RESERVOIR CHARACTERISATON AND STIMULATION FOR CONVENTIONAL AND UNCONVENTIONAL RESERVOIRS

DISSERTATION REPORT

Submitted By

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Under the guidance of

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April - 2016

DECLARATION

I hereby declare that this submission is my own and that, to the best of my knowledge and belief, it contains no material previously published or written by another person nor material which has been accepted for the award of any other Degree or Diploma of the University or other Institute of Higher learning, except where due acknowledgement has been made in the text.

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Certificate

This is to certify that Mr. Shashank Lele, a student of M.Tech. Petroleum Exploration, Sem-IV, University of Petroleum and Energy Studies, Dehradun, has successfully completed his dissertation work on topic ***"RESERVOIR CHARACTERISATON AND STIMULATION FOR CONVENTIONAL AND UNCONVENTIONAL RESERVOIRS"*** from 18th January, 2016 to 25th April, 2016 at Vindhyan Block, Frontier Basin, Oil and Natural Gas Corporation (ONGC), Dehradun. He has been exposed to reservoir engineering practices. During the training he has maintained excellent discipline, punctuality and normal code of conduct.

I wish him all the very best in his future endeavours.

Date: - 25th April, 2016

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CERTIFICATE

This is to certify that the project on **RESERVOIR CHARACTERISATON AND STIMULATION FOR CONVENTIONAL AND UNCONVENTIONAL RESERVOIRS** submitted by **SHASHANK LELE** (R770214019), to the University of Petroleum & Energy Studies, for the award of the degree of **MASTER OF TECHNOLOGY in Petroleum Exploration** is a bonafide record of project work carried out by them under my supervision and guidance. The content of the project, in full or parts have not been submitted to any other Institute or University for the award of any other degree or diploma.

Mentor	Co - Mentor
Dr. Pushpa Sharma	Dr. Mandira Agarwal
Professor	Associate Professor
UPES	UPES

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ABSTRACT

Reservoir Engineering provides an understanding of fluid flow and phase behavior for all fluids contained within the reservoir. Thorough understanding of the reservoir is a must in order to optimize its lifetime performance. Many tools and analysis offer us accurate measurements and characterization of the reservoir rocks and fluids. Initial steps include geology, petrophysics, well testing and well logging and formation evaluation. Formation pressure measurement, downhole fluid sampling and analysis along with laboratory PVT analysis are used to build a picture of reservoir potential and predict future performance.

Reservoirs can broadly be classified into conventional and unconventional reservoirs. The technique to approach each varies greatly from one another. Conventional reservoirs have been subject to extensive research, including the areas of well test analysis, PVT analysis, Enhanced Oil recovery and well logging, to name a few.

Present study deals with the hydrocarbon bearing formations of a type area in Frontier Basin. These fields are characterized by very low porosity, ultra-low permeability and low reservoir pressure. However, large areas of the field have been found to be charged with gas with high calorific value. The area is also characterized by naturally occurring fractures which aid in flow from reservoir to wellbore.

Considerable research is devoted to approaches and methods to commercially exploit gas from these reservoirs. Tools like V_P/V_S analysis, Horner's plot, Permeability Jail, analysis of relative permeability, water and gas saturation enable us to think of effectively extracting gas from these kinds of reservoirs. Efforts are made to design the well trajectory along the naturally occurring fractures identified using Fracture Analysis. Periodic stimulation of the wells is integral to ensure optimal performance. Such techniques include hydrofracking, acid fracturing, matrix acidization, radial jet drilling and GasGun technology. Case studies and worldwide examples involving use of such techniques have been dealt with in detail, in this report.

Present study is a treatise on the same. Outcome of the study will be helpful to ascertain the flow potential from the field.

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1. PREFACE

Oil and Natural Gas Corporation Limited (**ONGC**) is an Indian state-owned Oil and Gas company headquartered at Dehradun, India and contributes 69% of India's crude oil production and 62% of India's natural gas production. It is one of the Asia's largest and most active company involved in exploration and production of oil.

ONGC is the flagship company of India at present and in making this possible is a dedicated team of nearly 33,000 professionals with over 18,000 technically-competent experienced scientists and engineers which includes geologists, geophysicists, geochemists, drilling engineers, reservoir engineers, petroleum engineers, production engineers, engineering & technical service providers, financial and human resource experts and IT professionals.

ONGC has a unique distinction of being a company with in-house service capabilities in all the activity areas of exploration and production of oil & gas and related oil-field services. The company has adopted progressive policies in scientific planning, acquisition, utilization, training and motivation of the team.

Frontier Basin, Dehradun deals in Category III & IV sedimentary basins in India. These basins are generally poorly explored, logistically difficult, have diverse tectonic set-up and involve high risk & uncertain reward. Exploration in these basins is both- cost and technology intensive. Out of the seventeen onland frontiers in India, Frontier Basin is currently operating in three of them, viz. Himalayan Foothills, Rajasthan and Vindhyan, geographically spread over five states- Himachal Pradesh, Uttar Pradesh, Bihar, Madhya Pradesh and Rajasthan.

The topic was selected keeping in view the ongoing activities at Vindhyan Basin, dealing largely with tight gas reservoirs. This is a little explored and challenging area of study. Real reservoir characteristics were studied to pave way for better future characterization.

2. INTRODUCTION

A reservoir is formed of one or more subsurface rock formations of sedimentary origins containing liquid and gaseous hydrocarbons. It is essential that a good reservoir be porous and permeable and the structure is bounded by impermeable barriers which trap the hydrocarbons. Thus the study of reservoir engineering is important.

The objective of reservoir engineering is optimization. To obtain optimum profit from a field the engineer or the engineering team must identify and define all individual reservoirs and their physical properties, deduce each reservoir's performance, prevent drilling of unnecessary wells, initiate operating controls at the proper time, and consider all important economic factors, including income taxes. Early and accurate identification and definition of the reservoir system is essential for effective engineering. Conventional geologic techniques seldom provide sufficient data to identify and define each individual reservoir; the engineer must supplement the geologic study with engineering data and tests to provide the necessary information.

The goal of reservoir engineering, starting with the discovery of a productive reservoir is to set up a development project to optimize the hydrocarbon recovery. Primary applications of reservoir engineering include estimation of the hydrocarbon reserves in place along with recoverable reserves, well production potential, and calculation of a recovery factor and the association of a time scale to this recovery.

Reservoir specialists continue to study the reservoir throughout the life of the reservoir to derive the information required for the optimal production from the reservoir.

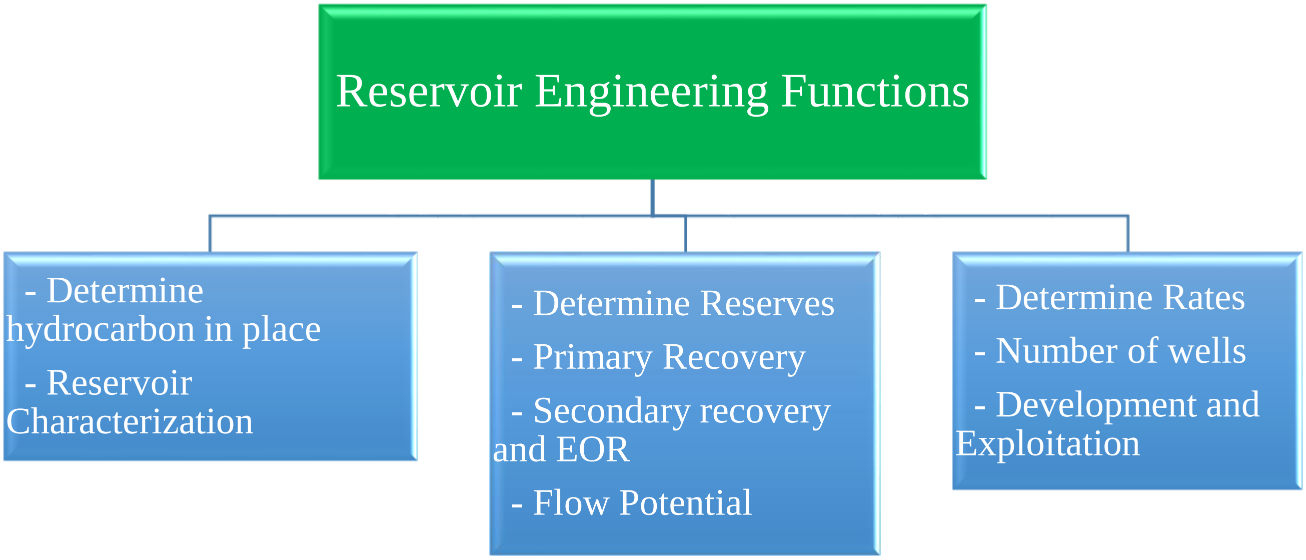


Figure 1: Reservoir Engineering Functions

Petroleum reservoirs are broadly classified as oil or gas reservoirs. This is a broad classification and these are further subdivided depending upon:

- Nature of reservoirs
- Initial reservoir Pressure and Temperature
- Composition of reservoir fluid

Based on reservoir properties, these reservoirs are characterized as conventional or unconventional reservoirs.

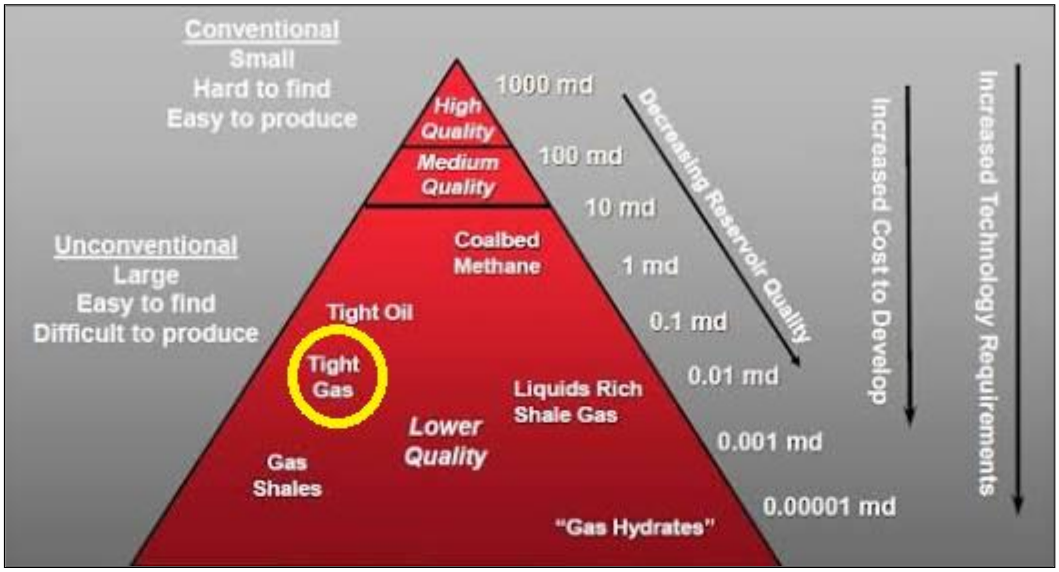


Figure 2: The Resource Triangle

Conventional reservoirs are those that can be produced at economic flow rates and that will produce economic volumes of oil and gas without large stimulation treatments or any special recovery process. An unconventional reservoir is one that cannot be produced at economic flow rates or that does not produce economic volumes of oil and gas without assistance from massive stimulation treatments or special recovery processes and technologies, such as steam injection. Typical unconventional reservoirs are tight-gas sands, coal-bed methane, heavy oil, and gas shales. Unlike conventional reservoirs, which are small in volume but easy to develop, unconventional reservoirs are large in volume but difficult to develop. Increasing price and the improved technology are the key to their development and the future. Unconventional resources are probably very large, but their character and distribution are not yet well understood. It is known to exist in large quantity but does not flow easily toward existing wells for economic recovery.

3. CONVENTIONAL RESERVOIRS

A conventional reservoir is defined as a reservoir in which buoyant forces keep hydrocarbons in place below a sealing caprock. Reservoir and fluid characteristics of conventional reservoirs typically permit oil or natural gas to flow readily into wellbores. The term is used to make a distinction from shale and other unconventional reservoirs, in which gas might be distributed throughout the reservoir at the basin scale, and in which buoyant forces or the influence of a water column on the location of hydrocarbons within the reservoir are not significant.

3.1 Recovery

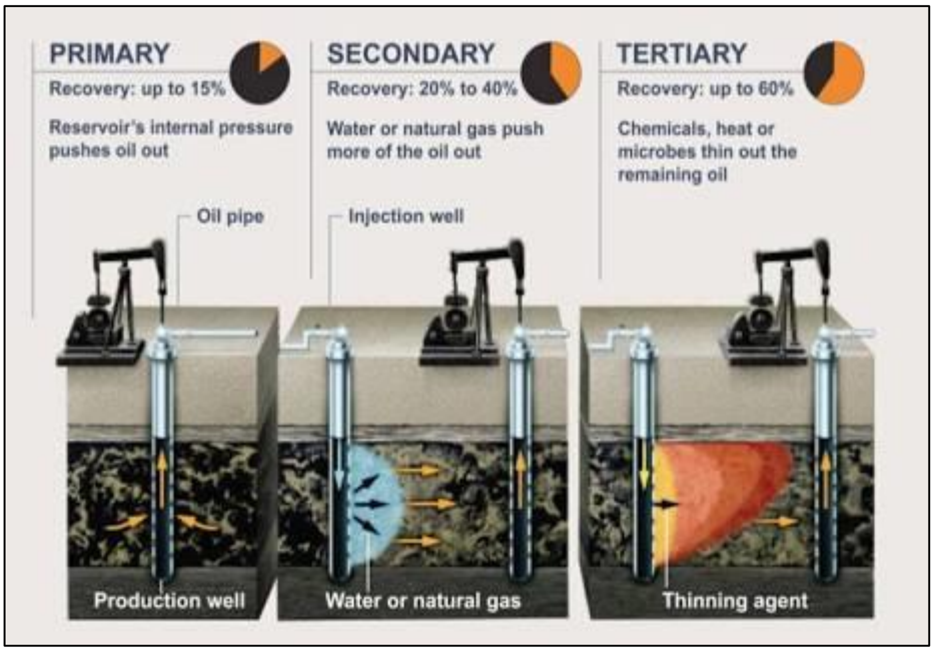


Figure 3: Types of recovery [16]

3.1.1 Primary Recovery

Oil recovery processes have been divided into three stages: primary, secondary and tertiary. Primary production is the result of natural displacement energy existing in the reservoir. Secondary processes involves maintaining the pressure in the reservoir through injection of water or gas and the last stage uses various chemicals, miscible gases or thermal energy to displace additional oil for better recovery of oil from the reservoir.

During the primary recovery stage, reservoir drive comes from a number of natural mechanisms. These include: natural water displacing oil downward into the well, expansion of the natural at the top of the reservoir, expansion of gas initially dissolved in the crude oil, and gravity drainage resulting from the movement of oil within the reservoir from the upper to the lower parts where the wells are located. Recovery factor during the primary recovery stage is typically 5-15%.

While the underground pressure in the oil reservoir is sufficient to force the oil to the surface all that is necessary is to place a complex arrangement of valves in the well head to connect the well to a pipeline network for storage and processing. Sometimes pumps, such as beam pumps and electrical submersible pumps (ESP), are used to bring the oil to the surface; these are known as artificial lift mechanisms. The mechanisms included are:

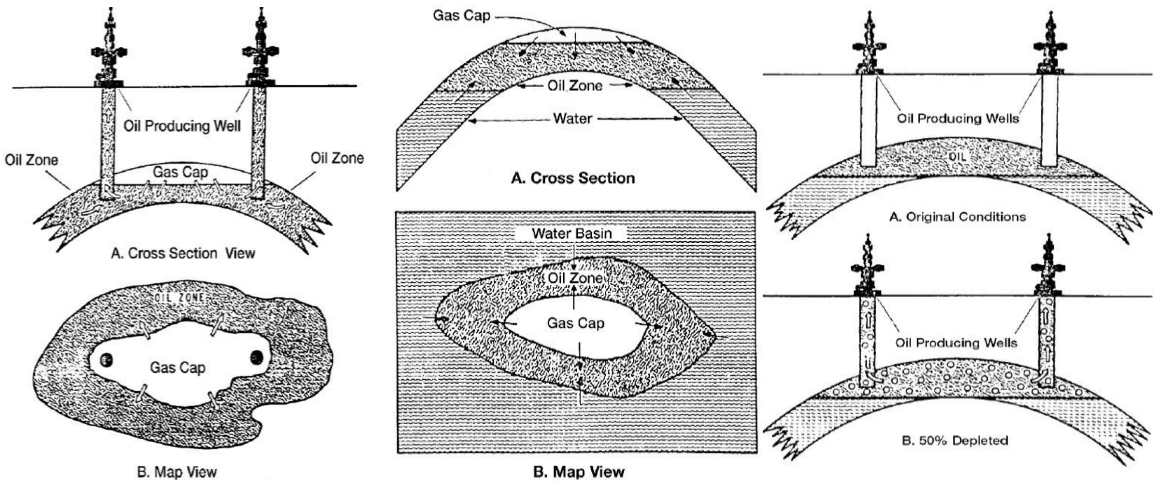


Figure 4: Types of drive mechanisms

Solution Gas drive:

Oil reservoirs that do not initially contain free gas but develop free gas on pressure depletion are classified as solution gas drives. The solution gas drive mechanism applies once the pressure falls below the bubble point. Other producing mechanisms may, and often do, augment the solution gas drive. Solution gas drive reservoir performance is used as a benchmark to compare other producing mechanisms.

