VOLUMETRIC CALCULATIONS AND ECONOMIC ANALYSIS OF GAS IN OFFSHORE BLOCK 4, LEBANON

A THESIS SUBMITTED TO THE GRADUATE SCHOOL OF APPLIED SCIENCE OF NEAR EAST UNIVERSITY

By
MOHAMAD QADI

In Partial Fulfillment of the Requirements for the Degree of Masters of Science in Petroleum and Natural Gas Engineering

NICOSIA, 2019

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Approval of Director of Graduate School of

Applied Sciences

Prof. Dr. Nadire ÇAVUŞ

We certify that this thesis is satisfactory for the award of the degree of Masters of Science in Petroleum and Natural Gas Engineering

Examining Committee in Charge:

Prof. Dr. Salih Saner	Committee Chairman, Petroleum and Natural Gas Engineering, METU NCC
Prof. Dr. Cavit Atalar	Supervisor, Petroleum and Natural Gas Engineering Department, NEU
Assist.Prof. Dr. Tuna Eren	Petroleum and Natural Gas Engineering Department, İKÇÜ
Assist. Prof. Dr. Serhat Canbolat	Petroleum and Natural Gas Engineering Department, NEU
Dr. Burak Kulga	Co-Supervisor, Petroleum and Natural Gas Engineering Department, NEU

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Name, Last name:

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ACKNOWLEDGMENTS

Thesis is like a bridge between theoretical and practical working. With this willing I joined this particular thesis. First, I would like to thank the supreme power the Almighty Allah who is obviously the one that has always guided me to work on the right path of life. Without Allah's grace, this thesis could not become a reality.

Next to Allah are my parents, whom I am greatly indebted for my brought up with love and encouragement to this stage. I am feeling oblige in taking the opportunity to sincerely thank my supervisor Prof. Dr. Cavit Atalar (Head of Petroleum and Natural Gas Engineering Department) and special thanks to my co-supervisor Dr. Burak Kulga.

Moreover, I am highly obliged in taking the opportunity to sincerely thanks to all the staff members of petroleum and natural gas engineering department for their generous attitude and friendly behavior.

At last but not the least, I am thankful to all my lecturers and friends who have been always helping and encouraging me throughout the year. I have no valuable words to express my thanks, but my heart is still full of the favors received from every person.

To my family…

ABSTRACT

Natural gas is increasing in significance as clean source of energy. The Eastern Mediterranean region has significant amount of natural gas. Countries like Egypt started gas production while Cyprus and Israel on their way. However, Lebanon and Syria are on progress to explore and discover the gas. In this thesis, the aim is to calculate the reserves of gas in offshore Block 4, in Lebanon.

Lebanon opened two blocks in its Exclusive Economic Zone for drilling and development of its offshore gas fields. In the first part of the study, Monte Carlo simulation technique was utilized to calculate the natural gas in place. Normal distribution function and probability distribution curve are applied in the simulations. Then, many scenarios have been considered, and probability distributions such as P10, P50, and P90 of the reserves are found in each of the reservoirs.

In the following section of the study, a decline analysis curve was plotted using Arp’s equation to estimate the gas production profile of the field for 10 years. In addition, economic studies made on Reservoir A, which has an estimation of 1.04 Tcf of natural gas in place. Three plans are considered to be applied on it. In the last plan, we drilled 5 wells which we can reach to all the reserves and it was the best scenario with highest net present value.

In the last part, some challenges in the oil sector in Lebanon are discussed. Moreover, it showed Lebanon’s plan to export or import gas options. The priority for the government is to use the natural gas initially in domestic demand, instead of fuel oil in power generation. Gas can be exported through pipelines and LNG if sufficient amount of gas exists.

Keywords: Reserves estimation; Monte Carlo simulation; probability distribution; NPV analysis

ÖZET

Temiz bir enerji kaynağı olan doğal gazın önemi giderek artmaktadır. Doğu Akdeniz bölgesi önemli miktarda doğalgaza sahiptir. Mısır, Kıbrıs ve İsrail gibi ülkeler gaz üretmeye başlamıştır. Ancak, Lübnan ve Suriye doğal gaz kaynaklarını araştırmak ve keşfetmek için çalışmalarına devam etmektedir. Bu çalışmada, Lübnan'da bulunan Blok-4 offshore gaz sahasındaki rezervlerin hesaplanması amaçlanmaktadır.

Lübnan sondaj ve saha geliştirme için Özel Ekonomik Bölgesi adı altında iki lisansta çalışmalara başlamıştır. Bu tezde, Monte Carlo simülasyon tekniği mevcut doğal gazı hesaplamak için kullanılmıştır. Simülasyonda normal dağılım fonksiyonu ve olasılık dağılım eğrisi uygulanmıştır. Daha sonra, her rezervuarlardaki olası P10, P50 ve P90 değerleri dikkate alınmıştır.

Ayrıca, gaz üretim profilini tahmin edebilmek için Arp denklemi kullanılmış ve 10 yıllık üretim düşüş analizi eğrileri incelenmiştir. Ek olarak, 1.04 tcf yerinde doğalgaza sahip olan Rezervuar A üzerinde üç farklı ekonomik analiz yapılmıştır. Ancak, son plan en yüksek net bugünkü değeri olan en iyisiydi.

Çalışmanın son kısmında, Lübnan'daki petrol sektöründe bazı zorluklar tartışılmıştır. Ayrıca, Lübnan gazının ihraç veya ithal etme olasılıkları gösterilmiştir. Hükümetin önceliği, iç talepte fueloil ile elektrik üretimi yerine üretilecek doğal gaz ile elektrik üretimi yapmaktır. Ardından, eğer yeterli miktarda gaz mevcutsa, çevre ülkelere boru hatları veya LNG yoluyla ihraç edilebilir.

Anahtar Kelimeler: Reserv tahmini; Monte Carlo simulasyonu; olasılık dağılım; NPV analiz

TABLE OF CONTENTS

ACKNOWLEDGMENTS ii

ABSTRACT iv

ÖZET v

LIST OF TABLES viii

LIST OF FIGURES ix

CHAPTER 1: INTRODUCTION

1.1 World’s Natural Gas Resources 1

1.2 World’s Natural Gas Consumption 2

1.3 Middle East Potential of Natural Gas 3

1.4 Fundamentals of Natural Gas 5

1.5 Forming of Natural Gas 5

1.6 Natural Gas Classifications 6

1.7 Natural Gas Specification 7

1.8 Natural Gas Field Development 7

1.8.1 Natural gas well drilling 8

1.8.2 Subsea manifold, templates, and flow lines 8

1.8.3 Production facilities 9

1.8.4 Transport infrastructure 11

1.8.5 Energy infrastructure 12

CHAPTER 2: EASTERN MEDITERRANEAN POTENTIAL

2.1 History of Natural Gas Resources 13

2.2 Hydrocarbon Resources 14

2.3 Lebanon’s Hydrocarbon Potential 16

2.3.1 Seismic survey 17

2.3.2 Laws 18
2.3.3 1st Round license 18

CHAPTER 3: METHODOLOGY
3.1 Uncertainties in Oil and Gas 22
3.2 Monte Carlo Simulation 23
3.3 Available Data 26

CHAPTER 4: RESULTS AND DISCUSSIONS
4.1 Results 30
4.2 Discussions 44

CHAPTER 5: PRODUCTION PROFILE OF THE FIELD
5.1 Decline Curve Analysis: 45

CHAPTER 6: ECONOMICAL ANALYSIS
6.1 Economical Parameters 49
6.2 Economical Analysis for Plan A 51
6.3 Economical Analysis for Plan B 52
6.4 Economical Analysis for Plan C 54
6.5 Lebanon's Domestic Gas Demand and Interim Gas Import Options 55

CHAPTER 7: CONCLUSIONS AND RECOMMENDATIONS
7.1 Conclusions 57
7.2 Recommendations 57

REFERENCES 58

LIST OF TABLES

Table 3.1: Data of Reservoir A 28
Table 3.2: Data of reservoir B 28
Table 3.3: Data of reservoir C 28
Table 3.4: Ranges of the given parameters of Reservoir A in English units 29
Table 3.5: Ranges of the given parameters of Reservoir B in English units 29
Table 3.6: Ranges of the given parameters of Reservoir C in English units 29
Table 4.1: Probable reserves in Reservoir A 31
Table 4.2: Probable reserves in Reservoir B 33
Table 4.3: Probable reserves in Reservoir C 35
Table 4.4: Probable reserves in Reservoir A and B 37
Table 4.5: Probable reserves in Reservoir A and C 39
Table 4.6: Probable reserves in Reservoir B and C 41
Table 4.7: Probable reserves in Reservoir A, B, and C 43
Table 6.1: Economic analysis for Plan A 51
Table 6.2: Economic analysis for Plan B 53
Table 6.3: Economic analysis for Plan C 54

LIST OF FIGURES

Figure 1.1: Distribution of proved reserves in 2017 ... 2
Figure 1.2: Distribution of worldwide consumption of natural gas ... 3
Figure 1.3: Natural gas production (Tcf) of countries in the Middle East ... 4
Figure 1.4: Consumption of natural gas (Tcf) of countries in the Middle East ... 4
Figure 1.5: Fixed Platform, Statoil, Gullfaks ... 10
Figure 1.6: Ultra-Deepwater floating platforms in the US Gulf of Mexico, Shell ... 11
Figure 2.1: Eastern Mediterranean’s natural resources ... 15
Figure 2.2: Petroleum exploration in Lebanon ... 17
Figure 2.3: Lebanon’s first offshore licensing round ... 19
Figure 3.1: Random versus systematic error illustration ... 21
Figure 3.2: Common distribution functions ... 24
Figure 3.3: Cumulative distribution function ... 25
Figure 3.4: Blocks win in the first offshore round license ... 26
Figure 4.1: OGIP distribution of Reservoir A ... 30
Figure 4.2: Cumulative probability distribution of OGIP in Reservoir A ... 31
Figure 4.3: OGIP distribution of Reservoir B ... 32
Figure 4.4: Cumulative probability distribution of OGIP in Reservoir B ... 33
Figure 4.5: OGIP distribution of Reservoir C ... 34
Figure 4.6: Cumulative probability distribution of OGIP in Reservoir C ... 35
Figure 4.7: OGIP distribution of Reservoir A and B ... 36
Figure 4.8: Cumulative probability distribution of OGIP in Reservoirs A and B ... 37
Figure 4.9: OGIP distribution of Reservoir A and C ... 38
Figure 4.10: Cumulative probability distribution of OGIP in Reservoirs A and C ... 39
Figure 4.11: OGIP distribution of Reservoir B and C ... 40
Figure 4.12: Cumulative probability distribution of OGIP in Reservoirs B and C ... 41
Figure 4.13: OGIP distribution of Reservoirs A, B, and C ... 42
Figure 4.14: Cumulative probability distribution of OGIP in Reservoirs A and B and C ... 43
Figure 5.1: Decline curve analysis ... 47
Figure 5.2: Cumulative gas production after 10 years ... 48

Figure 6.1: NPV analysis curve for Plan A 52
Figure 6.2: NPV analysis curve for Plan B... 53
Figure 6.3: NPV analysis curve for Plan C... 55

CHAPTER 1

INTRODUCTION

Natural gas is a significant factor of the world's supply of energy. It is one of the safest, cleanest, and most valuable of all energy sources. Natural gas is a mixture of hydrocarbon gases, but formed primarily of methane and other gases like ethane, propane, butane, etc.

Natural gas exists under pressure in rock reservoirs underground. There are two mechanisms of formation, biogenic and thermogenic natural gas. In addition, it is classified into three categories; associated, non-associated, and unconventional gas. These are according to the type of the reservoir. After finding significant amount of natural gas, now we start developing the field. Many decisions have made to start with drilling and completing the wells. Then, subsea production infrastructures are installed, like manifolds, templates, and flow lines.

1.1 World's Natural Gas Resources

Natural gas resources usually categorized according to the properties of the reservoir in which they are trapped (ETI, 2011). Resources referred to as conventional and unconventional. Conventional resources accumulate in a reservoir depend on its porosity and permeability characteristics together with the reservoir pressure, allow the natural gas to flow into the wellbore. However, unconventional resources have low permeability and the fluid in the reservoir cannot flow under normal circumstances (ETI, 2011).

Coalbed methane, Shale oil and gas, tight gas reservoir, and methane hydrates are examples of unconventional reservoirs (ETI, 2011). Such reservoirs have low recovery due to the lack of permeability and the complex structure in the reservoir, so we need new technology. There are two technologies applied to exploit the unconventional resources, hydraulic fracturing and horizontal drilling. Geologists and engineers increase the recovery rate of such reservoirs that have large reserves (ETI, 2011).

Enhancements in exploration and production technology permitted the growth of proved natural gas reserves in the last period specifically from unconventional sources. At the end of 2017, 6831.7 Tcf of proved natural gas reserves of the world was reported. Figure 1.1 shows that the majority these reserves are in the Middle East and Russia, with 2794.2 Tcf and 1234.9 Tcf respectively (BP, 2017).

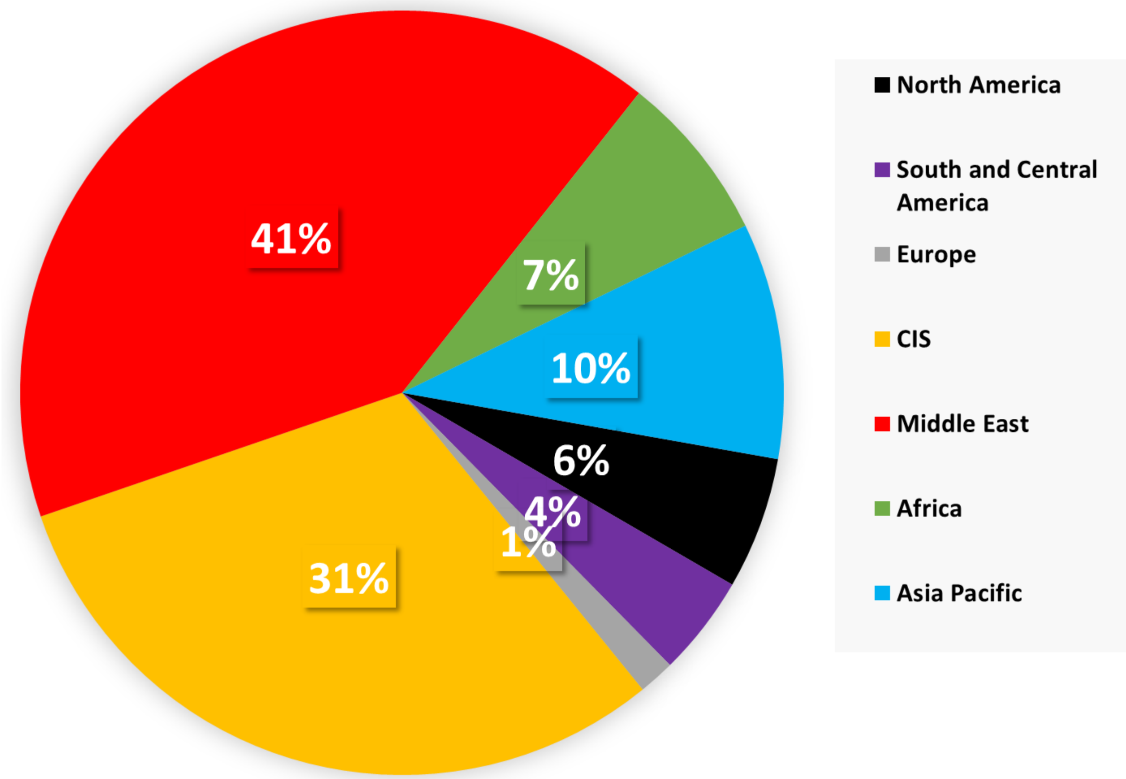

Figure 1.1: Distribution of proved reserves in 2017 (BP, 2017)

1.2 World's Natural Gas Consumption

Natural gas stays a vital fuel in the industrial and electric power sector. In power sector, the fuel efficiency of the natural gas has been a suitable choice for new generating plants (BP, 2017). Authorities begin applying national plans to diminish carbon dioxide emissions, so natural gas is the best choice since it burns cleaner than coal and petroleum products. Figure 1.2 shows the consumption of natural gas worldwide in 2017, around 130 trillion cubic feet (tcf) (BP, 2017). Developed and industrial countries consume the most natural gas in the world, such as US, Canada, Germany, Japan, China… (BP, 2017). Consumption of natural gas internationally expected to rise from 120 Tcf in 2012 to 202 Tcf in 2040, according to the International Energy Outlook 2016 (EIA, 2016).

World utilization of natural gas for electric power zone rises by 2.2% per year, and the natural gas consumption for manufacturing uses growths with an average 1.7% per year, from 2012 to 2040. The electric power section and the manufacturing uses together consist of 73% of the total rise in world natural gas consumption. (EIA, 2016)

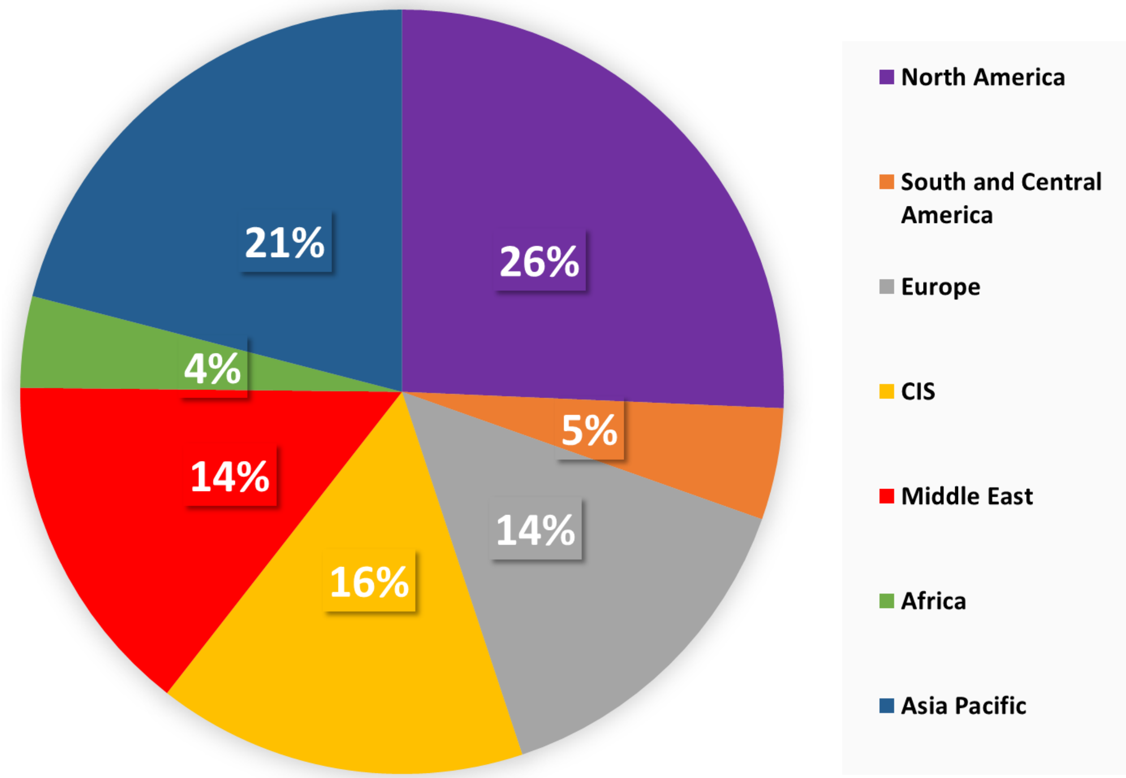

Figure 1.2: Distribution of worldwide consumption of natural gas (BP, 2017)

1.3 Middle East Potential of Natural Gas

Iran, Qatar, and Saudi Arabia are the main natural gas producers in the Middle East. In 2012, they produced 76% of natural gas in their region (Figure 1.3). Moreover, they have 40% of the world's proved natural gas reserves and around 20% of the rise in the world natural gas production, from 19 Tcf in 2012 to 36 Tcf in 2040 (EIA, 2016).

