Evaluation Of EOR Potential in Shale Oil Reservoir, Focusing on Wettability, and In-Situ Fluid Composition

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DEDICATION

I would like to dedicate this desertion to our beloved parents and my humble teachers of my whole student life.

DEAN of GRADUATE SCHOOL OF SCIENCE, ART, AND TECHNOLOGY KHAZAR UNIVERSITY, AZERBAIJAN

CERTIFICATE

This thesis, **"Evaluation of EOR Potential in Shale oil reservoir, focusing on wettability and in-situ fluid composition,"** was written by **Imtiaz Ahmed** under the direction of his supervisor **Prof. Shahin Negahban** and advisor **Ph.D. con. Fahad Iqbal Syed** and approved by the thesis committee members have been presented to and accepted by the HOD, Petroleum Engineering Department, in partial fulfillment of the Master of Petroleum Engineering requirements.

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In the name of Allah, who is the most magnificent and merciful, he is the one who grants us knowledge and courage to do things that we are not worthy of doing. The compilation of this desertion was a daunting task that was eventually made easy with the grace of Almighty Allah.

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I also acknowledge all other people who directly and indirectly supported me during the entire thesis. Without their support, this desertion would not have been this much interesting.

TABLE OF CONTENT

LIST OF ABBREVIATIONS

TCF	Trillion Cubic Feet
UGR	Unconventional Gas Reservoir
HC	Hydrocarbons
OGIP	Original Gas in Place
SRV	Simulated Reservoir Volume
P	Pressure
Kf	Fracture permeability
Lf	Fracture length
MMSCFD	Million standard cubic feet per day
DST	Drill stem test
mD OR md	Milli Darcy
Pwf	Wellbore flowing pressure
PI	Productivity Index
RF	Recovery Factor

ABSTRACT

Developing shale oil and gas resources is becoming essential due to the continuous depletion of conventional reservoirs. As the thrust towards shale oil resources increases, the petroleum industry, especially in countries striving to mitigate the challenges of such reservoirs. One of the essential techniques utilized to increase the production capability of such reservoirs is hydraulic fracturing. Besides, EOR gas injection assists the recovery of the process by increasing pressure and decreasing the oil's viscosity. This research evaluates EOR potential by focusing on wettability variations on recovery performance. In unconventional shale oil reservoir. The candidate reservoir is based on a simple layer cake model, simulated on a dual permeability approach with four fractured layers. The reservoir is first perforated, and then the reservoir is undergone through the EOR CO_2 cyclic gas injection process.

They huff and puff cycle has been done in the reservoir model for ten years. The research studies the effect of wettability on an unconventional reservoir. Three different wettability cases in 3 different permeability models, i.e., 0.00001 mD, 0.0001 mD, and 0.001 mD, are studied. The sensitivity result shows that the 0.001 mD model possesses the highest cumulative production accounts for 550,000 BBL, followed by 0.0001 mD and 0.00001 mD. Through sensitivity analysis and comparison, it has been concluded that wettability variations do affect the recovery performance in the reservoir model that is even below 0.01 mD permeability. Besides, the changes in the wettability in 3 different permeability distribution models significantly improve the production performance of the reservoir.

CHAPTER 1

INTRODUCTION

1.1 BACKGROUND

Shale oil is considered a liquid hydrocarbon. It exists in a free dissolved or adsorbed state in the shale rock. Shale rock is basically a source rock. The shale rock is typically made up of 58% clay, 28% quartz, 6% feldspar, 5% carbonate minerals, and 2% iron oxides. Shale rock contains 95% organic matter in all sedimentary rocks [1].

Figure 1.1.1 Oil Shale (Zoefact)

Shale oil is categorized into three categories depending upon the origin of organic material: terrestrial, lacustrine, and marine. Terrestrial oil shale descends from organic material such as animals and plants; lacustrine is formed from water algae remains. In contrast, marine oil shale deposits result from saltwater algae, acritarchs, and dinoflagellates. [2] The quality of Shale is essential to figure out to find out the suitability to produce it. Different factors are responsible for the oil shale quality, such as Richness, the organic carbon in the shale ore, hydrogen and moisture content, organic material content, and concentration of contaminants like nitrogen, sulfur, and metals. [3] Shale formation is categorized in the unconventional reservoir. It possesses significantly less permeability. It is produced from oil shale rock particles. Shale oil contains different hydrocarbons, including paraffin, olefin, and aromatics. Being an unconventional rock formation, shale oil extraction is quite different. It includes Pyrolysis, thermal dissolution, hydrogenation. The direct burning of raw shale oil extracted can be utilized as fuel.[4] Shale oil is from shale formation that trapped a considerable amount of hydrocarbon content, Kerogen. The shale oil can be extracted from the organic matter kerogen through the retorting method. The retorting method is used after mining oil shale rock is transported to the surface. The oil shale rock is crushed and loaded into the reactor, called a retort at the surface. At this stage, the temperature is 400-500°C. Here, the heating of Kerogen in the absence of oxygen will produce shale oil. The other method to recover oil from oil shale is the insitu method that includes burning oil shale underground and pumping the oil at the surface.[5] Shale oil deposits vary broadly; there are nearly 100 significant deposits in 27 countries worldwide. It is typically found at shallow depths less than 900 meters. [6]

With the gradual decline of conventional hydrocarbon resources, unconventional natural resources such as shale oil and gas have become the petroleum industry's limelight. Besides the new area of research in the petroleum domain, shale oil and gas are becoming an alternative for conventional oil and gas resources. Currently, only the USA and Canada are the major players in shale oil and gas production. The shale oil production in the USA was 4.9*106 barrels per day in 2015.[7] According to the USA EIA, the production may increase up to 7.1*106 barrels per day in 2040. [8]

According to U.S. geological survey 1965, oil shale resources are estimated to be at least 8 trillion barrels worldwide. [9] The United States has the largest oil shale resources globally, accounting for 6 trillion barrels, almost 75% of the world shale oil resources. [10] The countries that possess the highest shale oil resources are the USA, Russia, the Democratic Republic of Congo, and Brazil, which range from 80-250 billion barrels of resources. [11]

1.2 PROBLEM STATEMENT

The shale oil possesses ultra-low Porosity and low permeability. Recovery from shale oil only accounts for 10% of OOIP from the traditional unconventional reservoir recovery methods such as Hydraulic fracturing. The role of supportive technology; enhanced oil recovery will be evaluated to enhance the oil shale production. The rock property: wettability and the insitu fluid composition of oil shale are the parameters that will be analyzed to improve the recovery.

1.3 OBJECTIVES

The objectives of this study are:

- Development of a dual permeability shale oil simulation model of horizontal well and Analyzation of cumulative production, gas rate, and recovery factor with and without huff and puff.
- Analyzation of permeability changes on wettability in shale oil formation.
- Comparing the well performance in accordance with the alteration of wettability and permeability.
- To discuss the role of EOR in shale oil recovery.
- To analysis the potential of wettability on production
- To evaluate the in-situ fluid composition and how their alteration affects shale oil production.

1.4 SCOPE OF THE STUDY

As the conventional reserves are declining and with the increase in the demand for oil and gas supplies, there is a need to produce oil and gas from their unconventional assets. This thesis will prove helpful in modeling, developing, and estimating production from shale oil reservoirs through a comprehensive study of the potential of EOR in shale oil. Further, this study helps evaluate the fundamental parameter for optimizing hydraulic fracturing performance.

1.5 THESIS STRUCTURE

This thesis consists of five chapters.

Chapter #01:

The first chapter includes a detailed overview of the research work that includes the problems associated with shale oil reservoirs besides the objectives and scope of the study.

Chapter #02:

The second chapter focuses on the recovery techniques and supportive techniques to enhance shale oil production. Furthermore, it discusses the role of wettability and insitu fluid composition and their effects on recovery.

Chapter #03:

The third chapter models the candidate shale oil zone.

Chapter #04:

Chapter four deals with the results and discussions.

Chapter #05:

Chapter five concludes the thesis work with imperative outcomes and future recommendations.

CHAPTER 2

LITERATURE REVIEW

2.1 SHALE OIL

This chapter describes the work that many researchers have previously done. There are vast numbers of case studies published in different journals which cover various scenarios and different challenges for the design of shale oil production optimization. The conclusion of those research papers is discussed below.

Due to the increasing demand for energy globally and the conventional gas reserves are depleting with the passage of time. The energy industry has exploited unconventional assets to meet the demand and supply curve. Shale oil and gas have received significant attention because of their potential to supply the world with enough energy for decades to come. The United States is now the number one shale oil gas producer globally and, together with Canada, accounts for more than 25% of global shale oil and gas production. Shale oil will play an ever-increasing role in this resource base and economic outlook of the United States. Furthermore, shale oil and gas production are projected to increase to 49% of total gas in the United States by 2035, up from 23% in 2010, highlighting the significance of shale oil and gas in the future energy mix in the U.S. [3] Oil and gas shale is an organic-rich shale formation that serves as the hydrocarbons source rock and as the reservoir, Shale, a low permeable rock with a permeability of 0.0001 mD.

Oil shale is a sedimentary rock that contacts a hefty amount of organic matter; Kerogen had not undergone immense temperature and pressure compared to conventional oil. [12] Kerogen is processed and converted into shale oil and other hydrocarbons with advanced technologies. The type of Kerogen within the shale rock highly affects the hydrocarbon produced. For instance, the Kerogen in the coal-derived from plants produces hydrocarbon gasses. At the same time, the other hand, the oil shale kerogen is mainly derived from algae. The production from this gives the shale oil identical to conventional oil. [13]

2.2 Shale Reservoir Characteristics

Shale reservoir results from a mixture of salt and clay particles' compaction. However, their fissile nature, laminated orientation, and fined particles; are different from other claystone and mudstone. These can be easily broken along their lamination. [14] The grain particles are very small, less than 1/256 mm in diameter. [15] The permeability of shale formation is in the order of nano-Darcy. Shale formations possess minor natural fractures that make effective permeability higher than nano-Darcy. The shale formation is where hydrocarbons are generated in source rock or migrated within a short distance from the source rock. Oil shale is the shale rock formation, while shale oil is the hydrocarbon inside the shale rock. [16]

Core samples of the shale rock can provide helpful information regarding geochemistry and mineralogy. However, the properties are location-specific from where the sample was retrieved. To find the potential production of the shales, the geochemical properties typically derived from core data are essential. Besides, the geochemical properties of the shale rock are needed to characterize the total organic carbon (TOC), thermal capacity. Organic material present in shale rock is generated from plants and animals. The transformation of these living organisms through diageneses into Kerogen will break down to form hydrocarbons through a chemical process catagenesis. [17]

Source rock quality	TOC, %	Pyrolysis S2	Hydrocarbon, ppm
None	<0.5	<2	<200
Poor	0.5 to 1	2 to 3	200 to 500
Fair	1 to 2	3 to 5	500 to 800
Good	2 to 5	5 to 10	>1200
Very good	>5	>10	

Table 2.1: Evaluation criteria of Source rock (Courtesy of Schlumberger)

The shale formation has inherent few characteristics, which are given below:

- Very Low Porosity
- Very Low permeability
- Non-Darcy flow
- Rock surface desorption.

The above parameters affect the productivity and performance of the modeling techniques. The most significant element in modeling is rock surface desorption.it should be adequately well established and not avoided in reserve estimation and future production forecasting.[18] Some studies have suggested that gas desorption from shale rock surfaces may contribute to extra gas production from shale oil reservoirs. It has been reported that gas desorption contains up to 22% of the total gas production in 20-year period of production for two significant producers in the US, Barnett shale and Marcellus shale.[19]

Ultra-low Porosity and low permeability are the two-complex characteristics of shale oil gas reservoirs. This is the reason shale oil gas reservoirs produce at a very low rate. They possess ultra-low permeability that add more complexity in developing such reservoir causes a variety of challenges and concerns. Evaluation of hydrocarbon and development of shale oil reservoir and considering all related parameters as a definitive solution. [20]

2.2.1 Porosity

Porosity is the ratio of void spaces to the bulk volume in a formation. It is measured in percentage [21]. There are two types of Porosity, i.e., Total Porosity and Effective Porosity.

Total Porosity: it is defined as the total pore volume divided by the bulk volume of the rock.

Effective Porosity is defined as the volume of interconnected pores divided by the bulk volume of the rock.

In the case of shale rock, the Porosity is minimal up to micro and nano-size range. The void spaces in the shale formation have an inconsistent and minimal volume of water saturation and residual hydrocarbon. The effective Porosity in the shale formation is caused by the fracturing process [22]. This property of the rock plays a vital role in accumulating hydrocarbons.

2.2.2 Permeability:

It is defined as the measurement of the connectivity between the pore spaces and the capability of the rock to flow the fluid through these inter-connected pores. It is measured in Darcy or millidarcy [23]. Three types of permeability are absolute, effective, and relative permeability.

Absolute permeability: is defined as the ability of the rock to flow the fluid when only one type of fluid is present.

