COMPLETION METHODS IN THICK MULTILAYERED TIGHT GAS SANDS

A Thesis

by

OBINNA STAVELY OGUERI

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

December 2007

Major Subject: Petroleum Engineering

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Chair of Committee, Stephen A. Holditch
Committee Members, Ding Zhu
Ben Welch
Head of Department, Stephen A. Holditch

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ABSTRACT

Completion Methods in Thick Multilayered Tight Gas Sands. (December 2007)

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Tight gas sands, coal-bed methane, and gas shales are commonly called unconventional reservoirs. Tight gas sands (TGS) are often described as formations with an expected average permeability of 0.1mD or less. Gas production rates from TGS reservoirs are usually low due to poor permeability. As such, state-of-the-art technology must be used to economically develop the resource. TGS formations need to be hydraulically fractured in order to enhance the gas production rates. A majority of these reservoirs can be described as thick, multilayered gas systems. Many reservoirs are hundreds of feet thick and some are thousands of feet thick. The technology used to complete and stimulate thick, tight gas reservoirs is quite complex. It is often difficult to determine the optimum completion and stimulating techniques in thick reservoirs. The optimum methods are functions of many parameters, such as depth, pressure, temperature, in-situ stress and the number of layers. In multilayered reservoirs, it is important to include several sand layers in a single completion.

The petroleum literature contains information on the various diversion techniques involved in the completion of these multilayered reservoirs.

In this research, we have deduced and evaluated eight possible techniques that have been used in the oil and gas industry to divert multilayered fracture treatments in layered reservoirs. We have developed decision charts, economic analyses and computer programs that will assist completion engineers in determining which of the diversion methods are feasible for a given well stimulation. Our computer programs have been tested using case histories from the petroleum literature with results expressed in this thesis. A limited entry design program has also being developed from this research to calculate the fluid distribution into different layers when fracture treating multilayered tight gas reservoirs using the limited entry technique.

The research is aimed at providing decision tools which will eventually be input into an expert advisor for well completions in tight gas reservoirs worldwide.

DEDICATION

First of all, I dedicate this thesis to God for giving me the strength and will.

To my parents, for their immense support and prayers.

To my siblings, for their unconditional love

To the rest of my family for always supporting me.

ACKNOWLEDGMENTS

I would like to express my sincere gratitude and appreciation to the following people who greatly contributed in no small measure to this work: Dr. Stephen Holditch, head of the Petroleum Engineering department, who served as the chair of my graduate committee. His advice, knowledge and support guided me to the completion of this work. Thanks also to Dr. Ding Zhu and Dr. Ben Welch for serving as members of my graduate committee; Dr. Jerome Schubert, for his time; Crisman Research Institute, for funding my research; my colleagues, Adedayo Adebamiro and Rasheed Bello for their support; all my officemates and classmates for their friendship and continuous support; and finally to Texas A&M University for the quality education I have received and for being the home that I will never forget.

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CHAPTER I

INTRODUCTION

1.1 Tight Gas – An Unconventional Resource

Tight gas sands (TGS), coal-bed methane, and gas shales are generally known as unconventional reservoirs. Tight gas sands are often described as formations with limited permeability of 0.1mD or less. Production of gas from these reservoirs is limited because of its poor permeability, and thus, only a small percentage of the gas is economically producible without stimulation. As a result, these low permeability formations need to be hydraulically fractured in order to enhance production rates and to recover economic volumes of natural gas.

The production of tight gas was first widely developed in the 1960's in the Western United States San Juan Basin, fueled by improvements in hydraulic fracturing technology[1]. Price incentives in the form of tax credits and advancing technologies during the 1980's increased development, with production levels eventually reaching the current level of about 2.5 trillion cubic feet (tcf) per year from TGS in the United States. This represents 13% of current lower-48 US gas production. There are approximately 40,000 tight gas wells producing from 1,600 reservoirs in 900 fields[1]. The importance of the gas production from these low permeability reservoirs has grown every decade since the 1960s.

This thesis follows the style of *SPE Production & Facilities.*

Due to its low permeability, tight gas reservoirs have to be hydraulically fractured to produce commercial gas volumes at commercial flow rates.

The Department of Energy (DOE), United States Geological Survey (USGS), and other organizations have completed resource assessments of U.S. basins. However, there is still much that is not currently understood about the origin and development of these accumulations. Fig. 1.1 shows a distribution of the active tight gas basins[2].

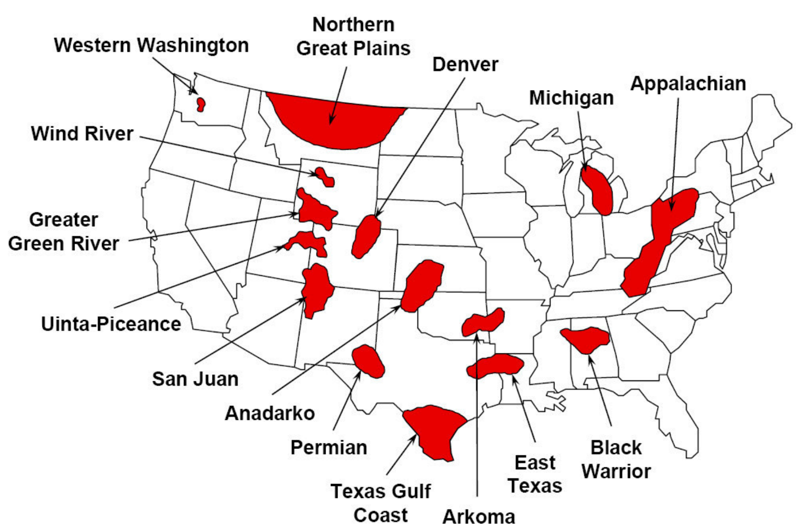


Fig. 1.1: Distribution of Tight Gas Basins in the United States[2]

Studies by the Gas Research Institute (GRI) have shown that around 25% of the natural gas used presently in the United States comes from unconventional reservoirs. Tight gas sands in the U.S. makes up for over 69% of the gas production from all unconventional gas resources and accounts for 19% of U.S. production[3]. The USGS has conducted detailed geologic studies and new assessments of several important basins, including those with large unconventional resource potential. These studies suggest that continuous – type sandstone reservoirs contain mean, undiscovered resources of approximately 80.6 tcf gas and 2500 million bbl of natural gas liquids (NGL) in the Green River Basin of southwest Wyoming; 18.8 tcf gas and 33.4 million bbl NGL in the Uinta and Piceance Basin; and 26.2 tcf gas and 144.4 million bbl NGL in the San Juan Basin.

Tight gas formations are heterogeneous in nature consisting of sandstone, siltstone, and shale dispersed vertically and horizontally throughout the formation. These layers of sandstone, siltstone, and shale can present a high contrast in values of permeability, porosity, and gas saturation depending on various geological aspects such as depositional environment, depth/time of burial, deposition sequence, and post-depositional activities (such as tectonic and digenesis)[4]. Understanding such complex systems thus becomes a challenge.

A significant challenge in tight gas formations is the completion of multi-layered pay zones. Thick, highly layered formations are being completed by operators on a daily basis in some areas. A lot of challenges are involved when completing these reservoirs. These challenges give rise to the main question:

How do we optimize completion techniques to ensure coverage of all pay zones while minimizing cost?

In this research, we have evaluated and analyzed all the information available through the petroleum literature and discussions with experts with respect to completion methods in multilayered, tight gas pay zones. We have analyzed the various diversion techniques and injection methods. We have developed decision charts that encompass these techniques / methods as functions of reservoir parameters such as depth, net pay and bottom-hole pressure. Finally, we have developed computer programs that produce the optimum diversion techniques and appropriate injection method for completing these pay zones as a function of formation characteristics.

1.2 Tight Gas Development

Increasing technologies and better reservoir knowledge are making the production of unconventional gas economically viable, and more efficient. This efficiency is bringing unconventional resources such as tight gas, coal-bed methane and shale gas into the reach of more companies around the world. Production from tight gas reservoirs, however, is still far from optimum, as only limited knowledge is available about the causes of the problems surrounding the stimulations (hydraulic fracturing) of low permeability reservoirs. Economically producing gas from the unconventional sources is still a great challenge today.

Besides the recognition and solution of technical problems, the petroleum engineers and geoscientists have to deal with the fact that some low permeability reservoir rocks may be potentially vulnerable to secondary skin effect (mechanical damage caused by the fracture treatment itself). One of these damage features may be the loosening and transport of fines from the pore-fillings such as clay minerals due to treatment-induced stress and their redeposition at the tight pore throats.

Tight gas reservoirs require advanced techniques to enable the reduction of migration distances from formation to well. Thus, modern technologies for the production of tight gas reservoirs are horizontal and multilateral wells, as well as under-balanced drilling. Also, stimulation and cementing technologies are proving most significant for improved economic production. Conventional technologies are used for field development of tight gas reservoirs.

Factors affecting the economic production from micro Darcy gas fields are:

- Accurate field and well modeling to improve the understanding of the reservoir;
- Development of optimum hydraulic fracturing procedures;
- Better understanding of petrophysical and geological aspects: permeability, porosity, water saturation, condensate rich gas, capillary forces, and presence of reactive clays;
- Application of advanced completion and stimulation techniques; and

- Application of advanced drilling techniques such as the need for under balanced drilling (UBD).

When gas is being produced from tight reservoirs, some form of stimulation is required to boost the production rate. This process is usually hydraulic fracturing. Wells completed in tight reservoir rocks have to be stimulated by one or several hydraulic fractures in order to achieve an economically adequate production rate. Tight gas reservoirs often show a much weaker response to the fracture treatments, when compared with more permeable rocks, resulting in low production rates and a high economic risk.

