NTNU – Trondheim
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Potential technical solutions to recover tight oil

Literature and simulation study of tight oil development

Kai Zhang

Petroleum Engineering
Submission date: June 2014
Supervisor: Ole Torsæter, IPT
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Preface

The thesis presents distribution of tight oil resource and future market outlook, illustration of tight oil development, feasibility investigation of nanotechnology applied in tight oil E&P, reservoir simulation within tight oil development. Based on the research, potential technologies proposed in tight oil E&P.

Appreciation is expressed to Professor Ole Torsæter(NTNU), Assistant Professor Nancy Chen(University of Calgary), Master student Menglu Lin(University of Calgary) and PhD student Shidong Li(NTNU) for their instruction to this work.

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Calgary, Canada

Abstract

Over past decades, technology innovation drove unconventional resources become conventional. Incorporating the technologies applied in shale gas development, exploiting tight oil comes into stage recently.

Advanced technology such as long horizontal wells combined with massively hydraulic fracturing was established as necessity to exploit tight oil reserve, however, primary recovery remains as low as 5.0-10.0% of original oil in place in tight oil reservoir with these technologies applied.[1]

Nanotechnology was regard as green and efficient alternative in E&P phase of petroleum industry because of its mechanical, chemical, thermal, electronic, optical, and magnetic properties. Feasibility study of it applied in tight oil E&P was investigated.

The thesis presents description of tight oil and methods to extract it in details, also distribution of tight oil resource and outlook of future market were shown. In addition to literature review, reservoir simulation within tight oil development carried out to seek potential technical solutions, WAG (water alternating gas) process tend to be an excellent methodology to recovery tight oil.

After a number of studies on the emerging technologies in tight oil E&P, associated with simulation works, on the basis of increasing fracture density, decreasing oil viscosity and increasing wettability alteration,[2] several technical solutions, like unconventional stimulation, CO_2 foam, air injection(low temperature oxidation), and NAG(nanofluids alternating gas), etc. are recommended in the exploitation of tight oil reservoir.

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1. Introduction

U.S. tight oil production surging raises tremendous focus on the unconventional resource.

Tight oil is light crude oil contained in low permeability formations, including but not limited to shale.[3] Since the oil itself requires very little refinement,[4] and extensive distribution, two times deepwater hydrocarbon resource,[5] developing tight oil resource has a bright future, tight oil production pushes U.S. crude supply to over 10% of world total.[6]

Its development generally has no natural or low production capacity, production cycle of single well is quite long. Incorporating the technologies applied in shale gas development, the economic production of tight oil becomes possible, however, primary recovery remains as low as 5.0-10.0% of original oil in place in tight oil reservoir, even the advanced technology such as long horizontal wells has been drilled and massively fractured applied.[1]

A number of studies on emerging technologies in tight oil E&P carried out, the advanced knowledge need to be emphasis in real-time measurement; post-fracture monitoring with production analysis; identifying sweet spots, then placing perforations to create complex conductive fractures; innovative proppants and proppants placement techniques in primary and complex fracture geometries, fluid recovery, formation damage control and permeability enhancement, proppant transport with less-damaging stimulation fluids, and environmentally responsible drilling, completion, and production services.[7]

Recent breakthrough in nanotechnology brings a bunch of possibilities in application to petroleum industry. Nanoparticles in the fluid have a very high surface to volume ratio, which provides a tremendous driving force for diffusion, they can easily move into tight formations without external force. Disjoining pressure exerted by nanoparticles come into effects at oil-rock interface, which effectively works to separate oil from rock surface and carry it out of the porous space.[8,9] The oil-water wettability alternation and interfacial tension reduction caused by nanofluids provide an excellent excuse in the EOR process.[10,11]

Reservoir simulations in homogenous model, heterogeneous model, and dual porosity model were run separately. Hydraulic fractures were created with the consideration of permeability varies with distance to wellbore, conductivity reduction and stimulation process. The role of capillary pressure in tight oil reservoir was investigated. WAG (water alternating gas) simulations and comparison between CO_2 and N_2 injection, waterflooding vs. nanoflooding were made.

According to the literature studies and simulation results, WAG process tends to be the optimum case in the development of tight oil reservoir. Lower gas injection rate initially in WAG process design with certain WAG ratio in a relative small cycle length contribute to a higher recovery factor. Also, nanotechnology has a great potential in tight oil E&P phase application.

Finally, several technical suggestions were made on the basis of increasing wettability alteration, increasing fracture density, and decreasing oil viscosity.[2]

2. What is Tight oil

Crude oil is commonly classified as either heavy or medium to light grade dependent on the density of hydrocarbon and its ability to flow.

2.1 Crude oil classification

The American Petroleum Institute's "API gravity" is a standard to express the specific weight of oil, computed as $(141.5/r_g) - 131.5$, where r_g is the specific gravity of the oil at 60 degrees Fahrenheit.

Light Oil

Light oil, also known as "conventional oil", has an API gravity of at least 22° and a viscosity less than 100 centipoises (cp).

Heavy Oil

Asphaltic, dense (low API gravity), and viscous oil that is chemically characterized by its content of asphaltenes (very large molecules incorporating most of the sulfur and perhaps 90% of the metals in the oil). Although variously defined, the upper limit for heavy oil has been set at 22°API gravity and a viscosity of less than 100 cp.

Extra Heavy Oil

The portion of heavy oil has an API gravity of less than 10°.

Extra-Heavy Oil Natural Bitumen

Also known as "oil sands", bitumen shares the attributes of heavy oil but is even more dense and viscous. Natural bitumen has a viscosity greater than 10,000 cp.[12]

Fig 2.1 API gravity [12]

2.2 The difference between tight oil and oil shale

Tight oil

Tight oil, also known as shale oil or light tight oil is petroleum that consists of light crude oil contained in petroleum-bearing formations of low permeability, often shale or tight sandstone. The flow of oil from rock to wellbore is limited by the largely impermeable fine-grained nature of the oil-hosting rock, the cause for the term “tight”. While some tight light oil plays produce oil directly from shales, most tight oil is produced from low-permeability siltstones, sandstones, limestones and dolostones that are associated with the shales from which oil has been generated.[3]

Tight oil can be free oil or absorbed oil. It is a continuous reservoir of self-generation and self-storage.[13]

Micropore with diameter bigger than 0.75μm and nanopore with diameter less than 0.75μm were observed in tight reservoirs. Mississippian Barnett Shale of the Fort Worth Basin, Texas, shows that the pores in these rocks are dominantly nanometer in scale (nanopores). Shale formation generally has poor porosity and low permeability, pre-fracture the porosity could be below 4%, permeability as low as 10^{-6} mD, the porosity can reach 10% following by hydraulic fracture, and the permeability can be increased to 2×10^{-6} mD.[14]

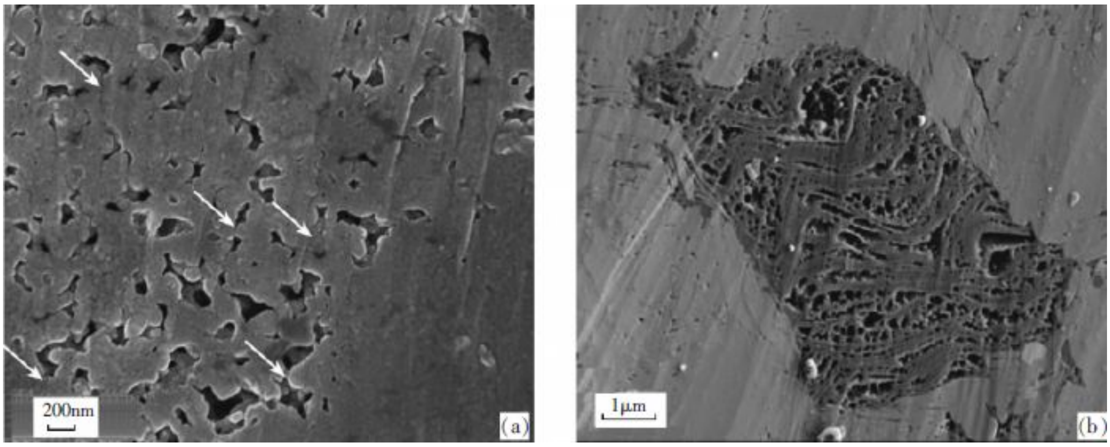


Fig 2.2 Intraparticle organic nanopores within Barnett shale[14]

Based on the Barnett shale pore structure analysis, the pore size is around 1/400 of sandstone, assemble about 40 CH_4, with diameter 0.38 nm of each, porosity of the shale reservoir is 4% to 10%, permeability 50 to 1000×10^{-6} mD.[13,14]

Every tight oil reservoir is unique and the stimulation and completion method should be determined based on its individual petrophysical attributes.[15] Its development generally has no natural or low production capacity, production cycle of single well is quite long and multistage hydraulic fracturing or refracturing regard as the key technology for the exploitation of tight oil.

Hydraulic fracturing techniques combined with horizontal well technology have enabled economical production from tight oil reservoirs with absolute permeability less than 0.1 md, the oil contained within tight reservoir rocks typically will not flow to the wellbore at economic rates without assistance of advanced drilling technology and completion process.

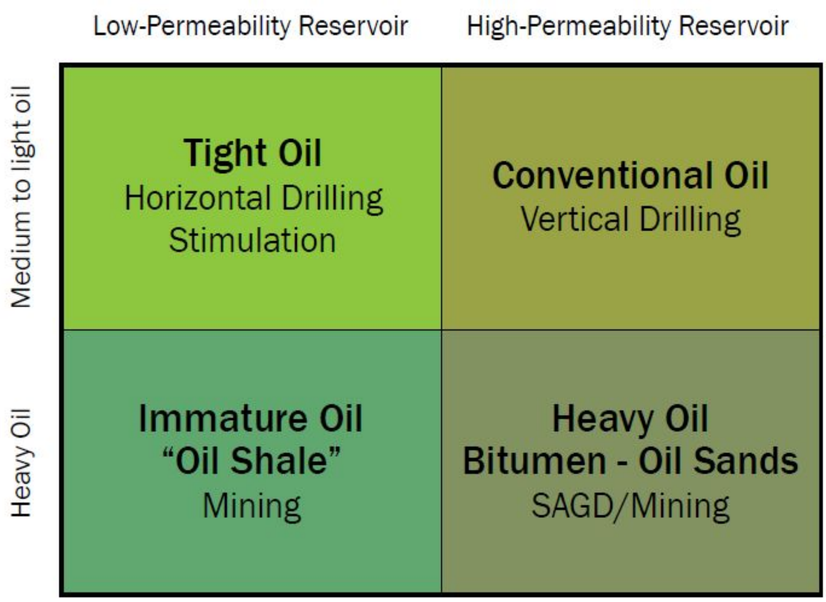


Fig 2.3 Technologies difference applied to various reservoir[4]

Oil Shale

Oil shale refers to any source rock that contains solid bituminous materials (called kerogen) that are released as petroleum-like liquids when the rock is heated in the chemical process of pyrolysis. Kerogen requires maturation process for oil extraction, heating the shale to recover contained oil and gas, for there is no other practical method for extracting a significant portion of contained oil. In the processes studied, shale is heated to about 900 degrees F,[16] at which temperature the organic material in shale rapidly decomposes into oil vapor and gas. Cooling this vapor stream produces liquid oil and uncondensed, light hydrocarbon produces liquid oil and uncondensed, light hydrocarbon gases.

Surface retorting or in situ upgrading needed to get valuable products, most development work on oil shale recovery has been directed to mining the shale, bringing it to surface, and then processing it in surface facilities. Various surface retorting processes can be classified according to the method used to provide heat for the retorting reaction.[17]

3. Reserve of tight oil

3.1 Tight oil reserve distribution

Tight source rocks are available all over the world, estimates of hydrocarbon resources in tight reservoir is worldwide, especially in shale rocks, is plentiful. Although they vary with different assumptions concerning recoverability potential with available technology, conservative estimates for hydrocarbon resources in shale basins exceed 2 trillion barrels of oil equivalent. Another uncertainty is the fraction of this resource that could be extracted in liquid form (e.g., oil, condensate, or NGLs).[5]

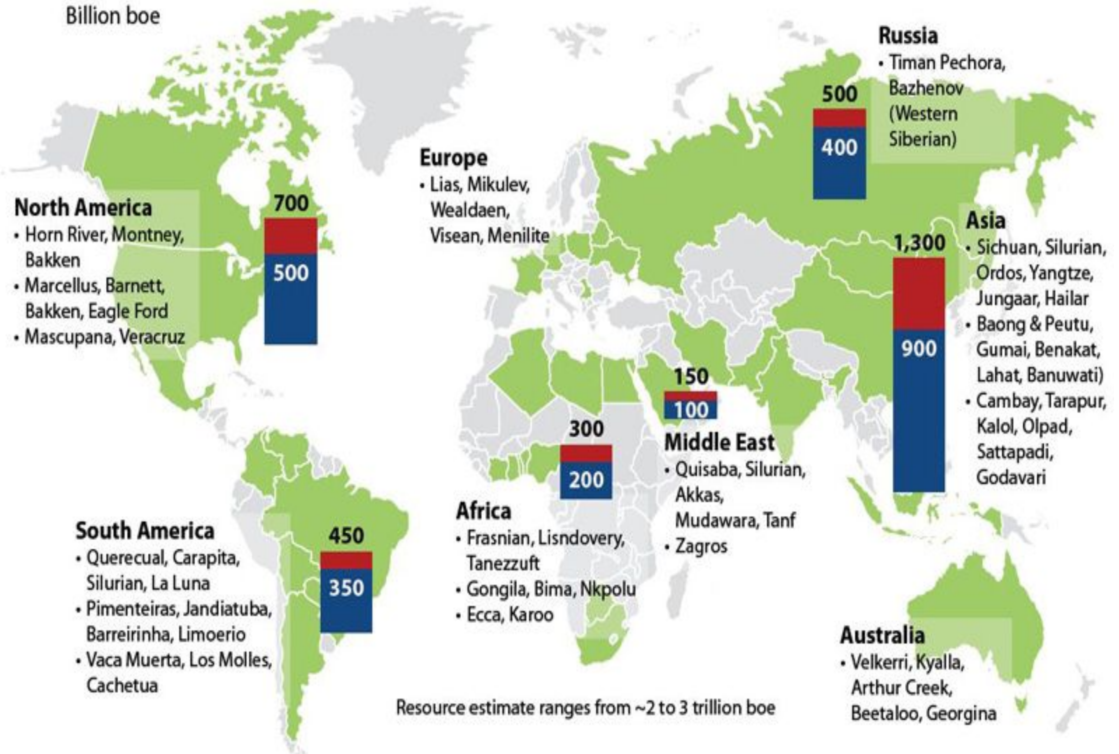


Fig 3.1 Total shale resources[5] (SOURCES: HART ENERGY; IEA; EIA; SLB; SBC ANALYSIS)

Schlumberger Business Consulting (SBC) completed a comprehensive model of tight oil, working with subsurface experts to review and analyze data on all major shale basins around the world. The model assessed key factors such as organic content, depth, and thermal maturity, in order to estimate the oil currently in place. The model also takes variables such as permeability, porosity, and thickness of the basins and topography into consideration, to determine the portion of resources that can be made to flow using existing technology.

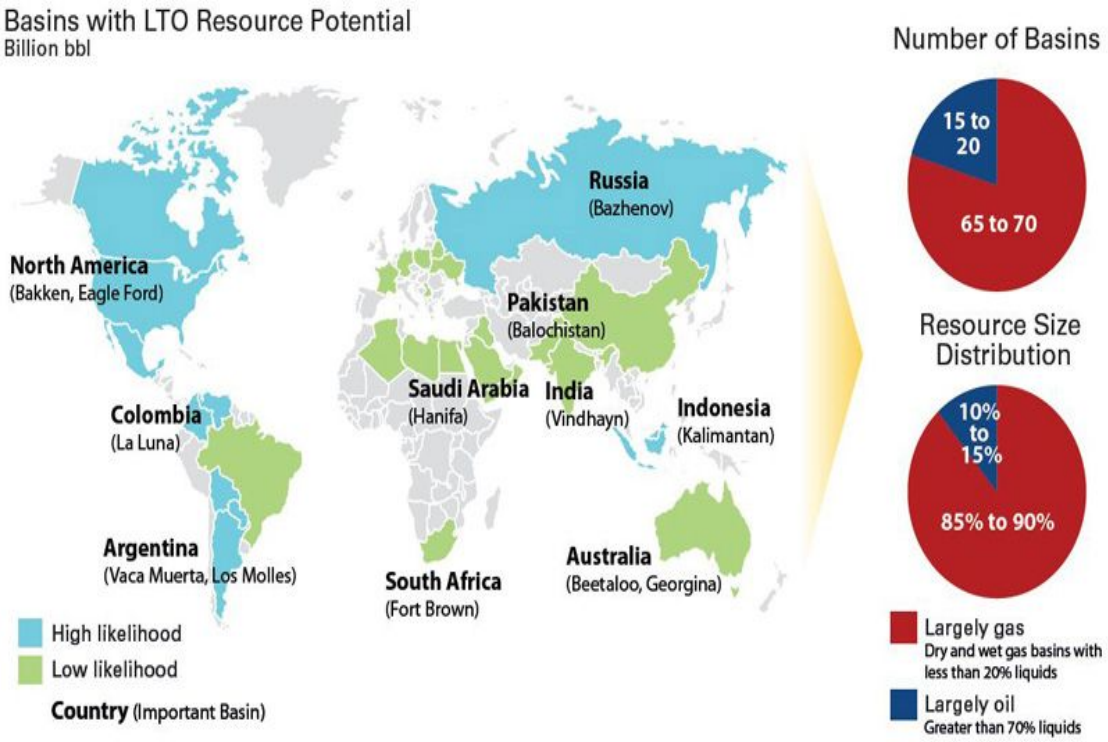


Fig 3.2 Tight oil include crude oil and condensate from all tight formations (SOURCE: SCHLUMBERGER PETROTECHNICAL SERVICES)[5]

The technically recoverable portion of light tight oil is approximately 10–15% of the global shale hydrocarbon resource (as shown in Table 3.1&3.2) in place based on this model, in other words, a lager fraction of shale hydrocarbon resource is in gaseous form.[5] A significant amount of tight oil resource, approximately two-thirds, is concentrated in the Americas (see Fig 3.2).

Table 3.1 Top 10 countries with technically recoverable shale oil resources [18]

Country	billion barrels
Russia:	75
United States	48 to 58
China:	32
Argentina:	27
Libya:	26
Venezuela:	13
Mexico:	13
Pakistan:	9
Canada:	9
Indonesia:	8
World Total	335 to 345

Table 3.2 Top 10 countries with technically recoverable shale gas resources[18]

Country	trillion cubic feet
China	1,115
Argentina	802
Algeria	707
U.S	665 to 1161
Canada	573
Mexico	545
Australia	437
South Africa	390
Russia	285
Brazil	245
World Total	7299 to 7795

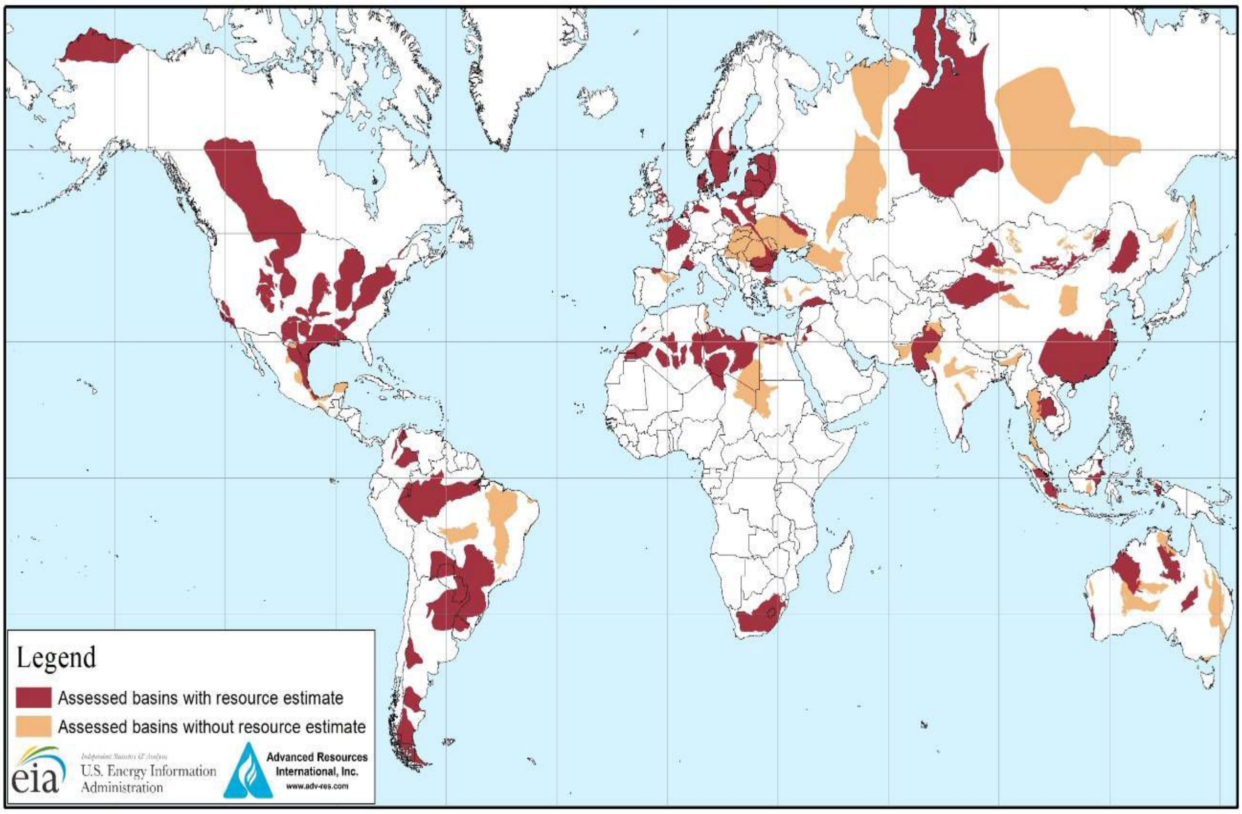


Fig 3.3 Map of basins with assessed shale oil and shale gas formations, as of May 2013[18](Source: United States basins from U.S. Energy Information Administration and United States Geological Survey; other basins from ARI based on data from various published studies)

Global light tight oil(LTO) resource is a quarter the size of oil sands and two times global deepwater resources, but the science of assessing oil and gas resources and reserves is not accurate, as shown in Fig 3.4, the reserve update continuously with the evolution of knowledge and technology.

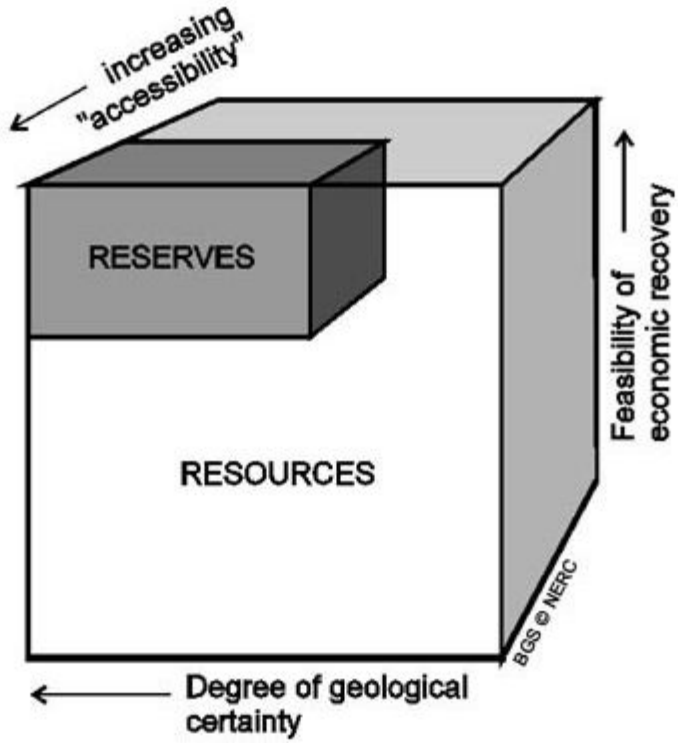


Fig 3.4 Resource and Reserve (Source British Geological Survey)

3.2 Future market of tight oil production

As shown in Fig 3.5, light tight oil reserves are quite competitive within marginal resource, two times deepwater hydrocarbon resource, the cost of production of hydrocarbon varies by geography. Supported by mature infrastructure and a favorable fiscal regime, as well as by extensive collaboration between operators and service companies, full cycle costs in the Bakken and Eagle Ford plays have dropped to as low as $50/bbl In the U.S. However, the U.S. experience is not representative for what we can expect to see worldwide.[5]

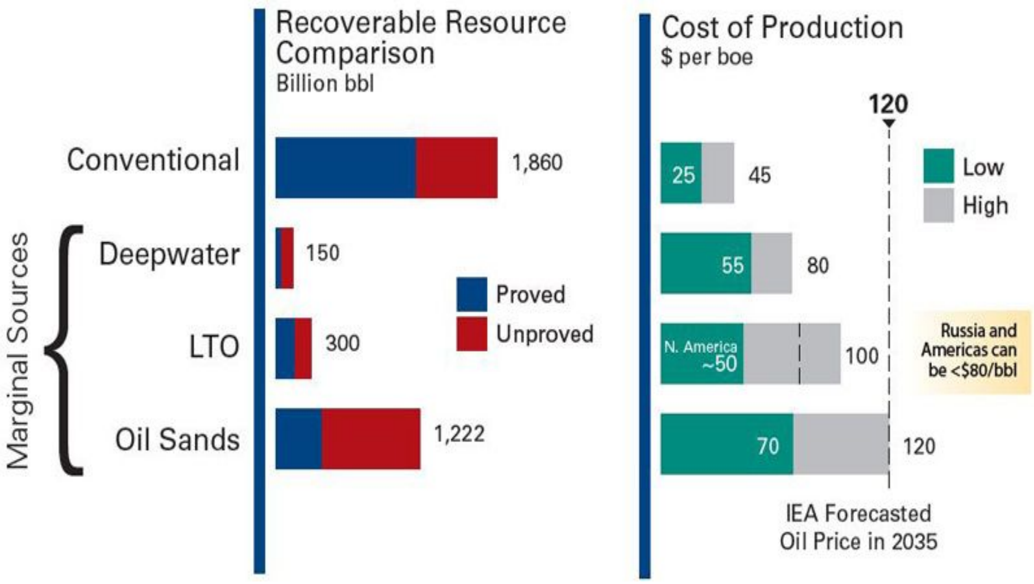


Fig 3.5 LIGHT TIGHT OIL VERSUS OTHER SUPPLY SOURCES[5]

Few countries have onshore infrastructure and service sector maturity comparable to that in America, which shown in Fig 3.6. In addition, regulations relating to the development of unconventional resources in the most prospective onshore regions are yet to be defined.

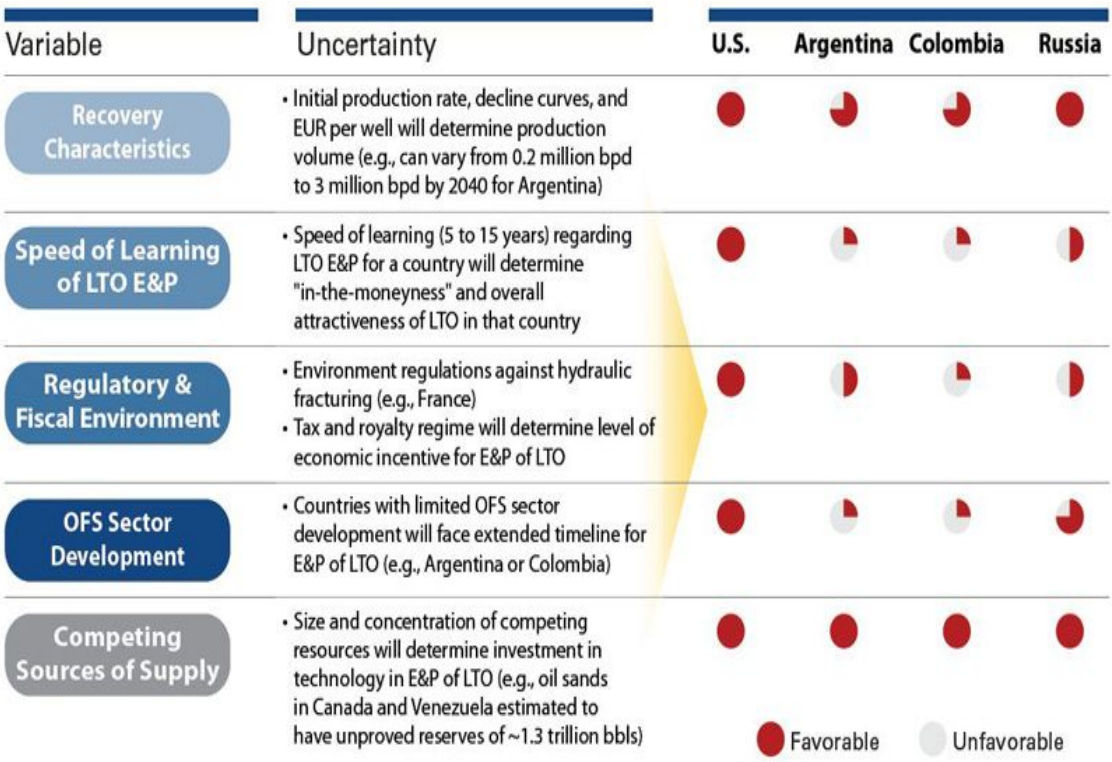


Fig3.6 UNCERTAINTY SURROUNDING TIGHT OIL RESOURCE DEVELOPMENT[5]

Despite the development of tight oil is at a disadvantage in some aspects, technology used in the U.S can be utilized in Argentina, particularly in the Vaca Muerta basin, and in Colombia, where analogous subsurface traits exist. Production costs are estimated to be bigger than $100/bbl in Argentina currently. But this can be lowered by more than 25% within five years. The Argentine government is willing to promote it as a source of energy with increasingly aware of the potential of light tight oil.[5] Similarly, operators in Russia are pursuing exploration of tight oil in the Bazhenov shale formation in western Siberia. The Russian Ministry of Finance is proposing new tax breaks for hard to recover reserves, of which tight oil can become a beneficiary.[19]

With time and effort, production costs can be brought down to the lower end of the range for marginal sources of supply, which includes frontier conventional fields. A production cost below $60/bbl is competitive with deepwater and oil sands, and can be achieved in the long term in certain regions outside the U.S, which makes LTO become a bright spot economically.

Besides resource calculations, SBC's LTO model includes a range of variables that are designed to present production prognoses.

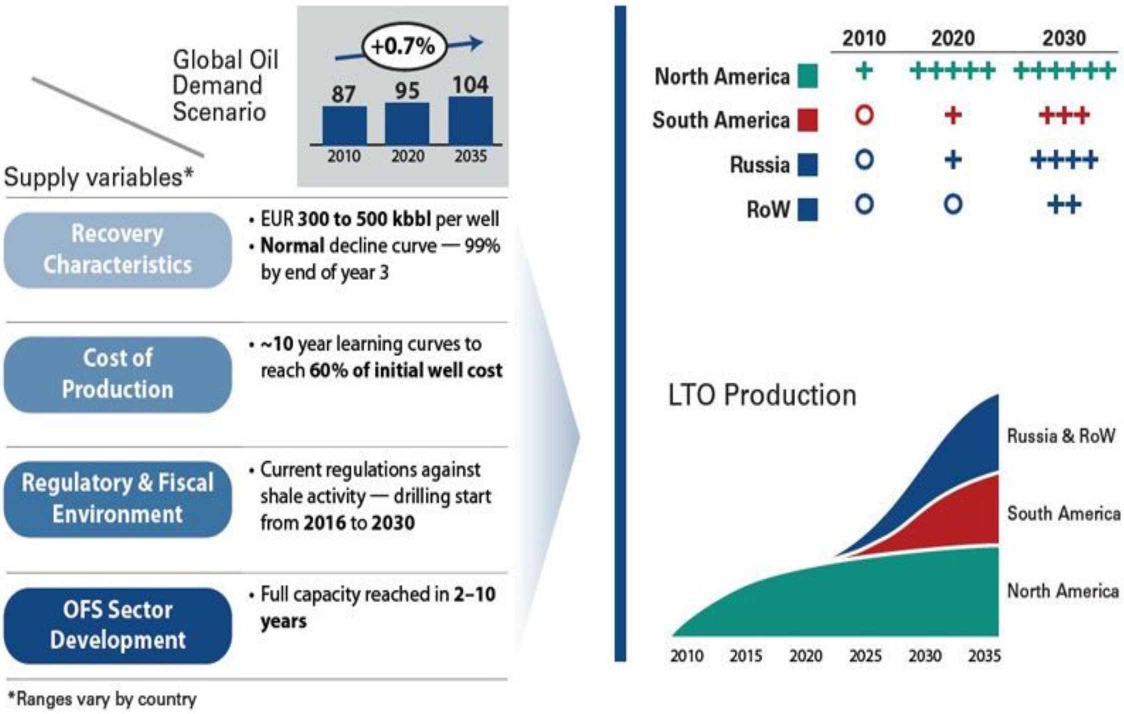


Fig 3.7 SIGNIFICANT RAMP UP IN LTO PRODUCTION OVER THE COMING DECADES(SOURCE: SBC LTO MODEL)[5]

As shown in Fig 3.7, tight oil production will grow at a rapid pace in North America based on SBC LTO model, more than 5 million bpd of production for North America by 2020. Outside North America, production will be influenced significantly by above-ground factors, as well as government enthusiasm for developing tight oil alongside conventional sources (this applies to Russia and some other countries outside North America). Non-North American tight oil production could amount to less than 10% of total global output by 2020, but may account for as much as 50% by 2035, tight oil production can account for over 5% of total world oil output in 20 years.[5]

3.3 Why tight oil

According to outlook for energy made by ExxonMobil, expanding prosperity across a rising population drives global energy demand, oil and gas will supply about 60 percent of global energy demand in 2040, up from 55 percent in 2010.[20]

As fast depleting of conventional oil resources, it becomes imperative to develop methods to harness unconventional oil resources such as tight oil. The total tight oil reserves in North America are estimated to be more than 30 billion barrels contained in 24 oil reservoirs, among which only 14 reservoirs are under development.[21]

Extensive oil and gas resources are known to be present in tight formations, however, advanced technologies needed to enable them to be produced. Most tight oil produced is of the medium to light variety, with a low viscosity, the oil itself requires very little refinement, existing surface infrastructure could often be utilized, reduce both surface impact and capital investment.[4]

4. What does tight oil exploration and development look like?

The Canadian Society for unconventional resources proposed various stages of unconventional resource development, which based on the premise that certain types of oil and gas exploration and development are undertaken at specific stages in the life of a project. Positive results from the exploration activities as well as a sound economic and investment environment guarantee the continuation of the project to next stage.

Various stages for tight oil E&P

Stage 1: Identify tight oil resource

Subsurface information from existing wells as well as archived seismic data indicates potential tight oil resource.

Stage 2: Resource evaluation

Land acquisition and the securing of seismic data lead to drilling location permits and land use agreements, vertical wells drilled initially to evaluate reservoir properties and resource potential, core samples always collected.

Stage 3: Pilot production evaluation

Initial horizontal wells and potential completion techniques help to determine production potential. Some level of multi-stage fracturing may take place at this point. Planning and acquisition of pipeline right-of-ways for field development also occurs during this stage.

Stage 4: Pilot production testing

Drilling of multiple horizontal wells from a single pad works as part of a full size pilot project. Optimization of completion techniques including drilling and multi-stage fracturing and micro-seismic surveys. Planning and acquisition of pipeline right-of-ways for field development.

Stage 5: Commercial development

Optimization of completion techniques, including multiple horizontal wells, multi-stage fracturing and micro-seismic monitoring present at this stage. Drilling and completion proceeds based on the field development plan as defined by regulatory well spacing, government approvals for construction of facilities and applicable technologies identified during the evaluation stage.

Stage 6: Project completion and reclamation

Completion of a project and reclamation of development sites and well pads to regulator standards occur as part of the final stage.

In general, tight oil development could be categorized into two types of exploration and development: Halo (infill) and Greenfield. Somewhere historical conventional oil wells existed, much of the new activities is defined as Infill or Halo. In these areas, tight oil development starts at stage 3, pilot production evaluation, where unconventional technologies are applied to a known reservoir, advanced technologies needed to improve the overall productivity of the new oil wells.

Greenfield exploration activities lie within regions where the resource potential of the oil bearing formations has not yet been established and requires more structured exploration planning. In these areas, stage 1 and 2 needed take into consideration.[4]

5. How to extract tight oil from reservoir

The oil extracted from tight reservoir is the same type of oil which produced from conventional reservoir. It is the advanced technology drives this extraction unconventional. Various technologies are used for different players, however, the most common methods used currently are horizontal drilling and multi-stage hydraulic fracturing.

Wells are drilled vertically initially to certain depth (typically 1km to 3km subsurface) above tight oil reservoir, and then the well is kicked off (turned) at an increasing angle until it runs parallel within the reservoir. Once horizontal, the well is drilled to a selected length which can extend up to 3-4 km. This portion of the well named horizontal leg.

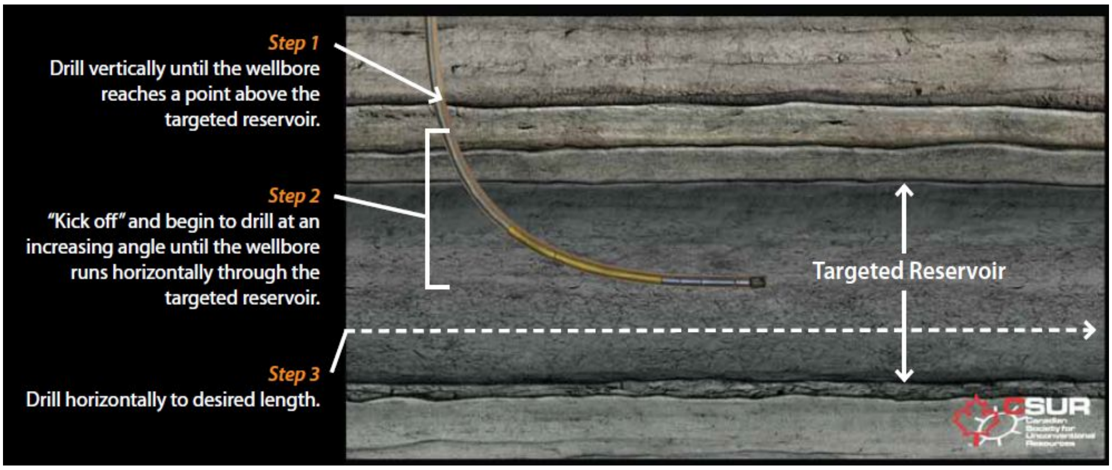


Fig 5.1 Horizontal well drilling[4]

5.1 Hydraulic Fracturing

Stimulation needed in the tight formation once the well has been drilled. The most common type of stimulation used in the oil and gas industry is referred to as hydraulic fracturing or fracking. Applying pressure by pumping fluids into the wellbore, pathways created in the reservoir through which the oil can flow to the wellbore. The permeability in conventional oil reservoirs is sufficient that hydraulic fracturing may not be needed to boom the production rate. While the permeability in unconventional reservoir is typically low so that the additional pathways have to be created to enable the economic production of oil and gas.

Fluids pumped into the reservoir at certain depth under specific pressure to create fractures, the type of fracture fluids depends on the reservoir characteristics. Commonly, water is used as base fluid; and three to twelve additives are added to water, based on the properties of source water and also of formation to be fracked. The additives could reduce friction, prevent microorganism growth and prevent corrosion, which normally represent 0.5% to 2% of the total fracturing fluid volume.[4]

The physics of fracturing

The size and orientation of a fracture, and the magnitude of the pressure needed to create it, are determined by the formation's in situ stress field, which may be defined by three principal compressive stresses, a vertical stress (σ_v) and a maximum and minimum horizontal stress ($\sigma_{H\max}$ and $\sigma_{H\min}$), they are oriented perpendicular to each other. The magnitudes and orientations of these three principal stresses are determined by the tectonic regime in the region and by depth, pore pressure and rock properties, which determine how stress is transmitted and distributed among formations. Fig 5.2 shows in situ stresses and hydraulic fracture propagation. Fractures open in the direction of the least principal stress and propagate in the plane of the greatest and intermediate stresses.