Effective permeability: is defined as the permeability of one fluid to flow in the presence of another fluid.

Relative permeability: is defined as the ratio of effective permeability to absolute permeability.

In shale formation, the permeability is in nano Darcy, and stimulation methods such as hydraulic fracturing are required to get the hydrocarbon [24].

2.2.3 Non-Darcy Flow:

Darcy law defines the rate at which well flows, depends upon the permeability (effective) and the reservoir fluid viscosity, and is the function of pressure difference [25].

In the case of shale formation, there is a strong adhesion force between the formation rock and the fluid in a low permeability formation. Darcy law is not appropriate for explaining the liquid flow regime in shale formation [26].

Non-Darcy flow does not follow Darcy's law which describes laminar flow, so in the Shale formation, the Reynolds number exceeds the limit of Laminar flow; thus, its fluid propagates in turbulent flow [27].

2.3 Shale Oil Extraction:

Unlike conventional oil, shale oil cannot be recovered only by drilling. There are two methods of recovering shale oil-ex situ and in situ processing. The ex-situ method requires the conventional mining method such as open pit, strip, or underground mining. Further, it is transported to a processing unit that will retort or heat the Shale; the process is called Pyrolysis.

While insitu method involves heating the shale rock directly inside the underground at low temperature and for a longer time. [28] [29]

2.3.1 Pyrolysis:

After the extraction of shale rock, the following process is Pyrolysis, where the Shale is exposed to extreme heat without oxygen that results in the chemical change in the rock. The Kerogen liquefies and separates from the rock as an oily substance. This oily substance is not actual crude oil, but it must undergo a refining process to transform into synthetic crude oil [30]

Pyrolysis is a powerful tool to evaluate the rock and kerogen sample's quantity, type, and thermal maturity. As the temperature gradually increases, the shale rock releases CO_2 besides hydrocarbons. [31] Graph line S1 shows free oil and gas released from the rock sample without cracking during the first heating stage. The heavy hydrocarbon breaks down during the second stage, S2, and evolves into hydrocarbons. The second stages provide information about the potential hydrocarbon production from the rock if thermal maturation continues. The third stage, S3, corresponds to CO_2 evolution expressed in milligrams per grams of rock. Understanding the amount of heat necessary to create different chemical compounds in the rock can help understand the history and the extent of thermal maturation it has already undergone. [32]

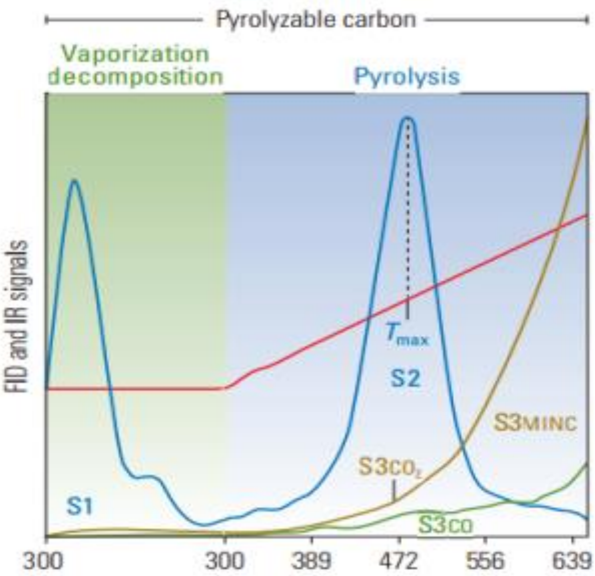


Figure 2.3.1- Pyrolysis results. Free hydrocarbons are measured by the S1 peak, and the residual hydrocarbons are measured by the S2 peak. (Courtesy by Schlumberger Geochemistry manual)

The shale oil possesses significantly less permeability; the oil shale resources are developed through horizontal drilling and multi-stage fracturing. However, 10% of the initial oil in place can be recovered. Thus, supportive technology is required to increase recovery. Enhanced oil recovery is used as a complementary recovery process in this regard. The laboratory results show that rock/fluid interaction highly influences the well performance. The rock/fluid interaction depends on rock wettability, reservoir conditions, and fracking fluid. The wettability being the most critical factor, its evaluation provides further information about the low oil recovery factor, residual oil location, and potential EOR technique to produce residual oil.

2.3.2 Horizontal well technique

For the last few years, the applications of horizontal well technology have been wide expedited by the increment of unconventional reservoirs. A horizontal well will have higher productivity at a low drawdown than a vertical well. The critical advantage of horizontal well technology is to boost the contact space with the formation.

Now it's well understood that a horizontal well is one of the best enhancements in economically developing shale reservoirs. The increasing oil price and the advancements in horizontal drilling and hydraulic fracturing technologies have allowed industries to satisfy the longer-term energy demand, though within the facing of speedy decline in traditional organic compound reserves. the benefits of the horizontal well may be thought of as followings:

1. Larger flow space
2. scale back the chance of water or gas cresting
3. Use in increased recovery applications
4. Created multiple little fractures
5. Cross many interested pay zones

Since the success achieved in Barnett shale, by utilizing horizontal well with multi-stage fracturing techniques, industries initiated the new era of horizontal drilling and completion styles to boost the productivity of shale oil wells. Currently, it's well understood that a horizontal well is one of the best enhancements in economically developing gas sedimentary rock reservoirs. The increasing gas demand and the advancements in horizontal drilling and hydraulic fracturing technologies have allowed industries to satisfy the longer-term energy demand, though within the facing of speedy decline in traditional reserves. It's famous that unconventional sedimentary rock gas reservoirs exist over giant quantities within the U.S. There are a unit several sedimentary rock gas basins remained to be explored and developed. It's essential to pick the proper completion approaches for horizontal wells considering the ultralow Porosity of sedimentary rock formation. Subsequent literature may be found concerning completion technique optimizations appropriate for a shale rock formation.

2.3.3 Hydraulic Fracturing Application

Hydraulic fracturing has received recognition for one of the most effective techniques for raising the productivity of unconventional reservoirs. Hydraulic fractures area unit accustomed to eliminating formation injury and extending the physical phenomenon of the fluid flow path to the wellbore. Permeability showed that non-Darcy effects area unit reduced, and also the well can suffer less productivity reduction once condensation interference happens.

Hydraulic fracturing has evolved into a method appropriate to stimulate most wells below very varied circumstances. Initially advised for low-permeability gas, it still plays a vital role in developing low-permeability formations and is progressively manufactured from shales and coal seams [33]. Generally, a vertical well trained and completed in an exceedingly tight gas reservoir should be successfully stimulated to produce gas flow at commercial rates and produce commercial gas volumes. Though in some naturally broken tight gas reservoirs, horizontal wells area unit sure-fire, usually they conjointly want fracture stimulation.

2.3.4 Horizontal well with multi-stage hydraulic fracturing

Multi-stage fracturing treatment has become a sure-fire that supplies gas from ultralow porosity sedimentary rock reservoirs. An outsized volume of fracturing fluid is injected to form multiple fractures, so the contact space of the wellbore with the reservoir may be considerably improved. Not like explosives that last short momentum isn't an honest approach. A pressure differential between the wellbore and the original reservoir is generated as fluid is pumped into the leaky formation. The speed will increase, the pressure distinction differential conjointly will increase. Eventually, this pressure differential can cause stress which will exceed the strain required to interrupt the rock apart, forming a fracture.

To create additional fracture stage density, multiple perforation clusters seem to be an honest thanks to adding fracture density stage. There's a trial to form additional perforation clusters utilizing restricted entry; however, the study indicated this effectiveness for rising production-proven dissatisfactory. In his paper, Baily [34] [35] argued that solely half-hour of the perforation intervals conducive showed supported production work information. A typical utilization technique of cemented liners with plug and perf technique encompasses a massive disadvantage. Making additional stages is proportional to additional fracture trucks, additional pumping frac fluid, crews. What is more, technically speaking, it's tough to use cemented liners and bridge plugs to form high stage numbers that are also a long job as expressed on top of.

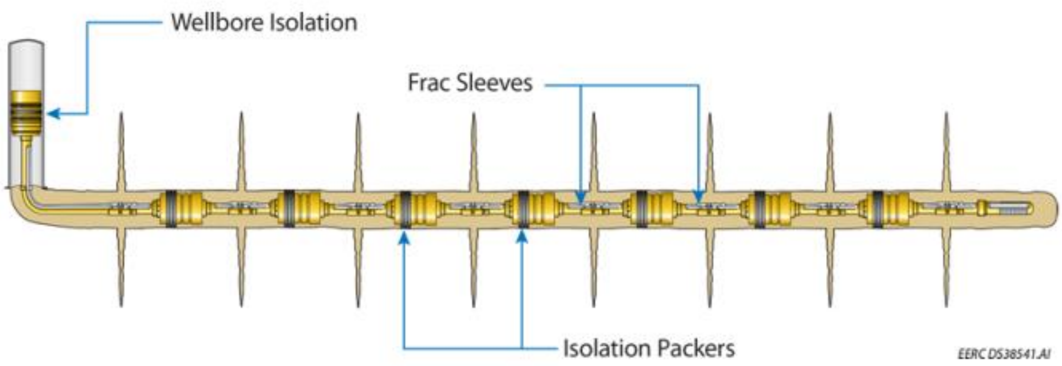


Figure 2.3.4 StackFRAC® HD™ Multi-Stage Fracturing (Courtesy by Packers Plus)

With techniques advancements, the StackFRAC HD application appears economical and technically possible for taking stages to count thirty or higher. The method uses a graduated ball drop system at the toe of the well to form upwards of twenty or additional stages. The system contains ported sleeves between isolation packers on a one-line string. Once the ball is born at the toe of the wellbore, it isolates the wellbore circulation, ensuing in the pressure buildup within the tube. This method intends the isolation packer to expand to isolate the horizontal wellbore into stages. After that, a ball born once more into the fluid and pumped up down the string can sit within the mechanical sleeve. This action can open the sleeve exposing the ports and amusing the fluid to the formation, which creates a hydraulic fracture among the isolated zones.

2.4 Factors affecting the fracturing in shale oil:

Few parameters are hurdle in modelling of Shale oil:

Understanding of relations among following parameters are the fundamental challenges of shale oil development

- Fracture Complexity i.e., Network Fracture Spacing
- Fracture Conductivity
- Matrix Permeability i.e., Uncertainty in matrix permeability
- oil Recovery[36]

2.4.1 Evaluating Production From Unconventional Gas Reservoirs

Researcher has determined the production from the shale oil gas rock by activating or stimulating the natural fractures or rock fabric with large volume of water and small mesh-proppants. Under stung the relation between the natural fractures and fracture that we have initiated. For a given matrix permeability and Pressure, gas production will be determined by the number and complexity of fractures created, their effective conductivity (kfwf), and the ability to effectively reduce the pressure throughout the fracture network to initiate gas production.[37]

2.4.2 Effect Of Network Size On Oil And Gas Recovery:

The effect of fracture network size is shown in Figure 2.4.2, illustrating that gas recovery can improve dramatically if the SRV can be increased

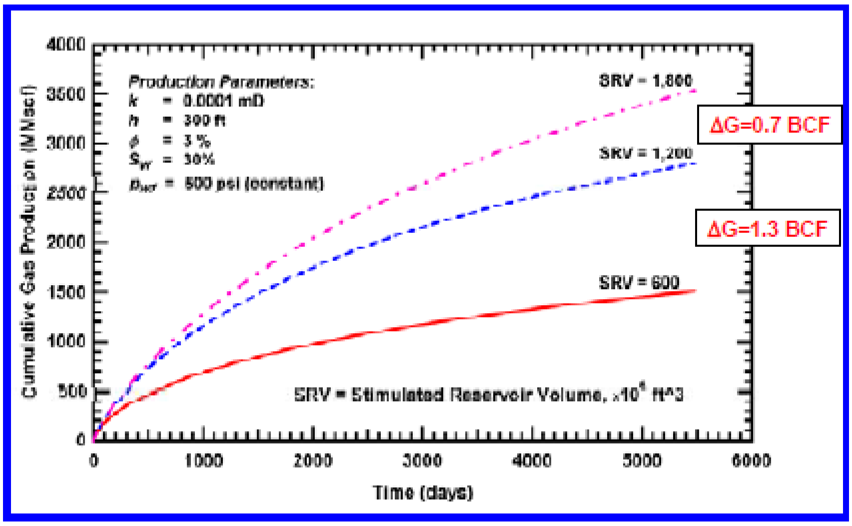


Figure 2.4.2 Effect of fracture network on recovery, Craig L.Cipolla (2008)

2.4.3 Network Fracture Conductivity

Figure 2.4.3 shows the effect of network fracture conductivity on gas production. The top portion of the figure shows the pressure distribution within the reservoir after 1 year for fracture conductivities of 0.5, 5, and 20 md-ft, illustrating that the very shale reservoir matrix cannot be effectively drained when the fracture conductivity is too low. The bottom portion of the figure shows the cumulative gas production for fracture conductivities, ranging from 0.5 to 50 md-ft, emphasizing the dramatic effect of network fracture conductivity on well performance and gas recovery. Fracture conductivity of 50 md ft or higher may be required to maximize production rate and gas recovery in this complex fracture network, even when matrix permeability is 0.0001 mD.