Natural fractures in the formation are an important factor in the economic recovery of gas from tight reservoirs. The distribution, orientation, and density of these natural fractures are important in proper planning and well scheduling in tight gas reservoirs. Advanced methods of gas production in these environments are taking advantage of gas flow from natural fractures in the reservoir rock. Reservoir engineers need detailed analyses of the effects of interstitial clays and fluids. The nature of the natural fractures and other characteristics of the reservoir were sufficiently well-determined that drilling could be accurately directed.

An understanding of the petrophysical properties such as the lithofacies associations, facies distribution, in situ porosities, saturations, effective gas permeabilities at reservoir conditions, and the architecture of the distribution of these properties, is required in order to comprehend the gas production from low permeability rocks.

The development of a multilayered TGS reservoir is accompanied with problems resulting from the highly heterogeneous spatial distribution of permeability and porosity throughout the reservoir layers. Also, problems associated with the stratification of deposits, variable production rate of wells inducing the selective bottom water intrusion to the deposit and giving rise to the trapping of hydrocarbons behind the hydrocarbons - water front, paraffins, resins and asphaltenes surround the development of a TGS.

It is essential to integrate core data and log analysis to reduce the uncertainty in the estimation of hydrocarbon in place and fluid distribution in tight gas reservoirs. A newly developed saturation-height function approach[1] has been successfully applied to calibrate log analysis to better define petrophysical properties such as formation water saturation and free water level in tight gas reservoirs. The application of this approach has played an important role in exploration and development decision-making processes for tight gas reservoirs.

1.3 Objectives of Study

The primary purpose of this research effort is to evaluate the diversion techniques and injection methods involved in completing tight gas sands with thick, multiple pay zones. We have developed decision charts and computer programs to assist an engineer in determining the best ways for diverting fracture treatments or selecting injection methods. These programs have been tested using best practices as documented in the petroleum literature.

This research is part of a larger project to develop an expert system that can be used to perform basin analogy, estimate unconventional gas resources in a basin, and develop best practices for drilling, completing and stimulating TGS reservoirs. We are building a computer model called TGS advisor. This work described in this thesis will be part of TGS advisor.

CHAPTER II

LITERATURE REVIEW

2.1 What Are Tight Gas Sands?

Tight gas sands in North America are generally known as sandstone formations with an expected value of gas permeability of 0.1 millidarcy (mD) or less. Several definitions of tight gas sands have been proposed in the petroleum literature.

Kuuskraa, V.A. and Haas, M.R. proposed that "tight gas is merely an arbitrary delineation of a natural geologic continuity in the permeability of a reservoir rock. The dominant characteristic of tight gas is that it is low in-situ flow capacity. Formations are called tight when their in-situ permeability is less than 0.1 mD. In addition, such reservoirs often contain lenticular pay zones and other heterogeneous geologic properties. As a result of these geologic complexities, characterization of tight gas sands remains a major technical challenge to geologists and engineers"[5].

The DGMK (German Society for Petroleum and Coal Science and Technocrats) announced a new definition for tight gas elaborated by the German petroleum industry: "Tight-gas plays, often called 'unconventional gas', are defined as gas-bearing sandstones or carbonates with an in-situ permeability of less than 0.1 mD. Many 'ultra tight' gas reservoirs have in-situ permeability as low as 0.001 mD"[6].

Misra, R. proposed that “tight gas sands are reservoirs that have low permeability (< 0.1 mD) and which cannot be produced at economic flow rates or do not produce economic volumes without the assistance from massive stimulation treatments or special recovery processes and technologies, such as fracturing, steam injection e.t.c.”[7]. He further stated that “conventional reservoirs have a reasonably consistent relationship between porosity and permeability whereas a tight reservoir does not have such relationship between porosity and laboratory measured permeability except that the in-situ permeability to gas generally is less than 0.1 mD”.

Holditch defined tight gas sands as “a reservoir that cannot be produced at economic flow rates or recover economic volumes of natural gas unless the well is stimulated by a large hydraulic fracture treatment or produced by use of a horizontal wellbore or multilateral wellbores”[8].

Summarizing all the stated definitions, a general definition for tight gas sands in North America could thus be that they are sands that have permeability of 0.1mD or less and cannot be economically viable without the aid of massive stimulation treatments. The poor permeability is primarily due to fine-grained nature of the sediments, compaction, or infilling of pore spaces by carbonate or silicate cements precipitated from water within the reservoir[9]. These sands are generally known to contain significant volumes of natural gas. They experience relatively high decline rates during initial production, then stabilize at low decline rates. Most hydraulically fractured tight gas wells can be matched using a hyperbolic decline curve model.

2.2 History and Reservoir Considerations

In the United States, formations were regarded as tight based on a certain criterion in order to make them eligible for tax credits. This criterion was that the formation should have an expected permeability to gas of 0.1 mD or less. In addition to the introduction of tax credits, the U.S. gas industry established the Gas Research Institute (GRI) to fund and manage research in various gas topic areas, including unconventional gas and tight sands[9]. The resulting research projects, combined with those of the U.S. Department of Energy led to substantial advances in technology which led to accelerated development of unconventional gas. The results of these research programs led to most of the "routine" technology being employed in today's industry[9].

Tight gas sands are usually found in the deeper portions of hydrocarbon-bearing basins[9]. In shallow, conventional reservoirs, gas wells can flow at high rates and decline exponentially. Gas flow rates from tight gas reservoirs are usually lower than what the industry expects from conventional reservoirs. In addition, the effective drainage area in a tight reservoir is usually much smaller than that of a conventional reservoir. Due to the low permeability, a tight gas reservoir cannot drain much of the reservoir over a 20 – 30 year period. As a result, to produce tight gas reservoirs economically, it is necessary to commingle as many zones as possible and to fracture stimulate every zone creating long fractures in each zone.

Major tight gas plays in the U.S. include the Cotton Valley of East Texas; the Mersaverde in New Mexico's San Juan Basin; the Canyon Sands in the Permian basin of West Texas; the Wasatch in Utah's Uinta Basin; the South Texas Wilcox/Lobo play and the Lance, Dakota and Frontier formations in Wyoming's Green River basin[10]. The greatest production growth from 2003 to 2025, however, is forecast to occur in the Rockies, mainly in the Greater Green River, Uinta and Piceance basins[10].

Tight gas reservoirs have to be hydraulically fracture treated before they can produce gas at economic rates. In the 1980s, viscous, cross-linked polymer fracture fluids that carried large volumes of sand were used to stimulate tight sand reservoirs. However, due to high costs and low gas recovery, many of the wells were uneconomic[10]. In the 1990s, less expensive techniques such as the slick-water fracturing technique that used high volumes of water and low concentrations of proppant were tried in some TGS reservoirs[10]. In many wells, multistage fracturing techniques were being used to stimulate wells with thick, multizone reservoirs. Multi-zone completion methods are currently used in many reservoirs. The coiled tubing fracturing technique, for instance, can be used to treat multiple zones with one trip in the hole instead of pulling out every time to go to the next zone.

A thorough analysis is needed to understand the reservoir properties of tight gas sands. According to Peiguin Yin[11], the upper cretaceous, tight, overpressured sandstones in the Wyoming basins are rich in lithic, chert, and feldspar grains due to the lithologic variations in the source areas and lack of transportation sorting. Quartz overgrowth cement and carbonate patches are normally seen in sandstones from the Lance, Almond and Frontier formations. These formations became tight due to mechanical compaction and chemical cementation resulting from increasing burial[11]. Permeability in these tight sandstones is generally less than 1mD while the porosity ranges from 5 to 8% which is as a result of the dissolution of detrital grains and cements. Peiguin Yin[11] further stated that the micropores in the clays and leached detrital grains contribute only to porosity, but do not contribute significantly to permeability. Consequently, permeabilities do not correlate well with core-measured porosities in these tight sandstones[11].

In some cases, tight gas reservoirs of various ages and types produce where structural deformation creates extensive natural fracture systems whether it is basin margin, foothills or plains. Unfortunately, many explorationists think of tight or low-permeability reservoirs as occurring only within basin-centered or deep basin settings[2]. Tight and unconventional reservoirs can occur in tectonic settings dominated by extensional, compressional or wrench faulting and folding. Tight gas reservoirs may also result from late burial diagenesis of the sandstone[2].

According to Naik[2], conventional reservoirs and low-permeability reservoirs have different characteristics and petrophysical attributes. The significant differences between the two reservoir types lie in the low-permeability structure itself, the impact that the low-permeability structure has on effective permeability relationships under conditions of multiphase saturation, and the response to overburden stress. A comparison between the traditional reservoir behavior and low-permeability reservoir behavior is expressed in Fig. 2.1. Naik[2] reported that, in a traditional reservoir, critical water saturation and irreducible water saturation occur at similar values of water saturation. Also, there is a relative permeability in excess of 2% to one or both fluid phases across a wide range 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. On the other hand, in a low-permeability reservoir, irreducible water saturation and critical water saturation can be dramatically different[2]. Unlike the traditional reservoir, where there is a wide range of water saturations at which both water and gas can flow, in the low-permeability reservoir, there is a broad range of water saturations at which neither gas nor water can flow. In some very low-permeability reservoirs, there is no mobile water phase even at very high water saturations. There is a large range of water saturations over which both water and gas are essentially immobile because of the effective permeability structure of most low-permeability reservoirs. Low-permeability reservoir rocks should be regarded as having insufficient permeability to either gas or water over a wide range of water saturations. A lack of water production should not be used to conclude that the rocks are at, or near, irreducible water saturation nor should these regions be regarded as water free[2].