Gas Cap drive:

Oil reservoirs are discovered with a segregated gas zone overlying an oil column. The overlying gas zone is referred to as a primary gas cap. In addition to free gas, gas caps usually contain connate water and residual oil. As reservoir pressure declines with production, gas evolves in the reservoir and migrates to the top of the structure to add to an existing primary gas cap or to form a gas cap and hence gas caps can enhance oil recovery considerably.

Natural Water drive:

As pressure decreases during pressure depletion, the compressed waters within the aquifers expand and overflow into the petroleum reservoir. The invading water helps drive the oil to the producing wells, leading to improved oil recoveries. Like gas reinjection and gas cap expansion, water influx also acts to mitigate the pressure decline. The degree to which water influx improves oil recovery depends on the size of the adjoining aquifer, the degree of communication between the aquifer and petroleum reservoir, and ultimately the amount of water that encroaches into the reservoir.

Compaction drive:
If pore volume contraction contributes prominently to overall expansion while the reservoir is saturated, then the reservoir is classified as a compaction drive. Compaction drives characteristically exhibit elevated rock compressibilities, often 10 to 50 times greater than normal. Rock compressibility is called pore volume (PV), or pore, compressibility and is expressed in units of PV change per unit PV per unit pressure change. Rock compressibility is a function of pressure.

Gravity drainage:

The density differences between oil and gas and water result in their natural segregation in the reservoir. This process can be used as a drive mechanism, but is relatively weak, and in practice is only used in combination with other drive mechanisms the best conditions for gravity drainage are:

- Thick oil zones. ·
- High vertical permeability.

The rate of production engendered by gravity drainage is very low compared with the other drive mechanisms examined so far. However, it is extremely efficient over long periods and can give rise to extremely high recoveries (50-70% OOIP). Consequently, it is often used in addition to the other drive mechanisms.

Combination drive:

Most oil reservoirs produce under the influence of two or more reservoir drive mechanisms, referred to collectively as a combination drive. A common example is an oil reservoir with an initial gas cap and an active water drive.

3.1.2 Secondary recovery

Over the lifetime of the well pressure will fall and at some point there will be insufficient underground pressure to force the oil to the surface. After natural reservoir drive diminishes, secondary methods are applied. They rely on the supply of external energy into the reservoir in the form of injecting fluids to increase reservoir pressure, hence replacing or increasing the natural reservoir drive with an artificial drive. Secondary recovery techniques increase the reservoirs pressure by water injection, natural gas reinjection and gas lift, which injects air, carbon dioxide or some other gas into the bottom of an active well, reducing the overall density of fluid in the wellbore. Typical recovery factor from water-flood operations is about 30%, depending on the properties of oil and the characteristics of the reservoir rock. On average, the recovery factor after primary and secondary oil recovery operations is between 35 and 45%.

3.1.3 Tertiary recovery

The way to further increase oil production is through the tertiary recovery methods or EOR. Although more expensive to employ on a field, EOR can increase production from a well to upto 75% recovery The figure belong gives the main types of EOR processes.

Enhanced Oil Recovery (EOR):

Enhanced oil recovery is oil recovery by the injection of materials not normally found in the reservoir. This definition covers all modes of oil recovery processes (drive, push-pull and well treatments) and most oil recovery agents. The definition does not restrict EOR to a particular phase (primary, secondary, tertiary) in the producing life of reservoir. It is the technology to increase oil recovery from porous media which is beyond the reach of conventional means. Conventional oil recovery produces an average of about one third of the original oil in place in the formation. The target of enhanced oil recovery is that large portion of oil that is not recovered by primary and secondary means. Low ROS can be obtained by selecting a recovery fluid that provides a very low interfacial tension between the oil and fluid. With very low interfacial tension the capillary number is large and high sweep efficiency can be obtained by selecting a recovery agent with low mobility or by increasing the mobility of oil. Enhanced oil recovery technologies are also being used for in-situ extraction of organic pollutants from permeable media. In these applications, the extraction is referred to as clean up or remediation and the hydrocarbon as product.

Application of an EOR process in a particular reservoir involves four important steps

- Identification of suitable EOR process
- Laboratories study
- Pilot testing
- Commercialization

Selection of the appropriate EOR process is the single most crucial factor for success of any EOR project. Each process has its specific application as they not only depend upon reservoir rock and fluid properties but also on past production history.

Crude oil recovery by EOR processes is rather difficult and high risk operation and its success is affected by a various factors. The major problem faced by engineers is to identify all the EOR processes applicable to candidate reservoir or check the suitability of particular process in the light of all information available about reservoir under study. This leads to crucial need for experts in this area of EOR process selection.

Wide varieties of processes have been considered for enhanced oil recovery and they are:

- Chemical EOR
- Thermal EOR

- EOR with Gas Injection
  - (a) Miscible EOR
  - (b) Immiscible EOR
- Microbial EOR

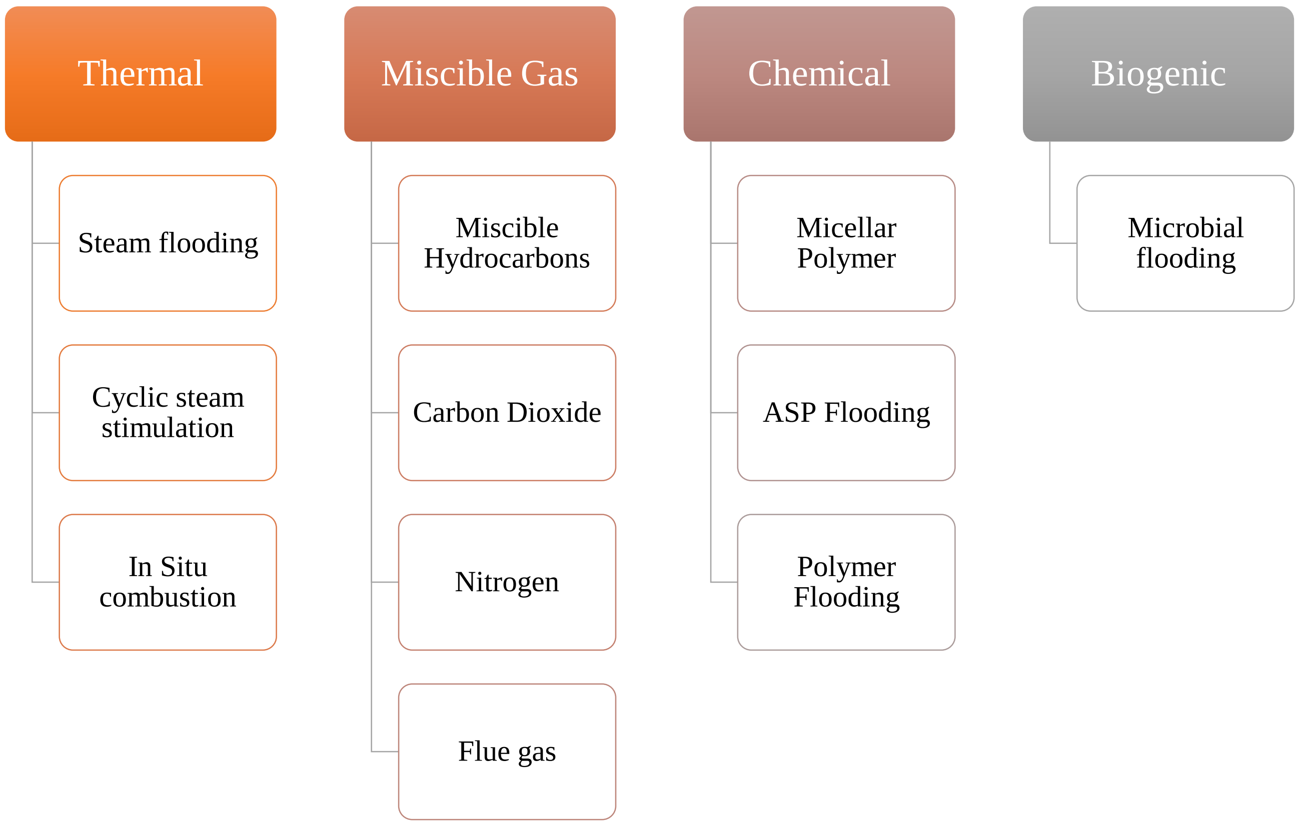


Figure 5: Overview of Enhanced Oil Recovery

4. UNCONVENTIONAL RESERVOIRS

Unconventional reservoirs are essentially any reservoir that requires special recovery operations outside the conventional operating practices. Unconventional reservoirs include reservoirs such as tight-gas sands, gas and oil shales, coalbed methane, heavy oil and tar sands, and gas-hydrate deposits and coal bed methane. These reservoirs require specialized recovery solutions such as stimulation treatments or steam injection or innovative solutions that must overcome economic constraints in order to make recovery from these reservoirs economically possible. It is essential to study these in detail before taking a decision to commercially exploit these wells.

Better reservoir knowledge and increasingly sensitive technologies are making the production of unconventional gas economically viable, and more efficient. This efficiency is bringing tight gas, coal-bed methane and gas hydrates into the reach of more companies around the world. However, production from tight gas reservoirs is still in its infancy, only limited knowledge is available about the causes of the problems concerning fracture stimulations of low permeability reservoirs. Economically producing gas from the unconventional sources is a great challenge today.

4.1 Coal Bed Methane

Coal bed methane refers to methane adsorbed into the solid matrix of the coal. It is called 'sweet gas' because of its lack of hydrogen sulfide. The presence of this gas is well known from its occurrence in underground coal mining, where it presents a serious safety risk. Coalbed methane is distinct from a typical sandstone or other conventional gas reservoir, as the methane is stored within the coal by a process called adsorption. The methane is in a near-liquid state, lining the inside of pores within the coal (called the matrix). The open fractures in the coal (called the cleats) can also contain free gas or can be saturated with water.

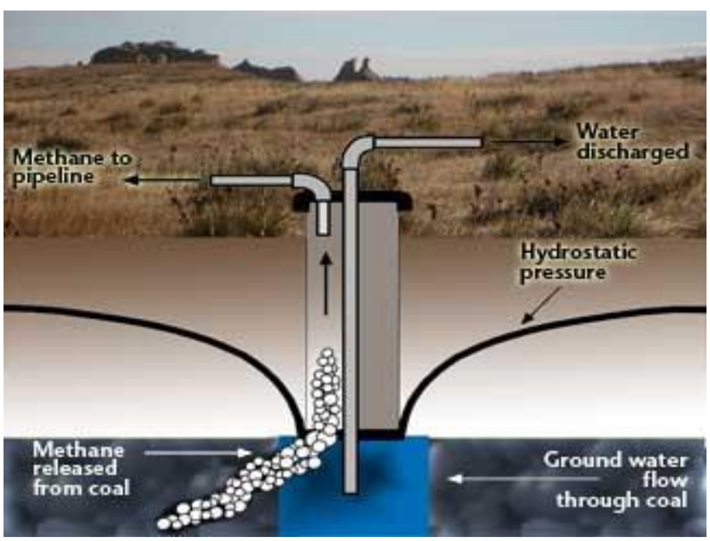


Figure 6: Extraction of Coal Bed Methane [16]

Unlike much natural gas from conventional reservoirs, coalbed methane contains very little heavier hydrocarbons such as propane or butane, and no natural-gas condensate. It often contains up to a few percent carbon dioxide. Gas contained in coal bed methane is mainly methane and trace quantities of ethane, nitrogen, carbon dioxide and few other gases. Intrinsic properties of coal as found in nature determine the amount of gas that can be recovered. The porosity of coal bed reservoirs is usually very small, ranging from 0.1 to 10% and the permeability lies in the range of 0.1–50 milliDarcys. The permeability of fractured reservoirs changes with the stress applied to them. Coal displays a stress-sensitive permeability and this process plays an important role during stimulation and production operations. Then the gas is sent to a compressor station and into natural gas pipelines. The produced water is either reinjected into isolated formations, released into streams, used for irrigation, or sent to evaporation ponds. The water typically contains dissolved solids such as sodium bicarbonate and chloride but varies depending on the formation geology.

Coalbed methane wells often produce at lower gas rates than conventional reservoirs, typically peaking at near 300,000 cubic feet (8,500 m^3) per day (about 0.100 m^3/s), and can have large initial costs. The production profiles of CBM wells are typically characterized by a "negative decline" in which the gas production rate initially increases as the water is pumped off and gas begins to desorb and flow. As production occurs from a coal reservoir, the changes in pressure are believed to cause changes in the porosity and permeability of the coal. This is commonly known as matrix shrinkage/swelling. As the gas is desorbed, the pressure exerted by the gas inside the pores decreases, causing them to shrink in size and restricting gas flow through the coal. As the pores shrink, the overall matrix shrinks as well, which may eventually increase the space the gas can travel through (the cleats), increasing gas flow

4.2 Shale Gas

As result of increasing natural gas prices and the increasing need to replace reserves, production from shale reservoirs gained significant interest in last few years. Shale reservoir is fined grained sedimentary rock inter-bedded with siliceous and carbonaceous material. Because shales ordinarily have insufficient permeability to allow significant fluid flow to a wellbore, most shales are not commercial sources of natural gas. Shale gas is one of a number of unconventional sources of natural gas; others include coalbed methane, tight sandstones, and methane hydrates.

Shale has low matrix permeability, so gas production in commercial quantities requires fractures to provide permeability. Shale gas has been produced for years from shales with natural fractures; the shale gas boom in recent years has been due to modern technology inhydraulic fracturing (fracking) to create extensive artificial fractures around well bores.

Horizontal drilling is often used with shale gas wells, with lateral lengths up to 10,000 feet (3,000 m) within the shale, to create maximum borehole surface area in contact with the shale.

Shales that host economic quantities of gas have a number of common properties. They are rich in organic material (0.5% to 25%), and are usually mature petroleum source rocks in the thermogenic gas window, where high heat and pressure have converted petroleum to natural gas. They are sufficiently brittle and rigid enough to maintain open fractures.

Some of the gas produced is held in natural fractures, some in pore spaces, and some is adsorbed onto the organic material. The gas in the fractures is produced immediately; the gas adsorbed onto organic material is released as the formation pressure is drawn down by the well.

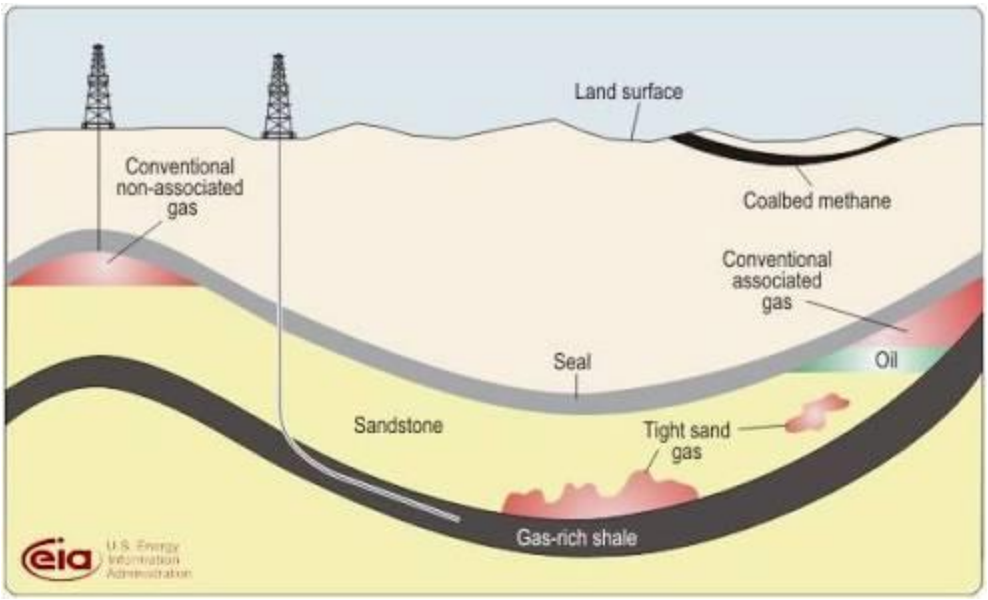


Figure 7: Shale Gas [17]

4.3Gas Hydrates

Gas Hydrates are formed where a large amount of methane is trapped within a crystal structure of water, forming a solid similar to ice. Gas hydrates are found where temperatures are low and water ice is common, significant deposits of gas hydrates have been found undersediments on the ocean floors of the Earth.