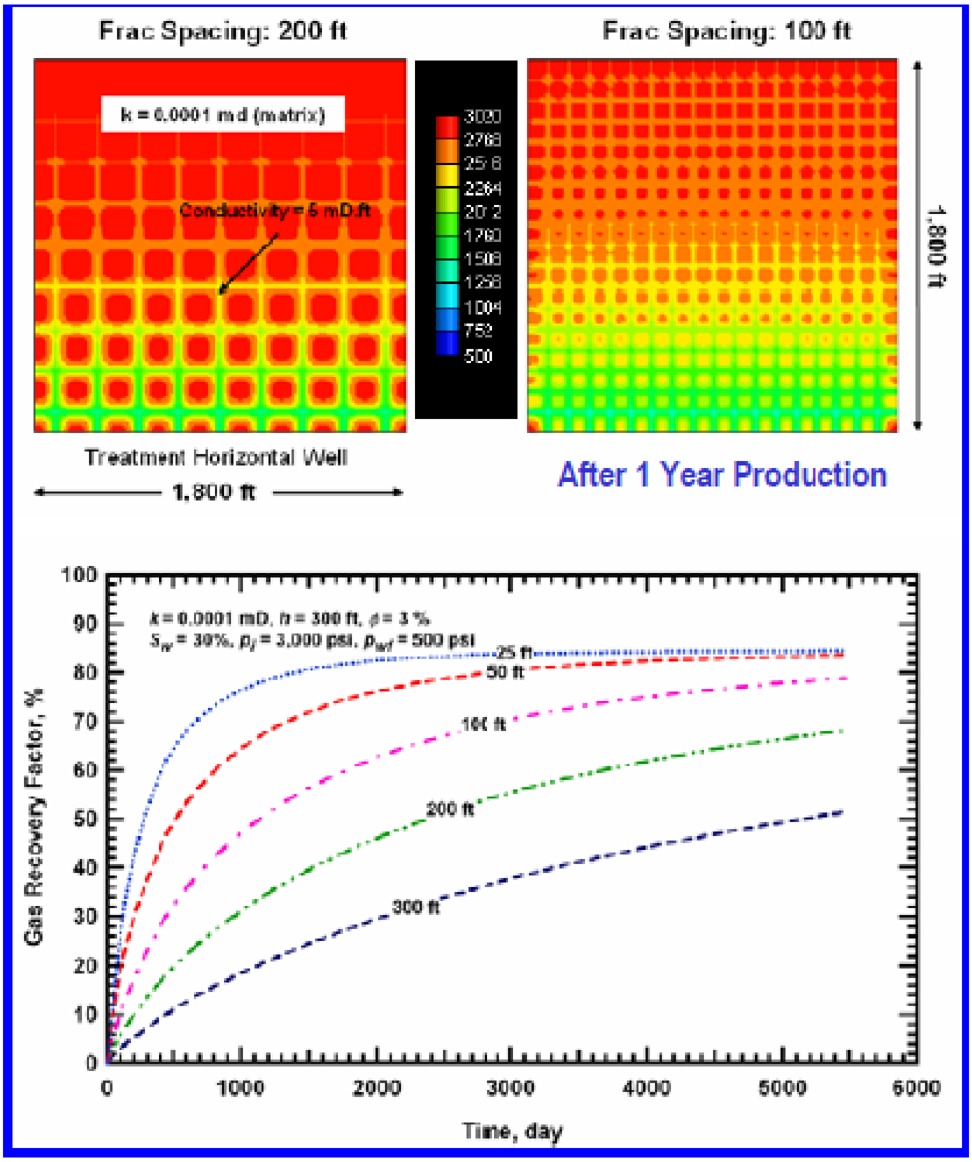


Figure 2.4.3 Effect of fracture conuctivity on recovery, Craig L.Cipolla (2008)

2.4.4 Fracture Spacing:

Figure 2.4.4 shows the effect of the spacing between the primary fractures in a horizontal well completion. The spacing between the primary fractures in a cased and cemented horizontal well is a function of the number of fracture treatment stages that are pumped. If a high relative conductivity primary fracture can be created, the effect of primary fracture spacing is small. 100 ft network fracture spacing However, if a high relative conductivity primary fracture cannot be created, then reducing the spacing between the primary Figure 2.4.4 - Impact of primary fracture spacing.

fractures by pumping more fracture treatment stages will materially affect production rates and gas recovery.

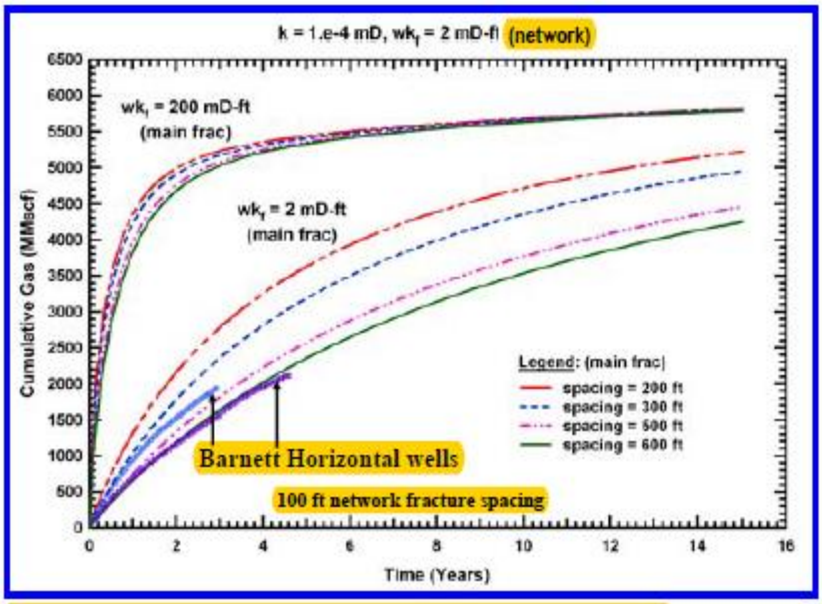


Figure 2.4.4 Effect of fracture spacing on recovery, Craig L.Cipolla (2008)

2.5 Economic Production from Shale:

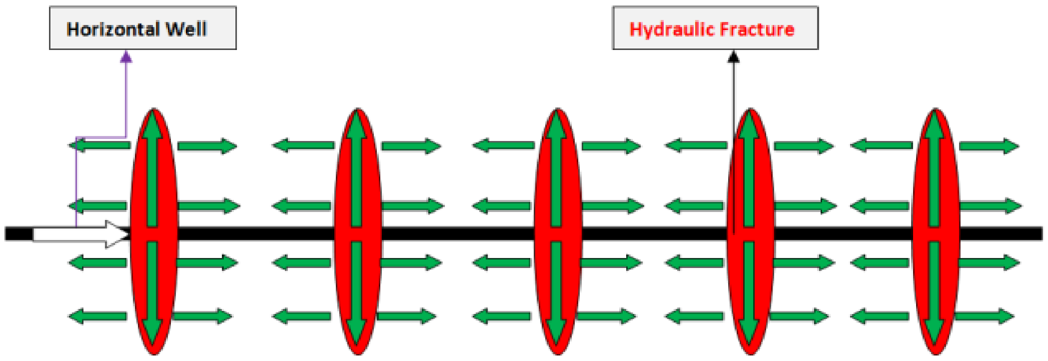
The economic production will achieve only if a very complex, highly nonlinear fracture network can be created that effectively connects a huge reservoir surface area to the wellbore. The success of Barnett shale field one of the examples in front of us that the economic production of gas is possible from shale (reservoir rock) that was previously considered source rock or cap rock.[38]

2.6 Cyclic steam Stimulation used for heavy oil production introduction

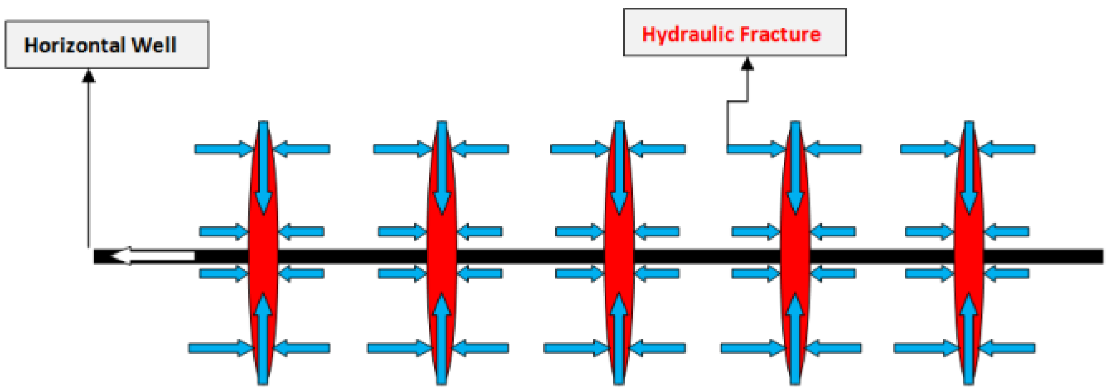
Cyclic steam stimulation was discovered accidentally within the Mene Grande field in Venezuela in 1959 once the Shell company tested a steam and steam poor out behind casing in an exceedingly steam injection well. Cyclic steam stimulation was originally used for the event of significant oil, and it was discovered that steam injection into a heavy-oil reservoir might increase production rate by factors of five to ten. Thermal recovery processes area unit the foremost advanced EOR processes and contribute vital amounts of oil to daily production [39]—most of the oil results from cyclic steam injection and stream drive. Before the appearance of thermal recovery techniques, primary production from significant oil reservoirs was five-hitter OOIP or less. The production rate declined with time because the reservoir energy depleted. Thermal techniques aim to scale back oil consistency to extend its quality through the injection of steam that brings the heat. In cyclic steam stimulation, steam is injected into a well at a high rate and air mass for a brief time (10 days to a month). The well is enclosed for many days for warmth distribution, known as the "soaking period." The initial oil rate is high due to the reduced oil consistency at the inflated reservoir temperature and below the take pleasure in the fast reservoir pressure by gas injection close to the wellbore. Oil rate declines with the decreasing of heated zone temperature results from heat removed with the created fluids and warmth loss. However, there are some technical failure cases for cyclic steam injection and earth science complexness and physics inefficiencies. Potential difficulties like high pressures in injection cycles, combined with poor quality ratios and high porosity streaks, result in sizeable viscous fingering and channeling. [40] Well, issues and surface issues that arise due to cyclic aggressive steam injection embrace accelerated corrosion of steel merchandise, resulting in breaching the casing, which happens comparatively ordinarily.

These potential difficulties mix with the high value of generating heat and alternative prices that build the economic viability of such project's problematic. However, in our work, we don't care about the thermal impact, just like the temperature influence of injected fluid, that isn't steam stimulation. Therefore, we tend to use a black-oil model for simplicity. We primarily evaluate the system's consistency reduction and relative porosity changes caused by miscibility with injected gas. There are some accelerations of recovery by the increasing reservoir pressure by virtue of injected gas close to the broken space.

The technique we tend to develop is illustrated in Figures 2.6 in that



cyclic gas stimulation is applied in a horizontal well with multi-stage hydraulic fractures. Cyclic gas stimulation as a secondary recovery technique is applied once primary production. Our work investigated completely different well schedules for cycle variations (Injection time and production schedule in every cycle). It was discovered that there's a vital contribution to progressive oil recovery quantity to just about twenty-second seconds. Traditionally, primary production from oil reservoirs even applied with hydraulic fracturing techniques was 5-10% OOIP or less. We tend to believe this method's event can also promote the successful development of oil reservoirs, particularly below the current lower cost of gas. While not incentives from gas worth, the trade inclines to target the stormy development of unconventional reservoirs like oil reservoirs. This thesis is devoted to checking a way to improve the recovery in oil reservoirs due to no alternative techniques on the



market at this point.

Figure 2.6 Cyclic gas injection applied in horizontal well with multi-hydraulic fractures (Well production schematic diagram, a horizontal well is used as production well)

2.7 Recovery Mechanisms

The overall driving mechanisms that give the natural energy necessary for oil recovery may be rock and liquid enlargement drive, depletion drive, gas cap drive, water drive, gravity evacuation drive, and combination drive. Oil enlargement may be an essential half among those mechanisms, but not the handiness of alternative artificial introduced energy. The rock and fluids expand thanks to their compressibility.