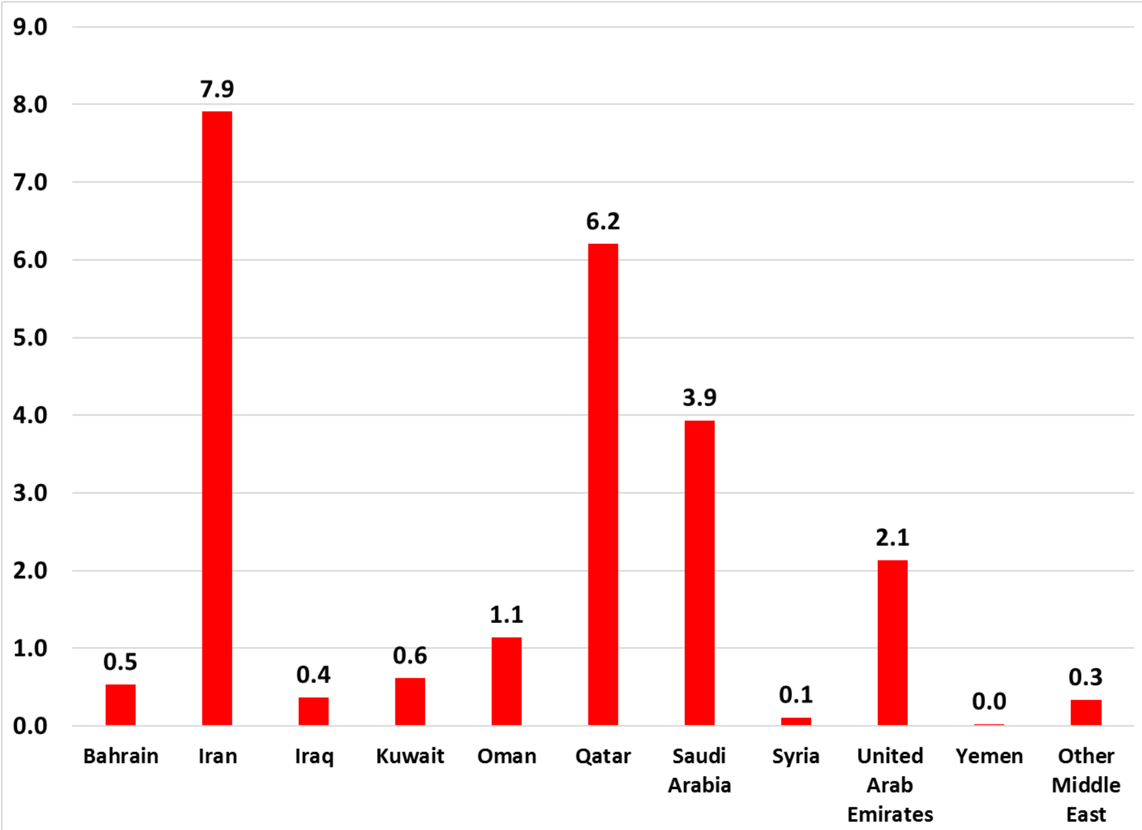

Figure 1.3: Natural gas production (Tcf) of countries in the Middle East (BP, 2017)

In the Middle East area, half of total energy utilization in 2012 in natural gas have been accounted be Middle East (Figure 1.4). Their natural gas utilization rises by an average 2.5% per year from 2012 to 2040, especially in the manufacturing sector, according to International Energy Outlook 2016. Iran, Saudi Arabia, and United Arab Emirates leads the utilization of natural gas in the Middle East region, due to their investment in military, industrial, and power sector…

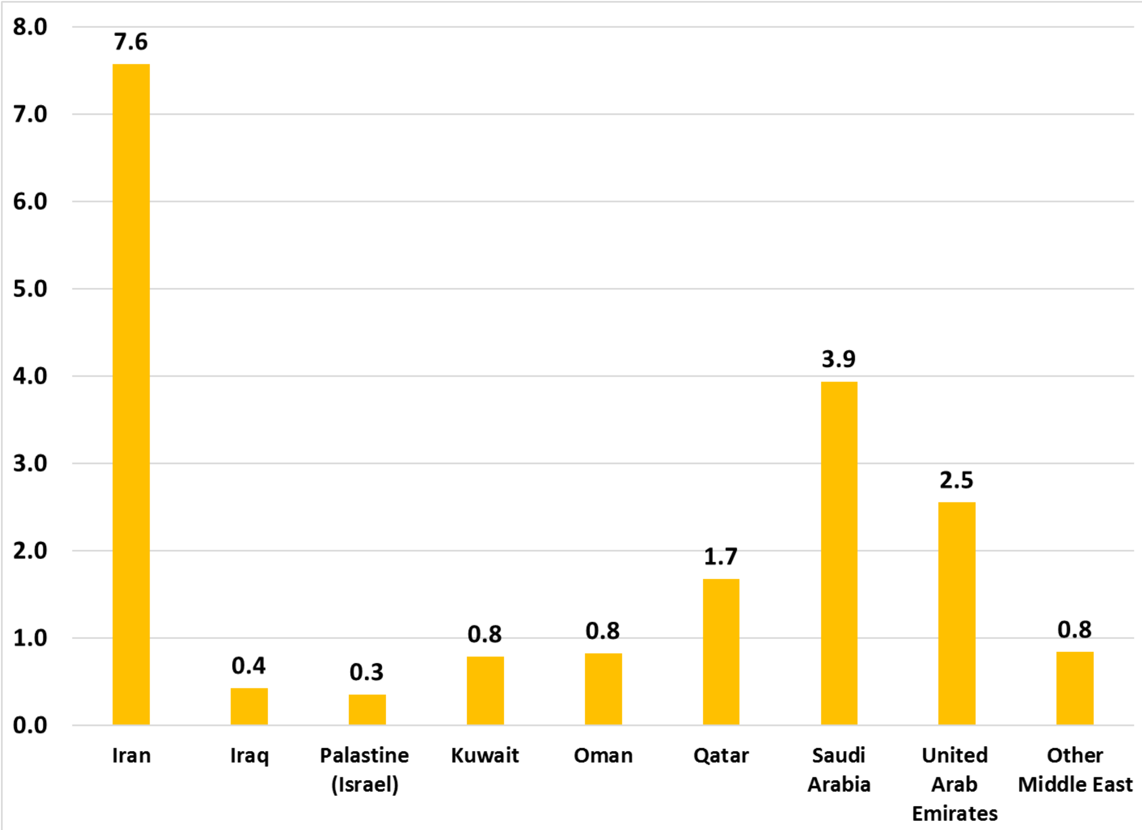

Figure 1.4: Consumption of natural gas (Tcf) of countries in the Middle East (BP, 2017)

1.4 Fundamentals of Natural Gas

Natural gas is an odorless combination of light hydrocarbons; it defined as gas gotten from natural reservoir (Mokhatab, 2006). It contains significant amount of methane together with heavier hydrocarbons. Moreover, in the raw condition it contains a large quantity of non-hydrocarbons, such as nitrogen, hydrogen sulphide and CO_2. It is generally saturated with water (Mokhatab, 2006).

The behavior of natural gas is various due to the changes pressure and temperature (Mokhatab, 2006). A graph called phase envelope defines the phase of the natural gas component at a given pressure and temperature. There are two properties linked to it, needed to be mentioned (Mokhatab, 2006).

Cricondenbar pressure and cricindentherm temperature are related to the phase envelope. Cricondenbar is the maximum pressure above which no gas can be formed. Cricondentherm is the maximum temperature above which no gas can be formed (Mokhatab, 2006).

1.5 Forming of Natural Gas

Natural gas exists under pressure and temperature in reservoirs underground. It dissolves in heavier hydrocarbons and water or occurs by itself. The same as crude oil, natural gas is also produced from the reservoir. Natural gas has been made through degradation of organic matter gathered millions of years ago.

There are two mechanisms for forming natural gas. Biogenic gas made by bacterial breakdown of organic substances. Thermogenic gas made by heat cracking of the organic matters. (Rojey, 1997)

Because natural gas and oil are found with water, and because they are less dense, they would rise vertically, including all the way to the atmosphere. Much has escaped over time and continues escaping recently (Wang, 2009). However, if a vertical barrier is encountered as cap rock, it stops the migration and confines gas-in-place. Therefore, for natural gas to accumulate, three things have to be present: the source rock for the creation of natural gas; the porous media to accommodate the created gas; and the impermeable rock on top to trap the gas inside the porous reservoir (Wang, 2009).

1.6 Natural Gas Classifications

Natural gas are extracted from geological formations. It is categorized into three categories: non-associated gas, associated gas, and unconventional gas.

- Non-associated gas: These are reservoirs that contain almost entirely natural gas at reservoir conditions (Mokhatab, 2006). They mostly found at greater depths. If the fluid at the surface remains gas, then it is called "dry gas." If the surface pressures cause some liquid hydrocarbons to evolve, it is called a "wet gas" reservoir (Mokhatab, 2006).

- Associated gas: during production phase, the reservoir starts losing its pressure. Some associated gas comes out from crude oil as the pressure still reduced on the way and on the surface (Mokhatab, 2006). Good reservoir management is necessary to prevent such gas from coming out of the oil solution. Therefore, we can increase the recovery of oil production and maintain the pressure inside the reservoir (Mokhatab, 2006).

- Unconventional gas: The term unconventional gas is widely used, but it refers more to the geological setting and rock type rather than to the gas itself, which is nearly all methane (Wang, 2009). The most common, "tight gas", formed in sandstones or carbonates, refers to low-permeability formations with permeabilities less than 1 md and often as low as 0.001 md. In such "tight" reservoirs, it is essentially not possible for much of the gas to flow naturally (Wang, 2009). Coalbed methane (CBM) refers to methane gas that is found adsorbed in many buried coalbed deposits. Finally, shale gas is gas found in organic shale rocks, which exist in relative abundance in the United States. Because these reservoirs have virtually no permeability, the choice of well completions has been horizontal wells with multiple hydraulic fractures (Wang, 2009).

1.7 Natural Gas Specification

Natural gas is distributed into sweet and sour gas. They are classified according to the content of H_2S and CO_2 in it. Sour gas has a high content of these components. Treating of natural gas should be applied to meet some specification that may differ liable on which part the treating is applied (Gas, 2018).

Transport of natural gas is very dangerous. Water and sour gas content qualifications are essential to confirm safe and consistent transport of natural gas from an offshore production facility to a treating plant (Mokhatab, 2006).

Water dew point will allow us to avoid the droplet of water in the natural gas pipeline. The water content must be low enough during worst conditions (Mokhatab, 2006). This is at high pressure and low temperature can occur if the export pipeline is puffed down (Mokhatab, 2006).

It is vital to avoid liquid dropout in pipelines for several reasons. The formation of hydrates, corrosion problems and effective complications leading to safety risk may be happened (Mokhatab, 2006).

The processing of sour gas depends on two factors. First, sour gas contains high concentrations of hydrogen sulphide and carbon dioxide, which may corrode the pipelines and production facilities (Mokhatab, 2006). Second, sour gas should pass by processing plants to change into sweet gas. Then, it meets the sales specifications (Mokhatab, 2006).

1.8 Natural Gas Field Development

After an oil company discovers a natural gas field, the next step is to find the best method to develop it. Many decisions have to be made, and all of them will affect the outcome of each other. It is important to look upon the development as an entire task, so we can make optimization and operations research an interesting implement to find a good result for the whole natural gas field development problem. The next subsections will summary unlike parts of a natural gas field development.

1.8.1 Natural gas well drilling

Drilling is one of the most important and complex operations in the oil and gas industry. It involves a lot of equipment (drill bits and pipes/strings, casings), fluids (drilling fluids/muds, completion fluids, cement slurries, formation fluid), and movements (equipment movement, fluids and solids/rock cutting movement, and circulation). The drilling process can be operated in a drilling rig that contains all the necessary equipment (Wang, 2009).

The objectives of drilling are to reach the target zone with minimum cost and time, to deliver a usable and stable borehole for further completion and production, to minimize pay zone damage and fluid invasion; and, of course, to ensure all personnel are safe, no contamination to the fresh water, and no (or minimum) damage to the environment. (Devereux, 1998)

Several unique problems affect the drilling of natural gas wells (Wang, 2009).

- There could be a need for higher-grade casing because of the occasional need for higher burst rating in gas wells (Wang, 2009).
- When using oil based drilling fluids, gas solubility could be a problem. Oil based systems can partially mask the existence of a gas kick, thereby creating well control situations in gas wells (Wang, 2009).
- Although not exclusive to gas wells, but more likely to occur, when the reservoir fluid is associated with corrosive gases, such as H_2S and CO_2, there would be increase demands from the casing selection, using corrosion resistant alloys (Wang, 2009).
- Although all industry well control schools stress that to handle well control issues in gas wells is similar to oil wells, the wellhead equipment (blowout preventer or BOP, flanges, connections, etc.) could require higher premium products on some gas wells because of higher wellhead pressures and leak potential (Wang, 2009).

1.8.2 Subsea manifold, templates, and flow lines

The offshore exploration of hydrocarbon are increasing. Many fields are developed as subsea field developments. Many conditions specify the plan of whether to use subsea equipment or not. The wells drilled from a stable platform can be linked directly to the production facility without the need for any apparatus (Graham, 2008). For small fields, the under-sea developments formed with a particular satellite well and linked to the production facilities with a chain of pipelines and umbilical (Graham, 2008).

However, large fields with several drilled wells need other alternatives to develop the subsea equipment (Graham, 2008). An underwater manifold system is recommended to use. Each well or template are connected to this manifold which is then tangled back to the production facility with a single set of pipelines (Graham, 2008). This solution will save expenditures on flow lines and umbilical that would be required.

Flow lines are also essential to bring several chemicals to inject in the natural gas flow (Graham, 2008). For instance, monoethyleneglycol (MEG) to dodge the formation of hydrates that would then chunk the flow of gas in the pipes.

1.8.3 Production facilities

Natural gas undergoes many treatments to meet transport and sales specification. Some processing occurs on the production facility. The choice of suitable production platform depends on water depth, distance to shore, and current adjacent production substructure. Production platforms can be distributed into two focal sorts: fixed and floating platform.

Fixed Platform consists of a tall vertical section reinforced by piles fixed in the seabed (Figure 1.5). On the top, it has a deck, a drilling rig, and production facilities. The stable platform considered economically feasible for fitting in water depths up to 1500 feet (API, 2018).

Figure 1.5: Fixed Platform, Statoil, Gullfaks (Gullfaks, 2014)

- Compliant Tower involves a narrow, bendable tower, and piles fixed in the seabed. The piles can maintain a deck for drilling and production processes. It resist large lateral forces by supporting major lateral deflections. It is used for water depths between 1000 and 2000 feet (API, 2018).

- SPAR Platform (SPAR) consists of a large diameter particular vertical cylinder reinforcing a deck. It has on the top a surface deck with drilling and production apparatus like typical fixed platform, three kinds of risers, and a hull that is tied using a rigid catenary system of six to twenty lines, fastened into the seafloor. SPAR's are used in water depths up to 3000 feet, although current technology can extend its use to water depths as great as 7500 feet (API, 2018).

- Floating Production System (FPS) comprises of a semi-submersible unit, which is prepared with drilling and production tools (Figure 1.6). It is attached with wire rope and chain, or can be dynamically located using rotating thrusters. Production risers are designed to transport hydrocarbons from subsea wells to the surface deck. The floating production system can be used in ultra-deep water (API, 2018).

Figure 1.6: Ultra-Deepwater floating platforms in the US Gulf of Mexico, Shell (Stephen Whitfield, 2018)

- Floating Production, Storage and Offloading System (FPSO) contains a large tanker type vessel fixed to the seafloor. An FPSO is considered to process and produce from adjacent subsea wells. Then, transfer the stored oil to a minor transport tanker. The transport tanker then transports the oil to aground facility for further treating. An FPSO may be suitable for economic fields located in distant deep-water areas where a pipeline infrastructure does not exist (API, 2018).

1.8.4 Transport infrastructure

After starting production, the distance from the field to the market will decide the choice of how to carry the gas. There are two ways for transportation of natural gas either through pipelines or as LNG (Johansen, 2011).

The transportation cost for LNG is identified to be higher than the transportation cost for short distances compared to pipeline transport (Johansen, 2011). Over a definite distance, LNG is the cheaper choice. If the natural gas field is large enough, or the capacity of the current pipeline system is too small for a long enough time, it will anyway be essential to build a new pipeline. Specialized pipeline placing vessels are used to do this (Johansen, 2011).

1.8.5 Energy infrastructure

The function of a production platform needs a lot of power. Many apparatus such as pumps and compressors consume very high power (Johansen, 2011). There are two ways to provide the platform with the necessary power. First, the platform generates its own power internally using the gas produced from the field and through gas turbines (Johansen, 2011). Second, the platform import electricity from onshore due to many reasons, weight restrictions, and emission of CO_2 and high natural gas prices (Johansen, 2011).

CHAPTER 2

EASTERN MEDITERRANEAN POTENTIAL

Recently major amounts of natural gas have been discovered offshore in the Eastern Mediterranean. Countries in the Levant Basin, like Lebanon, Syria, Egypt, Cyprus, and Israel, have big opportunity to increase their energy security and even export natural gas to other regions. According to the United States Geological Survey, there could be 122 trillion cubic feet of natural gas and 1.7 billion barrels of recoverable oil in the Levant Basin (USGS, 2011). Many fields have been discovered such as, Tamar, Leviathan, Aphrodite, Zohr.

Lebanon finished his first offshore license and signed a consortium with three international companies, Eni, Total, and Novatek to start developing Blocks 4 and 9 in the exclusive economic zone of Lebanon.

2.1 History of Natural Gas Resources

The development in the eastern Mediterranean's hydrocarbon sector began in Syria following the achievements in adjacent countries such as Saudi Arabia. In oil production, Syria has been more successful than Israel and Jordan. Syria became a natural gas producer after 1980 while Israel waited until mid-2000s (EIA, 2013).

Jordan depends on import of oil and gas due to the lack of hydrocarbon resources. Countries like Lebanon and Cyprus still in the beginning of oil exploration and development. On the other hand, they wish to benefit from an effective offshore exploration in the Levant Basin to improve national natural gas resources (EIA, 2013). The energy resources in the Eastern Mediterranean are positioned between the main supply countries in the Middle East and the major demand in Europe. Syria benefits from the transit fees paid by adjacent exporters like Iraq and Saudi Arabia. Unfortunately, these pipelines stopped working due to the wars in the region. Today, there is significant focus on exploration and new projects. As the area endures to discover and develop hydrocarbon resources, the pressure increases to find markets for gas sales (EIA, 2013).

2.2 Hydrocarbon Resources

Offshore exploratory activities have been started late in the East Mediterranean. Countries of Easter Mediterranean are still considered hydrocarbon-poor province, except Syria, which has significant amount of produced oil and natural gas for several decades (El-Katiri, 2014). Other countries depend on importing their completely domestic energy needs. The new offshore discoveries show significant amount of hydrocarbons, which allow Cyprus, Israel, Lebanon, and Palestine, change the picture of importing their energy (El-Katiri, 2014).

In Figure 2.1, large offshore area of the Eastern Mediterranean make the Levant Basin, which is the midpoint of new energy exploration in the region. According to the U.S. Geological Survey (USGS), the Levant Basin has probable undiscovered natural gas resources of 122 Tcf and undiscovered oil resources of 1.7 billion barrels (EIA, 2013).

Cyprus has been divided politically and territorially between the Greek Cypriot Republic of Cyprus and Turkish Republic of Northern Cyprus. Turkey and Turkish Cypriots refused to accept the Exclusive Economic Zone claims of the Greek Republic of Cyprus, without a plan of unification of the island (Ratner, 2016).

Noble Energy discovered the Aphrodite Field offshore of Cyprus in 2011. The field was appraised to have 4.5 Tcf of natural gas reserves. Another discovery 7 Tcf at Calypso in Block 6. Cyprus intend to develop the field and start exporting gas by 2019 (Ratner, 2016). The production of natural gas from the Aphrodite Field and usage of it domestically in Cyprus is difficult and cost a lot due to lack in the natural gas infrastructure. This would need the construction of both overland pipelines in Cyprus to transport the gas and power plants or manufacturing facilities that could use the gas (Ratner, 2016).

Cyprus has two solutions to export their natural gas, either transport the gas to the bordering countries or build an LNG export station to send gas to Europe (Today, 2018). Cyprus prefers to construct a pipeline joining Aphrodite to Egyptian LNG export terminals rather than constructing an LNG facility in Cyprus, since it is less expensive. Exporting gas from Aphrodite through Egypt would take benefit of Egypt’s underutilized Idku terminal (Today, 2018).

Cyprus finished its third licensing round for offshore exploration in July 2016. This newest round comprises blocks next to the Egyptian Zohr supergiant field and attracts the interest of some global companies (Service, 2016).