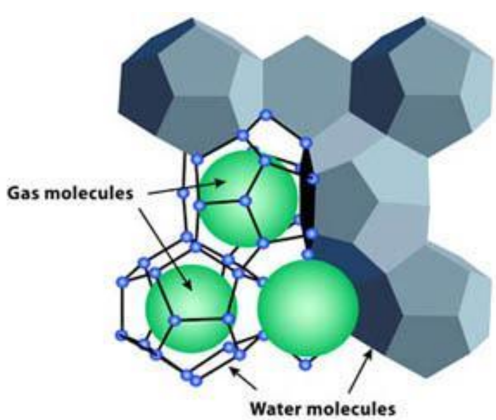


Figure 8: Structure of Gas Hydrates [16]

Gas hydrates are common constituents of the shallow marine geosphere and they occur in deep sedimentary structures on the ocean floor. Methane hydrates are believed to form by migration of gas from deep along geological faults, followed by precipitation or crystallization, on contact of the rising gas stream with cold sea water. The ice-core Gas hydrates record is a primary source of data for global warming research, along with oxygen and carbon dioxide.

Gas hydrates are restricted to the shallow lithosphere (i.e. < 2,000 m depth). Furthermore, necessary conditions are found only in either continental sedimentary rocks in polar regions where average surface temperatures are less than 0 °C; or in oceanic sediment at water depths greater than 300 m where the bottom water temperature is around 2 °C. The sedimentary Gas hydrates reservoir probably contains 2–10 times the currently known reserves of conventional natural gas. This represents a potentially important future source of hydrocarbon fuel. However, in the majority of sites deposits are thought to be too dispersed for economic extraction. Other problems facing commercial exploitation are detection of viable reserves and development of the technology for extracting methane gas from the hydrate deposits.

4.4 Tight Gas Reservoirs

Fractured, tight and unconventional petroleum reservoirs, although less common and less well understood than conventional sandstone and carbonate reservoirs, have become an increasingly important resource base. Fractured reservoirs are composed of naturally fractured rock. Tight reservoirs contain no natural fractures, but cannot be produced economically without hydraulic fracturing. Tight and unconventional reservoirs are often perceived as entailing higher costs and risks than conventional reservoirs. Reservoir engineers look unfavorably on them because they are difficult to evaluate and recovery techniques must be judiciously chosen and carefully applied in order to avoid production problems. Tight gas" lacks a formal definition, and usage of the term varies considerably. The term "Tight Gas Reservoir" has been coined for reservoirs of natural gas with an average permeability of less than 0.1 mD (1 x 10-16 m^2). Many 'ultra tight' gas reservoirs may have in-situ permeability down to 0.001 mD

Conventional methods of producing gas from tight reservoirs usually requires some form of artificial stimulation, such as hydraulic fracturing. Wells completed in tight reservoir rocks have to be stimulated by one or several hydraulic fracs in order to achieve an economically adequate production rate. Compared with more permeable rocks, tight gas reservoirs often show a much weaker response to the frac treatments, resulting in low production rates and a high economic risk. It is known that natural rock fractures are an important factor in the economic recovery of gas from tight reservoirs. Advanced methods of gas production in these environments are taking advantage of gas flow from natural fractures in the reservoir rock. The distribution, orientation, and density of these fractures is key to proper planning and well scheduling in tight gas reservoirs. The nature of the natural fractures and other characteristics of the reservoir were sufficiently well-determined that drilling could be accurately directed.

The permeability that determines the easy at which a fluid can flow, is a function governed by the Darcy's law of fluid flow in porous media. Effective porosity, viscosity, fluid saturation and the capillary pressure are some of the import parameter controlling the effective permeability of a reservoir. Besides the factors relating to the fluid nature, the rock parameters are equally important. These are controlled by depositional and postdepositional environments the reservoir is subjected to. The depositional setting like deepbasinal site or the over-bank levees in flood plain areas are more prone to the deposition of very fine sand to silt and clays, which form poor reservoirs on lithification.

The most significant differences between conventional reservoir and low-permeability reservoirs lie in the low-permeability structure itself, the response to overburden stress, and the impact that the low-permeability structure has on effective permeability relationships under conditions of multiphase saturation. The figure below provides a comparison of traditional reservoir behavior with low-permeability reservoir behavior. In a traditional reservoir, there is relative permeability in excess of 2% to one or both fluid phases across a wide range of water saturation. Further, in traditional reservoir, critical water saturation and irreducible water saturation occur at similar values of water saturation. Under these conditions, the absence of widespread water production commonly implies that a reservoir system is at, or near, irreducible water saturation. In low-permeability reservoir, however, irreducible water saturation and critical water saturation can be dramatically different. In traditional reservoir, there is a wide range of water saturations at which both water and gas can flow. In low-permeability reservoir, there is a broad range of water saturations in which neither gas nor water can flow. In some very low-permeability reservoir, there is virtually no mobile water phase even at very high water saturations. Because of the effective permeability structure of most low-permeability reservoir, there is a large range of water saturations over which both water and gas are essentially immobile. This is called "Permeablilty Jail".

The low permeability of these reservoirs slows down their response to pressure transient testing so it is difficult to obtain dynamic reservoir properties and to production so it is difficult to characterize the gas in place. The need to hydraulically fracture wells in these reservoirs to obtain commercial flow rates adds to the complexity of the problem.

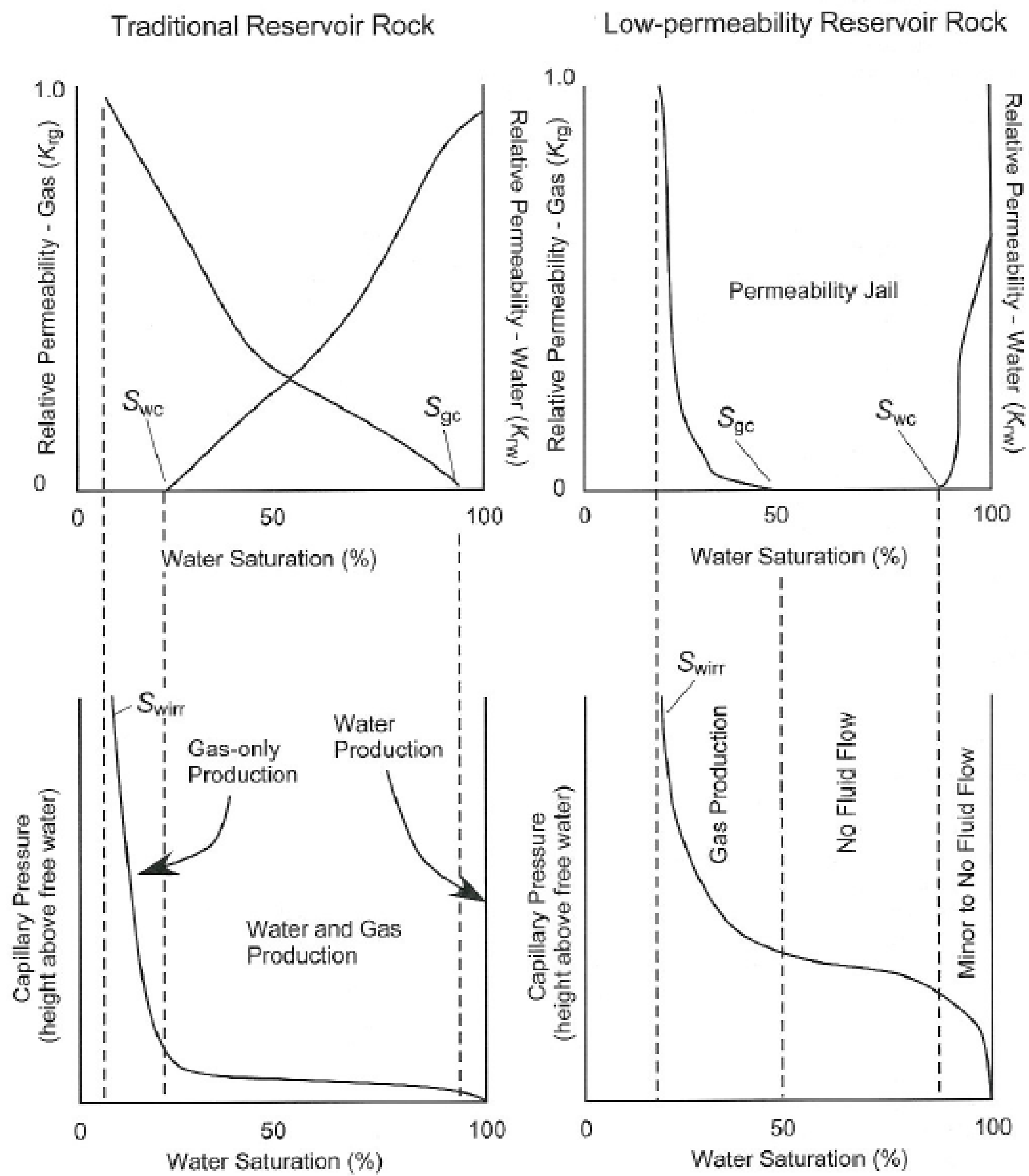


Figure 9: Permeability Jail [4]

4.4.1 CASE STUDY, SON VALLEY, VINDHYAN BASIN

A. Reservoir Characterization

Present study deals with the hydrocarbon bearing formations of Son Valley, Vindhyan Basin. This basin is Proterozoic in nature. It is characterized by very low porosity (3-4%), ultra-low permeability (micro Darcy range) and low (sub hydrostatic reservoir pressure. However, large areas of the field are charged with high calorific value (C_1> 90%). This area is also characterized by naturally occurring fractures which aid in the flow of gas from the reservoir to the wellbore.

In case of a particular object water saturation is as low as 30-35%. For formations with high rates of gas production, water saturation was found to be 30%. Where the production rates were found to be low, water saturation was found to be as high as 60%. Critical gas saturation in most cases is not less than 25-30%. So, for a total water saturation of 70% or more, the gas is highly unlikely to flow. However in many places, water saturation is very high and touches the 100% mark. The difference between total and effective water saturation must not be more than 15-20%. Should this be the case, the bound water will block the flow of gas and lead to low to negligible gas production.

SNo.	Depth (m)	Porosity (%)	Air Permeability (mD)	Grain Density (g/cc)
Well: A				
1.	1664.01	2.02	0.020	2.665
2.	1664.08 (Horizontal)	0.66	0.463	2.667
3.	1664.08 (Vertical)	4.01	0.161	2.656
Well: B				
4.	- NA -	0.93	3.24 (Fractured Sample)	2.677
5.	- NA -	0.38	>0.01	2.665
Well: G				
6.	1020.065 (Horizontal)	1.03	>0.01	2.690
Well: H				
7.	1173.025 (Horizontal)	0.14	>0.01	2.662
8.	1173.025 (Vertical)	0.17	>0.01	2.679
Well: D				
9	1446.24-1446.34	1.90	< 0.001	2.713
10	1592.95-1593.05	0.53	< 0.001	2.696
11	1594.72-1594.81	1.35	0.005	2.695
12	1597.88-1597.98	1.78	< 0.001	2.698

Table 1: Petrophysical properties obtained from cores

From the logs it was observed that the maximum porosity in the basin was about 5-6%. The average porosity was determined to be 2-3%.

Well G

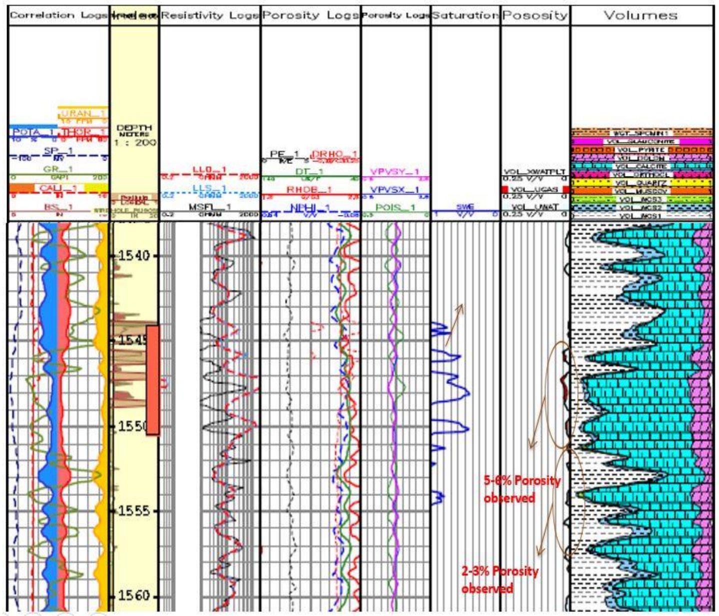


Figure 10: Porosity data from Logs

Well A

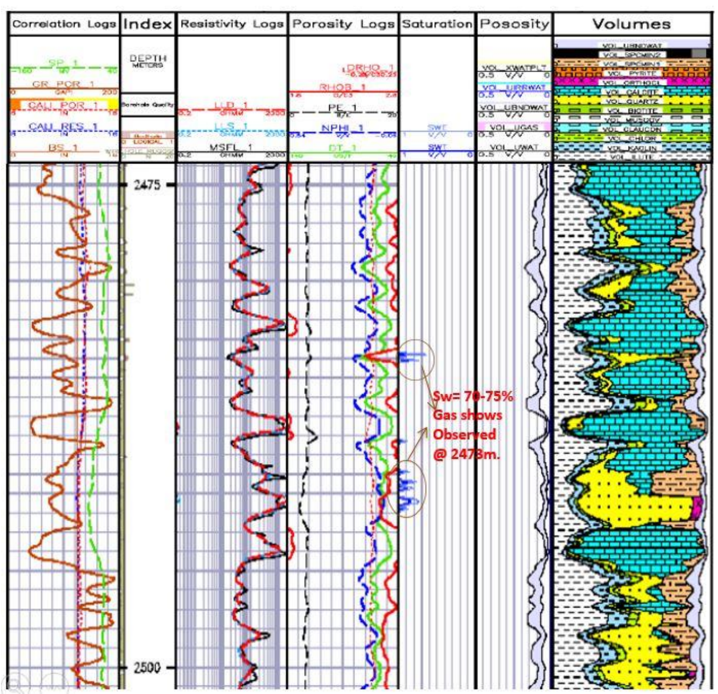


Figure 11: Water Saturation Data from Logs

B. To find the water saturation in tight gas reservoir

1. Water Saturation

Saturation is defined as that fraction, or percent, of the pore volume occupied by a particular fluid (oil, gas, or water). Hence water saturation is defined as the ratio of water of volume to the total pore volume occupied.

The fluids in most reservoirs are believed to have reached a state of equilibrium and, therefore, will have become separated according to their density, i.e., oil overlain by gas and underlain by water. In addition to the bottom (or edge) water, there will be connate water distributed throughout the oil and gas zones. The water in these zones will have been reduced to some irreducible minimum. The forces retaining the water in the oil and gas zones are referred to as capillary forces because they are important only in pore spaces of capillary size. Connate (interstitial) water saturation ($S_{w)}$ is important primarily because it reduces the amount of space available between oil and gas. It is generally not uniformly distributed throughout the reservoir but varies with permeability, lithology, and height above the free water table.

The obtained data is a well log from a tight gas reservoir. In this case, technical characteristics of unconventional gas reservoir include:

- Significant Formation Thickness
- Isolated reservoirs in the same formations
- Difficult to detect the water zones
- Underpressurized reservoir
- Ultra low permeability
- Correlation of source rock and reservoir rock.