The relationships between relative permeability, capillary pressure, and position within a trap in conventional and low permeability reservoirs are expressed in Figs. 2.2a and 2.2b. In both cases, the map shows a reservoir body that thins and pinches out in a structurally updip direction. In a low permeability reservoir as shown in Fig. 2.2a, significant water production is restricted to very low structural positions near the free water level (FWL). In many cases, the effective permeability to water is so low that there is little to no fluid flow at or below the FWL. Above the FWL, a wide region of little to no fluid flow exists. Further updip, water-free gas production is found. In a conventional reservoiras shown in Fig. 2.2b, water production extends downdip to a FWL. In the middle part of the reservoir, both gas and water are produced, with water decreasing updip. The updip portion of the reservoir is characterized by water-free production of gas.

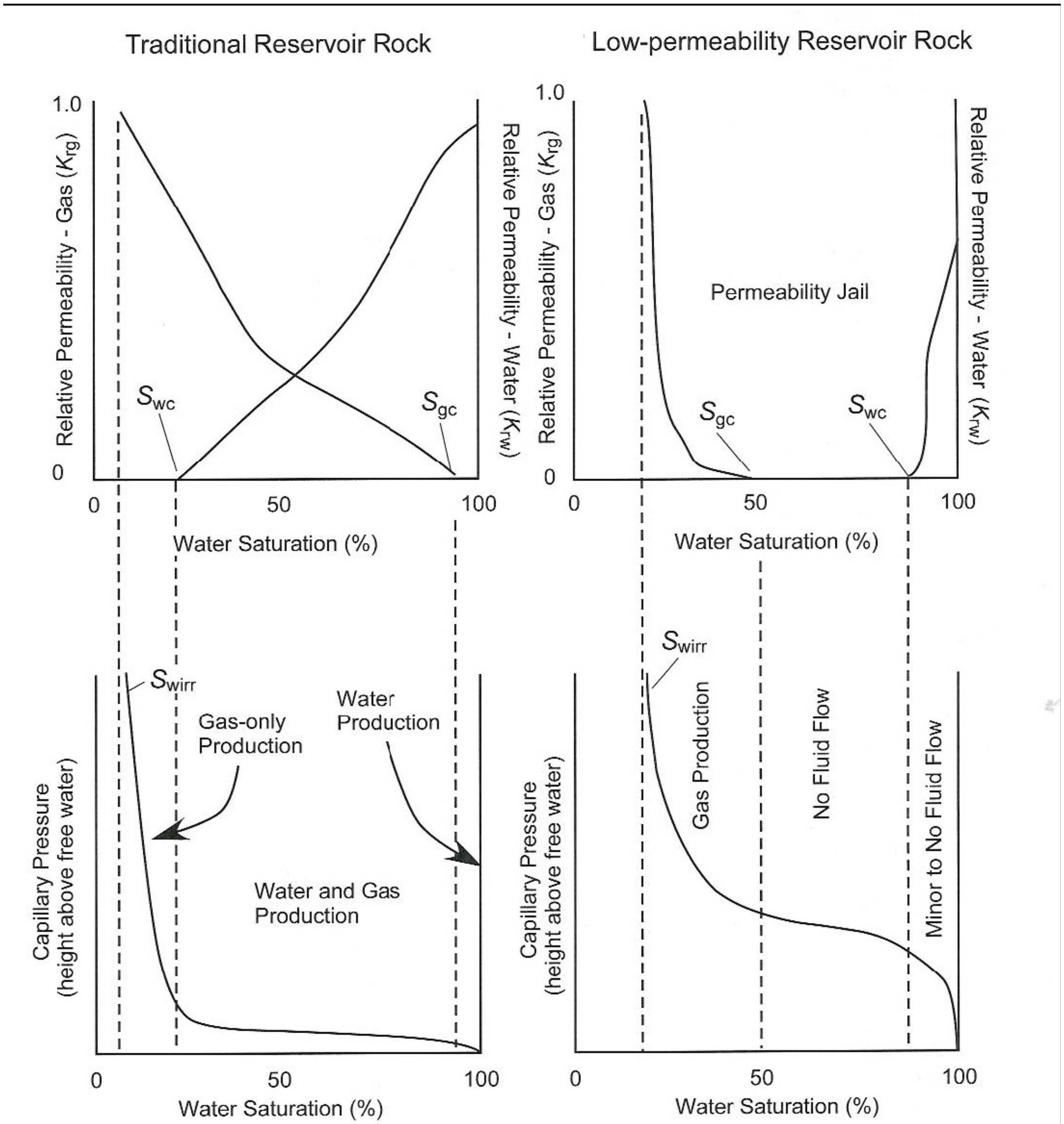


Fig. 2.1: Schematic illustration of capillary pressure and relative permeability relationships in traditional and low-permeability reservoir rocks[2]. Critical water saturation (*S*wc), critical gas saturation (*S*gc), and irreducible water saturation (*S*wirr) are shown

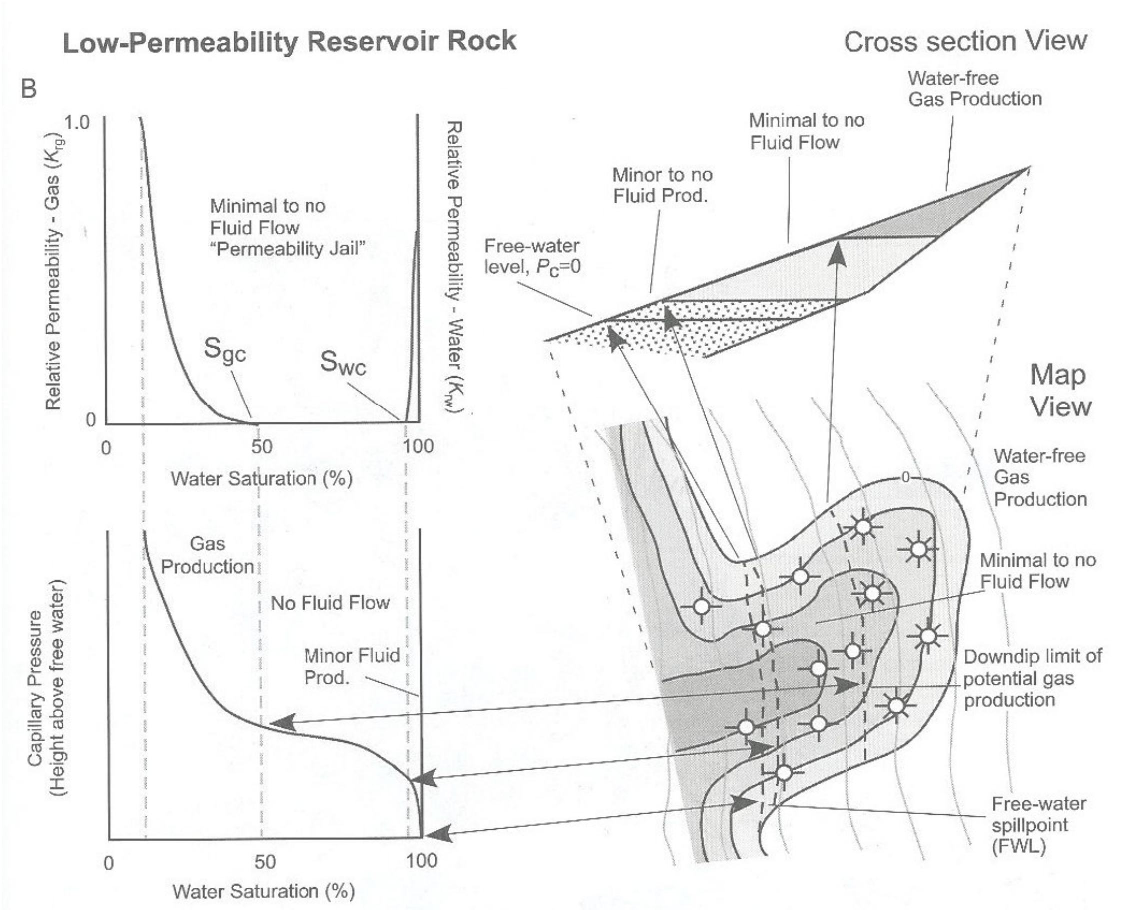


Fig. 2.2a: Schematic illustration highlighting relationships between capillary pressure, relative permeability and position within a trap, as represented by map and cross section views for a reservoir with low-permeability. The map illustrates a reservoir body that thins and pinches out in a structurally updip direction[12]