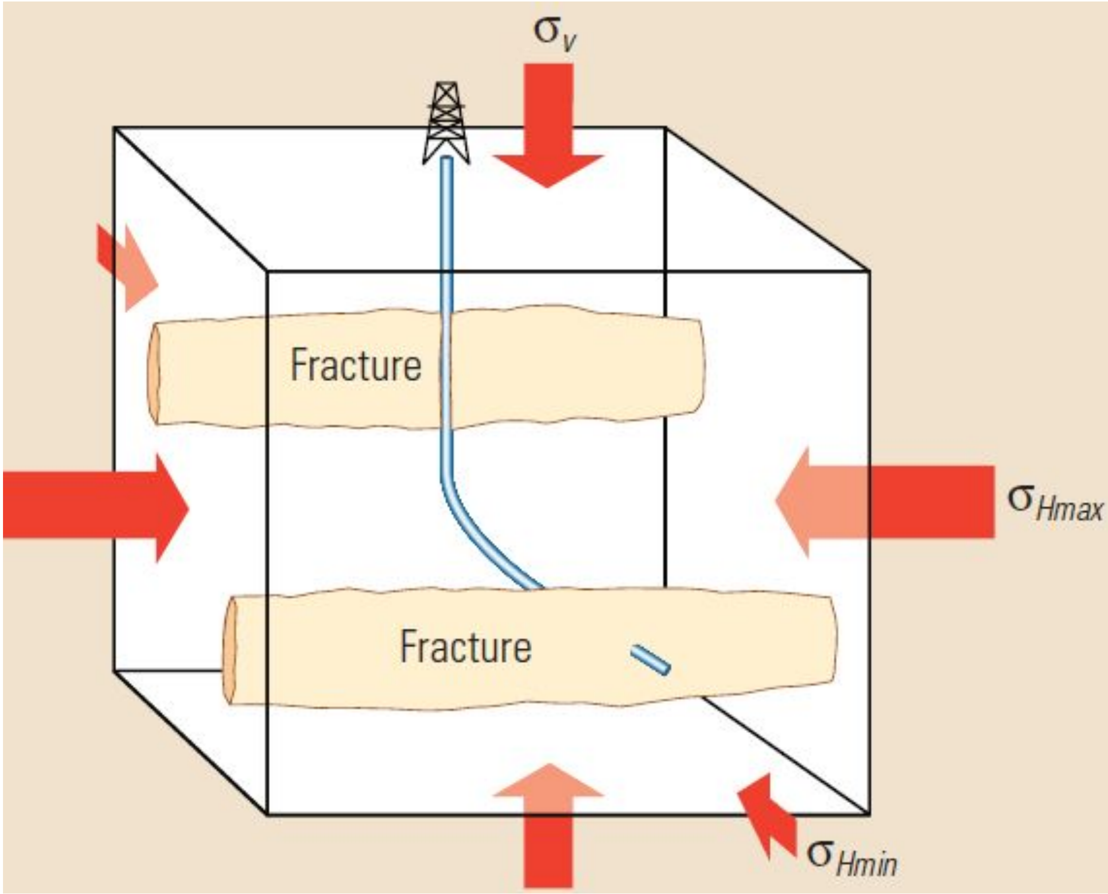


Fig 5.2 In situ stresses and hydraulic fracture propagation[22]

During hydraulic fracture operation, fluid pumped into the targeted formation at a prescribed rate, and pressure builds to a peak at the breakdown pressure, then it drops, indicating the rock around well has broken. Pumping stops and pressure drops to below the closure pressure. During a second pumping cycle, the fracture opens again at its reopening pressure, which is higher than the closure pressure. After pumping, the fracture closes and the pressure subsides. The initial pore pressure is the ambient pressure in the reservoir zone.

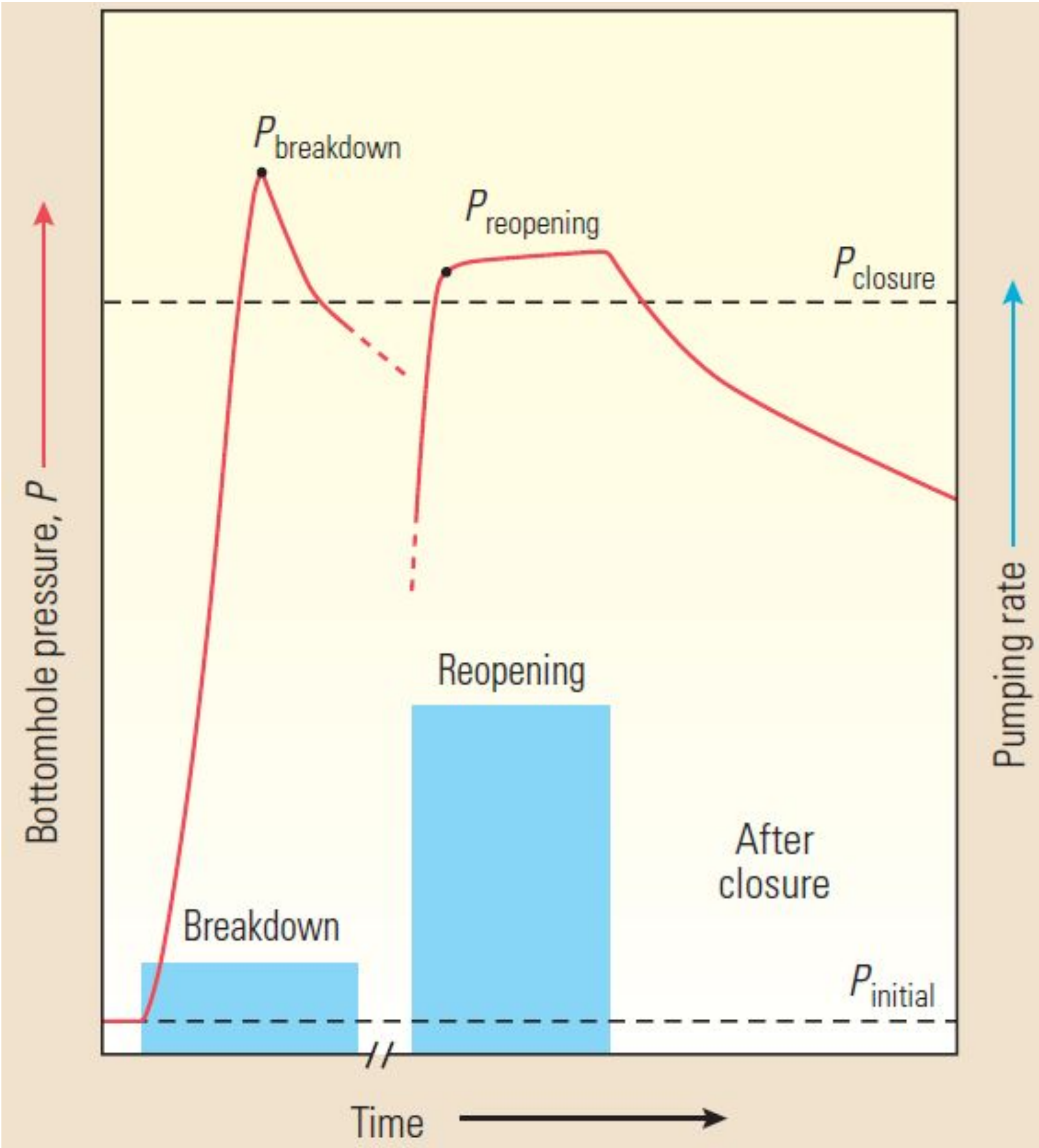


Fig 5.3 Fracture pressures[22]

A sudden drop in pressure at the surface indicates fracture initiation, as the fluid flows into the fractured formation, the fracture initiation pressure must exceed the sum of the minimum principal stress plus the tensile strength of the rock in order to break the rock in the target zone. To determine the fracture closure pressure, allowing the pressure to subside until it indicates that the fracture has closed again. The fracture reopening pressure is determined by pressurizing the zone until a level of pressure indicates the fracture has reopened. The closure and reopening pressures are controlled by the minimum principal compressive stress. Therefore, induced down hole pressures must exceed the minimum principal stress to extend fracture length.

After performing fracture initiation, the zone is pressurized to the fracture propagation pressure, which is greater than the fracture closure pressure. Their difference is the net pressure, which represents the sum of the frictional pressure drop and the fracture-tip resistance to propagation.

Once the fractures have been created, sand or ceramic beads (proppants) are pumped into the openings to hold the fractures created. In sandstone or shale formations, sand or specially engineered particles injected to hold fractures open; in carbonate formations, acid pumped into the fractures to create artificial roughness.

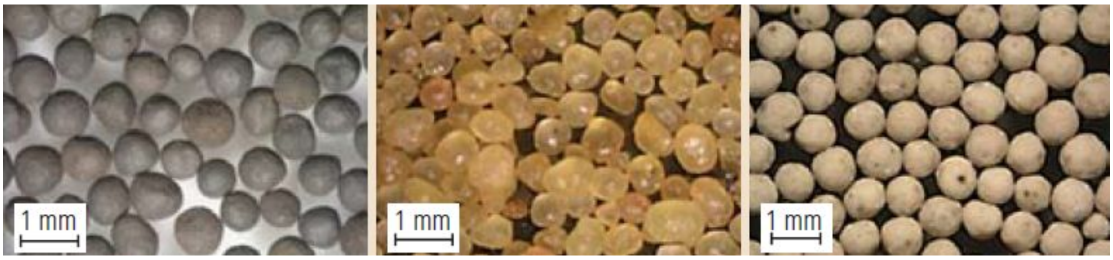


Fig 5.4 Proppant[22]

To maintain a constant rate of fluid injection, the volume injected includes the additional volume created during fracturing and the fluid loss to the formation from leak off through the permeable wall of fractures. However, the rate of fluid loss at the growing fracture tip is quite high. Therefore, it is not possible to initiate a fracture with proppant in the fracturing fluid because the high fluid loss would cause the proppant at the fracture tip to reach the consistency of a dry solid, causing bridging and screenout conditions. Consequently, some volume of clean fluid have to be pumped before any proppant used.[22] The volume of fracture fluid and porppant used for each hydraulic fracture depends on the anticipated production rate following the treatment.

In tight oil exploitation, hydraulic fracturing process typically involves multiple stages along the wellbore. Packer or plugs used to isolate each stage and make sure that the fracture grows in the direction and distance we want.

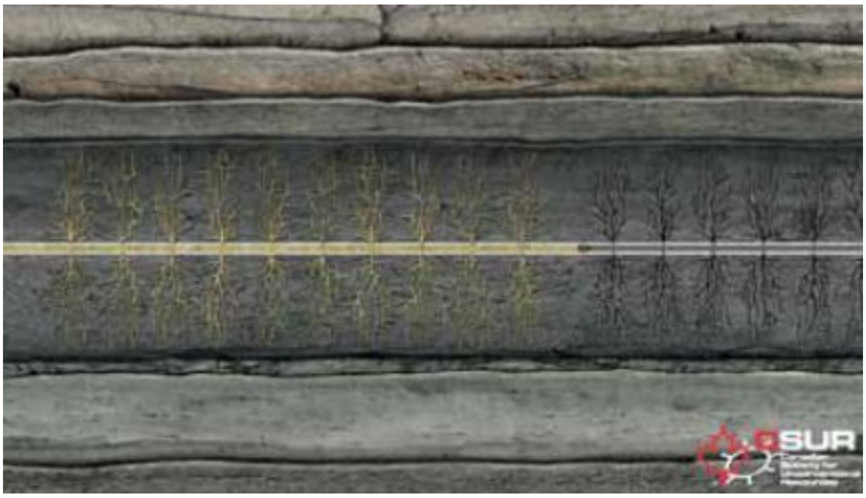


Fig 5.5 multi-stage fracture stimulation [4]

The image shows two fracture stimulations, the darkened fractures were completed as one stage and are temporarily isolated while those shown in yellow occur as the next stage. The number of fractures required in a wellbore based on the characteristics of the formation.[4]

The stimulation treatment ends when the planned pumping schedule end or a sudden rise happen in pressure, which indicates that a screenout has taken place. A screenout is a blockage caused by bridging, accumulation, clumping or lodging of the proppant across the fracture width that restricts fluid flow into the hydraulic fracture.

5.2 Monitoring

During fracture stimulation operations, it is quite important to know where the fractures go in the reservoir. Monitoring of the fracturing process in real time can be accomplished using a variety of techniques, such as pressure responses and micro-seimic monitoring, etc.

Microseismic events are micro-earthquakes induced by changes in stress and pore pressure associated with hydraulic fracturing. Microseismic caused by slippage or tensile deformation that occurs along pre-existing weak planes.(natural fracture, faults, joint. etc) The frequency range of the emitted elastic waves are of 3Hz to above 400Hz. Received signal consist of compressional (primary or P) and shear (secondary or S) waves which are used to compute the location of the event, the difference of arriving times between the P- and S- waves to the monitoring array gives the distance from the detected event to reservoirs.[23]

Measuring micro-seismic events that are occurring as fracture stimulation takes place provides industry professionals with visual evidence that fractures are being developed both vertically and horizontally. Immediate adjustments can be made during the operation to ensure the fractures go within the production potential zone since the micro-seismic events measured in real time. The magnitude of seismic events created by hydraulic fracture is many times smaller than events which can be felt at surface.

Following completion of fracturing operations, the micro-seismic model could define the limit and improve fracture stimulation in the wellbores. Recoverable resources, areas of insufficient stimulation can be defined by the horizontal and vertical model, and also a visual assurance that potential groundwater sources are protected.

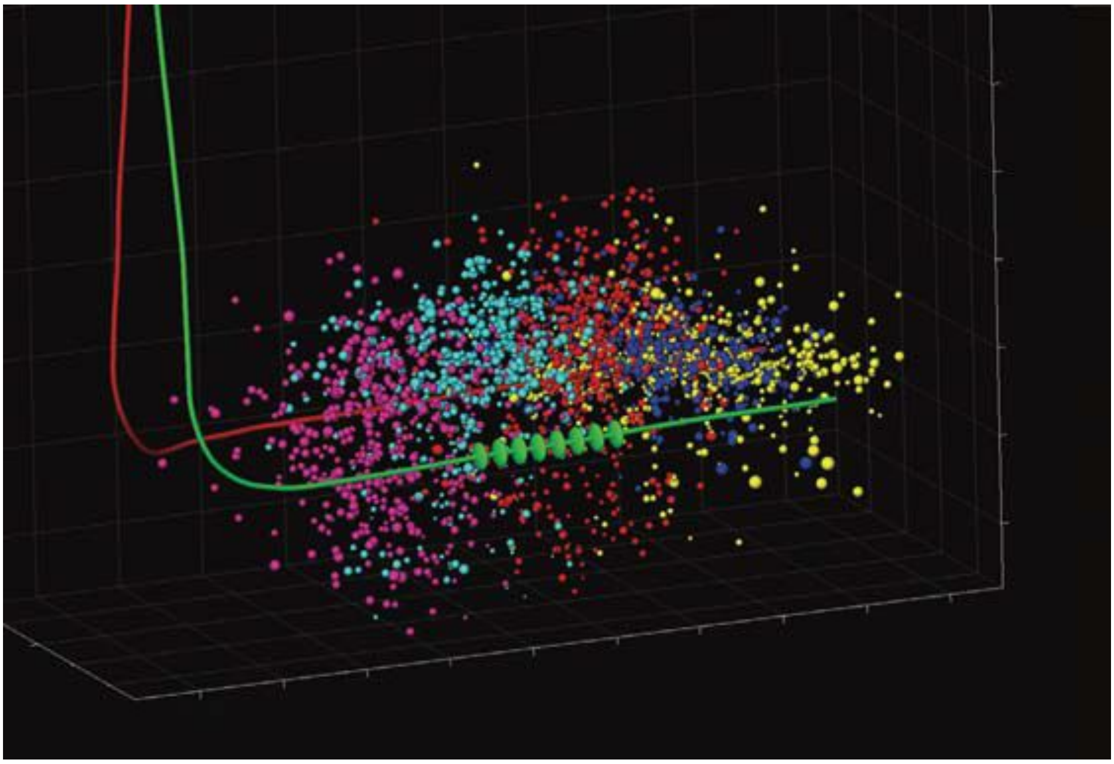


Fig 5.6 Microseismic monitoring of multiple-stage hydraulic stimulation.[22]

In Fig 5.6, five fracturing stages were pumped into the treating well (red line) while being monitored from a second well (green line with location of geophones shown as green disks). Microseismic events during stages 1 through 5 are indicated by the yellow, blue, red, cyan and magenta dots, respectively. Real-time microseismic monitoring may allow completion engineers to adjust operations during execution to improve the effectiveness of the treatment.

5.3 Minimize footprint

Companies are striving to reduce environmental impacts and to minimize costs associated with tight oil development. The application of multiple wells from single pad has been recognized as an opportunity to achieve both of these objectives. Fewer access roads are required and the concentration of facilities and pipelines within the pad minimizes surface disturbance.

During drilling and completion of well, there is a significant space requirement for the equipment used. Once the well complete and commercial production initiated, the lease site requirements are typically reduced by as much as 50%.[4]

5.4 How to protect drinking water

Proper well construction, a critical step taken by the oil and gas industry to several different sets of steel casing which protect potential groundwater source, contribute to isolate the wellbore. There are individually cemented into the wellbore to provide barrier which isolate wellbore fluids from the rock intervals.

Cement is pumped down the center of casing and circulates back to the surface in the space outside of the casing, which we called annulus, following the installation of each string of casing in the well. After these steps complete, the cement is allowed to set prior to the continuation of drilling, and geophysical log is run somewhere to determine the integrity of the cement that surround the casing, which helps to ensure the wellbore is adequately cemented and capable of withstanding the pressure associated with hydraulic fracturing. Prior to stimulation, the well is pressure tested to ensure the integrity of the casing system that has been installed underground.[4]

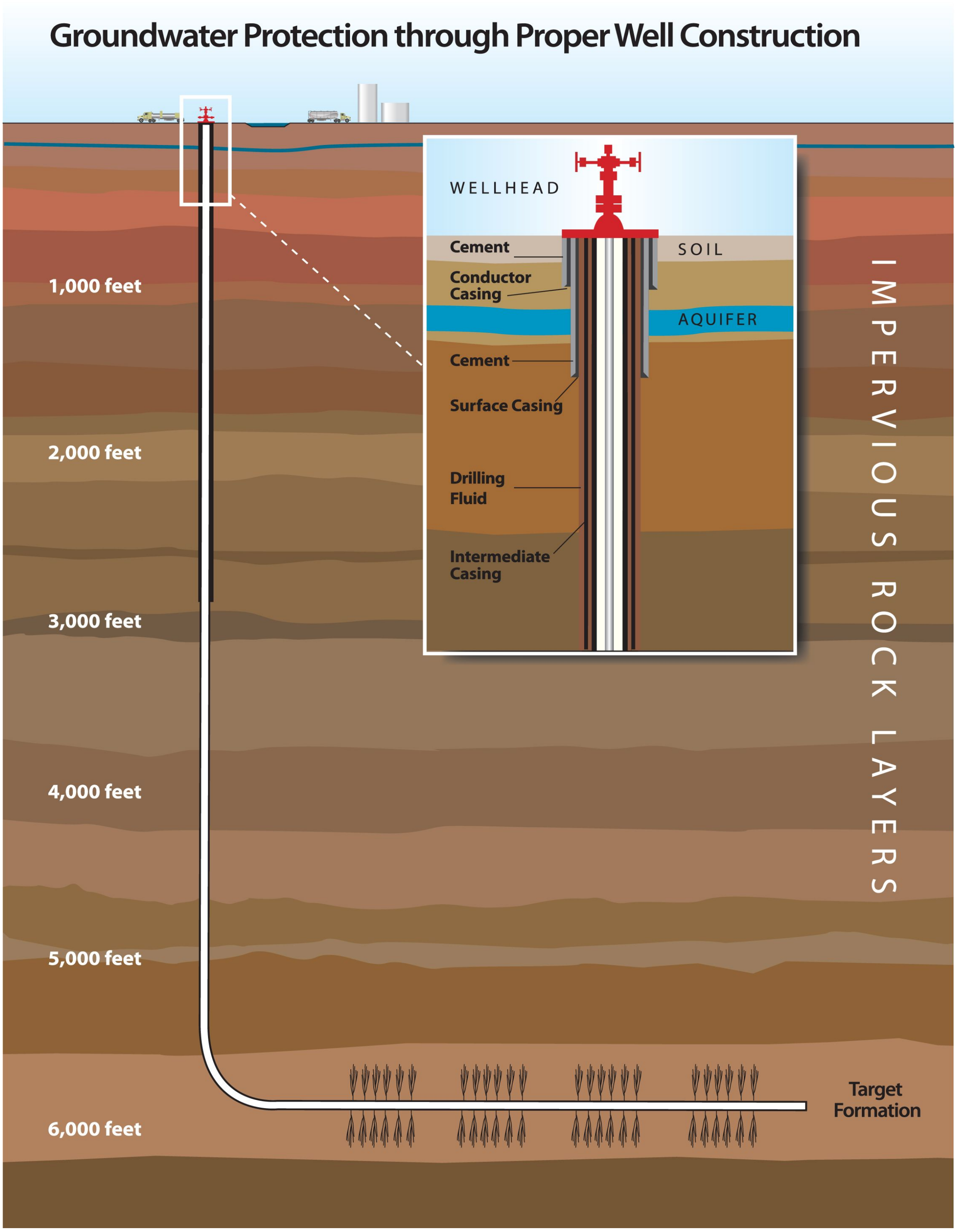


Fig 5.7 Groundwater source protection by proper well construction [24]

Under state regulation, comprehensive rules are in place to ensure that wells are constructed in a manner that protects freshwater supplies. Specific regulations vary between jurisdictions, but in all cases steel casing and cement are used to isolate and protect groundwater zones from deeper oil, natural gas and saline water zones.[4]

According to the British Columbia Oil and Gas Commission (BCOGC), the Saskatchewan Ministry of Energy Resources, and the Alberta Energy Resources

Conservation Board (ERCB), there has never been a confirmed case of groundwater contamination resulting from hydraulic fracturing in British Columbia, Saskatchewan or Alberta, the three provinces where most oil and gas drilling activity in Canada occurs.[3]

6. Technical focus of tight oil E&P

Opportunities and challenges exist side by side with science and technology advancing in tight oil E&P, the advanced knowledge in tight oil E&P need to be emphasis in real-time measurement; post-fracture monitoring with production analysis; identifying sweet spots, then placing perforations to create complex conductive fractures; innovative proppants and proppant placement techniques in primary and complex fracture geometries, fluid recovery, formation damage control and permeability enhancement, proppant transport with less-damaging stimulation fluids, and environmentally responsible drilling, completion, and production services.[7]

6.1 Reservoir Geometry

Based on the experiences with tight gas exploitation, several conceptual models summarized by Clarkson, et al, which may applied to the wellbore versus fracture geometry in various reservoirs, these models can be used to analyze tight oil reservoirs developed with horizontal wells.

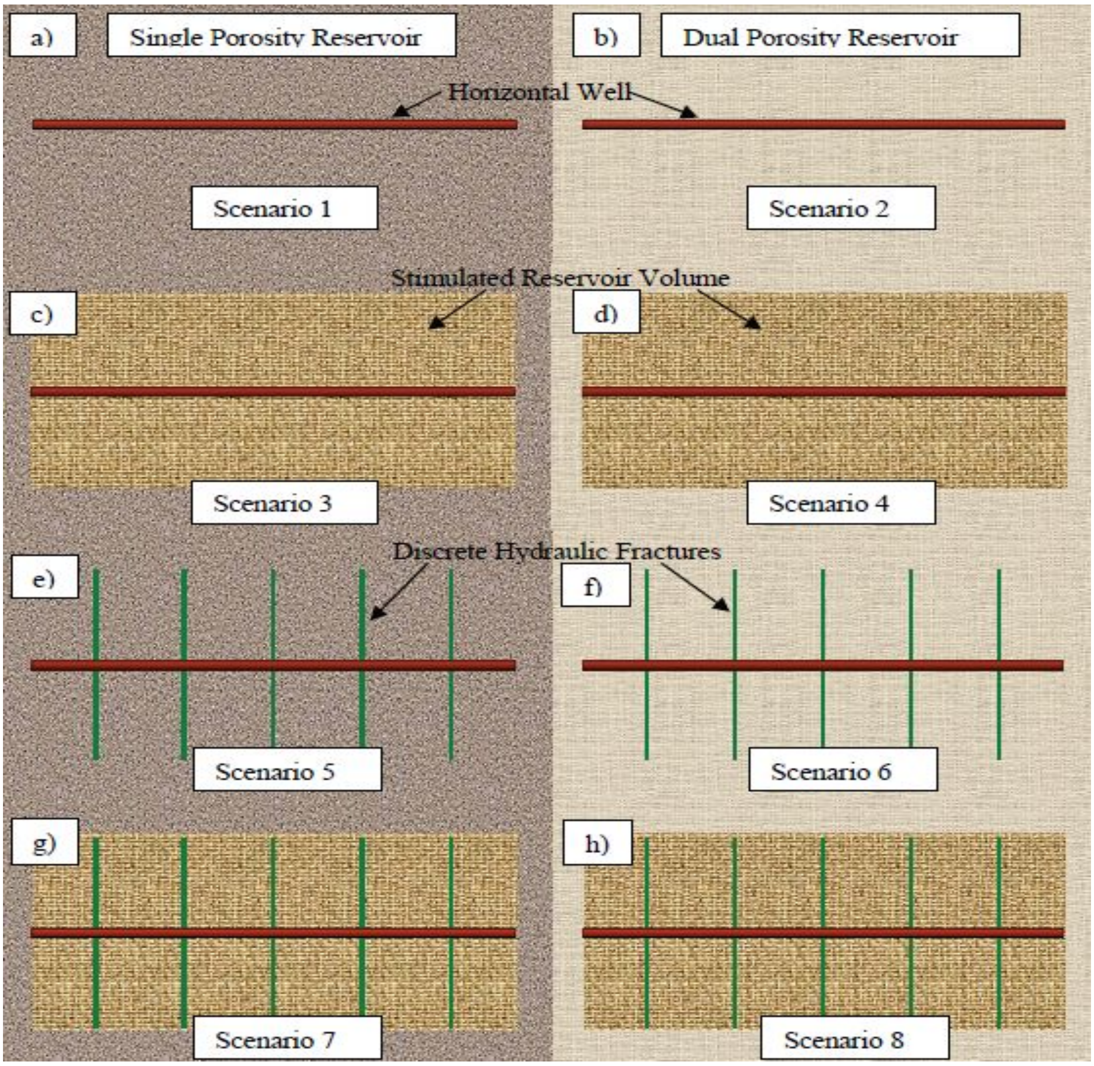


Fig 6.1 Possible combinations of reservoir/hydraulic fracture encountered for tight oil reservoirs.[25]

Fig 6.1 a represents an open hole horizontal well in single porosity model, this type of completion is likely ineffective in ultra-low permeability reservoirs because of the lack of contact surface area. Fig 6.1 b shows an open hole horizontal well in a dual porosity reservoir or a multi-fractured horizontal well where fracture complexity has been created. In Fig 6.1 c, the background reservoir is single porosity model, and the SRV(stimulated reservoir volume) is limited to a region immediately around the horizontal well. Fig 6.1 d represents multi-fracture combined with horizontal well works in naturally fractured reservoir, the SRV and background reservoir would have different fracture permeability and porosity. Scenarios 5-8 represent discrete hydraulic fractures which have a different conductivity than the fracture network.

Several possible combinations of fracture geometry could exist in tight oil reservoirs, flow regime identification and integration of surveillance techniques needed to identify proper model, which is critical for proper extraction of stimulation properties.[25] In formations where a strong fracture barrier is present (as in some tight oil/gas plays) or the treatment is designed to limit fracture height growth, an elliptical or rectangular geometry may be more applicable. A circular geometry is adequate when a formation where gross pay is significantly thicker than net pay and significant height growth is possible.

Selecting the appropriate model for interpreting production data from reservoir is quite important, however, modeling fluid flow in tight reservoirs still remains challenges.

Dual-porosity model which consists of uniformly distributed fractures and matrix blocks is widely used in the analysis of fractured reservoirs. Its assumption of uniform matrix and fracture properties throughout the reservoir which may not be true in reality. Studies in western Canada sedimentary basin show that effective hydraulic fracture connection with natural fracture system enhances the reservoir volume drained by a well. This hydraulic fracture connection transforms the dual-porosity reservoir into a triple-porosity system. Triple-porosity models can comprise (1) two fracture networks and one matrix or (2) two types of matrix and one fracture network. All existing triple-porosity models assume sequential depletion (negligible matrix–hydraulic fracture communication), the sequential assumption can result in unreasonable estimates of micro-fractures and hydraulic fracture properties when significant matrix–hydraulic fracture communication exist or negligible bulk matrix–micro-fractures contact area compared to bulk matrix–hydraulic fracture contact area. Hence, Ezulike and Dehghanpour proposed a quadrilinear flow model (QFM) that relaxes the sequential depletion assumption by conceptually dividing the matrix volume into two sub-domains: one feeds hydraulic fracture and the other feeds micro-fracture. QFM also converges to the sequential triple-porosity model in the absence of matrix-hydraulic fracture communication; and converges to the dual-porosity model in the absence of micro-fractures

Ezulike et al made a comparative study of the reservoir parameters estimated from the application of these models to the same production data. The results show dual porosity model is appropriate if analog studies (e.g. outcrop, micro-seismic and image log analyses) reveal high spacing aspect ratio (negligible micro fractures) in the reservoir. Linear sequential triple-porosity model is appropriate if analog studies reveal low spacing aspect ratio (e.g. matrix hydraulic fracture face damage or high micro fracture density within a given hydraulic fracture spacing). QFM is the general case and is appropriate for all spacing aspect ratios.[26]

6.2 Flow regime analysis and production forecast

The series of flow-regime that may develop as a result of fracture geometry: single discrete Bi-Wing fracture developing from each stage.

1. Transient Flow in Fracture

Single-phase flow of water along the primary fracture network to the perforations. For each set of perforation clusters, radial flow is assumed to occur to the horizontal well within a cylinder that is the length of the perforation cluster and width of the primary fracture network. For multi-stage flow back, there would be n cylinders flowing back to the well, where n corresponds to the number of fracture stages that are effective.

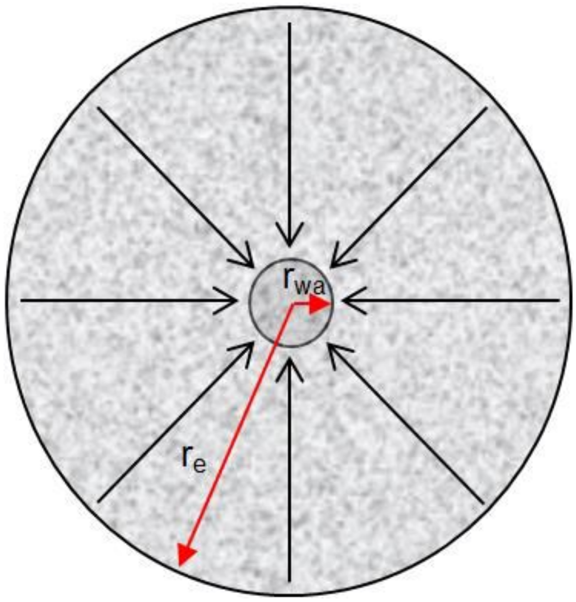


Fig 6.2 Cross-section view [27]

2. Fracture Depletion (Storage)

Single-phase flow of fracture water during primary fracture depletion (prior to breakthrough of hydrocarbons or formation water from the matrix). Once the pressure transient reaches the end of the propped and effective primary fracture network, fracture depletion starts to occur.

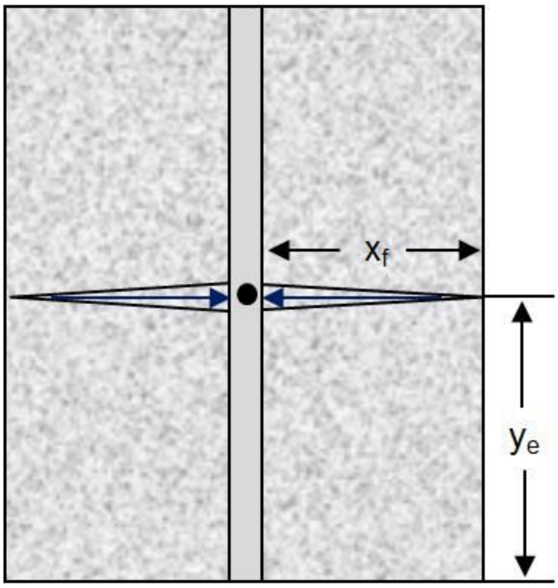


Fig 6.3 Plan View (Single Fracture Stage) [27]

3. Coupled Matrix Transient Linear Flow/Fracture Depletion

Once fracture pressure drops below breakthrough pressure, hydrocarbon and formation water enter the fracture as a result of transient linear flow from the matrix. Oil and water then flow towards the well via fracture depletion. Note that effective fracture half-length is reduced following hydrocarbon breakthrough.

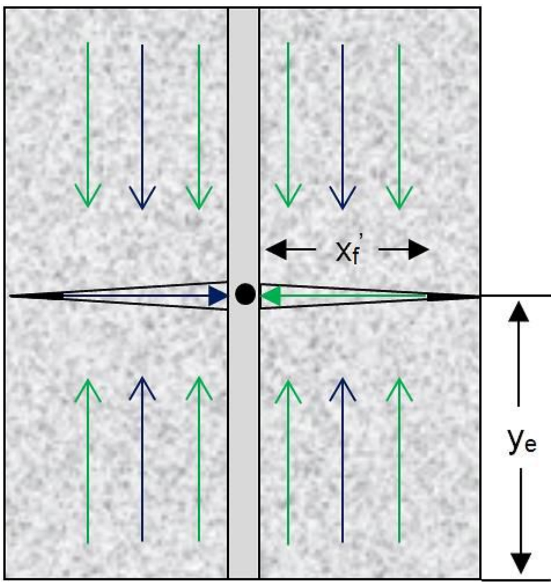


Fig 6.4 Plan View (Single Fracture Stage) [27]

4. Transient Linear

A continuation of rate limiting transient linear flow of oil between stages in the lower permeability matrix. This transient linear flow period lasts longer than flow-regime 3, possibly for several years.

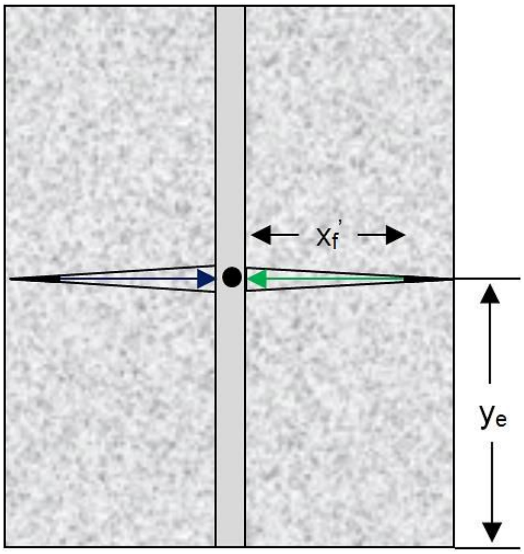


Fig 6.5 Plan View (Single Fracture Stage)[27]

5. Pseudo Steady State Flow

A second no-flow boundary develops between fractures stages (actually between closest perforation clusters of adjacent stages) followed possibly by pressure depletion.

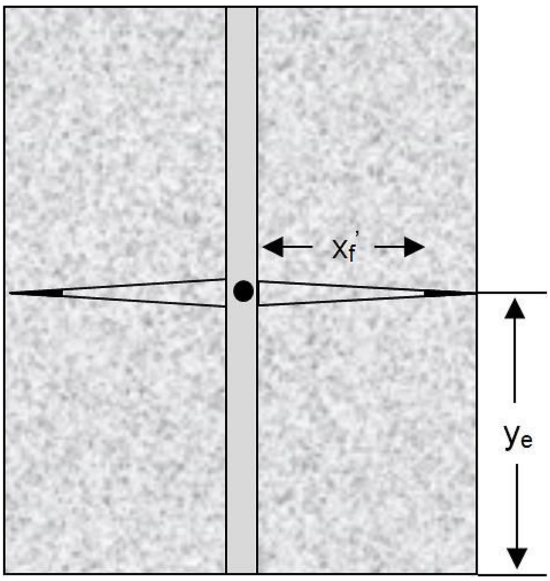


Fig 6.6 Plan View (Single Fracture Stage) [27]

6. Late (Compound) Linear

This is an additional transient linear flow period in which flow is from outside the stimulated reservoir volume towards the horizontal well. This flow-regime is often not observed in tight reservoirs.

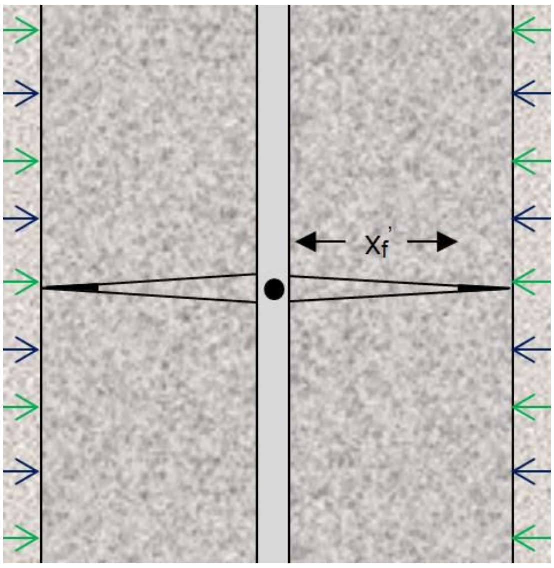


Fig 6.7 Plan View (Single Fracture Stage) [27]

Flow-regime 2 and 3 are generally flow-regimes available for analysis during typical flow back operations for light tight oil reservoirs.

Flow regime analysis

Flow regime analysis (straight line methods): rate transient derivative methods could be used to identify flow regime, followed by analysis of specific flow regime data using Cartesian plots. Transient (linear, bilinear, elliptical and radial) and boundary dominated flow analyzed by the technique, reservoir and effective stimulation properties may be extracted from the fit of straight lines to dataset. Derivative analysis technique is also applicable in the analysis.

Flowback analysis

1. Diagnostic plots.

Water RNP(rate normalized pressure) and water RNP derivative, also known as RNP are applied to assess data quality and flow regimes.

2. Rate Transient Analysis

Several specialty straight-line plots are also used to assist in analytical history-matching, flowing material balance and radial flow analysis are used to estimate hydraulic fracture properties (pre-breakthrough fracture half-length and fracture permeability).

3. Deterministic History-Matching.

Analyzing multi-phase (water, oil and gas) production and flowing pressures to estimate total hydraulic-fracture half-length and fracture permeability.

Flow regime 2 is modeled using methods applied to commercial coal bed methane plays and conventional permeable sands, which are assumed to be in boundary dominated flow, and flow regime 3 is modeled as a combination of transient linear flow and fracture depletions.

4. Stochastic Analysis

Kovacs et al proposed stochastic analysis (Monte Carlo simulation) could be used to assess the uniqueness of the deterministic match by developing a distribution of key parameters which can be used to match the data.

Initially, all uncertain parameters are defined using probability distributions (lognormal distributions were used), parameters which have minimal impact on the match are set to a single deterministic value and parameter ranges are reduced based on the values involved in success cases. Monte Carlo simulations are re-run using the reduced number of inputs and reduced input ranges until the desired results are achieved (i.e. number of success cases).

They also take salinity model and fracture compressibility into consideration in order to improve the uniqueness and accuracy of the history matches.[27]

Production forecast

The following methods could be applied in the analysis and forecast of production.

Type curve analysis: production data in dimensionless form are matched to dimensionless type curve developed from empirical solutions to flow equations corresponding to a specific reservoir model. Reservoir and stimulation properties may be extracted from the match based on the definition of the dimensionless variables.