Israel has one of the East Mediterranean's most widespread exploration histories since 1950s. During the late 2000s, the picture of some isolated and small Israeli gas finds has been changed. Since the starting of 2009, Israel mentioned that it discovered many commercial gas fields such as Tamar Field that contains 9.7 Tcf (El-Katiri, 2014).

In 2010, "Israel" discovered a large field called Leviathan with 22 tcf of natural gas. This considered the largest discovery in the history of hydrocarbon exploration in Israel (Barden, 2013). Then many small discoveries occur with range between one and five Tcf, such as Dalit, Marya, Sara etc. all these fields positioned Israel as a well noticed of all Eastern Mediterranean countries in terms of gas reserves (Barden, 2013).

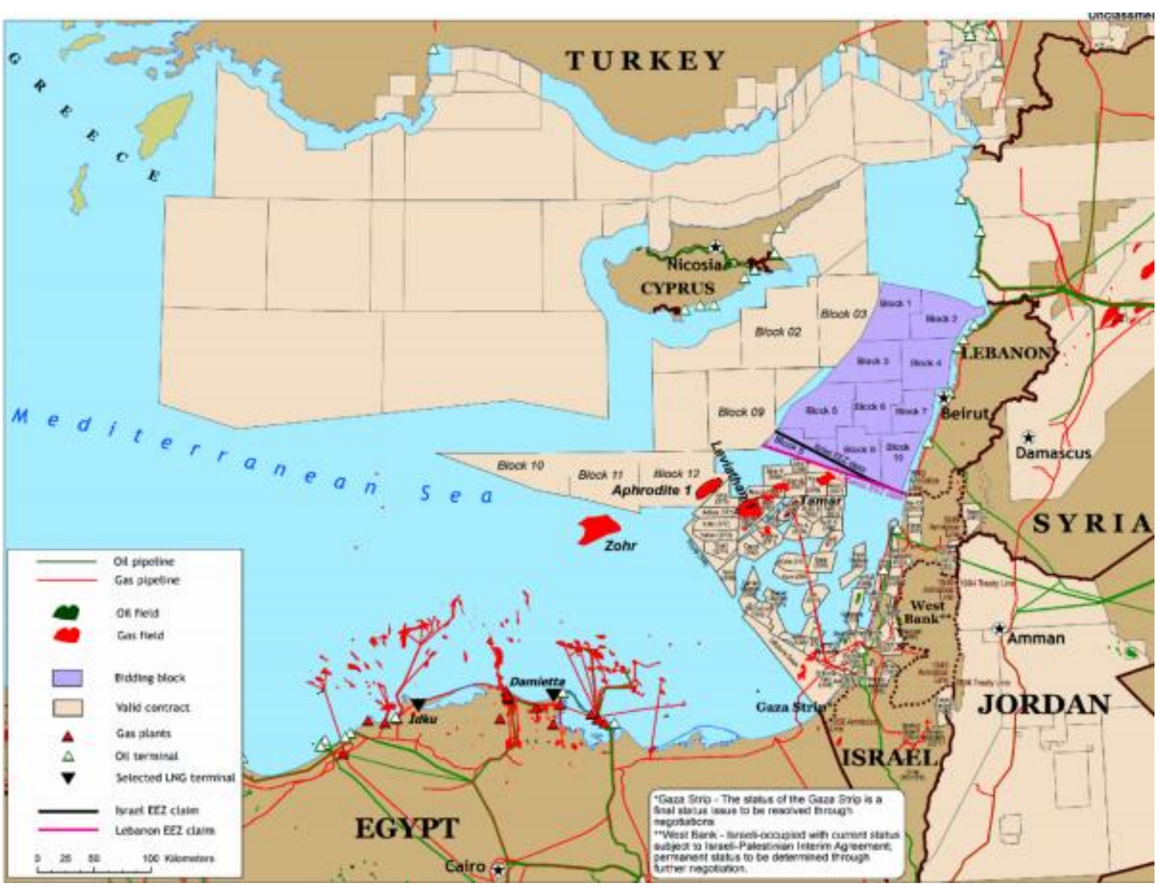

Figure 2.1: Eastern Mediterranean's natural resources (Ratner, 2016)

Syria is the most experienced gas producer in the Eastern Mediterranean. It has proven oil of 2.5 billion barrels and 8.5 Tcf natural gas reserves. Syria's production of natural resources allow it to have an energy self-sufficiency, also it exports oil to Turkey and Europe. Syria's civil war delayed the exploration in its offshore territories. As the war ended, Syria will start using their efforts to exploit its natural resources (El-Katiri, 2014).

The Palestinian Authority awarded a 25 years exploration license for the marine area off the Gaza Strip. British Gas Group and the Athens-based Consolidated Contractors Company held the license 90% and 10% respectively (Henderson, 2014). In 2000, BG discovered the Gaza Marine field about 36 Km offshore with 600 m seabed depth. In the same year, BG drilled another successful well to confirm the size of the field that is around 1 trillion cubic feet. However, due to the Arab-Israeli conflict the production from Gaza field was banned (Henderson, 2014).

Egypt's natural gas resources are distributed offshore in the Nile Delta or onshore in the Western Dessert. Recently, Eni Company discovered a giant natural gas field in the Mediterranean and Egypt authorities started production around 2 billion cubic feet in 2018 (Mohamed, 2018). Zohr Gas field is located 190 km north Egypt, in 100-km^2 area and 1450 m depth. It contains around 30 trillion cubic feet of natural gas. Zohr is expected to provide the Egyptian economy with an important increase estimated at $2.5 billion annually (Mohamed, 2018).

2.3 Lebanon's Hydrocarbon Potential

Lebanon is located on the dynamic north-west boundary of the Arabian plate; it is part of the grater Levant region. Latest exploration achievements in the Levant area have motivated the Lebanese government to promote a widespread 3D seismic data to support offshore exploration. Academic and engineering research associates interpreted the consequences of the seismic data to improve the understanding the formation of the Levant region (Ghalayini, 2018). The results of these studies includes:

- An original stratigraphic model for the Levant Basin created on seismic data, forward modelling, and wide fieldwork (Hawie, 2013).
- The interpretation of the new 3D seismic data of the Levant Basin gives more details about its structural framework and their boundary (Ghalayini, 2018).

- A detailed geochemical valuation of the mother rock potential provided an efficient appraisal of the hydrocarbon potential in Lebanon by sampling basin model (Bou Daher, 2016).
- An upgraded model of the crustal assembly of the Levant Basin established by deep seismic and gravity modelling (Inati, 2016).

2.3.1 Seismic survey

The exploration of hydrocarbon in Lebanon started in the 1930s. Two companies were the main in the exploration activity in the country. The CLP drilled the first well in 1947, and then more are drilled, but without any commercial success (Ghalayini, 2018). In 1970, the first offshore seismic data was developed by Oxoco off north Lebanon, and in 1971 Delta attained 320 km of 2D seismic lines in addition to a gravity survey on the Shaheen permit (Ghalayini, 2018).

Multi-Client seismic data is presented from Petroleum GeoServices (PGS) and Spectrum. Between 2008 and 2011, the PGS Lebanese Multi-Client 3D seismic data surveys covering 9700 km2 and linearly 9700 km of 2D seismic data between 2006 and 2012. Figure 2.2 shows the Spectrum Lebanese Multi-Client seismic datasets contains 3D seismic surveys covering 5,360 km² (2012-2013) and 2D seismic surveys covering 5,172 linear km (2000-2002). (LPA, 2018)

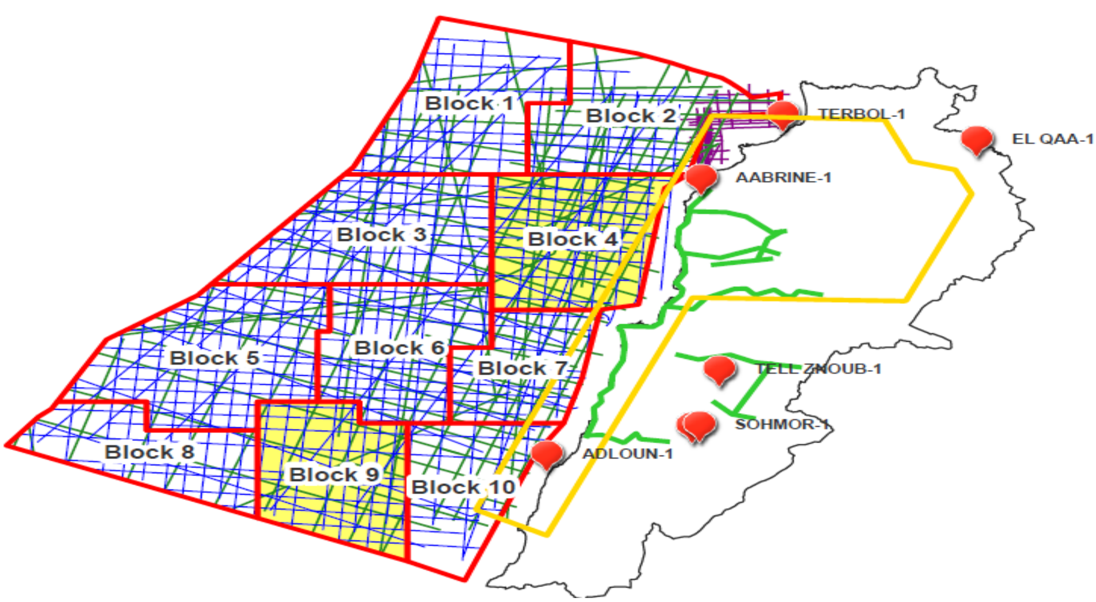

Figure 2.2: Petroleum exploration in Lebanon (LPA, 2018)

2.3.2 Laws

The Offshore Petroleum Resources Law (132/2010) that is accompanied by the Petroleum Activities Regulations (Decree 10289/2013) as well as other decrees, including the Model Contract Decree, the Environmental Strategic Assessment Decree, and the Block Delineation Decree, regulate petroleum activities within Lebanon's territorial waters and exclusive economic zone (Fayad, 2016).

The Lebanese Petroleum Administration was established in 2012, under the Offshore Petroleum Resources Law, Decree 7968/2012. The LPA is a dependent body and falls under the instruction of the Ministry of Energy and Water Resources (Fayad, 2016). It is responsible for the organization, monitoring, and supervision of petroleum activities, including the processing of licenses and the application of agreements. The administration consisted of six sections: planning; engineering; geophysics; legal affairs; finance; and HSE (Fayad, 2016).

In addition, the government regulated royalties, profit, and tax decree. All petroleum extracted from reservoirs placed within the state's waters has been entitled to royalties. The rights holders must pay royalties to the state equal to a flat percentage of 4% of the gas produced and a varying and sliding scale percentage of between 5% and 12% for crude oil based on monthly average daily production rate. Profit petroleum which is revenues remaining after the deduction of royalties and cost recovery, that is divided between the state and the rights holders (LPA, 2018). Law of taxation number 57/2017 specifies the income tax relevant to petroleum activities, and addresses requirements associated to the Right Holders Operator's shortage carry forward happening in one specific year to the following years (LPA, 2018).

2.3.3 1st Round license

On the 26th of January 2013, and based on the endorsement of the Lebanese Petroleum Administration, the Minister of Energy and Water "Cesar Abi Khalil" opens five blocks for bidding in the 1st offshore licensing round in Lebanon. The LPA had previously prepared a study driven by the following goals that the Lebanese Government purposes to attain during the first licensing round:

- Beating commercial discoveries that defend the required investments in infrastructure that will allow the authorities to exploit and develop the petroleum resources.

•	Protection the rights of Lebanon to benefit from its prospective petroleum resources over its complete exclusive economic zone (LPA, 2018).

First, fifty international companies registered concern, including several main oil companies, such as Total, ENI, Shell, Statoil, Chevron, and ExxonMobil. Forty-six companies were qualified, including 12 operators (Fattouh, 2015).

In Figure 2.3, a consortium of three international companies made a proposal to explore gas in naval blocks four and nine. The companies are Total SA (France), ENI International B.V. (Italy) and JSC NOVATEK (Russia). In turn, drilling activities in Blocks 4 and 9 will start in 2019 after the Consortium confirms the needed logistics and studies during 2018 (LPA, 2018).

Figure 2.3: Lebanon's first offshore licensing round (Gas, 2018)

Cesar Abi Khalil, Energy and Water Minister, asked the Lebanese Petroleum Administration to start preparing for the launch of a second round of offshore licensing for oil and gas companies (Star, 2018).

CHAPTER 3

METHODOLOGY

According to Webster's dictionary, uncertainty is "absence of sureness about someone or something. It may range from a falling short of certainty to an almost complete shortage of belief or knowledge especially about an outcome or result" (Webster, 2018). According to Schlumberger's oilfield glossary, uncertainty is "the degree to which a data set may be in error or stray from expected values. Sometimes measured in terms of variance or standard deviation, uncertainty exists in data because of a diversity of problems, such as deprived calibration or contamination or damage to rocks prior to measurement" (Schlumberger, 2018).

There are four basic categories of uncertainties:

- **Measurement Inaccuracy**: All oilfield measurements include some degree of error or inaccuracy. Poor calibration, human error in executing the measurement, or a fundamental level of inaccuracy of the instruments making the measurements are lead to such errors (Heather, 2001).

Figure 3.1 shows that random errors are basic measurement precision differences occur in the repeated trial in making the measurements. In the oilfield setting, random error is difficult to be determined since most measurements are only taken once. However, systematic errors, such as poor calibration, lead to answers that appear dependable, but they are partial in some direction away from the correct measurement (Heather, 2001).

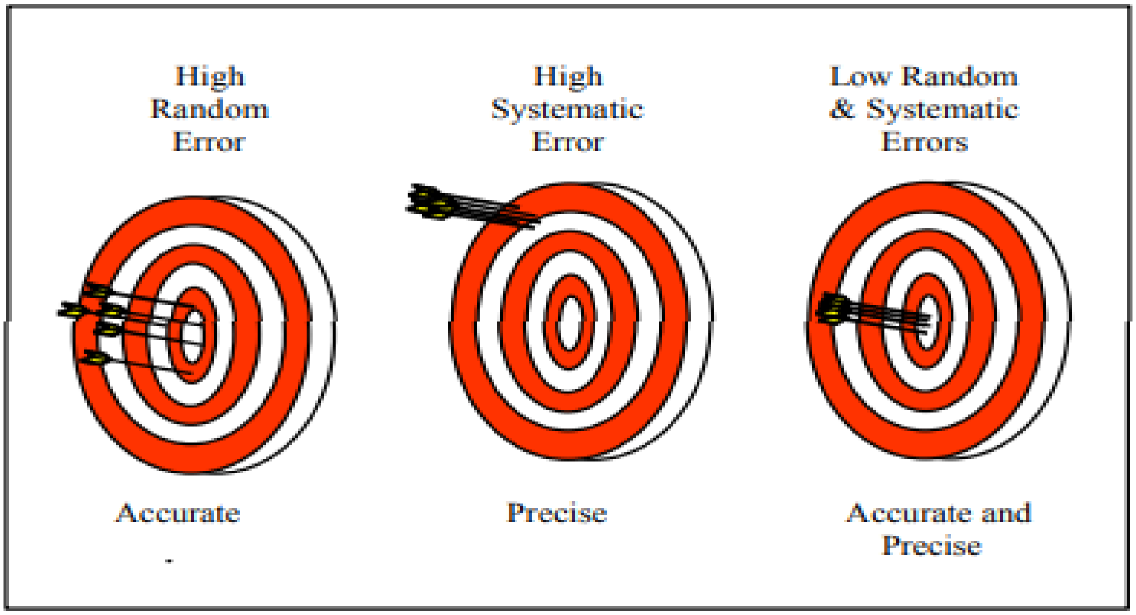

Figure 3.1: Random versus systematic error illustration (Heather, 2001)

- **Computational Approximation**: Formulas and correlations developed several years ago from empirical data and used in many computations performed in a reserves evaluation (Heather, 2001). A line or curve has been drawn for such correlations through experimental measurements. The degree of scatter and the range in the original data have been forgotten over time. The point is to show that parameters we regularly take for granted, are indeed simplified exemplifications of relatively complicated and scattered relationships. As such, this uncertainty must be tried and built into the analysis (Heather, 2001).
- **Incomplete data:** missing information occurs in almost every evaluation. To fill the gaps, criticism and reasonable expectations should be applied. The assumption will vary according to the experience and enthusiasm of every person (Heather, 2001).
- **Stochastic System:** at the technical level, engineers focus on their knowledge and then use the data available to calculate and estimate the missing. The fluctuation in price of oil and gas affected the volume of the produced reserves (Heather, 2001).

3.1 Uncertainties in Oil and Gas

The oil and gas industry faces many uncertainties related to many factors such as reserves estimation, production forecasting and pricing fluctuation. In the field of petroleum, we can distinguish between two types of uncertainties, underground and above ground uncertainties (Hdadou, 2014).

The underground uncertainties are related to the geological and engineering characteristics of a reservoir. However, fluctuations in prices, changes in demand and supply, changes in regulations, and variations in estimator's judgments are examples on the aboveground uncertainties (Hdadou, 2014). Infrastructure, production profile, quality of oil, functioning costs, reservoir characteristics are uncertainties occur at the development and production phase, the engineering parameters demonstrate a high level of doubts in relation to these critical variables. These uncertainties initiated from geological models and together with economic and engineering models involved high-risk choice scenarios, with no assurance of effectively discovering and developing hydrocarbons resources (Suslick, 2009).

- **Exploration risk analysis**

During the exploration stage, major uncertainties are related to volumes in place and economics. Initial total hydrocarbon in place is decomposed into proved, probable, and possible reserves (Suslick, 2009). These calculations for the reserves have many uncertainties and the economic evaluations started to decide whether are commercial or not to produce (Suslick, 2009).

- **Field appraisal and development risk analysis**

As information increases, these risks are diminished, therefore the significance of the risks related to technology and recovery factor increases (Suslick, 2009). In the groundwork of development strategies, field management decisions are difficult issues because of the great work required to forecast production with the necessary accuracy, the number and type of decisions, and the dependency of production plan definition on many types of uncertainty with clear effect on risk quantification (Suslick, 2009).

In order to evade enormous computation effort, some explanations are always necessary. The key point is not to lose accuracy while the definition of simplifications and expectations that can be made to advance performance. Several types of uncertainties can be integrated using modeling tool and treatment of attributes (Suslick, 2009).

3.2 Monte Carlo Simulation

Monte Carlo methodologies are at least 50 years ago, in the beginning of 1967, many statistical sampling techniques could be considered Monte Carlo methods. In the petroleum literature, due to the improvements in computer hardware and software, Monte Carlo sampling has been simplified (Gilman, 1998).

Engineers, geoscientists, and other professionals accept Monte Carlo simulation methods to calculate prospects or to analyze difficulties that involve uncertainty (Macary, 1999). Followings are among the common applications of Monte Carlo simulation:

- Estimation of recoverable hydrocarbons from a reservoir,
- Predicting production and revenue streams for a well or a field,
- Evaluation of a water-flood viewpoint
- Comparison of net present values of another investments.

In addition, Monte Carlo simulation is the most powerful risk assessment technique (Macary, 1999). However, this technique requires progressive statistical information through which one can get dependable simulation. Monte Carlo simulation takes on singular position in the field of reserve estimation, which presents important and important area of interest to any reservoir engineer (Macary, 1999).

There are some advantages to use Monte Carlo's simulation (Murtha, 1993):

- The results contain all information about possible outcomes compared with either the scenario or deterministic approach (Murtha, 1993).
- The simulation emphasizes the underlying model with its assumptions and helps the user evaluate and combine historical data (Murtha, 1993).
- Sensitivity analysis affirm the key parameters and help quantify the value of additional information (Murtha, 1993).

- The results enable us to know how many wildcats will have to drill, which alternative is more risky, does one alternative control the other (Murtha, 1993).

A Monte Carlo's simulation starts with a model. Then the parameters decomposed into input and output. Each input parameter is a range of maximum and minimum, and then it is viewed as a random variable. A simulation is a succession thousands iterations, during which the output values are saved. Afterward, the output values are gathered into a histogram or a cumulative distribution function (Murtha, 1993). The probabilistic approach marries the volumetric model concept and the Theory of Probability to detect the distribution of the probability for attaining a certain set of conclusions (Macary, 1999).