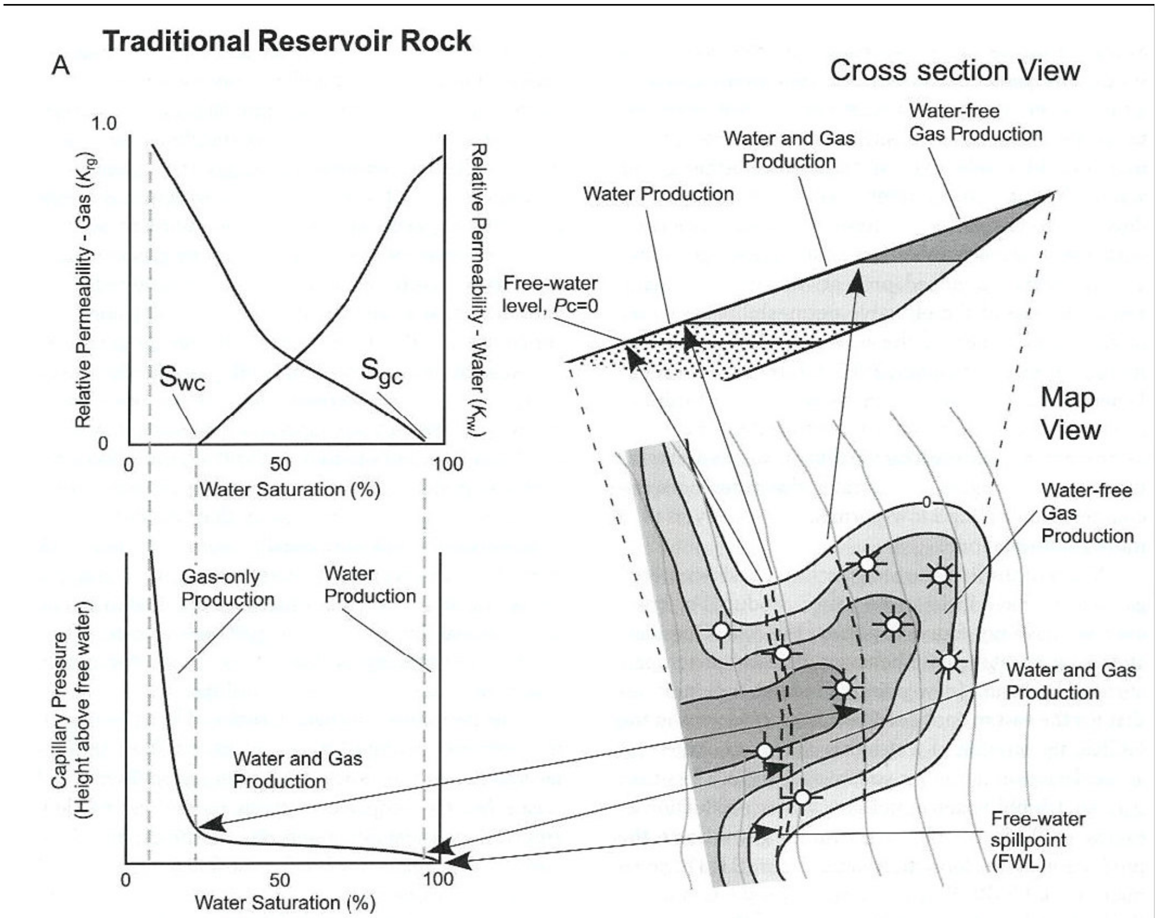


Fig. 2.2b: Schematic illustration highlighting relationships between capillary pressure, relative permeability and position within a trap, as represented by map and cross section views for a reservoir with traditional rock properties. The map illustrates a reservoir body that thins and pinches out in a structurally updip direction[12]

2.3 Basin – Centered Gas Accumulations

According to Law[13], basin-centered gas accumulations (BCGA) are regionally pervasive accumulations that are gas saturated, abnormally pressured (high or low), commonly lack a downdip water contact, and have low permeability reservoirs. They vary from single, isolated reservoirs to multiple, stacked, lenticular reservoirs. BCGAs have been widely described by the term “tight gas sand”. These accumulations have also being associated with the term “deep basin gas” by Masters[14]. Law[13] further stated that thermal maturity and hydrocarbon generation in the BCGAs is normally as a result of the deep burial of gas and oil prone source rocks. He categorized the BCGAs into the direct type, which is characterized by having gas-prone source rocks; and indirect type, characterized by having liquid prone source rocks. Majority of the BCGAs, however, are the direct type.

The commercial production of gas from BCGAs is generally associated with areas that have improved permeability. These areas are known as “sweet spots”. Sweet spots, according to Surdam[15], are “those reservoir rocks that are characterized by porosity and permeability values greater than the average values for tight gas sands at a specific depth interval”. He[15] reported that “the commercial production from BCGAs is strongly dependent on the presence of open natural fractures and the ability to connect these natural fracture systems through hydraulic fracture stimulation” Table 2.1 summarizes the attributes commonly associated with basin-centered gas systems[1].

Table 2.1: Summary of characteristics commonly associated with low-permeability, Basin-Centered Gas Accumulations[1]

Geographic area	Tens to hundreds of square miles Common in the more central, deeper portions of sedimentary basins Located in widespread gas saturated regions Much larger than conventional oil and gas traps
Resource Size	Very large in-place resource Low overall recovery factor
Relationship to water	Generally lack downdip water contacts Generally located downdip of pervasive water saturated rocks Water production is generally absent to very low
Trap boundaries	Structural and stratigraphic traps, in the conventional sense, are thought to be of limited importance
Reservoir Pressure	Overpressure and underpressure are both common
Source rocks	In close proximity to reservoir rocks
Reservoir permeability	Generally less than 0.1md

Failure to fully comprehend that low-permeability reservoirs have unique petrophysical properties has led to a misunderstanding of fluid distributions in the subsurface. In order to fully appreciate the controls on gas-field distribution as well as the controls on individual well and reservoir performance, an understanding of multiphase, effective permeability to gas as a function of both varying water saturation and overburden stress is expected. A better understanding of the relationship between rock fabric and gas productivity requires careful investigations into multiphase permeability under conditions of varying water saturation and net-overburden stress, as well as an analysis of capillary pressure and net-overburden stress. The lack of widespread water production does not imply that vast areas of a sedimentary basin are at irreducible water saturation; instead, it implies a complex, effective permeability-to-gas relationship.

Shanley et al.[12] came to some conclusions on the controversy of basin centered and low-permeability reservoirs, which are critical to the future exploration and production of these resources. Some of these are stated below:

- Exploration efforts in low-permeability settings must be deliberate and focus on fundamental elements of hydrocarbon traps.
- Improvements in completion and drilling technology will allow well identified geologic traps to be fully exploited, and improvements in product price will allow smaller accumulations or lower-rate wells to exceed economic thresholds, but this is true in virtually every petroleum province.
- Petrophysics is a critical technology required for understanding low-permeability reservoirs.

- Low-permeability reservoir systems like those found in the Green River Basin are not examples of "basin-center" or "continuous-type" accumulations, nor are they a unique type of petroleum system.
- Only truly 'continuous-type' gas accumulations are found in hydrocarbon systems in which gas entrapment is dominated by adsorption, such as coalbed methane, or where the reservoirs are in close juxtaposition with their source rocks.
- Resource assessments of these regions have assumed a continuous, recoverable gas accumulation exists across a large area locally interrupted by the development of "sweet spots." However, this viewpoint is at odds with the reservoir characteristics of low-permeability reservoirs.
- Significant production is dependent on the presence and identification of conventional traps.

Shanley et. al.[12], thus, believe that existing resource estimates are likely to have been overestimated. Resource assessments in these low-permeability "basin-centered" regions must recognize the reservoir properties inherent to these rocks and should integrate the necessary concept of source, trap, seal, migration and charge, and be conducted in a manner consistent with the assessment of conventional oil and gas systems.

2.4 Multilayered Tight Gas Sands - Diversion Techniques

Many wells are completed and drilled each year in tight gas reservoirs that have many distinct layers that can contribute to production if adequately treated. According to McDaniel[16], when an oil or gas well has penetrated multiple pay zones that are known to have the potential to contribute high production rates if adequately fracture stimulated, it is easy to justify the expense and effort of using mechanical isolation to help ensure effective stimulation of each zone or groups of closely spaced zones. He further said that most operators consider the preferred method which involves:

1. Perforate the lowest zone, then pump the hydraulic fracture treatment;
2. Flow back / cleanup the stimulated zone (10’s of hours to 10’s of days);
3. Mechanically isolate the stimulated zone(s) and repeat the entire multi-day process again on the next zone up-hole (and possibly a third or fourth zone if needed); then
4. Remove the mechanical isolation hardware, complete well and turn to sales.

Although the method above serves as the appropriate method to clean up completely the fracture fluid in the gas zone in between fracture treatment stages, the process may not be used by some operators due to the high costs involved especially if workover rigs have been used. The method requires lots of rig time and additional fracture costs to mobilize equipment.

Many papers in the petroleum literature provide information on techniques involved in completing multilayered, tight gas reservoirs in order to help operators achieve their production goals. Different methods can be applied, ranging from the single stage fracturing treatments using limited entry perforating to the conventional multistage fracture treatments using a packer and bridge plug. Poor choices are normally made on a regular basis concerning the completion technique due to a limited understanding of the method or the reservoir itself. McDaniel[16] said that most times, an operator understands the variances of a reservoir, but does not realize the limitation that these variances should bring to the process of choosing the optimal stimulation/completion method. Even when the choice has been made to use the low-cost completion/stimulation approach, the resulting well ends up not producing at optimum levels or, sometimes, even at economic levels of gas flow rate. McDaniel[16] listed three of the basic elements that contribute in controlling stimulation costs:

1. Length of time needed for the completion and stimulation;
2. The number of times a fracturing service crew must rig-up equipment on location; and
3. The number of days that fracturing equipment is on location each time.

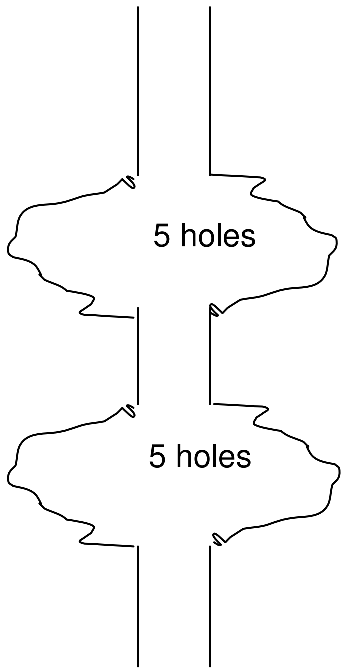
2.4.1 Limited Entry Technique

Bazan[17] refers to the "limited entry" technique as the technique of limiting perforation sites throughout a completion interval in order to create a pressure differential across the perforations to aid in treatment diversion.