S_w, uninvaded zone water saturation is most fundamental quantity used in log evaluation. In addition to S_w, must also determine if:

- water saturation is low enough for water-free completion
- the hydrocarbons are moveable
- the zone is permeable
- there is a commercial volume of recoverable hydrocarbon reserves

For most sandstone reservoirs, determination of water saturation is done by Archie's equation.

$$S_w = \left(\frac{a}{\Phi^m} * \frac{R_w}{R_t} \right)^{\frac{1}{n}}$$

Where,

S_w = Water saturation

R_w = Resistivity of water
R_t = Resistivity of formation
Φ = Porosity
a = tortuosity factor
m = cementation exponent
n = saturation exponent

DEPTH	CALI	DRHO	DTC	GR	LLD	LLS	MINM	MSFL	NPHI	PE	RHO	SP
717.2	12.3743	0.0355	68.1367	165.7794	38.2403	34.0825	0	41.6578	16.6825	4.0484	2.7297	-15.4909
717.3	12.4257	0.0359	67.9195	161.7402	37.6229	33.8268	0	41.28	16.9634	4.0076	2.7297	-15.5243
717.4	12.4947	0.0369	67.7646	161.0166	37.0882	33.6008	0	39.911	16.8965	3.9974	2.7297	-15.5989
717.5	12.4707	0.0384	67.634	162.4486	36.087	33.0101	0	39.8205	17.151	3.9953	2.7297	-15.7006
717.6	12.467	0.04	67.3467	170.4893	35.644	32.7511	0	38.198	17.9606	3.9661	2.7297	-15.7056
717.7	12.4434	0.0399	67.132	173.1472	35.1594	32.4793	0	37.0213	17.9384	3.9338	2.7297	-15.7432
717.8	12.4561	0.0388	67.0509	173.4746	34.7106	32.2054	0	36.865	17.9721	3.881	2.7295	-15.7284
717.9	12.428	0.0372	66.8922	171.7698	33.8825	31.6339	0	36.5689	18.4454	3.7868	2.7295	-15.7208
718	12.4711	0.0359	66.6668	170.8699	33.4808	31.343	0	36.0282	18.6555	3.7584	2.7295	-15.7219
718.1	12.4667	0.0347	66.5214	171.455	33.0469	30.9861	0	36.076	18.3917	3.7555	2.7295	-15.6992
718.2	12.468	0.0328	66.2679	171.2157	32.4723	30.2186	0	36.2782	18.0612	3.7596	2.7297	-15.8223
718.3	12.4533	0.0301	66.2679	170.0292	32.378	29.9692	0	34.57	18.2738	3.7874	2.7298	-15.8975
718.4	12.4853	0.0287	66.2679	169.9019	32.3791	29.8309	0	34.5181	18.519	3.7977	2.7298	-15.9314
718.5	12.497	0.0287	66.2679	171.1718	33.1471	30.2751	0	32.1157	18.3097	3.8122	2.7298	-15.9906
718.6	12.4948	0.0343	66.2679	175.3321	33.8443	30.7682	0	34.9421	18.3915	3.8269	2.7298	-15.9614
718.7	12.4567	0.0409	66.2679	175.4225	35.155	31.8285	0	38.2294	18.0214	3.8046	2.7298	-15.9494
718.8	12.4471	0.047	66.2679	173.586	39.6191	35.701	0	44.6402	17.6651	3.748	2.7298	-15.863
718.9	12.3959	0.0544	66.2679	167.0424	42.5193	38.3334	0	46.8208	16.2324	3.5994	2.7298	-15.8552
719	12.4306	0.0557	66.2679	163.8262	45.9012	41.362	0	44.4034	15.5713	3.5516	2.7298	-15.7563
719.1	12.4446	0.0588	66.2803	160.8502	56.7077	51.9731	0	67.6606	14.6731	3.549	2.7298	-15.5428
719.2	12.351	0.0976	66.2803	151.6512	64.4847	59.8792	0	83.1348	12.1946	3.6879	2.7299	-15.4667

Table 2: Sample of Log Data for Tight gas Reservoir

2. Steps followed:

- Find out the average porosity from the neutron and density logs.
- R_w is calculated form the Micro Spherical Focused Log (MSFL) which gives us the resistivity of the flushed zone. Alternatively, minimum R_t is taken.
- R_t is the formation resistivity which is taken directly from the Latero-Log Deep (LLD).
- For calculation purpose, we take a=1, m=2 and n=2.

This is done and repeated for each log reading to give an accurate picture of the water saturation in the well.

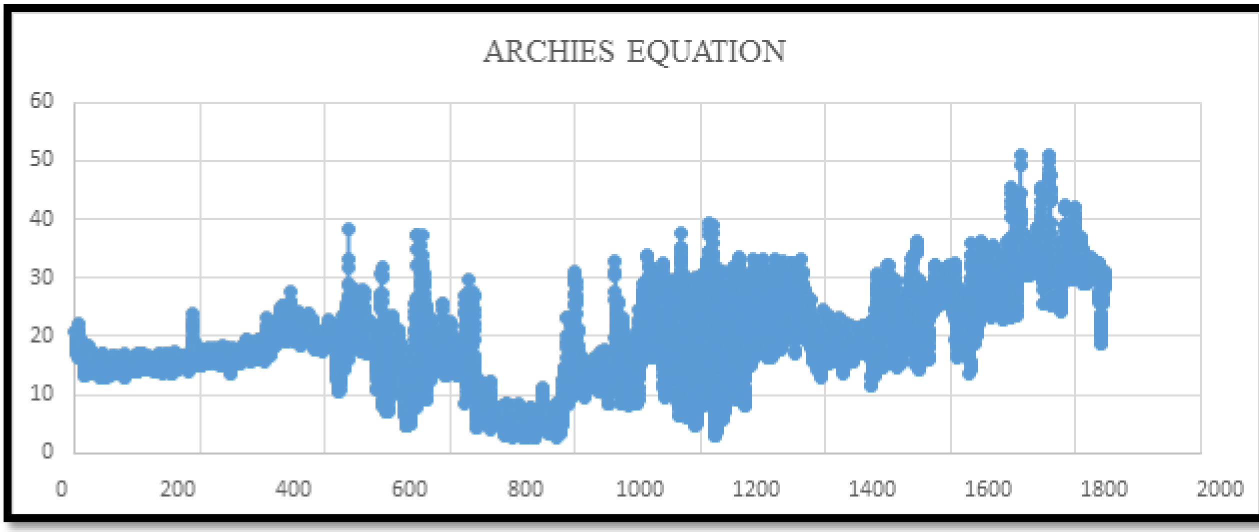


Figure 12: Water saturation By Archie's Equation (Water saturation vs Depth)

Archie's equation is largely applied to sandstone reservoirs. For reservoirs with significant shale content or limestone reservoirs the Archie's equation cannot be used as it is. The shale content is taken into account by the Indonesian equation.

Here, the volume of shale is calculated using the Gamma Ray logs.

$$V_{sh} = \gamma_L - \gamma_{min} / \gamma_{Shale} - \gamma_{min}$$

Indonesian equation is:

$$S_w = \left\{ \left[\left(\frac{V_{sh}^{\,2-V_{sh}}}{R_{sh}} \right)^{1/2} + \left(\frac{\phi_e^{\,m}}{R_w} \right)^{1/2} \right]^2 R_t \right\}^{-1/n}.$$

Where V_{sh} is the shale volume as calculated from above.

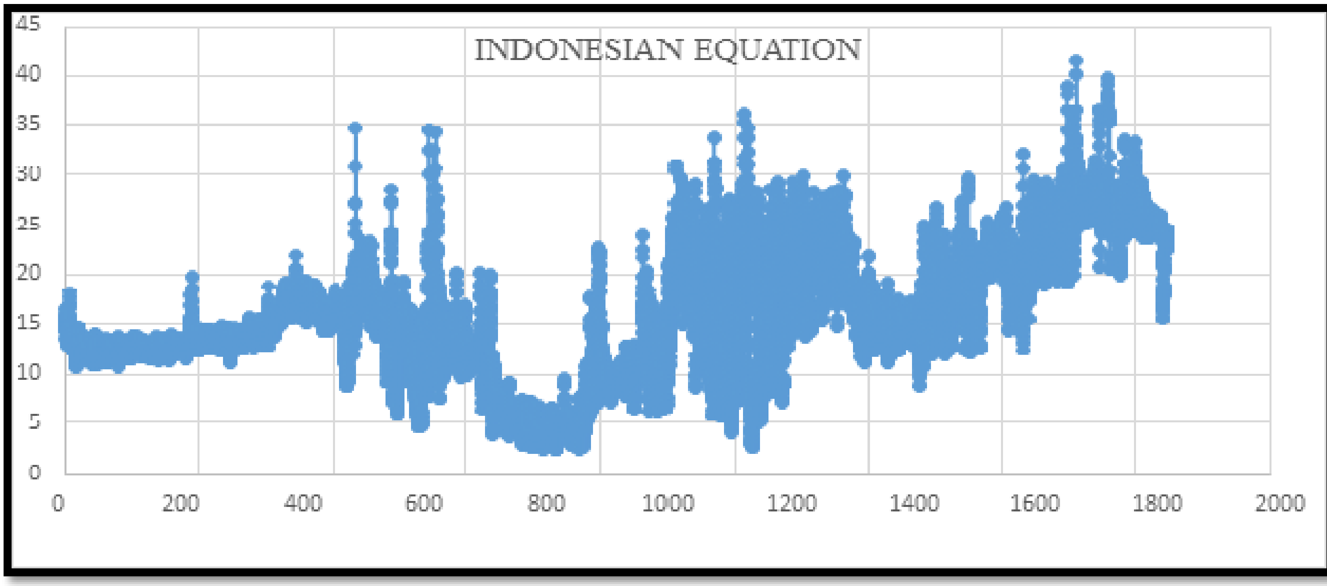


Figure 13: Water saturation By Indonesian Equation (Water saturation vs Depth)

3. Results

- It is noted that the water saturation for the well lies between 2% and 53% by Archie's equation and 3% to 42% when calculated by Indonesian equation. Hence higher accuracy is achieved when using Indonesian equation.
- Two prospective gas bearing zones are identified where the water saturation is low:
  - ➢ 750 m to 850 m
  - ➢ 975 m to 1150 m

C. Fracture analysis and Strike Orientation

1. XRMI

The X-tended Range Micro Imager (XRMI™) tool, a wireline borehole imaging tool, is designed to obtain quality images even in environments with a high formation resistivity to mud resistivity (R_t/R_m) ratio. The expanded operating range of the XRMI tool over conventional electrical imaging services is achieved through its state-of-the-art 32-bit digital signal acquisition architecture combined with a large increase in available power for the excitation current. As a result, the signal-to-noise ratio of the raw measurements is improved by a factor of up to five, and the dynamic range is expanded by a factor of up to three.

The resulting images offer superior fidelity, even in highly resistive formations (Rt > 2,000 ohm-m) or relatively salty borehole fluids (Rm < 0.1 ohm-m). Tool Design and Superior Image Quality Besides the new electronics, the mandrel architecture derived from Halliburton's highly successful EMI™ imaging tool greatly helps the XRMI tool generate superior-quality borehole images. Pads mounted on six independently articulated arms help maintain pad contact in Rugose, washed-out, elliptical, or highly deviated boreholes. Further, a high sampling rate (120 samples per foot) and borehole coverage help obtain high-resolution pictures of the borehole walls.

The XRMI tool reduces E&P risk by helping:

- Take the guess-work out of identifying the subsurface sedimentary sequence
- Describe the reservoir facies just like "cores," the ground truth
- Show bedding dips that help rationalize the choice for the next drilling location
- Choose the sidewall core zones, formation testing zones, and perforation intervals accurately by integrating images with other open-hole logs
- Show true picture of the reservoir regarding fractures

2. Steps followed:

- Study the obtained XRMI log carefully.
- For each selected interval, note the following:
  - Fracture Interval
  - Fracture Intensity
  - Nature of Fracture
  - Percentage of occurrence of fractures
  - Maximum and Minimum strike directions
- The intensity is classified as low, medium and high depending on the number of fractures.
- The nature of fracture is open, partially open and closed fracture. This is denoted on the log by color. Blue signifies open fracture, green partially open and red denotes closed fractures.

- List the strike direction for the log in ascending order and note the number of occurences of each strike angle.
- Form a Rose Diagram indicating the two major trends.
- Identify these trends and bisect it. This gives us the direction of Maximum Horizontal Stress.
- Perpendicular drawn to this indicated the Minimum Horizontal Stress direction.

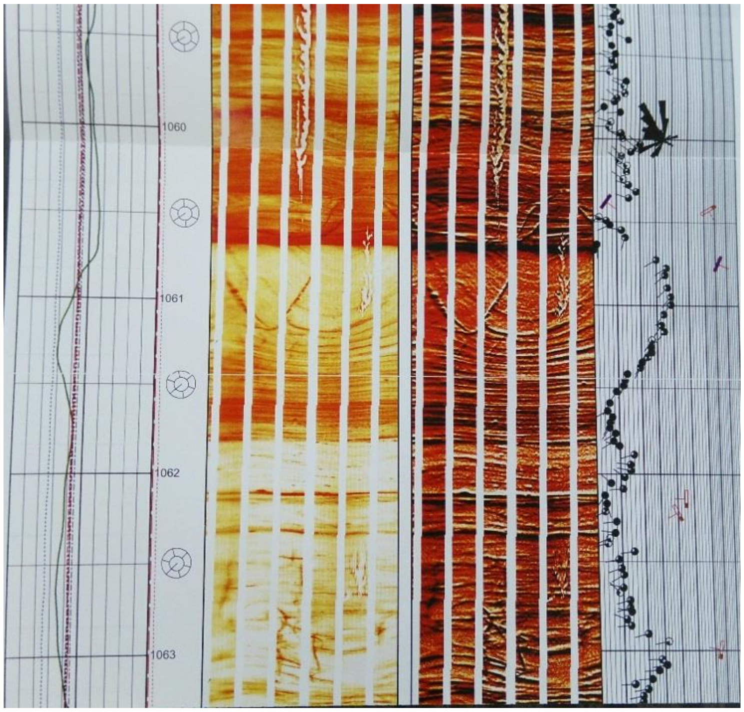


Figure 14: Sample of XRMI log

WELL A

Fracture Interval	Intensity	Nature	POF	OF	CF	S MAX	SMIN
1005-1006	low	partially open	1	0	0	95	
1008-1009	low	partially open	1	0	0	60	
1010-1011	low	partially open	1	0	0	20	
1011-1012	low	partially open	1	0	0	30	
1013-1014	low	partially open	1	0	0	170	
1014-1015	low	partially open	1	0	0	160	10
1017-1018	low	partially open	1	0	0	160	
1018-1019	medium	partially open	1	0	0	80	30
1023-1024	medium	partially open, open	0.33	0.66	0	160	90
1024-1025	low	partially open	1	0	0	40	
1025-1026	low	partially open	1	0	0	160	
1026-1027	low	partially open	0	1	0	80	
1027-1028	low	partially open	1	0	0	30	
1028-1029	low	partially open	1	0	0	20	

Table 3: Sample of data compliled from XRMI log

3. Strike Orientation Diagrams

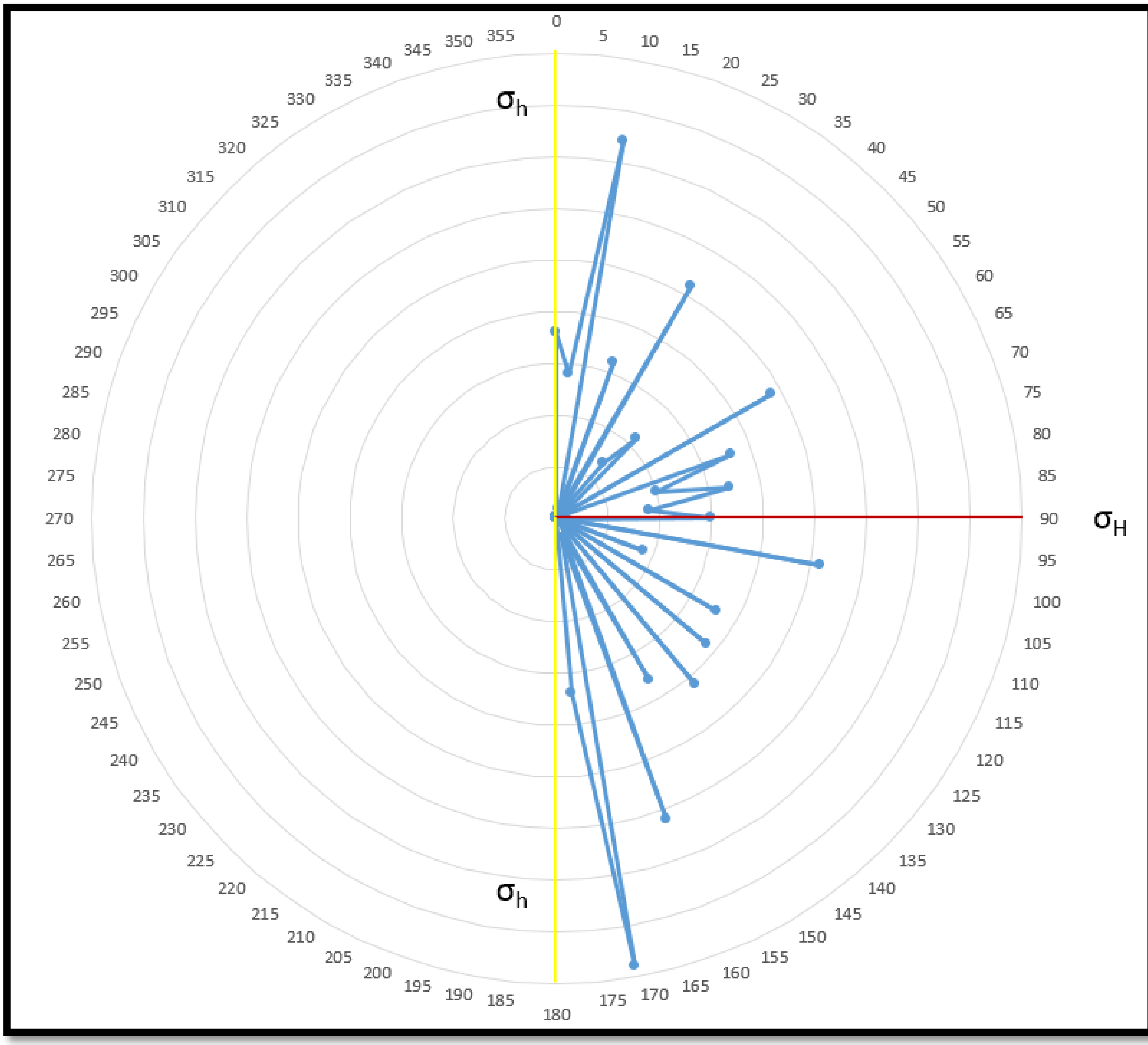


Figure 15: Strike orientation for Well 'A' showing direction of Minimum and Maximum horizontal stress