As the enlargement of fluids and reduction within the pore volume occurs with the decreasing reservoir pressure, the crude and water are going to be forced out of the pore house to the wellbore because the pressure drops within the fracture system, oil flows from the matrix to equilibrate the matrix pressure with the encircling fracture pressure. This production mechanism may be thought of as enlargement of the oil among the matrix block, either on top of the bubble purpose or by answering gas drive below the bubble purpose. Most of the oil is contained within the matrix system in oil reservoirs. However, the assembly of oil to the wells is thru the high porosity fracture system. AN injected fluid doesn't sweep out oil from the matrix block in such a system. Production from the matrix blocks may be related to numerous physical mechanisms, including:

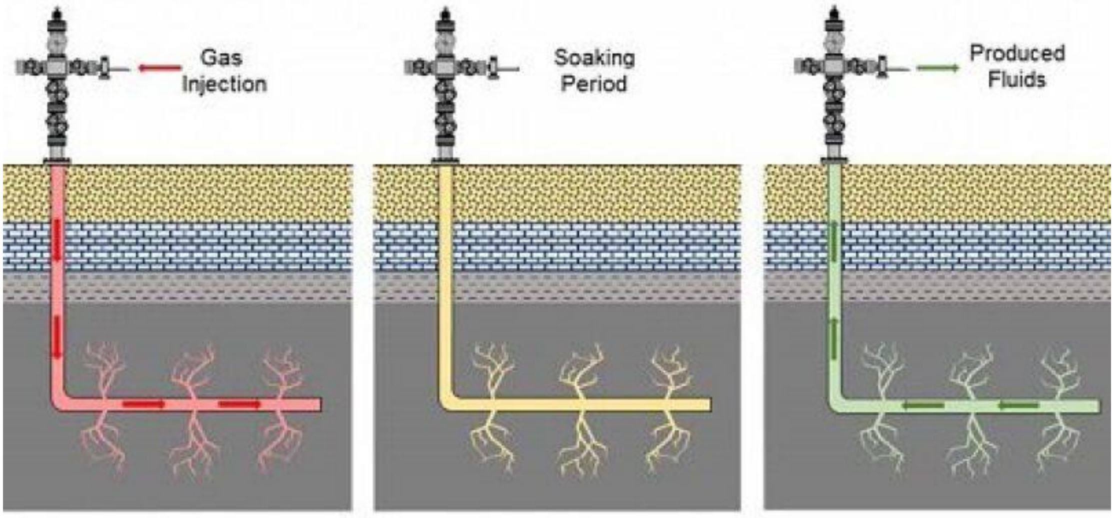


Figure 2.7 Huff and Puff Process (JPT, 2017)

The mechanisms behind gas cyclic injection for increasing oil recovery include:

1. The injected Gas helps to produce energy for the reservoir.

2. The injected Gas dissolves within the crude by decreasing oil consistency and oil enlargement.

3. Gas compatible flooding helps scale back gas and oil capillary pressure [41]

2.8 World Shale Resources

According to EIA In addition to the conventional oil and oil resources there is a huge potential for unconventional resources, which remain untapped and largely these are shale reserves.

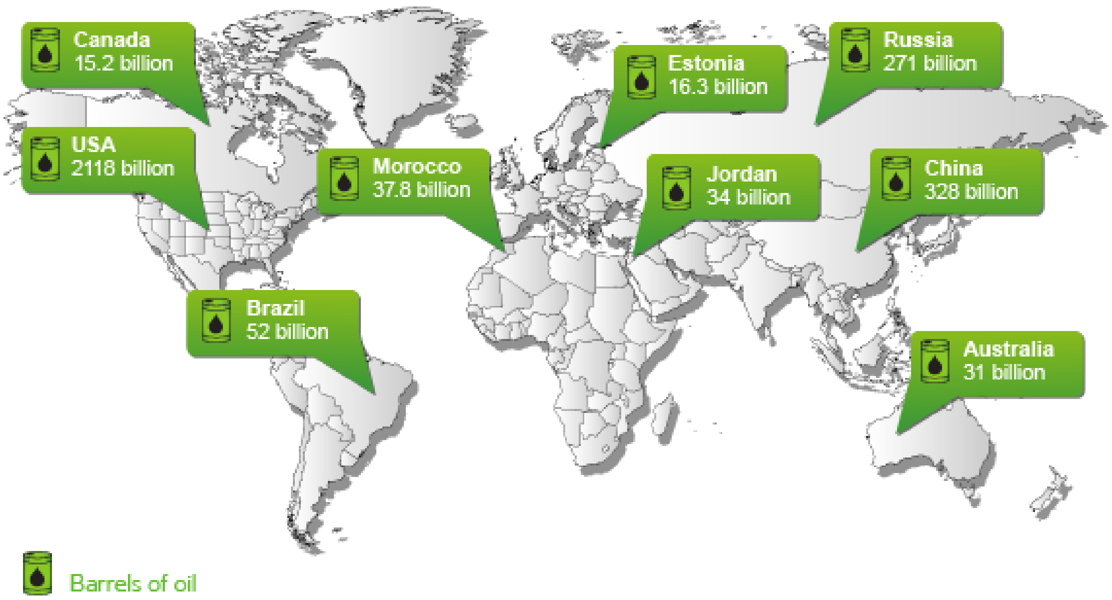


Figure 2.8 World Oil Shale Resources (Enefit, Jordan, 2015)

The largest oil shale resources are in the USA, Brazil, Jordan, Russia and Morocco

Oil shale is becoming an important resource globally because of its value as an alternative to other fossil fuels like crude oil and coal. As the resources of crude oil and coal become depleted, while demand for energy sources continues to increase, more and more attention is being focused on oil shale.

Estonia, which has been using its oil shale resources for oil and power production for almost 100 years.

Brazil and China already use oil shale as an energy source, while in the USA – which is estimated to hold approximately 72% of the world's oil shale reserves [42]

2.8.1 Pakistan Shale oil Resources

According to EIA in addition to the conventional oil and gas resources there is a huge potential for unconventional resources, which remain untapped and largely these are shale reserves.

Studies suggests that 70% of Pakistan's total area may have shale rock.[43]

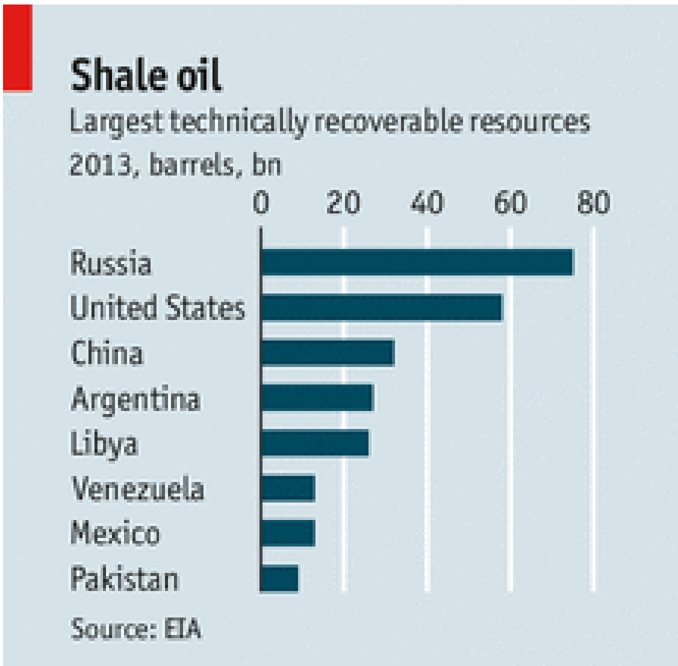


Figure 2.8.1 Pakistan Shale Oil Resources (US EIA 2013)

USEIA had reported in April 2011 the presence of 206 TCF shale gas in lower Indus Basin out of which 51 TCF was termed technically recoverable.

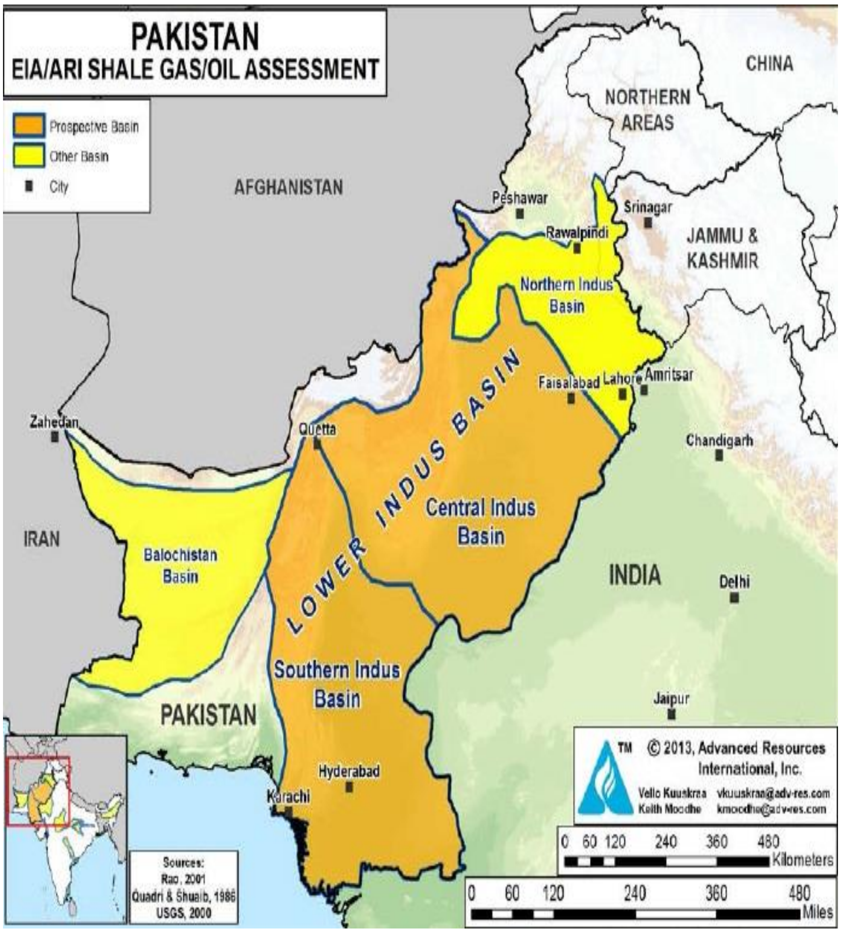
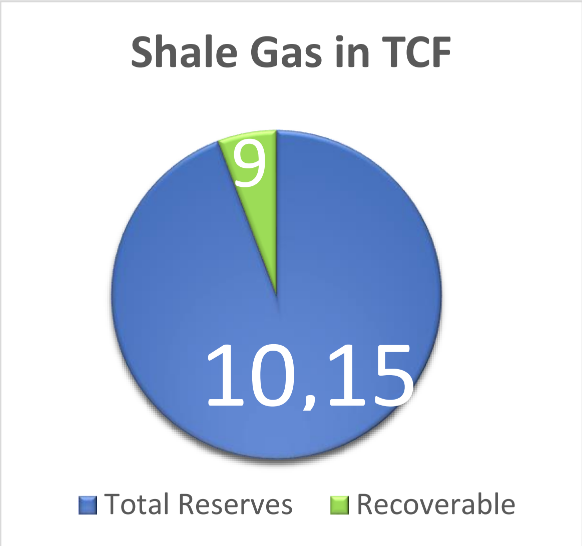


Figure 2.8.1.1 Pakistan Shale Basins (US EIA 2013)

Pakistan's shale oil and gas resources are mostly located in the lower Indus basin region, predominantly in Ranikot and Sembar, mainly in upper Sindh and lower Punjab while a sizeable reserve is also found in Khyber Pakhtunkhwa. Prospective basins are Southern Indus Basin and Central Indus Basin along with the important Baluchistan basin and Northern Indus Basin. The following map illustrates the shale gas basins and its potential in Pakistan.[44]



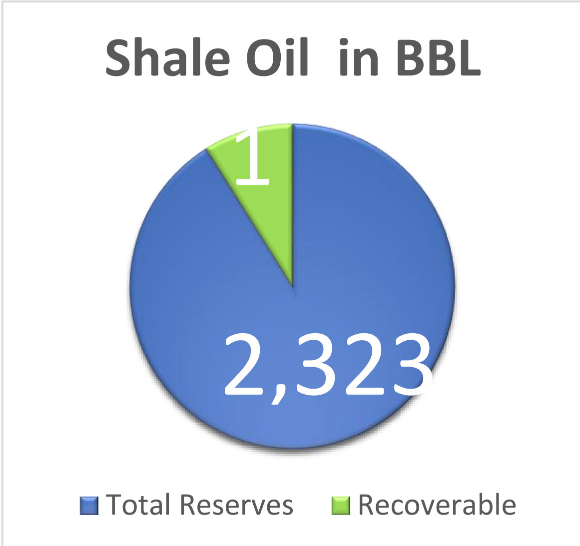


Figure 2.8.1.2 MPNR Report (2015)

Oil and gas are major components of Pakistan's energy mix meeting over 80% of energy need i.e. 48% gas and 32% oil. 75% of oil is being imported at a cost of $12 billion per annum. Pakistan's current annual consumption of oil is only 150 million barrels. Even if it more than triples in the next few years, the 14 billion barrels currently technically recoverable would be enough for more than 27 years.