There are three types of graphs of common distribution (Figure 3.2):

- Normal distribution function
- Lognormal distribution function
- Triangular distribution function

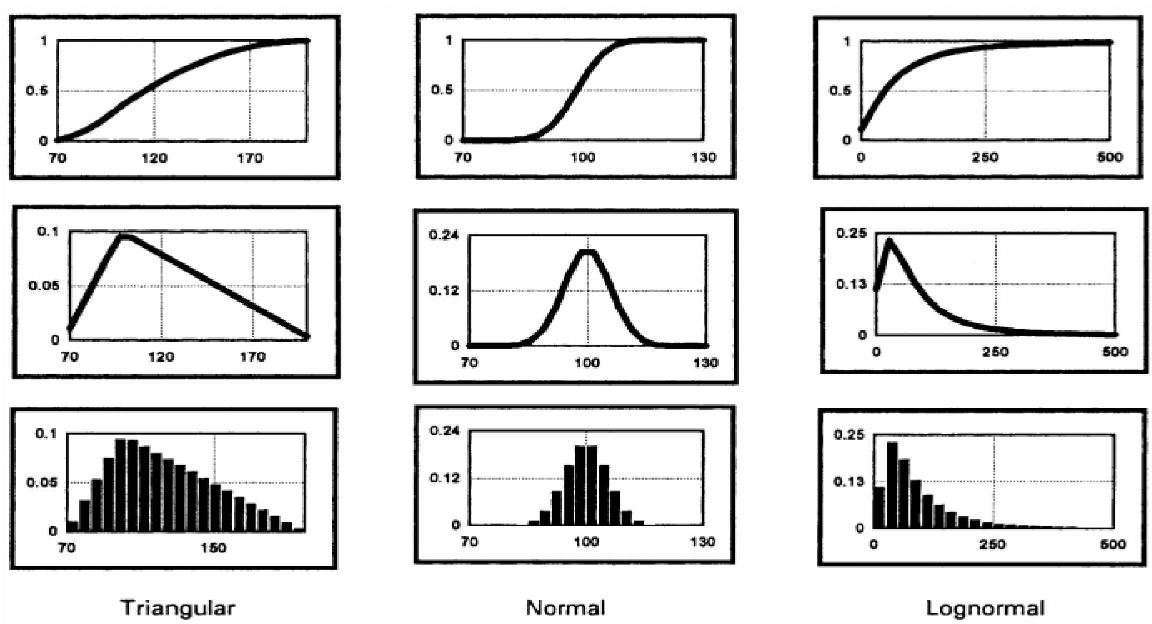

Figure 3.2: Common distribution functions (Murtha, 1993)

A cumulative distribution function (CDF) represents the output parameter. It illustrates how Monte Carlo sampling is accomplished and allow comparing alternatives. On the vertical axis, a uniformly distributed random number between zero and one is selected. On the horizontal axis, a unique value of the corresponding random variable is determined (Figure 3.3).

Three values should be obtained from the cumulative distribution function. P10, P50 and P90 are geo-statistical reservoir models; they are important task for flow simulation, risk analysis, reservoir forecasting and management (Derakhshan, 2008).

- P90 proven reserves: the quantity for which there is 90% probability that the actual resources are equal or higher.
- P50 proven + probable reserves: the quantity for which there is 50% probability that actual reserves are equal or higher.
- P10 proven + probable + possible reserves: the quantity for which there is 10% probability that the actual resources are equal or higher.

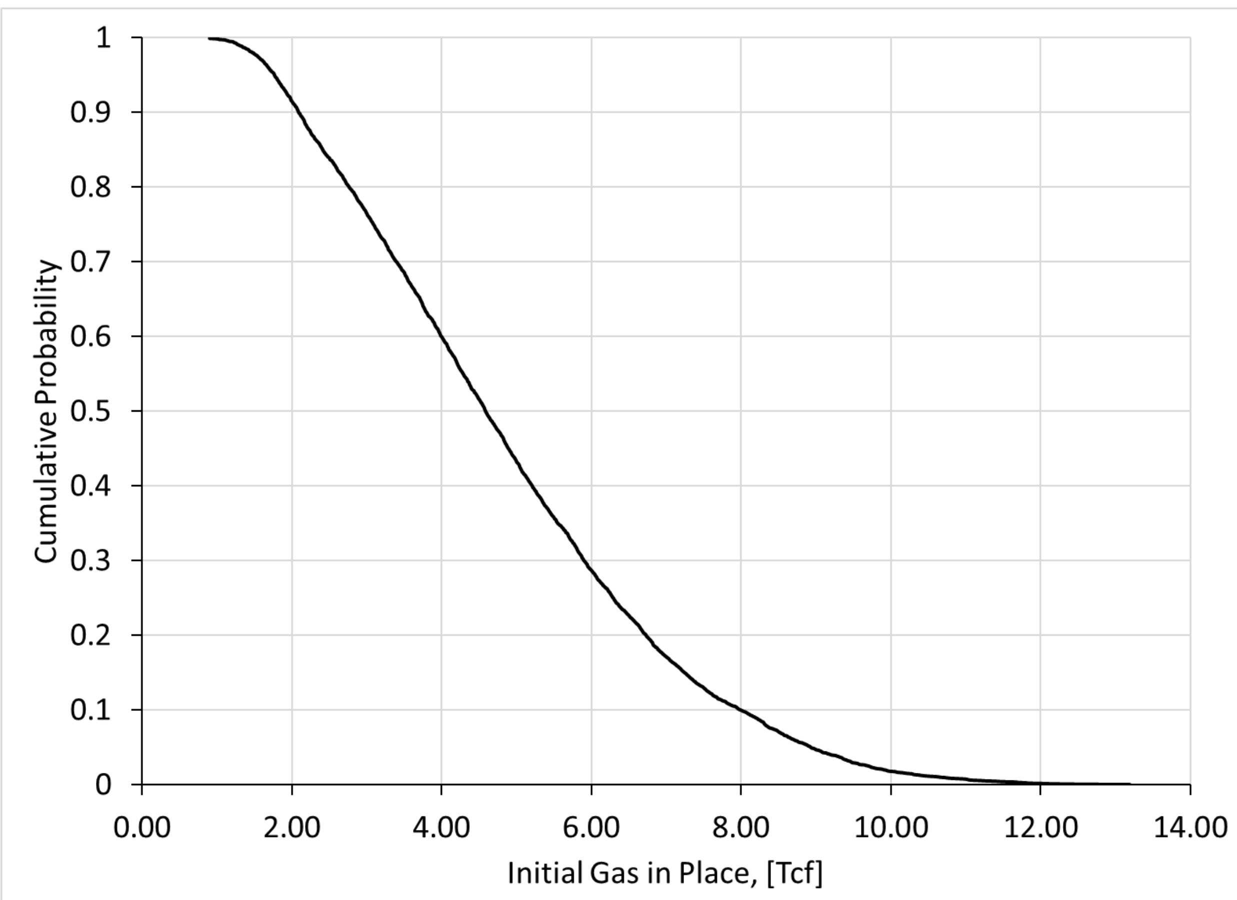

Figure 3.3: Cumulative Distribution Function

3.3 Available Data

Three international companies made a proposal to explore gas in offshore Blocks 4 and 9 (Figure 3.4). The companies are Total SA (France), ENI International B.V. (Italy) and JSC NOVATEK (Russia). In turn, in the beginning of 2019 the drilling activities will start in Blocks 4 and 9. Then, the Consortium confirms the needed logistics and studies throughout 2018 (LPA, 2018).

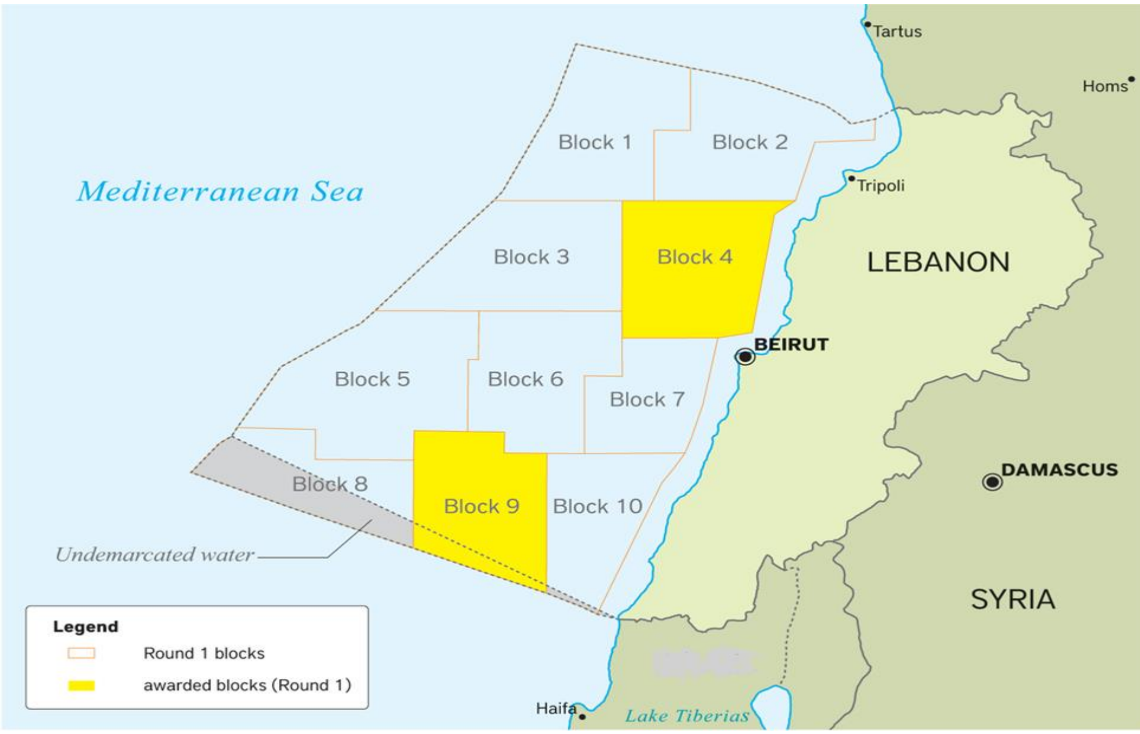

Figure 3.4: Blocks win in the first offshore round license (Butt, 2018)

Block 4 is located in the northern part of Lebanon. Its area is about 1911 km^2, water depth between 686 m -1845 m and 30 km distance to the shore. According to the Lebanese Petroleum Administration, Block 4 is divided into 3 reservoirs with expected volumes 4-5 tcf of natural gas.

In this study, we will apply Monte Carlo simulation on Block 4 in offshore Lebanon and see the possible reserves we can produce from the block.

Calculation of original gas in place is according to this formula:

$$G = \frac{43560 \times A \times h \times \phi \times Sg}{B_{gi}} \quad (3.1)$$

G: original gas in place [Tcf]

A: area of the reservoir [acre]

h: thickness of the reservoir [ft]

Φ: porosity [%]

S_g: saturation of gas [%]

B_{gi}: initial gas formation volume factor [RB/scf]

In our case study, gross rock volume in an anticline is

$$\mathrm{GRV} = \frac{A \times h}{2} \tag{3.2}$$

Also, Net to Gross percentage (NTG) is to be considered and the gas expansion factor is

$$E = \frac{1}{B_g} \tag{3.3}$$

So, after modification the original gas in place formula will be

$$G = \frac{43560 \times \frac{A \times h}{2} \times \phi \times S_g \times \mathrm{NTG}}{\frac{1}{E}} \tag{3.4}$$

In the Monte Carlo simulation, the input parameters are A, h, Φ, S_g, NTG, E and the output parameter is G. These parameters for three reservoirs A, B & C of Block 4 are presented in Tables 3.1 to 3.3

Table 3.1: Data of Reservoir A (LPA,2018)

Area (km^2)	25
Thickness (m)	300 – 400
Porosity (%)	15 – 30
Saturation of gas (%)	60 – 80
Net to Gross (%)	10 – 50
Gas expansion factor (scf/rcf)	330 – 340

Table 3.2: Data of Reservoir B (LPA,2018)

Area (km^2)	15
Thickness (m)	300 – 400
Porosity (%)	15 – 30
Saturation of gas (%)	60 – 80
Net to Gross (%)	10 – 50
Gas espansion factor (scf/rcf)	330 – 340

Table 3.3: Data of Reservoir C (LPA,2018)

Area (km^2)	10
Thickness (m)	300 – 400
Porosity (%)	15 – 30
Saturation of gas (%)	60 – 80
Net to Gross (%)	10 - 50
Gas expansion factor (scf/rcf)	330 – 340

Then, get maximum and minimum range for each parameter.

Table 3.4: Ranges of the given parameters of Reservoir A in field units

Area (acres)	5930 - 6425
Thickness (ft)	98 -1310
Porosity (-)	0.15 - 0.3
Saturation of gas (-)	0.6 - 0.8
Net to Gross (-)	0.1 - 0.5
Gas expansion factor (scf/rcf)	330 - 340

Table 3.5: Ranges of the given parameters of Reservoir B in field units

Area (acres)	3212 – 4201
Thickness (ft)	985 – 1310
Porosity (-)	0.15 - 0.3
Saturation of gas (-)	0.6 - 0.8
Net to Gross (-)	0.1 - 0.5
Gas expansion factor (scf/rcf)	330 – 340

Table 3.6: Ranges of the given parameters of Reservoir C in field units

Area (acres)	1977 – 2965
Thickness (ft)	985 – 1310
Porosity (-)	0.15 - 0.3
Saturation of gas (-)	0.6 - 0.8
Net to Gross (-)	0.1 - 0.5
Gas expansion factor (scf/rcf)	330 – 340

CHAPTER 4

RESULTS AND DISCUSSIONS

Using excel, probability normal distribution is applied on the three Reservoirs A, B, and C. Then, the cumulative probability curve is drawn to reach P90, P50, and P10 of the reserves.

4.1 Results

Reservoir A

Figure 4.1 shows the Original Gas in Place (OGIP) distribution of Reservoir A. In this figure, blue bars show the probabilities of gas in place for each of the ranges. The red line shows logarithmic distribution for Reservoir A. According to this figure, most of the OGIP distribution are ranged in between 1.3 Tcf to 3.6 Tcf.

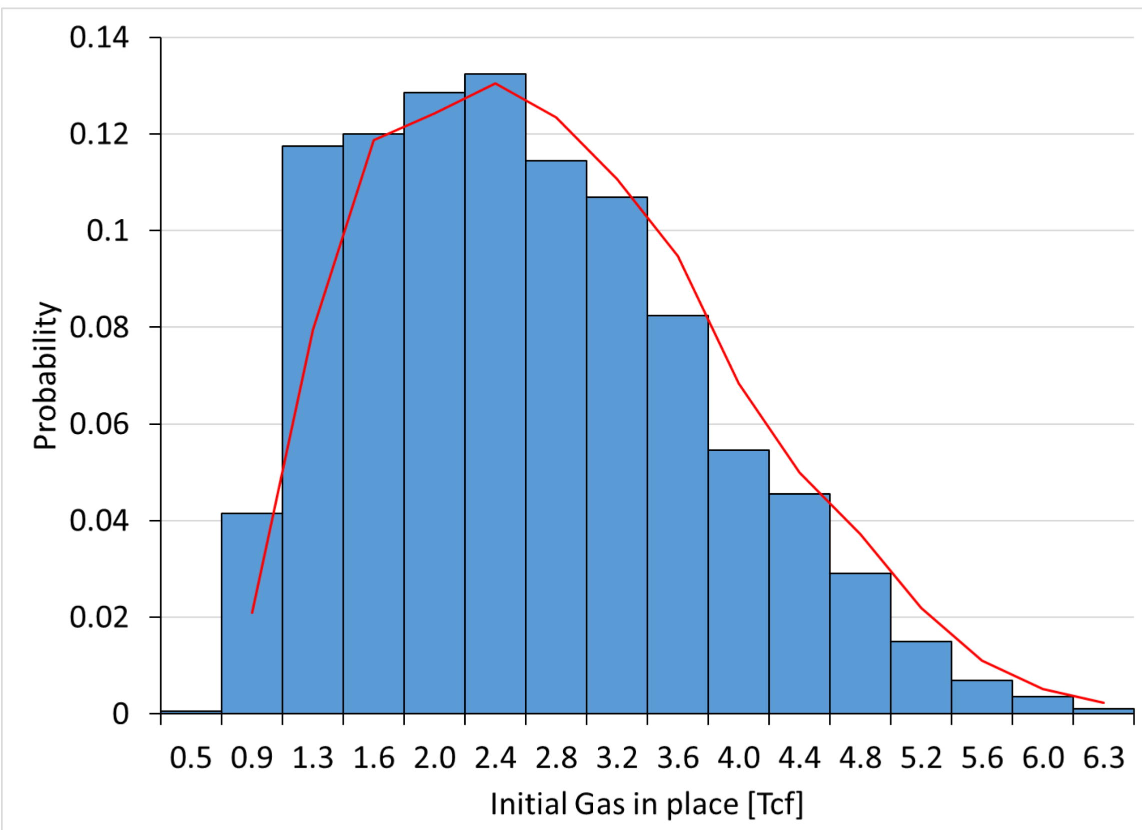

Figure 4.1: OGIP distribution of Reservoir A

Figure 4.2 is the cumulative probability distribution curve; we can obtain P90 P50 P10 for the initial gas in place in Reservoir A. P90 looks mostly considered in oil and gas industry. For Reservoir A, 90% we will have 1.04 Tcf of natural gas in place, but this percentage maybe increased to reach near 2.31 Tcf, which represents 50% of the natural gas in the reserves. P10 shows 4 Tcf of natural gas which looks a little impossible to reach due to many problems faced in the drilling and the damage production zone.

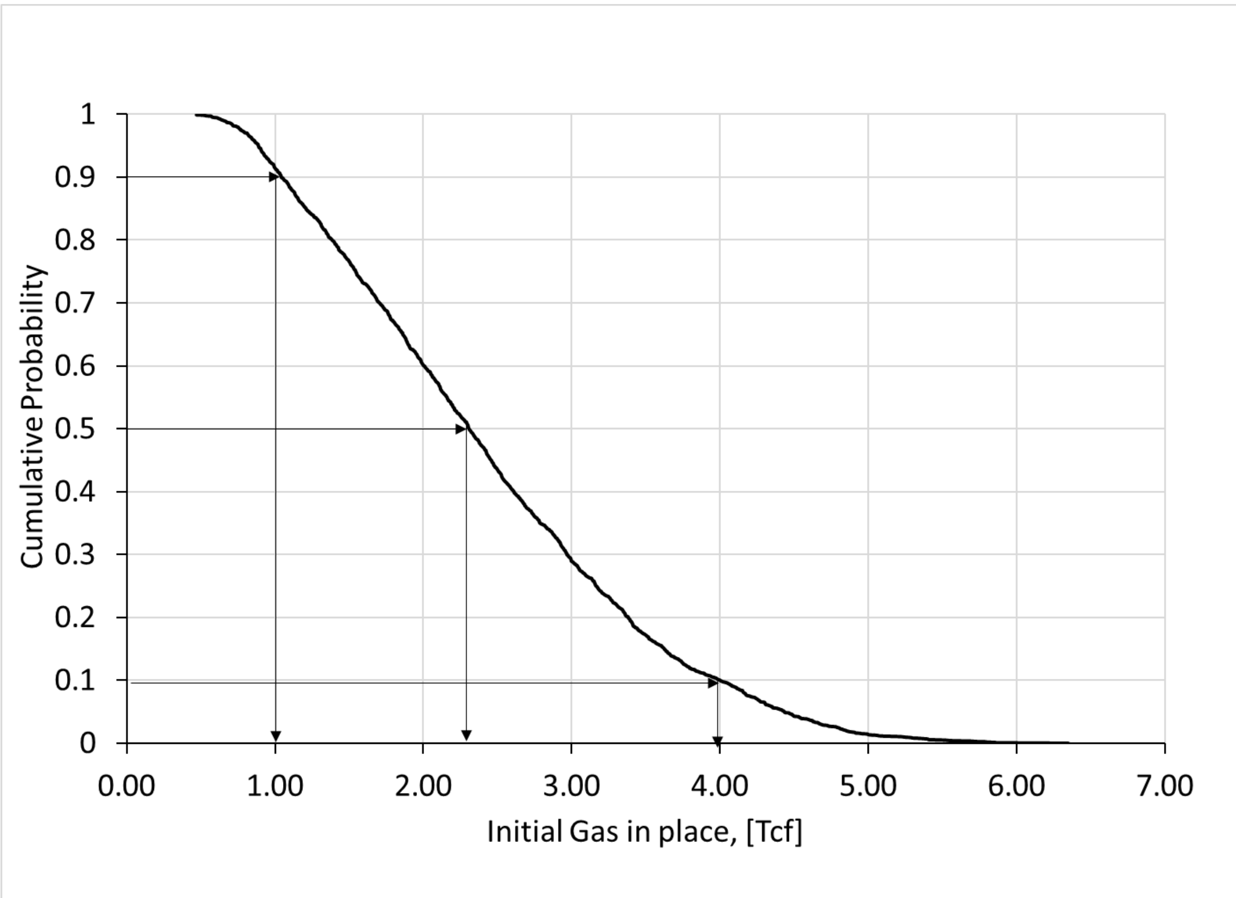

Figure 4.2: Cumulative probability distribution of OGIP in Reservoir A

Table 4.1: Probable reserves in Reservoir A

P90	1.04 Tcf
P50	2.31 Tcf
P10	4.00 Tcf

Reservoir B

Figure 4.3 shows the Original Gas in Place (OGIP) distribution of Reservoir B. In this figure, blue bars show the probabilities of gas in place for each of the ranges. The red line shows logarithmic distribution for Reservoir B. According to this figure, most of the OGIP distribution are ranged in between 0.8 Tcf to 2.2 Tcf.