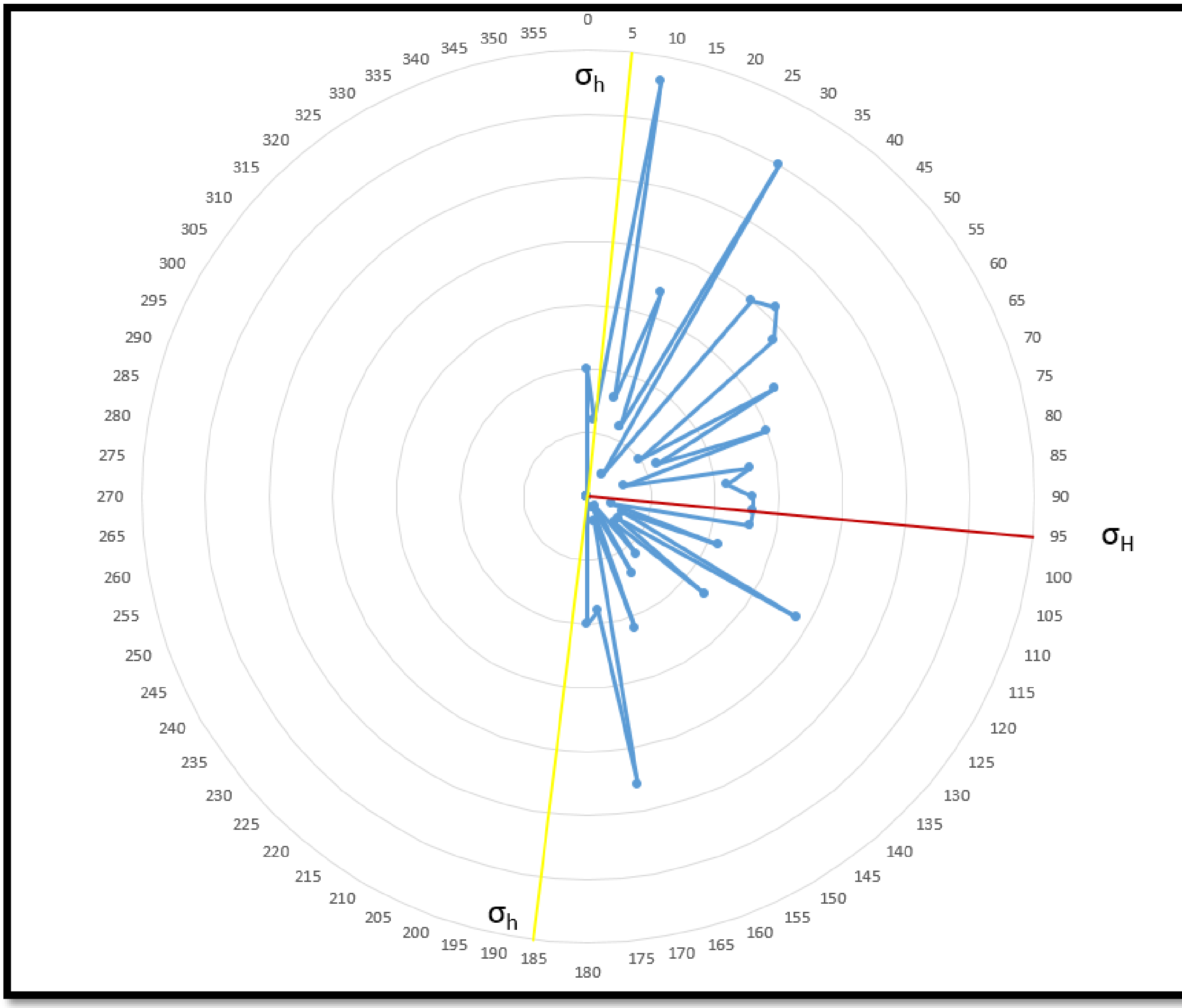


Figure 16: Strike orientation for Well 'B' showing direction of Minimum and Maximum horizontal stress

4. Results

- The Rose Diagram obtained from the well data clearly indicate two major trends of strike directions of fracture.
- One is found to be parallel to a lineament near the basin while the other is found to be parallel to a major fault present in the basin.
- The direction of Maximum Horizontal stress is found to be 90º for Well "A" while it is found to be 95º for Well "B"
- The direction of Minimum Horizontal stress is perpendicular to the direction of Maximum Horizontal Stress.

5. WELL TEST ANALYSIS

Detailed reservoir information is essential to the petroleum engineer in order to analyze the current behavior and future performance of the reservoir. Pressure transient testing is designed to provide the engineer with a quantitative analyze of the reservoir properties. A transient test is essentially conducted by creating a pressure disturbance in the reservoir and recording the pressure response at the wellbore, i.e., bottom-hole flowing pressure p_{wf}, as a function of time. The pressure transient tests most commonly used in the petroleum industry include:

• Pressure drawdown
• Pressure buildup
• Multirate
• Interference
• Pulse
• Drill Stem
• Fall off
• Injectivity
• Step rate

It has long been recognized that the pressure behavior of a reservoir following a rate change directly reflects the geometry and flow properties of the reservoir. Information available from a well test includes:

• Effective permeability
• Formation damage or stimulation
• Flow barriers and fluid contacts
• Volumetric average reservoir pressure
• Drainage pore volume
• Detection, length, capacity of fractures
• Communication between wells

5.1 Pressure drawdown test

A pressure drawdown test is simply a series of bottom-hole pressure measurements made during a period of flow at constant producing rate. Usually the well is shut-in prior to the flow test for a period of time sufficient to allow the pressure to equalize throughout the formation, i.e., to reach static pressure. The fundamental objectives of drawdown testing are to obtain the average permeability, k, of the reservoir rock within the drainage area of the well and to assess the degree of damage of stimulation induced in the vicinity of the wellbore through drilling and completion practices. Other objectives are to determine the pore volume and to detect reservoir heterogeneities within the drainage area of the well. During flow at a constant rate of Q_o, the pressure behavior of a well in an infinite-acting reservoir (i.e., during the unsteady-state flow period) is given by equation, as:

$$p_{wf} = p_i - \frac{162.6\,Q_o\,B_o\,\mu}{kh}\left[\log\left(\frac{kt}{\phi\,\mu\,c_t\,r_w^2}\right) - 3.23 + 0.87s\right]$$

where k = permeability, md
t = time, hr
r_w = wellbore radius
s = skin factor

The above expression can be written as:

$$p_{wf} = p_i - \frac{162.6\,Q_o\,B_o\,\mu}{kh}$$
$$\times\left[\log(t) + \log\left(\frac{k}{\phi\,\mu\,c_t\,r_w^2}\right) - 3.23 + 0.87s\right]$$

This equation suggests that a plot of p_{wf} versus time t on semilog graph paper would yield a straight line with a slope m in psi/cycle. This equation can be also rearranged for the capacity kh of the drainage area of the well. If the thickness is known, then the average permeability cab be calculated.

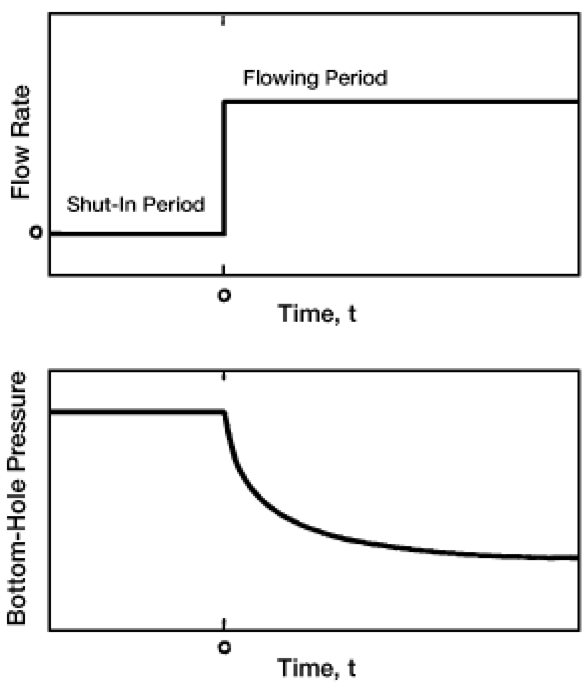


Figure 17: Idealized Drawdown Test [1]

5.2 Pressure Buildup Test

Pressure buildup testing is the most familiar transient well-testing technique, which has been used extensively in the petroleum industry. Basically, the test is conducted by producing a well at constant rate for some time, shutting the well in (usually at the surface), allowing the pressure to build up in the wellbore, and recording the down-hole pressure in the wellbore as a function of time. From these data, it is possible to estimate the formation permeability and current drainage area pressure, and to characterize damage or stimulation and reservoir heterogeneity or boundaries frequently we assume that the test is conducted in an infinite acting reservoir in which no boundary effects are felt during the entire flow and later shut-in period. The reservoir is homogeneous and containing in a slightly compressible, single-phase fluid with uniform properties so that the *Ei* function and its logarithmic approximation apply. Horner's approximation is applicable. Wellbore damage and stimulation is concentrated in a skin of zero thickness at the wellbore. Flow into the wellbore ceases immediately at shut-in. If a well is shut-in after it has produced at rate q for time t_p and the bottom-hole pressure p_{ws} is recorded at time Δt, then a plot of p_{ws} versus log { $t_{p\,+}$ Δt}/ Δt will give a straight line, which is represented by the following equation:

$$P_{ws} = P_i - 162.6\ \frac{qB\mu}{kh}.\ \log\left[\ (tp+\Delta t)/\Delta t)\right]$$

Where the slope

$$m = 162.6\ \frac{qB\mu}{kh}$$

Analysis of the above gives us the equation for the pressure buildup. It was introduced by Horner in 1951 and is known as Horner’s equation. On the Horner plot, the scale of time ratio increases from left to right. Because of the form of the ratio, however, the shutin time Δt increases from right to left. Graphically, P_i (initial reservoir pressure) is the intercept at { $t_{p\,+}$ Δt}/ Δt = 1.0. The absolute value of the slope m is used in analyzing the test result. The formation permeability k can be calculated from the slope and given by

$$k = 162.6\ \frac{qB\mu}{mh}$$

Pressure buildup analysis is also used to determine:

- Effective reservoir permeability
- Extent of permeability damage around the wellbore
- Presence of faults and to some degree the distance to the faults
- Any interference between producing wells
- Limits of the reservoir where there is not a strong water drive or where the aquifer is no larger than the hydrocarbon reservoir

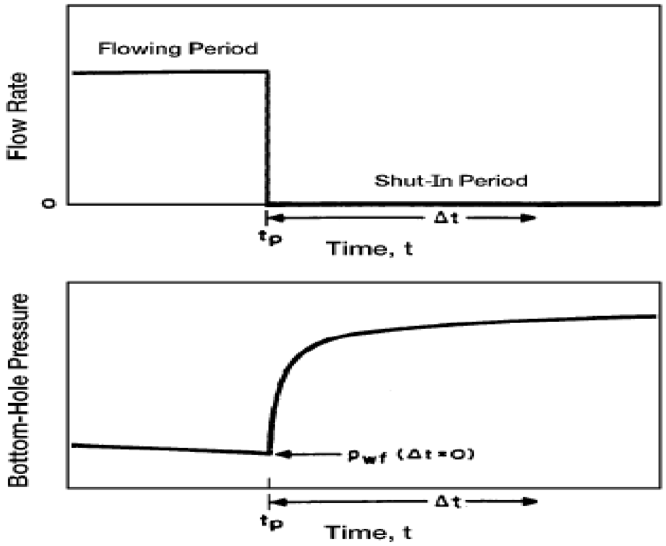


Figure 18: Idealized Buildup Test [1]

5.2.1 CASE STUDY

A. Calculation of permeability with Horner's Plot

1. Horner's Plot

As stated above, the Horner's Plot is made to estimate the permeability from the well tests, more specifically, pressure buildup tests by measuring the slope m. If we extrapolate this line further to infinite shut in time, we can get the original Formation pressure P_i.

We assume that this is an infinite acting reservoir with a line source well. We also assume it to be a homogeneous reservoir with single phase liquid. As a result, the equation is:

$$P_{ws} = P_i - 162.6\ \frac{qB\mu}{kh}.\ \log\left[\ (tp+\Delta t)/\Delta t)\right]$$

This suggests that a plot of p_{ws} versus (tp +Δt)/Δt would produce a straight line relationship with intercept p_i and slope of -m, where:

$$m = 162.6\ \frac{qB\mu}{kh}$$

Where,

P_{ws} = Well shut in pressure, psi

P_i = Initial Pressure, psi

B = Formation Value Factor

q = Flow rate, m^3/day

k = Permeability, milliDarcy

h = effective thickness, m

m = slope of Horner's Plot

This is used to calculate the permeability.

On the Horner plot, the scale of time ratio increases from left to right. Because of the form of the ratio, however, the shutin time Δt increases from right to left. It is observed from the equation that $p_{ws} = p_i$ when the time ratio is unity. Graphically this means that the initial reservoir pressure, pi, can be obtained by extrapolating the Horner plot straight line to $(tp + \Delta t)/\Delta t = 1$.

	Time (hrs)	(tp+Δt)/Δt	Pws (psi)
	0	0	3716.7
Q = 55485 m3/d	0.1333	158.5398	3906.4
Bg = 0.004667	0.2666	79.7697	3987.8
μ = 0.0392 cP	0.4	53.5	4011
H = 7.5 m	0.5333	40.3775	4022.6
Tp=21 Hr	0.8	27.25	4026.5
	1.066	20.6887	4034.2
	1.333	16.7504	4038.1
	1.7333	13.1156	4042
	3.6666	6.7274	4049.7
	6.6666	4.15	4057.5
	8.6666	3.4231	4061.3
	9.0666	3.3162	4065.2
	10.6666	2.9688	4073
	16.6666	2.26	4080.7
	21.2	1.9906	4080.7

Table 4: Field data received from Well 'C'

2. Steps followed

- Find t_p, the cumulative production since completion divided by the rate, immediately before shut-in.
- Plot p_{ws} versus log $(tp + \Delta t)/\Delta t$ on semilog graph paper.
- Identify Early Time Region and beginning of Middle Time Region. The MTR ends when the radius of investigation begins to detect the drainage boundaries of the tested well; at

this time the buildup curve starts to deviate from the straight line. This is the beginning of the end time region.

- Find slope m of the straight-line portion of the Horner plot (MTR).Once the MTR is identified, determine the slope and intercept.

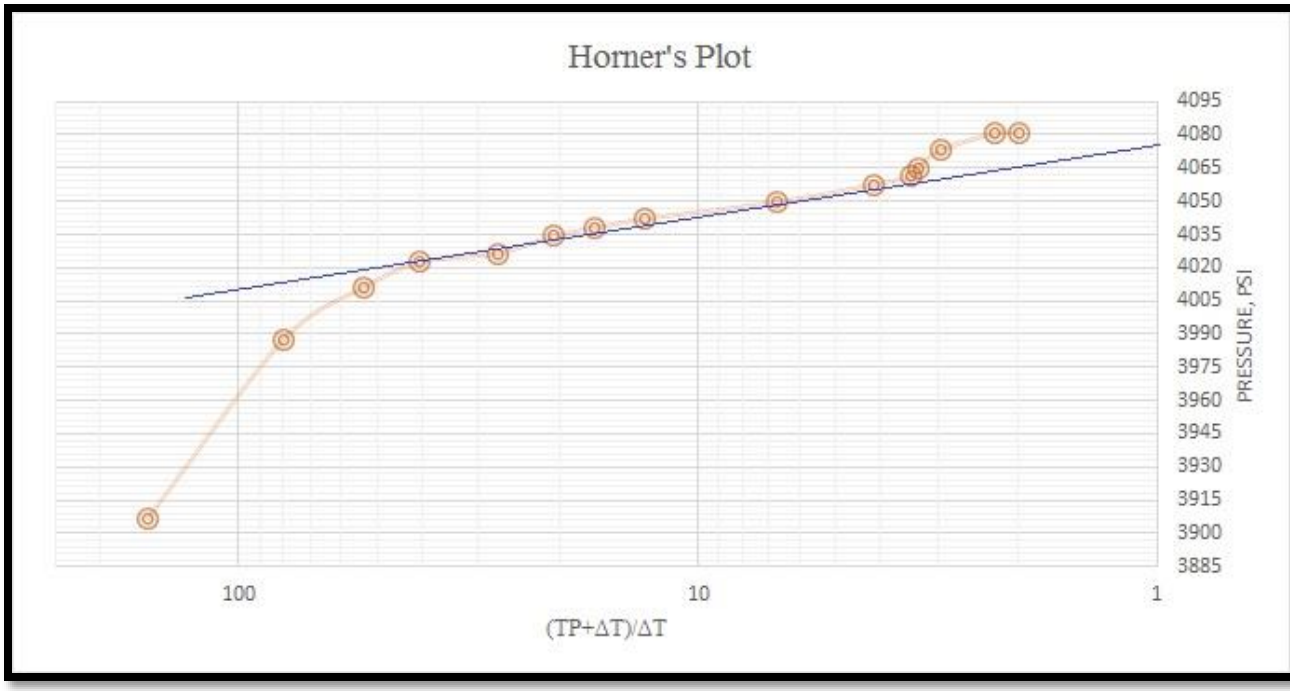


Figure 19: Horner's Plot for Well 'C'

From the above, it is inferred that:
Slope "m" = 25 psi/cycle
P_i = 4075 Psi

Using the given field data and the obtained slope of the Middle Time Region from the Horner's Plot, substituting in above equation, the Permeability k is found to be 8.8027 mD.