According to Lagrone et. al.[18], the limited entry treatment is performed by:

1. Limiting the number of perforations in a well; and
2. Providing sufficient injection rate to require the restricted capacity of the perforations to divert the treatment to a greater portion of the perforated interval.

In this technique, the number and diameter of the perforations in the casing is limited to increase the bottom-hole treating pressure above the fracture initiation pressure of each successive zone to be treated. Also, by increasing the injection rate, there is a corresponding increase in the perforation friction. Maintaining the perforation friction at maximum during the treatment produces optimum results. As the injection rate is increased, the perforations create an increase in the available bottom-hole casing pressure. This accompanying increase, thus, breaks down or fractures the next zone[18]. Fig. 2.3 shows a representation of the limited entry technique. Fig. 2.4 shows that the perforation friction varies directly with the rate pumped through the perforation[18]



Assuming total fluid quantity of 100,000 gals,

Pump 1 stage of 100,000 gals at 10 – 20 gals

Fig. 2.3: A representation of the limited entry technique

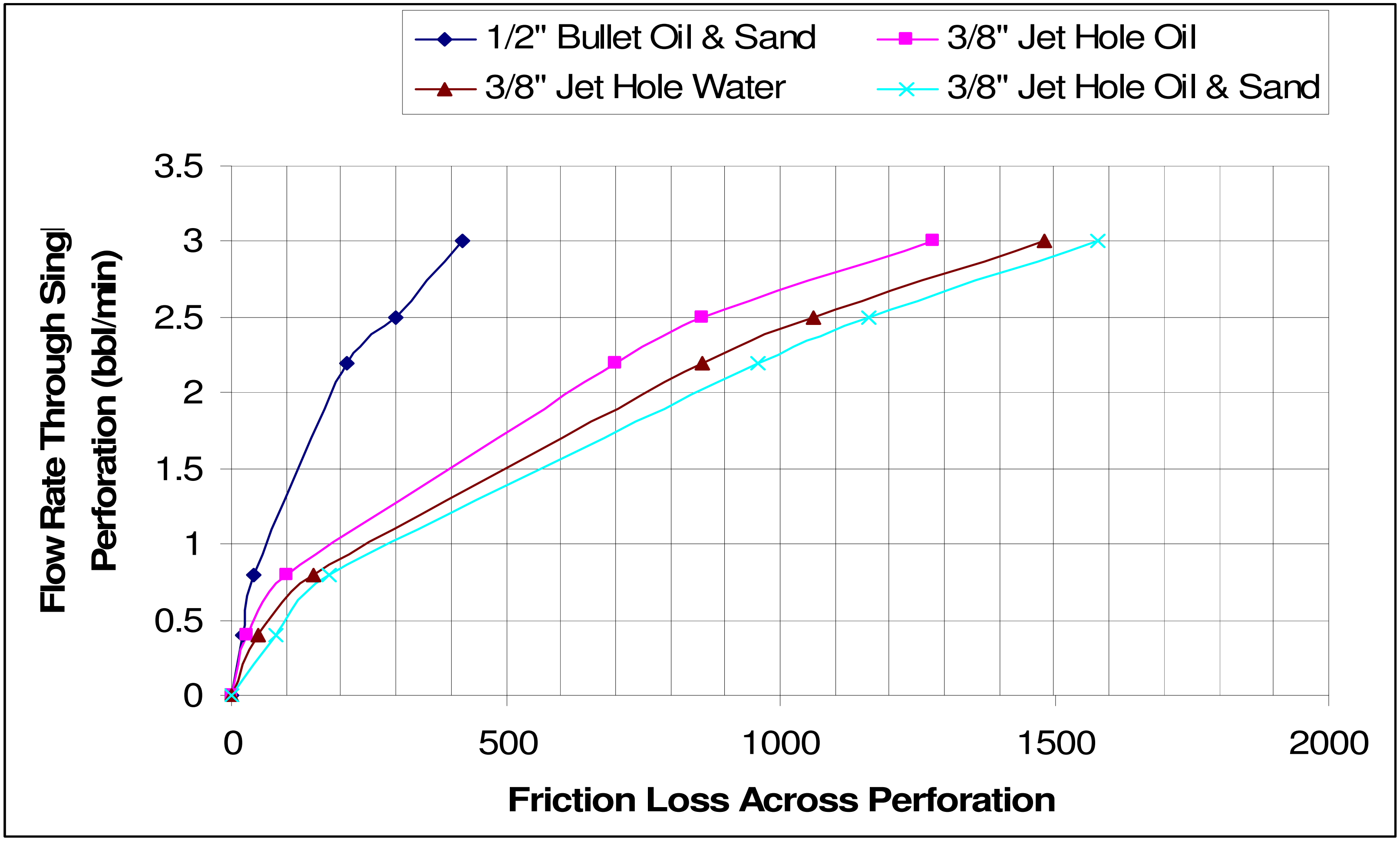


Fig. 2.4: Flow rate vs. perforation friction; laboratory measured[18]

Lagrone et. al.[18] maintained that small diameter perforations are better in limited entry treatments to increase perforation friction and also lower hydraulic horsepower requirements. In other words, by using the small perforations, less hydraulic horsepower is required to deliver an injection rate adequate to maintain a maximum perforation friction. Fig. 2.4 shows that, for the same perforation friction, approximately twice as much fluid can be injected through a $\frac{1}{2}$-in. hole as through a $\frac{3}{8}$- in. hole[18]. Consequently, $\frac{3}{8}$- in. holes are generally used for limited entry treatments.

Following a trial and error method, in the design of a limited entry treatment, a minimum number of perforations are first chosen to treat all of the pay zones and proportion the treatment properly. Secondly, an injection rate is determined for those perforations that will maintain maximum perforation friction (within casing pressure limitations)[18]. The essentials necessary to determine the number of perforations accepting fluid are: (1) accurate injection rates, (2) accurate surface injection pressures and (3) an instantaneous shut-in pressure (ISIP) at the beginning of the job.

As with every other technique, there are constraints associated with the limited entry technique. One such constraint is that the perforations may erode as proppants are pumped through the holes which, in effect, reduce the perforation friction dramatically. Perforation erosion is often suspected as the major reason for inadequate treatment coverage i.e. portions of the pay remaining untreated. For limited entry to work, a good cement bond is needed around the casing, the proper number and size of perforations must be placed in each porous interval, and barrier to fracture growth must exist between each porous interval.

Despite the constraints, the limited entry technique still proves to be the best method of diversion in some deep wells where other forms of diversion are costly and the sizes of the pay zones are small.

2.4.2 External Casing Perforating System (ExCAPE)

The external casing perforating system (ExCAPE) was developed specifically for a project in Kenai, Alaska[19] and is designed to deliver pin-point perforating for the stimulation of discreet productive intervals along with a mechanical means to complete individual zones in a rapid, cost effective manner. The technique was chosen for the Beluga sands in the Kenai gas field to improve economics and total hydrocarbon recovery by effectively and economically stimulating the low quality sand bodies[20]. The economics of the conventional completion techniques never allowed the potential resource in these sands to be stimulated. Also, the conventional techniques prohibited evaluation of the sands to determine whether they could be commercially developed and added to the reserve base[20].

The ExCAPE system incorporates integral isolation devices, perforation guns that are mounted external to the casing, and methods to fire the guns and actuate the isolation devices remotely[19]. Fig. 2.5 represents an ExCAPE module with its components[19]. The guns are fired using a ¼ in. stainless steel external hydraulic control line at an average of eight modules per line. Fig. 2.6 illustrates a schematic of a portion of the wellbore in which a second interval is being perforated and the isolation valve actuated[20]. The isolation devices are compatible with conventional primary cementing and fracture stimulation operations. The flapper valves are actuated when an interval is perforated, and serve to isolate lower intervals during fracture stimulation operations[20]. These isolation valves hold approx. 8,000 psi differential pressure, and each zone is treated by itself. The isolation devices can be removed with a specially machined nozzle on coiled tubing at the conclusion of stimulation operations[19].

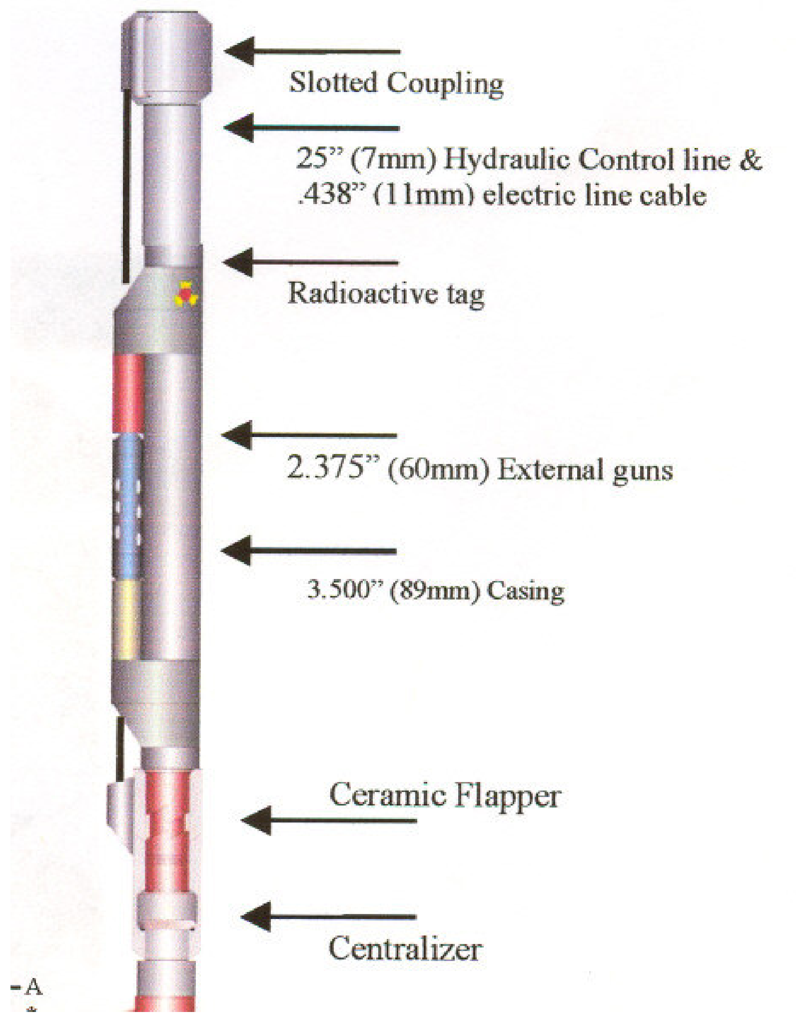


Fig. 2.5: EXCAPE module with its components[19]