Similarly, even if Pakistan current gas demand of 1.6 trillion cubic feet triples in the next few years, it can be met with 95 trillion cubic feet of technically recoverable shale gas for more than 25 years. [44]

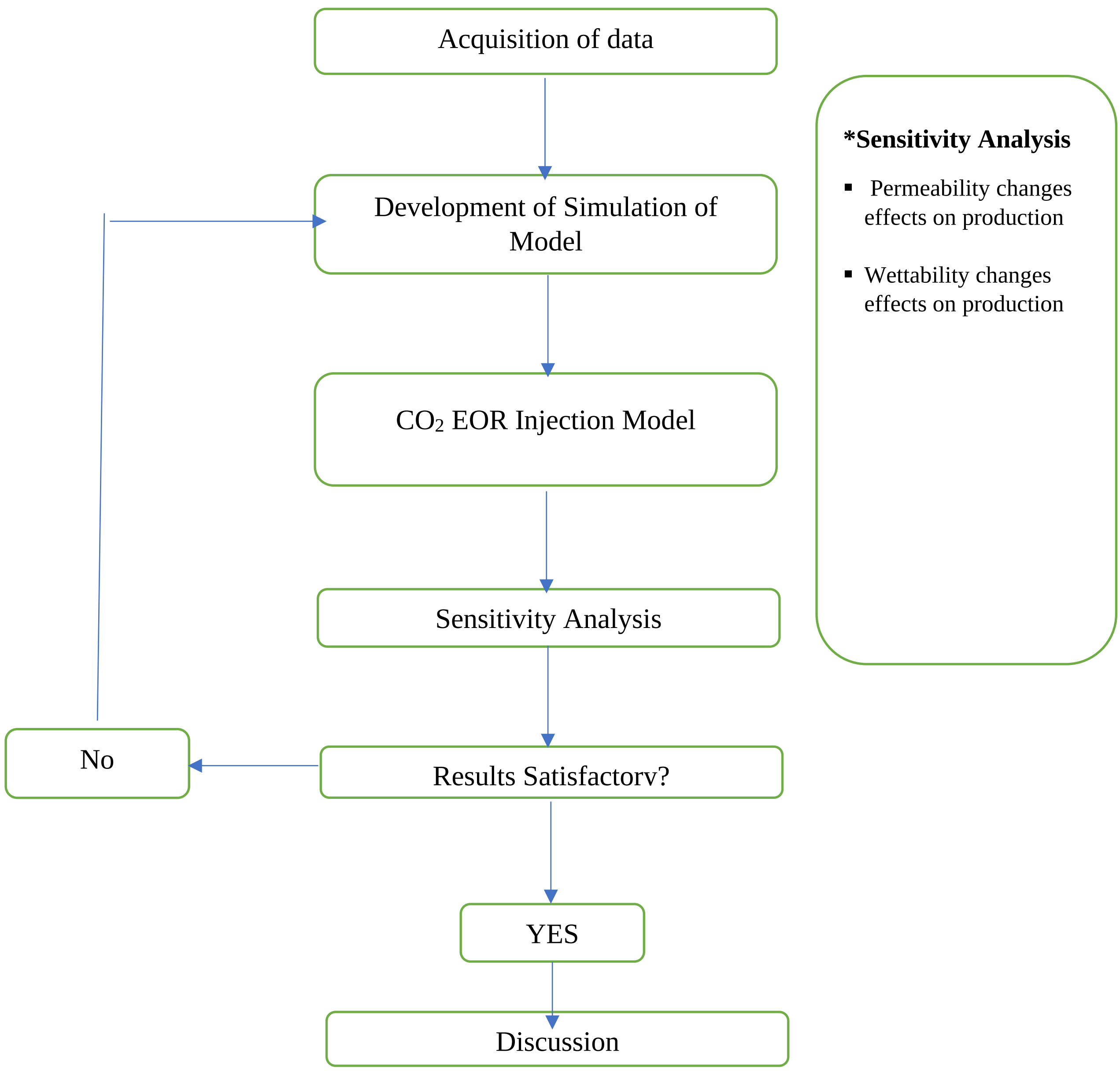
The availability of large domestic shale oil and gas expands the opportunity to reduce Pakistan dependence on imports to overcome the current energy crisis and to fuel the industrial economy. With newer technologies on the horizon, the level of technically recoverable shale oil and gas resources could increase substantially in the future.

Given Pakistan's heavy dependence on natural gas for energy and as feedstock for industries such as fertilizer, fiber and plastics, it's important to pursue shale gas field's development under reasonably tight environmental regulations to minimize risks to the ground water resources.

CHAPTER 3

METHODOLOGY

The start of this chapter takes place with the step-by-step shale oil reservoir modeling. It includes the discussion of shale oil reservoir performance cases without and with huff and puff. By which shale oil productivity impacted. Besides, the impact of permeability on wettability is analyzed. Furthermore, the sensitivity analysis led to the Analyzation of the wettability and recovery factor of the reservoir. The methodology adopted for completing the whole study is shown in the figure.



3.1 RESERVOIR MODELING WORKFLOW

The CMG simulator has been used to model reservoir behavior in this study. CMG models the reservoir by LGR (Local Grid Refinement). Following workflow is used to simulate shale oil reservoir and validate

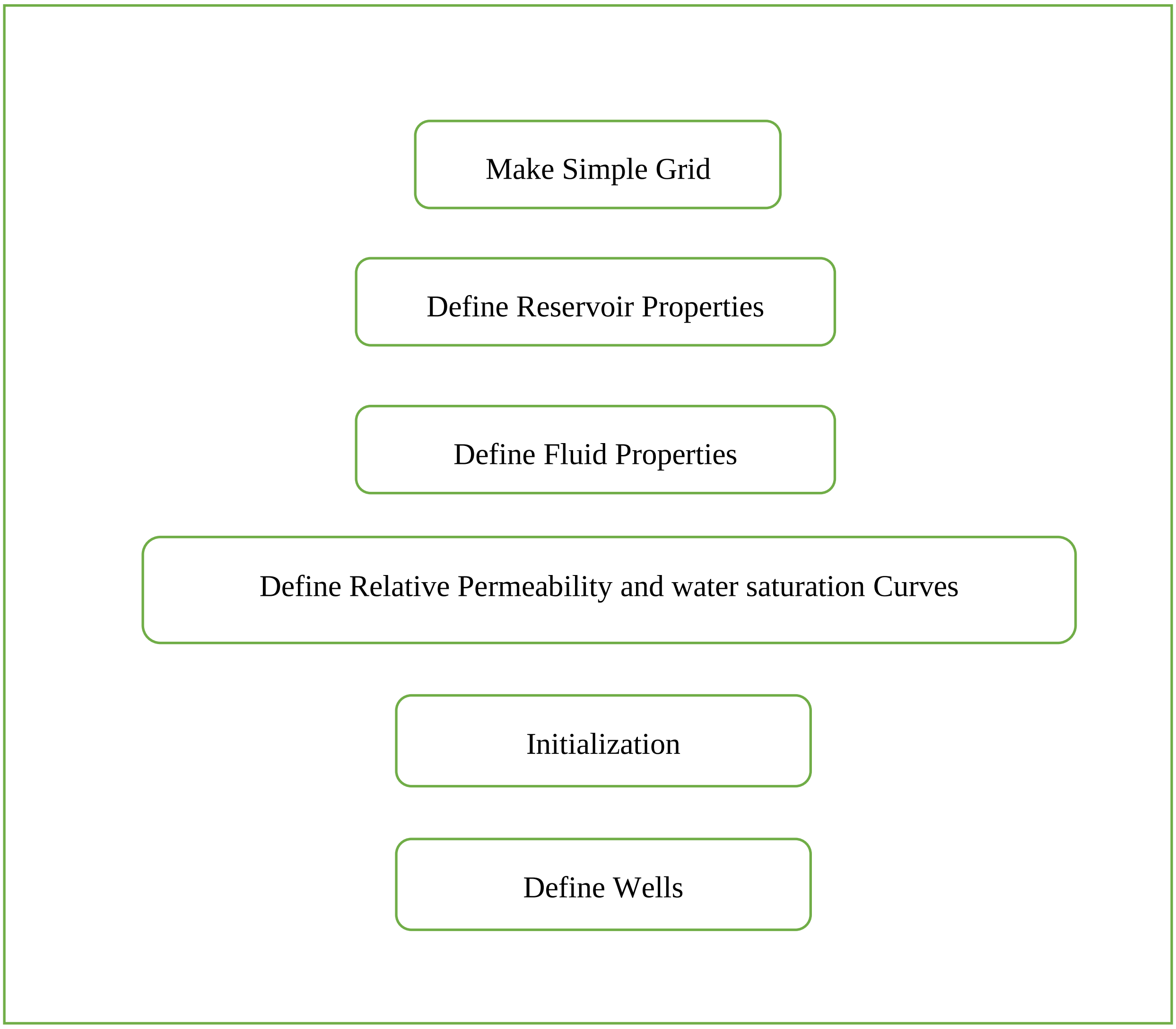


Figure 3.1 Workflow to simulate Shale Oil Reservoir

3.1.1 Gridding

The first step in the simulation model construction is to develop a grid-based upon the structural data and geometry of the reservoir. The simulator used in this study allows us to either specify the drainage area for automatic modeling of grids or define the number of rid blocks and their sizing.

3.1.2 Reservoir Rock Properties

The next step is to define an important reservoir. The properties include:

- Permeability
- Y-Permeability
- Z-Permeability
- Net-to-Gross Thickness
- Porosity.

3.1.3 Fluid Properties

After defining reservoir properties in this gas-water system which gas specific gravity.

- Water density
- Water Salinity
- Reference pressure and temperature.
- Impurities.

Other fluid properties such as Z-factor, Gas compressibility, Gas Formation Volume Factor, water formation volume, etc., can be calculated through pre-defined correlations available in the simulator.

3.1.4 Initialization

It involves defining Reservoir pressure at datum depth, water-gas contact depths, pressure, and temperature gradients, etc.

3.1.5 Wells

Wells are then set up in the simulation model to allow the reservoir fluid to flow up to the space. The data required in this section is:

- Well Locations
- Datum Depth
- Perforation Intervals
- Hydraulic Fracturing data (if applicable)
- Deviation Survey
- Well Constraints
- Wellbore ID etc.

3.1.6 Model Run

After specifying all the discussed data, the model is history matched with the previous production well data, and then the simulation model is set to run.

3.1.7 Validation of Model

After developing the whole model, software validated the model, i.e., CMG.

3.2 RESERVOIR & MODEL DESCRIPTION

'The candidate Shale oil in X-area has a drainage area of approximately 80 acres with square geometry. Also, this shale oil reservoir is divided into five layers of equal thickness. The permeability of this reservoir ranges from 0.00001 md to 0.001 md, which clearly shows its heterogeneous nature. The average Porosity for this case is 25%. The reservoir has gas as its major phase, along with water. Hence, a gas-water Simulation system is used for modeling such a case.

A horizontal well, four vertical fractures were created, having fracture half-lengths of around 450ft is drilled and completed at the center of the reservoir. The relationship of Gas properties concerning pressure is shown in the upcoming figures

The hydraulic fractures are represented in Local Grid Refinement by defining fracture half-length, fracture conductivity, fracture width, and fracture height data. The perforations are made in the whole reservoir. The relative permeability curve is based on the literature. The figure shows the relative permeability curve for this gas-water shale system