3. Results

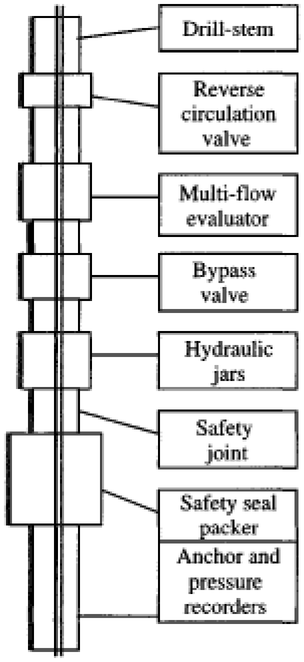
- The slope "m" of the Horner's Plot is found to be 25 psi/cycle.
- Calculated permeability is 8.8027 mD
- Initial reservoir pressure is extrapolated to 4075 psi.

5.3 Drill Stem Test

Drill-stem testing provides a method of temporarily completing a well to determine the productive characteristics of a specific zone. As originally conceived, a drill-stem test provided primarily an indication of formation content. The pressure chart was available, but served mainly to evaluate tool operation. Currently, analysis of pressure data in a properly planned and executed DST can provide, at reasonable cost, good data to help evaluate the productivity of the zone, the completion practices, the extent of formation damage and perhaps the need for stimulation. A drill-stem test provides an estimate of formation properties and wellbore damage. These data may be used to determine the well's flow potential with a regular completion that uses stimulation techniques to remove damage and increase effective wellbore size.

Reservoir characteristics that may be estimated from DST analysis include:

- Average effective permeability: This may be better than core permeability since much greater volume is averaged. Also, effective permeability rather than absolute permeability is obtained.
- Reservoir pressure: Measured, if shut-in time is sufficient, or calculated, if not.
- Wellbore damage: Damage ratio method permits the estimation of what the well should make without damage.
- Barriers, permeability changes, and fluid contacts: These reservoir anomalies affect the slope of the pressure buildup plot. They usually require substantiating data to differentiate one from the other.
- Radius of investigation: An estimate of how far away from the wellbore the DST can "see".
- Depletion: Can be detected if the reservoir is small and the test is properly run.



Basics of DST Operations are:
The drill-stem test often uses two bombs and one or more flow, and shut-in sequences are recorded.
Some important factors of the DST chart are:
1. Going into hole
2. Initial flow period
3. Initial shut-in period
4. Final flow period
5. Final shut-in period
6. Going out of hole

The DST, if properly applied, has become a very useful tool for the Well Completion Engineer

Figure 20: Schematic of a DST Tool [15]

5.4 Interference tests

Interference testing is one form of multiple-well testing. These tests are used to determine whether two or more wells are in pressure communication in the same reservoir and, when communication exists, to provide estimates of vertical formation permeability *k* and porosity/compressibility product in the vicinity of the tested wells. In the homogeneous isotropic system, the porosity and thickness are the same everywhere in the reservoir. Permeability *k* is also the same everywhere and in all direction. Interference is conducted by producing from or injecting into one of these wells (active well) and the pressure response is observed in the other well (observation well. The active well starts producing at uniform pressure at time zero and the other pressure response in the observation well at a distance *r* from active well begins after some time lag.

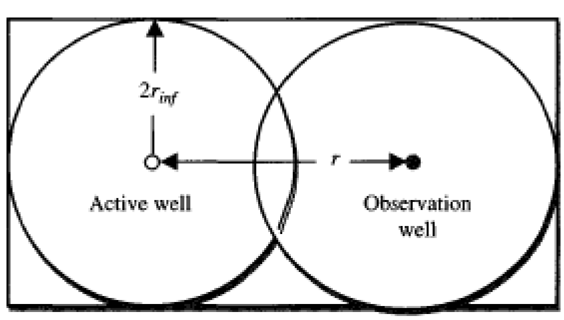


Figure 21: Interference Test [1]

6. PVT ANALYSIS

Petroleum reservoirs are broadly classified as oil or gas reservoirs. These broad classifications are further subdivided depending on:

- The composition of the reservoir hydrocarbon mixture
- Initial reservoir pressure and temperature
- Pressure and temperature of the surface production

It is essential to study the conditions under which these phases exist.
The experimental processes of these conditions are expressed in different types of diagrams commonly called phase diagrams like the pressure-temperature diagram.
These multicomponent pressure-temperature diagrams are essentially used to:

- Classify reservoirs
- Classify the naturally occurring hydrocarbon systems
- Describe the phase behavior of the reservoir fluid

To fully understand the significance of the pressure-temperature diagrams, it is necessary to identify and define the following key points on these diagrams:

- **Cricondentherm (T_{ct}):** The Cricondentherm is defined as the maximum temperature above which liquid cannot be formed regardless of pressure. The corresponding pressure is termed the Cricondentherm pressure p_{ct}.
- **Cricondenbar (p_{cb}):** The Cricondenbar is the maximum pressure above which no gas can be formed regardless of temperature. The corresponding temperature is called the Cricondenbar temperature T_{cb}.
- **Critical point:** The critical point for a multicomponent mixture is referred to as the state of pressure and temperature at which all intensive properties of the gas and liquid phases are equal. At the critical point, the corresponding pressure and temperature are called the critical pressure pc and critical temperature Tc of the mixture.
- **Phase envelope (two-phase region):** The region enclosed by the bubble- point curve and the dew-point curve, wherein gas and liquid coexist in equilibrium, is identified as the phase envelope of the hydrocarbon system.
- **Bubble-point curve:** The bubble-point curve is defined as the line separating the liquid-phase region from the two-phase region.
- **Dew-point curve:** The dew-point curve is defined as the line separating the vapor-phase region from the two-phase region.

6.1 Oil Reservoirs

6.1.1 Ordinary Black Oil

A pressure-temperature phase diagram for ordinary black oil is shown below. It should be noted that quality lines which are approximately equally spaced characterize this black oil phase diagram.The liquid shrinkage curve approximates a straight line except at very low pressures.

When produced, ordinary black oils usually yield gas-oil ratios between 200–700 scf/STB and oil gravities of 15 to 40 API. The stock tank oil is usually brown to dark green in color.

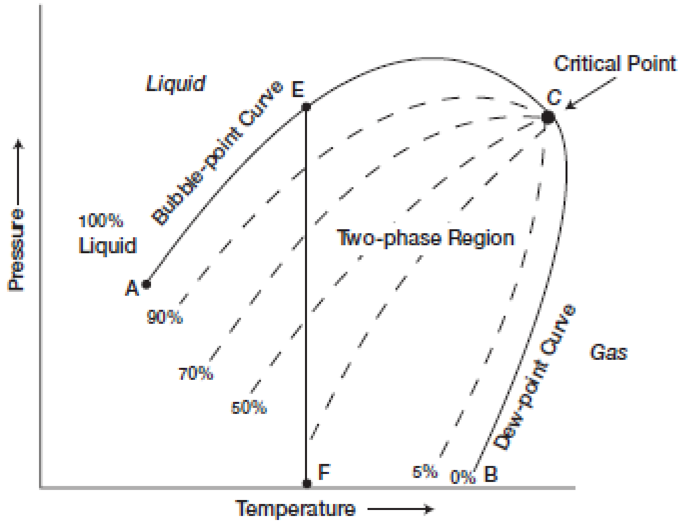


Figure 22: Ordinary Black Oil [2]

6.1.2 Low-shrinkage Crude Oil

The diagram is characterized by quality lines that are closely spaced near the dew-point curve. The liquid-shrinkage curve, shows the shrinkage characteristics of this category of crude oils. The other associated properties of this type of crude oil are:

- Oil formation volume factor less than 1.2 bbl/STB
- Gas-oil ratio less than 200 scf/STB
- Oil gravity less than 35° API
- Black or deeply colored

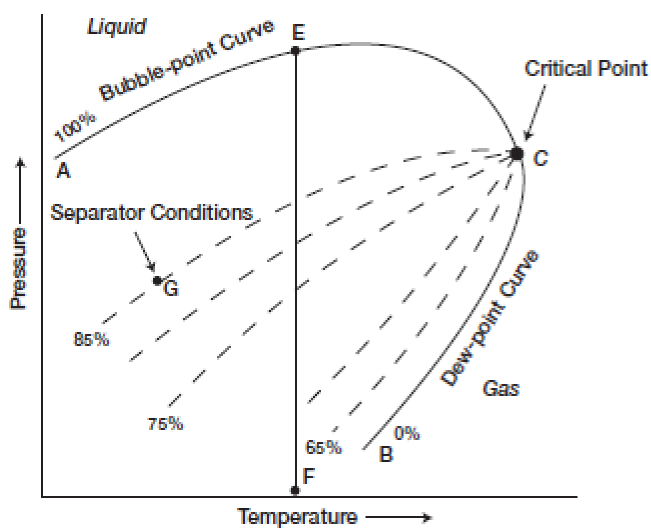


Figure 23: Low Shrinkage Crude Oil [2]

6.1.3 High-shrinkage (volatile) Crude Oil

It can be noted that the quality lines are together near the bubble-point and are more widely spaced at lower pressures. This type of crude oil is commonly characterized by a high liquid shrinkage immediately below the bubble-point as shown. The other characteristic properties of this oil include:

- Oil formation volume factor less than 2 bbl/STB
- Gas-oil ratios between 2,000–3,200 scf/STB
- Oil gravities between 45–55° API
- Lower liquid recovery of separator conditions as indicated by point G
- Greenish to orange in color

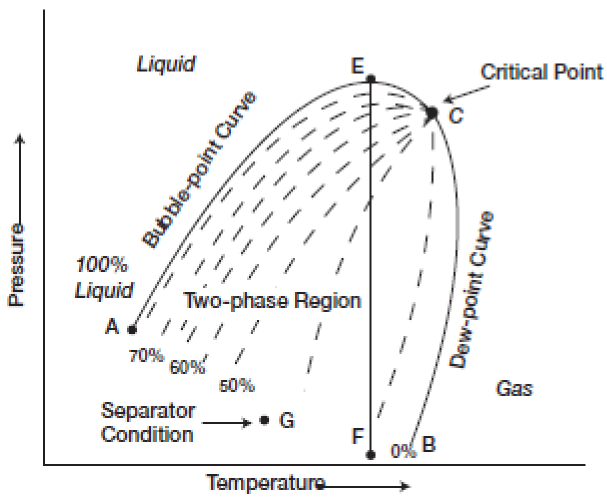


Figure 24: High Shrinkage Crude Oil [2]

6.1.4 Near-critical Crude Oil

If the reservoir temperature T is near the critical temperature T_c of the hydrocarbon system the hydrocarbon mixture is identified as a near-critical crude oil. Because all the quality lines converge at the critical point, an isothermal pressure drop may shrink the crude oil from 100% of the hydrocarbon pore volume at the bubble-point to 55% or less at a pressure 10 to 50 psi below the bubblepoint. The near-critical crude oil is characterized by a high GOR in excess of 3,000 scf/STB with an oil formation volume factor of 2.0 bbl/STB or higher.

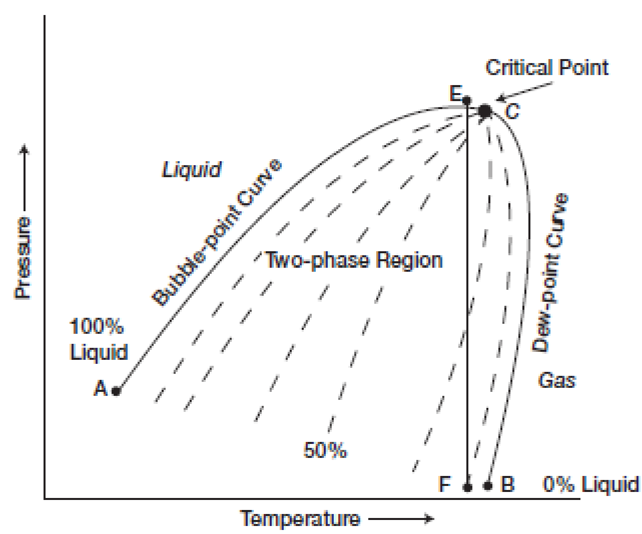


Figure 25: Near Critical Crude Oil [2]

6.2 Gas Reservoirs

If the reservoir temperature is above the critical temperature of the hydrocarbon system, the reservoir is classified as a natural gas reservoir. On the basis of their phase diagrams and the prevailing reservoir conditions, natural gases can be classified into four categories:

6.2.1 Retrograde gas-condensate

If the reservoir temperature T lies between the critical temperature T_c and cricondentherm T_{ct} of the reservoir fluid, the reservoir is classified as a retrograde gas-condensate reservoir. This category of gas reservoir is a unique type of hydrocarbon accumulation in that the special thermodynamic behavior of the reservoir fluid is the controlling factor in the development and the depletion process of the reservoir. When the pressure is decreased on these mixtures, instead of expanding (if a gas) or vaporizing (if a liquid) as might be expected, they vaporize instead of condensing. Because the reservoir pressure is above the upper dew-point pressure, the hydrocarbon system exists as a single phase (i.e., vapor phase) in the reservoir. As the reservoir pressure declines isothermally during production from the initial pressure to the upper dew-point pressure, the attraction between the molecules of the light and heavy components causes them to move further apart further apart. As this occurs, attraction between the heavy component molecules becomes more effective; thus, liquid begins to condense. This retrograde condensation process continues with decreasing pressure until the liquid dropout reaches its maximum. Further reduction in pressure permits the heavy molecules to commence the normal vaporization process. This is the process whereby fewer gas molecules strike the liquid surface and causes more molecules to leave than enter the liquid phase. The vaporization process continues until the reservoir pressure reaches the lower dew-point pressure. This means that all the liquid that formed must vaporize because the system is essentially all vapors at the lower dew point.

The associated physical characteristics of this category are:

- Gas-oil ratios between 8,000 to 70,000 scf/STB. Generally, the gas-oil ratio for a condensate system increases with time due to the liquid dropout and the loss of heavy components in the liquid.
- Condensate gravity above 50° API
- Stock-tank liquid is usually water-white or slightly colored

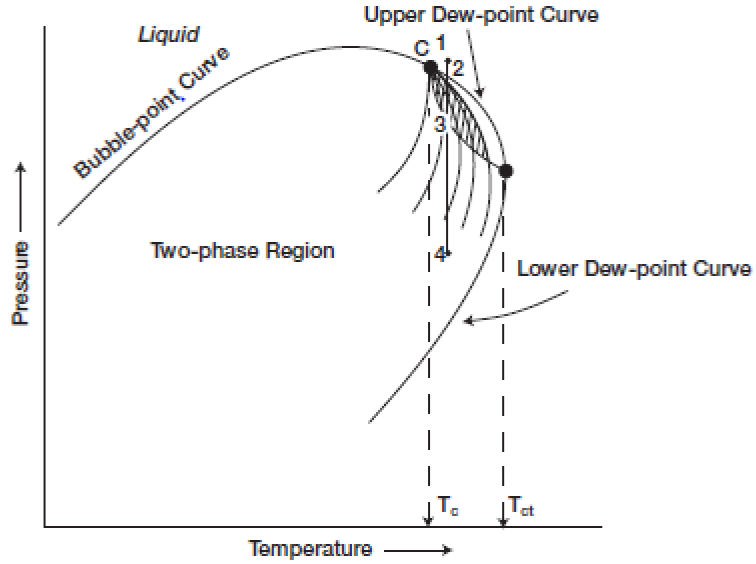


Figure 26: Retrograde Gas Condensate [2]

6.2.2 Near-critical gas-condensate

If the reservoir temperature is near the critical temperature the hydrocarbon mixture is classified as a near-critical gas-condensate. The volumetric behavior of this category of natural gas is described through the isothermal pressure declines and also by the corresponding liquid dropout curve. Because all the quality lines converge at the critical point, a rapid liquid buildup will immediately occur below the dew point.

