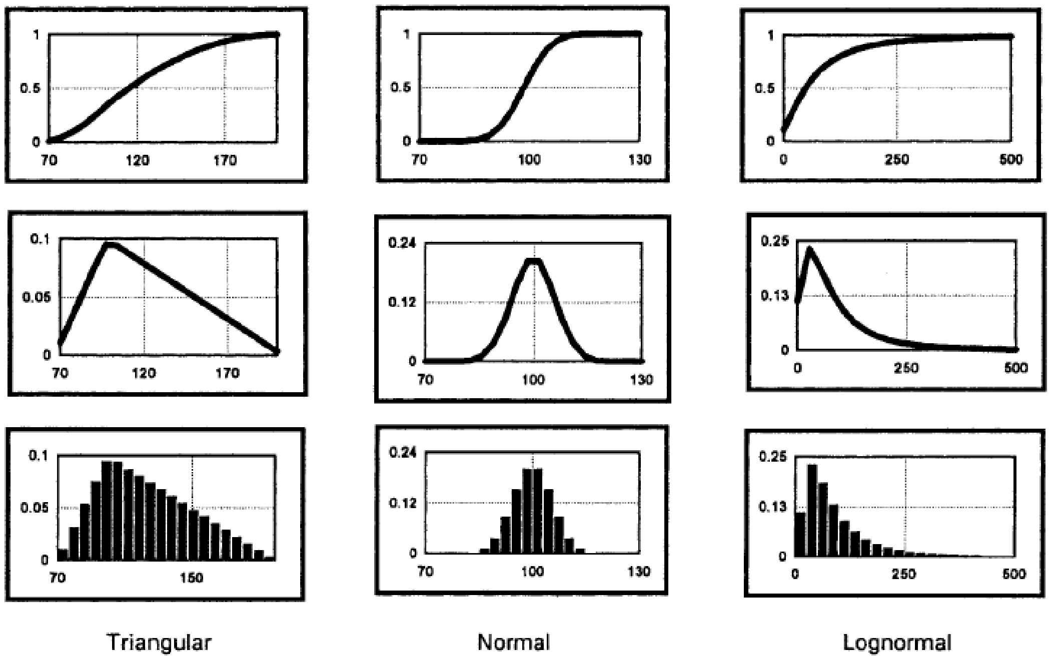

Figure 140 – Three Common Distribution Types (Rows: 1st CDF, 2nd PDF and 3rd Histogram) (after Murtha 1993).

Now let us look at the calculation of mean and variance values if there is not enough number of samples. Here, we assume the distribution of variables in *RGIP* and *ROIP* calculations are Triangular, which is the most basic distribution type (Figure 141).

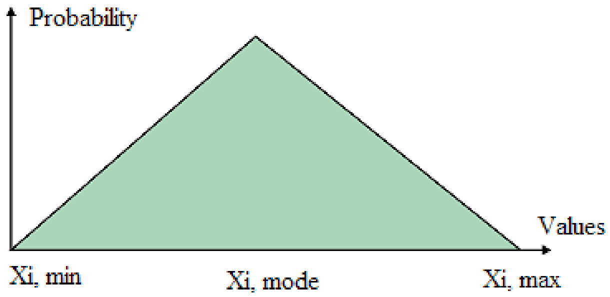

Figure 141 – The Most Basic Distribution Type

$$\mu_{xi} = \frac{Min + Max + Mode}{3} \tag{A.11}$$

$$\sigma_{xi}^2 = \frac{(Min)^2 + (Max)^2 + (Mode)^2}{18} - \frac{(Min \times Max + Min \times Mode + Max \times Mode)}{18} \tag{A.12}$$

In order to use Equations A.8 to A.10, μ_{Xi} and σ_{Xi}^2 should be converted to $\mu_{\ln Xi}$ and $\sigma_{\ln Xi}^2$ by following formulations:

$$\mu_{\ln xi} = \ln \mu_{Xi} - \frac{1}{2}\ln\left(1 + \frac{\sigma_{Xi}^2}{\mu_{Xi}^2}\right) \tag{A.13}$$

$$\sigma_{\ln Xi}^2 = \ln\left(1 + \frac{\sigma_{Xi}^2}{\mu_X^2}\right) \tag{A.14}$$

Then, P10, P50 and P90 values are calculated by AUPM. Notice that, here $\ln f$ is normal hence f is log-normal and f represents *RGIP/ROIP* functions.

$$P_{10} = \exp\left(\mu_{\ln f} - 1.28 \cdot \sigma_{\ln f}\right) \tag{A.15}$$

$$P_{90} = \exp\left(\mu_{\ln f} + 1.28 \cdot \sigma_{\ln f}\right) \tag{A.16}$$

$$P_{50} = \sqrt{P_{10}.P_{90}} \tag{A.17}$$

Recalling that, $\sigma_{\ln f} = \sqrt{\sigma^2_{\ln f}}$ equation holds.

As for the mean and variance values;

$$\mu_f = \exp\left(\mu_{\ln f} + \frac{\sigma^2_{\ln f}}{2}\right) \qquad \textbf{(A.18)}$$

$$\sigma^2_f = \mu^2_f \cdot \left[\exp\left(\sigma^2_{\ln f}\right) - 1\right] \qquad \textbf{(A.19)}$$

The uncertainty contributions of each input variables to total uncertainty can also be calculated by UPC approach. Equations A.20 to A.22 are used to calculate UPC's with correlations in input pairs and without any correlation.

$$\sum_{i=1}^{M} UPC_i + \sum_{i=1}^{M-1} \sum_{j=i+1}^{M} UPC_{ij} = 1 \qquad \textbf{(A.20)}$$

$$UPC_i = \frac{\sigma^2_{\ln Xi}}{\sigma^2_{\ln f}} \qquad \textbf{(A.21)}$$

$$UPC_{ij} = 2 \cdot \frac{\sigma_{\ln Xi \cdot} \sigma_{\ln Xi \cdot}}{\sigma^2_{\ln f}} \cdot \rho_{\ln Xi . \ln Xj} \qquad \textbf{(A.22)}$$

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