The figure 3.2 shows the simulation model of the reservoir having fractured

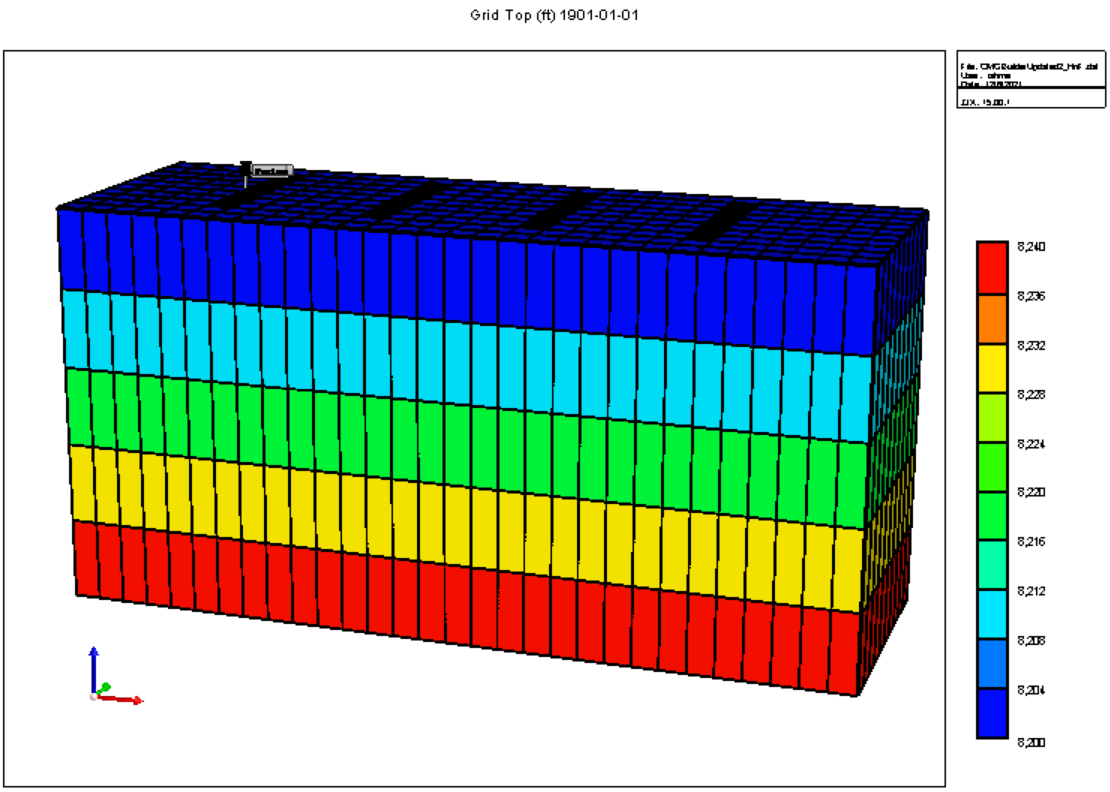


Figure 3.2: Reservoir Model with CO_2 Huff and Puff Injection

Horizontal well. The whole model is developed as per workflow and have the following properties:

Total Bulk Reservoir Volume,	RES FT3	3.75000E+07
Total Pore Volume,	RES FT3	9.93820E+0
Total Hydrocarbon Pore Volume,	RES FT3	7.45365E+0
Original Oil in Place, OOIP	STD BBL	7.19718E+0
Original Gas in Place, OGIP	STD FT3	1.31164E+09

3.2.1 Relative Permeability curves

Relative Permeability and water saturation curves are next to be defined in the simulation model, which models the fluid flow behavior in the reservoir based on their saturations [14]; Brook's and Corey's equation for gas-water system is a widely accepted correlation to develop relative permeability curves.[15] Following are Brook's and Corey's equations in a gas water system.

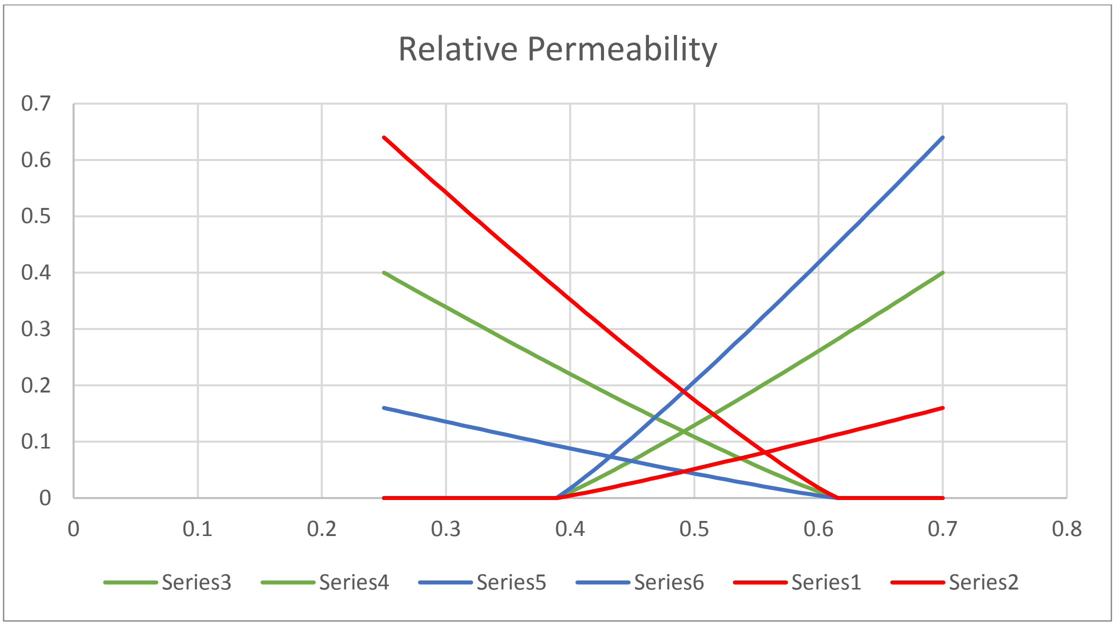


Figure 3.2.1 Relative water permeability vs. Water saturation

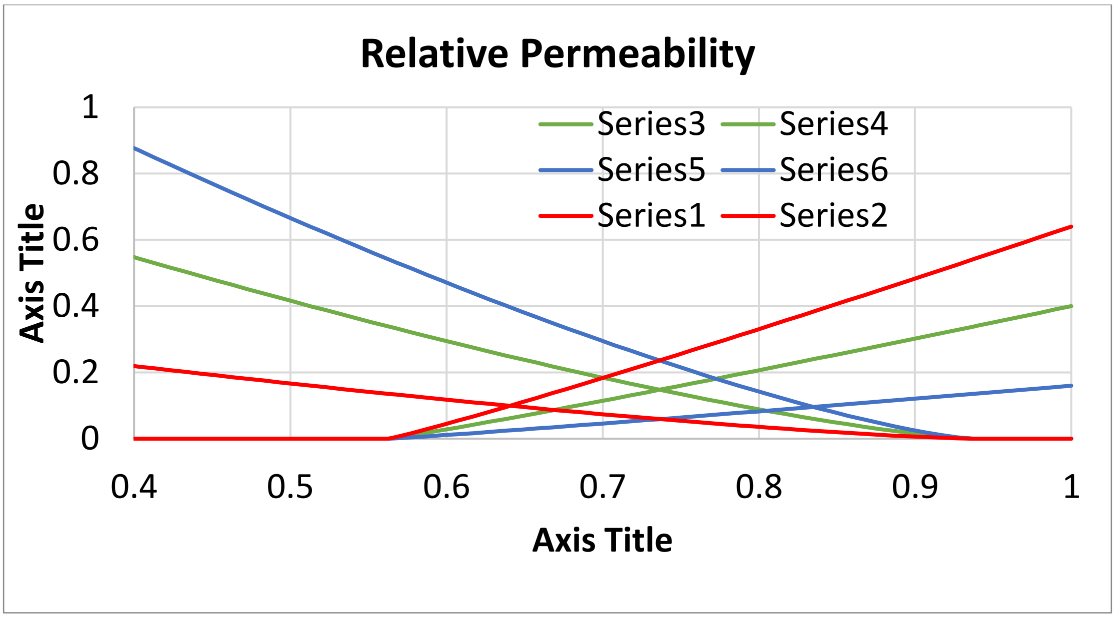


Figure 3.2.1.2 Relative permeability of Gas vs. Water saturation

The above relative permeability curves are the illustration of different wettability. In case of relative permeability water, it ranges from 0.43, 0.48 and 0.56. While in case of relative permeability of gas, it ranges from 0.63, 0.75 and 0.85

3.3 DEVELOPMENT OF SENSITIVITY CASES

After the development section of the model, the next point is to investigate the productivity obtained by incorporating the following wells independently in the simulation model

- Performance of huff and puff EOR in Shale oil reservoir.
- Effect of permeability variation on production.
- Effect of wettability alteration on production.

All the above simulation cases are run for 10 years. The productivity obtained from all the above wells is to be compared to determine a technically feasible well-completion scheme. The effect of the following parameters on the productivity of shale oil is analyzed after selecting a technically feasible well.

Horizontal Well length	3000 ft
Fracture Half-length	350 ft
Fracture Conductivity	0.001 mD. ft
Fracture Spacing	80
Number of fractures	4
Fracture width	0.001 ft
Fracture Permeability	0.001 md
Fracture Height	150 ft
Rock compressibility	1e-6
Reference pressure	1500
Reference depth	1050 ft
Water gas contact	1500 ft
Maximal Adsorbed mass CH_4	0.10gmol/lb

Langmuir Adsorption constant	0.002 1/psi
Rock density	120 lb/ft3

After that, the productivity obtained from the above parameters is compared, and the best parameter is determined.

CHAPTER 4

RESULTS AND DISCUSSION

This chapter compares shale oil reservoirs with 3 different permeability models; each possesses three relative permeability curves representing different wettability. It compared different parameters that increase production.

4.1 CUMULATIVE PRODUCTION

By comparison of Kr1, Kr2, and Kr3 cases in the 0.00001 mD models, it is found that cumulative production in the Kr3 case is the highest.

4.1.1 0.00001 mD Kr1 v/s Kr2 v/s Kr3:

In the 0.00001 mD shale oil model, the Kr1 possesses 25,000 bbl, Kr2 has 38,000 bbl, and Kr3 possesses 79,000 bbl.

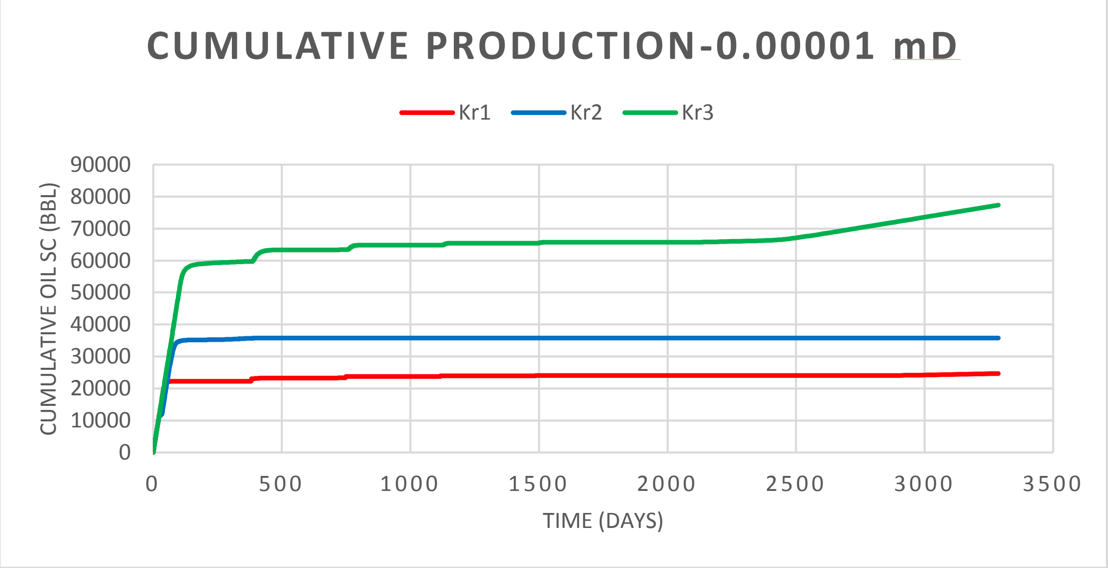


Figure 4.1.1 Cumulative production-0.00001 mD, Kr1 v/s Kr2 v/s Kr3

4.1.2 0.0001 mD Kr1 v/s Kr2 v/s Kr3:

The cumulative production increases in the 0.0001 mD permeability model compared to the 0.00001 mD models. The highest production accounts for 270,000 BBL.