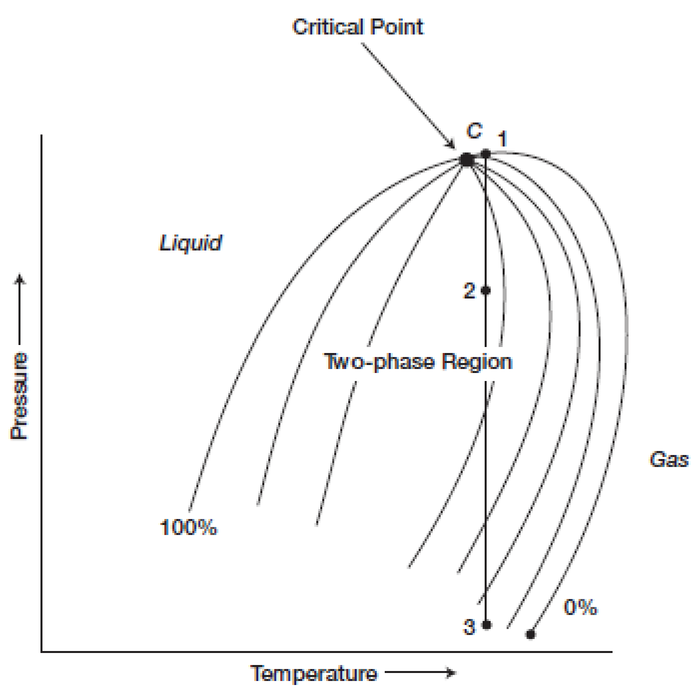


Figure 27: Near Critical Gas Condensate [2]

6.2.3 Wet gas

In a wet gas reservoir, reservoir temperature exceeds the cricondentherm of the hydrocarbon system, the reservoir fluid will always remain in the vapor phase region as the reservoir is depleted isothermally

As the produced gas flows to the surface, however, the pressure and temperature of the gas will decline. If the gas enters the two-phase region, a liquid phase will condense out of the gas and be produced from the surface separators. This is caused by a sufficient decrease in the kinetic energy of heavy molecules with temperature drop and their subsequent change to liquid through the attractive forces between molecules.

Wet-gas reservoirs are characterized by the following properties:

- Gas oil ratios between 60,000 to 100,000 scf/STB
- Stock-tank oil gravity above 60° API
- Liquid is water-white in color

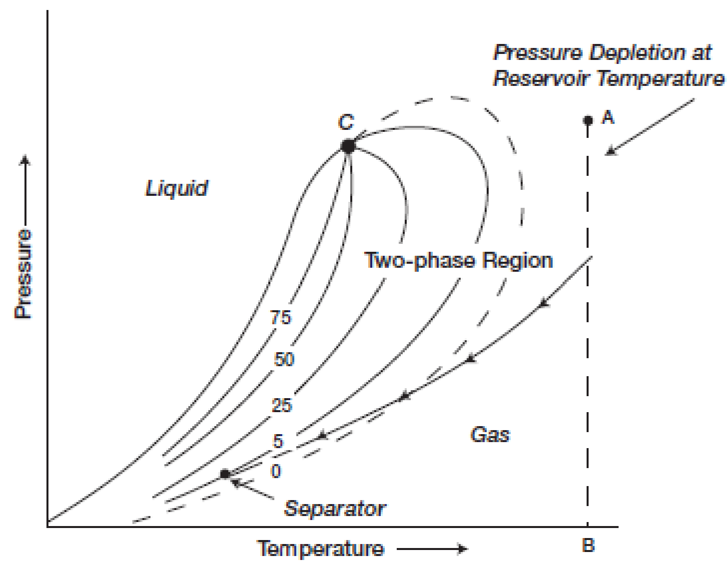


Figure 28: Wet Gas [2]

6.2.4 Dry gas

The hydrocarbon mixture exists as a gas both in the reservoir and in the surface facilities. The only liquid associated with the gas from a dry-gas reservoir is water. Usually a system having a gas-oil ratio greater than 100,000 scf/STB is considered to be a dry gas. Kinetic energy of the mixture is so high and attraction between molecules so small that none of them coalesce to a liquid at stock-tank conditions of temperature and pressure.

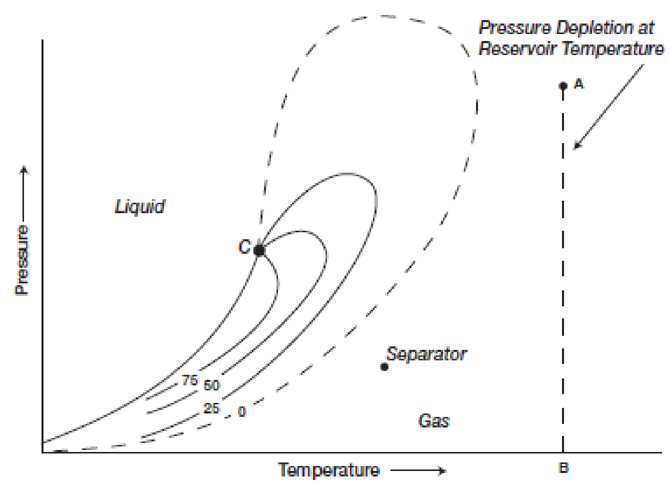


Figure 29: Dry Gas [2]

7. WELL STIMULATION

Sometimes, hydrocarbons may exist in a formation but are unable to flow readily into the well because the formation has very low permeability. This may be due to:

- Natural low permeability formation
- Formation damage around the well bore due to
    - Drilling
    - Completion
    - Workover
    - Production
    - Water/Gas Injection
    - IOR/EOR

Opening up new channels in the rock for the oil and gas to flow through is called stimulation. Stimulation treatments commonly used are:

- Injection of acid to partially dissolve the rock
    - Matrix Acidization
    - Fracture Acidization
- Hydraulic Fracturing to split the rock and prop it open with proppants
- Radial Jet Drilling
- GasGun

7.1 Matrix Acidization and Acid Fracturing

Matrix stimulation by acidization is accomplished by injecting chemicals to dissolve and/or disperse materials near the wellbore that impair well production in sandstones or to create new, unimpaired flow channels between the wellbore and a carbonate formation.

It involves pumping of acid into the well bore to remove near well bore formation damage and other damaging substances. This procedure commonly enhances production by increasing the effective well radius.

Functions of acid matrix job include

- To inject acid into formation at a pressure less than the pressure at which fracture can be opened
- To dissolve the clays, mud solids near the wellbore which had choked the pores
- To enlarge the pore spaces
- To leave the sand and remaining fines in a water wet condition

Two basic types of acidization are characterized through injection rates and pressures:

- Injection Rates below fracture pressure are termed Matrix Acidization
- Injection Rates above fracture pressure are termed Fracture Acidization

Matrix Acidizing is applied primarily to remove skin damage around the wekk bore. During matrix acidizing, the acids dissolve the sediments and mud solids within the pores that are inhibiting the permeability of the rock. Due to extremely large surface area contacted by acid in matrix treatment, spending time is very short. Hence it is difficult to affect formation more than a few feet from the well bore.

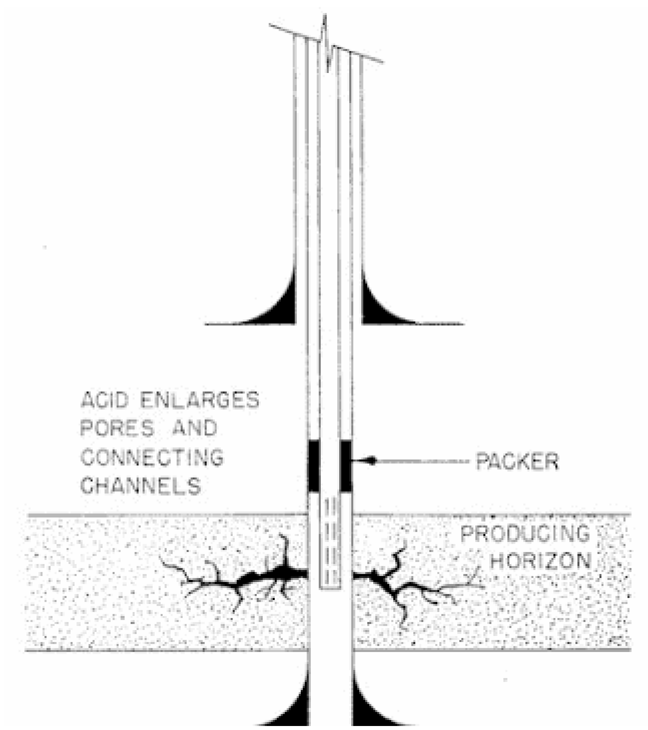


Figure 30: Matrix Acidization [15]

Fracture acidizing is an alternative to hydraulic fracturing and propping in carbonate reservoirs. In fracture acidizing, the reservoir is hydraulically fractured and then the fracture faces are etched with acid to provide linear flow channels to the wellbore. Mostly, acid fracturing is confined to carbonate reservoirs and should never be used to stimulate sandstone, shale or coal seam reservoirs. But, long etched fractures are difficult to obtain because of high leak off and rapid reaction with the formation.

For sandstone reservoirs, mostly Hydrochloric acid (HCl) is used while for carbonate reservoirs, a combination of Hydrochloric acid (HCl) and Hydrofluoric acid (HF) is used as basic rock dissolution chemical. The steps in acidization are given below:

- Preflush Stage (5% - 10% HCl)
    - 50 to 100 gal/ft of formation in general
    - To remove carbonates
    - To push NaCl or KCl away from wellbore
- Acid stage
    - Hydrochloric acidlto dissolve carbonates
    - Hydrofluoric acid to dissolve clay/sand
- After Flush stage
    - To make formation water wet
    - To displace acid away from well bore

Acidizing can cause a number of well problems. Several additives have to be used with the acid before it is injected into the reservoir:

- Surfactant

  Surfactants are used on all acid jobs to reduce surface and interfacial tension, to prevent emulsions, to water wet the formation and to safeguard against other associated problems. It is also used to disperse or flocculate clays and fines. Surfactants are useful to create or break foams and prevent water blocks in the formation.

- Corrosion Inhibitor

  Once the acid is pumped into the formation, it is in contact with a lot of equipment in the subsurface. It is in the best interest of the operator to ensure that this equipment is free from corrosion. So to protect acid pumping and handling equipment and to protect the subsurface well equipment, corrosion inhibitors are used. They are chemical additives which reduce the rate of corrosion of steel by acid.

- Non Emulsifier

  It is a temperature sensitive additive that is temperature sensitive. It contains a water soluble polymer group which prevents the emulsion formation between oil and water.
  It also helps to reduce the surface tension and prevent damage.

- Antisludge Agent

  Sludge is a precipitate formed from reaction of high strength acid with crude oil. Primary ingredients of sludge are usually asphaltenes. Sludges may contain resins and paraffin waxes, high molecular weight hydrocarbons, clays and other materials. So the addition of certain surfactants prevent the formation of sludge by keeping the colloidal material dispersed.

- Iron Controller
  Precipitation of iron may lead to the blockages in the formation and the scaling in the subsurface equipment.

- Mutual Solvent
  Mutual solvents are used to maintain water wet formations and to reduce water saturation near the wellbore. They also help to reduce the absorption of the surfactants and inhibitors on the formation.

- Friction Reducer
  These are used to ease the friction of the gels while they are pumped into the formation through coil tubing. They are useful to suppress fluid turbulence and thus reduce the friction pressure associated with high injection rates.

- Clay Stabilizer
  Clay stabililizers are used to keep clays in suspension and to prevent migration and swelling of clays. Normal treating concentrations normally are 1% (V/V)

- Diverting Agent

Diverting agents are used to place the reactive fluid evenly. Among the pay zones in wells completed in multiple layers with permeability contrast

There are several factors that contribute to the reaction rate of the acid. The analysis of these is essential to the success of the acid job:

- Area of contact per unit volume of the acid
- Formation Temperature
- Acid Concentration
- Acid Type
- Physical and chemical properties of the formation rock
- Flow velocity of the acid

7.2 Hydraulic Fracturing

Hydraulic fracturing is the process of pumping fluid into a wellbore at an injection rate that is too high for the formation to accept without breaking. During injection, the resistance to flow in the formation increases. The pressure in the wellbore increases to a value called the break-down pressure, that is the sum of the in-situ compressive stress and the strength of the formation. Once the formation “breaks down,” a fracture is formed, and the injected fluid flows through it. From a limited group of active perforations, ideally a single, vertical fracture is created that propagates in two "wings" being 180° apart and identical in shape and size. In naturally fractured or cleated formations, it is possible that multiple fractures are created and/or the two wings evolve in a tree-like pattern with increasing number of branches away from the injection point.

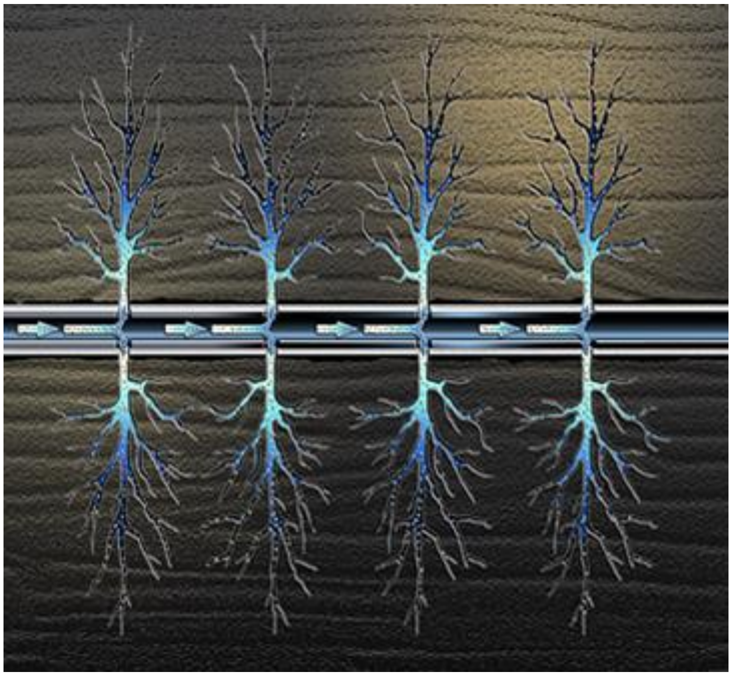


Figure 31: Hydraulic Fracturing [16]

Fluid not containing any solid (called the "pad") is injected first, until the fracture is wide enough to accept a propping agent. The purpose of the propping agent is to keep apart the fracture surfaces once the pumping operation ceases, the pressure in the fracture decreases below the compressive in-situ stress trying to close the fracture. In deep reservoirs, man-made ceramic beads are used to hold open or "prop" the fracture. In shallow reservoirs, sand is normally used as the propping agent.

The most critical parameters for hydraulic fracturing are:

- Formation permeability
- The in-situ stress distribution
- Reservoir fluid viscosity
- Skin factor
- Reservoir pressure
- Reservoir depth
- The condition of the wellbore

A hydraulic fracture is formed by pumping fracturing fluid into a wellbore at a rate sufficient to increase pressure at the target depth (determined by the location of the well casing perforations), to exceed that of the fracture gradient (pressure gradient) of the rock. The fracture gradient is defined as pressure increase per unit of depth relative to density, and is usually measured in pounds per square inch, per square foot, or bars. The rock cracks, and the fracture fluid permeates the rock extending the crack further, and further, and so on. Fractures are localized as pressure drops off with the rate of frictional loss, which is relevant to the distance from the well. Operators typically try to maintain "fracture width", or slow its decline following treatment, by introducing a proppant into the injected fluid – a material such as grains of sand, ceramic, or other particulate, thus preventing the fractures from closing when injection is stopped and pressure removed. Consideration of proppant strength and prevention of proppant failure becomes more important at greater depths where pressure and stresses on fractures are higher. The propped fracture is permeable enough to allow the flow of gas, oil, salt water and hydraulic fracturing fluids to the well.

The location of one or more fractures along the length of the borehole is strictly controlled by various methods that create or seal holes in the side of the wellbore. Hydraulic fracturing is performed in cased wellbores, and the zones to be fractured are accessed by perforating the casing at those locations.

Fluid is typically a slurry of water, proppant, and chemical additives. Additionally, gels, foams, and compressed gases, including nitrogen, carbon dioxide and air can be injected. Typically, 90% of the fluid is water and 9.5% is sand with chemical additives accounting to about 0.5%.