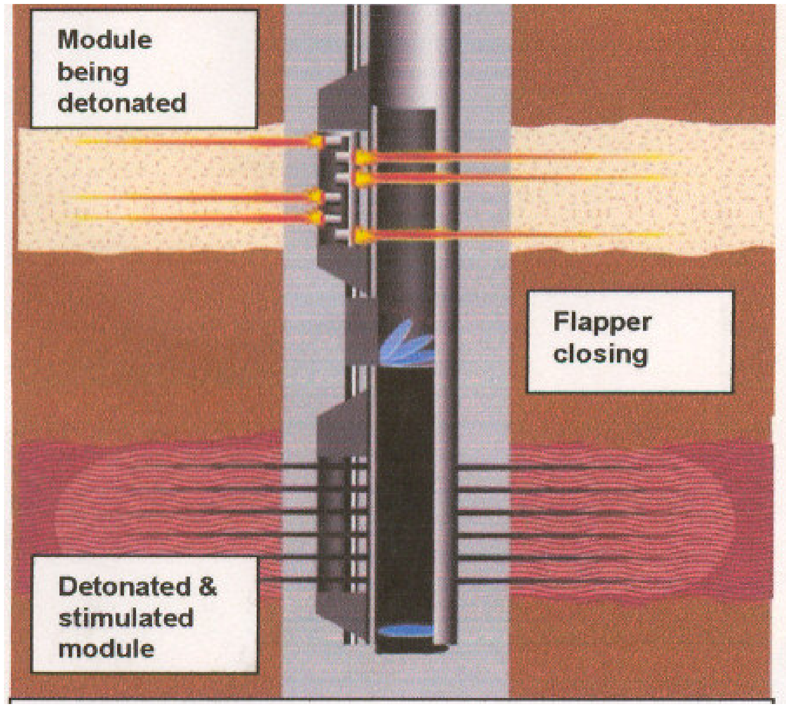


Fig. 2.6: Schematic of one module detonating while the flapper is closing above a previously detonated module[20]

Eller et. al.[20] listed a number of benefits associated with the ExCAPE technique. They include:

1. Significant reduction in total completion time and acceleration of first production;
2. Less bypassed pay and improved stimulation quality in a stacked-pay environment;
3. Direct measurement of the bottom hole pressure (BHP);

4. Monobore well designs, which help prevent liquid loading and facilitate rigless well repairs;
5. Lower fracturing fluid volume requirements due to smaller tubulars, and the displacement fluid for one stimulation stage becoming the pad fluid for the subsequent stimulation stage;
6. Lower total development costs due to the reduction in tubular requirements, rig time, and associated services;
7. Lower frac horsepower requirements by only stimulating a single interval at a time; and
8. Improved safety, well control, and environmental operations because the equipment is remotely actuated without having to convey equipment inside the casing.

Nine wells were successfully drilled, cemented, and fracture stimulated in the tight gas sands of four separate fields on the Kenai Peninsula, Alaska utilizing the unique ExCAPE system[19]. A total of 124 modules were run, cemented in place, detonated, and fracture stimulated for this nine well program. There was 100% success with gun detonation and actuation of ceramic isolation devices. Also, post treatment production for the wells reviewed across the four various fields has been at least at forecasted levels to at nearly double forecast.

Before running the ExCAPE system, the hole has to be conditioned adequately so as to prevent the pipe from becoming stuck significantly off depth. The depths of the perforating modules are normally verified by running a through-casing gamma ray (GR) and casing collar log (CCL). These determine the location of each module relative to the zone of interest.

Challenges and disadvantages associated with the ExCAPE technique include:

1. Removal of the isolation devices with a machined nozzle on coiled tubing;
2. Extra measures to ensure the success of the cementing operation are carried out since squeezing a poor cement job is not an option. Also, many tough cement design and operational challenges have to be analyzed and solved because of the uniqueness of the external casing equipment design used in the process;
3. The EXCAPE system requires a slightly larger borehole size to accommodate its hardware; and
4. Effective planning by a multidisciplinary team, months in advance of spudding the well is required.

To date, the ExCAPE module has been run to 14,000 feet and in horizontal wells with over 4,000 feet of lateral length. It has also been run at 300°F, and with 16.5 lb/gal drilling fluids.

2.4.3 Flow-Through Composite Frac Plugs (FTCFP)

Ebernard et. al.[21] refers to the Flow -Through Composite Frac Plugs **(**FTCFP) as a specific tool that works as a bridge plug when the pressure above it (such as during a fracture treatment) is higher than the pressure below the plug. The tool then allows fluid-flow from below through the plug when the pressure above is lower than the pressure below (such as when flowing the well back).

The first FTCFPs were developed for completions of coalbed methane (CBM) treatments in the Northeastern United States in 1996. The success of FTCFPs was recognized as a way of eliminating the problems associated with traditional isolation methods for multiple-treatment wells in the Rockies[21]. The first FTCFPS applied in the Rockies were run in the Wind River Basin in Wyoming in 1998 for the Mesaverde and Meeteetse completions at depths of 10,000 to 13,000 ft. To date, flow-through composite bridge plugs are still used exclusively at the Pavilion and Muddy Ridge Fields in the Wind River Basin[21].

FTCFPs require less rig time than conventional cast iron bridge plugs. They are designed to set securely in the casing and then be easily removed using coiled tubing conveyed downhole motors and drilling tools in an under-balanced environment after remedial operations are complete[22]. Using a mill, either by coiled tubing and a downhole motor or on a jointed pipe with surface power swivel are the most successful methods for removing a FTCFP. With coiled tubing, the recommended method is to use a five-bladed mill, medium to heavy “cutrite” 1/8-in. to ¼-in. size, with a 30^0 taper from the outside inwards toward the middle[21].

Long and Kundert[23] pointed out in their conclusions that FTCFPs are responsible for greater well productivity and reduced completion time as a result of the elimination of well-killing operations. Kill fluids, especially in deep wells, can reduce production from a well by damaging newly fractured zones to the extent that production is cut in half or to nothing at all. An integrated study of the Jonah field showed that 11% of the fracture treatment did not show any production after being killed. The long killing period was the major cause of under performance.

The FTCFP is constructed like a drillable composite bridge plug except that it has a 1-in. diameter hole through its center[21]. A tapered seat, which holds a weighted plastic ball, is located on the top of the tool. When the FTCFP is placed in the well, the weighted ball sits on the seat and provides a pressure-tight seal to stop any flow through the FTCFP from above[21]. Fig. 2.7[23] shows the cross-section of an FTCFP with the plastic ball on top of the tool. When the zones are being fractured above the FTCFP, its performance is likened to that of a bridge plug. Fig. 2.8[23] shows different intervals stacked with composite frac plugs. When the well is opened for flow testing, the ball is lifted from its seat on the FTCFP, allowing the zones below to produce through the center of the tool.

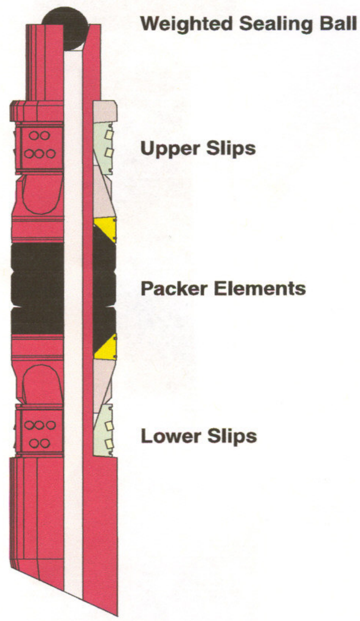


Fig. 2.7: Flow through composite frac plug[23]

The entire FTCFP is constructed of easily drillable materials. No metal parts are used, only composite material ceramics in the buttons of the slip wedges that engage the casing. The average drill-out time per plug is 15 to 30 minutes. After drill-out, the tubing can be hung in the well as a velocity string to aid in liquid unloading once the gas flow rates decline below the outlined velocity required to lift liquids up the casing.