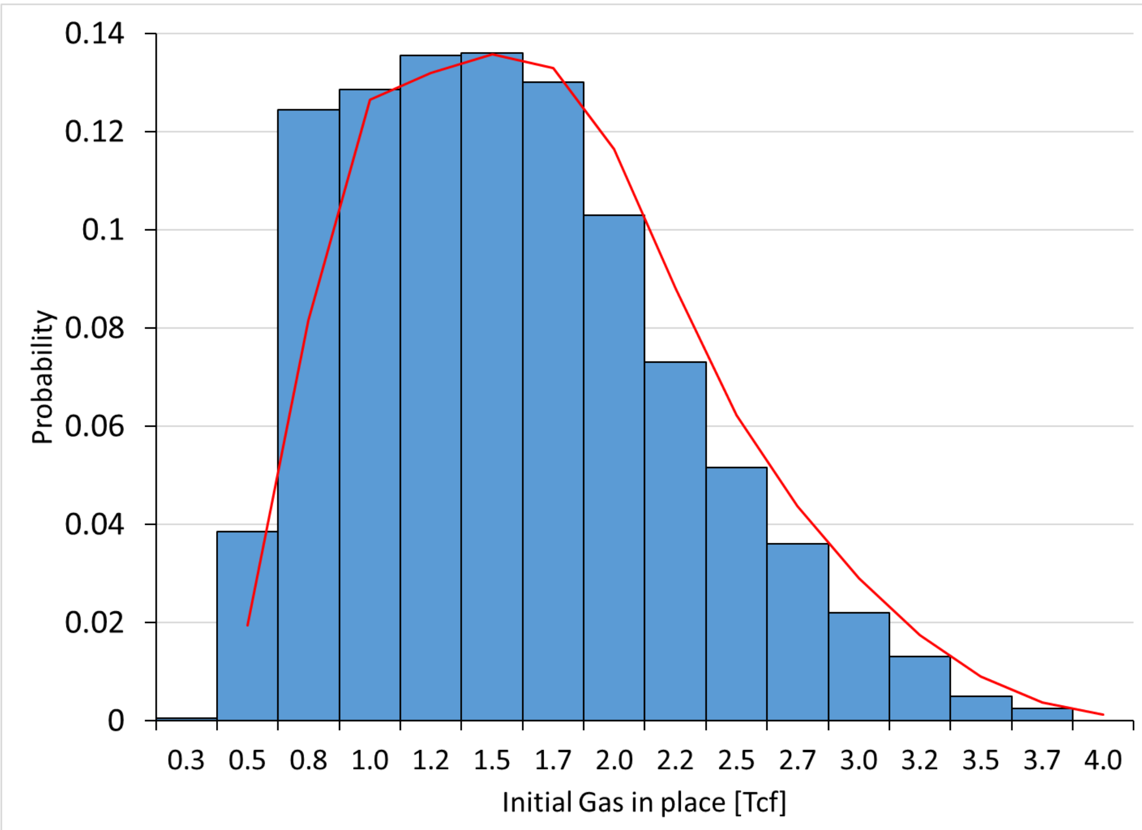

Figure 4.3: OGIP distribution of Reservoir B

Figure 4.4 is the cumulative probability distribution curve; we obtain P90 P50 P10 for the initial gas in place in Reservoir B. P90 looks mostly considered in oil and gas industry. For Reservoir B, 90% we will have 0.627 Tcf of natural gas in place, but this percentage maybe increased to reach near 1.38 Tcf, which represents 50% of the natural gas in the reserves. P10 shows 2.4 Tcf of natural gas, which looks a little impossible to reach due to many problems faced in the drilling and the damage production zone.

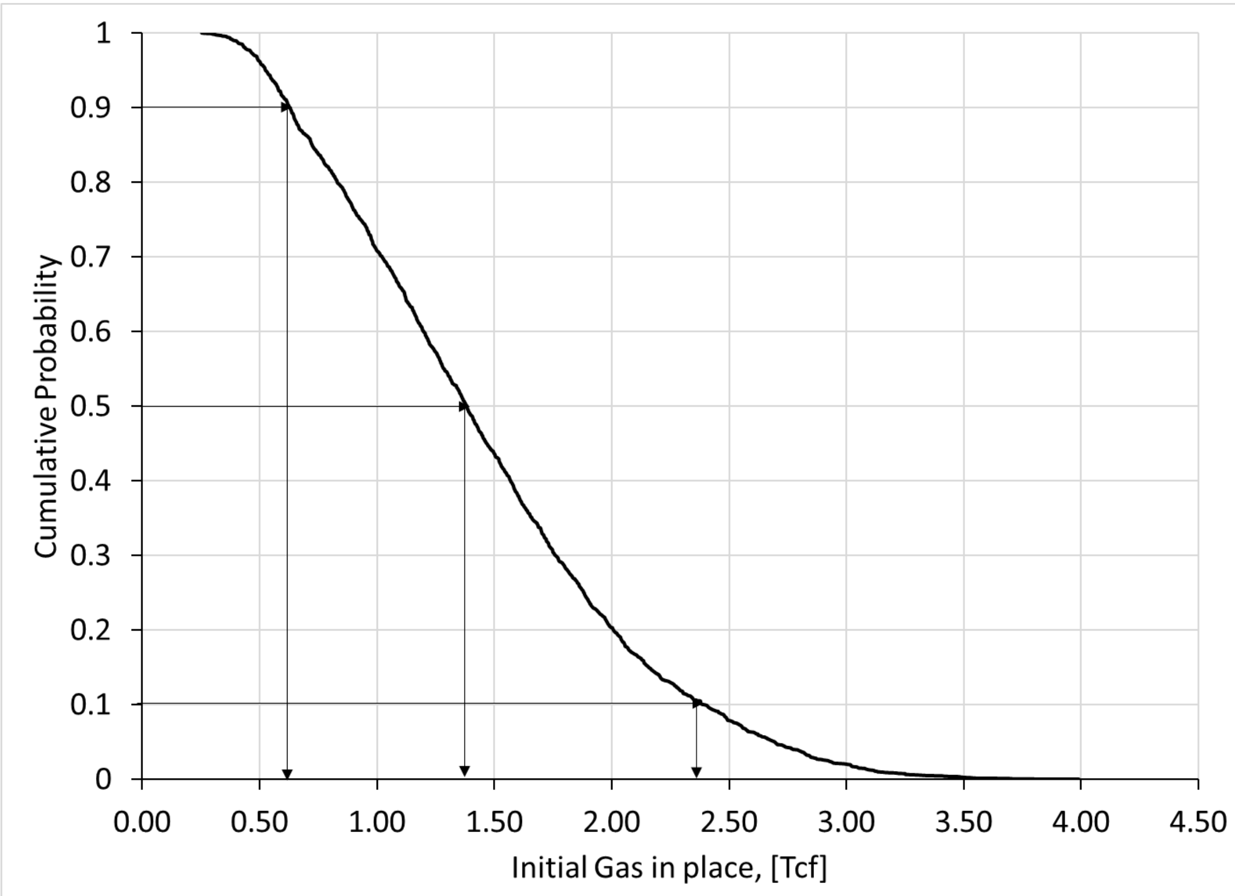

Figure 4.4: Cumulative probability distribution of OGIP in Reservoir B

Table 4.2: Probable reserves in Reservoir B

P90	0.63 Tcf
P50	1.38 Tcf
P10	2.40 Tcf

Reservoir C

Figure 4.5 shows the Original Gas in Place (OGIP) distribution of Reservoir C. In this figure, blue bars show the probabilities of gas in place for each of the ranges. The red line shows logarithmic distribution for Reservoir C. According to this figure, most of the OGIP distribution are ranged in between 0.53 Tcf to 1.20 Tcf.

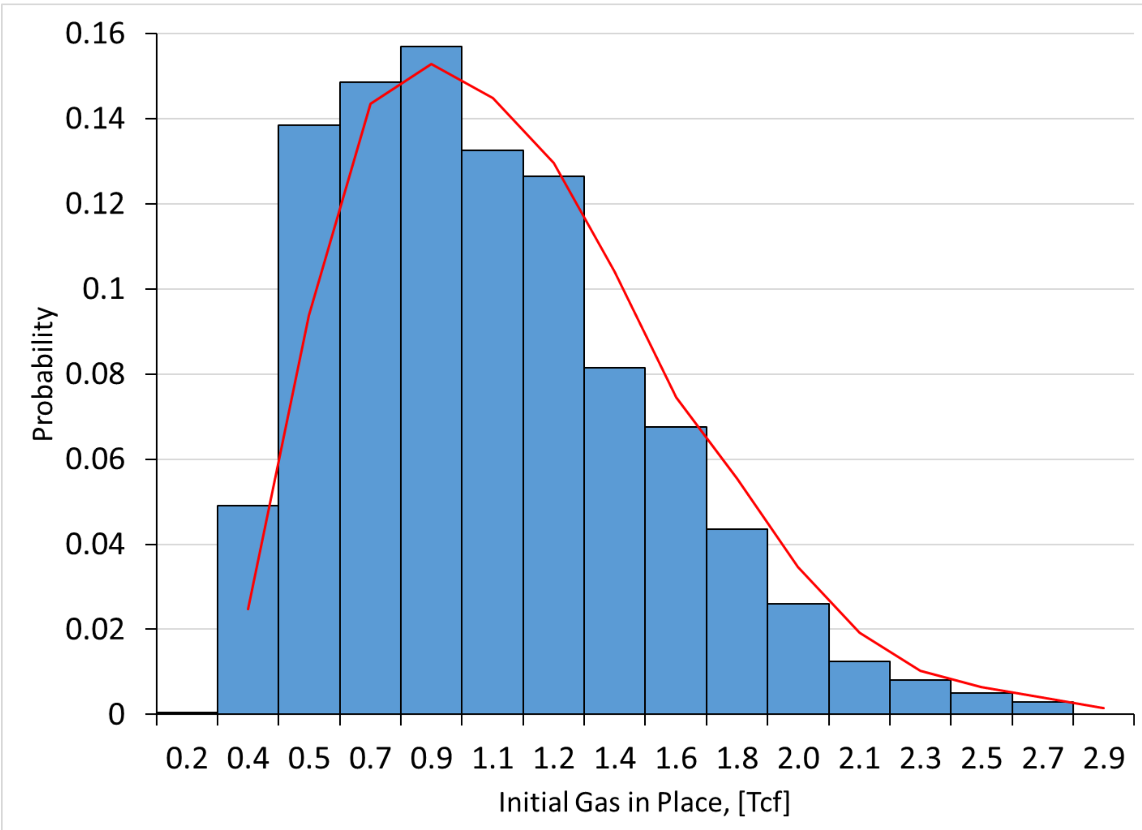

Figure 4.5: OGIP distribution of Reservoir C

Figure 4.6 is the cumulative probability distribution curve; we obtain P90 P50 P10 for the initial gas in place in Reservoir C. P90 looks mostly considered in oil and gas industry. For Reservoir C, 90% we will have 0.42 Tcf of natural gas in place, but this percentage maybe increased to reach near 0.89 Tcf, which represents 50% of the natural gas in the reserves. P10 shows 1.6 Tcf of natural gas, which looks a little impossible to reach due to many problems faced in the drilling and the damage production zone.

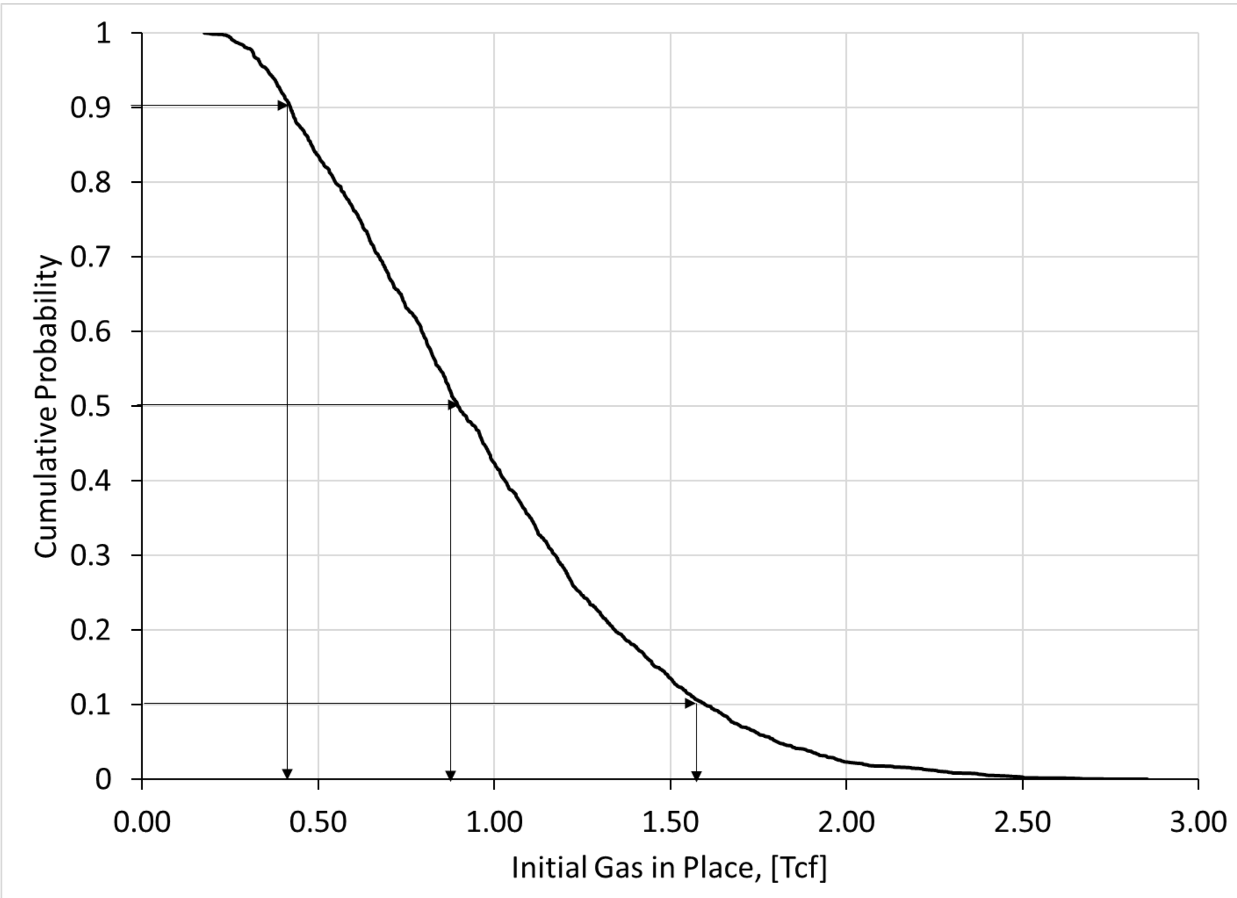

Figure 4.6: Cumulative probability distribution of OGIP in Reservoir C

Table 4.3: Probable reserves in Reservoir C

P90	0.42 Tcf
P50	0.90 Tcf
P10	1.60 Tcf

Now we take the probability of combination of the reservoirs to see how much reserves we will have.

Reservoirs A and B

Figure 4.7 shows the Original Gas in Place (OGIP) distribution of Reservoirs A and B. In this figure, blue bars show the probabilities of gas in place for each of the ranges. The red line shows logarithmic distribution for Reservoir A and B. According to this figure, most of the OGIP distribution are ranged in between 2.00 Tcf to 5.85 Tcf.

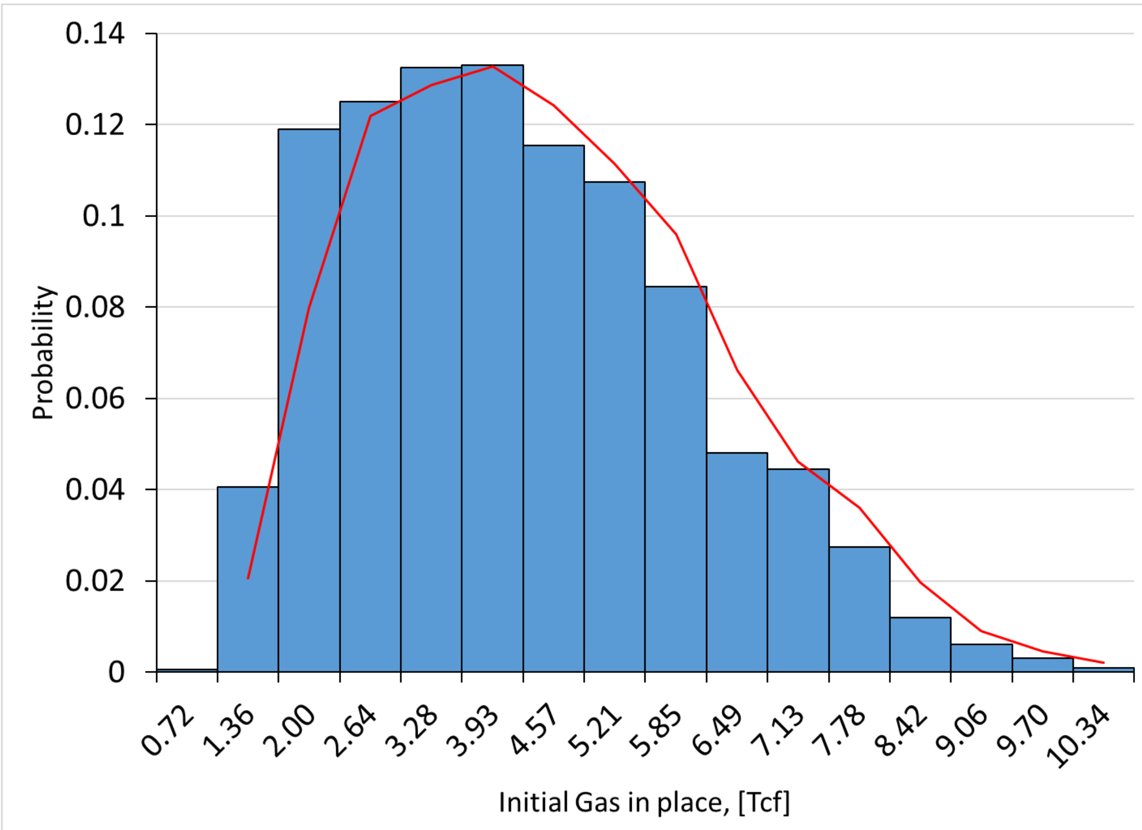

Figure 4.7: OGIP distribution of Reservoir A and B

Figure 4.8 is the cumulative probability distribution curve; we obtain P90 P50 P10 for the initial gas in place in Reservoirs A and B. Both reservoirs have significant amount of natural gas. The best scenario is to produce from both so we can reach to 3 Tcf of natural gas in the field. P90 looks mostly considered in oil and gas industry. For Reservoirs A and B, 90% we will have 1.67 Tcf of natural gas in place, but this percentage maybe increased to reach near 3.69 Tcf which represents 50% of the natural gas in the reserves. P10 shows 6.4 Tcf of natural gas, which looks a little impossible to reach due to many problems faced in the drilling and the damage production zone.