Reservoir simulation: matching dynamic data (production and pressure data) by adjusting input parameters of the model to calibrate the simulation model, which in turn can be used to forecast future production.[25]

Clarkson et al. proposed a new analytical approach to forecast the production, they realized it is approximate to represent the transient from one linear flow period to the other by using radial flow, elliptical flow will precede radial flow in reality, which works well for a wide range in hydraulic fracture properties.[25]

Bansal et al proposed a methodology can be applied for different tight oil reservoirs worldwide. The methodology utilizes Artificial Neural Networks (ANN) to map the existing complex relationships between seismic data, well logs, completion parameters and production characteristics, which can be used to forecast oil, water and gas cumulative production for a two year period, it also helps to avoid less productivity wells thus improving economics of tight oil development.[28]

6.3 What matters: Geological and engineering parameters?

Randy studied the data collected from publicly available sources, especially IHS Energy's US Well database, they proposed reservoir quality is the most important factor influencing production based on the studies of the Barnett and Bakken formations, well architecture and completion variables such as stage length may also have quite significantly impact on production. Stimulation parameters such as treatment size, injection rate, and materials may have varying degrees of influence on the outcome. This conclusion was determined from bubble mapping using GIS(Geographic Information System), then further confirmed by boosted-tree models.[29]

Ghaderi et al. studied the controlling factors of primary recovery at the Cardium Formation, which is tight oil formations, they are summarized in order of significance: the numbers of well per section, the length of the well, operating bottom hole pressure of the wells, fracture half length. Fracture conductivity has a lesser effect on recovery factor, but will impact early production. Higher fracture density may accelerate oil production, but also accelerate gas saturation fracture between fractures, which reduced oil mobility and impairs long term oil production.[30]

Effects of natural fractures

During the fracture operations, the fluid could penetrate into the natural fractures and dilate them, contribute to more permeability and greater penetration into natural fracture. At some point, there is sufficient pressure in the natural fractures to begin jacking them open, which also requires a low stress bias. Once open, they continue to propagate as orthogonal hydraulic fractures as long as the fluid supply supports them. Multiple natural fracture can be open in this way, thus creating the fracture network.[31]

Inference of permeability and fracture closure can be challenging considering the significant effect on the water imbibition of shale and possible complex leak off due to natural fractures.[32]

Effect of formation strength

Understanding mineralogy and fluid sensitivity, especially for shale reservoirs, is essential in optimizing the completion and stimulation treatment for the unique attributes of each shale play.[15]

The brittleness of the shales is also regarded as an important factor for developing a large fracture network that maintains conductivity upon production drawdown. Softer shale is likely to be more challenge when trying to achieve large conductivity networks.[31]

Hard, brittle rock can offer an advantage since more likely the presence of natural fracture, thus respond better to stimulation, versus a softer shale that has the advantage of being easier to prop open.[15]

6.4 Hydraulic Design

Hydraulic fracturing raises well productivity by improving its contact area with the target formation, and the configuration of hydraulic fractures and their orientation should satisfy two conditions in order to increase the sweep efficiency: maximizing contact area with reservoir matrix and maximizing distance between the producer fractures and injector fractures.[33]

Ernesto et. al proposed an integrated approach to generate a wider slate of novel and relevant engineering choices in the design process, which considers the progressive analysis and application of subsurface diagnostics and modeling capabilities, and how they influence meaningful decisions in the area of hydraulic fracture design.[32]

Subsurface Diagnostics:[32]

The vertical stress profile and pore pressure estimation can be get from a diagnostic fracture injection test. Microseismic is used to calibrate vertical stress profiles generated from core and sonic log data and infer fracture length via comparisons against a range of simulation outcomes for credible leak-off and pumped volumes.

The fracture height can be measured with either temperature logs, permanent distributed temperature sensing fiber optics, or proppant tracer.

Production logs show how effectively fractures were generated in the lateral section, radioactive traced proppant provides the location of propped fractures and how well fractures propagate away from and perpendicular to the well.

Low cost technologies emerging within industry that use drilling data to improve the definition of production properties along horizontal well. Image logs and the determination of rock strength properties using sonic logs used to identify natural fractures near wellbore, but it is quite expensive, thus using data already available from mud and drilling operations as a low-cost source of data to improve hydraulic fracture becomes a trend, software fracid_ubd is being used for fracture characterization.[32,34]

Also rock strength determination while drilling technique applied in final development. The software DWOB-DROCK developed by Dr. Geir et. al takes drilling data and gives the prediction of Young's modulus.[32]

Using distributed acoustic sensing diagnostics in the field has provided insight into uneven distribution of proppant within a fracture stage.[32,35]

Modeling capabilities:

Planner 3D model, as a common method in the industry, estimates height, length and width of fractures. It assumes fractures grow within a plane and fractures are symmetrical on both sides of well and can account for shadow stress from neighboring fractures by reflecting a reduction in width and length, it has proven its value in comparing different fracture geometries at different rates and fluid types when calibrated with microseismic data, however, it is unable to yield a more credible set of answers given the fracture geometries and fracture response mechanisms that are not captured in existing planar 3D simulators.

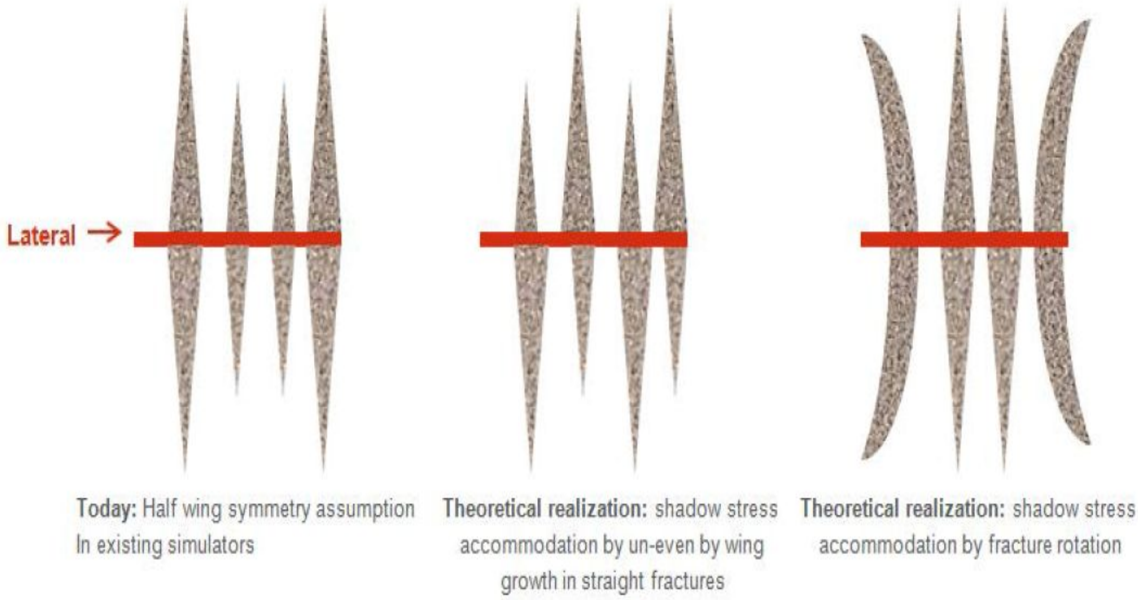


Fig 6.8 possible fracture geometries not captured in existing simulators[32]

Fig 6.8 shows top view of fractures, the simplification of simulating a half length fracture does not permit fracture to accommodate shadow stress by uneven half lengths or widths in the same fractures versus suppressing the fractures in the middle of cluster, also the 3D planar model shows inability in covering fracture rotation.

FrackOptima, as a non-planar 3D hydraulic fracture simulator, introduced to simulate multiple non-planar fractures in multistage hydraulic fracturing along horizontal wells and model various geometric configurations.[36] It opens the door to begin phasing out the cookie-cutter design approach. The non-planar 3D simulator with multi-cluster and multi-well capabilities introduces valuable design opportunities around shadow stress modeling and forwards to a more comprehensive design strategy, and away from the standardized, repetitive design approach through all the steps required to frack a complete multi-well pad.

Meaningful Decisions:

Initial screening evaluation of slick-water, gel fractures, hybrids can be completed with planar 3D models.[37]

Landing depths and rate sensitivities highly related to the presence of shale laminations, carbonate layers and differential vertical strengths within pay zone.

Evaluating the point of diminishing economic returns for a single fracture job after capturing indications of fluid performance at various rates.

Estimating fracture spacing considering recovery economics and shadow stress combined with optimum single fracture design yields a final design, makes the project ready for integration with the well and completion design.

As the hydraulic design process is coupled to many design parameters, also related to the layering, zone thickness, permeability, etc, it is hardly sequential.

Ernesto et al. proposed that refracture of horizontal wells will eventually a competitive means to keep facility utilization high and offer a viable alternative to drilling new wells, especially with the large inventory of wells, low gas price environment in North America, various completion options.[32]

6.5 The emerging technologies applied in tight oil reservoir

As more and more focus on tight oil reserve, which drives technical evolution to produce tight oil with the consideration of economic, technical and environmental perspectives.

Fracture monitoring

Single well monitoring depends on Ts-Tp travel time difference and hodogram angle to locate events. Multi-well monitoring allows for travel time traingulation plus hodogram angles. Dual well hydraulic fracture monitoring was proposed by Xu et. al and conducted in the tight sand oil reservoir at Ordos basin, which helps to delineate feature in much more detail and accuracy, reducing uncertainty, improving mapped fracture location.[23]

Combining the microseismic analysis with surface and downhole tilt fracture mapping allowed characterization of the created fracture networks.[38] It is the downhole microseismic technology that provide the information about detailed structure of the network fracturing process. High quality microseismic mapping data is essential to understand completion and stimulation behavior.

Surface tiltmeters help to determine how the volume of fluid distribute between the primary fracture azimuth and other fractures plans that open, thus providing a measure of complexity. In addition, surface tiltmeters can also provide information about the occurrence of fracture along the length of a horizontal well, although limits exist on resolution based on the depth of the fracture. Radioactively tagged proppant can used to assess the completion behavior and cement quality in horizontal wells, and chemical tracers can distinguish interconnections between wells and flow back percentages during various stages. Pressure diagnosis prior to, during, after fracturing are useful for assessing fracture behavior.[31]

Norman, et.al proposed fracture network can be discovered and optimized through mapping technology and primarily microseismic. For the shales, mapping has proved itself to be valuable in assessing the fracturing results.[31]

Unconventional stimulation

The efficiency of fracture stimulation diminish as the laterals exceed 5000 ft, it involves even greater challenge to run an eight stage fracture job at more than 5000ft. Tradition methods include pumping fracture fluids into the open hole or isolating separate zones of horizontal well. The former method typically results in the fracture fluid into the area with least resistance, which has a negative effect on the rest of wellbore. The later one typically need several steps (repeated cementing, plugging, perforating and fracturing), and also includes multiple trips as well as the expense of additional crew and equipment during operation.

In addition, completing high angle wells also meets challenges when getting tools through doglegs and other restrictions. The packers in the selected fracture system are shorter than standard tools, which contribute to navigate better through such tight formations. Brent et. proposed swellable packer fracture sleeve system for the Bakken shale job, the pre-job planning and mobilization in shop resulted in savings of six hours of rig time. The analysis before and during the job resulted in more accurate placement of fracture sleeves, contribute to a higher production than traditional methods.[39]

The high pressure in normal gel fracture treatments by using viscous fluids with high proppant concentrations may limit the fracture length. Hydraulic fracture treatments may depend on the fracture conductivity that can be sustained, and this is in turn related to the residual fracture width. Residual fracture width can be related to fracture roughness in core tests, but healing of fractures should ideally be determined under in-situ conditions. A consistent method of integrating well tests analysis, production logs and fracture geometry simulations needed to obtain a comprehensive reservoir stimulation model is proposed by Wong et. [40]

Hydraulic fracturing at high temperature and high pressure basins often requires pumping at very high surface pressure for prolonged periods, surface treating pressure can exceed 69 MPa at Songliao, Tarim, and deep Sichuan basins tight reservoir in China, open hole fracturing has potential to reduce the pumping pressure needed to break down the formation and the potential to maximize connectivity between the wellbore and the network of natural fractures.[41]

A lot of trial to decrease polymer loading made in fracturing fluids in order to optimize hydraulic fracture conductivity, developing new polymer-free fluids, implementing foams as fracturing fluids, increasing proppant size and concentration, enhancing polymer breaker performance, increasing breaker concentration, and implementing the tip screenout technique. All these methods have some positive impact on proppant pack conductivity but result in higher risk of premature screenout. Since conductivity is created by the proppant pack, which physically limits permeability. The new channel fracturing technique develops open networks of flow channels within the proppant pack; thus, the fracture conductivity is enabled by such channels rather than by flow through the pores between proppant grains in the proppant pack. A special fibrous material added into the carrying fluid to consolidate propant structure.

Rifat et al. concluded channel fracturing technology is applicable and valuable for low permeability mature oilfield with properly design, whcih helps to improve productivity index of 51% compared to offset wells treated with conventional fracturing.[42]

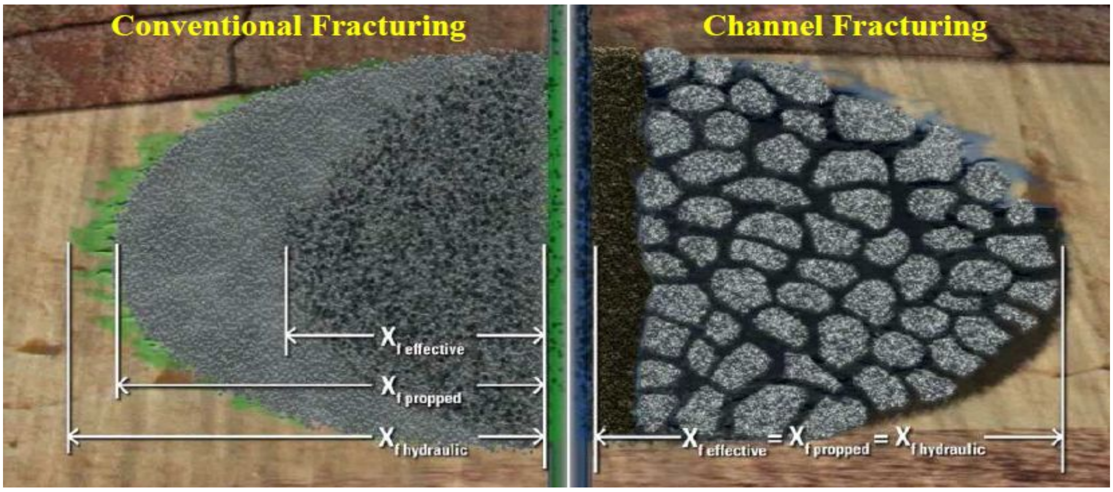


Fig 6.9 Representation of the channel fracturing technology(right) with respect to a conventional propped fractue(left)[42]

The damage profile around a horizontal wellbore is neither radial nor distributed evenly along its entire length since formation anisotropy creates an elliptical damage profile, which is unlike the vertical well damage profile. Linus et al. developed a more-realistic volume requirement and placement method to deal with the identified damage profile, which offers the desired estimation of the volume of acid required to stimulate horizontal wells and selective stimulation where production hot spots exist in horizontal drain holes by directing acid treatments to where they are desired.[43]

The acid stimulation test conducted in the Onnagawa tight oil formation which is Miocene, bio-siliceous shale, acid stimulation is not intended to remove drilling and completion damage, but improve natural fracture conductivity by dissolving the calcite and clay filling in natural fractures, the oil production dramatically increased from 1.5 kl/day (10 BOPD) to 50.0 kl/day (315 BOPD).[44]

CO_2 treatment

Fracturing with carbon dioxide is one of the most effective and cleanest approaches available today to boost hydrocarbon production.[45]

CO_2 is injected in a liquid state by conventional frack pumps, which could carry high concentrations of proppant and is compatible with kinds of treating fluids (including acids). Also injection rates can be improved by adding booster capacity.

The use of CO_2 in fracturing is effective for several reasons:

Because of its density, carbon dioxide is not susceptible to gravity separation, also it provides solution gas drive for effective clean up. When carbon dioxide dissolves in water, it forms carbonic acid (H_2CO_3), which dissolves the matrix in carbonate rocks.

CO_2 buffers water-based systems to a pH of 3.2, controlling clay-swelling and iron and aluminum hydroxide precipitation.

CO_2 acts as a surfactant to significantly reduce interfacial tension and resultant capillary forces, thus removing fracturing fluid, connate water and emulsion blocks.

CO_2 can be used with foam qualities of 20-50% to provide energy and still optimize fracture length

When subjected to normal well stimulation pressures, carbon dioxide exhibits a hydrostatic head equal to or greater than fresh water. This lowers both treating pressures and horsepower costs.

CO_2 can be pumped with synthetic and natural polymers, lease crude or diesel as a foam or micro-emulsion, raising the hydrostatic head and lowering viscosity of the system; this, in turn, reduces horsepower costs. Its density contributes to carry high levels of proppant in foam form.

It also provides the energy to remove formation fines, loose or crushed proppant, reaction products and mud lost during drilling. Swabbing of treating fluids can be substantially reduced. By reducing the need for swabbing, associated treatment costs can be saved.

Wells with low bottom hole pressure or sensitivity to fluids can benefit from CO_2 treatment. Compared to a gelled water fracturing, a 70 quality foam job allows only 30% of the water to contact the formation. This decreases the chances of clay-swelling problems and inhibited production.[45]

There have been studies focused on CO_2 injection in tight oil reservoirs [46, 47], but existence of fractures in the formation is detrimental to CO_2 flooding, [46] which results in poor sweep efficiency and early breakthrough. However, song et al. studied the performance of four flooding schemes, i.e., waterflooding, near-miscible CO_2 flooding, miscible CO_2 flooding, and water alternating CO_2 flooding, which are evaluated by the coreflooding experiments. The continuous CO_2 flooding processes under either miscible or near-miscible condition lead to a superior oil recovery performance in comparison with the waterflooding process, and the miscible water alterneating CO_2 flooding process is found to be the most favorable flooding scheme for tight formations in terms of both recovery efficiency and fluid injectivity, the optimum producing pressure in the continuous CO_2 flooding process can be set as the minimum miscibility pressure (MMP) of the tight oil sample, while the optimum WAG ratio falls in the range of 4:1 to 8:1.[48]

Regards of recovery improvement of CO_2 flooding in tight oil reservoir, Ghaderi et al suggested that profitability of CO_2 EOR processes could rely heavily on market conditions. They proposed a new approach, which takes into account both uncertainties in reservoir and cost structure, also includes compositional simulation, combined with design of experiment, method of response surface, Monte Carlo simulation to sensitize the probability of each parameter and quantify their financial impacts on CO_2 EOR projects. This methodology is extremely valuable in the assessment of risks when uncertainties are high or the problem is rather complex, such as CO_2 EOR/sequestration in tight oil reservoirs.[49]

Song et al studied the performance of CO_2 huff and puff process in tight oil formations, indicating the underlying mechanisms governing CO_2 huff and puff processes in tight oil formations, including swelling effect, viscosity reduction, interfacial tension reduction, solution gas drive, and light components extraction. The near miscible and miscible CO_2 huff and puff processes result in higher recovery efficiency compared to that of waterflooding, which confirmed by both numerical simulation and experimental measurements. The results shows that the optimum injection pressure of the CO_2 huff and puff process can be set around the minimum miscibility pressure (MMP) between crude oil and CO_2, while the soaking time can be optimized for maximizing oil recovery. [50]

Produced water reinjection

In general, more than 300,000 lbm of proppant and 2,000 bbl of water needed for one fracture stage to use, and each well may have several fracturing stages.[41] Reuse of produced water for hydraulic fracturing most likely the environmental friendly option, which will reduce the need of sourcing new water and the need for down hole water disposal. The produced water reinjection forecast needs a lot of data but only few available during the design phase, the specification of water quality is linked to injection pressure. Jalel et al proposed the principle of uncertainty evaluation could give the injection pressure needed in the pilot under fracturing regime.[51]

Case Study of re-inject produced water into tight oil reservoir conducted by Chen et al, produced water treatment for water re-injection into tight reservoir is economically viable.[52]

Table 6.1 Tight reservoir re-injection criteria [52]

item	Specification
total suspended solids	< 1.0 mg/L
oil in water concentration	< 5.0 mg/L
particle size	< 0.8 μm

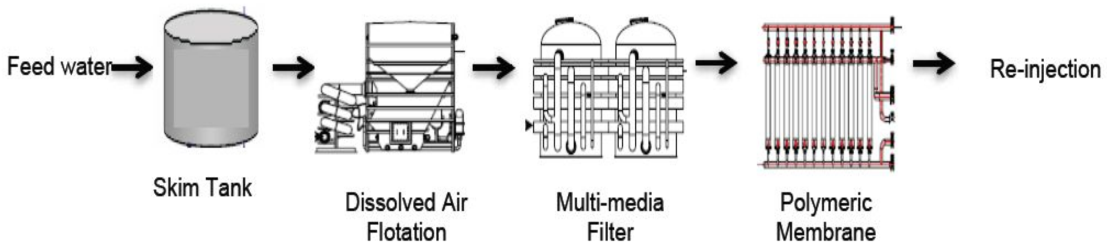


Fig 6.10 Standard tight oil reservoir reinjection water process [52]

Effective pumps

Jet pumps are simple passive device which use a high pressure fluid as the motive flow to boost the pressure of produced gas and liquid phases, which can be used to lower the wellhead pressure in order to meet downstream production pressure requirements, also increase production. Its application includes boosts production and pressure, prevent flaring low pressure gas, eliminate the need for intermediate compressor, de-bottlenecking compressor, prevent high pressure wells backing out low pressure wells, and revival of liquid loaded well.[53]

7. Nanotechnology--Great potential in tight oil E&P

Breakthrough in nanotechnology, which is more efficient and environmental friendly, sounds a bright perspective beyond the current alternatives for energy supply. The unique combinations of mechanical, chemical, thermal, electronic, optical, and magnetic properties made contribution to different aspects in oil and gas industry.

Nanoscale is usually defined to be from 100nm down to approximately 1 nm. The nanoparticles in the fluid have a very high surface to volume ratio, which provides a tremendous driving force for diffusion, especially at elevated temperatures,[8] it can easily move into even tight formations without external force. When they come into contact with oil-rock interface which is a discontinuous phase, film then exerts a pressure on the discontinuous phase, called a disjoining pressure, which effectively works to separate oil from rock surface and carry it out of the rock pore, combined pressure exerted by millions or billions of nanoparticles is really high.[9]

7.1 Spreading of nanofluids on solids

The spreading of nanofluids varies with the spreading of liquids without nanoparticles. Nikolov studied the complex solid-nanofluid-oil interactions using the combined differential and common light interferometric method, the self-structuring of nanoparticles confine in a thin film.[54] The excess pressure within the wedge-film region separate the two surface confining the nanofluid.(Fig 7.1), and the disjoining pressure has an oscillatory exponential decay with thicker film,(Fig 7.2) also with both the period of oscillation and the decay factor equal to the effective diameter of the nanoparticles. The structural disjoining pressure dominates at scales longer than the effective diameter of a nanoparticle, below which other disjoining pressure components (such as van der Waals, electrostatic, and solvation forces) are prevalent.[55]

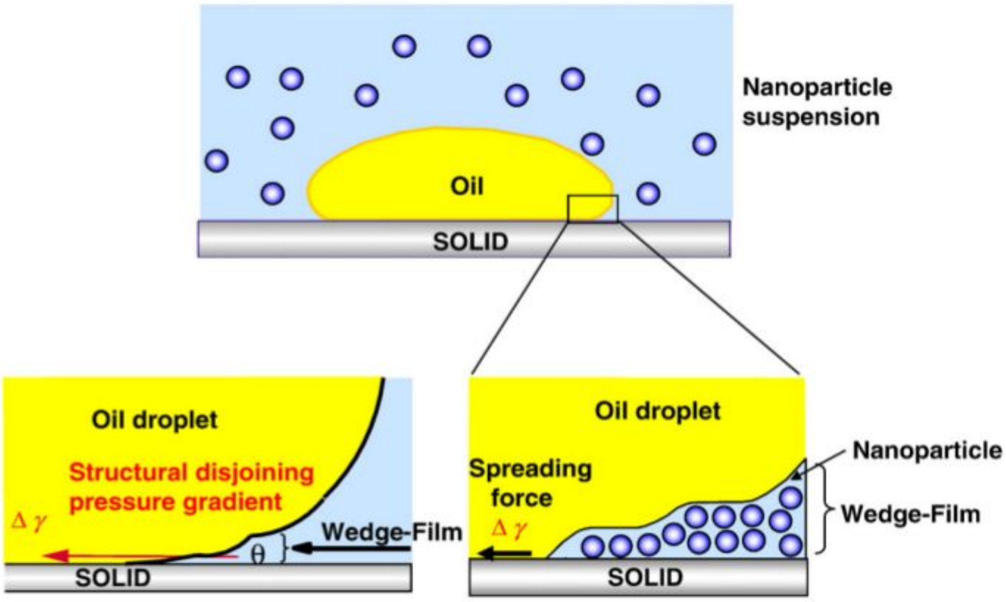


Fig 7.1 Nanoparticle structuring in the wedge film resulting in a structural disjoining pressure gradient at the wedge.[56]

As the film thickness decreases toward the wedge vertex, the structural disjoining pressure increases. The driving force for the spreading of nanofluid is structural disjoining pressure gradient or film tension gradient directed toward the wedge from the bulk solution; as the film tension increases toward the vertex of the wedge, it drives the nanofluid to spread at the wedge tip (the three-phase contact line moves), thereby enhancing the dynamic spreading behavior of the nanofluid (Fig 7.1).

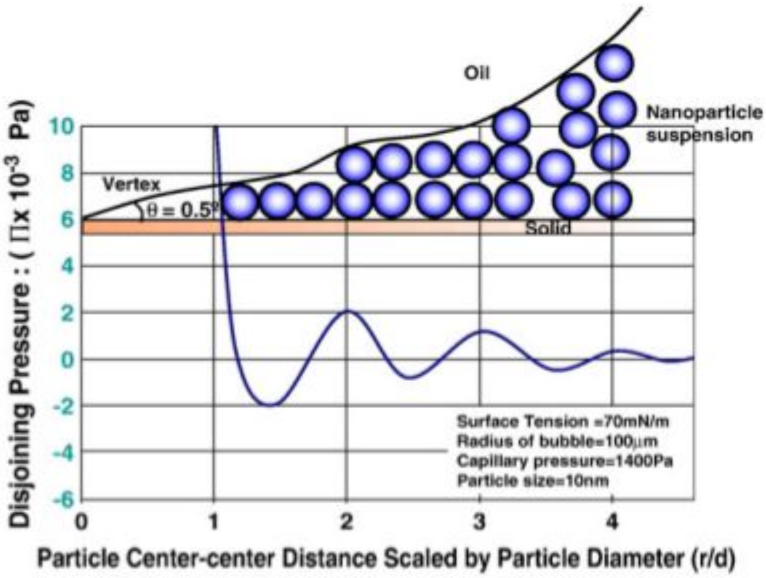


Fig 7.2 Pressure on the walls of wedge for 0.5°contact angle at the vertex as a function of radial distance[56]

The spreading of nanofluid due to structural disjoining pressure increased with an increase in the concentration of the nanofluid when the drop volume was constant. For a given constant effective volume of the nanofluid, the nanofluid's rate of spreading decreased with a decrease in the drop volume.[56] As the drop volume decreases, the capillary and hydrostatic pressures resist the spreading of nanofluid. Thus, the driving force for spreading of nanofluid would be the difference between the film tension gradient and the opposing forces operating in the meniscus.

Spreading is generally described in terms of the spreading coefficient S, given by

$$S = \sigma_{sg} - \sigma_{sl} - \sigma_{\lg} \tag{7.1}$$

Where σ is the respective interfacial tension existing between the solid–gas σ_{sg}, solid–liquid σ_{sl} and liquid–gas $\sigma_{\lg}$ phases.[57] When the spreading coefficient S < 0, partial spreading occurs and the equilibrium three phase contact angle is not zero.

An analytical expression for the structural disjoining pressure based on a solution of the Ornstein–Zernike equation was given by Trokhymchuk et al.[58] For hard sphere particles in vacuum confined between two rigid hard walls which form symmetric films.

$$\prod_{st}(h) = \prod_1 \cos(\omega h + \varphi_2) e^{-\kappa h} + \prod_2 e^{-\delta(h-d)} \qquad For\ h \geq d \tag{7.2}$$

$$\prod_{st}(h) = -P \qquad For\ 0 \leq h \leq d \tag{7.3}$$

Where d is the diameter of the nanoparticle and all other parameters ($\prod_1, \varphi_2, \omega, \kappa$) are fitted as cubic polynomials in terms of the nanoparticle's volume fractions (ϕ), and $\phi = 6n_p / \pi d^3$, n_p is the number of particles per unit volume of the system. P refers to the bulk osmotic pressure of the nanofluid.

The film-meniscus microscopic contact angle, θ_e, is related to the disjoining pressure, given by the Frumkin–Derjaguin equation:

$$\prod_0(h_e)h_e + \int_{h_e}^{\infty} \prod(h)dh = \sigma_{o/\ell}(\cos\theta_e - 1) = S \tag{7.4}$$

Complete spreading occurs when this angle, θ_e is zero. In equation (4) where h is the equilibrium thickness of a thin film, Π_0 is represented by the sum of the capillary pressure P_c and the hydrostatic pressure of the droplet P_g, and Π is the disjoining pressure represented by three major terms: $\Pi = \Pi_{vw} + \Pi_d + \Pi_{st}$. Π_{vw} represents the short-range van der Waals force, Π_d accounts for forces which are electrostatic or steric in nature and Π_{st} represents the long range structural forces arising from the ordering of the nanofluid's particles in the wedge film. The second term is the integral of the disjoining pressure over the thickness of the wedge, is the film tension.[59] It should be noted that earlier Kralchevsky and Denkov [60] proposed a semi-empirical relation for the oscillatory structural disjoining pressure.

The nanofluid's rate of spreading driven by structural disjoining pressure, which varies with the concentration of nanofluid and drop volume for one concentration, the spreading of the nanofluid due to structural disjoining pressure increased with an increase in the concentration of the nanofluid when the drop volume was constant.

For a given constant effective volume of nanofluid, the nanofluid's rate of spreading decreased with a decrease in the drop volume. As the drop volume decreased, the capillary pressure increased and the structural disjoining pressure was constant (the constant effective volume). The capillary and hydrostatic pressures resist the spreading of the nanofluid. Thus, the driving force for the spreading of the nanofluid would be the difference between the film tension gradient and the opposing forces operating in the meniscus.[56]

Sefiane et al. [61] studied the forced spreading dynamics of nanofluid drops on hydrophobic surfaces. Results obtained from the advancing/receding contact line analysis show that the nanoparticles in the vicinity of the three-phase contact line enhance the dynamic wetting behavior of aluminum–ethanol nanofluids for concentrations up to approximately 1% concentration by weight. Two mechanisms were identified as a potential reason for the observed enhancement in spreading of nanofluids: the structural disjoining pressure would drive the spreading of the nanofluid as proposed by Wasan. However, at concentrations higher than 1 wt.%, they believed that the viscous forces dominate the structural disjoining pressure. The authors also indicated that nanoparticles might adsorb on the solid surface. Liquid would then slip on the particles like it does on a super hydrophobic structured surface due to the reduction in friction.

A higher concentration could cause a higher disjoining pressure, since a larger amount of nanoparticles can structure inside the wedge film and provide the excess pressure. This could probably result in mobilization of larger oil droplets. However, increasing the concentration also results in more severe permeability impairment. It is not desirable to reduce the permeability to a great extent. This makes the combination of achievable mobilization of oil as a result of spreading of hydrophilic nanoparticles, and permeability impairment an important topic.

7.2 Potential E&P application

Because of the advantages of nanoparticle, it shows great potential in E&P of tight oil reservoir.

Drilling

As harsher conditions are met, the need for effective drilling bits increase, therefore, carbon nanomaterials are extremely interesting with unique mechanical, structural, electrical and thermal properties, especially works in tight formation.[62]

Chakraborty 2012, studied the functionalization of nanodiamond, integration into the PDC matrix, property improvement on the basis of PDC matrix. Functionalized nanodiamond is stable and processable in various solvents, which shows potential for considerably performance benefits over traditional PDC systems.[63]

Nano-based mud additive is expected to improve the thermal conductivity of nanofluids, which consequently will provide more efficient cooling of drill bits, and longer operational cycles. In addition, additives in casing helps to increase compressive.[64]

Maintaining wellbore stability is the most critical aspect of petroleum drilling operations. But conventional water-based drilling mud can easily penetrate into shale formation, subsequently cause swelling and sloughing of wellbore, the nanoparticles based drilling fluid could generate an ultra-thin, tight and relatively impenetrable mud cake deposited on the borehole wall, in addition, nanoparticles could also posses the relative small porous space to block throats and interact with the clay particles, minimize fluid invasion into shale formation hence increased borehole stability.[65]

Also the addition of nanoparticles did not raise the mud weight, so they could also used as bridging agent without increasing the solid content of fluid, which could helps a lot in drilling in high angle wells, horizontal and directional wells.[65]

The drilled formation solids (cuttings) are regarded as controlled or hazardous waste, they can be disposed of in the following ways: decontamination treatment followed by discharge into the sea, injection of the cuttings into the well, or transfer to a controlled hazardous-waste landfill. The lowest environmental effect for solids treatment, especially for offshore operation, is decontamination treatment followed by discharge. However, oil content in the treated cuttings of >1% still exists in the dried solids by conventional decontamination technology, which does not meet strict environmental regulations in some ecologically sensitive countries (e.g., the UK and North Sea countries). Nanoemulsion technology can provide ultralow oil/water interfacial tension (IFT) then improve oil-removal efficiency. The cuttings-treatment process researched by Saphanuchart et al can achieve oil content of <1%.[66]

Exploration

The natural old methods utilize the gravitational, magnetic, electrical, and electromagnetic to explore petroleum fields.[67] As mentioned, many of these techniques lack the required resolution and the capacity to deeply penetrate reservoir lithologies, especially in tight formations.

Nanoparticles are suitable for the development of sensors and formation of imaging in oil exploration since it could be altered in optical, magnetic, and electrical properties compared to their bulk counterparts.[68] Nanomaterials combined with smart fluids can be used as extremely sensitive sensors for pressure, temperature, and stress downhole under harsh conditions.[64] Nano-computerized tomography(CT) can image tight gas sands, tight shales, and tight carbonates in which the pore structure is below what micro-CT can detect.[62]

Completion

Viscoelastic surfactant fluids have been used as completion fluids in the oil industry as gravel-packing, fracture-packing, and fracturing fluids because of its rheological properties, however, excessive fluid leak off and poor thermal stability has significantly limited their usage. Since the loss of fracturing fluid has negative impact on the productivity of hydraulically fractured wells, the liquid is trapped at the fracture face because of capillary effects. This reduces the relative permeability of the hydrocarbon phase during flow back, which will lead to a reduction in the effective producing fracture area, even if the drawdown is greater than the capillary pressure.[69]

Huang 2007, studied the nanometer-scale particles, through chemisorption and surface charge attraction, associated with viscoelastic surfactant fluids to: (1) stabilize fluid viscosity at high temperature; (2) produce a pesudo filter cake of viscous viscoelastic surfactant fluids that significantly reduces the rate of fluid loss and improves fluid efficiency.[70]

The nano-sized particles such as nanosilica or nano-Fe_2O_3, as additive to improve the properties of the resulting cement.[71] Due to the very high surface area of nanomaterials, it could enter the interstitial areas and other areas of high porosity in the cement, therefore, less permeable structure could be formed, and also the strength of the cement could be improved.

Nanomaterials could be applied in the oil well cementing industry studied by Santra: (1) nanosilica and nanoalumina as potential accelerators; (2) nanomaterials including carbon nanotubes (CNTs) with high aspect ratio to enhance mechanical properties; (3) nanomaterials to reduce permeability/porosity; and (4) nanomaterials to increase thermal and/or electrical conductivity.[72]

Production

Formation damage of oil reservoirs as a result of fines migration is a major reason for productivity decline. Nanofluids that contain nanoparticles exhibit specific properties, including a high tendency for adsorption and being good candidates for injection into the near wellbore region, because of the small nanoparticle sizes. a packed column is used to study the use of different types of nanoparticles to reduce fines migration in synthetic porous materials by Habibi, the results showed that addition of 0.1 wt% of MgO and SiO_2 nanoparticles reduced fines migration by 15% compared with the reference state.[73]

Combining with the development of top-down and bottom-up synthetic methods, a new generation of nano-membranes has been developed for the separation of metal impurities in heavy oil, and separating gas streams and enabling GTL production in tight gas reservoir.[74,75] By exploiting methods common in the microelectronics industry, the cost of manufacturing highly uniform and reproducible membranes is quite competitive.[75]

Pollution by chemicals is a persistent problem during production, filter and membranes designed with nanoscale precision provide full control over what flows through, which could make the industry considerably greener.[76]

EOR

As oil production decline in 33 of the 48 largest oil producing countries,[77] and the frequency of new explorations are significantly lower, many fields are abandoned with a residual oil saturation over 30 %,[78] increasing the recovery factor is of great importance.

Primary recovery remains as low as 5.0-10.0% of original oil in place in tight oil reservoir, even the advanced technology such as long horizontal wells have been drilled and massively fractured applied [1].

The efficiency of waterflooding is governed by spontaneous imbibition of water into oil-containing matrix blocks in fractured reservoirs. The rate of oil recovery increases with increasing wettability alteration, increasing fracture density, and decreasing oil viscosity.[2]

Wettability depends on the brine, oil and mineral compositions as well as temperature.[79, 80, 81] Wang and Gupta [82] studied the influence of temperature and pressure on wettability of reservoir rocks. Contact angle did not vary much by different pressure; in contrast, temperature showed a significant effect on the wettability of crude-oil/brine/quartz systems. Using atomic force microscopy, Kumar et al. [83] have shown that wettability of a rock is controlled by adsorption of asphaltenic components on the mineral surface.

Wettability of a rock can be altered thermally [84] and chemically, low salinity brine [85] as well as through selective ions [86, 87, 88]. The thermal process needs a very high temperature (~200 °C); even the low salinity brine process needs a high temperature.[89]

Mike O. Onyekonwu studied the ability of three different polysilicon nanoparticles (PSNP) such as lipophobic and hydrophilic PSNP (LHPN), hydrophobic and lipophilic PSNP (HLPN) and neutrally wet PSNP (NWPN) to enhance oil recovery. The experiments conducted centered on laboratory coreflooding using two kinds of oil, brine and polysilicon nanofluids on water wet rocks obtained from the Niger Delta. The results obtained indicate that NWPN and HLPN are good enhanced oil recovery (EOR) agents in water wet formations.[90]

Nano-emulsions with the droplets size between 20 and 500 nm, could be obtained by a low energy cost method, Maserati 2010, who proposed that solvent in water nano-emulsions used as cement spacer formulation could optimize the cleaning of casing during the cement job.[91] Compared with the traditional spacers, the nano-spacer has better performance in mud removal, reverse wettability, and casing-bore adhesion of the concrete.[65]

Because of the small drop size, they are not subject to gravity-driven separation owing to the density differences of the two phases.[92] Emulsions stabilized with nanoparticles can withstand the high-temperature reservoir conditions without much retention for extended periods[93]. This can substantially expand the range of reservoirs to which EOR can be applied. Finally, nanoparticles can carry additional functionalities such as super-paramagnetism and reaction catalysis. The former could enable transport to be controlled by application of magnetic field. The latter could enable in situ reduction of oil viscosity.[94] Nano-emulsions containing oilfield chemicals may find applications to well treatments (scale inhibition, acidizing, etc.), flow assurance (eg., multiple additive packages), and deposit removal/clean-up. Their long-term stability and ease of preparation from a concentrated precursor are compatible with oilfield logistics requirements.[92]

Shidong, Luky, Ole et al. investigated the potential of hydrophilic silica nanoparticles suspension as enhanced oil recovery agent and find out the main mechanisms of nanofluids for EOR. Hydrophilic nanoparticles with average particle size of 7 nm were used in both visualization glass micromodel flooding experiments and core flooding experiments in their studies. Nanoparticals characterization showed consistent nano size from SEM and good fluid stability after a day.

The experimental results indicated silica hydrophilic nanoparticals suspension can reduce the interfacial tension between oil phase and water phase, and interfacial tension decreases when nanofluid concentration increase, nanofluids can increase recovery about 4-5% compared to brine flooding.

To change the wettability of a rock surface, they need to adhere and spread over the surface. For optimal distribution, factors such as concentration and particle size are important.