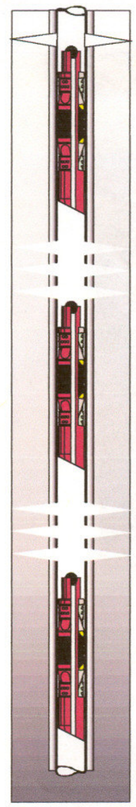


Fig. 2.8: Stacked composite frac plugs[23]

According to the field study by Ebernard et. al.[21] performed in 2003, the use of the FTCFP has resulted in a step change increase in well productivity in the Jonah Field by an average 0.6 Bcf in the first 12 months. The technology has brought about a positive change in the completion of wells containing multiple sand intervals. The tool reduced or eliminated post-treatment damage to the hydraulic fractures caused by previous completion techniques. This production differential is believed to be the result of the following[21]:

1. The zones did not have to be killed after clean-up. All previously treated zones helped clean up each subsequent treatment;
2. Not shutting in for long periods of time; and
3. Effectively stimulating more sand with mechanical isolation

As a result of this case study and others, the use of the FTCFPs is regarded a best practice for completing multiple pay wells in the Rocky Mountain region.

2.4.4 Coiled Tubing Fracturing (CTF)

The combination of coiled tubing services with fracture stimulation operations has been dated as far back as 1992. However, the early CTF treatments were not accepted universally due to limitations in their applications. These limitations were as a result of numerous operational and fracture design constraints. CTF, which was later applied in multi-stage fracture stimulation, sometimes reduces completion time and enhances the economics of the wells. CTF has improved well stimulation by allowing for selective placement of the proppant[24]. This fracturing technique was then broadened to include stimulation of wells where the tubing integrity prevented conventional fracturing. The wells under consideration were slim-hole completions that were several years old[24] in the field.

Coiled tubing fracturing is an innovative solution for both new well completions and workover applications. When combined with specially designed bottomhole assemblies, it can effectively isolate zones of interest without the need for costly workover operations. This technique has become very successful in stimulating shallow gas wells. The majority of the wells completed with this technology have been recently drilled, with some having up to 17 fracture treatments over a 900 foot interval[25]. The standard practice involved in using the CTF technique is to start at the deepest perforated interval and proceed uphole. Figs. 2.9a and 2.9b show coiled tubing fracturing operations. All the intervals to be perforated and stimulated are first chosen, with the intervals perforated as a single operation. The wells are fracture stimulated, also in a single operation utilizing coiled tubing and a selective fracture stimulation tool[26]. With shallow intervals (< 700 m), 60.3 mm coiled tubing is used. Fig. 2.10 shows a standard bottomhole assembly used to isolate intervals. The tool comprises of a compression set packer, a ported sub joint and an upper cup type tool[26].

According to a study by Stromquist et. al.[26], a total of nine wells were fracture stimulated in 2000 on the Tilley gas field in southeast Alberta using coiled tubing, with an average of 7 fractures pumped per well. In 2001, the average number of fractures was increased to approximately 10 per well with twenty five wells being fracture stimulated. The twenty five new wells were fracture stimulated in twenty-five consecutive days with no weather delays, stuck tools or tool failures[26]. A comparison of fracture treatments performed prior to 2000 and the coiled tubing fracture treatments pumped in the 2000 and 2001 projects is presented in Table 2.2.

Fig. 2.9a: A coiled tubing truck involved in a fracturing operation *(source: Sclumberger)*

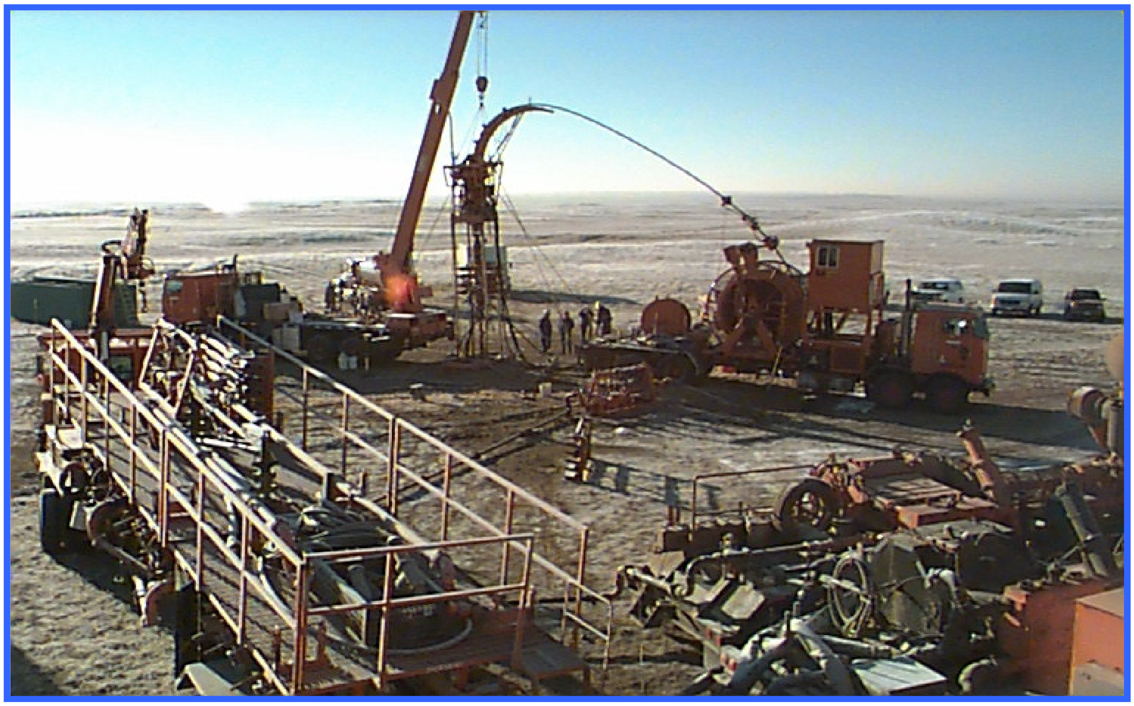


Fig. 2.9b: A coiled tubing operation (source: Schlumberger)

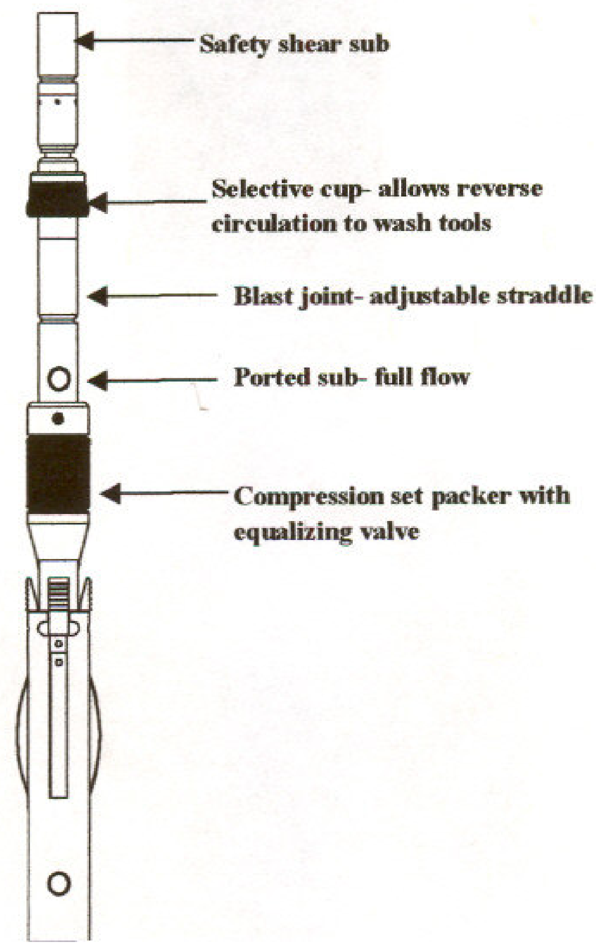


Fig. 2.10: Standard bottom-hole assembly[26]

Table 2.2: New well fracture history from 1996 to 2001 on the Tilley Milk River Gas Unit[26]

Year	Number of New Wells	# Separate Fracture Treatments	Total Proppant per Well (Tonnes)
1996	10	30	95.9
1997	1	3	80.0
1998	5	15	92.0
1999	1	3	95.0
2000	9	57	72.5
2001	25	255	79.2

The benefits of coiled tubing fracturing, as summarized by the Stromquist et. al.[26] study are:

1. Elimination of work over rig costs, bridge plugs, and well head isolation tools;
2. Complete stimulation of primary and secondary zones with multistage fracturing;
3. Reduced wellsite visits for the fracturing and perforating equipment;
4. Reduced rental time of tanks, flowback equipment, consulting and safety services;
5. A shorter well downtime and thus, accelerated production leading to shortened payback periods;
6. Elimination of costly remedial cement squeezes when stimulating bypassed payzones; and
7. Less gas vented to atmosphere as a result of combined flowback for all stimulated zones.

Fig. 2.11 shows a comparison in the application of coiled tubing and conventional techniques in fracturing operations.