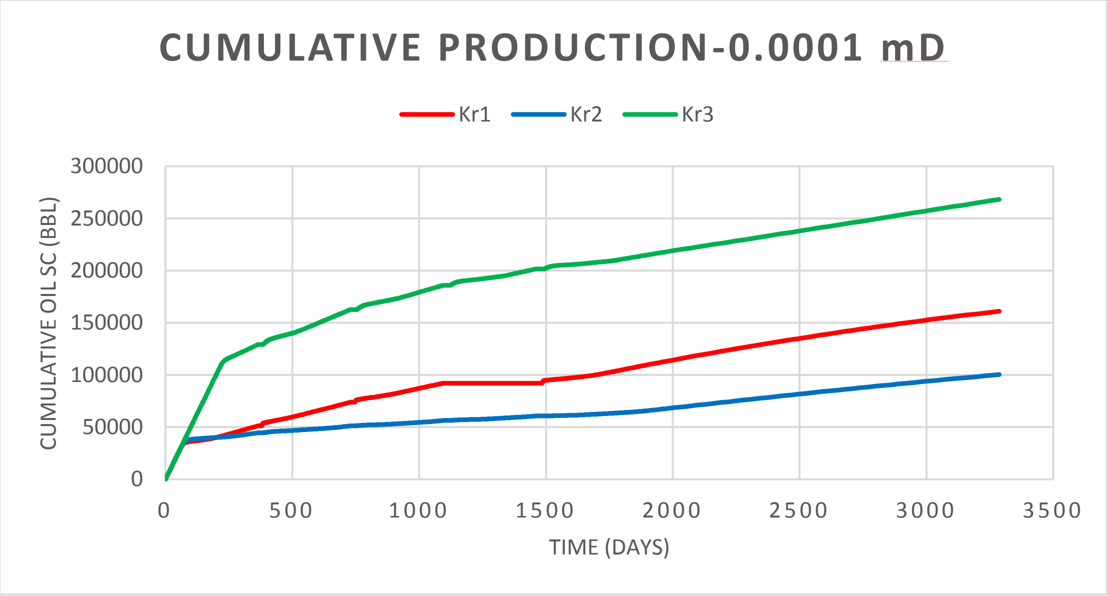


Figure 4.1.2 Cumulative production-0.0001 mD, Kr1 v/s Kr2 v/s Kr3

4.1.3 0.001 mD Kr1 v/s Kr2 v/s Kr3:

The cumulative production is the highest in the 0.001 mD permeability model and at kr3 that accounts for around 550,000 BBL followed by kr2 and kr3

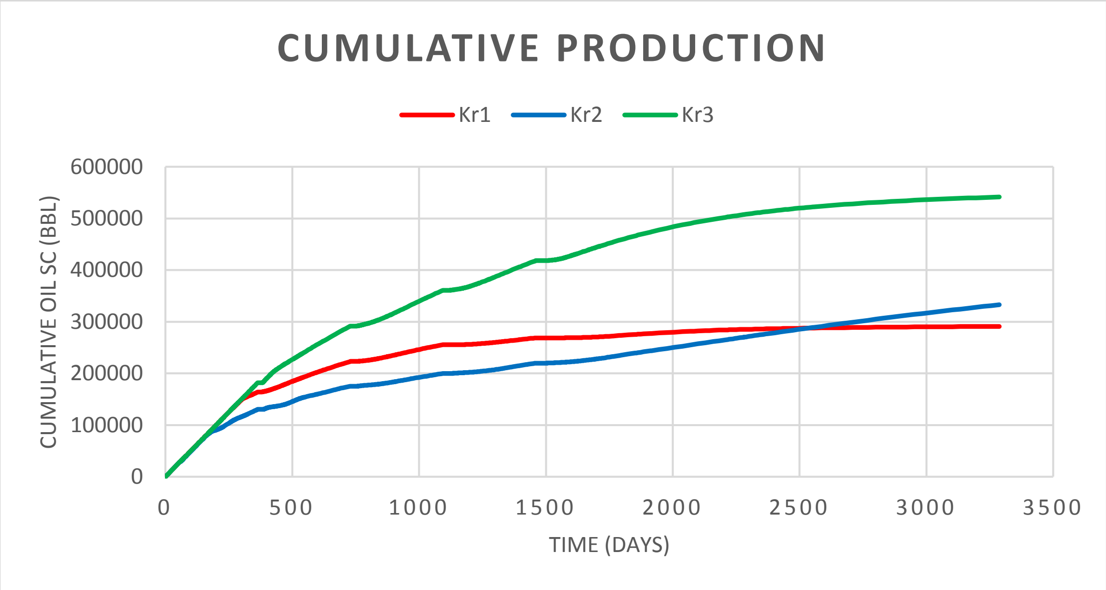


Figure 4.1.3 Cumulative production-0.001 mD, Kr1 v/s Kr2 v/s Kr3

4.2 Oil Rate

4.2.1 0.00001 mD Kr1 v/s Kr2 v/s Kr3:

The oil rate has decreased over time.

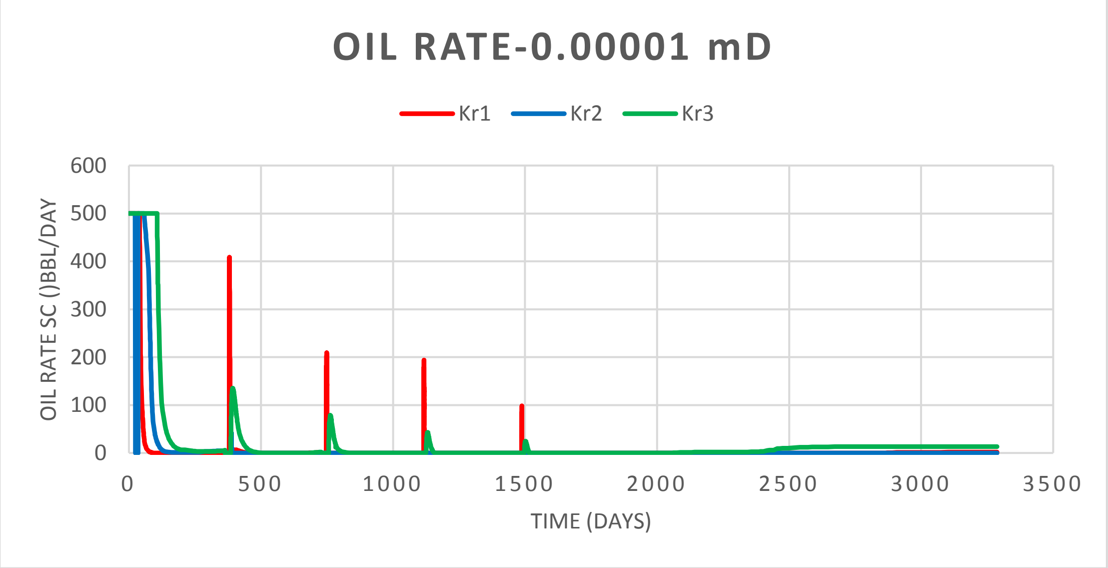


Figure 4.2.1 Oil Rate-0.00001 mD, Kr1 v/s Kr2 v/s Kr3

4.2.2 0.0001 mD Kr1 v/s Kr2 v/s Kr3:

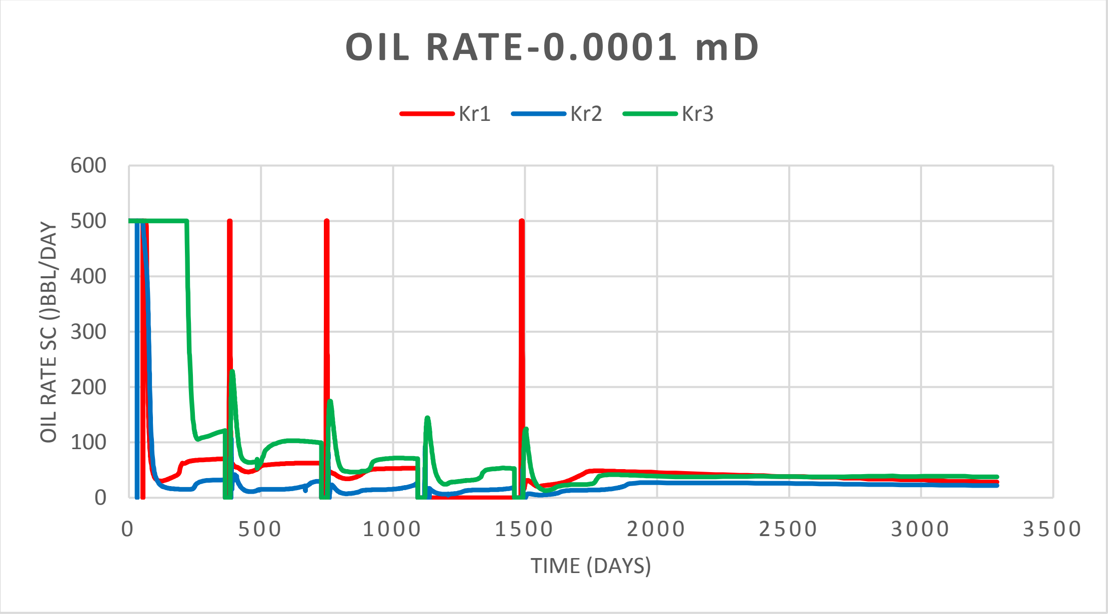


Figure 4.2.2 Oil Rate-0.0001 mD, Kr1 v/s Kr2 v/s Kr3

4.2.3 0.001 mD Kr1 v/s Kr2 v/s Kr3:

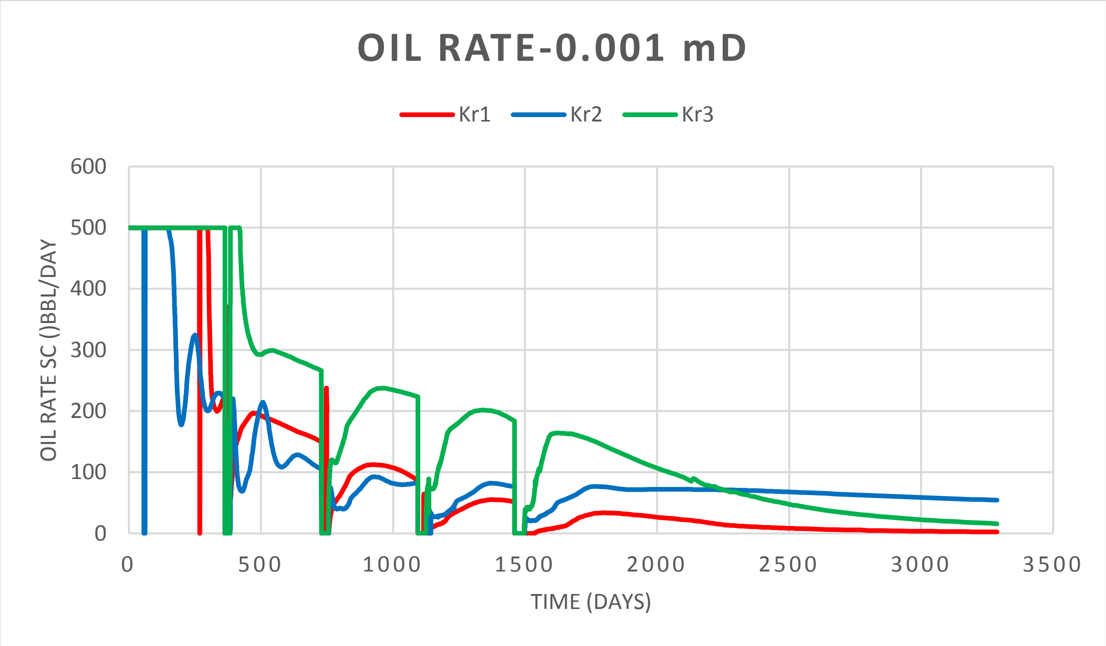


Figure 4.2.3 Oil Rate-0.0001 mD, Kr1 v/s Kr2 v/s Kr3

4.3 Average Reservoir Pressure

4.3.1 0.00001 mD Kr1 v/s Kr2 v/s Kr3:

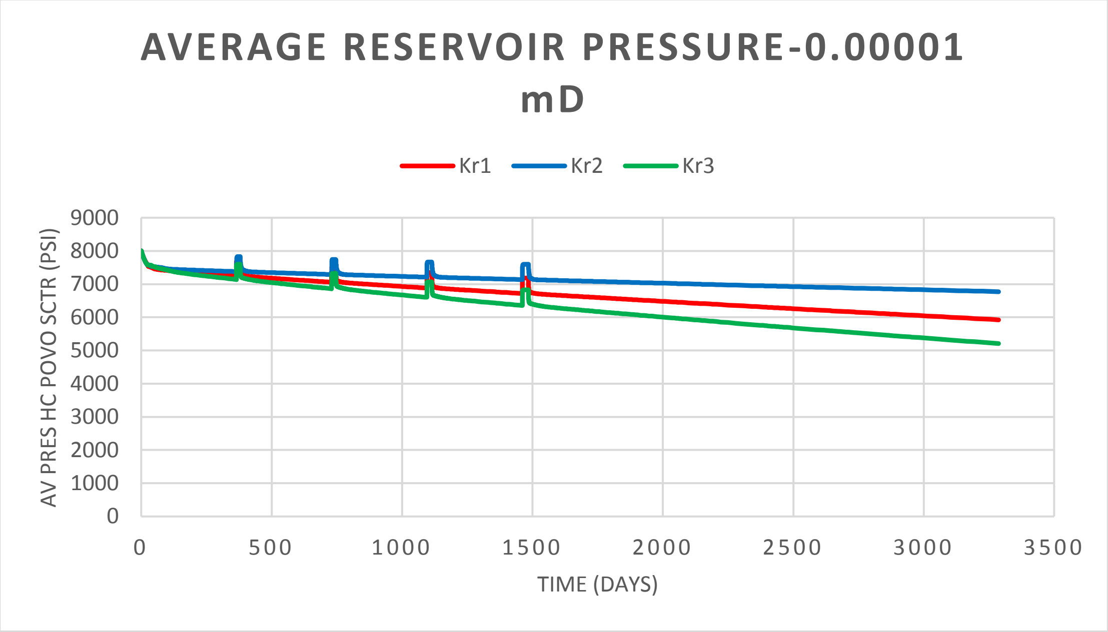


Figure 4.3.1 Average Reservoir Pressure-0.00001 mD, Kr1 v/s Kr2 v/s Kr3

4.3.2 0.0001 mD Kr1 v/s Kr2 v/s Kr3:

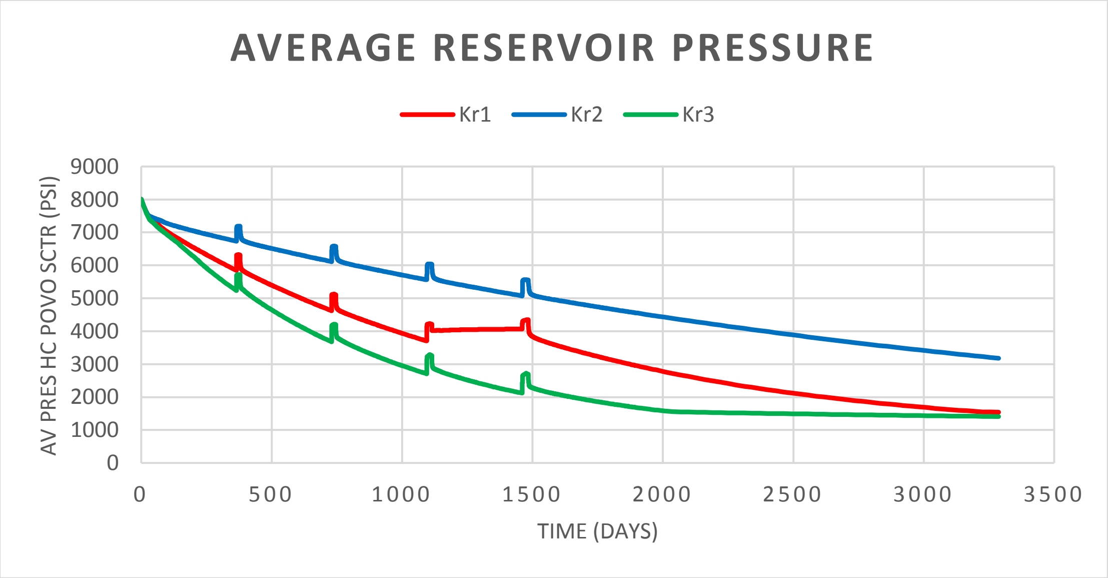


Figure 4.3.2 Average Reservoir Pressure-0.0001 mD, Kr1 v/s Kr2 v/s Kr3

4.3.3 0.001 mD Kr1 v/s Kr2 v/s Kr3:

The recovery factor increases in fracturing network cases.

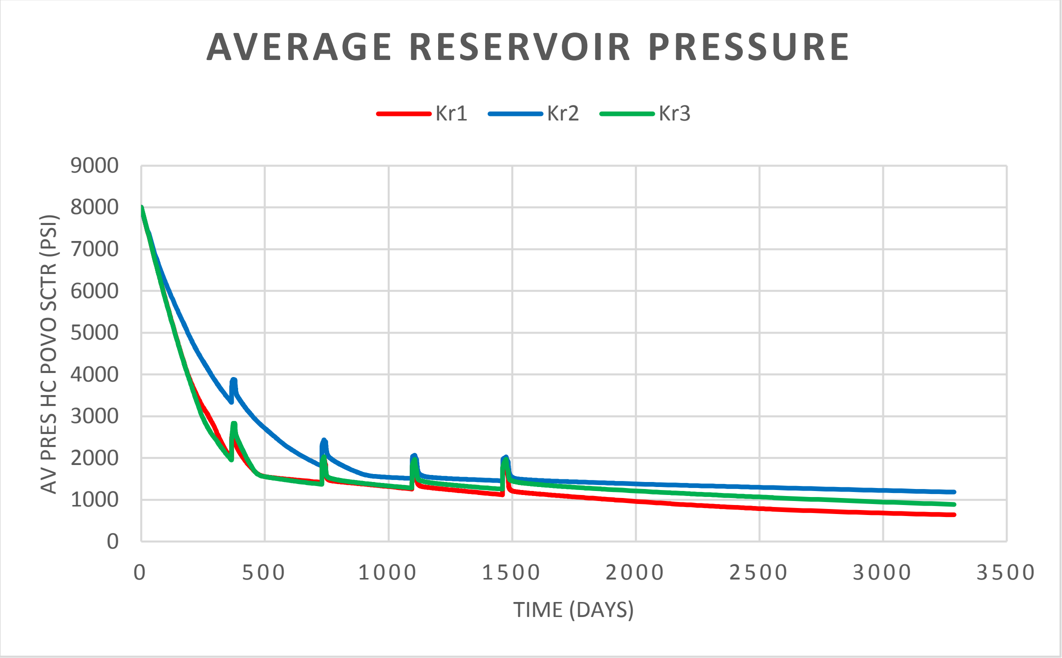


Figure 4.3.3 Average Reservoir Pressure-0.001 mD, Kr1 v/s Kr2 v/s Kr3

4.4 Recovery Factor

4.4.1 0.00001 mD Kr1 v/s Kr2 v/s Kr3:

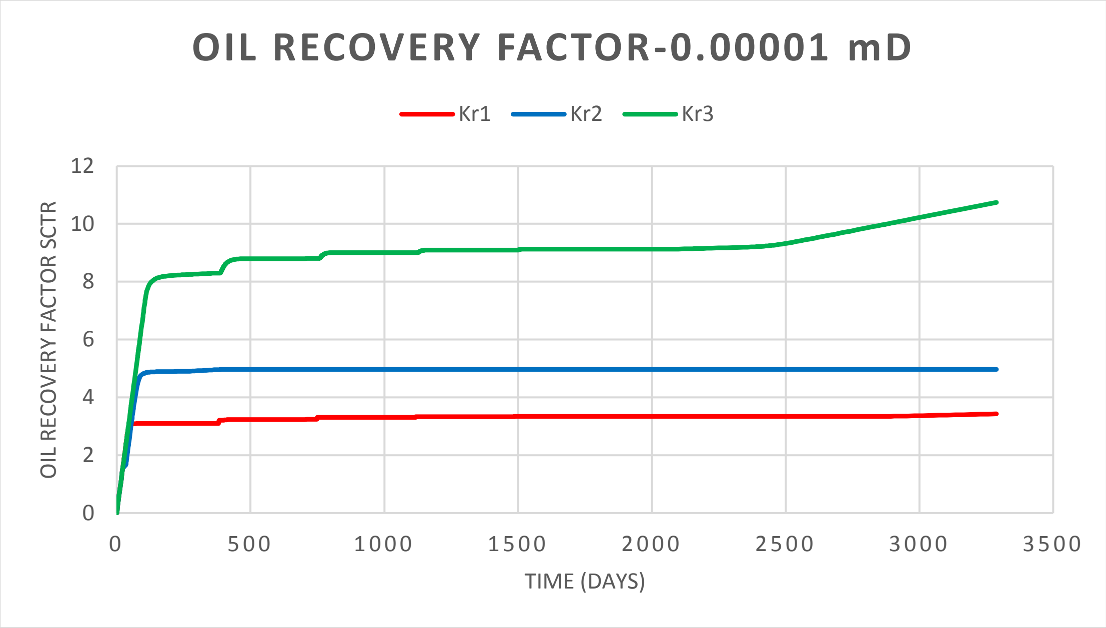


Figure 4.4.1 Oil Recovery Factor-0.00001 mD, Kr1 v/s Kr2 v/s Kr3

4.4.2 0.0001 mD Kr1 v/s Kr2 v/s Kr3:

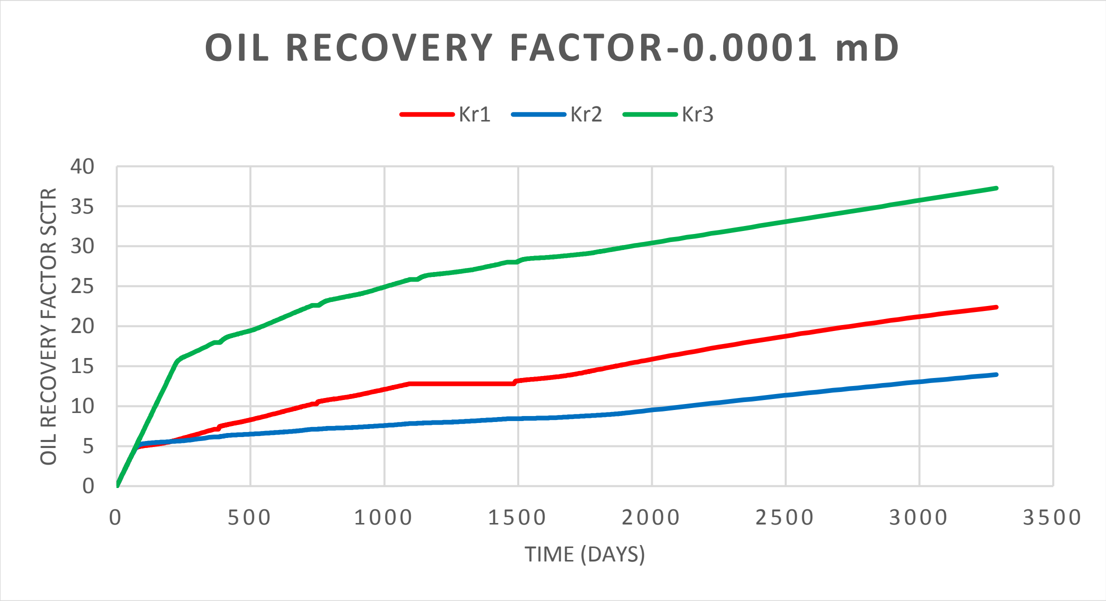


Figure 4.4.2 Oil Recovery Factor-0.0001 mD, Kr1 v/s Kr2 v/s Kr3

4.4.3 0.001 mD Kr1 v/s Kr2 v/s Kr3:

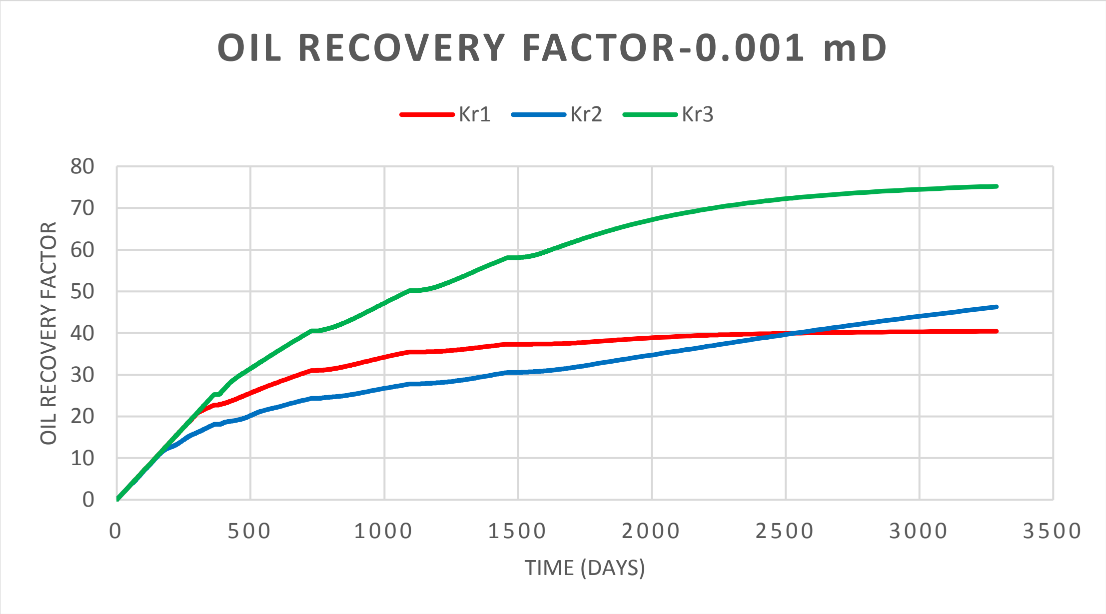


Figure 4.4.3 Oil Recovery Factor-0.001 mD, Kr1 v/s Kr2 v/s Kr3

CHAPTER 5

CONCLUSIONS AND RECOMMENDATIONS

5.1 CONCLUSIONS

- The study can be concluded into following points:

❖ LGR grid can effectively model shale oil reservoirs with the advantage of developing complex well trajectories with hydraulic fractures.

❖ The reservoir production is compared on different well cases, i.e., 0.00001 mD, 0.0001 mD, and 0.001 mD. Each permeability case possesses three different wettability cases.

❖ In 0.001 permeability, the cumulative production drastically increases the production (from 79,000 to 550,000 BBL)

❖ The recovery factor obtained from the above cases is 13%, 34%, and 76%, respectively.

5.2 RECOMMENDATIONS

- Simulation can be carried out using corner-point geometry.

- Change the soaking time and analyse the performance.

  The soaking time may play a key role also like other parameters as discussed in the research. Increasing the soaking time could affect the performance parameters. Therefore, this sensitivity analysis should be carried out.

- Sensitivities on different parameters can be carried out and its effect can be investigated in future work.

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