Nanofluids with various concentration ranges were synthesized with synthetic saline water for optimization study, the wettability alteration due to nanofluids was observed, and adsorption of nanoparticals on water wet solid surface can block some pore channels, but this is not selective plugging so the permeability of porous media might be impaired during injection of nanofluids, therefore, oil recovery is not proportional to nanofluids concentration.

In addition, there is no PH alteration during flooding process in glass micromodel. Compare to brine flooding into water-wet Bereat sandstone, the performance of nanofluids flooding as secondary mode is much better than as tertiary mode.[95,96,97,98]

7.3 Effect on permeability and porosity due to adsorption of nanoparticles

Nanofluids seems an excellent alternative in the tight oil E&P, however, microscopic adsorption tests imply that nanoparticles can be adsorbed on pore surfaces of sandstones and in turn reduce the pore radius.[99] In view of the presence of pore diameters from 100 to 1000000nm in reservoir rock, the permeability and wettablity of pore surface could be modified by adsorption of nanometer scale powder with different wettablities. Both the deposition on the pore surfaces and blocking at pore throats of particles may lead to formation damage expressed as the reduction in porosity and permeability. Instantaneous porosity is expressed by

$$\phi = \phi_0 - \sum \Delta\phi \tag{7.5}$$

Where $\sum \Delta\phi$ is the variation in porosity, caused by retention of nanoparticles.

In addition, a modification of Xianghui and Faruk Civan's model for permeability is presented as an expression for instantaneous permeability.

$$K = K_0 \left[(1-f)k_f + \frac{f\phi}{\phi_0} \right]^n \tag{7.6}$$

K_0 and ϕ_0 are initial permeability and porosity, while K and ϕ are existing local permeability and porosity. k_f is given as a constant for fluid seepage allowed by the plugged cores, the range of index n is from 2.5 to 3.5, and f is a flow efficiency factor of cross-section area open to flow, as a linear function of the volume of particles of hydrophobic and lipophilic polysilicon(HLP) entrapped at pore throats, is given by

$$f = 1 - \alpha_{fe,o} v^*_{o,o} \tag{7.7}$$

The change of wettability may induced by the retention of HLP in porous media. The relative permeability changes as the retention occur, according to the size of particles of HLP, HLP is classified into n compositions. For the volume, V_i, of composition i entrapped in pores, the total volume of retention of HLP satisfies the following formula:

$$V = \sum_{i=1}^{n} V_i \tag{7.8}$$

The specific area of composition i can be defined based on the assumption of spherical particles in the form of point contact.

$$s_{bi} = \frac{A}{V} = \frac{n_i^3 \pi d_i^2}{\frac{1}{6}\pi n_i^3 d_i^3} = \frac{6}{d_i} \tag{7.9}$$

Assuming v_i is the volume of particles i of HLP absorbed on the pore surfaces and v_i^* is the volume of particles i entrapped at pore throats per unit bulk volume of the porous media, and adsorption developed as a single layer at the beginning, the surface area for composition i is given by

$$s_i = \left(v_i + v_i^*\right)s_{bi} \tag{7.10}$$

The total surface area in contact of fluids for all the composition of HLP per unit bulk volume of porous space is given by:

$$s = \beta\sum_{i=1}^{n} s_i = \beta\sum_{i=1}^{n}\left(v_i + v_i^*\right)\frac{6}{d_i} \tag{7.11}$$

In which β is the surface area coefficient, the specific area of sand face can be calculated by empirical formula:

$$s_v = 7000\phi\sqrt{\frac{\phi}{K}} \tag{7.12}$$

When $s > s_v$, the total surface per unit bulk volume of the porous media is completely occupied by HLP that is absorbed on pore surface or entrapped at pore throats, wettability is dominated by HLP, however, $s < s_v$ shows that only parts of surfaces per unit bulk volume of the porous media is occupied by HLP, the relative permeability of oil and water are to be considered as a linear function of the surfaces covered by nanoparticles[100]

$$K'_{rwjp} = K_{rwj} + \frac{K'_{rwj} - K_{rjw}}{s_v}s \tag{7.13}$$

$$K'_{rojp} = K_{roj} + \frac{K'_{roj} - K_{row}}{s_v}s \tag{7.14}$$

8. Reservoir simulation within tight oil

The data of reservoirs and wells in Canada could obtain through Software Accumap. As shown in Fig 8.1, yellow dots mean cities, black dots shows petroleum reserve, circumstance represent the border of province. The amplifying picture of the field selected shows in the top right corner

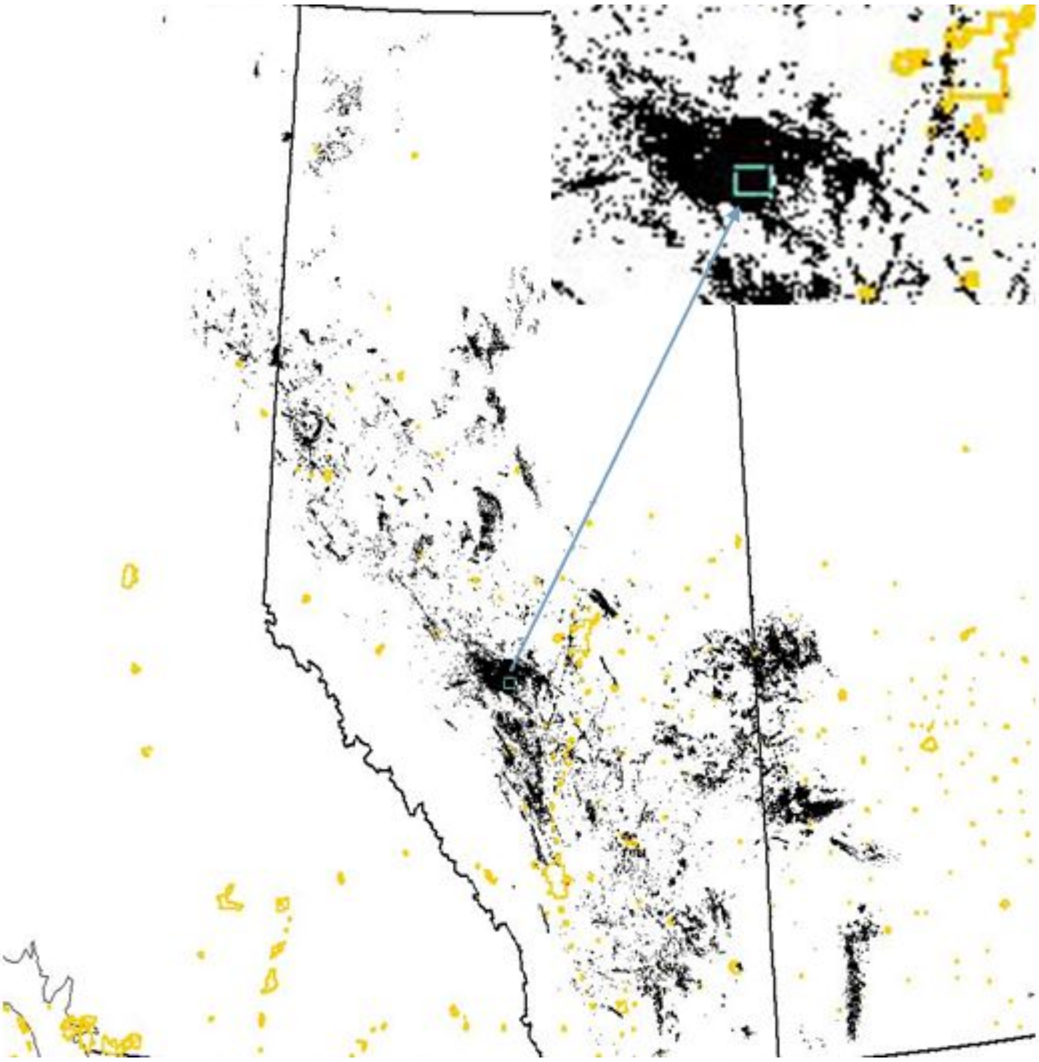


Fig 8.1 The Pembina Field (Source: Accumap)

Limited by the time of stay at University of Calgary, Canada, synthetic reservoir models were created, of which data refer to paper SPE 152084, help to guarantee the models created are consistent with tight oil reservoir.

8.1 Homogeneous model:

The reservoir oil is undersaturated light oil with stock tank gravity of 38 °API and initial solution gas-oil ratio (GOR) of 730 scf/stb.[33]

Table 8.1 Reservoir fluid properties [33]

Reservoir fluid properties	
Parameters	Value
Pb, psia	2450
Rs at Pb, scf/stb	730
Oil viscosity at Pb, cp	0.63
Bo at Pb, res.bbl/stb	1.37
Oil density at STP, lbm/ft^3	52.1
Average gas viscosity, cp	0.01
Average gas density at STP, lbm/ft^3	0.065
Water vicosity, cp	0.57

Table 8.2 Reservoir input for base case[33]

Parameters	Value
Length, ft	5250
Width, ft	1350
Thickness, ft	15
Depth at top of formation, ft	5297
Initial reservoir pressure, psi	2520
Reservoir temperature, ℉	127
Average horizontal permeability, mD	0.61
Horizontal to vertical permeability ratio	0.1
Reservoir pore volume, bbl	2.2×10^6
Reference pressure, psi	1000
Rock compressibility at P_{ref}, psi^{-1}	5.0×10^{-6}
Number of grids($N_x\times N_y\times N_z$)	105×27×5
Grid size($D_x\times D_y\times D_z$), ft	50×50×3

Start data: 1991-01-01

Table 8.3 Saturation profile and porosity distribution

Layer	Porosity	Swi	Soi
1	0.087	0.25	0.75
2	0.097	0.25	0.75
3	0.111	0.25	0.75
4	0.16	0.3	0.7
5	0.13	0.35	0.65

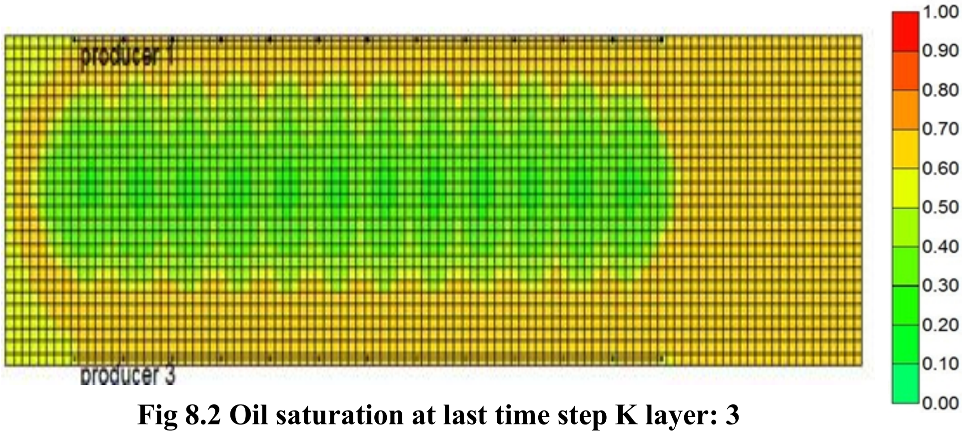


Fig 8.2 Oil saturation at last time step K layer: 3

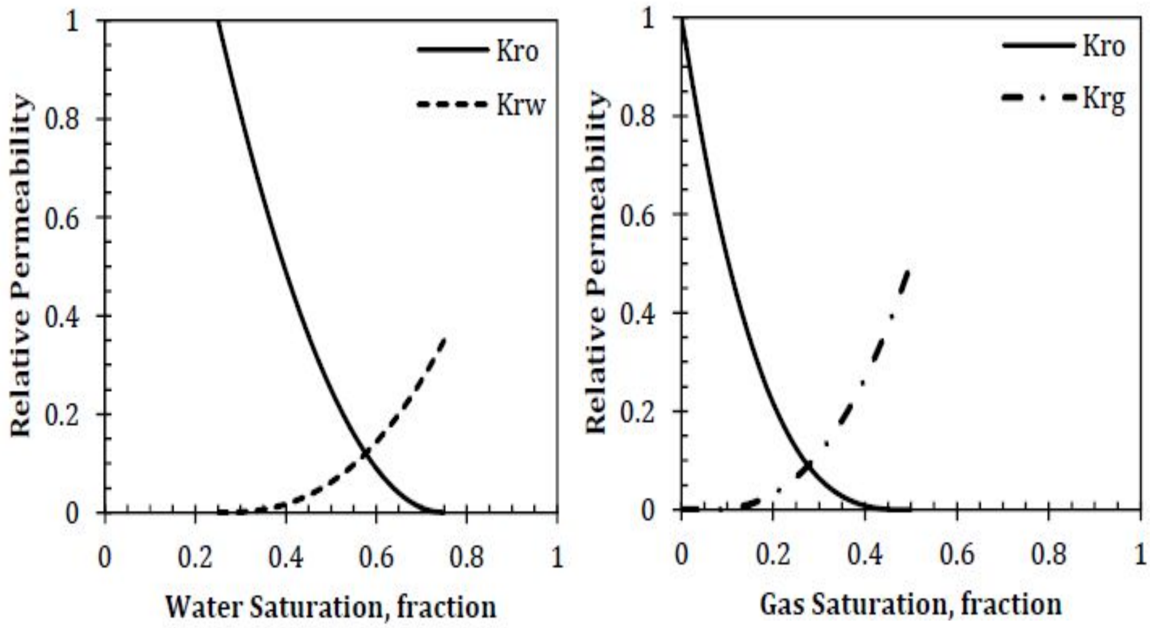


Fig 8.3 Relative permeability[33]

Exploitation of the reservoir model start from 1991-01-01, two horizontal production wells were put in layer 3 at the margin area of the model with surface liquid rate 320 bbl/day and bottom hole pressure 300 psi. Initially there is no gas cap, the rock type is water wet.

8.2 Heterogeneous system

The data file created by Eclipse initially, then ECL 100 Import Assistant used to create IMEX file. The average permeability keeps 0.61 mD, which is the same as homogeneous model, other parameters keep the same as in homogeneous system.

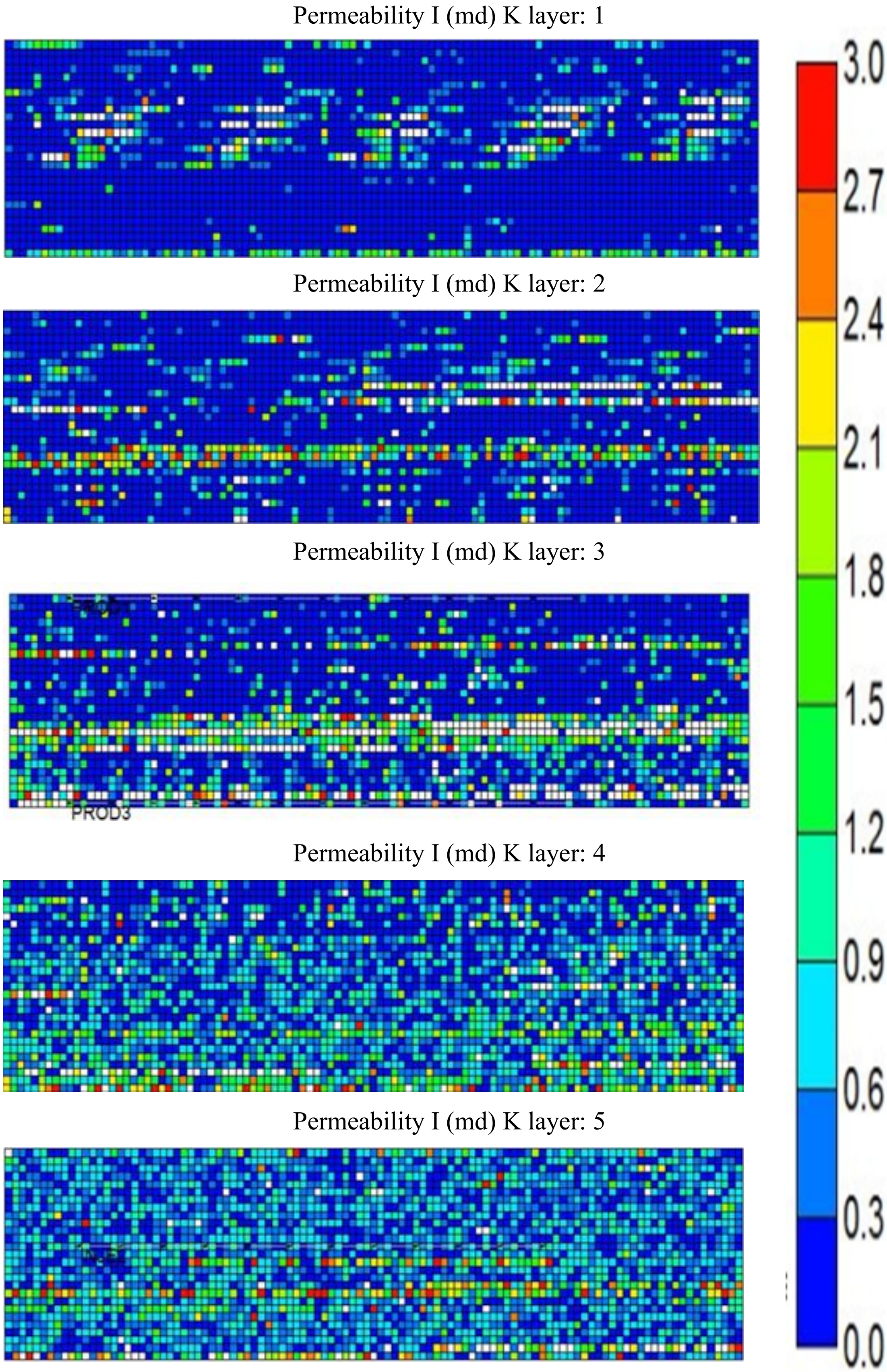


Fig 8.4 Heterogeneous system

8.3 Dual porosity

Dual porosity model used in the simulation to represent naturally fractured system. The presence of fractures could be evidenced by mud losses, high productivity not relatable to matrix permeability, pressure build-up characteristics, flow meter surveys, and core analysis.[101] Dual porosity model was created by converting the single porosity model, then fracture properties were added, fractures spacing were 500 ft horizontally and 15ft vertically, it has a permeability 10 md in all direction. Relative permeability to oil and water in the fracture covers the full spectrum of saturations from 0 to 1. The matrix capillary pressure is generally much greater than the fracture capillary pressure. The pressure differential from matrix to fracture causing oil flow to the fracture and water flow to the matrix. This is the imbibition effect, but other forces such as gravity and viscous forces are also simultaneously effective.[102] The rock compaction for fractures keeps the same as in Table 8.2.

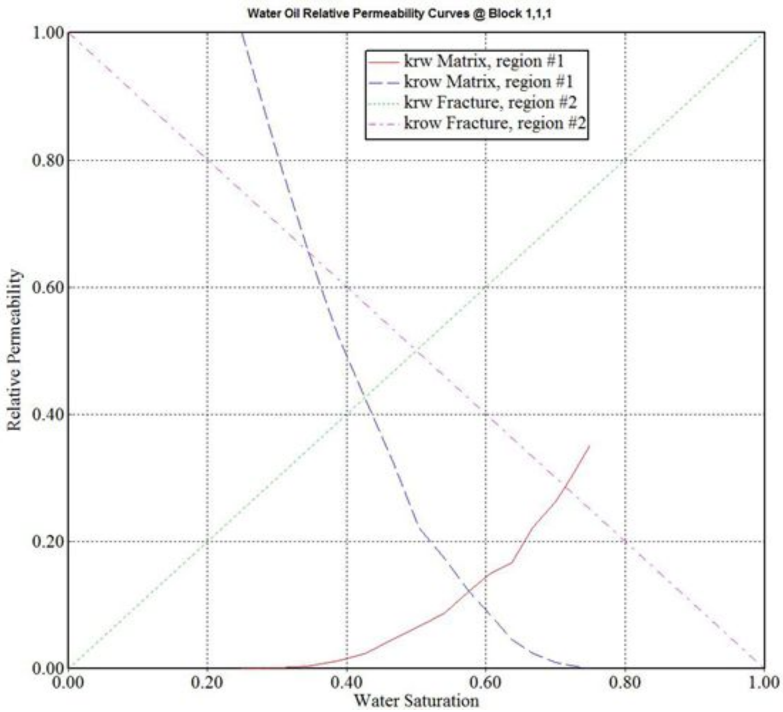


Fig 8.5 water oil relative permeability curve

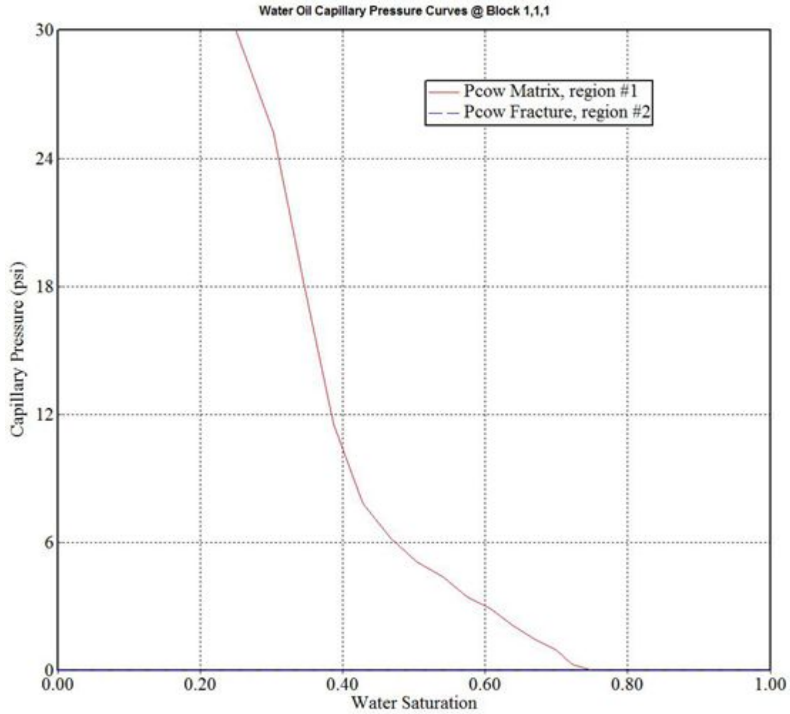


Fig 8.6 Water oil capillary pressure

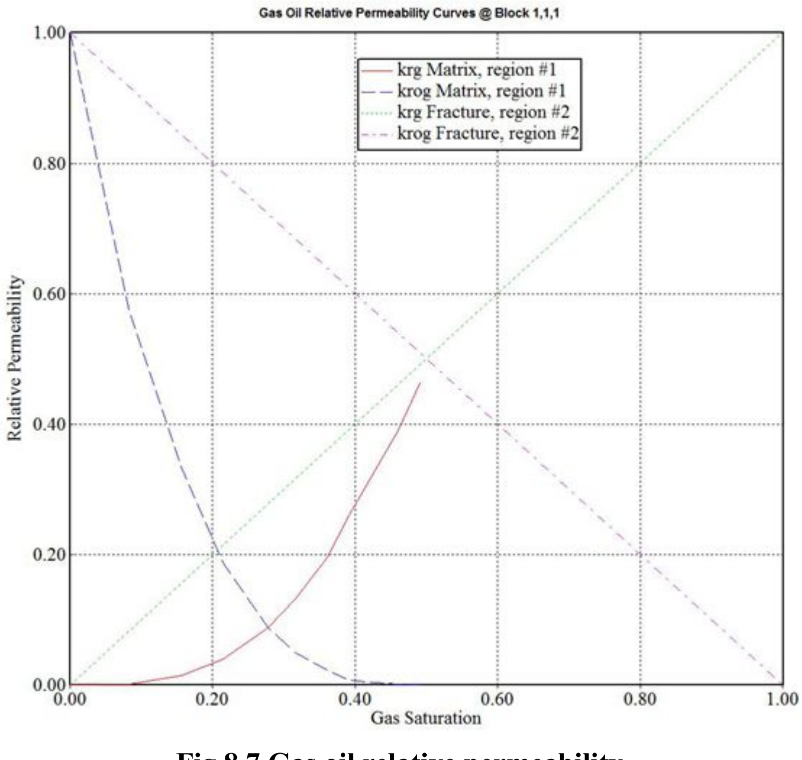


Fig 8.7 Gas oil relative permeability

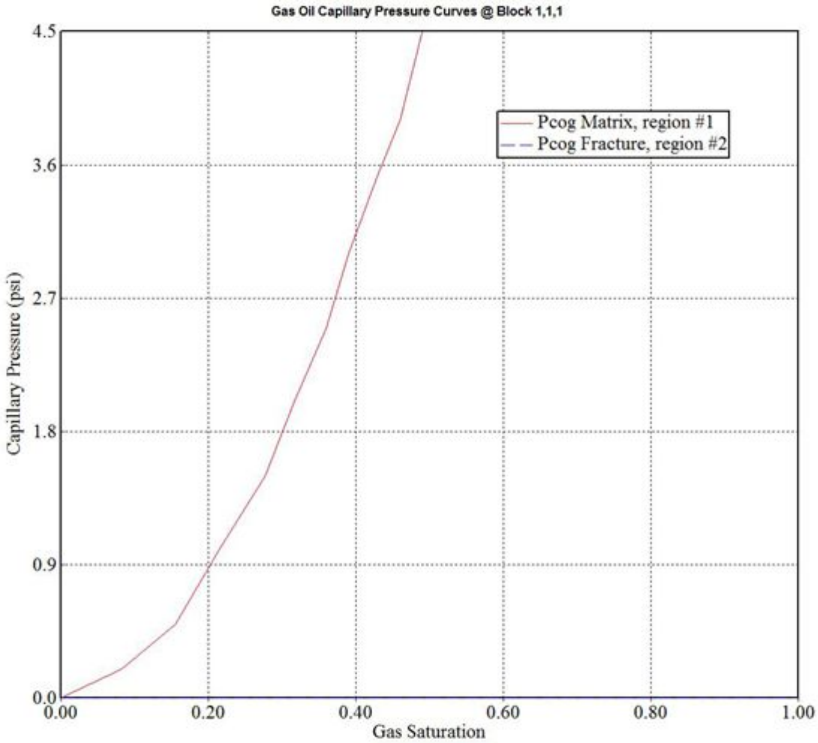


Fig 8.8 Gas oil capillary pressure

8.4 Hydraulic fracturing

For tight formation, hydraulic fracture is a necessity in the production phase. Horizontal wells in the models were fractured in the transverse direction, the planes of hydraulic fractures are perpendicular to the well trajectory.

There are several ways to simulate hydraulic fractures: single porosity approach, which treats target formation and hydraulic fractures in a single grid system, with fractures being represented as high permeability grid cells; dual porosity approach, which separates target formation and fractures into two different grid systems: a matrix system and fracture system. The matrix system accounts for the storage of hydrocarbon and the fracture system provides a pathway for hydrocarbon to flow in the system.

Numerically, dynamic performances from single porosity can approximate with those from dual porosity system and vice versa. A realistic estimation of stimulated volume and its distribution is essential in production prognosis, the microseismic based fracture network modeling approach can be used to get realistic characterization of hydraulic fractured system, which contributes to future field development such as in-fill drilling and re-fracturing of underperforming wells.[103]

Shale has both Darcy flow and diffusion in matrix, however, in hydraulic fractures, fluid flow at high velocities deviates from what would be expected with Darcy's Law, which is Non-Darcy flow. To correctly capture the transient effects around the hydraulic fractures, fine gridding of the matrix is required. Local refinement is used around fractures to have more accuracy where it is needed compare to skin factor modification. Logarithmic Refinement, more refinement close to the fracture where it is needed and less refinement far away from the fracture, helps to captures transient flow with least amount of grid blocks compare to even gridding. The hydraulic fractures have a constant width of 2 ft and the conductivity is around 150 md-ft.

Table 8.4 Well and fracture properties[33]

Well & fractures properties	
Bottom hole pressure of producers, psia	300
Injection rate, rb/day	320
Surface Liquid rate, bbl/day	320
Numbers of fractures along producers	13
Numbers of fractures along injector	12
Spacing between consecutive fracture, ft	300
Half length of fracture, ft	225
Height of fracture, ft	15
Conductivity of hydraulic fracture, md-ft	150
Fracture orientation	J-axis

Table 8.4 shows the parameters of wells and fractures. Injection rate was altered into 640 rb/day in the WAG study.

The following picture shows the fractures added into the model, all the perforations of well were fractured, the fractures have a permeability of 75 md with 2ft width. The amplified figure shows the local gird refinement for fractures.

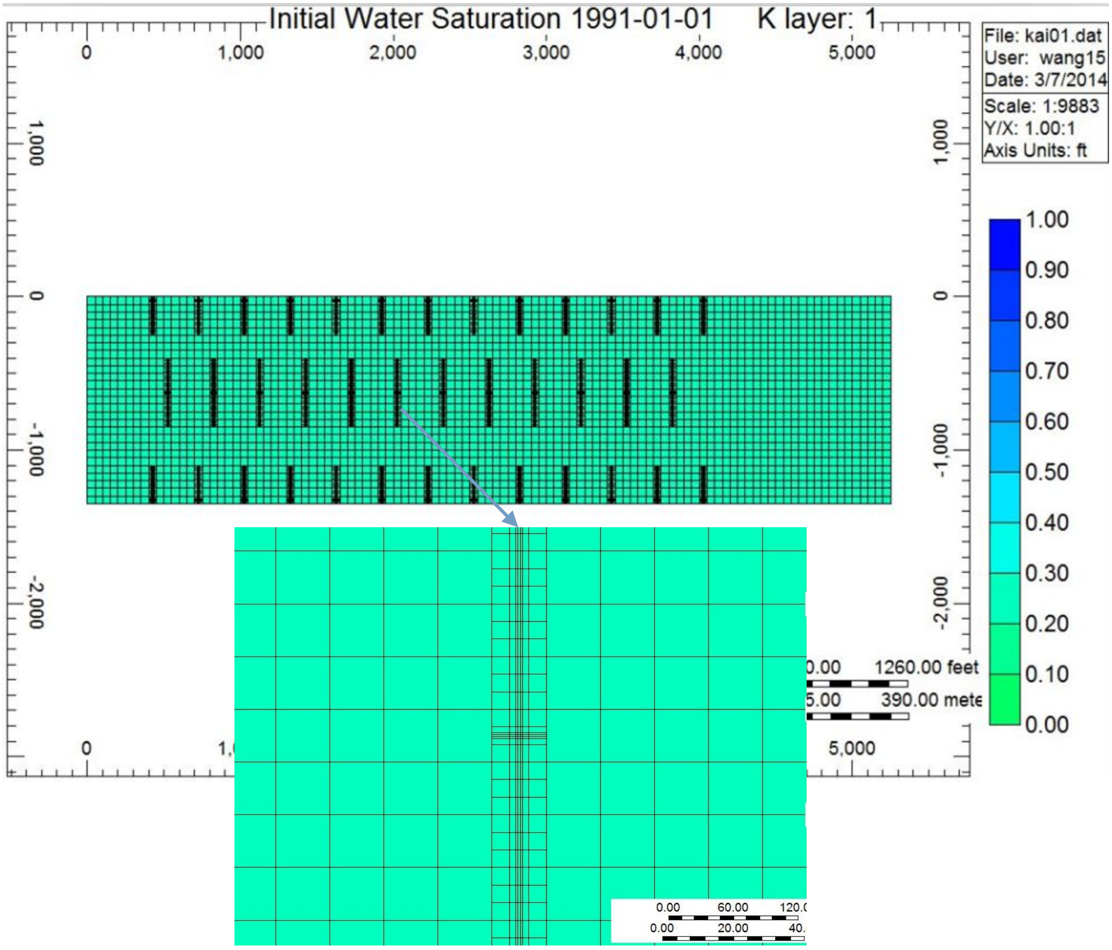


Fig 8.9 Hydraulic fracture by Local Grid Refine

In hydraulic fracture well, the permeability varies with the distance away from the wellbore. Therefore, the fractures was modified, the following picture shows the permeability gradient 0.33md/ft in hydraulic fractures.

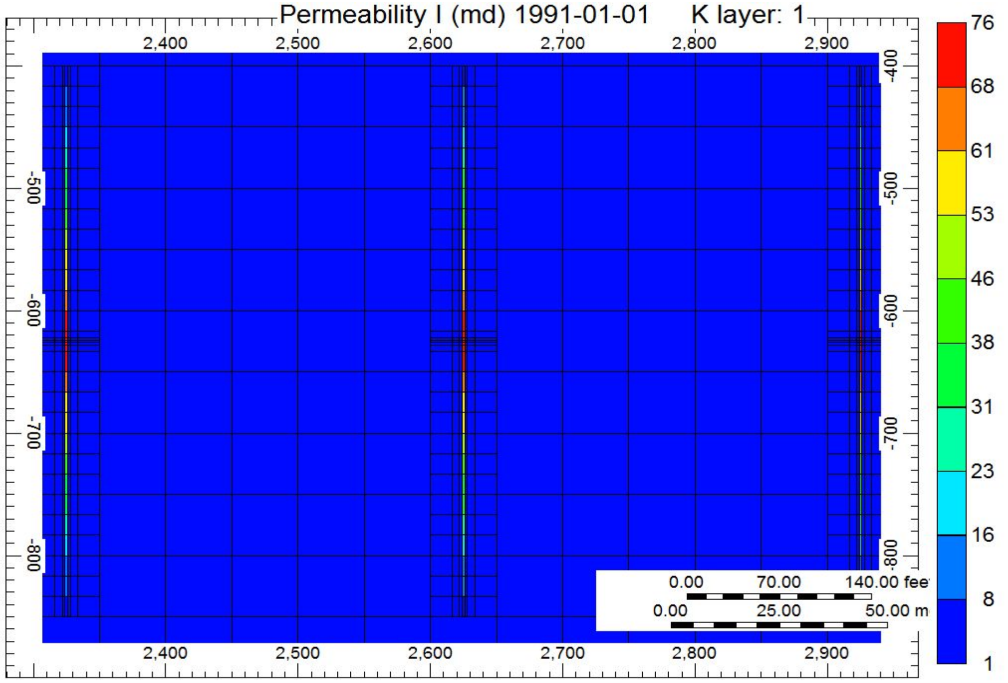


Fig 8.10 permeability in fractures varies with the distance to wellbore

As pressure drops in fractures, the fracture conductivity will drop, therefore, pressure dependent compaction assigned to the hydraulic fractures.

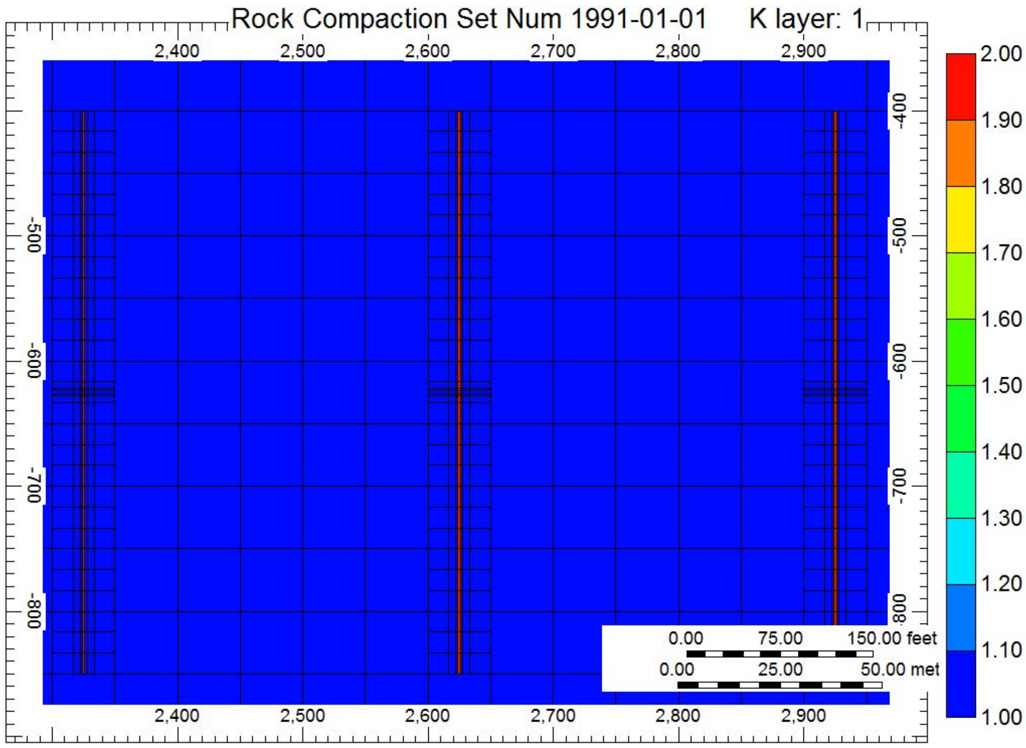


Fig 8.11 Various Rock compaction in matrix and hydraulic fracture

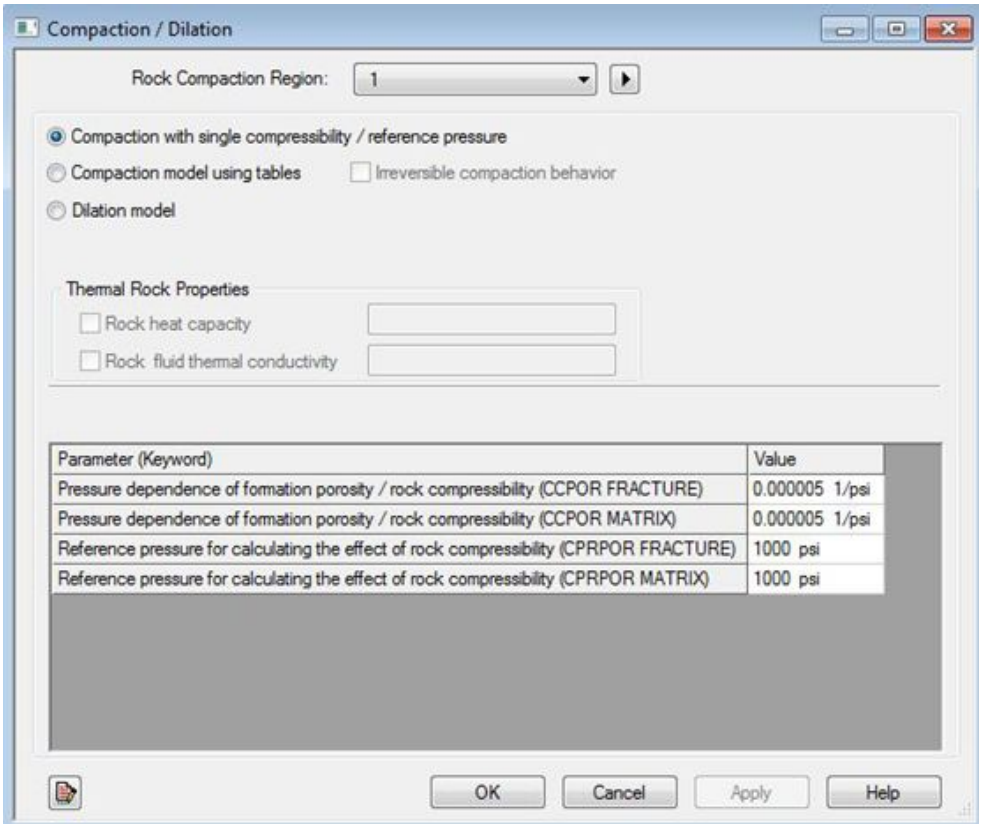


Fig 8.12 Constance rock compaction for matrix and naturally fractures

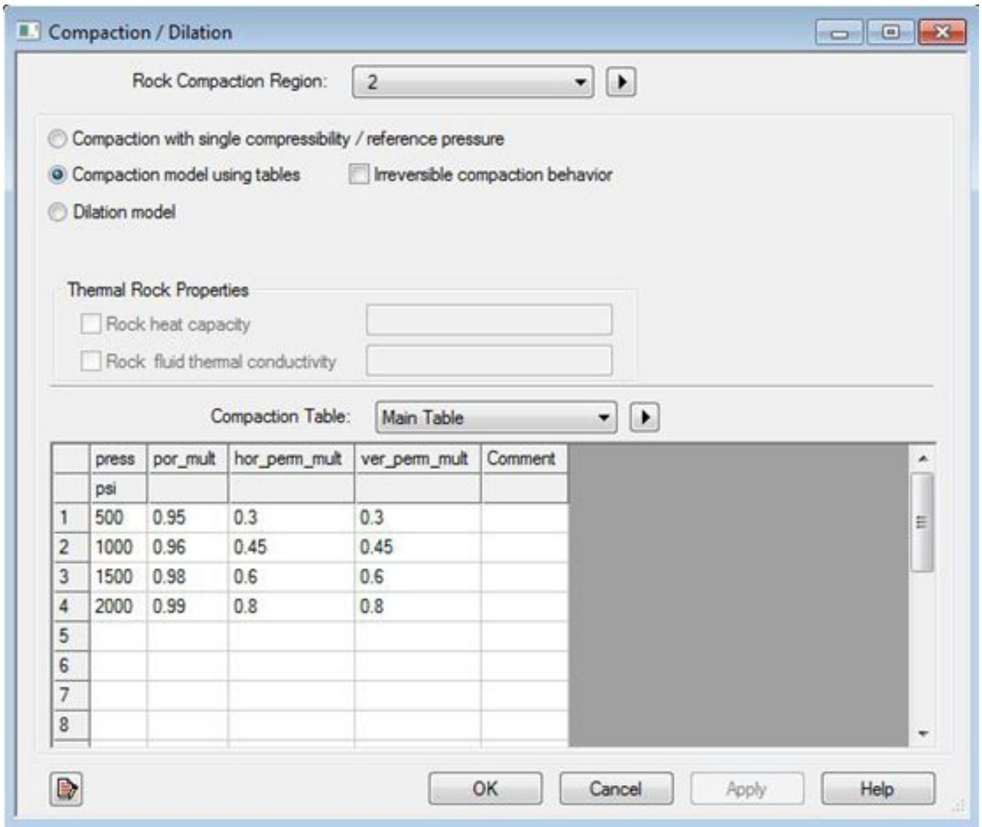


Fig 8.13 pressure dependent rock compaction for hydraulic fractures

In order to account for the drilling fluids invasion during the stimulation, the water saturation should be adjusted in the hydraulic fractures. In this case, the initial saturation in hydraulic fractures was set to be 0.45; however, in matrix, the initial water saturation is 0.25.