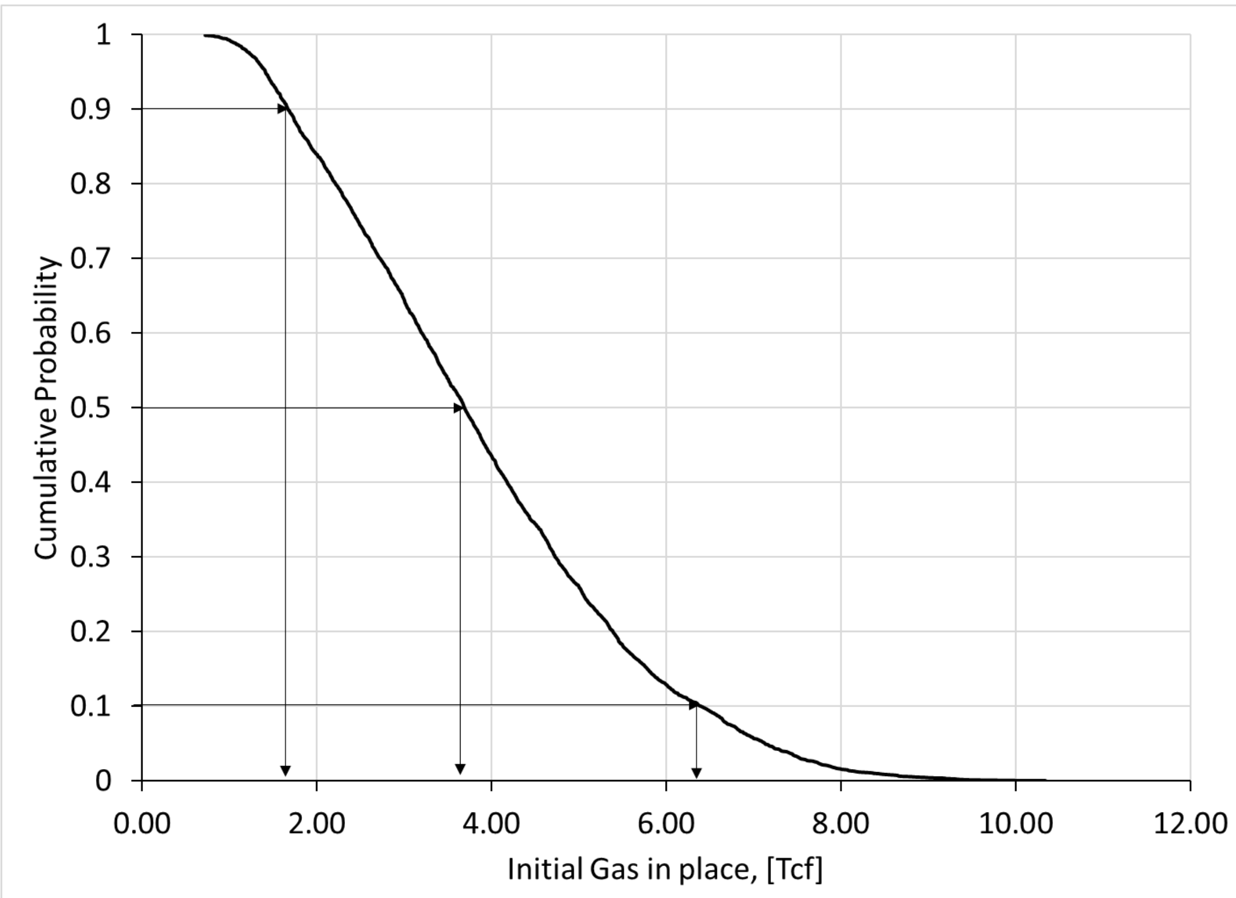

Figure 4.8: Cumulative probability distribution of OGIP in Reservoirs A and B

Table 4.4: Probable reserves in Reservoir A and B

P90	1.67 Tcf
P50	3.69 Tcf
P10	6.40 Tcf

Reservoirs A and C

Figure 4.9 shows the Original Gas in Place (OGIP) distribution of Reservoirs A and C. In this figure, blue bars show the probabilities of gas in place for each of the ranges. The red line shows logarithmic distribution for Reservoirs A and C. According to this figure, most of the OGIP distribution are ranged in between 1.78 Tcf to 5.21 Tcf.

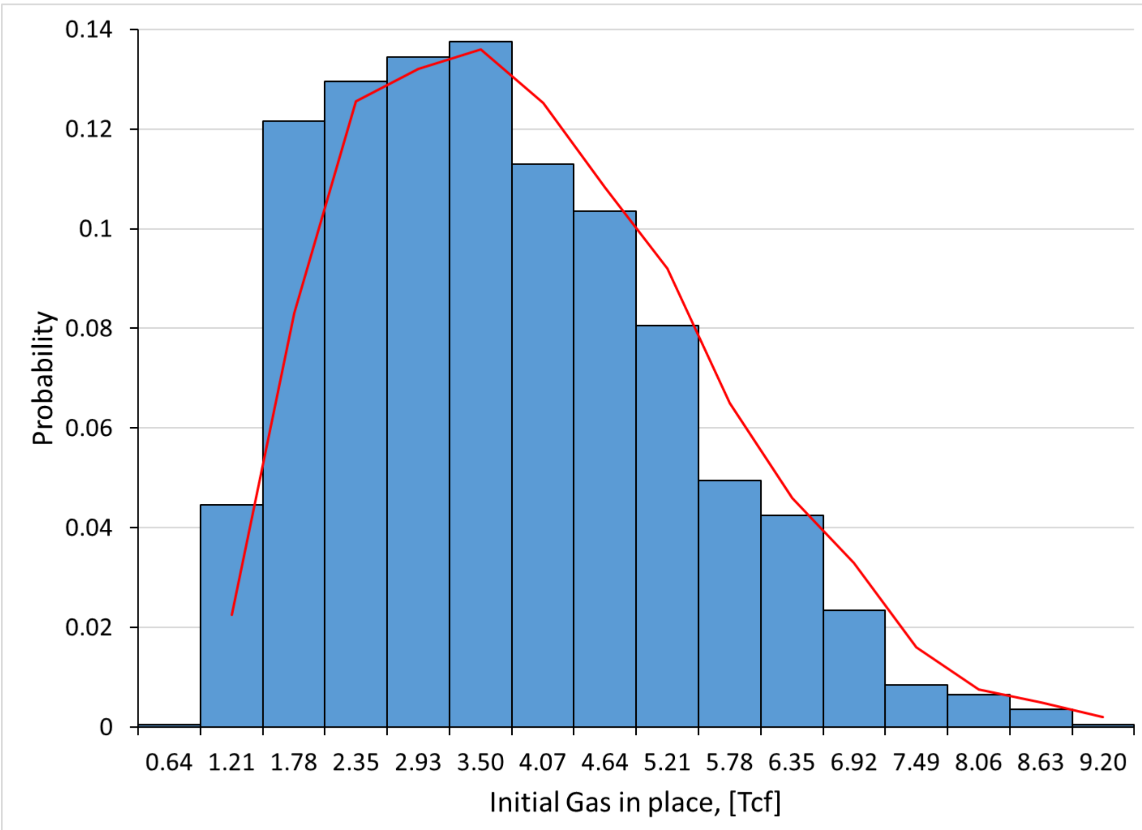

Figure 4.9: OGIP distribution of Reservoir A and C

Figure 4.10 is the cumulative probability distribution curve, we obtain P90 P50 P10 for the initial gas in place in Reservoirs A and C. Reservoir C is the smallest reservoir with less amount of natural gas. Therefore, it will not be good to take any combination with such reservoir. P90 looks mostly considered in oil and gas industry. For Reservoirs A and C, 90% we will have 1.46 Tcf of natural gas in place, but this percentage maybe increased to reach near 3.2 Tcf which represents 50% of the natural gas in the reserves. P10 shows 5.6 Tcf of natural gas, which looks a little impossible to reach due to many problems faced in the drilling and the damage production zone.

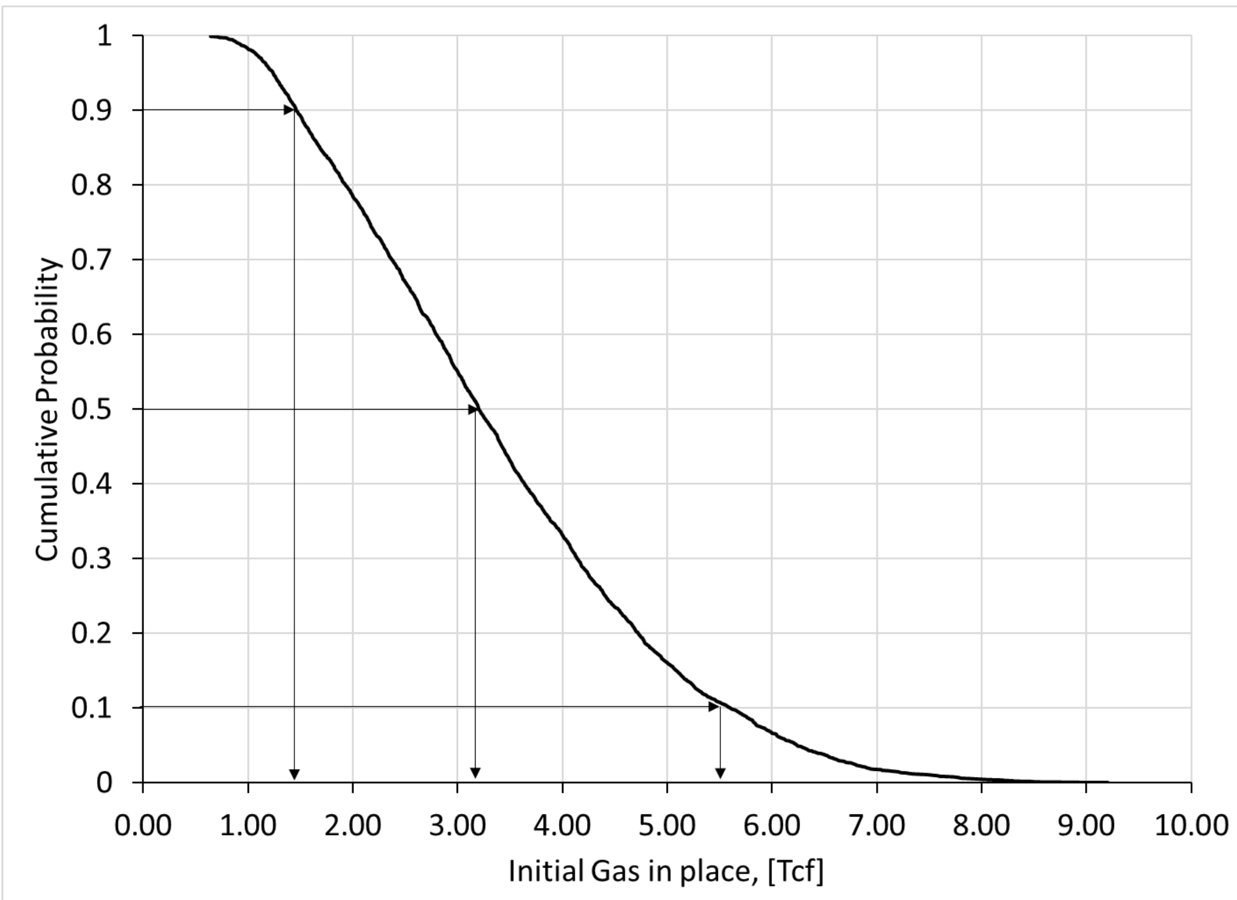

Figure 4.10: Cumulative probability distribution of OGIP in Reservoirs A and C

Table 4.5: Probable reserves in Reservoir A and C

P90	1.46 Tcf
P50	3.20 Tcf
P10	5.60 Tcf

Reservoirs B and C

Figure 4.11 shows the Original Gas in Place (OGIP) distribution of Reservoirs B and C. In this figure, blue bars show the probabilities of gas in place for each of the ranges. The red line shows logarithmic distribution for Reservoirs B and C. According to this figure, most of the OGIP distribution are ranged in between 1.28 Tcf to 3.42 Tcf.

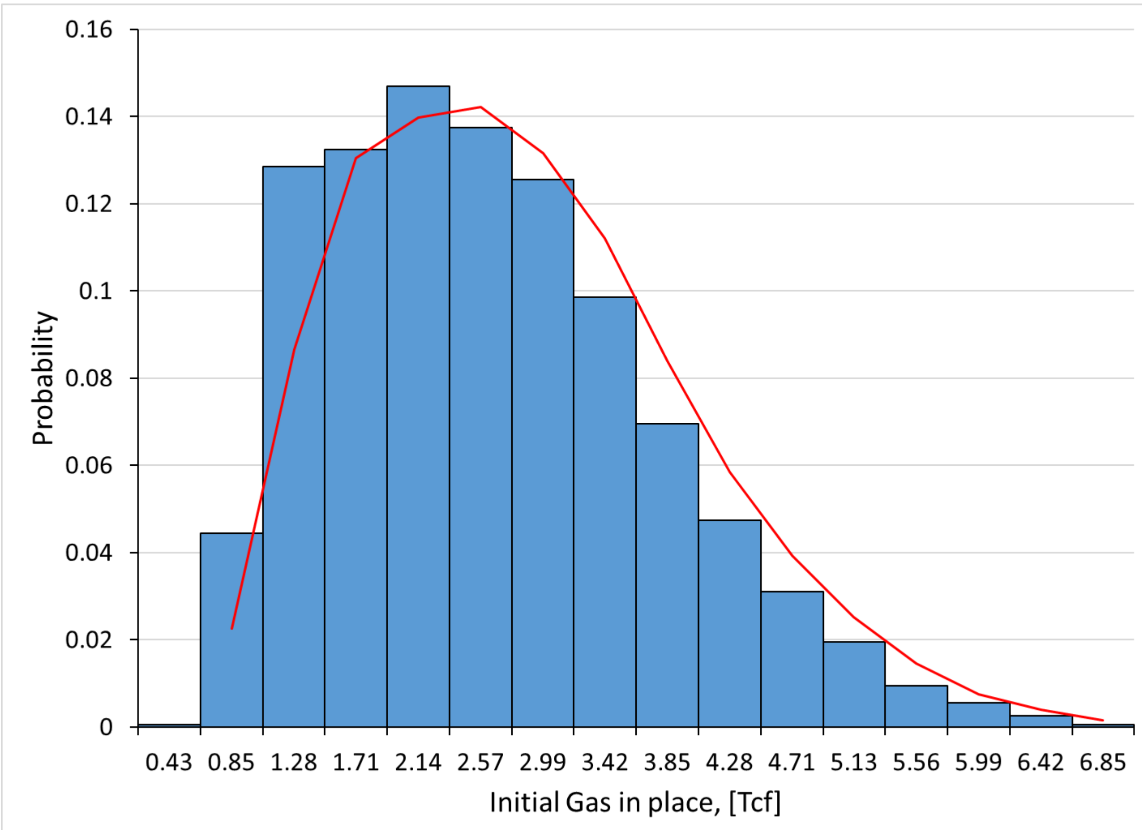

Figure 4.11: OGIP distribution of Reservoir B and C

Figure 4.12 is the cumulative probability distribution curve, we obtain P90 P50 P10 for the initial gas in place in reservoirs B and C. Reservoir C is the smallest reservoir with less amount of natural gas. Therefore, it will not be good to take any combination with such reservoir. P90 looks mostly considered in oil and gas industry. For Reservoirs B and C, 90%, we will have 1.05 Tcf of natural gas in place, but this percentage maybe increased to reach near 2.28 Tcf, which represents 50% of the natural gas in the reserves. P10 shows 4 Tcf of natural gas which looks a little impossible to reach due to many problems faced in the drilling and the damage production zone.

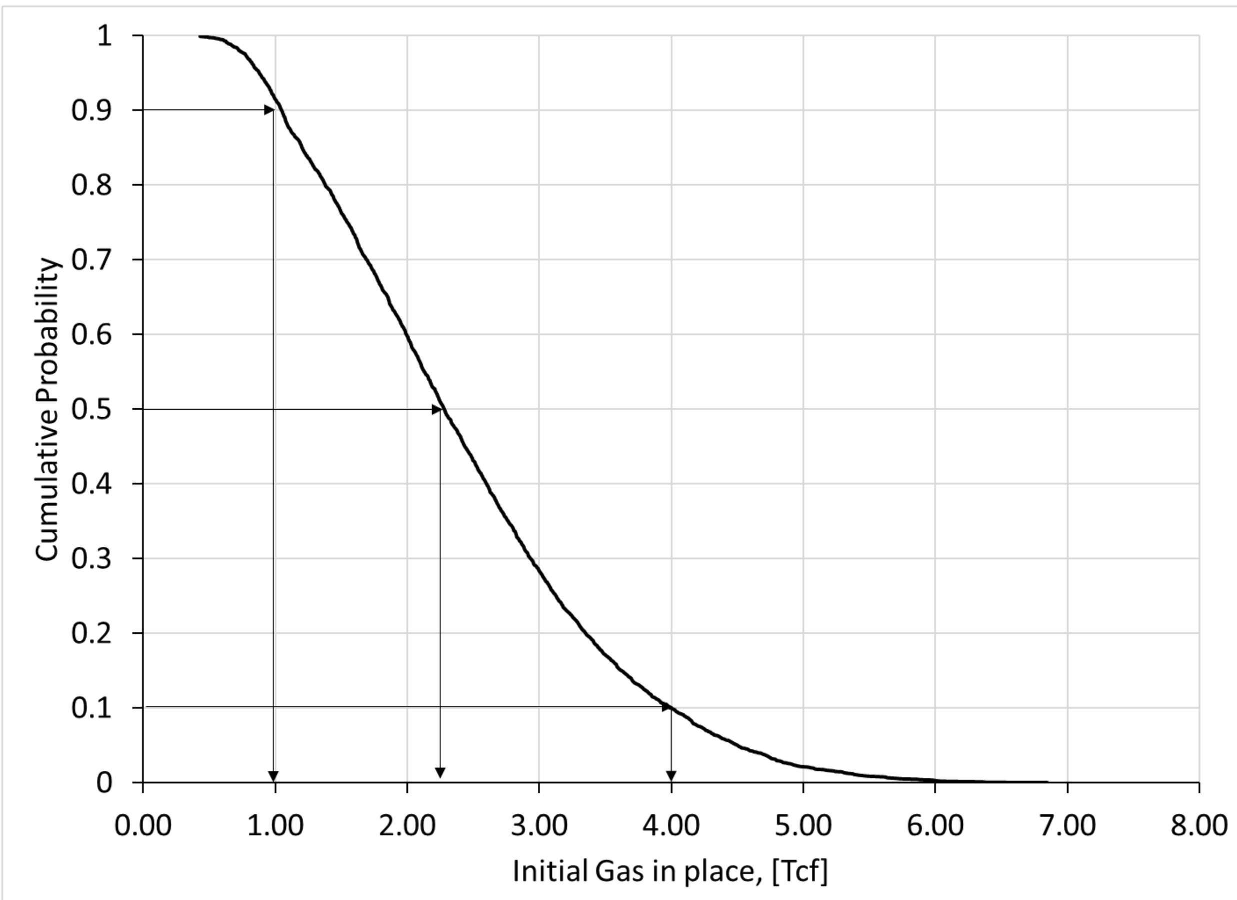

Figure 4.12: Cumulative probability distribution of OGIP in Reservoirs B and C

Table 4.6: Probable reserves in Reservoir B and C

P90	1.05 Tcf
P50	2.28 Tcf
P10	4.00 Tcf

Now we take the combination of the three Reservoirs A and B and C. They will have significant amount of natural gas in the field, but this cannot be happened due to economical calculations.

Reservoirs A and B and C

Figure 4.13 shows the Original Gas in Place (OGIP) distribution of Reservoirs A, B, and C. In this figure, blue bars show the probabilities of gas in place for each of the ranges. The red line shows logarithmic distribution for Reservoirs A, B, and C. According to this figure, most of the OGIP distribution are ranged in between 2.53 Tcf to 7.45 Tcf.