The proppant is a granular material that prevents the created fractures from closing after the fracturing treatment. Types of proppant include silica sand, resin-coated sand, bauxite, and man-made ceramics. The choice of proppant depends on the type of permeability or grain strength needed. In some formations, where the pressure is great enough to crush grains of natural silica sand, higher-strength proppants such as bauxite or ceramics may be used. The most commonly used proppant is silica sand, though proppants of uniform size and shape, such as a ceramic proppant, are believed to be more effective. Typical chemical additives can include one or more of the following:

- Acids—hydrochloric acid or acetic acid is used in the pre-fracturing stage for cleaning the perforations and initiating fissure in the near-wellbore rock.
- Sodium chloride (salt)—delays breakdown of gel polymer chains.
- Polyacrylamide and other friction reducers decrease turbulence in fluid flow and pipe friction, thus allowing the pumps to pump at a higher rate without having greater pressure on the surface.
- Ethylene glycol—prevents formation of scale deposits in the pipe.
- Borate salts—used for maintaining fluid viscosity during the temperature increase.
- Sodium and potassium carbonates—used for maintaining effectiveness of crosslinkers.
- Anaerobic, Biocide, BIO—Glutaraldehyde used as disinfectant of the water (bacteria elimination).[55]

- Guar gum and other water-soluble gelling agents—increases viscosity of the fracturing fluid to deliver proppant into the formation more efficiently.
- Citric acid—used for corrosion prevention.
- Isopropanol—used to winterize the chemicals to ensure it doesn't freeze

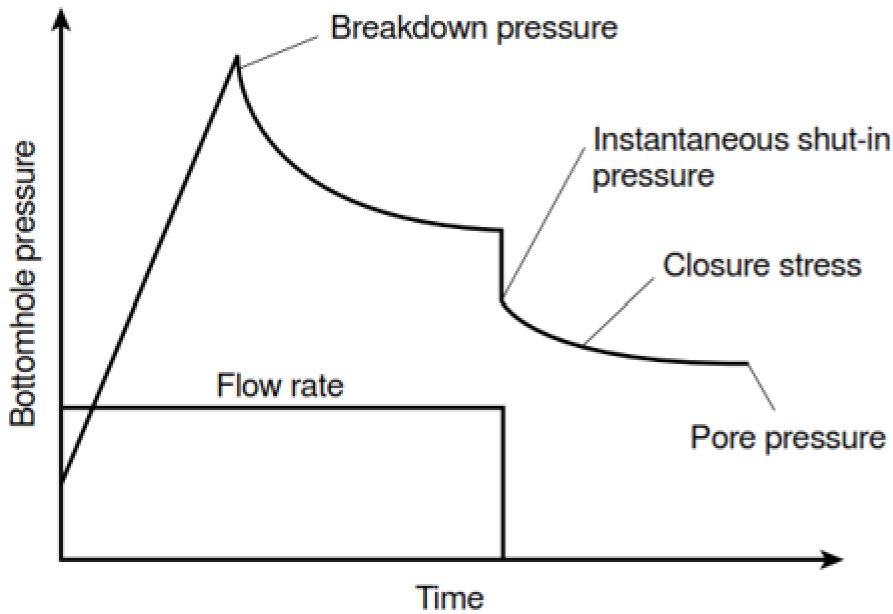


Figure 32: Bottom hole Pressure Variation While Hydrofracking [15]

7.3 GasGun

The GasGun generates high pressure gases at a rate that creates a fracturing behavior dramatically different from either hydraulic fracturing or explosives. The time to peak pressure is approximately 10,000 times slower than explosives and 10,000 times faster than hydraulic fracturing. While the physics of this dynamic process are complex to model, proven results from the field demonstrate the practical advantages to a GasGun stimulation.

The GasGun uses solid propellant, often referred to as a low explosive, to generate high pressure gas at a rapid rate. The rate is tailored to the formation characteristics to be rapid enough to create multiple fractures radiating 10 to 50 feet from the wellbore, but not so rapid as to pulverize and compact the rock as is experienced for classic high explosives such as nitroglycerine. The star-shaped pattern of multiple fractures removes wellbore damage or blockage and increases the formation permeability near the wellbore.

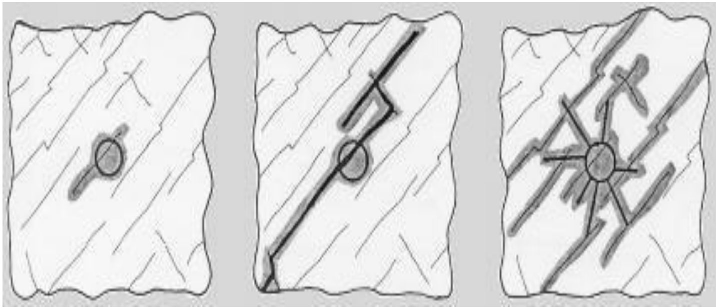


Figure 33: Comparison of GasGun with explosives and hydrofracking [18]

The propellant used is similar to that used in large-bore military guns. While the concept of using solid propellants to stimulate oil and gas wells is not entirely new, the GasGun incorporates a vastly improved design with progressively burning propellants that have been proven by independent research to be many times more effective in creating fractures and increasing formation permeability.

Multiple advantages of the GasGun include:

- Minimal vertical growth out of pay
- Multiple fractures
- Selected zones stimulated without the need to set packers or ball off
- Minimal formation damage from incompatible fluids
- Homogeneous permeability for injection wells
- Minimal on-site equipment needed
- Much lower cost

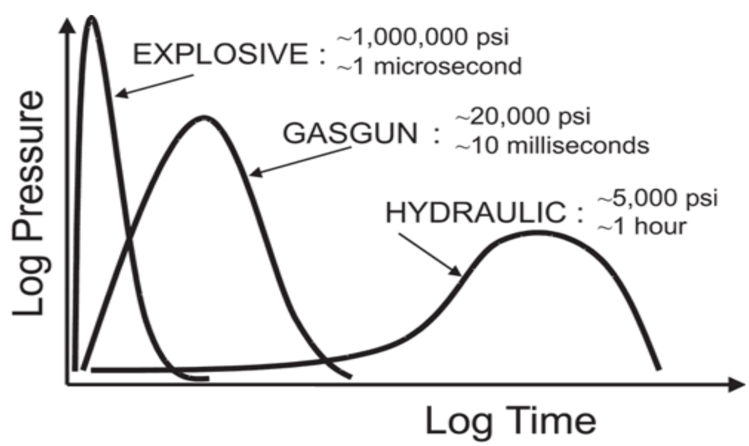


Figure 34: Comparative Pressure data for GasGun [18]

7.4Radial Jet Drilling

Radial Jet Drilling, which uses a high-pressure water jet, aims to drill numerous radial laterals in one layer or multiple layers from the main wellbore. Radial Jet Drilling is an efficient method to exploit low-permeability, shallow, marginal, and Coal Bed Methane reservoirs at low cost. Over the past 30 years, Radial Jet Drilling services have been used in many countries, such as the US, Canada, China, and Argentina, yielding significant improvements in productivity.

The Radial Jet Drilling system differs significantly from conventional drilling. Radial Jet Drilling uses a high-pressure water jet to drill into the rock formation by means of a jet bit. The Radial Jet Drilling operation first anchors the deflector at the target formation by use of coiled tubing (CT). Then, a special casing cutter runs into the hole to mill the casing and cement. After the casing and cement are penetrated, the high-pressure hose and jet bit run into the hole until they reach the formation, and drilling fluid is pumped through the jet bit to drill laterals. The self-driving jet bit differs significantly from a mechanical drill bit. It features forward and backward nozzles to generate a high-pressure jet; the forward jet breaks the rock to create the borehole (30–50 mm), whereas the backward jet drives the bit forward and expands the lateral diameter behind the jet bit.

In conventional drilling, hydraulics design aims to maximize the Rate of Penetration under the limitations of economy, well structure, the operating characteristics of the equipment and pipe, borehole stability, and cutting-removal efficiency. In Radial Jet Drilling, the penetration process relies on the backward self-driving effect and forward high-pressure-jet rock-breaking effect of the jet bit. The hydraulics design should satisfy the requirements of equipment-safety working pressure and lateral-extending capacity.

There are three primary penetration mechanisms that drill the rock in RJD: erosion, pore-elastic tension and cavitation. The high-pressure fluid jet erodes the formation by pumping a relatively small amount of water at high pressure and high velocity through a very small hole. Pore-elastic tension occurs when high-pressure water enters the pore space, increasing the pore pressure and causing the rock to fracture. The sudden increase in pore pressure produces cavitation: fluid-free bubbles are formed in the areas of lesser pressure and immediately implode, causing shockwaves that enhance the fracturing of the formation.

The primary benefit of RJD is its economics. It can be a cost-effective method to complete vertical wells to perform like an open-hole horizontal completion. Drilling a new or sidetrack horizontal completion with a rotary rig requires pulling the tubing, killing the well and drilling large-diameter completions at traditional rates of penetration. These expenses can make drilling horizontal wells with a rotary rig cost-prohibitive in a small field. RJD can be accomplished with a small CTU and standing pumping equipment. With the appropriate combination of deflector shoe and tubing diameter, the laterals can be jetted through-tubing, eliminating the need for pulling the production tubing.

Figure 35: Radial Jet Drilling [5]

The first step of the drilling process is to remove the production equipment from the well and rigup the CTU. The end of the coil tubing (CT) is equipped with a 90°deflector shoe that points sideways into the formation when lowered downhole. This deflector shoe is essentially a 90° elbow. The CT is then lowered down the well until the deflector shoe reaches the target formation.

In a cased-hole application, a special cutter is lowered into the well by CTU until the cutter reaches the casing. The cutter is then energized to perforate the casing and cement. After the casing is penetrated, the high-pressure hose with the jet nozzle can be lowered downhole inside the CT. Once the nozzle has reached the formation, the drilling fluid is pumped through the high-pressure hose and exits the nozzle, which both jets the lateral and advances the nozzle and hose into the formation.

The fluid exits the nozzle at very high speeds, erodes the reservoir and drills the lateral. At the end of the process, the pressure in the hose is decreased as the hose is removed from the jetted hole, which circulates out remaining cuttings. If only one lateral is being jetted, the procedure is complete. If more laterals are to be completed, then the process is repeated as many times as desired.

7.4.1 CASE STUDY

A. Stimulation of well using Radial Jet Drilling

The Donelson West field is about 1,200 acres reservoir of fine crystalline limestone in Cowley County, Kansas, USA. It has an average permeability of 1- 10 milliDarcies and an average porosity of 15-20%. The net pay varies from 6-10 ft. To date, the field has been on primary depletion.

1. Original Oil in Place (OOIP)

The formation volume factor of the produced crude is 1.1. Reservoir volumetrics indicate that a total of 2.7 million bbl of oil may have originally been in place. With a 35% recovery factor, as much as 0.95 million bbl may be recoverable.

2. Production History

The Donelson West field commenced the production in 1967. During 1968, the field produced 83,000 bbl from 13 wells, after which production began to decline. During 1973, the field produced only 14,858 bbl. Over the past 10 years, production from the field has been very low. From 2000 to 2009, the field averaged 1,033 bbl/year, with a maximum annual production of 1,701 bbl/year during 2009.

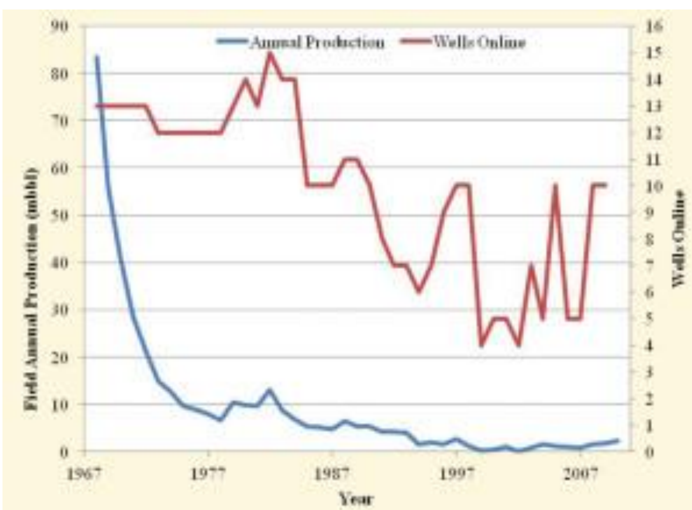


Figure 36: Production History of Donelson West Field [3]

Historical production from the field is characterized by immediate and severe decline. Production over the past decade is only a fraction of the field initial production. This is due to the fact that the field is on primary depletion. Cumulative production from the field through 2011 was about 0.45 million bbl. With an OOIP of 2.7 million bbl, only about 17% of total reserves have been produced, and approximately 2.2 million bbl remain. Since there has been no pressure support, it is possible that the field's total recovery factor could be improved significantly. If total recovery is increased to 35%, as much as 0.5 million bbl of additional reserves could be recovered. Given the low production, long history, and sizeable remaining reserves, this field was a candidate for investment.

3. Historical Field Development

The field was originally developed with vertical completions. These completions were followed by acid/nitrogen fracturing. The wells were not all identically treated, and those treated with between 10,000-15,000 gal of acid and 125,000 Mcf nitrogen produced at higher rates than other wells fractured with less acid.

4. Field Redevelopment

A new program to produce the remaining recoverable reserves was developed. The overall plan consisted of stimulating the existing wells and initiating an infill drilling program. This plan was completed in several phases. The initial phase consisted of recompleting and stimulating eight existing wells and drilling two new wells in the lease. Ultimately, the field will be drilled on 10-acre spacing, and each well will be completed with Radial Jet Drilling laterals. After the laterals have been completed, each will be hydraulically fractured with 15,000 gal of acid and 250,000 Mcf of nitrogen.

5. Drilling Operations and Results

The laterals were drilled over a period of several weeks. The wells were completed with four 600-ft laterals that each required 500 gal of acid to drill. After the jetting, each well was stimulated with 15,000-gal acid fracturing followed by 250,000 Mcf of nitrogen.

The step-change in production after the Radial Jet Drilling and acid fracturing was strong. Prior to stimulation, the wells struggled to reach 200 bbl/month. Afterwards, production reached nearly 500 bbl one month and is consistently in the range of 250 bbl/month.

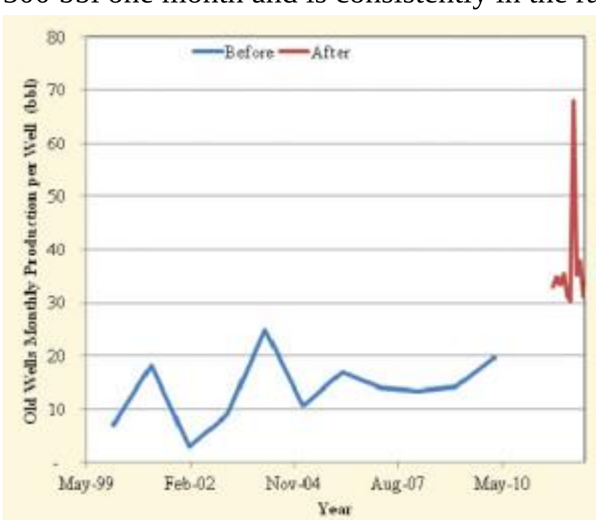


Figure 37: Comparative Data before and after stimulation process [3]

The success of the treatment is evident. The per well average production rates for the three years prior to the stimulation work was 16 bbl/month of oil. After the treatments, well production rate is on average 38 bbl/month per well. Excluding the seventh month, during which benefits from two pump replacements were seen, the monthly average rate per well was 34 bbl. This is a two-fold increase in production.

6. Result

The data indicates that the old wells are producing more oil, and on average, each of the producing wells is producing more oil. The overall stimulation job including the Radial Jet Drilling and acid fracturing campaign was a success, with well production doubling afterward.

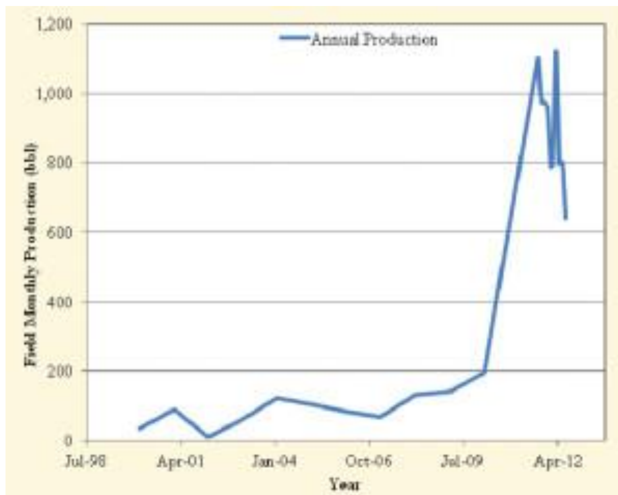


Figure 36: Result of successful stimulation job [3]

8. CONCLUSIONS

- The work related to the dissertation has been successfully completed on the selected topic “Reservoir Characterization and Stimulation for Conventional and Unconventional Reservoirs”.
- Objective of understanding the concept of reservoir engineering has been achieved.
- Importance of reservoir engineering for both conventional and unconventional reservoirs for their characterization and exploitation has been understood.
- Case study for well test analysis has been carried out. Unconventional tight gas reservoir of Proterozoic Vindhyan Basin was analyzed and hydrocarbon bearing zones were evaluated. Besides, Fracture analysis and Strike orientation studies were also carried out for the very tight limestone reservoir.
- Various stimulation techniques to enhance well productivity have also been discussed for their selection criteria to obtain better flow as well as to work out the well economics.

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