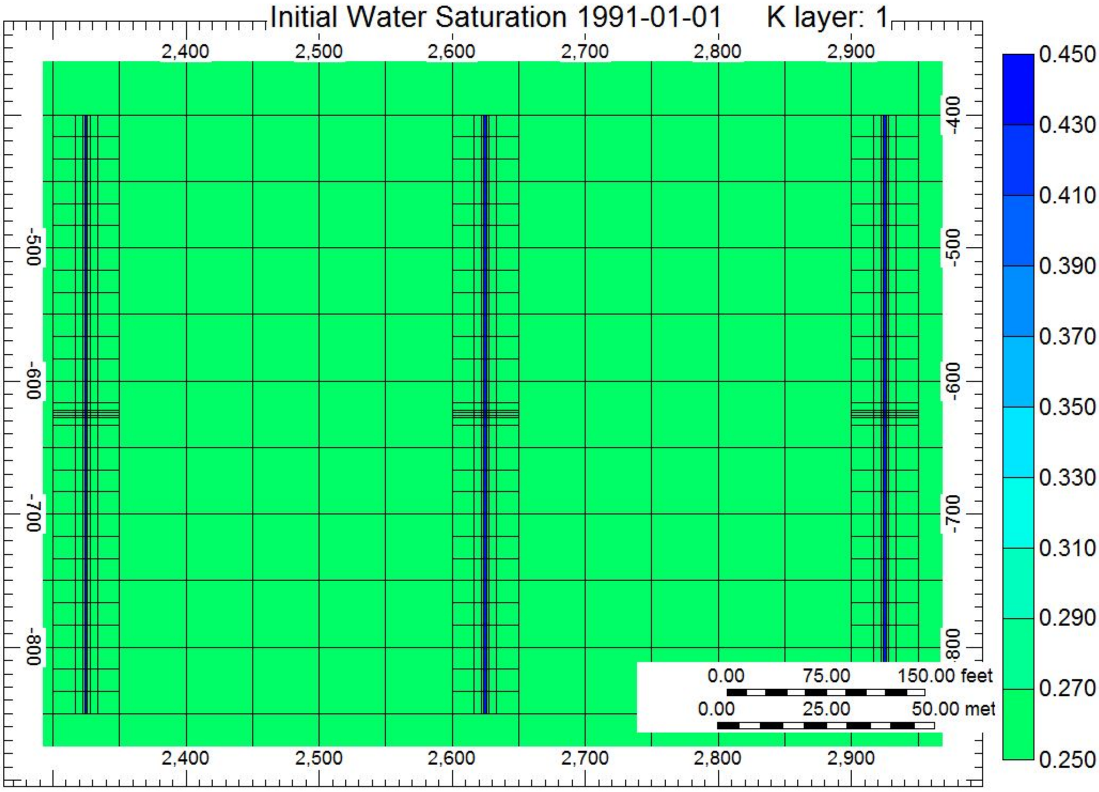


Fig 8.14 mimic the stimulation water saturation profile

9. Result and Discussion

9.1 The role of capillary pressure

The difference in pressure across the interface between two immiscible fluids defined as capillary pressure.

$$p_c = p_{non-wetting\ phase} - p_{wetting\ phase} \qquad (9.1)$$

The quantities p_c , $p_{non-wetting\ phase}$ and $p_{wetting\ phase}$ are quantities that are obtained by averaging these quantities within the pore space of porous media either statistically or using the volume averaging method.

In oil-water systems, water is typically the wetting phase, while for gas-oil systems, oil is typically the wetting phase.[104]

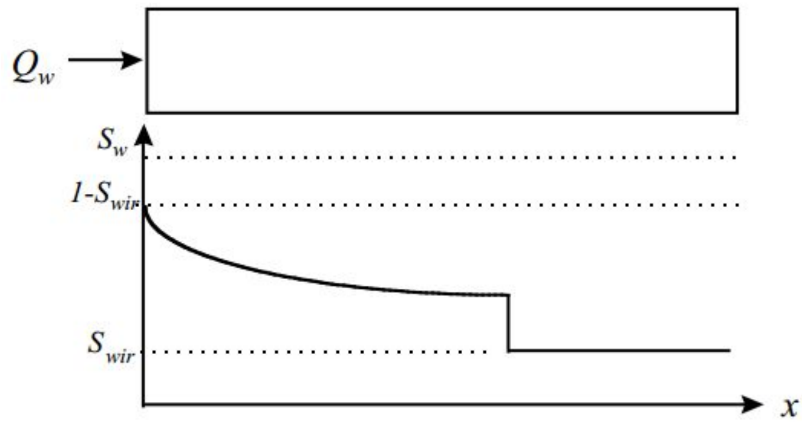


Fig 9.1 For negligible capillary pressure, the water will move through the porous medium as a discontinuous front [105]

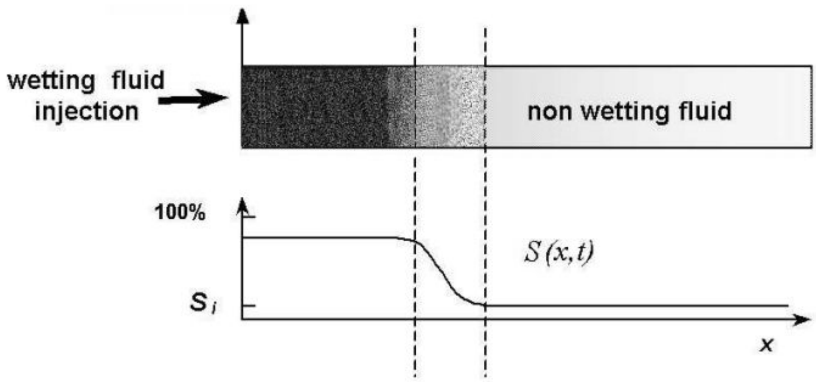


Fig 9.2 Capillary dispersion behind the front, S(x, t) does not reach 100% as some non-wetting phase remains trapped[106]

The advance of the wetting fluid accelerated or slowed down by capillary forces, associated with pore size and structure. The water front moves forward with continuous saturation profile.

Homogenous model

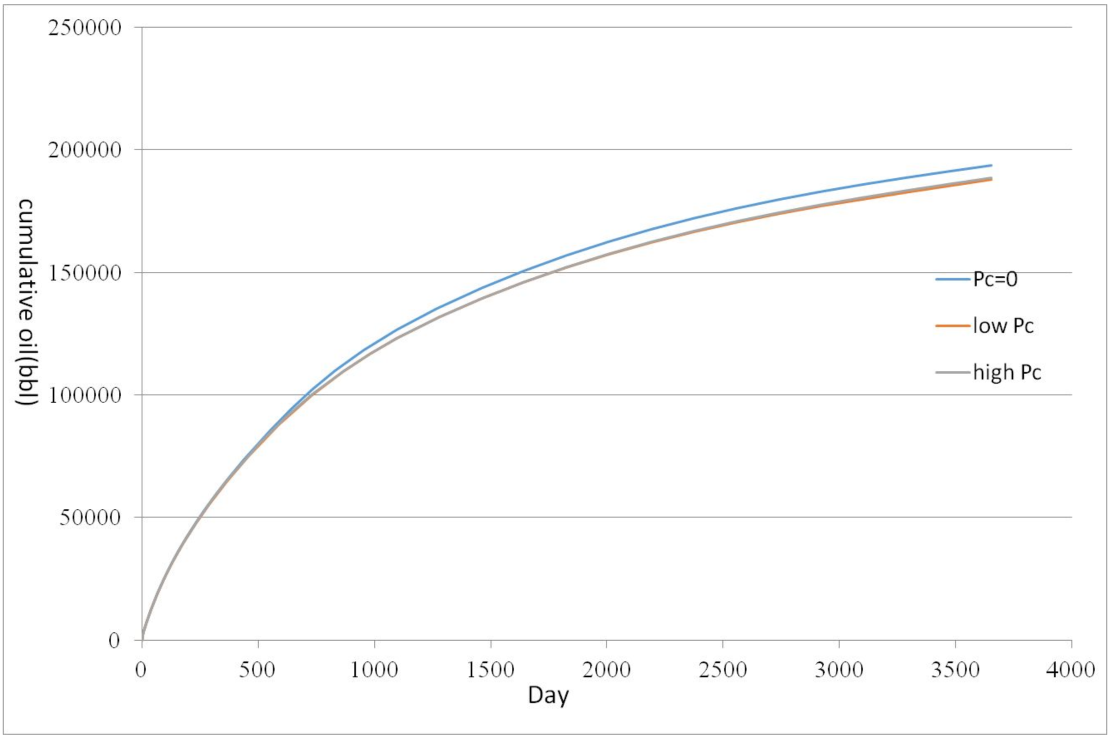


Fig 9.3 Oil production with various capillary pressure

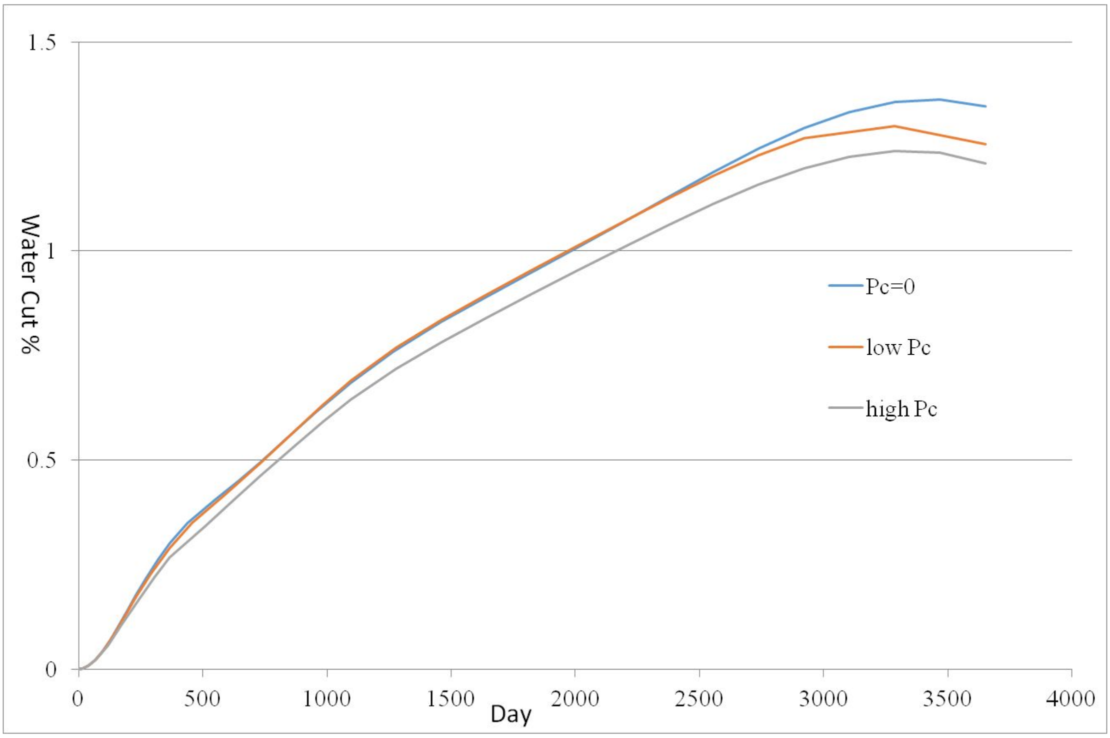


Fig 9.4 Water cut with various capillary pressure

The result is consistent with simulation done by Ahmad et al.[107] Oil rate is higher initially if neglect the capillary effects[108], also the water cut increase as the oil/water capillary pressure decrease.

Initially the capillary pressure has no effects on the oil production since viscous forces govern oil recovery in tight oil formation, also as Ahmad et al. concluded that measures should be taken to overcome viscous force in order to get more oil produced.[107]

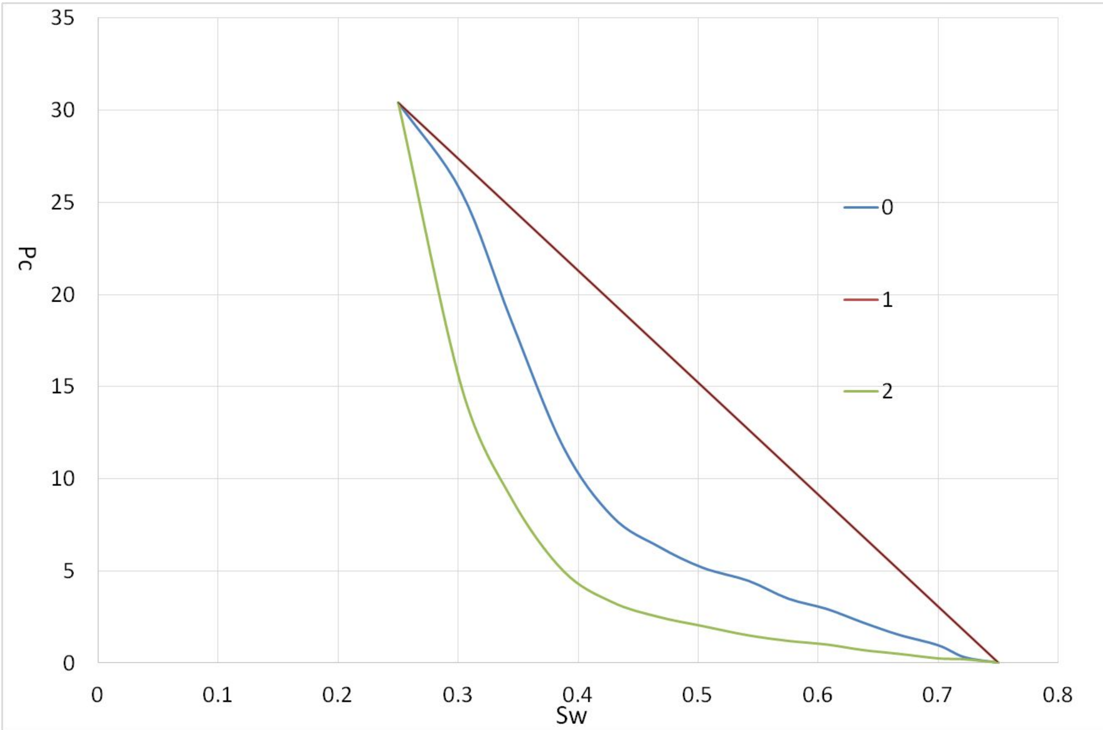


Fig 9.5 Different scenarios of capillary curvature

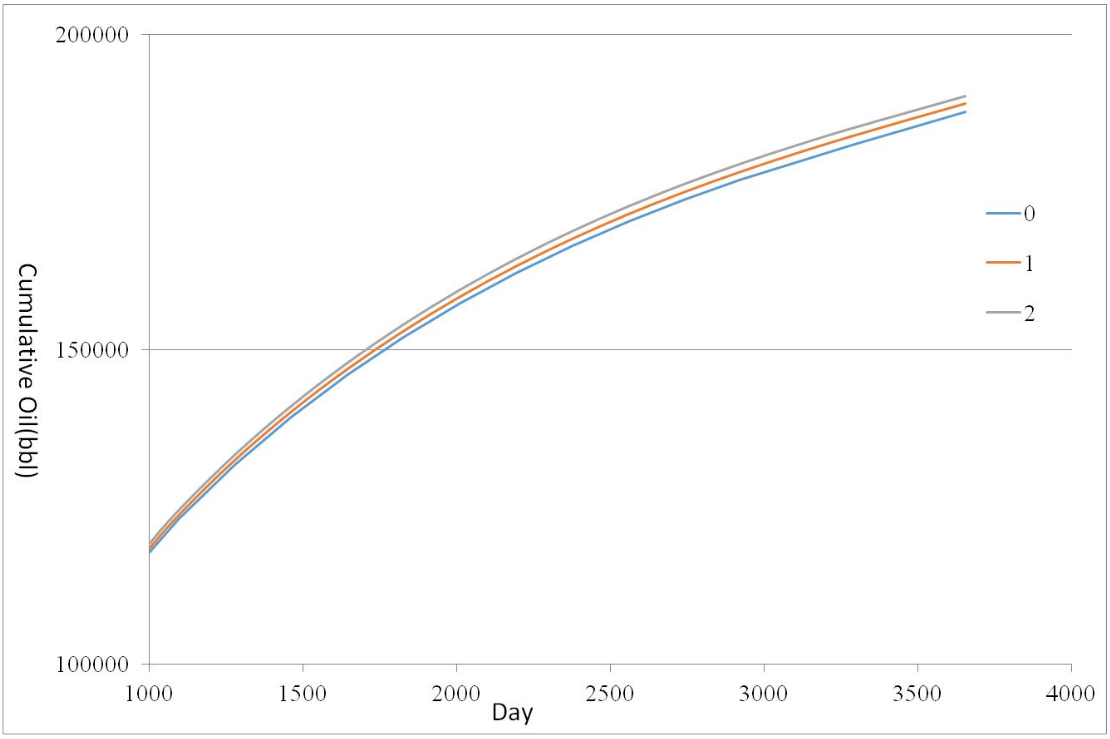


Fig 9.6 Oil production with various curvature

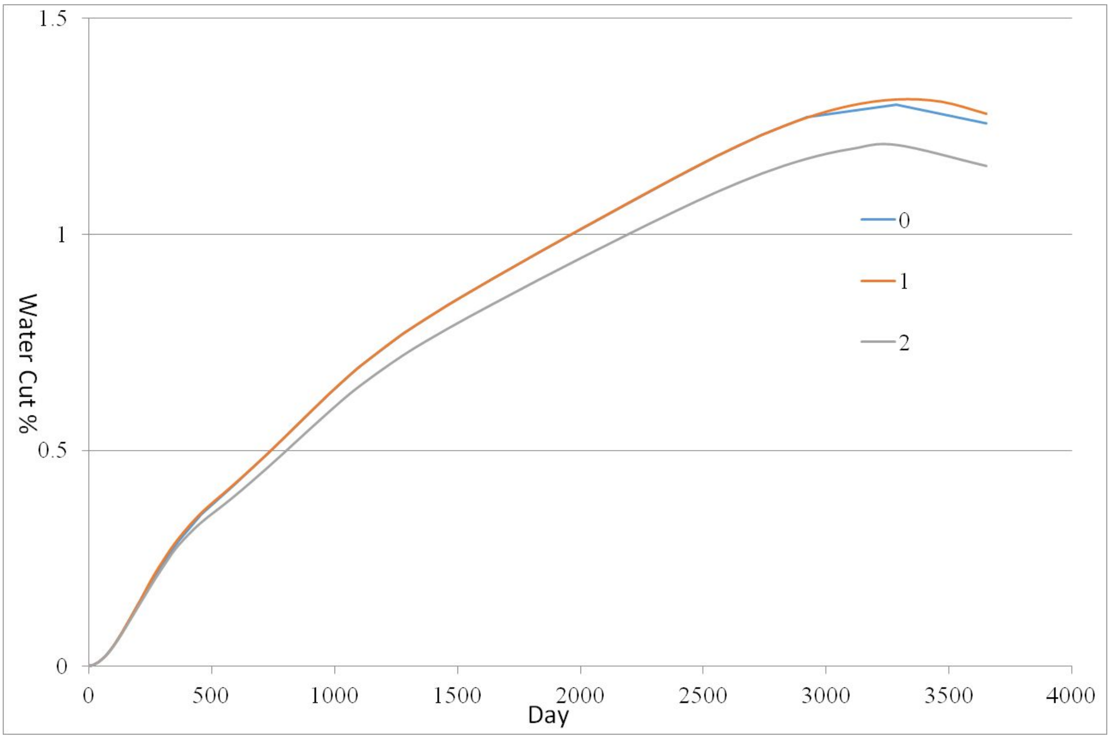


Fig 9.7 Water cut for various curvature

The curvature of capillary pressure has a weak effect on oil production, as the curvature of capillary pressure increase, water cut decrease. The main role of capillary pressure is in the initial distribution of fluids in reservoir. It can also affect fluid flow. The curvature in Pc can be related to the pore size distribution in numerical reservoir simulation.[108]

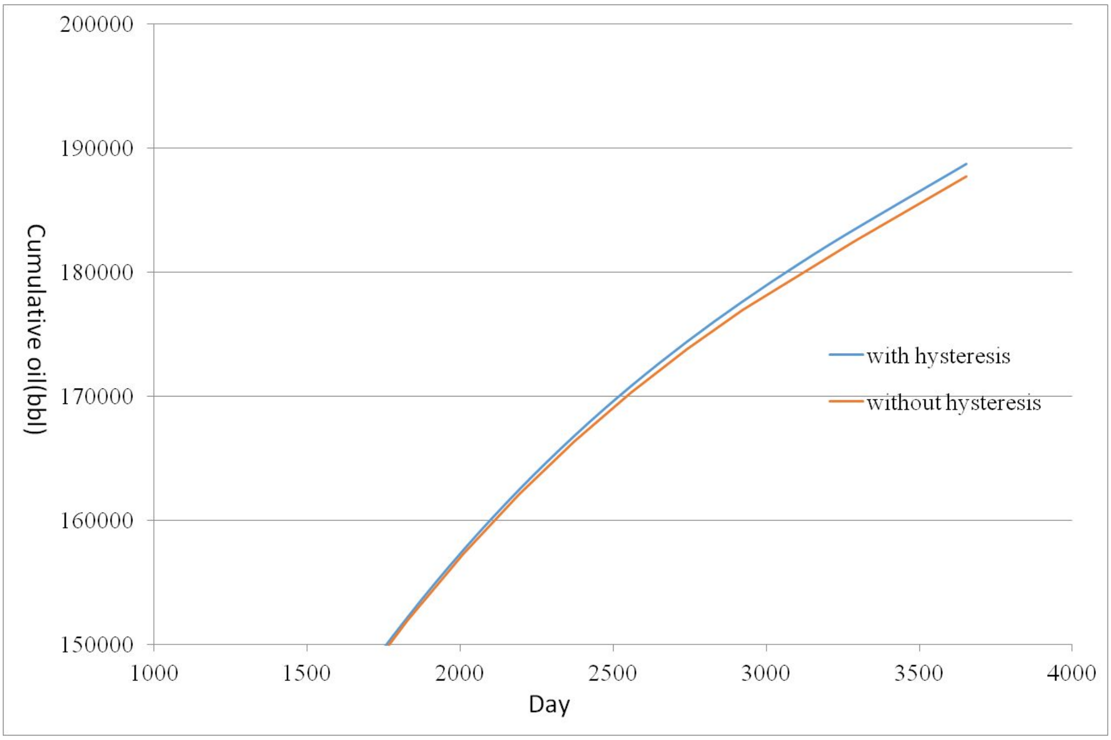


Fig 9.8 Oil production with the effect of hysteresis

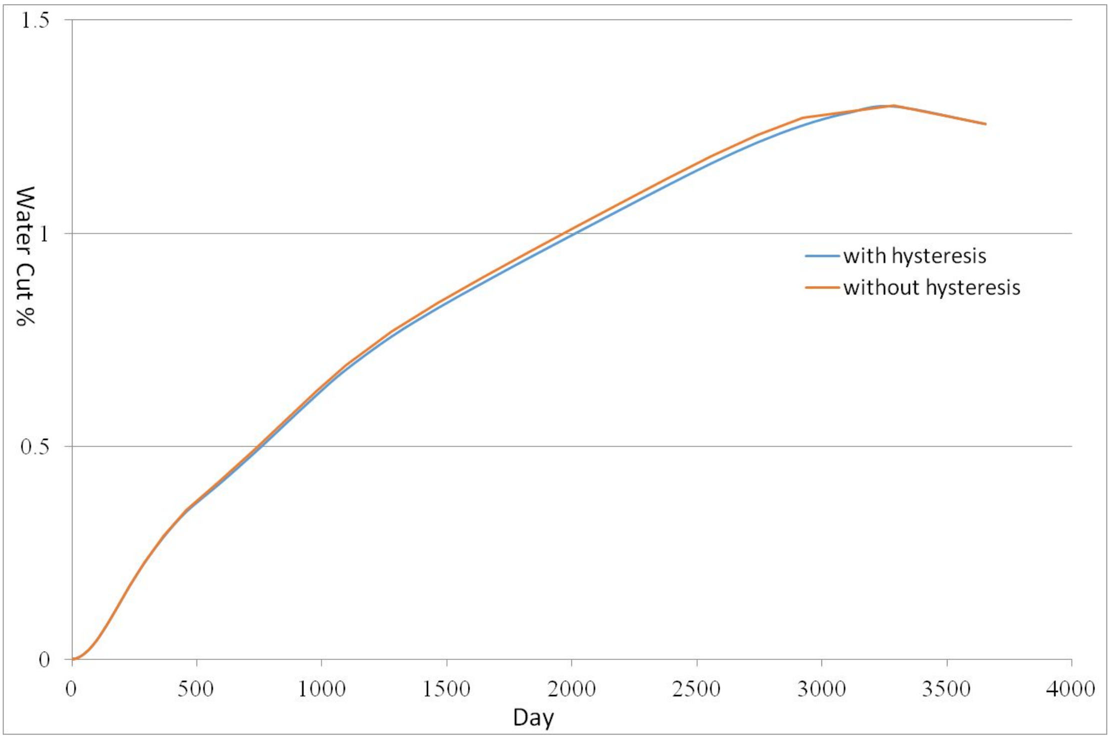


Fig 9.9 Water cut with the effect of hysteresis

Fig 9.9 shows computation in two cases with hysteresis consideration and without it. Water cut increase and oil recovery decrease in case without hysteresis.

This results can't be considered as general conclusions in tight oil reservoir since our given reservoir model was homogeneous with a water-wet rock, also the results is not completely consistent with the work done by salarieh[108], because the reservoir models vary in some degree, also in real case, the reservoir is quite complex with high or low heterogeneity and various rock wetting condition in different part of reservoir, however, the ideas of capillary study could be used as instruction in the history matching, also Gregory et al concluded that capillary pressure is significant in tight reservoirs. Stimulation fluid invasion into smaller pore diameters and invasion of proppant free stimulation fluid into both induced fractures and dilated natural fractures will have an effect. The way to manage the capillary forces will exert an effects on the production decline rates and long-term health of wells in tight reservoirs.[7]

Heterogeneous system

The following figures present the results for capillary effects with increasing heterogeneity. We can see capillary pressure plays more on oil recovery as reservoir heterogeneity increase

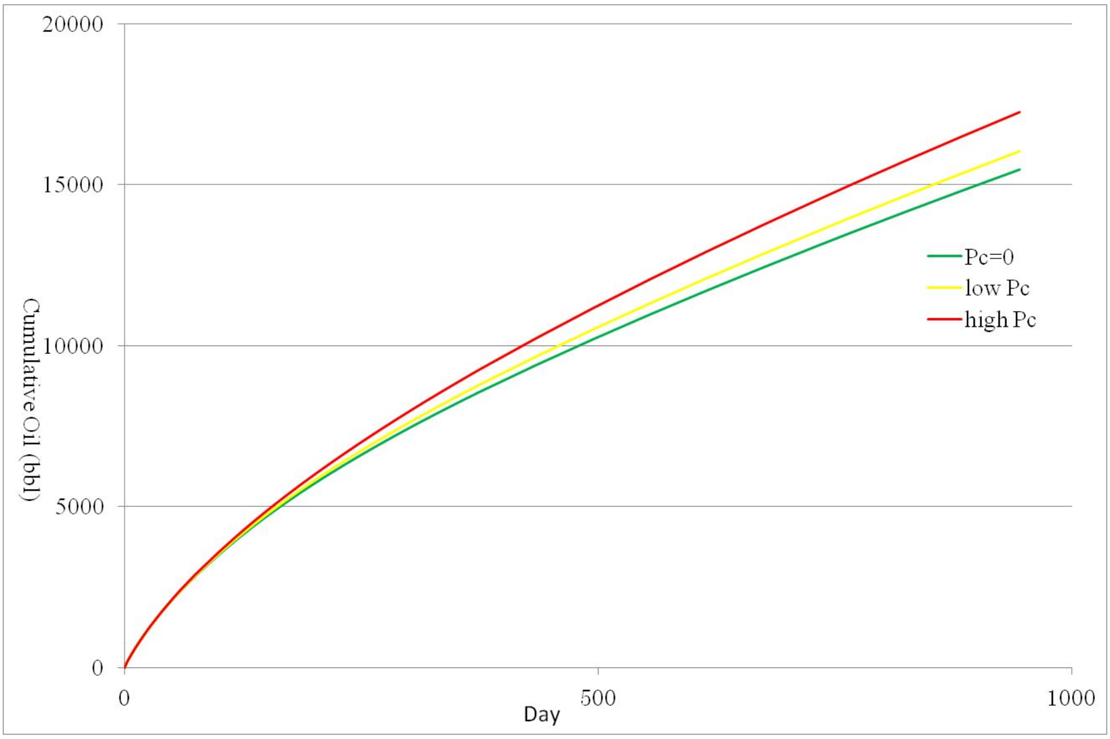


Fig 9.10 Oil production with various capillary pressure

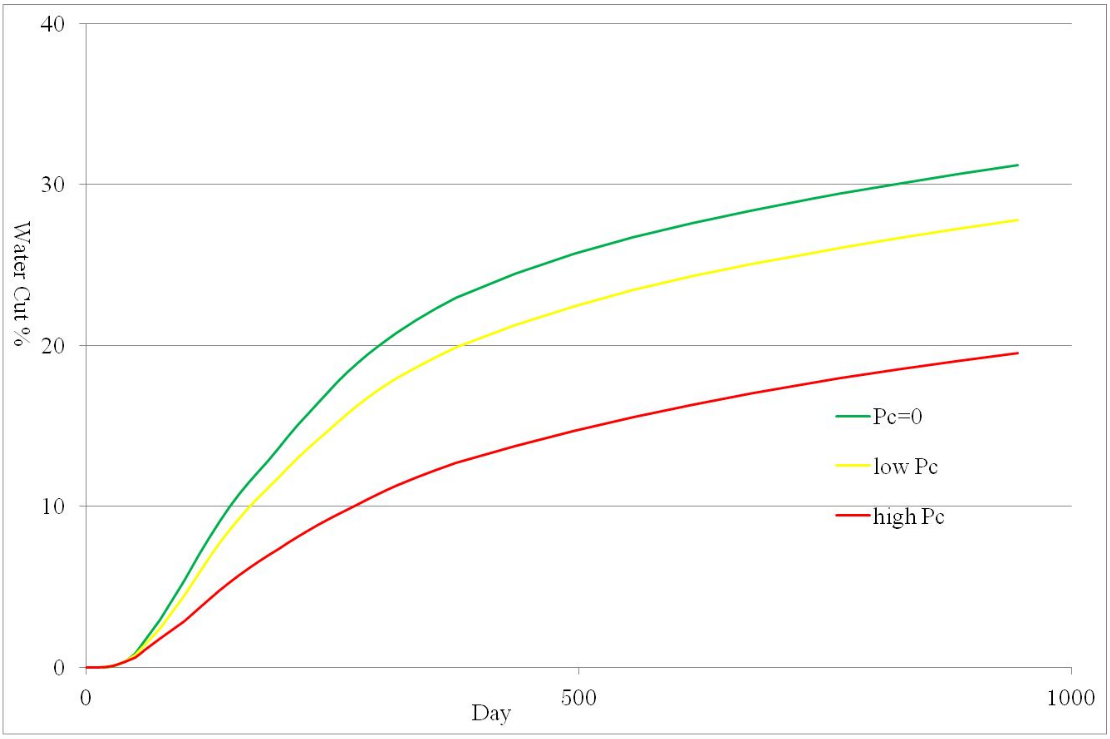


Fig 9.11 Water cut with various capillary pressure

As reservoir heterogeneity increase, associated with high flow rate, low matrix permeability, and weak imbibition result in water fingering through high permeable blocks to wellbore, water cut increase to a large value even without fracturing. In this case, the capillary pressure helps to trap water in blocks, the higher capillary pressure, the lager recovery factor, the lower water cut.

The accuracy of simulations could improve in some degree. Wang et al proposed the combined effect of capillarity and compaction should be taken into consideration on oil production since the bubble point pressure is reducing as the reservoir being compacted. Leverett J-function should be the approach used to evaluate capillary pressures for tight oil. Viscosity and density are reduced as the pore space is confined from 50 nm to 10 nm, which is a typical pore size in tight oil reservoir such as the Bakken. The implication is that confinement increases the driving energy and flow capacity of tight oil reservoir, which favors the extraction of more liquid, however, the reduction of oil mobility due to reduction of permeability by compaction can offset the increase of mobility due to reduction of viscosity. The extended simulator used to capture the pressure-dependent impact of the nanopore structure on rock and fluid properties, which contribute to a better understanding of abnormal production behavior observed in the Bakken field, such as long-lasting, relatively constant producing GOR even when the pressure near well has dropped below bubble point pressure. Fluid properties in fractures can be maintained unconfined, while fluid in matrix will be confined.[109]

9.2 Hydraulic Fracture

After reservoir fracturing, simulations were made to compare oil production and water cut for cases with fractures and without fractures, results as shown in Fig 9.12 and Fig 9.13.

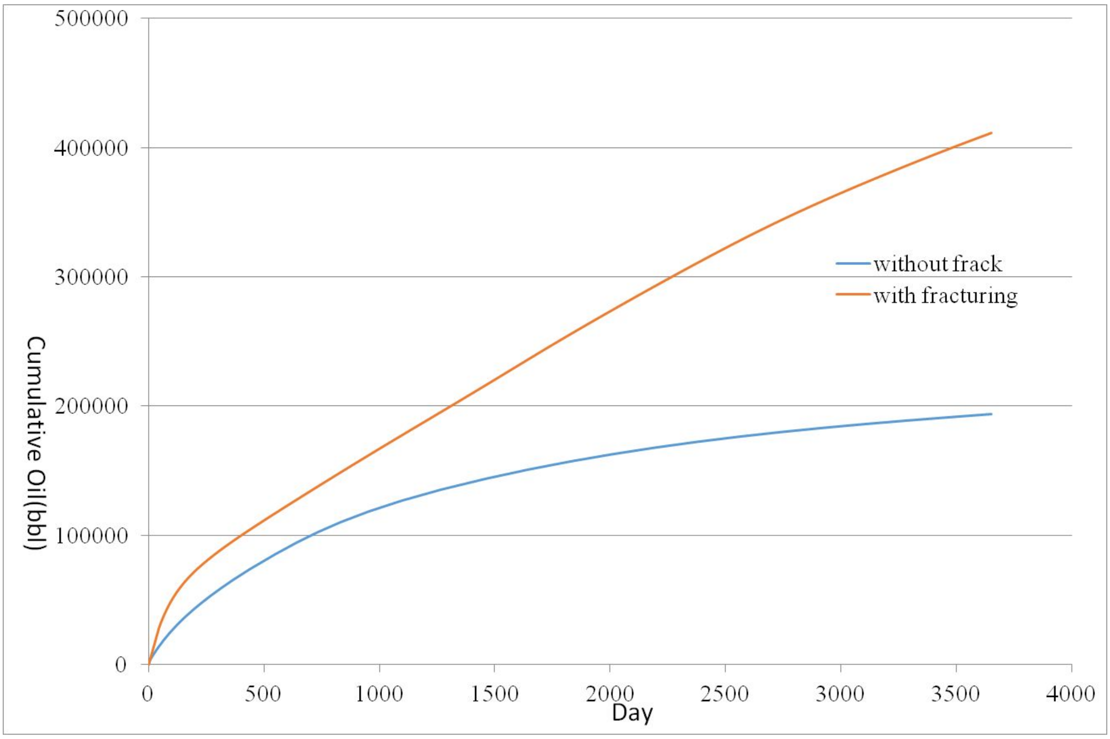


Fig 9.12 Oil production improved by hydraulic fracture

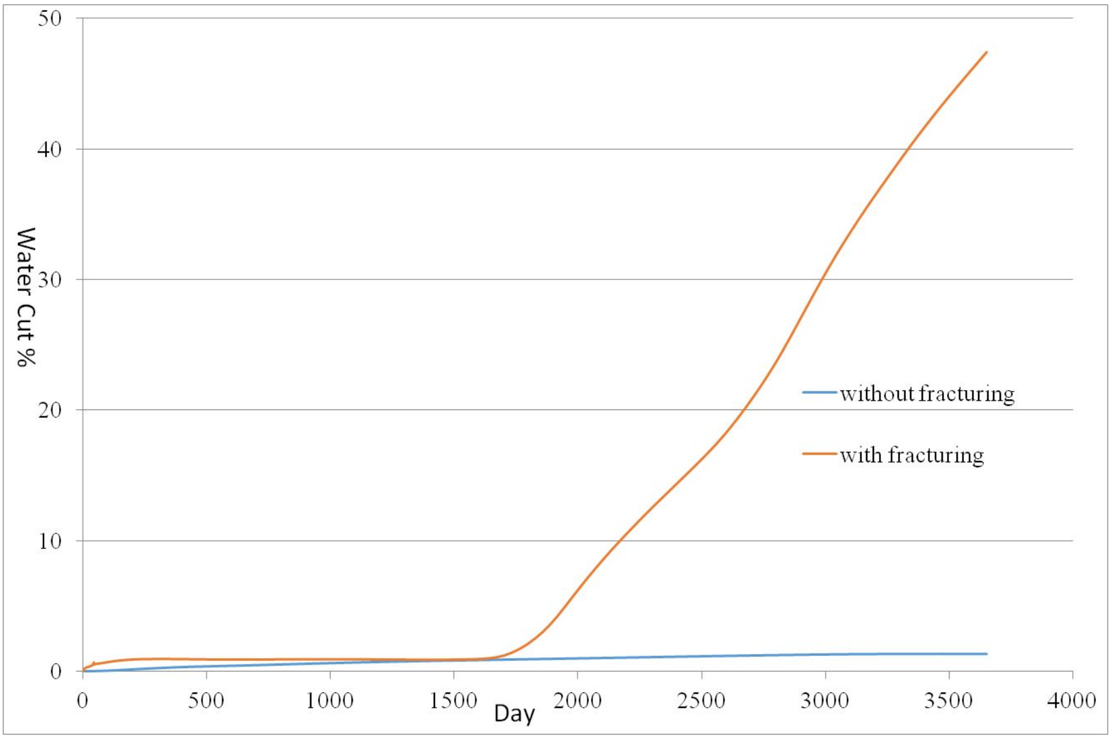


Fig 9.13 Water cut with hydraulic fracture

The oil production was boosted by hydraulic fractures, also it is well established that hydraulic fracturing is a cost-effective way to extract hydrocarbon from tight formation.[103]

Early production levels will be dependent on the length of propped fracture from the wellbore that has actually cleaned up.[7] The effects of half length of fractures on oil production were simulated in the model.