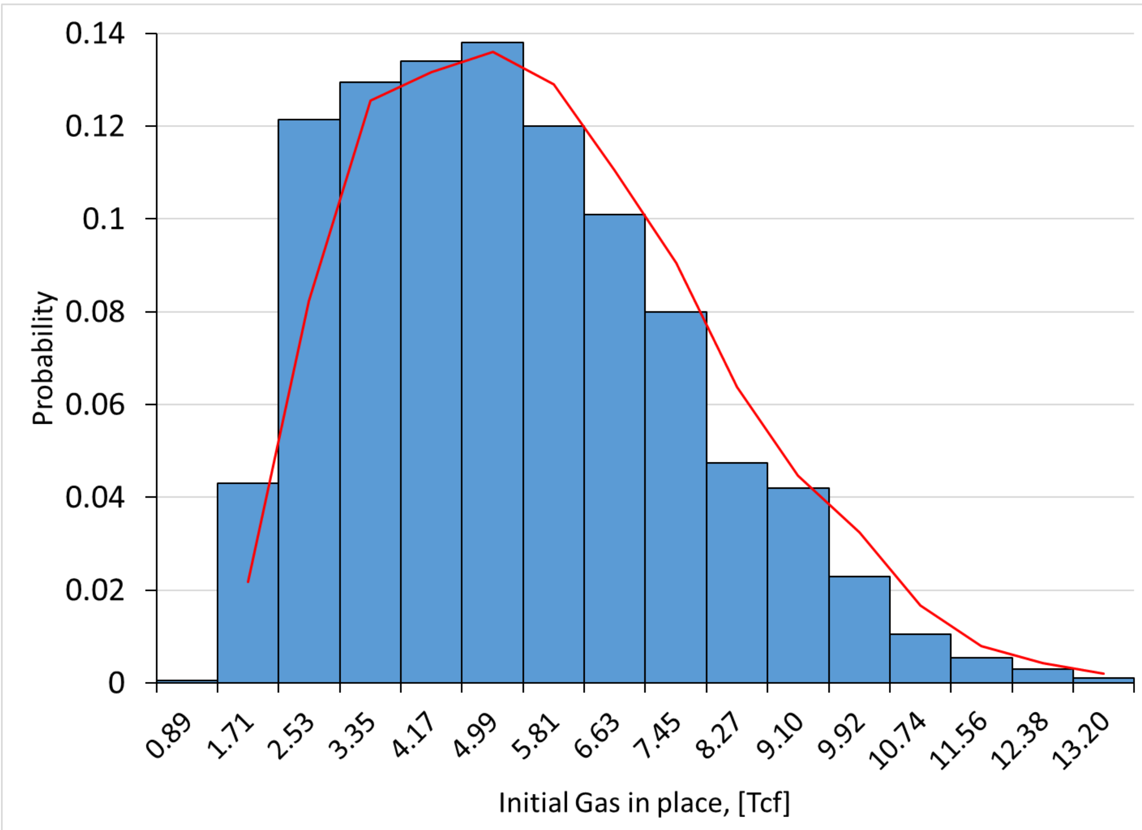

Figure 4.13: OGIP distribution of Reservoirs A, B, and C

Figure 4.14 is the cumulative probability distribution curve; we obtain P90 P50 P10 for the initial gas in place in Reservoirs A and B and C. For Reservoirs A and B and C, 90% we will have 2.09 Tcf of natural gas in place, but this percentage maybe increased to reach near 4.58 Tcf which represents 50% of the natural gas in the reserves. P10 shows 8 Tcf of natural gas which looks a little impossible to reach due to many problems faced in the drilling and the damage production zone.

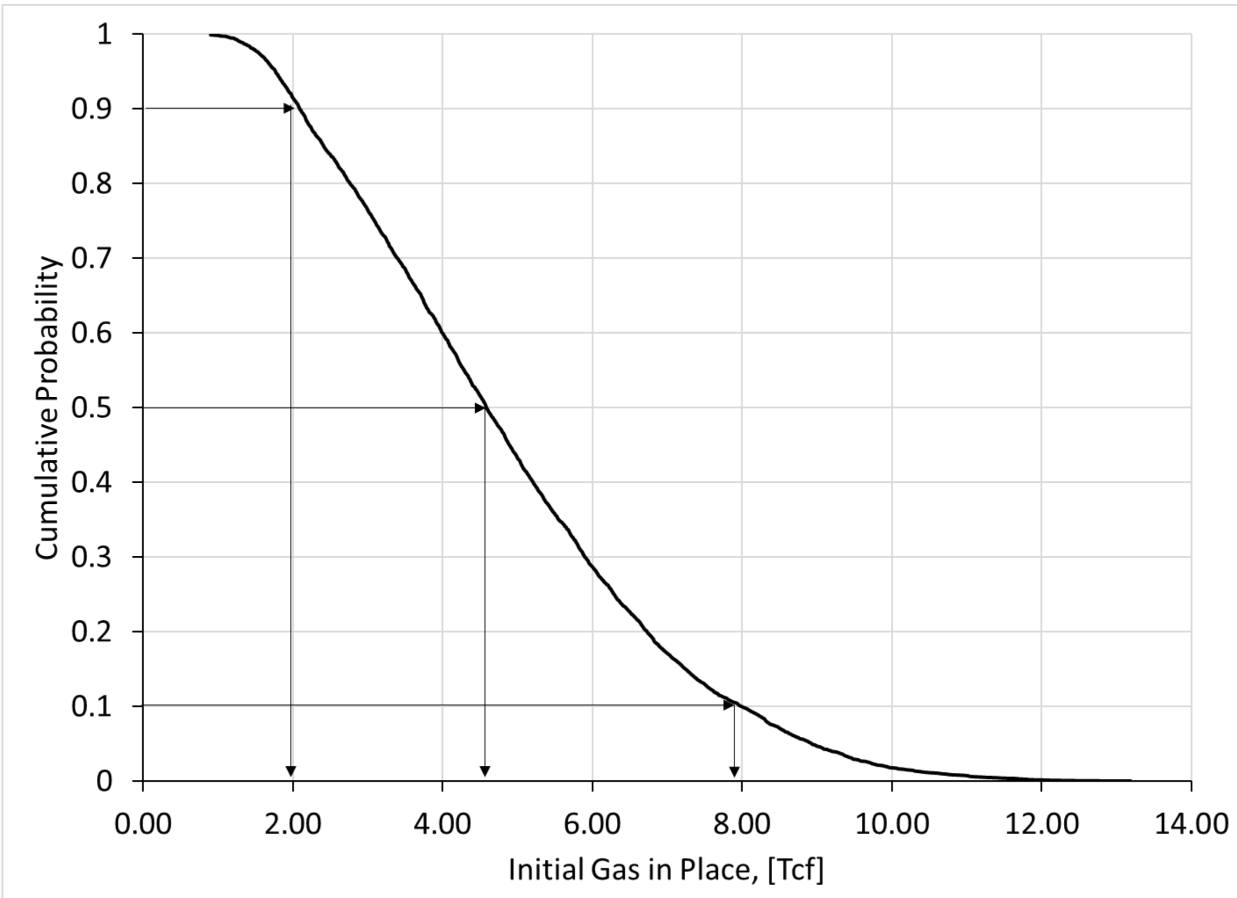

Figure 4.14: Cumulative probability distribution of OGIP in Reservoirs A and B and C

Table 4.7: Probable reserves in Reservoir A, B, and C

P90	2.09 Tcf
P50	4.58 Tcf
P10	8.00 Tcf

4.2 Discussions

In Block 4, considerable amount of natural gas in place are expected. We have two big reservoirs A and B, and a small reservoir C. In Monte Carlo's simulation, P10, P50, and P90 should be selected to see how much probable reserves we have in the field. P90 is mostly considered in oil and gas industry due to many problems faced while drilling which may affect the production zone, such as: skin factor, water influx, etc. However, P90 stays a probability, which may be increased to reach near P50.

For Reservoir A, P90 was selected from the Monte Carlo's simulation and 1.04 Tcf of natural gas will occur. This amount of natural gas in place can be increased to reach 2 Tcf.

For Reservoir B, P90 was selected and 627 billion cubic feet of natural gas in place will occur in the reservoir. This amount can be increased to reach 1 Tcf of natural gas in place.

However, Reservoir C is the smallest in area and reserves. P90 was selected then 420 billion cubic feet of natural gas will occur.

At the beginning of January 2019, Eni, Total and Novatek will start drilling in both Blocks 4 and 9. One well to be drilled in every block to ensure the quantity of reserves of natural gas we have. All uncertainties can be clarified after drilling and completing the first well. Then, well testing, well logging, and coring will be applied on the reservoir to start analysis the data and calculate the permeability, effective porosity, pressure, and the proven amount of natural gas that can be produced.

Many economic studies done to compare the costs to the revenues by calculating the cash flow, net present value, and the feasibility of the produced natural gas. The best scenario is to start with Reservoir A and develop it until commercial amount of natural gas was found. Then, start to explore in Reservoir B that has significant amount of reserves. Therefore, production from both reservoirs A and B, which in Monte Carlo's simulation show that for P90 they have 1.67 Tcf of natural gas and it may be increased up to 3 Tcf.

CHAPTER 5

PRODUCTION PROFILE OF THE FIELD

During development process of the field, engineers need to specify how much they will produce natural gas per day. Then, they decide how much wells will be drilled together with a pattern distribution of the wells to produce as much as we can from the field.

5.1 Decline Curve Analysis:

Decline curves are the most common methods of estimating the value of oil and gas wells and forecasting their production (Tiab, 2001). In 1908, Arnold and Anderson presented the earliest literature of mathematical decline analysis approach. In 1944, Arps advanced the standard exponential, hyperbolic and harmonic decline equations (Tiab, 2001).

The two basic problems in evaluation work are the determination of a well's most probable future life and the estimate of its future production (Arp, 1944). Volumetric calculations sometimes can solve on or both problems, but sufficient data are not always available to cancel all guesswork (Arp, 1944). Production rate of a producing well is the simplest and most readily existing variable characteristic, and the logical way to find an answer to the two problems mentioned above, by extrapolation, is to plot this inconstant production rate either against cumulative production or against time, spreading the curves thus obtained to the economic limit (Arp, 1944).

Then Fetkovich did an advanced approach in 1973. This has been used to calculate and estimate the reserves later (Tiab, 2001).

Hyperbolic Model

$$q(t) = \frac{q_i}{[1 + bD_i t]^{1/b}} \tag{5.1}$$

q: time varying production rate

q_i: initial production rate parameters

b: hyperbolic decline exponent parameter b<1

D_i: initial decline rate parameter

Cumulative production G_p for hyperbolic model

$$G_p(t) = \frac{q_i}{(1 - b)D_i}\left[1 - (1 + bD_i t)^{1-(1/b)}\right] \tag{5.2}$$

Natural gas reservoirs have high recovery factor, which reaches until 80%. Special compressors are used to increase the production of natural gas from the reservoir. In addition, production engineers increase the size of tubing in the well to allow more natural gas to flow from the reservoir to the surface. In the Eastern Mediterranean fields, as in Zohr field, the daily production of natural gas will reach 2.9 billion cubic feet per day by mid-2019 according to Eni CEO Claudio Descalzi (Ismail, 2018). In Cyprus, Aphrodite field has 4.2 Tcf of natural gas with 5 production wells and 800 million cubic feet per day (Chris, 2017).

In Lebanon offshore Block 4 we have three reservoirs. Reservoir A is the biggest in area with P90 1.04 Tcf of natural gas in place. The recovery factor is between 40% and 60%. According to neighbor's gas fields, we can produce from Reservoir A 300 million standard cubic feet per day for 10 years.

Figure 5.1 shows the decline curve analysis of the daily natural gas production for 10 years. The field start from 300 million standard cubic feet per day. After 10 years, the production of natural gas decrease as years pass to reach 141 million standard cubic feet per day.

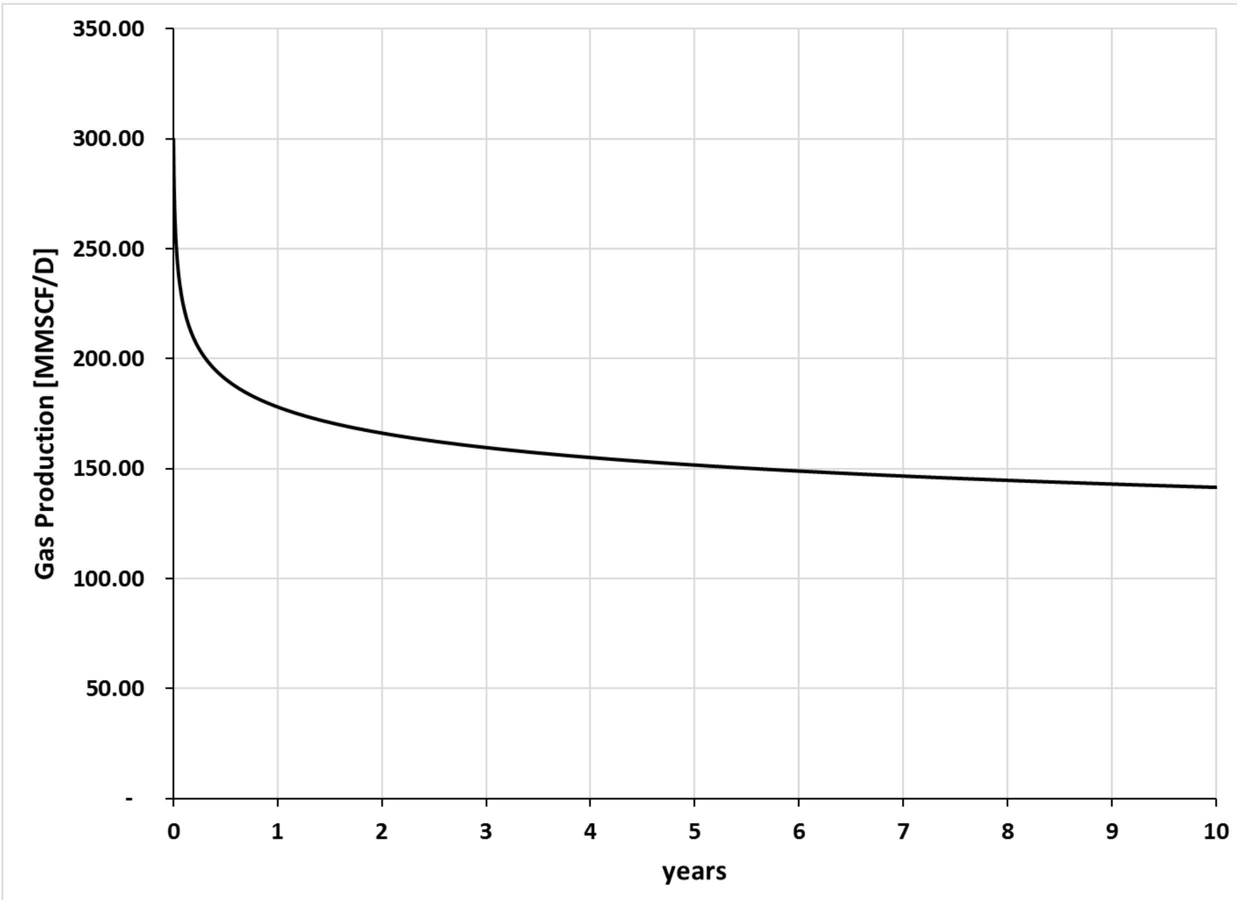

Figure 5.1: Decline curve analysis

Figure 5.2 shows the cumulative natural gas production of the field for 10 years. The curve reaches 561 billion standard cubic feet (Bscf) of natural gas after 10 years passed. According to P90 that gives 1.04 tcf then for 50% recovery factor, which looks average percentage between 40% and 60%, we will reach 520 billion standard cubic feet of natural gas in place. Therefore, Monte Carlo simulation's data match the cumulative natural gas production with 300 million standard cubic feet per day for 10 years.

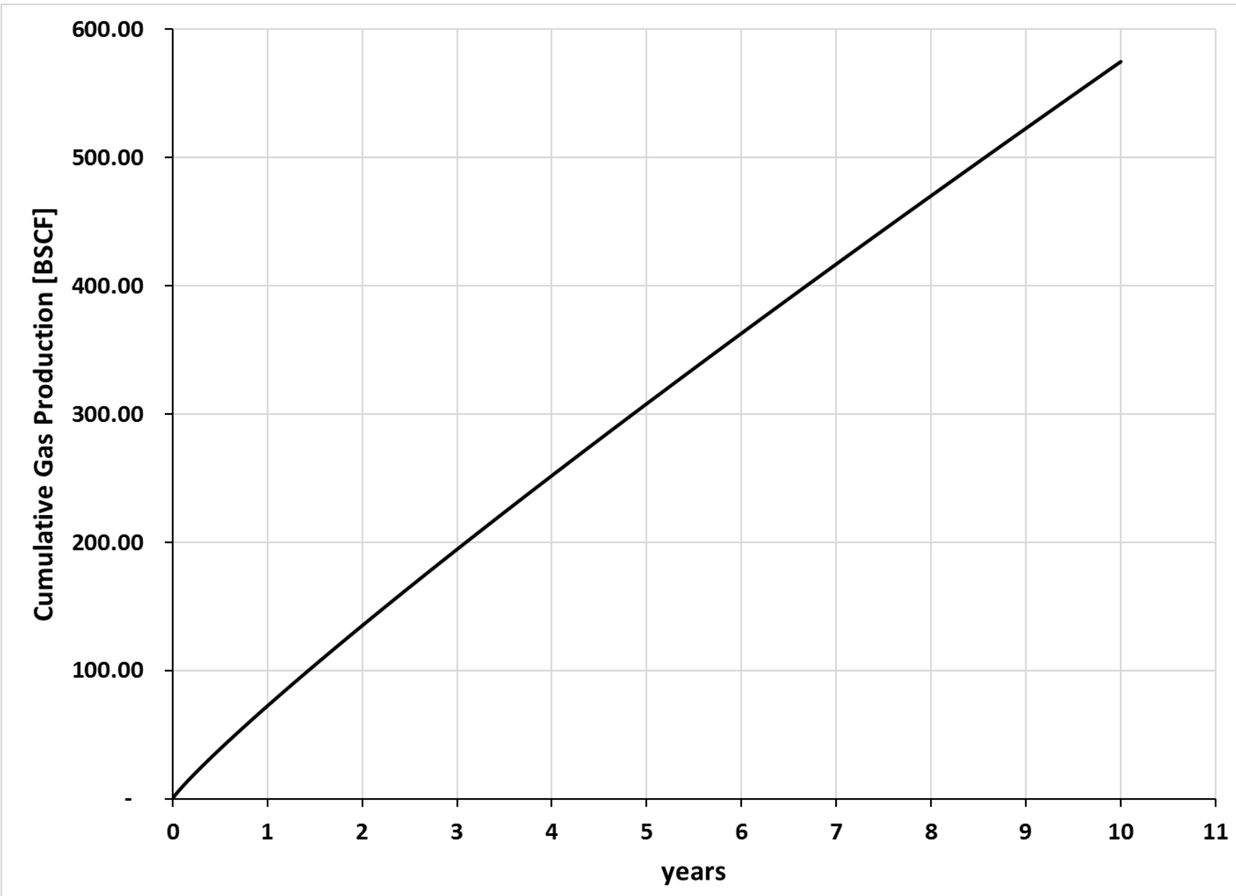

Figure 5.2: Cumulative gas production after 10 years

Now the aspect is how much wells we will drill to develop and produce 300 million standard cubic feet per day (MMscf/d). This will refer to some economic studies to show the revenues and the costs of the whole task from drilling to operations to production and transportation. Cash flow and net present value (NPV) to be done to see how feasible the number of wells in comparison to the daily production of natural gas.

CHAPTER 6

ECONOMICAL ANALYSIS

Every decision in the oil and gas industry is made based on an economic evaluation. Making the decision to capitalize in petroleum exploration and production projects is always a very complicated struggle. These projects are obstructed by many high risk issues associated with the petroleum industry, such as moderately high initial investment requirements, long-term investment horizons and negative cash flow during the first few years. These factors, coupled with dangerously instable price levels, makes the number of risks in the data used in decision making to invest in petroleum projects very high, and this consequently considers heavily on the minds of decision makers.

6.1 Economical Parameters

Commercial, non-commercial, and marginal fields are classifications of oil and gas accumulations.

- Commercial fields: These fields take into account the current risks of production operations such as geological, technical, political… The development of the field would result in a profitable operation for the producing company. At the end, we will reach to positive Net Present Value (Adamu, 2013).
- Non-commercial fields: these are fields with unexpected profitable operation. The probability to reach positive Net Present Value is less than 30% (Adamu, 2013).
- Marginal fields: these are fields in the middle zone; development can be profitable at their worst economic conditions. The probability of reaching a positive NPV is then between 30-70% (Adamu, 2013).

Parameters used in economic evaluation.

- CAPEX: Capital Expenditure is paid only once at the beginning of the project. The CAPEX can be broken down into two main categories, exploration and development costs.
- DRILLEX: It is the money paid during drilling and completing the well.