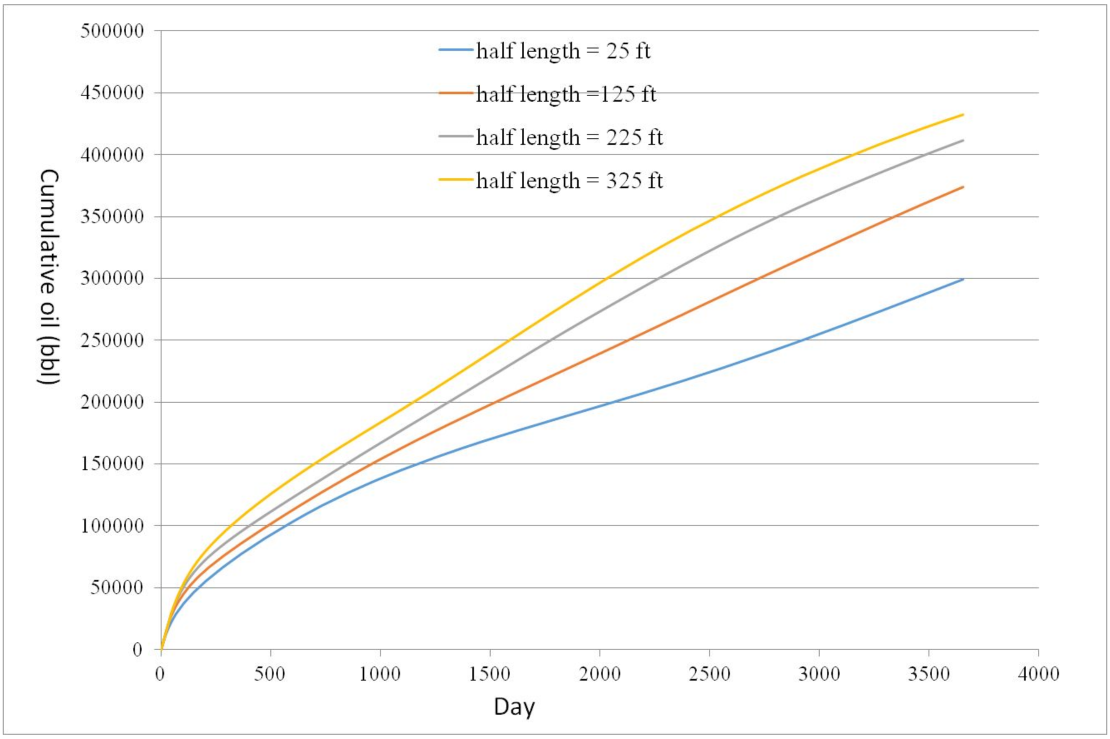


Fig 9.14 Oil production with various fracture half length

As shown in above figures, the cumulative oil production increases as the half length of fracture extended, however, the optimal fracture half length exist if economic analysis linked to the simulation since the incremental rate of cumulative oil production decrease as the half length increase.

The hydraulic fracturing process has been highly controversial despite the boom of oil recovery in tight formation.

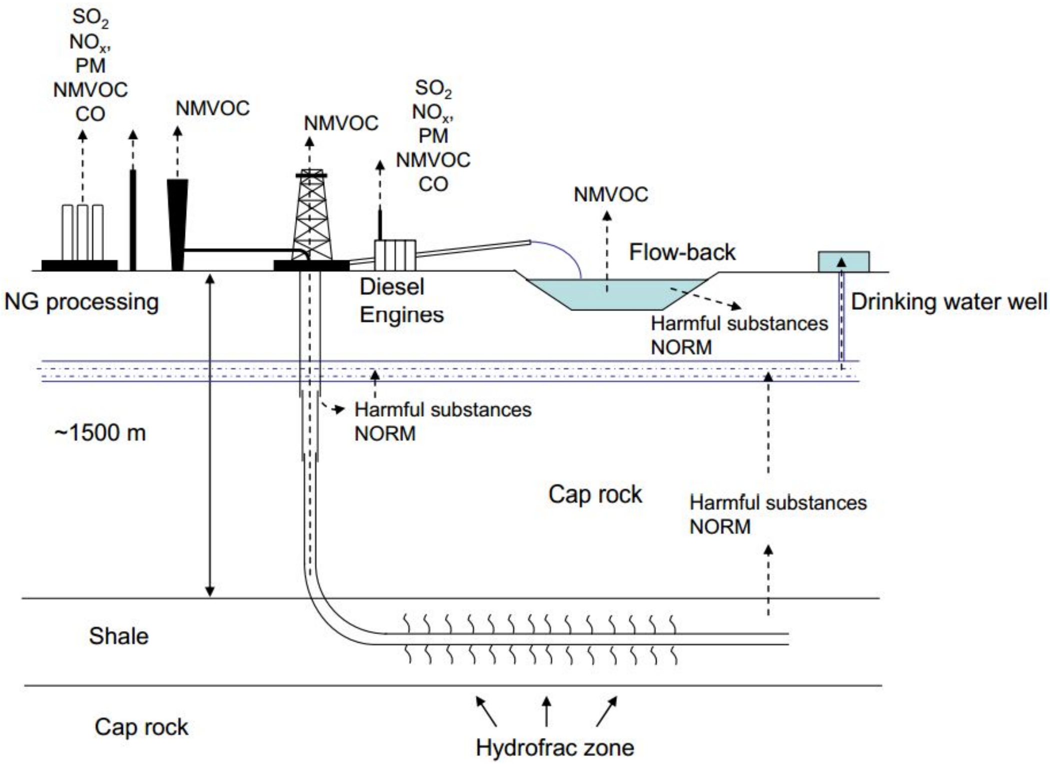


Fig 9.15 Potential flows of air pollutant emissions, harmful substances into water and soil, and naturally occurring radioactive materials [110]

Shallow freshwater contamination

The shallow layers are protected from injected fluid by a number of layers of casing and cement, as a practical matter, fracturing operations cannot proceed if these layers of protection are not fully functional. It is estimated that 20-85% of fracturing fluid remains underground.[111] In shale gas-extraction areas (one or more gas wells within 1 km), average and maximum methane concentrations in drinking-water wells increased with proximity to the nearest gas well were 19.2 and 64 mg CH_4/L, a potential explosion hazard; in contrast, dissolved methane samples in neighboring nonextraction sites (no gas wells within 1 km) within similar geologic formations and hydrogeologic regimes averaged only 1.1 mg/L.[112]

Surface Water Pollution

Approximately between 20% and 50% of the water used for fracturing gas wells returns to the surface as flow back. Recycling might be one of the possible solutions.[111]

Water Quantity Usage

Water is primary component of fracturing fluid. As shown in Table 9.1, a lot of water needed during the fracturing process.

Table 9.1 Average Freshwater Use per Well for Drilling and Hydraulic Fracturing[113]

Shale play	average freshwater used (gallon)	
	for drilling	for hydraulic fracturing
Barnett	250000	4600000
Eagle Ford	125000	5000000
Haynesville	600000	5000000
Marcellus	85000	5600000
Niobrara	300000	3000000

Air quality

Engine exhaust from increased truck traffic, emissions from diesel-powered pumps used to power equipment, intentional flaring or venting of gas for operational reasons, and unintentional emissions of pollutants from faulty equipment or impoundments, which could pose risks to ail quality.[113] The component used in the fracture fluid such as diesel fuel, kerosene, benzene, toluene, xylene, and formaldehyde, are toxic enough to create toxic air emissions.[114]

Community disruption

An unfavorable factor of tight oil extraction is increased land occupation and community disruption due to drilling pads, processing and transporting facilities, areas for trucks, as well as roads.[110,114]

9.3 Gas Injection

Besides water flooding, gas injection is also quite popular in the field development. N_2 and CO_2 are widely used as injected gas.

Nitrogen is generated on site by processing atmospheric air utilizing membrane separation technology. The membrane separation technology yields Nitrogen at a cost of approximately $1.00 per MCF that contains volumetrically up to 5-percent Oxygen. N_2 is an inert gas, it does not contribute to corrosion of equipment. N_2 has a lower solubility in oil and less of an impact on oil properties than CO_2. It requires the injection of approximately 2.5 MCF of Nitrogen to recover one barrel of oil in the Big Andy field located in eastern Kentucky.[115]

74.4% of CO_2 used for EOR is provided by gas treating and processing facilities associated with the production of CO_2 rich natural gas from formations, while 19.4%

originates in natural gas plants, 4.8% from a coal synfuel plant, and the remaining from various chemical and petroleum facilities.[116] Mohammed-Sing(2006) suggested that CO_2 improves oil recovery due to oil viscosity reduction, oil swelling and near wellbore damage removal.[117]

Brock and Bryan summarized 21 miscible floods, 4 immiscible multi-well floods and 5 immiscible "huff 'n' puff" projects, it shown incremental recoveries predicted by the various operators ranged from 5 to 22 percent of original-oil-in-place, and the CO_2 utilization values, which ranged from a 2.4 Mcf/STB to 13 Mcf/STB on a net basis.[118]

N_2 and CO_2 flooding could alter the oil composition in some degree.

Table 9.2 Oil composition alternation after 6 cycles of injection [115]

Component	Original	Post-CO_2 injection	Post-N_2 injection
C3	0.00212	0.00075	0
iC4	0.00221	0.00106	0.001251
nC4	0.01539	0.01026	0.011449
iC5	0.01586	0.01219	0.012299
nC5	0.04736	0.0439	0.042975
C6	0.03386	0.03479	0.032255
C7+	0.88181	0.89363	0.896351
N_2	0.00139	0.0017	0.00342
CO_2	0	0.00173	0
TOTAL	1	1	1

N_2 and CO_2 component could exert an effect on phase envelop of hydrocarbon.

Volatile Oil:

CO_2 lower the cricondenbar of the volatile oil and the critical point of mixture shifts considerably to the left. The net effect is enhancing miscibility, shrinkage of the two phase region and expanding the liquid phase region

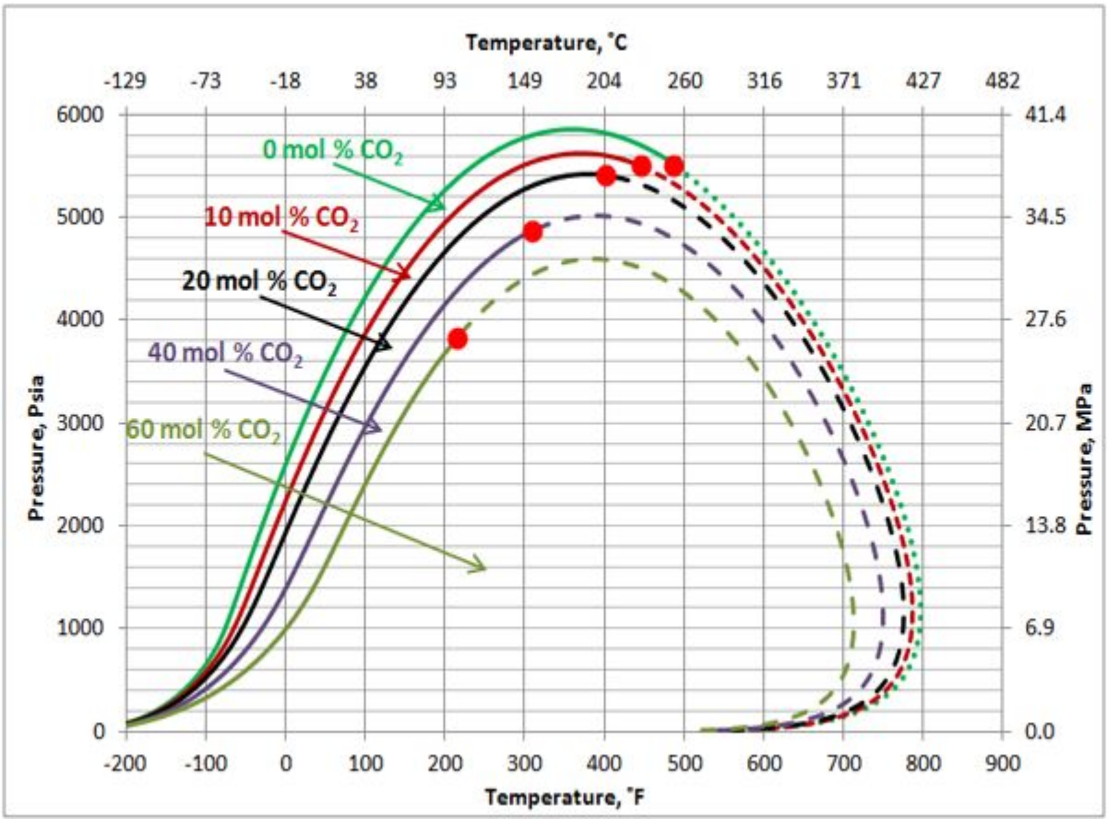


Fig 9.16 The impact of CO_2 concentration on the volatile oil phase envelope[119]

Rich Gas

N_2 raises the cricondenbar of the rich gas, shifts the critical point to the left and decreases miscibility. It is best used for pressure maintenance.

CO_2 lowers the cricondenbar, shifts the cricondentherm to the right but shifts the critical point to the left.

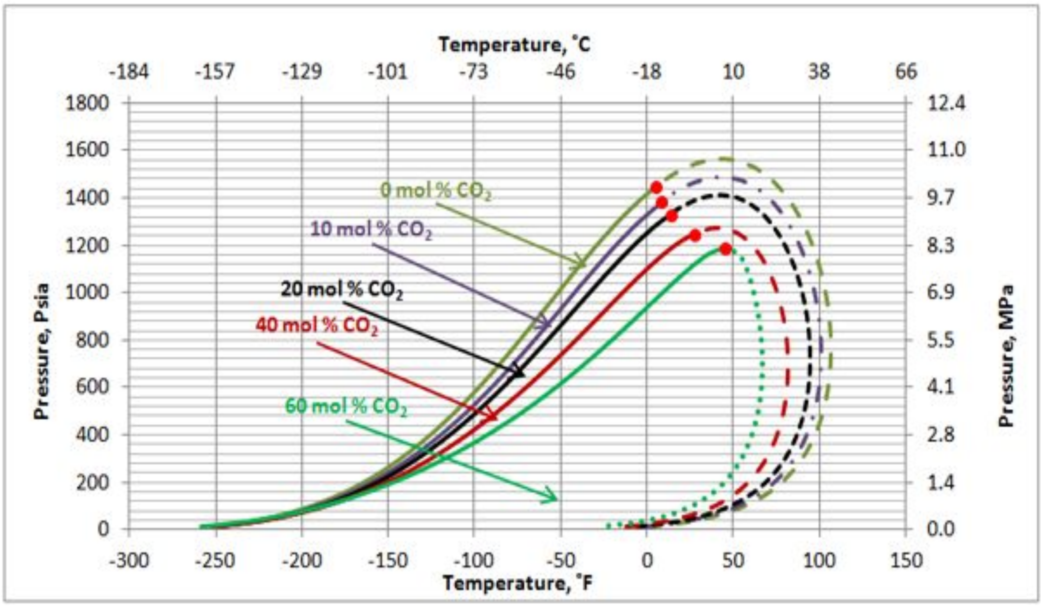


Fig 9.17 The impact of CO_2 concentration on the rich gas phase envelope[119]

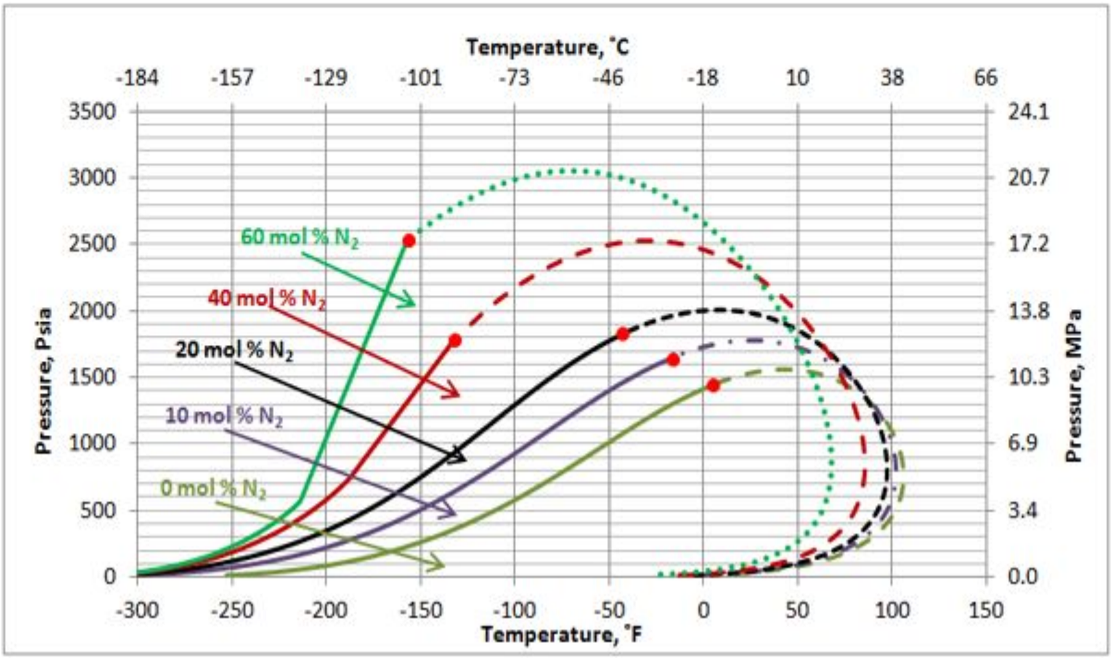


Fig 9.18 The impact of N_2 concentration on the rich gas phase envelope[119]

Black Oil

Contrary to the case of volatile oil, the cricondenbar rises as the CO_2 content increases but both the critical and cricondentherm points shift to the left. Compared to Fig 9.16 for volatile oil, the impact of CO_2 on the black oil phase envelope is much less.

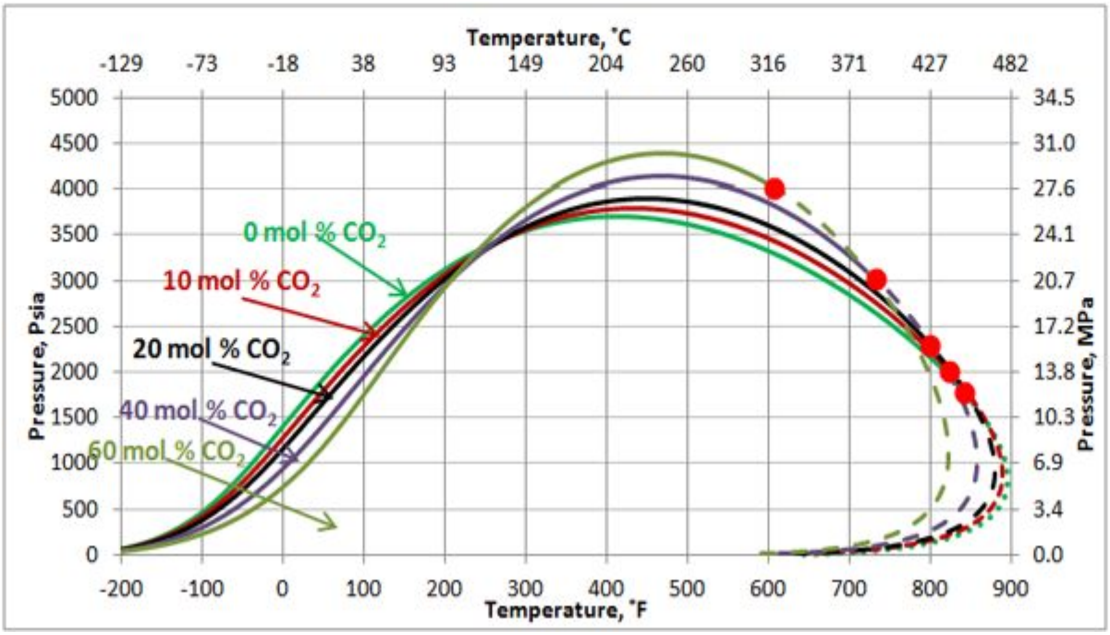


Fig 9.19 The impact of CO_2 concentration on the black oil phase envelope[119]

According to the experimental work done by E. Ghoodjani and S.H. Bolouri, different oil gas permeability curves were assigned to N_2 and CO_2 injection process in the simulation.

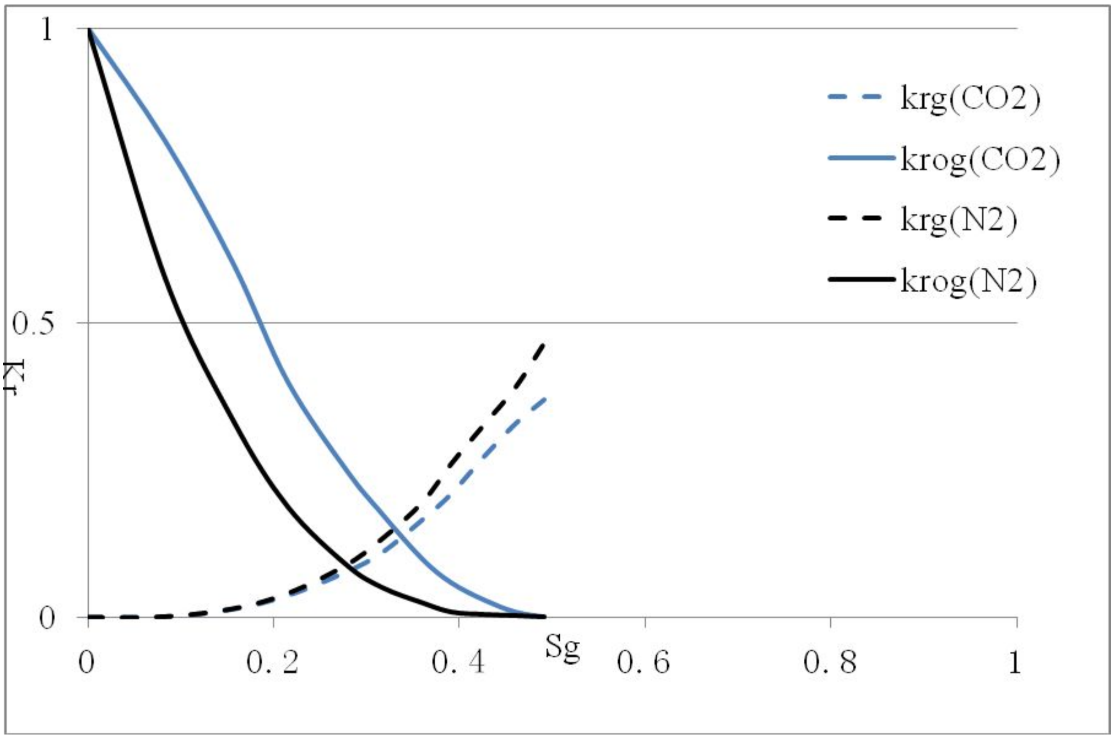


Fig 9.20 The oil-gas permeability difference for CO_2 and N_2

As shown in Fig.9.20, oil permeability is higher in CO_2 injection compared to N_2 injection. For the gas permeability, as the gas saturation increased, N_2 relative permeability becomes higher than CO_2 relative permeability. [120]

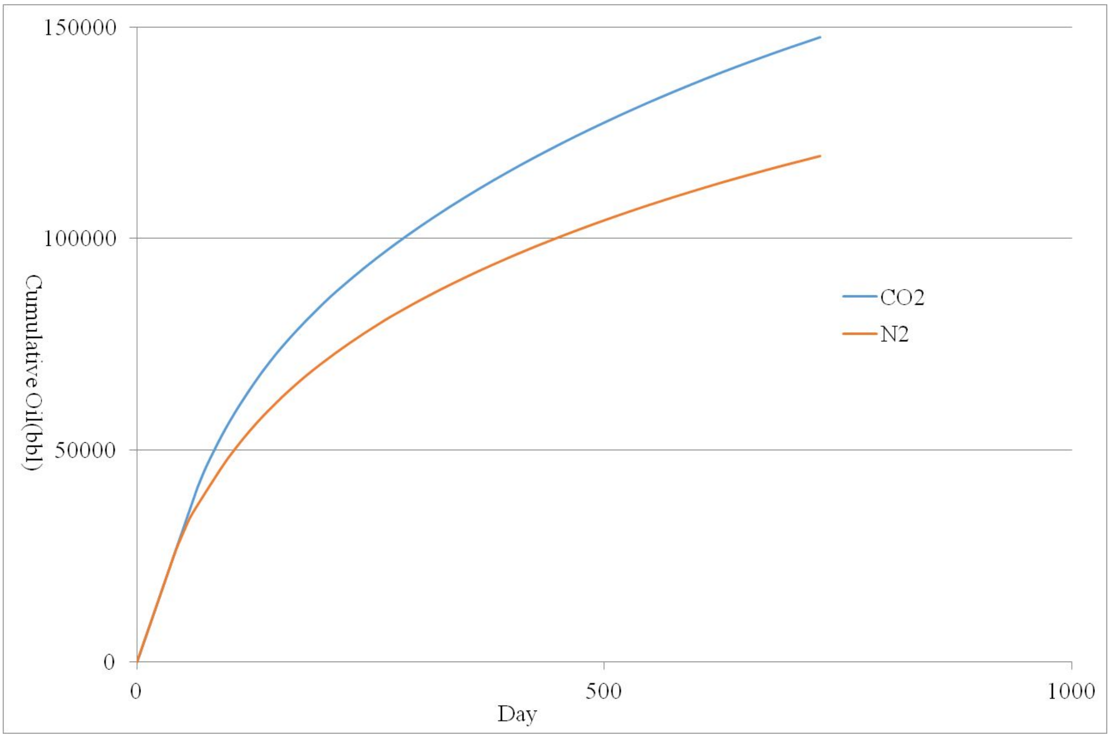


Fig 9.21 Oil production comparison between CO_2 and N_2

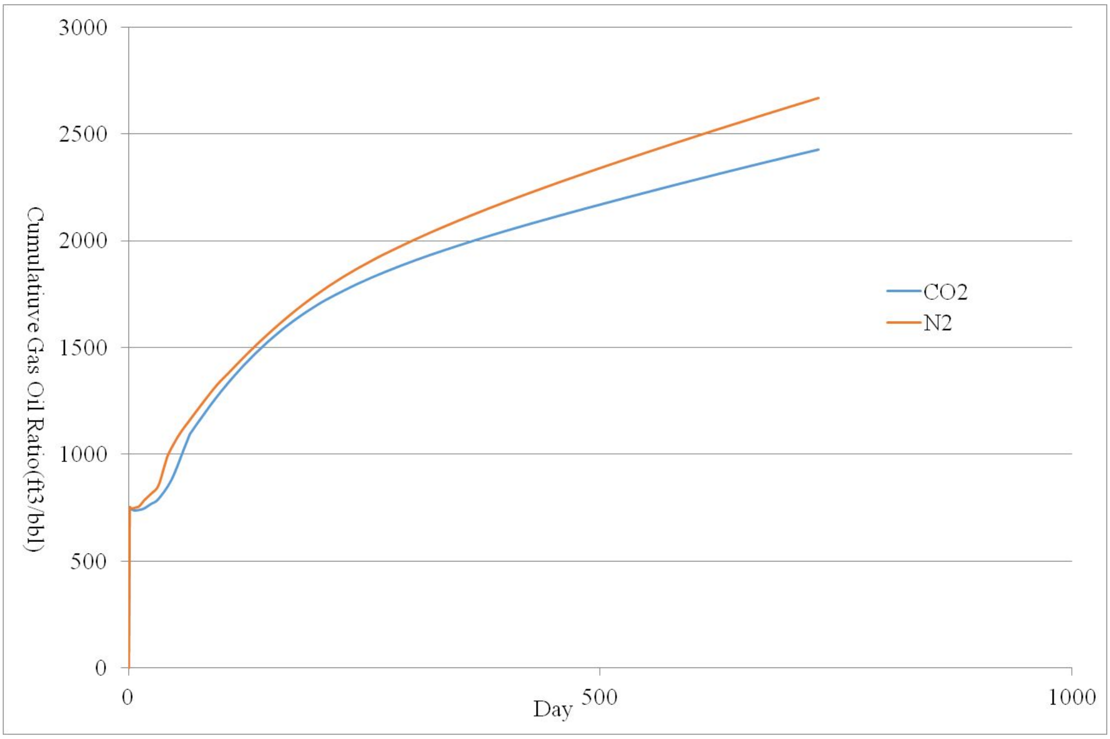


Fig 9.22 Gas oil ratio comparison between CO_2 and N_2

Interfacial tension and viscosity reduction, and oil swelling account for oil relative permeability improvement, which causes the cumulative oil production of CO_2 injection becomes higher than N_2 injection. Gas oil ratio is higher in N_2 injection compared to CO_2 injection.[120]

Despite better production caused by CO_2 flooding compare to N_2, the operational problems of CO_2 injection are also not negligible.

Corrosion

Steel corrosion is a result of the corrosive environment created by the carbonic acid formed in the presence of water.

This can be reduced by using duel water and CO_2 lines and dehydrating CO_2 before compression and transportation

Asphaltene Deposition

Asphaltene deposition is initiated by CO_2 when the critical content of CO_2 is exceeded, the critical content point of CO_2 is dependent on oil composition, temperature and pressure must be evaluated at early stage of screening methods for CO_2 EOR.[121] The most important factor on which the asphaltene precipitation depended on the CO_2 concentration, it has been found that 20–40% permeability reduction by asphaltene deposition was caused by adsorption mechanism in the CO_2 flooding process during a slow process,[122] also the higher permeability vuggy matrix showed the highest asphaltene precipitation in the core during CO_2 injection.[123]

During CO_2 flooding, the dissolution of rock minerals as well as salt precipitation and asphaltene precipitation might modify reservoir porosity and permeability.[123]

CO_2 breakthrough and unstable fronts

Earlier breakthrough happened when CO_2 make fingers in the oil zone. Unstable fronts is because of unfavorable mobility ratio, which can be reduced by using WAG process.[124]

Reservoir heterogeneity exert more pronounced effect in CO_2 flooding than water flooding, the accurate reservoir characterization is an important factor in the design of CO_2 flooding.[123]

9.4 WAG

The mobility ratio between the injected gas and reservoir oil is unfavorable because of the low viscosity of gas, which cause viscous fingering and reduced sweep efficiency.[33] Therefore, water injection and gas injection are carried out alternately for periods of time to provide better sweep efficiency, known as WAG process, this process is used mostly in CO_2 flooding to improve hydrocarbon contact time and sweep efficiency of the CO_2.[125]

WAG injection has been widely applied since the late 1950s. It is applied to quite a few field in various degree include Snorre, Statfjord, Gullfaks, Heidrun, Norne, Veslefrikk and Siri. The typical improved oil recovery (IOR) potential for WAG injection is around 5-10% when compared to water injection.[126]

The following parameters are crucial in the WAG design.

Slug Size: It means the cumulative volume of injected gas, normally expressed as percentage of hydrocarbon pore volume (HCPV). Generally, the more miscible gas injected, the higher the incremental oil recovery.[33]

WAG Ratio: It is the ratio of the volume of injected water to that of gas, which is one of the most important parameters in the WAG process.

Cycle Length: The timing of switch between gas and water, the time span of WAG may also have considerable effect.

The cycle length and WAG ratio were investigated in the simulation.

Homogenous model

Cycle Length

In this case, three years of production data with WAG ratio 1:1 was investigated in the simulation, which shows the details in Table 9.3. The water injection rate is 640 rb/day, and gas injection rate is 3593 rft^3/day.

Table 9.3 Cycle length investigation

scenario	WAG ratio (fraction)	WAG cycle length (months)	Gas injection (months)	Water injection (months)
1	1	12	6	6
2	1	24	12	12
3	1	36	18	18

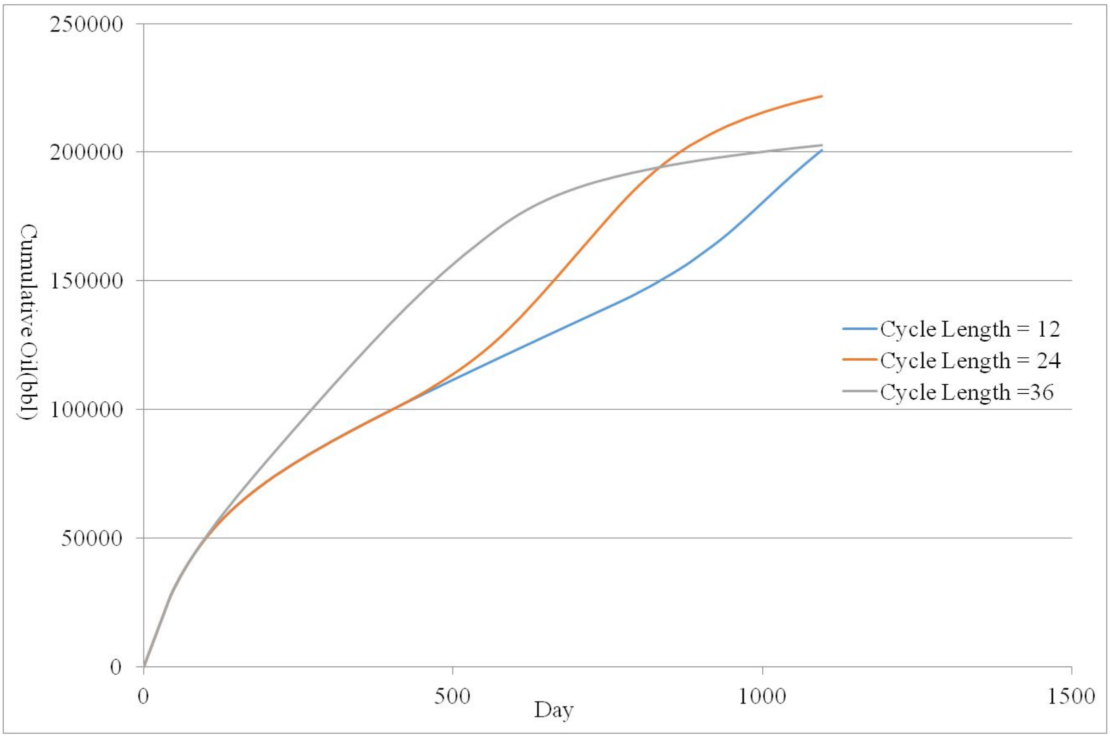


Fig 9.23 Oil production with differtent WAG cycle length

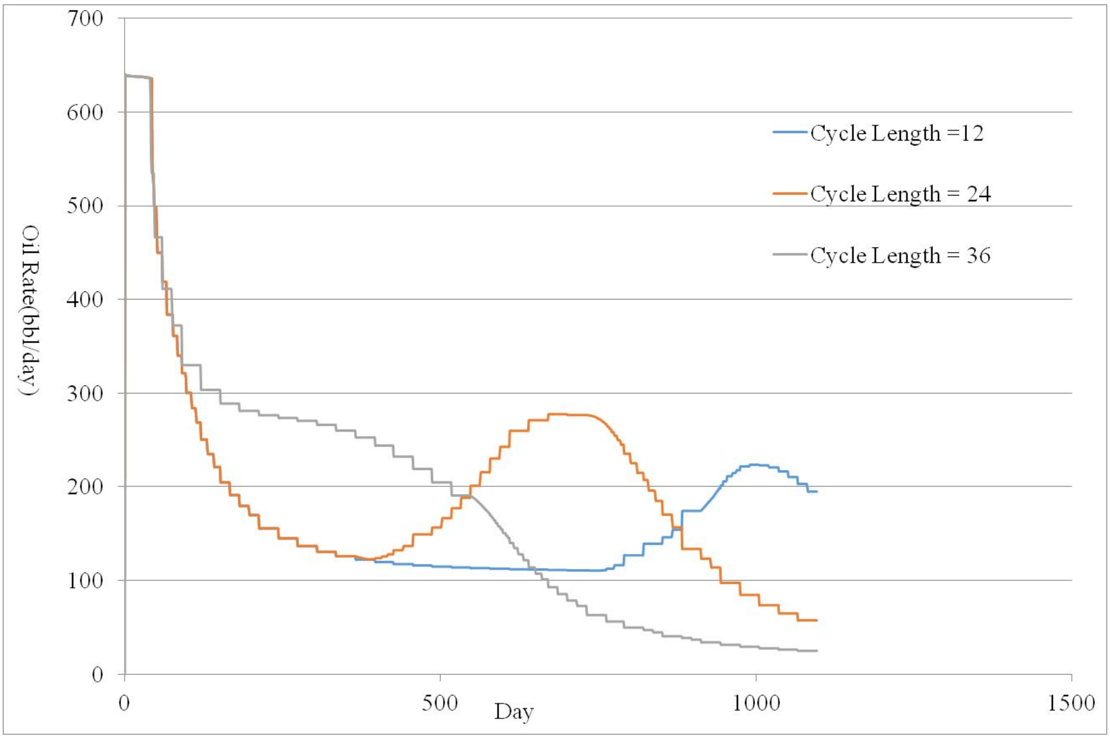


Fig 9.24 Oil rate with different WAG cycle length

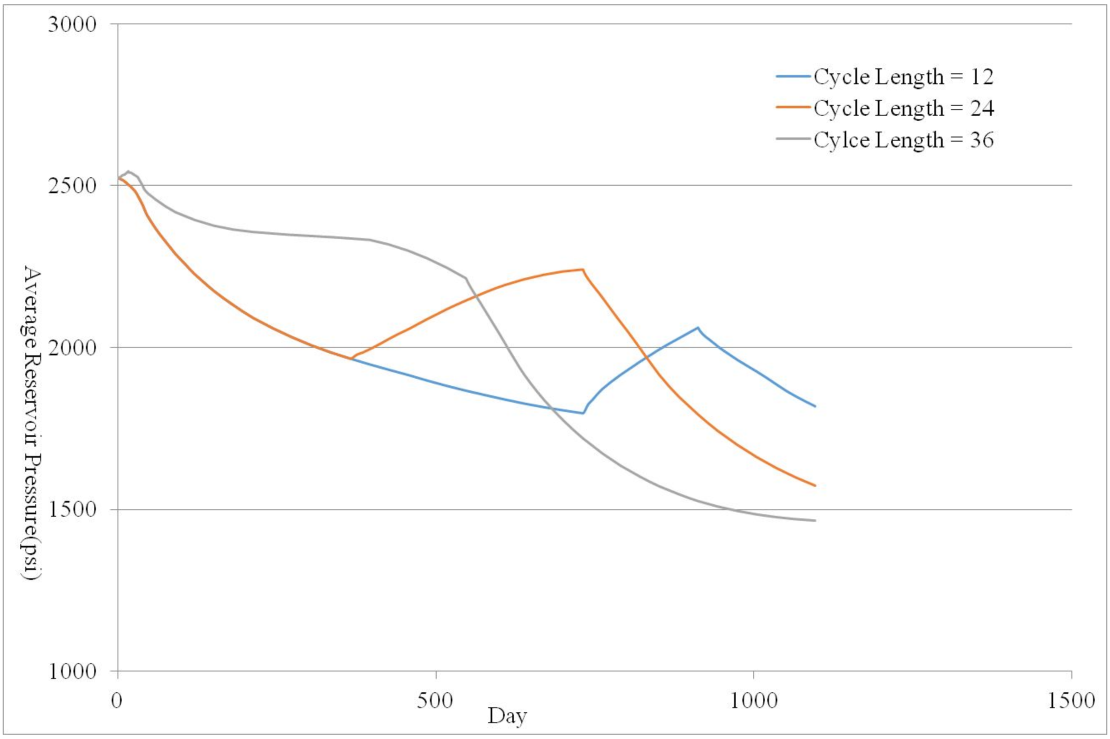


Fig 9.25 Average reservoir pressure with various cycle length

As we can see from Fig 9.23 to Fig 9.25, the average reservoir pressure decrease as WAG cycle length increase, and the WAG process could boost reservoir pressure and oil rate in a certain period. The cycle length has an effect on oil rate, also reservoir pressure. Even the WAG could boost oil rate, it doesn't mean the longer the

WAG, the better the oil production, also Ghaderi concluded that decreasing the cycle length increases recovery factors since the higher average reservoir pressure, which caused by the higher frequency of water injection, results in proper gradient between producers and injectors.[33] Also, the cycle length was found to be critical to WAG process design.[127]

The average pressure drop dramatically after the gas breakthrough, therefore, the lower gas rate initially in the gas injection may have a better sweep efficiency.

Two cases of gas injection were proposed to test this statement.

Table 9.4 Various gas rate injection test

scenario	WAG ratio (fraction)	WAG cycle length (months)	Water injection bbl	Gas injection ft^3
1	1	36	640(18 months)	3593(18 months)
2	1	36	640 (18 months)	1797(6 months) 4491 (12 months)

The results were presented in the following figures, as we can see, initially the scenario 1 has a higher oil rate, but as the pressure drops quicker in scenario 1, and scenario 2 has a higher recovery than constant gas injection case.

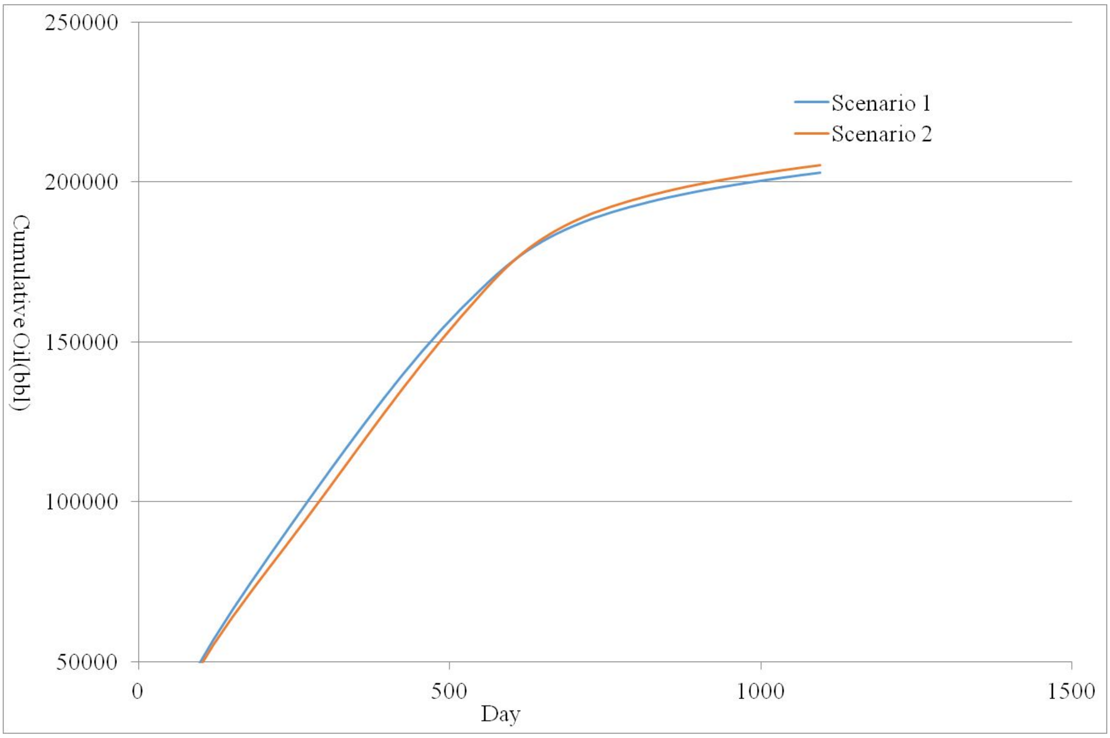


Fig 9.26 Cumulative oil production with constant gas injection rate and various gas rate

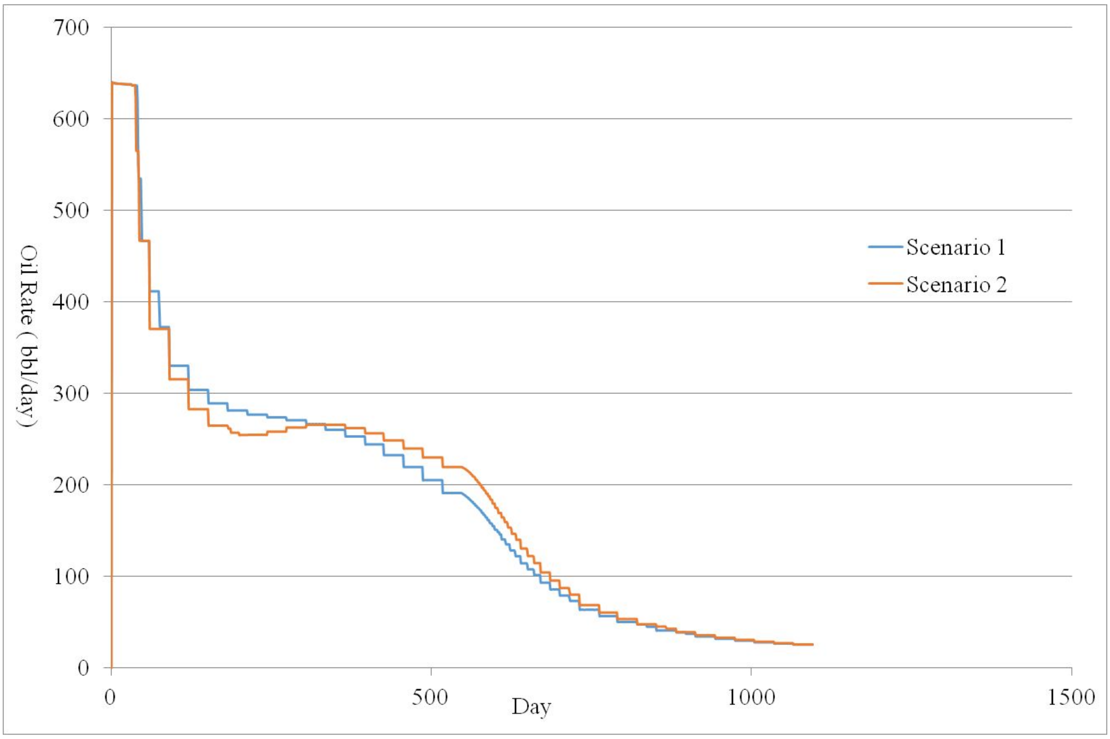


Fig 9. 27 Oil rate with constant gas injection rate and various gas rate

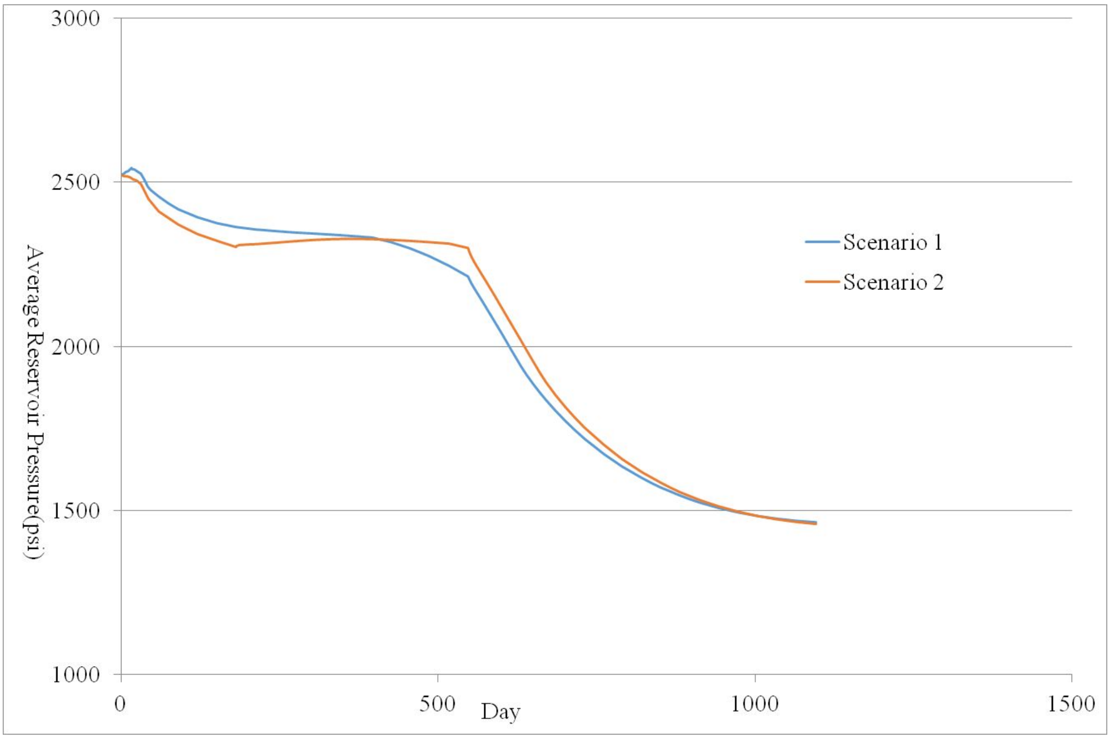


Fig 9. 28 Average reservoir pressure with constant gas injection rate and various gas rate

WAG Ratio

In order to investigate the effect of WAG ratio on oil recovery, several scenarios were proposed, which are summarized in Table 9.5.

Table 9. 5 WAG ratio investigation

Scenario	WAG Ratio	Duration(year)
1	1-0	Water(3)
2	0	Gas(3)
3	0-1	Water(1)+Gas(2)
4	1-1	Water(1)+WAG(2)
5	1-2	Water(1)+WAG(2)
6	2-1	Water(1)+WAG(2)
7	1-3	Water(1)+WAG(2)
8	3-1	Water(1)+WAG(2)

The WAG ratio in Table 9.5 is in-situ ratio, the water injection rate is 640 rbbl/day, and the gas rate is 3593 rft^3/day.

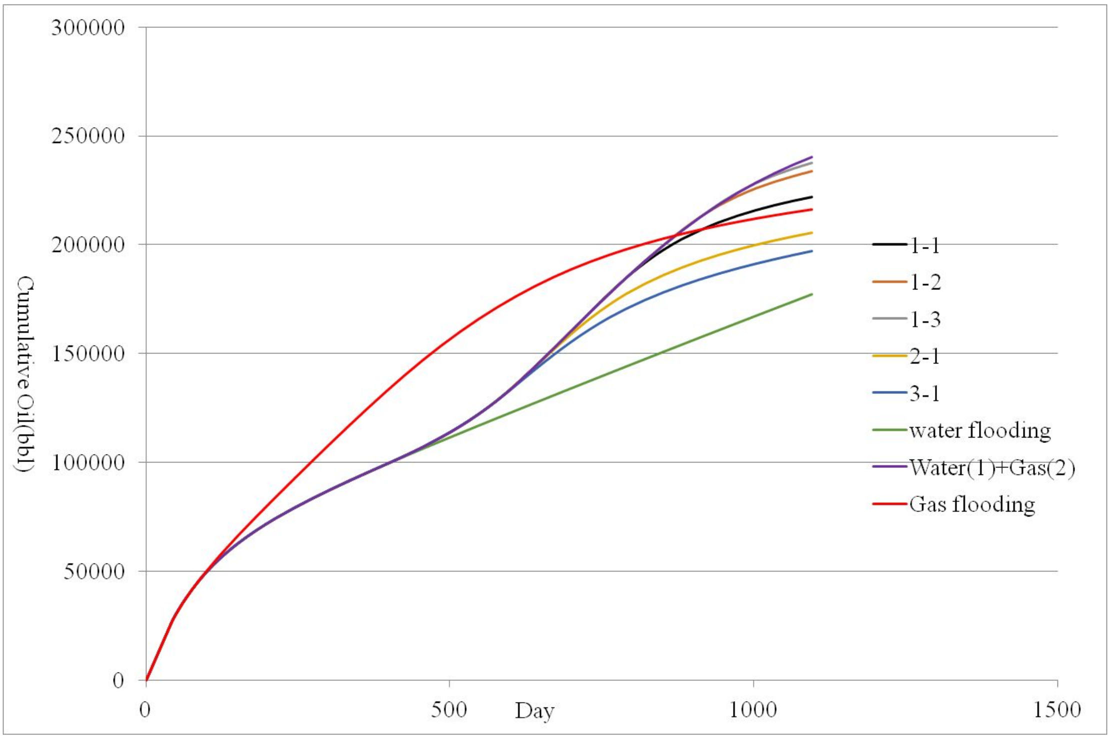


Fig 9.29 Cumulative oil with different WAG ratio

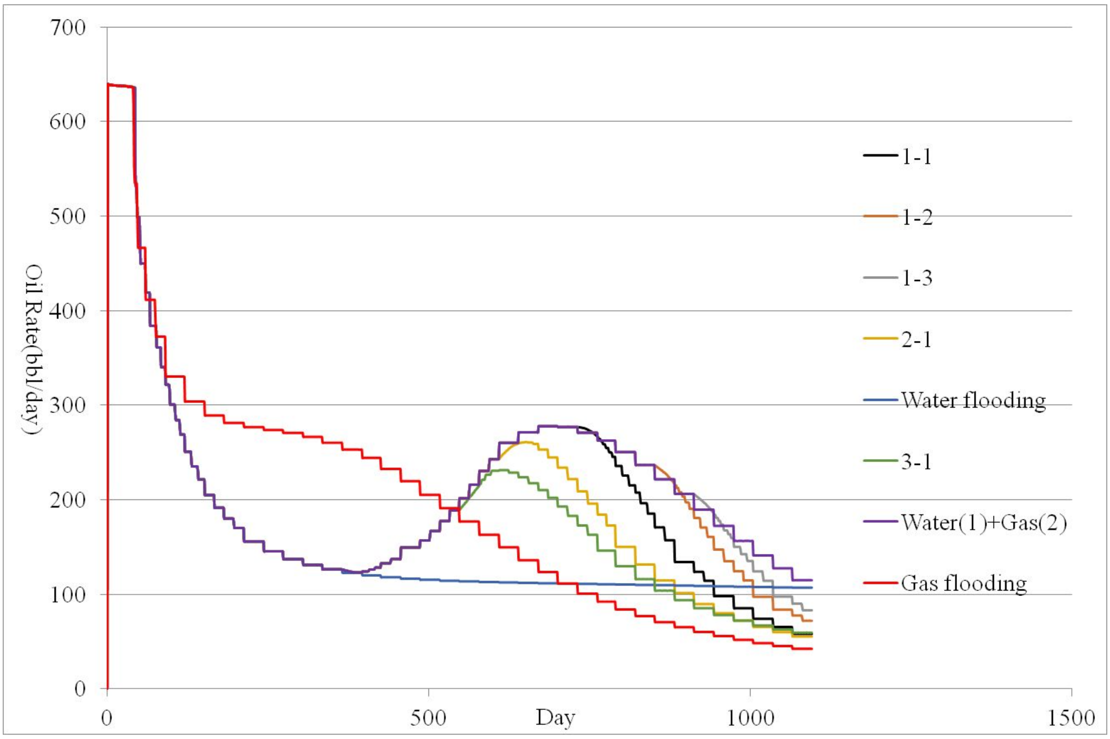


Fig 9.30 Oil ratio with different WAG ratio

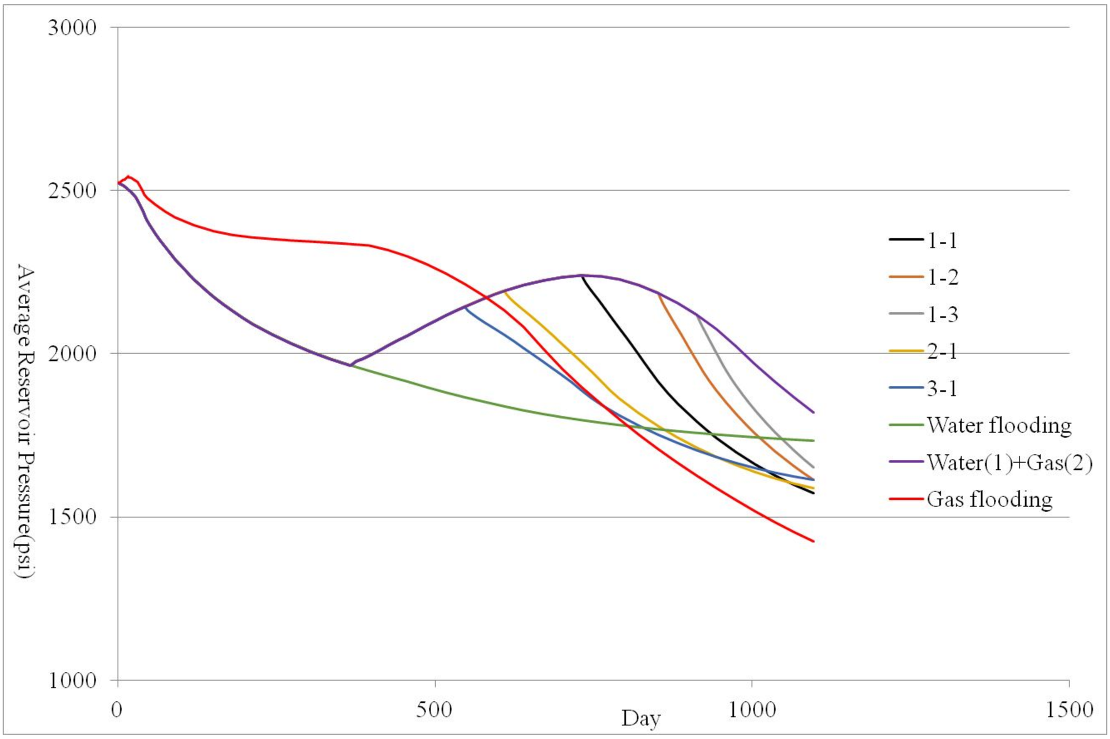


Fig 9.31 Average reservoir pressure with different WAG ratio

The various WAG ratios have different effects on oil recovery and average reservoir pressure. One year water flooding and then 2 years gas injection seems the best case, for WAG ratio, case 1:3 has the best oil recovery, however, if the economic elements linked to the WAG process, maybe the 1:2 is the optimum WAG ratio.

Actually the optimum value for WAG ratio is quite reservoir dependent, the overall performance of WAG process depends on the permeability distribution, gravity segregation, and flow behavior of different phase. Gas availability and rock type also exert an effect on WAG design.[33,127]

Heterogeneous system

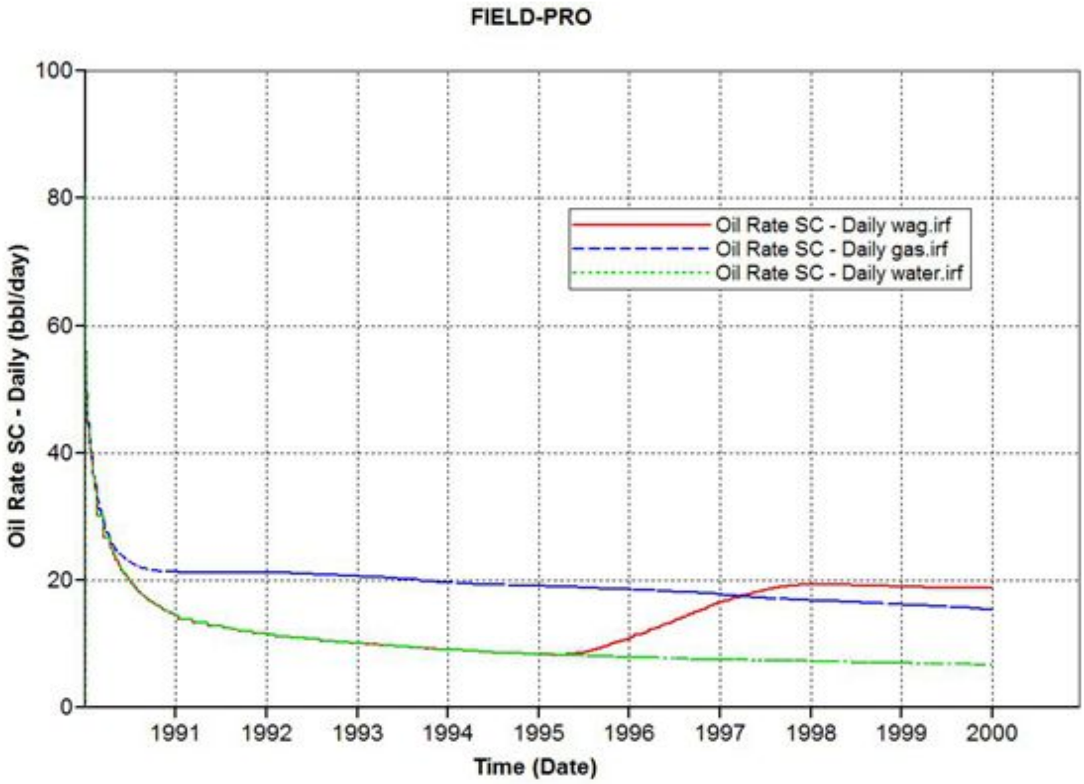


Fig 9.32 Oil rate difference between water, gas and WAG injection

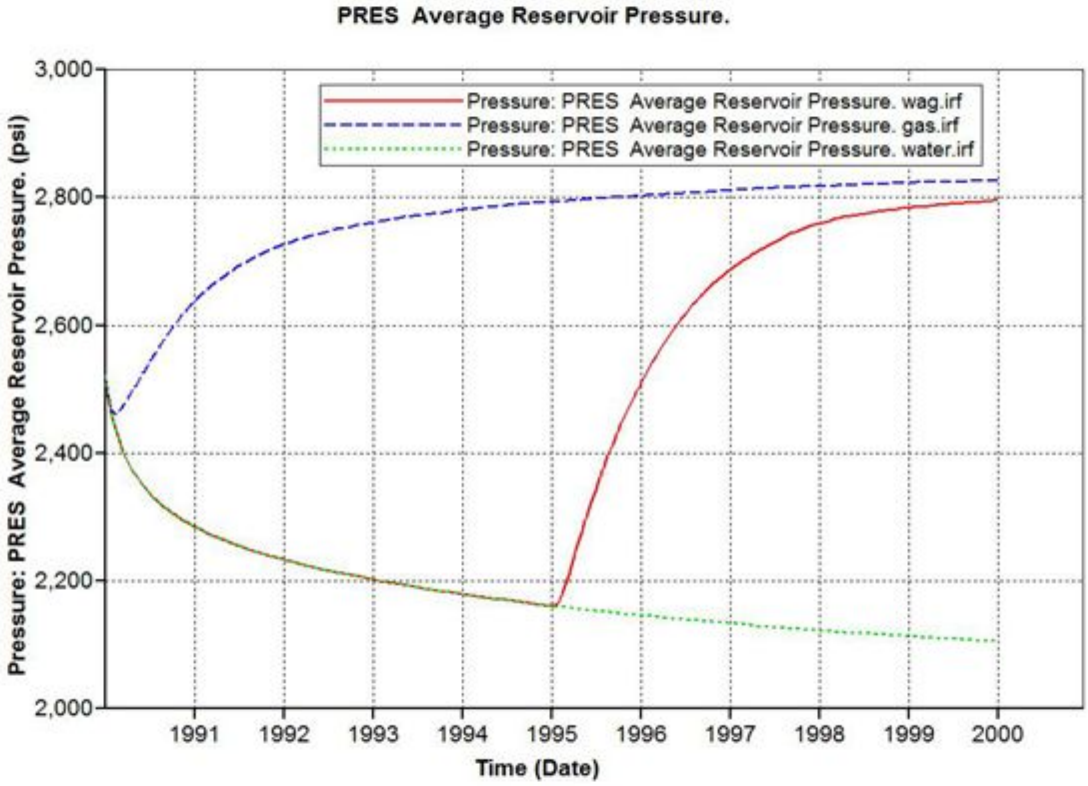


Fig 9.33 Average pressure difference between water, gas and WAG injection

Dual porosity

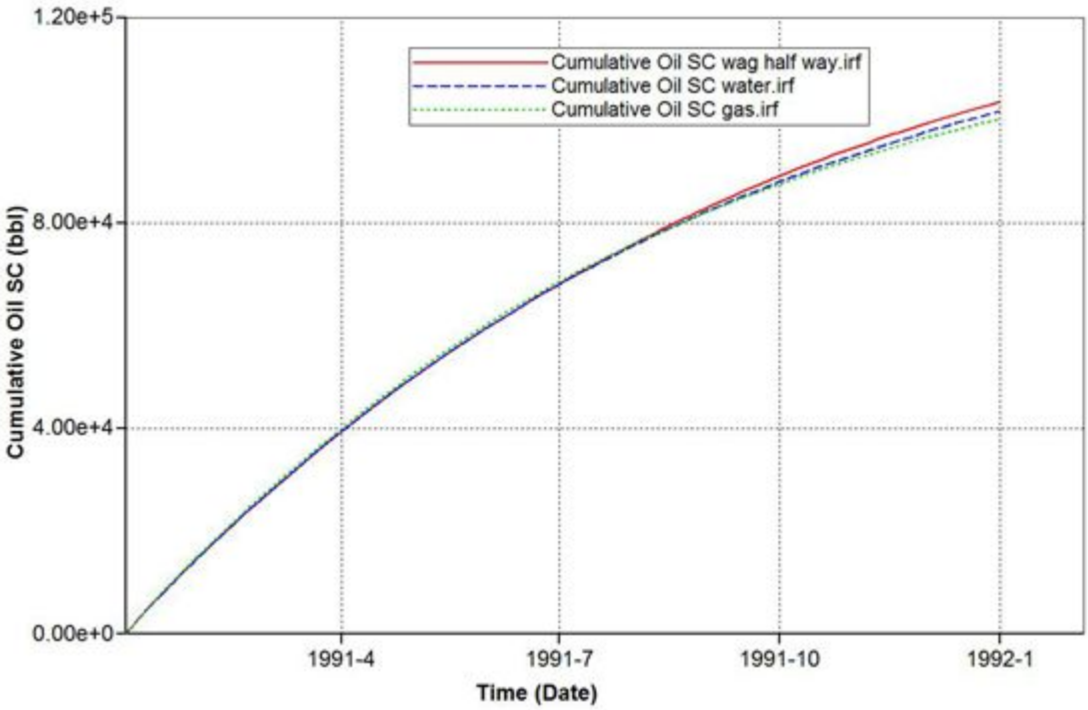


Fig 9.34 Cumulative oil production difference between water, gas and WAG injection

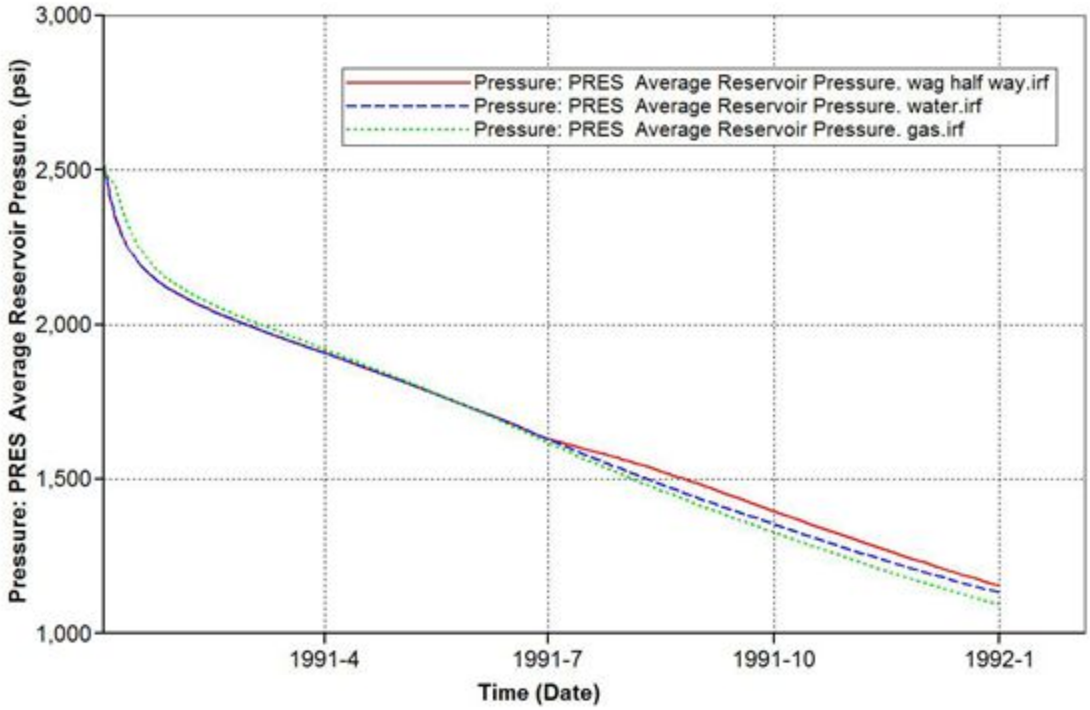


Fig 9.35 Reservoir pressure difference between water, gas and WAG injection

As shown in the above figures, the WAG process is better than either water flooding or gas flooding, no matter in oil rate or reservoir pressure, the WAG process contribute to a better sweep efficiency and higher oil recovery.

There are no consistent results in CO_2 and WAG process on oil recovery. Some researchers mentioned WAG is not suitable for tight reservoir, continuous CO_2 injection is more appropriate in the development of tight oil reservoir.[116] Also there is also claim that CO_2 injection was found to be effectively apply into the naturally fractured reservoirs after water injection.[123] The miscible water alternating CO_2 flooding process is found to be the most favorable flooding scheme for tight formations in terms of both recovery efficiency and fluid injectivity, the optimum producing pressure in the continuous CO_2 flooding process can be set as the minimum miscibility pressure (MMP) of the tight oil sample.[48]

Even the WAG process could boost the oil production in some degree, some challenges related to WAG injection still need to be carefully taken:[126]

Mechanisms

Understanding microscopic effects, particularly in cases where three-phase flow and hysteresis are important for the IOR effect. Capillary phenomena and wettability are important properties for low-permeable rock and may be taken advantage of or manipulated for IOR gains.

Predictions.

Use of foam (foam-assisted WAG or FAWAG).

Gas costs

Gas injection is usually seen as supplementary to on-going water flooding, and finding technical and commercial ways to reduce gas costs would prove beneficial.

Location optimization

For WAG process, the injected water and gas usually tend to sweep different part of reservoir because of the density contrast. The upper portion of the porous space tends to be swept by gas while water will sweep the hydrocarbon at lower spots.[128] Therefore, the optimum location for WAG process was investigated.

Table 9.6 WAG location optimization

scenario	injector location	producer location
1	layer 1	layer 3
2	layer 2	layer 3
3	layer 3	layer 3
4	layer 4	layer 3
5	layer 5	layer 3

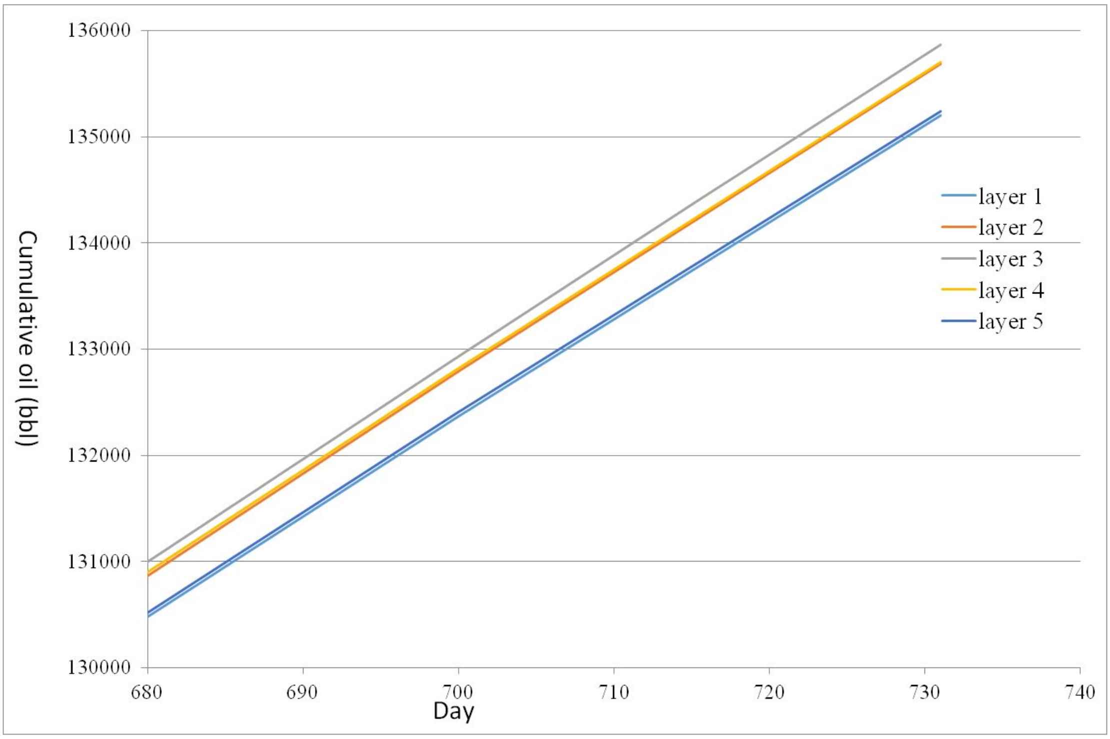


Fig 9.36 WAG location optimization

Water injection alone tends to sweep the lower parts of a reservoir, while gas injected alone sweeps more of the upper parts of a reservoir owing to gravitational forces. As shown in the Fig 9.36, the WAG injector in the middle of the target formation tend to sweep more oil than the injector at the top or bottom, which is the worst case.

9.5 Nanoflooding

Nanoparticles added into the water as injection fluid, which can alter the wettability and decrease oil water interfacial tension. The measurement of nanofluids properties and contact angle was summarized in the following tables.

Table 9.7 Density and viscosity measurement.[129]

Properties of brine and hydrophilic AEROSIL® 300 in brine at 21.5°C				
	Brine 3 wt.%	0.01 wt.%	0.1 wt.%	0.5 wt. %
Density [g/cm^3]	1.020	1.019	1.020	1.022
Viscosity [cp]	1.007	0.983	1.137	1.453
Properties of oil and hydrophobic AEROSIL® R106 in oil at 21.5°C				
	Oil	0.01 wt.%	0.1 wt.%	0.5 wt. %
Density [g/cm^3]	0.729	0.724	0.723	0.726
Viscosity [cp]	0.9	0.894	0.894	0.903

The density and viscosity almost keep constant in the range of 0.01 wt% and 0.1

wt% of nanoparticles with brine, and there is no PH alteration during flooding process in glass micromodel. The 0.5 wt% of nanoparticles is out of interests since the permeability reduction can't be negligible.

Table 9.8 Porosity and permeability measurement scenarios [129]

Core type	Nano-silica	Core plug	Nanofluid concentration
Water wet Berea sandstone	Hydrophilic	# 1	0.01 %
		# 7	0.01 %
		# 3	0.1 %
		# 12	0.1 %
		# 4	0.5 %
		# 8	0.5 %
	Hydrophobic	# 5	0.01 %
		# 14	0.01 %
		# 11	0.1 %
		# 13	0.1 %
		# 15	0.5 %
		# 16	0.5 %

Table 9.9 Porosity and permeability measurement result[129]

Core plug	old porosity	new porosity	Deviation	old permeability (mD)	new permeability (md)	Deviation
# 1	17.49%	15.34%	-2.14%	334.4	354.6	6.04%
# 7	17.03%	14.68%	-2.36%	336.7	334.4	-0.68%
# 3	17.88%	15.44%	-2.45%	319.2	335.3	5.04%
# 12	16.42%	15.13%	-1.29%	319.6	333.8	4.44%
# 4	15.95%	14.67%	-1.28%	359.6	275.4	-23.41%
# 8	16.19%	15.12%	-1.07%	361.2	141.1	60.94%
# 5	18.96%	16.61%	-2.35%	367.9	373	1.39%
# 14	16.63%	14.70%	-1.93%	332.4	328.1	-1.29%
# 11	18.55%	16.41%	-2.14%	384	348.9	-9.14%
# 13	17.89%	15.96%	-1.93%	383.1	378.4	-1.23%
# 15	16.61%	15.33%	-1.28%	346.4	230	33.60%
# 16	16.39%	15.33%	-1.06%	345.9	171	50.56%

Table 9.10 Oil/water Contact angle measurement[10]

Oil/water Contact angle measurement	
Sample	contact angel
pure water(3 wt % NaCl)	34.81
tap water(3 wt % NaCl)	20.22
pure water(3 wt % NaCl, 0.01% Nano-Silica)	27.62
pure water(3 wt % NaCl, 0.02% Nano-Silica)	20.81
pure water(3 wt % NaCl, 0.03% Nano-Silica)	16.77
pure water(3 wt % NaCl, 0.04% Nano-Silica)	24.57
pure water(3 wt % NaCl, 0.05% Nano-Silica)	12.83
pure water(3 wt % NaCl, 0.06% Nano-Silica)	11.42
pure water(3 wt % NaCl, 0.07% Nano-Silica)	13.81
pure water(3 wt % NaCl, 0.08% Nano-Silica)	12.44
pure water(3 wt % NaCl, 0.09% Nano-Silica)	7.89
pure water(3 wt % NaCl, 0.10% Nano-Silica)	12.71

Table 9. 11 Interfacial tension measurement [11]

Fluid	Interfacial tension(average)
oil/Di water	5.54
oil/0.01 wt% nanoparticles	5.213
oil/0.1 wt% nanoparticles	5.439
oil/0.5 wt % nanoparticles	5.27

According to Table 9.9, the porosity and permeability were tailored to nanoflooding.

Table 9. 12 Porosity and permeability in waterflooding vs. nanoflooding

porosity(waterflooding)	porosity(nanoflooding)
0.087	0.08526
0.097	0.09506
0.111	0.10878
0.16	0.1568
0.13	0.1274
permeability/mD (waterflooding)	permeability/mD (nanoflooding)
0.61	0.60

Contact angle of oil-water alternation and interfacial tension reduction have an effect on relative permeability. As Owens concluded that the relative permeability to oil decreases and the relative permeability to water increases at a given saturation as the degree of rock preferential water wettability decreases.[130]

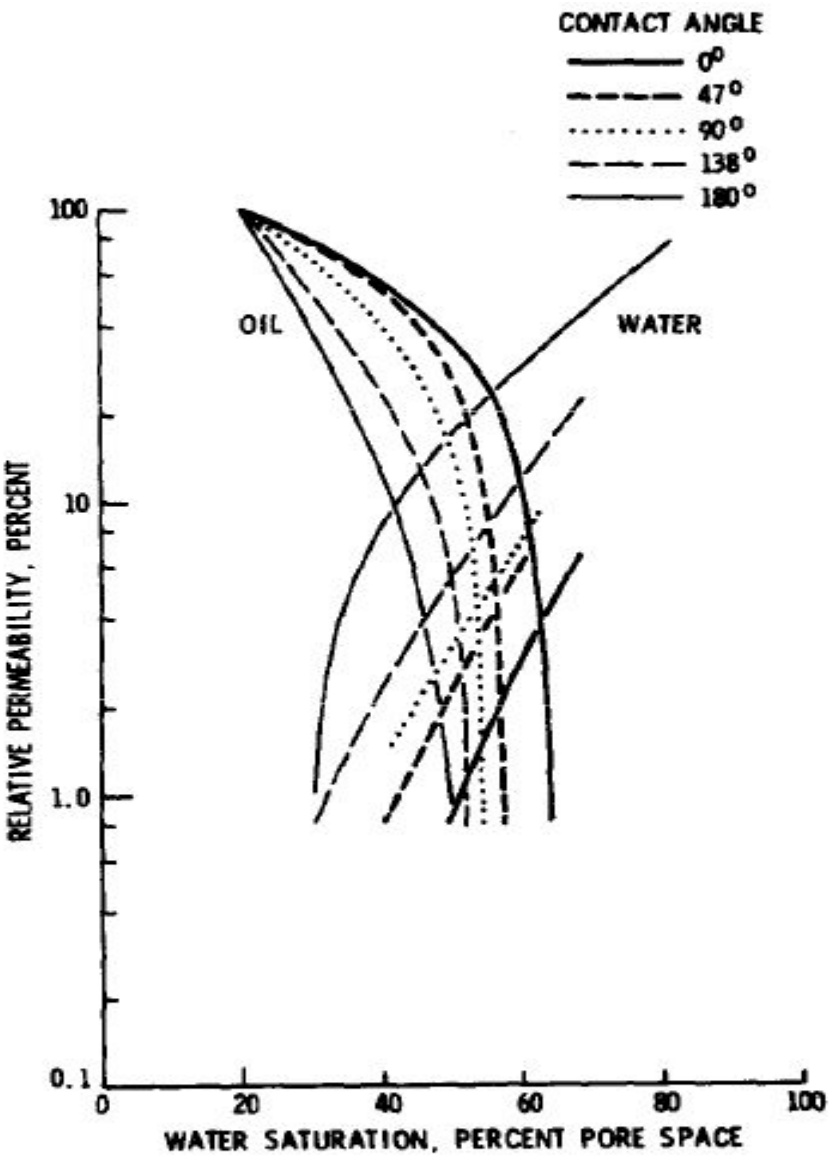


Fig 9.37 Imbibition relative permeabilities for range of wetting conditions, Torpedo sandstone.[130]

Erle et. al. studied the effect of three types additives, using one additive that did not affect the interracial tension (sodium tripolyphosphate), one additive that had a slight effect on the interfacial tension (8.5 pH brine), and one additive that lowered the interfacial tension (a detergent).