- OPEX: Operating Expenditure are those costs that are necessary to maintain production from the well. OPEX can be classified into six categories, such as labor cost, operating service, materials, utilities, annual overhead cost, and production transportation.
- Cash Flow: It is the difference between the revenues and the total costs.
- Discounted Cash Flow: Discounted cash flow is a method, which interprets the time value of money by discounting the upcoming cash flow to a present value reference.
- NPV: Net present value is suggested as the only screening criterion that need be calculated for selecting investments. The calculation is made directly by discounting the project cash flow one time at the cost of capital. If the value is positive or zero, the project will meet the investor's minimum criteria for selection. If it is negative, it will not.

Formulas used in economical analysis.

Cash Flow

$$\mathrm{CF} = \mathrm{REVENUE} - \mathrm{COST} \tag{6.1}$$

Discounted Cash Flow

$$\mathrm{DCF} = \frac{\mathrm{CF}}{(1+\mathrm{i})^{\mathrm{j}}} \tag{6.2}$$

i: discounted factor

j: year measured from project start up

Net Present Value

$$\mathrm{NPV} = \sum \frac{\mathrm{CF}}{(1+\mathrm{i})^{\mathrm{j}}} \tag{6.3}$$

According to the US gas market for 1 million British thermal unit (MMBtu) its value is 3.75 \$. Then, 1 MMscf = 1048 MMBtu.

As mentioned before that Block 4 consists of three reservoirs A, B, and C. Reservoir A is the largest reservoir with P90 1.04 Tcf of natural gas. Three plans were developed for the reservoir to reach the recovery factor of 600 Bscf.

6.2 Economical analysis for Plan A

Plan A we considered one well to be drilled in average of three months. The well produces around 60 MMscf per day, according to the neighboring natural gas fields in the Eastern Mediterranean region, the companies increase the diameter of the tubing to allow more gas to flow. The cost of the well around 35 million dollars with investment 100 million dollars and annual operating 50 million dollars. The inflation rate is 7% and the 5% increase for every year of DRILLEX and OPEX (Company, 2018).

Table 6.1 is the economic analysis in plan A. It shows the daily production and the production per year with the revenues. Then, it shows the costs from DRILLEX, CAPEX, and OPEX. In addition to the cash flow and the discounted cash flow. The net present value shows a negative number that means it is not feasible to continue with this plan (Figure 6.1). Therefore, it is not reasonable to drill only one well with 60 MMscf per day. Moreover, in such rate of production we cannot reach all the reserves in the reservoir.

Table 6.1: Economical analysis for Plan A

Years	Gas production scf/day	Gas production in year	Revenue USD	DRILLEX USD	CAPEX USD	OPEX USD	Total Cost USD	Cash Flow USD	Discount Cash Flow USD
1	0	0	0	35,000,000	100,000,000	0	135,000,000	-135,000,000	-126,168,224
2	60,000,000	14,530,000,000	57,102,900	0	0	50,000,000	50,000,000	7,102,900	6,203,948
3	35,630,000	12,520,000,000	49,203,600	0	0	52,500,000	52,500,000	-3,296,400	-2,690,844
4	33,250,000	11,880,000,000	46,688,400	0	0	55,125,000	55,125,000	-8,436,600	-6,436,242
5	31,930,000	11,480,000,000	45,116,400	0	0	57,881,250	57,881,250	-12,764,850	-9,101,162
6	31,030,000	11,200,000,000	44,016,000	0	0	60,775,313	60,775,313	-16,759,313	-11,167,438
7	30,340,000	10,970,000,000	43,112,100	0	0	63,814,078	63,814,078	-20,701,978	-12,892,152
8	29,800,000	10,790,000,000	42,404,700	0	0	67,004,782	67,004,782	-24,600,082	-14,317,472
9	29,340,000	10,640,000,000	41,815,200	0	0	70,355,021	70,355,021	-28,539,821	-15,523,772
10	28,950,000	10,500,000,000	41,265,000	0	0	73,872,772	73,872,772	-32,607,772	-16,576,138
11	28,610,000	10,390,000,000	40,832,700	0	0	77,566,411	77,566,411	-36,733,711	-17,451,921
								NPV	-226,121,415.88

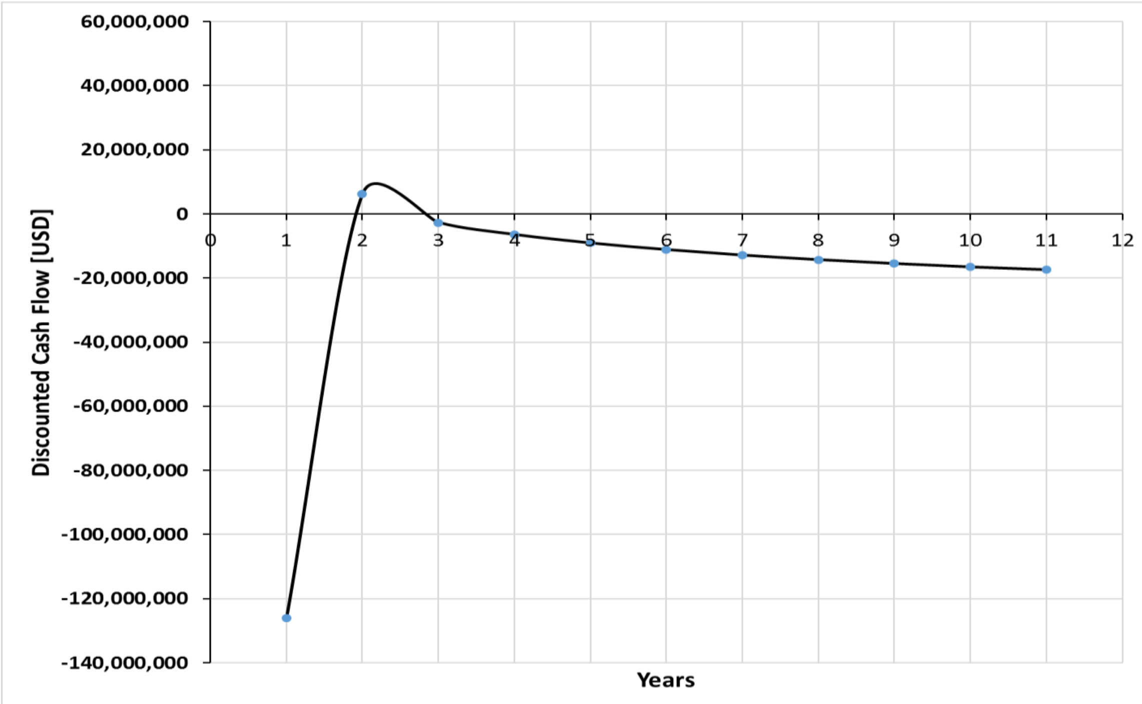

Figure 6.1: NPV analysis curve for Plan A

6.3 Economic analysis for Plan B

Plan B we considered three wells to be drilled in average of one year. The well produces around 60 MMscf per day. The cost of the well around 35 million dollars with investment 150 million dollars and annual operating 80 million dollars. The inflation rate is 7% and the 5% increase for every year of DRILLEX and OPEX.

Table 6.2 is the economic analysis in Plan B. It shows the daily production and the production per year with the revenues. Then, it shows the costs from DRILLEX, CAPEX, and OPEX. In addition to the cash flow and the discounted cash flow. The net present value shows a positive number that means it is feasible to continue with this plan (Figure 6.2). Therefore, we can drill three wells with 60 MMscf per day. Moreover, in such rate of production we can reach to 344 Bcf of the reserves that we can produced.

Table 6.2: Economical analysis for Plan B

Years	Gas production scf/day	Gas production in year	Revenue USD	DRILLEX USD	CAPEX USD	OPEX USD	Total Cost USD	Cash Flow USD	Discount Cash Flow USD
1	0	0	0	105,000,000	150,000,000	0	255,000,000	-255,000,000	-252,475,248
2	180,000,000	43,580,000,000	171,269,400	0	0	80,000,000	80,000,000	91,269,400	89,471,032
3	106,880,000	37,550,000,000	147,571,500	0	0	84,000,000	84,000,000	63,571,500	61,701,872
4	99,750,000	35,630,000,000	140,025,900	0	0	88,200,000	88,200,000	51,825,900	49,803,671
5	95,800,000	34,450,000,000	135,388,500	0	0	92,610,000	92,610,000	42,778,500	40,702,275
6	93,090,000	33,590,000,000	132,008,700	0	0	97,240,500	97,240,500	34,768,200	32,753,217
7	91,030,000	32,920,000,000	129,375,600	0	0	102,102,525	102,102,525	27,273,075	25,438,089
8	89,390,000	32,370,000,000	127,214,100	0	0	107,207,651	107,207,651	20,006,449	18,475,620
9	88,020,000	31,910,000,000	125,406,300	0	0	112,568,034	112,568,034	12,838,266	11,738,538
10	86,860,000	31,510,000,000	123,834,300	0	0	118,196,436	118,196,436	5,637,864	5,103,885
11	85,850,000	31,160,000,000	122,458,800	0	0	124,106,257	124,106,257	-1,647,457	-1,476,655
								NPV	81,236,297.04

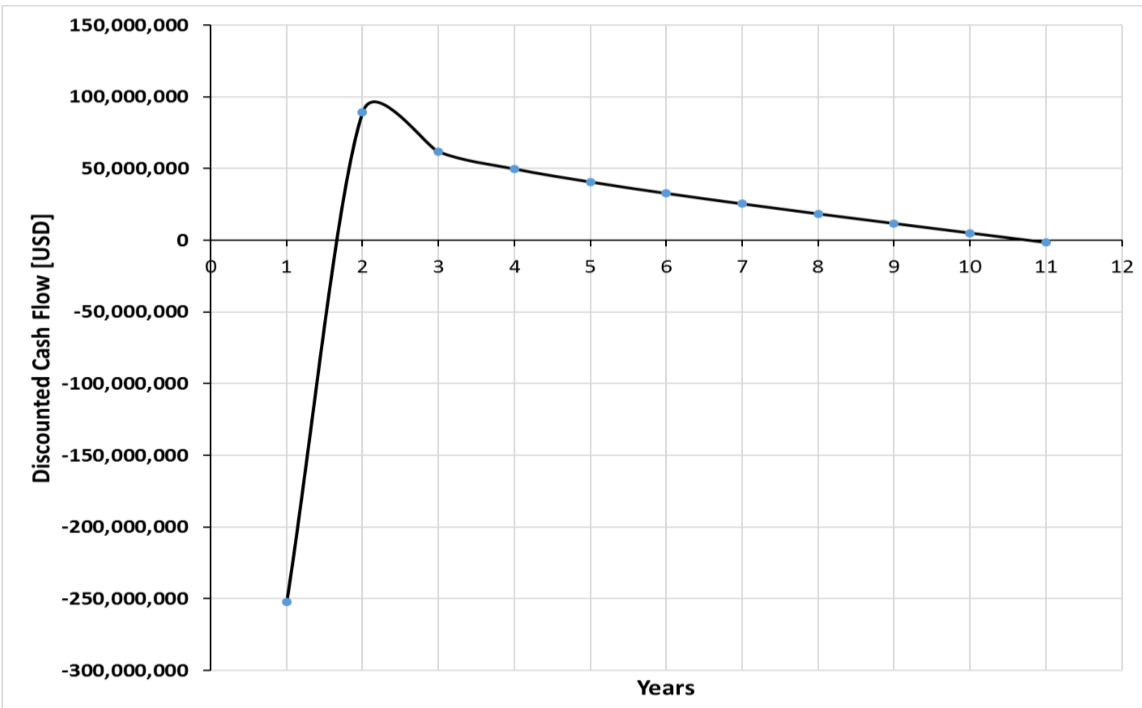

Figure 6.2: NPV analysis curve for Plan B

6.4 Economic analysis for Plan C

Plan C we considered five wells to be drilled in average of two years. Three wells in the first year and two wells in the second. The well produces around 60 MMscf per day. The cost of the well around 35 million dollars with investment 200 million dollars and annual operating 100 million dollars. The inflation rate is 7% and the 5% increase for every year of DRILLEX and OPEX.

Figure 6.5 is the economic analysis in Plan C. It shows the daily production and the production per year with the revenues. Then, it shows the costs from DRILLEX, CAPEX, and OPEX. In addition to the cash flow and the discounted cash flow. The net present value shows a positive number that means it is feasible to continue with this plan (Figure 6.3). Therefore, we can drill five wells with 60 MMscf per day. Moreover, in such rate of production we can reach to all available reserves 574 Bcf. This plan has the highest NPV value so it is the best choice for development of the reservoir.

Table 6.3: Economical analysis for Plan C

Years	Gas production scf/day	Gas production in year	Revenue USD	DRILLEX USD	CAPEX USD	OPEX USD	Total Cost USD	Cash Flow USD	Discount Cash Flow USD
1	0	0	0	105,000,000	100,000,000	0	205,000,000	-205,000,000	-191,588,785
2	0	0	0	73,500,000	100,000,000	0	173,500,000	-173,500,000	-151,541,619
3	300,000,000	72,640,000,000	285,475,200	0	0	100,000,000	100,000,000	185,475,200	151,403,012
4	178,140,000	62,580,000,000	245,939,400	0	0	105,000,000	105,000,000	140,939,400	107,521,993
5	166,250,000	59,390,000,000	233,402,700	0	0	110,250,000	110,250,000	123,152,700	87,806,173
6	159,660,000	57,410,000,000	225,621,300	0	0	115,762,500	115,762,500	109,858,800	73,203,557
7	155,140,000	55,980,000,000	220,001,400	0	0	121,550,625	121,550,625	98,450,775	61,310,195
8	151,720,000	54,860,000,000	215,599,800	0	0	127,628,156	127,628,156	87,971,644	51,200,298
9	148,980,000	53,950,000,000	212,023,500	0	0	134,009,564	134,009,564	78,013,936	42,434,412
10	146,710,000	53,180,000,000	208,997,400	0	0	140,710,042	140,710,042	68,287,358	34,713,830
11	144,760,000	52,520,000,000	206,403,600	0	0	147,745,544	147,745,544	58,658,056	27,868,020
12	141,570,000	51,940,000,000	204,124,200	0	0	155,132,822	155,132,822	48,991,378	21,752,758
								NPV	316,083,843

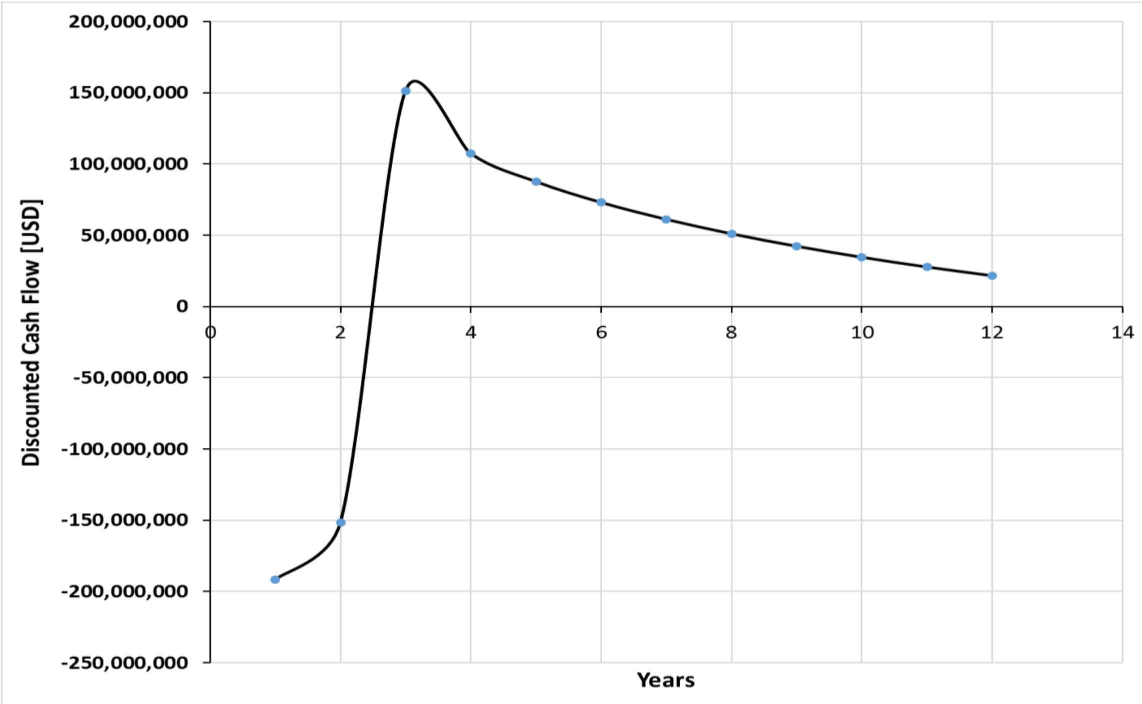

Figure 6.3: NPV analysis curve for Plan C

6.5 Lebanon's Domestic Gas Demand and Interim Gas Import Options

The first exploratory well will confirm whether the recoverable offshore resources are commercial or not. Authorities should balance between the usage of gas to meet local needs or export it. In the government policy, meeting the local needs, especially in the power segment, should be the top priority (El-Katiri, 2015).

In 2010, the Ministry of Energy and Water put a plan to use natural gas for two-thirds of the fuel mix, and to rise the fixed capacity to 5000 MW by 2020. The increase in the proportion of gas in the power mix would require heavy investment in the gas infrastructure (El-Katiri, 2015). One of the planned project is a costal pipeline of 173 km and 36-inch connecting a planned storage terminal onshore close the future Floating Storage Regasification Unit (FSRU) to Tyre in southern Lebanon, letting all of Lebanon's main power plants to tap the gas supply. Nevertheless, this project faces many obstacles plus terrestrial reclamation and finding the necessary funding for its construction (El-Katiri B., 2015).

Lebanon's position in the Eastern Mediterranean, with good seaside and land access, gives it a natural benefit for gas exports. The margin with "Israel" is closed but Lebanon has a number of other regional transaction selections (El-Katiri, 2015).

The “Islamic Pipeline” is a pipeline project transporting up to 25 bcm of Iranian gas to bordering Iraq and Syria. This can be a lifetime for Lebanon’s power sector. However, the project suffered from finance and practical problems related to the international sanction regime against Iran, lacking gas production within Iran to export additional quantities, and the security situation in Iraq and Syria (El-Katiri, 2015).

The “Arab Gas Pipeline” connects Egypt and Jordan. It transported Egyptian gas to Jordan and Lebanon. It can be used for opposite flows to both markets and relatively cheap link to be built between Lebanon and the pipeline. However, many doubts affect the practicality of this option. The distance is long and subject to disturbances. Before Lebanese gas becomes available, Jordan and Egypt may have contracted to buy gas, from Israel or other suppliers (El-Katiri, 2015).

Lebanon’s restricted chances for safeguarding pipeline gas imports from neighboring countries, LNG remains the country’s only choice. LNG has been considered as a selection since the 1990s, but the high original construction costs of an onshore regasification station converted policy efforts toward safeguarding lower-cost regional pipeline gas imports (El-Katiri, 2015).

CHAPTER 7

CONCLUSIONS AND RECOMMENDATIONS

7.1 Conclusions

The Eastern Mediterranean has newly discovered and prospective future hydrocarbon resources are of huge economic and geostrategic importance. Countries like Egypt, Cyprus, and Israel, since late 2000s, made their first significant offshore hydrocarbon discoveries. All countries in the Levant Basin have a chance to provide a cost actual source of energy for their historically import reliant on energy economies. In addition, they will have a potential high value source of revenues from gas exports into and outside the region.

Lebanon, as part of the Eastern Mediterranean, has many challenges before starting producing natural gas. The government will face many complex and difficult decisions. Some of these challenges are the formulation, acceptance, and implementation of the necessary laws, the founding of effective institutional and adjusting structures, and the efficient and obvious management of gas revenues.

In offshore Block 4, Lebanon has a chance to reach 1.04 Tcf of natural gas from one reservoir. This number can increase if we develop the other reservoir then additional amount of gas will be produced. Many economic studies will be done to decide whether the reserves are commercial or not. A plan with 5 wells in Reservoir A looks feasible with 60 MMscf per day.

7.2 Recommendations

Lebanon’s natural gas should be used primarily to meet local needs, instead of fuel oil in power generation. If adequate amounts are discovered to badge exports, these should, be through pipeline sales to countries in the district, such as Syria, Egypt, and Jordan. A joint LNG export facility with Cyprus might become reasonable if both countries discover abundant additional quantities of gas.

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