The oil and water relative permeability was not affected by a change in viscosity. K_{ro} and k_{rw} curves can be affected individually by additives that change the wettability of the oil-brine-rock system. Sodium tripolyphosphate affected only the kro, dilute NaOH affected only the krw curve, and detergent affected both curves.[131]

Different water-oil relative permeability assigned in order to make a comparison in waterflooding and nanoflooding, associated with the porosity and permeability reduction, as shown in Table 9.12.

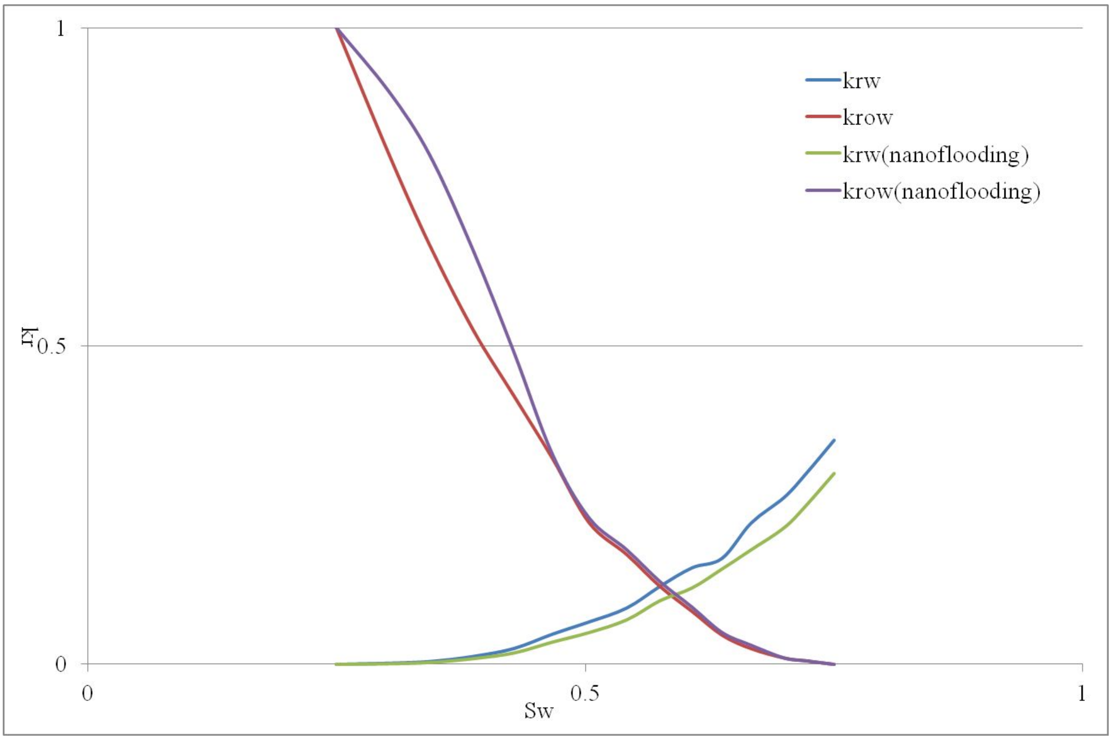


Fig 9.38 Relative permeability for waterflooding and nanoflooding

Homogeneous model

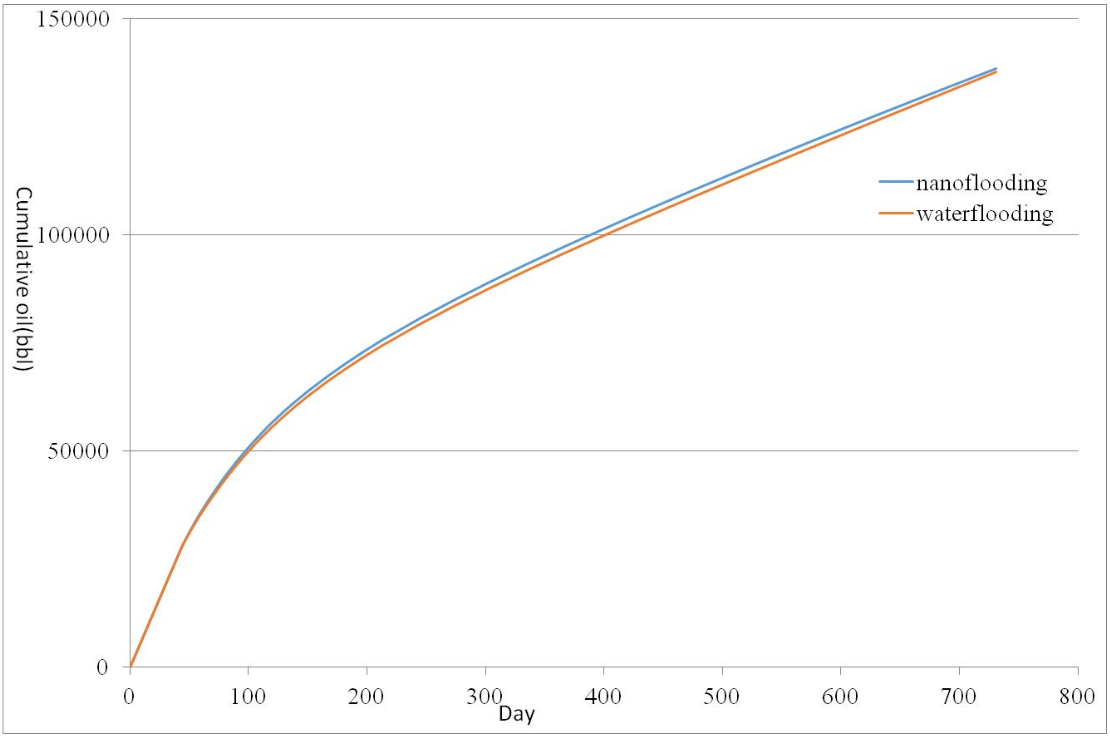


Fig 9. 39 Cumulative oil production waterflooding vs. nanofluids

Heterogeneous system

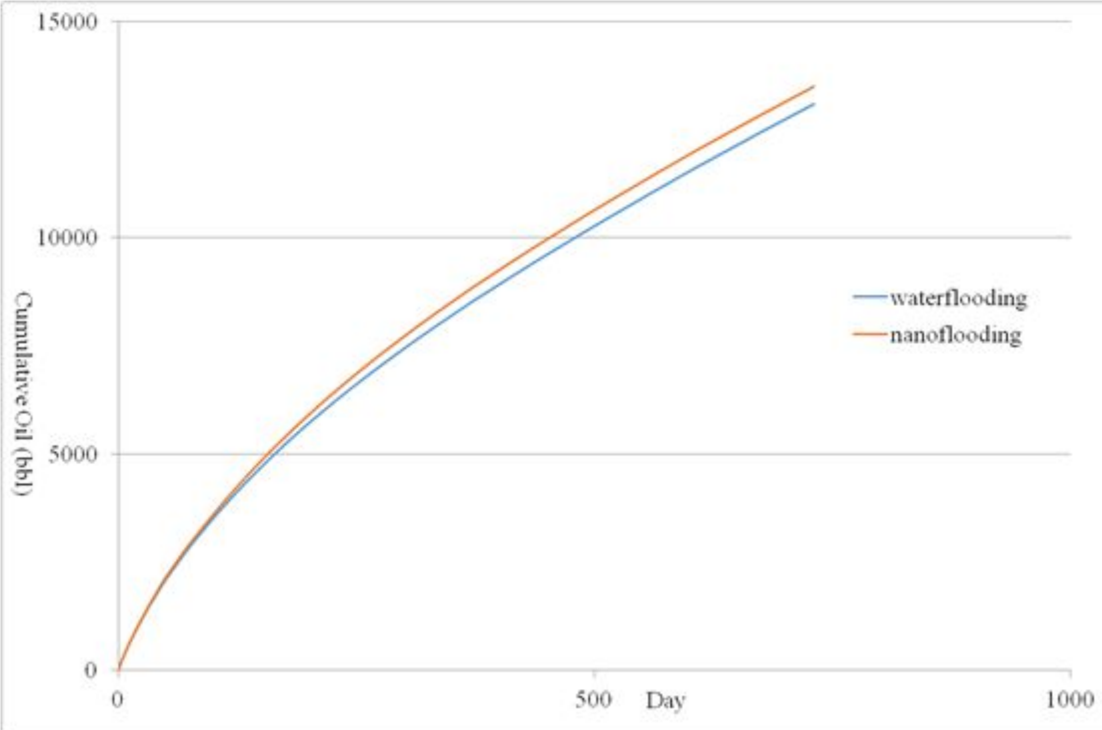


Fig 9.40 Cumulative oil production waterflooding vs. nanofluids

The nanoflooding has a potential to increase the oil production in tight oil reservoir, as shown in above figures.

There are several studies on nanoflooding EOR trial. Compare to brine flooding into water-wet Bereat sandstone, the performance of nanofluids flooding as secondary mode is much better than as tertiary mode, nanofluids can increase recovery about 4-5% compared to brine flooding.[95,96,97,98]

Pros and cons

Waterflooding is applicable over a wide range of reservoir conditions, also it introduces new operational problems such as water treatment, corrosion control, water handling, sand production, water-oil ratio control, waste water disposal and hydrogen sulphide problems, which can be solved by early identification, analysis and treatment.[132]

Except for weak permeability and porosity reduction caused by nanofluids, there are also some concerns related to nanotechnology.

Airborne particles associated with engineered nanomaterials are of particular concern, as they can readily enter the body through inhalation. Although current data are insufficient to provide definitive strategies for working safely with engineered nanomaterials, they do point towards the need to approach these materials with caution.[133]

Reduction of adverse effects that result from normal operating conditions could be done through effective occupational and environmental management practices, the concerns could be acceptable by improvement of understanding in nanotechnology.

Dual porosity

Instead of comparison between nanoflooding and waterflooding, various injector bottom hole pressure were investigated to represent cocurrent and countercurrent flow.

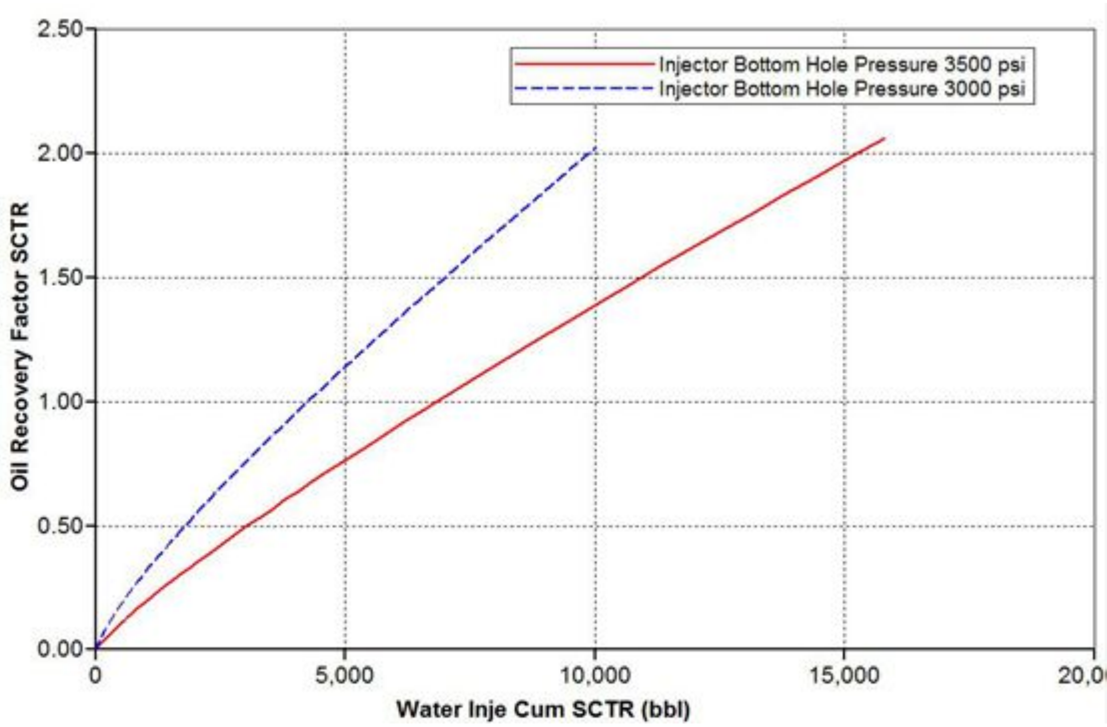


Fig 9.41 various injection rate

As shown in Fig 9.41, in fractured reservoir, during low injection rate more time is allowed for spontaneous imbibition to occur before water breakthrough. Therefore, breakthrough recovery is higher for lower injection rates, which consistent with the experiment work done by Ole et al.[101]

As shown in Fig 9.42, the matrix function as storage of oil, and fractures act as flow channel, reduction of interfacial tension can play a significant role in improving final recovery in fractured system, due to increased gravity effects, which in turn, change process from capillary countercurrent flow to gravity driven cocurrent flow.[101]

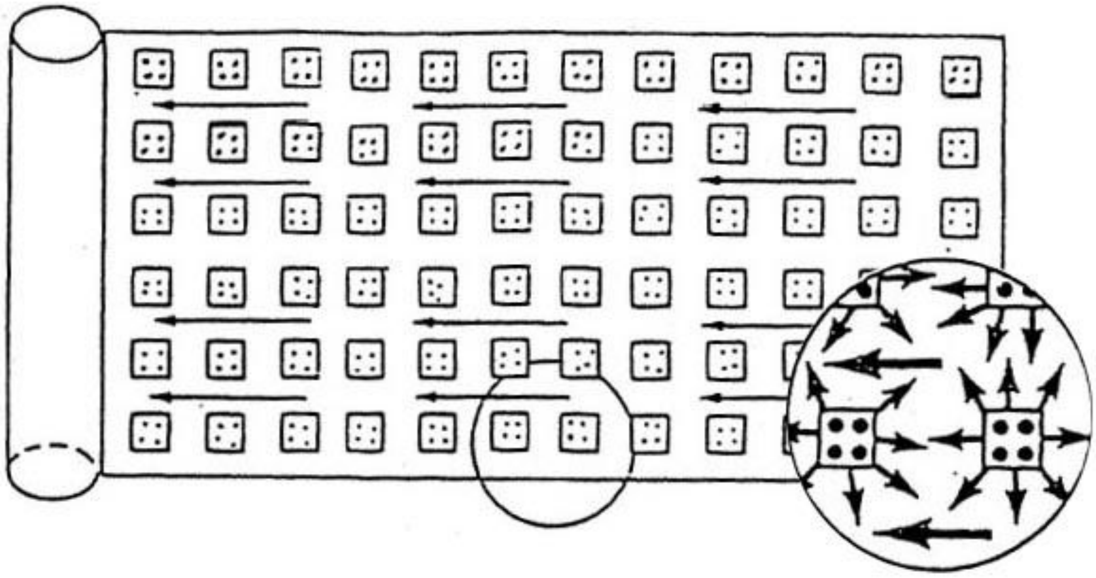


Fig 9.42 Matrix-fracture fluid exchange during the flow toward the well[134]

The inverse Bond number, N_B^{-1} for showing the relative importance of gravity to capillary forces, as expressed in the following equation:[101]

$$N_B^{-1} = C\frac{\sigma\sqrt{\phi / k}}{\Delta\rho g H} \tag{9.2}$$

Where C is constant for the capillary tube model, $\Delta\rho$ is the density difference between oil and water (kg/m^3), σ is interfacial tension(IFT) (N/m), g is gravity (m/s2), ϕ is porosity (fraction), k is permeability (m^2) and H is the height of the medium (m).

If N_B^{-1} is reduced by decreased IFT, gravity forces become more important. As IFT is reduced, there is a transition from countercurrent capillary dominated flow to cocurrent gravity-driven flow during an imbibition process.[101]

Nanoflooding in the reduction of interfacial tension could contribute to cocurrent flow in dual porosity system, results in higher recovery.

9.6 Weakness of the simulations

For single porosity model, the rock compaction was set to be constant at all time, however, it will change during reservoir depletion. When run the simulation to compare the waterflooding and nanoflooding, the properties and relative permeability curve for nanofluids were modified according to the experiments done by several researchers and findings by Owens, the lack of relative permeability curve for nanoflooding in tight oil core sample from experiments will cause inaccuracy in some degree.

Reservoir simulation of WAG injection is very challenging because a representative three-phase saturation model is required to predict relative permeability and capillary pressure as water and gas saturations increase and decrease alternately.[135] In the simulations, constant bubble point pressure was assigned to all grid blocks, which may bring inaccuracy in some degree. In WAG process, as we inject gas into the undersaturated oil, and at the same time produce the reservoir at a higher reservoir rate, oil pressure is decreasing and bubble point pressure is increasing.

Each grid blocks was assigned with same size in the simulation, which may also bring some inaccuracy in some degree, variable flow area do occur for fluids flow through porous media in tight oil reservoir.

The simulation of a fracture as a rectangular wedge is just a approximate assumption, the field case is quite complex and variable to simulate exactly.[136,137] Lin etc. proposed that fracture geometry should take into consideration in simulating fractures, especially for high conductivity fractures.[138] Rock properties with low surface hardness, high clay content, low modulus, high creep, and high rock/fluid interaction are problematic for developing a sustained fracture conductivity, which is not exactly take care of in the simulation.[139]

For dual porosity model, the naturally fractures maybe not uniformly distributed, and the naturally fracture may dilate in stimulation process, also the productivity of naturally fractures may change during reservoir depletion. Capillary continuity, and reinfiltration should take into consideration, which helps to improve the accuracy of dual porosity simulation.[140]

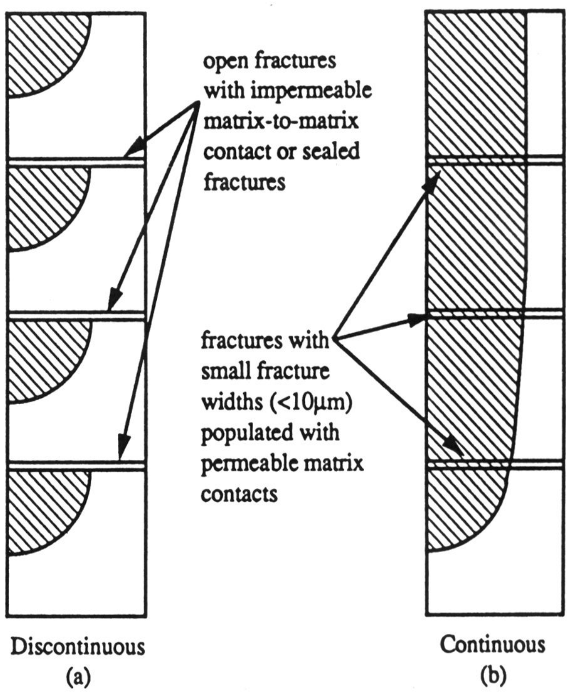


Fig 9.43 Effect of vertical capillary continuity on saturation distribution[140]

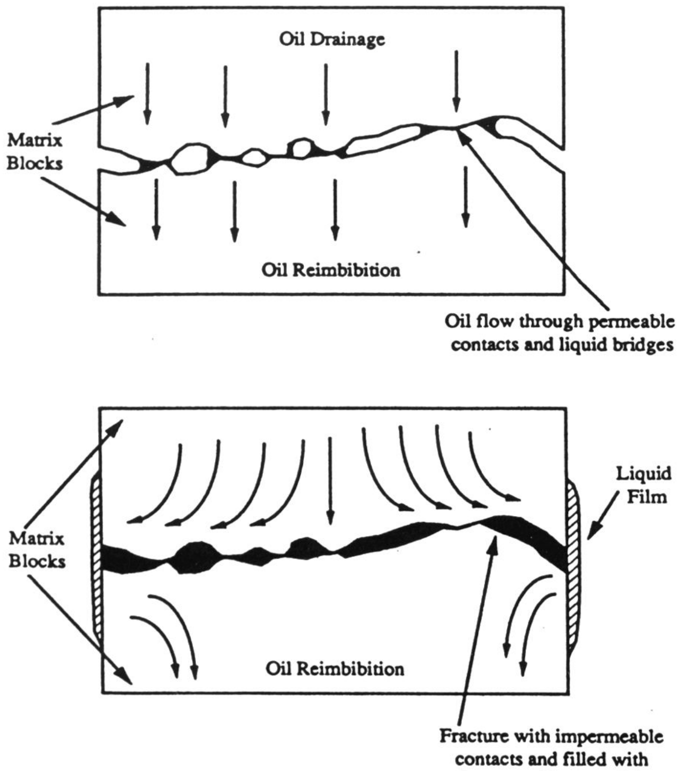


Fig 9.44 Reinfiltration of fluids from higher to lower matrix blocks[140]

10. Recommendation

Every tight oil reservoir is unique, the stimulation process and field development should be determined based on its individual petrophysical attributes.[15] Based on the research done, several ideas were proposed as potential technologies in tight oil E&P, which have potential to deliver more environmental friendly and cost effect solutions.

Exploration

The functionalization of nanodiamond, integration into the PDC matrix shows potential for considerably performance benefits over traditional PDC systems.[63] The nanoparticles based drilling fluid could generate an ultra-thin, tight and relatively impenetrable mud cake deposited on the borehole wall, in addition, nanoparticles could also posses the relative small porous space to block throats and interact with the clay particles, minimize fluid invasion into shale formation hence increased borehole stability. Also the addition of nanoparticles did not raise the mud weight, so they could also used as bridging agent without increasing the solid content of fluid, which could helps a lot in drilling in high angle wells, horizontal and directional wells.[65] Nanoemulsion technology can provide ultralow oil/water interfacial tension (IFT) then improve oil-removal efficiency in cuttings treatment.[66]

Nanomaterials combined with smart fluids can be used as extremely sensitive sensors for pressure, temperature, and stress down hole under harsh conditions.[64] Nano-computerized tomography(CT) can image tight gas sands, tight shales, and tight carbonates in which the pore structure is below what micro-CT can detect.[62] The nanometer-scale particles associate with viscoelastic surfactant fluids help to reduce the rate of fluid loss and improves fluid efficiency.[70]

Nanomaterials could enter the interstitial areas and other areas of high porosity in the cement, therefore, less permeable structure could be formed, which resulted in improving the properties of the resulting cement.[71,19] Addition of 0.1 wt% of MgO and SiO_2 Nanoparticles reduced fines migration by 15% compared with the reference state.[73]

Membranes designed with nanoscale precision provide full control over what flows through, which could make the industry considerably greener.[76]

Novel Stimulation

The conductivity of propped fractures within the Bakken shale appears to be a function of a variety of factors, including proppant and rock strength, as well as formation embedment and spalling.[141] Tight oil plays generally require larger grades of proppant(20/40 and 30/50) than gas plays.[142]

Evolution of reservoir stimulation technique, such as fracturing fluid systems and proppant types is vital for tight oil development.

Table 10.1 and 10.2 summarized the various fracturing technologies and proppant types applied in US.

Table 10.1 Technical classification system for Frac Treatment Types[142]

Frac type	Definition
Conventional	Using a gelling agent and one or more crosslinkers in order to transport proppant into a hydraulic fracture
Water Frac	Using a friction reducer, a gelling agent or a viscoelastic surfactant in order to transport proppant into a hydraulic fracture
Hybrid	Using a combination of a friction reducer, gelling agent, acid gelling, or one or more crosslinkers in order to transport proppant into a hydraulic fracture
Energized	Incorporating an energizer, normally nitrogen or carbon dioxide, into the base fluid in order to generate foam that transports proppant into a hydraulic fracture
Other/Unknown	Treatment type category includes: Acid Frac, Gas Frac, Matrix Acidizing, as well as a classification was unknown or unavailable, generally due to incomplete data

Hybrid frac treatments have accounted for the majority of horizontal wells treated since late 2011 in US, also hybrid fracturing technique and different materials (70/100-, 40/70-, and 20/40- mesh proppants; slickwater; and linear or crosslinked gels) have been implemented to stimulate tight oil reservoirs in the Changqing field, which yield a post-fracture production increase of 300% compared with traditional fracturing treatments.[143] However, conventional fracture designs appear to maintain roughly 30% share in Bakken tight oil plays.

Table 10.2 Proppant Type Definitions[142]

Proppant Type	Definition
Sand	Includes all raw frac sand types, including Northern White, Ottawa, Brady, Brown Sand, Texas Gold, etc.
Resin-Coated Sand	Includes only resin-coated proppants for which the substrate is sand. This catogary does not include any double-counting with the Sand category described above
Ceramic	Any proppant for which the substrate is a ceramic or otherwise manufactured proppant, resin-coated ceramic proppant is included in this category

A huge amount of ceramic proppant used in Bakken wells, also some operators shift to lower cost proppants, such as sand and resin-coated sand.[142]

In case naturally fractures exist in reservoir, Dennis et al studied the effect of cemented natural fractures on hydraulic fracture propagation, bypass, separation of weakly bonded interfaces, diversion, and mixed-mode propagation are likely in hydraulic-fracture intersections with cemented natural fractures. As hydraulic-fracture height/natural-fracture height (HHF/HNF) decreases, the likelihood of fracture diversion increases. As HHF/HNF increases, the likelihood of fracture bypass increases.[144]

Unconventional fracturing technology is highly recommended in tight formations. Formations with subirreducible water saturation can be stimulated with fluids that minimize the interfacial tension (such as surfactant gels), minimize the amount of water used in the fluid (such as energized or foamed fluids), dehydrate the formation (such as alcohol based fluids) or completely eliminate water (such as hydrocarbon based or liquid carbon dioxide based fluids), which varies with reservoir characteristics.[145] Channel fracturing technology is applicable and valuable for low permeability mature oilfield with properly design.[42] A microemulsion additive made with biodegrade solvent/surfant/cosolvent and water performs better than conventional surfactant and methanol treatments during fracture cleanup, which results in lower pressures to displace injected fluids from low permeability core samples.[146]

Less than 50% of the fracturing fluid is recovered during cleanup, associated with invasion into matrix, results in decreased production. Gelled LPG used in hydraulic fracture demonstrated quick and complete fracture fluid recovery, longer effective fracture half length, elimination of liquid block in the invaded zone, superior production.[147]

Self-suspending proppant(SSP) technology offers a promising alternative to the proppant systems in hydraulic fracturing applications. Conventional proppant particles are encapsulated with a thin layer of a high-molecular-weight hydrogel polymer, and then dried to form SSP system, result in better placement of proppant in the fracture, leading to lower water injection requirements, lower proppant usage, and improved well productivity.[148]

Thermoplastic alloy lightweight proppant (TPA-LWP) used to stimulate Pictured Cliffs formation, result in high porosity fractures with sustainability of conductivity, the average amount of proppant pumped in four horizontal wells was 14 lbm/ft; whereas, it was 720 lbm/ft in the five wells stimulated with conventional 20/40-mesh proppant.[149]

Persistent Interfacial Tension Management fluid cooperate with high conductivity proppants contribute to improve well performance.[150]

Exploitation

Huge amount of water needed in the development of tight oil reservoir, produced water reinjection is highly recommended especially in areas where water resource is rare. Produced water reinjection is viable only in a fractured regime, pressure and water quality in terms of optimum total-suspended-solid (TSS) and oil-in-water (OIW) contents needed take care for long term efficiency of this regime, since produced water reinjection in matrix (or radial injection) regimes inexorably leads to a continuous decline of injectivity. Several methods help to design produced water reinjection, the first approach is based on analogs and correlation laws, the second is based on laboratory experiments, and the third uses simulations with predictive models.[151]

The rate of oil recovery in tight oil reservoir increases with increasing fracture density, decreasing oil viscosity and increasing wettability alteration.[2]

Productivity of near wellbore fracture region highly depends on the propped contact area with high reservoir quality rock and the long term retention of fracture conductivity and fracture face permeability, which requires height-growth containment to maximize surface area in contact with the reservoir, fracture width control (flow rate, viscosity, and fracture pressure) to extend the region of moderate fracture complexity, nonhomogeneous proppant distribution to minimize retention of solids from the far field, and limited loss of fracture-face permeability.

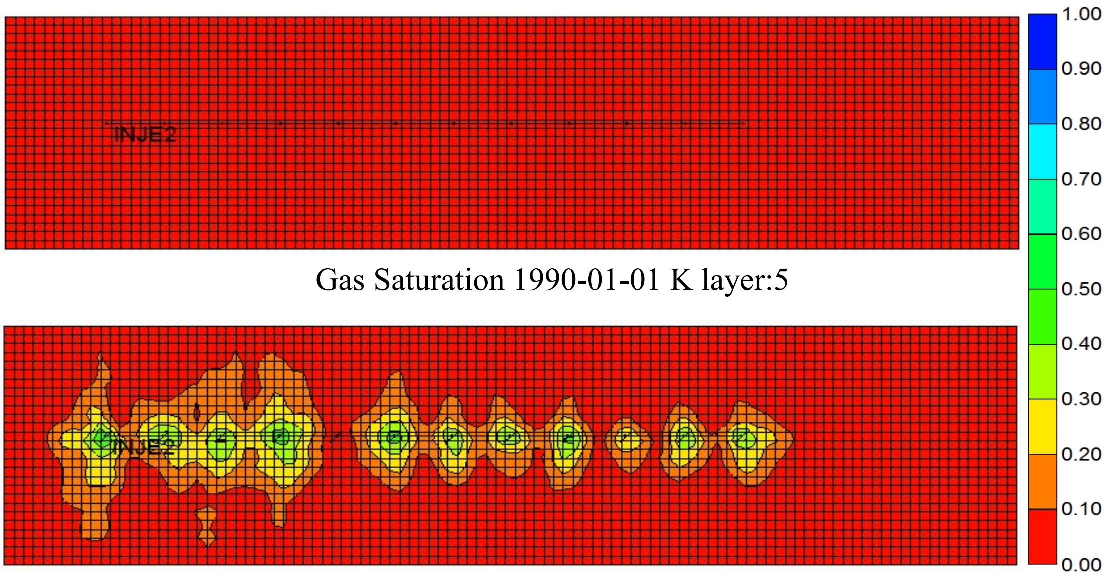
Productivity of the far wellbore fracture region depends on proppant placement and retention of fracture conductivity during flowback and early production.

Despite wellbore is not a region of fracturing, its placement and completion configuration has a tremendous effect in the development of the other regions. In particular, it has a controlling effect on the evolution and geometry of the connector region.[139]

Refracturing of horizontal wells is a competitive mean to keep facility utilization high and offer a viable alternative to drilling new wells[32] Also produced water re-injection after treatment into tight reservoir is economically viable[52]

CO_2 foam (stabilized with surfactant or nanoparticles):

CO_2 injection suffers from viscous fingering, gravity override, and channeling of CO_2 in heterogeneous formations and the inefficient displacement of oil in below-miscibility-pressure reservoirs because of the unfavorable CO_2 mobility.



Gas Saturation 1990-01-01 K layer:5

Gas Saturation 2000-01-01 K layer:5

Fig 10.1 Gas saturation profile during CO_2 injection

It has been shown in lab and modeling studies that CO_2 foam stabilized with CO_2 soluble surfactants has exhibited economical and technical advantages in effective control of CO_2 mobility in porous media [152] In fractured core plugs, the injection of CO_2-foam accelerated oil recovery compared to pure CO_2 injection by adding a viscous displacement in addition to diffusion.[153]. CO_2 foam field trials conducted by Hoefner et al, which resulted in a significant reduction in gas production and indications of increased oil production.[154] Also later CO_2 breakthrough can be seen in the CO_2 foam injection compare to CO_2 flooding. Because Foam decreases CO_2 relative permeability and increases its viscosity, increases the contact time between CO_2 and the rock matrix in fractured reservoirs.[155]

Surfactant injected into CO_2 phase directly after a water cycle, the CO_2 injectivity decreased by more than 50% compared to CO_2 injection alone.[156] Higher surfactant concentration for CO_2 foam resulted in greater CO_2 viscosity, but the optimum value should be formulated in the further design for cost effective CO_2 foam EOR process.[155] CO_2 foam could be a solution to recovery tight oil, for CO_2 foam injection to be effective, the history matched model to forecast development was necessary, also the foam behavior.[156] In addition, nanoparticles applied to stabilize CO_2 foam may overcome the long term instability and surfactant adsorption loss issue.[116]

Air injection:

Air combines the benefits of low cost and universal accessibility. When air injected into reservoir, low temperature oxidation(LTO) may occur at reservoir temperature, and in some cases, the heat generated can initiate the in-situ combustion(ISC) process.[157] Laboratory experiments were conducted by Fassihi et al. to study the effect of LTO (< 450°F) on crude oil properties, which resulted in increasing both oil viscosity and density, for light oil, these increases were minor and should have insignificant effects on process performance, also CO_2 was the gaseous product of the LTO reactions.[158] As the flue gas(typically 85% of N2, 13% of CO_2, 2% of CO) generated in air injection process, it contribute to a higher oil recovery in several cases.[159,160,161]

Hughe et al. proposed that formation depth should be more than 1000m, thickness ranges from 1 to 20m, and permeability is between 0.1 md and 1000md after the research in light oil reservoir, the Cooper-Eromanga Basin, Carnarvon Basin (Barrow Island) and the Surat-Bowen Basin.[162] Research of air injection in low-permeability reservoirs(permeability ranges from 0.2 to 1md, average permeability 0.6 md) by Jiang et al. shown that air injection, which can effectively maintain reservoir pressure, help to build effective pressure displacement system much easier than water injection since air intake capacity is far greater than water intake capacity in low permeability reservoirs, also LTO reaction cause CO_2 and N_2 drive and temperature increase, which improve production performance.[160] The air injection is recommended in the tight oil development in some degree on the basis of the injected oxygen consumed in the reservoir before reaching producers.

NAG

Waterflooding can be ineffective for unfavorable (i.e., mixed- to oil-wet) matrix wettability when naturally fractures exist. Fractures increase the exposure of the injected gas to oil in reservoir rock, which renders gas/oil gravity drainage more effective than it is in unfractured reservoirs. WAG flooding combines the merits of the two injection fluids on macroscopic and microscopic scales while stabilizing the injection front, delaying breakthroughs, and, therefore, leading to increased oil recovery compared with continuous water or gas injection.[135]

It has been shown that changing a well from water to CO_2 after a prolonged water cycle can lead to a short-lived increase in production.[163] Also nanofluids can increase recovery about 4-5% compared to brine flooding in water-wet Bereat sandstone because of the wettability and interfacial tension alternation.[95,96,97,98] The lab work shown the benefits of complex nanofluids additives in improving fracture half length and relative permeability to hydrocarbon.[164] The field trial of complex nanofluids based foam treatment alternate CO_2 injection resulted in low CO_2 production and better oil recovery.[165]

Based on the work presented in the thesis, the nanofluids seems a good substitute to water, the WAG process performs better than either waterflooding or gas injection, the nanofluids alternating gas(NAG) is recommended in tight oil development.

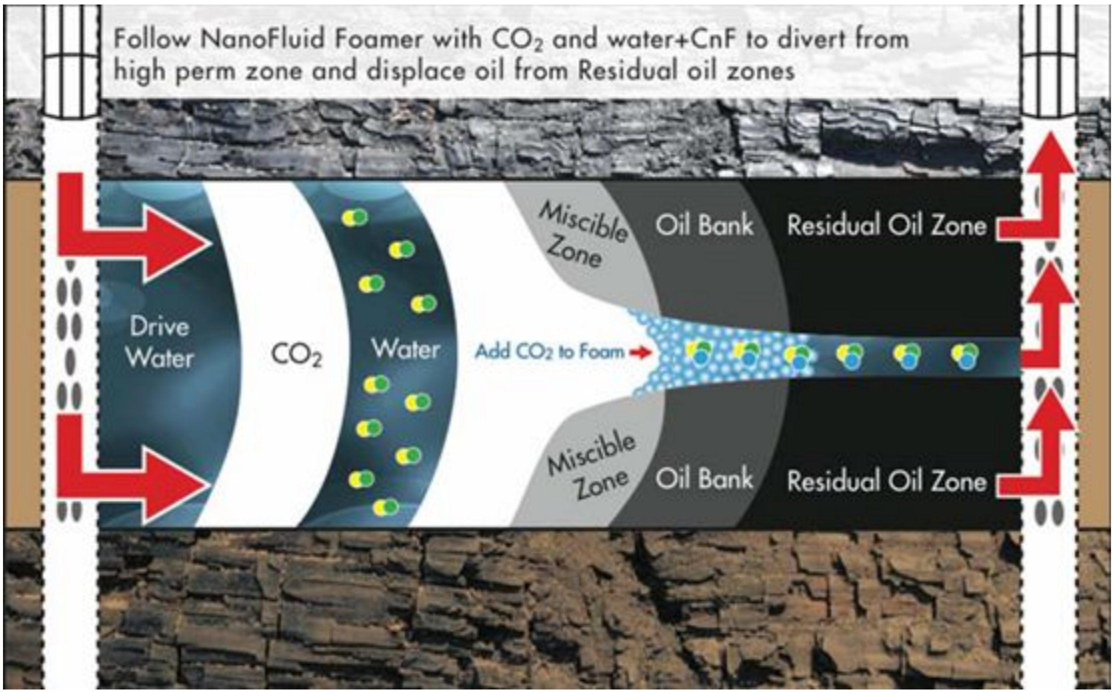


Fig 10.2 CO_2 WAG conformance Source: CESI CHEMICAL[165]

Besides above recommendations, the advanced knowledge in tight oil E&P need to be emphasis in real-time measurement; post-fracture monitoring with production analysis; identifying sweet spots, then placing perforations to create complex conductive fractures; innovative proppants and proppant-placement techniques in primary and complex fracture geometries; fluid recovery; formation-damage control and permeability enhancement; proppant transport with less-damaging stimulation fluids; and environmentally responsible drilling, completion, and production services.[7]

11. Conclusion

1. Nanotechnology has a bright future in tight oil E&P phase in both economic and environmental aspects.

2. Capillary pressure plays more on oil recovery as tight oil reservoir heterogeneity increase.

3. A higher oil rate could be seen in tight oil production when hysteresis phenomenon is taken into consideration.

4. WAG injection tends to be an excellent process to recover tight oil and it performs better in the middle of target formation.

5. Recovery speeds up with decreasing WAG cycle length.

6. Lower gas injection rate initially in WAG process design contribute to a higher recovery factor.

7. Low water injection rate initially in naturally fractured system contribute to co-current flow, which results in higher oil recovery.

8. CO_2 foam stabilized with surfactant or nanoparticles, air injection (low temperature oxidation), nanofluids alternating gas (NAG) are highly recommended in tight oil development.

12. Future work

Optimum value for the number of fractures per well should be investigated. In this case, the understanding of permeability distribution is paramount for optimum well completion design and cost optimization.[136]

Productivity in hydraulic fractures depends on long term mechanical stability and is independent of reservoir quality. Competent rock with high surface hardness, low time dependence (low creep), and low softening associated with rock/fluid interactions helps to maintain fracture conductivity.[139] Fractures geometry needed take into consideration in simulating fractures.

Experimental work could be done in tight oil core sample to test CO_2 foam, air injection process, and nanofluids with weight concentration in the range of 0.01% to 0.1%[95,96,97,98] alternating gas (NAG), then a tight oil reservoir model with field data should be created and verified through history matching to further confirm the results from experimental works.

Economic model should link to the proposed technologies, contribute to a better perspective in the pros and cons of these ideas.

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