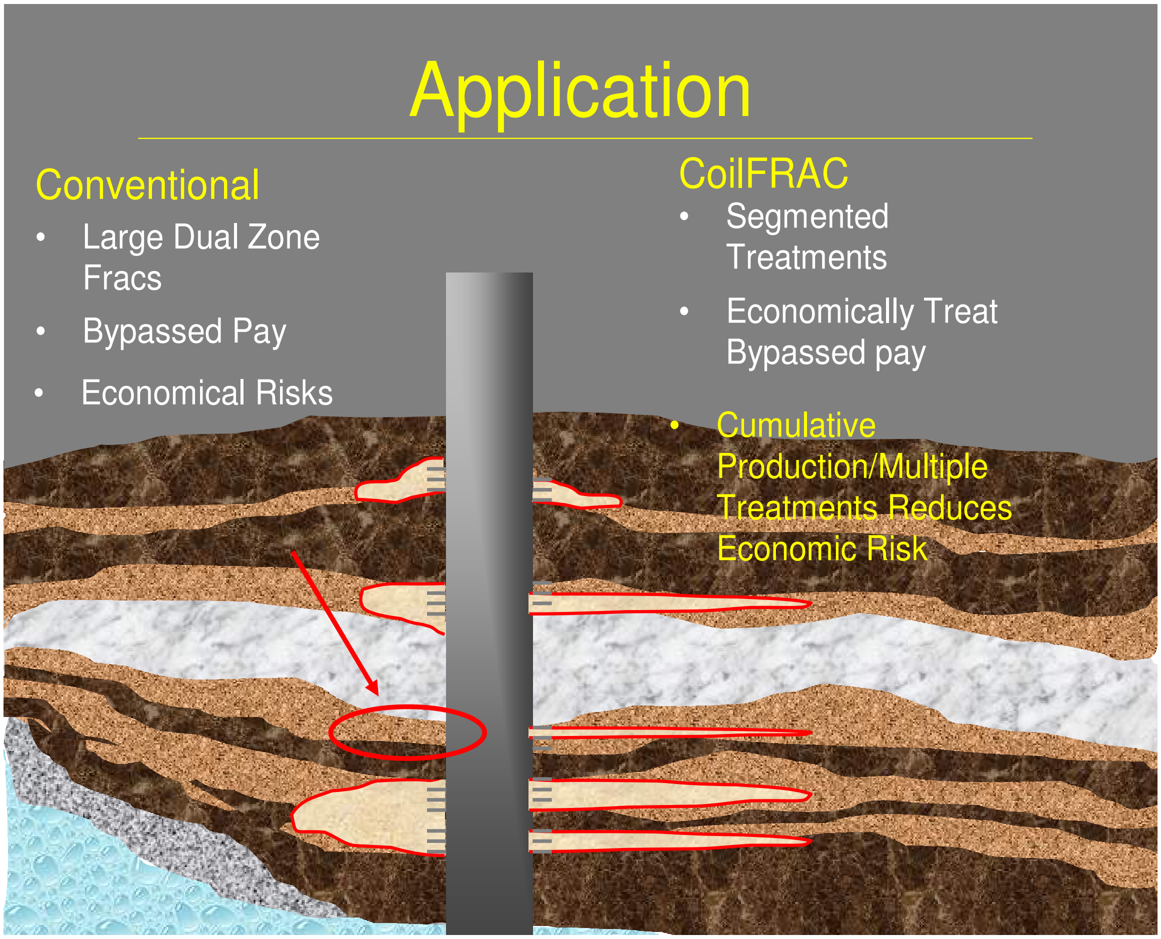


Fig. 2.11: The application of coiled tubing fracturing (*source: Schlumberger)*

In an under pressured reservoir, large zones (>75ft) are not fracture treated using coiled tubing. This is because the larger zone requires a higher rate to achieve optimal treatment. These higher rates rules out coiled tubing as a result of the potential treating pressures.

2.4.5 Pseudo-Limited Entry

The success of well stimulation treatments has always been limited by the inability to divert the treating fluids adequately into the zones where they are needed. The pseudo-limited entry technique is a method where the treatment is staged using ball sealers. Here, all the intervals are perforated with the same number of perforations. This method allows the flow of fluid through only one or two zones at a time, thus, giving better coverage of the zone. Fig. 2.12 shows a representation of the pseudo-limited entry technique. Assuming 10 holes are perforated in each zone, as shown in Fig. 2.12, and a total fluid quantity of 100,000 gals is to be pumped. The procedure will go as thus:

1. Pump stage 1 of 50,000 gals at 10 – 20 BPM;
2. Drop 10 balls while pumping; then
3. Pump stage 2 of 50,000 gals at 10 – 20 BPM.

Gabriel and Erbstoesser[27] referred to ball sealers as small spheres which seat on and seal perforations accepting an undesirable quantity of treating fluid. This method needs a certain number of perforations to be placed in two or more intervals. The ball sealers are added to the treating fluids during the stimulation process, carried to the perforations along with the fluids, and seat on perforations accepting disproportionate quantities of fluid[28]. The fluid is then diverted to other zones that need treatment. When compared to other diversion techniques, these ball sealers are inexpensive, and easy to apply. Unfortunately, it is almost impossible to control where the fracture fluid enters the formation and where the balls eventually seat or come to seat.

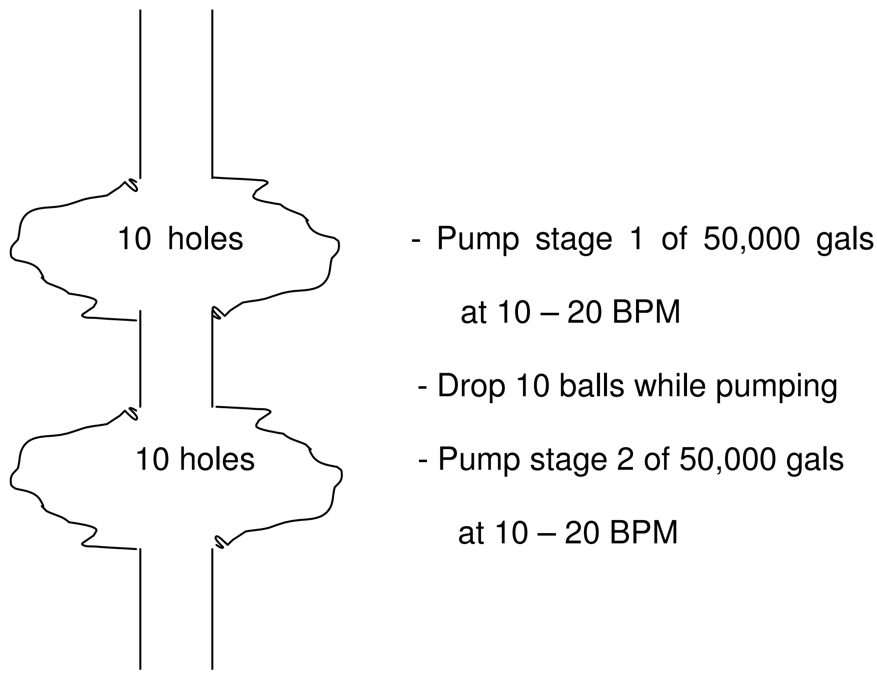


Fig. 2.12: A representation of the pseudo-limited entry technique

In his 1980 study, Erbstoesser[28] identified four parameters that were important to the ball seating efficiency:

1. Fluid viscosity;
2. Density contrast between the ball and the fluid;
3. Flow rate through the perforations; and

4. Flow rate past the perforations.

Erbstoesser's study, however, singled out density contrast between the ball and the fluid as the most important parameter affecting seating efficiency. His study revealed that buoyant ball sealers, which are ball sealers that have a density less than that of the treating fluid, achieved 100% seating efficiency in both matrix and fracturing treatments as long as the balls were transported to the perforated interval. The 100% efficiency with the buoyant balls is due to the fact that they cannot sink into the quiescent rathole fluid[27]. Fig. 2.13 represents a schematic of the ball sealer seating process[28]. To properly apply the buoyant ball sealer technology, the forces that control the transportation of the ball down the wellbore to the perforated interval must be calculated.

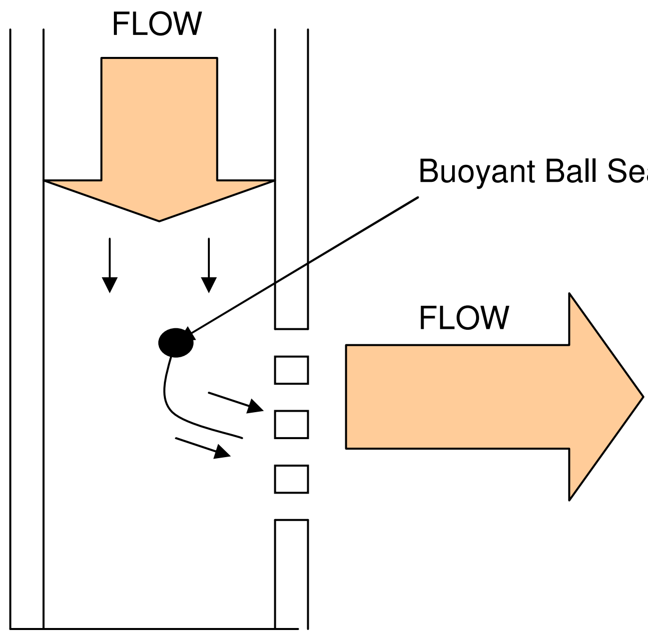


Fig. 2.13: Schematic representation of the ball sealer seating process[28]

Ball sealers are introduced into the treating fluid by certain tools known as ball injectors. Two basic types of ball injectors are used today: open-pot and positive displacement injectors[27].

The open-pot injector is made up of a pressure-tight steel container with a crankshaft mechanism to introduce balls into the flow line[27]. This type of injectors depends on gravity and the ball's density to enable successful ejection of the ball. The action of a star wheel at the lower end of the crankshaft forces the loaded balls into the flowline one at a time. When buoyant ball sealers are used, the injector must be fitted with a weight that prevents the balls from floating to the top of the injector where they cannot contact the star wheel[27].

Unlike the open-pot injectors, the positive displacement injectors neither rely on gravity nor density for ejection of the balls. Here, each ball is individually loaded and compartmentalized within the ball injector[27]. A certain number of balls would then be ejected based on the rotation of the crankshaft.

It is recommended that pumping should continue throughout the treatment once the balls have been displaced to the perforations. This is to maximize the efficiency of the ball sealers because the balls may unseat if pumping is stopped.

Ball catchers are tee-shaped devices used to recover the balls produced to the surface following the treatment. These devices, which are placed downstream of a full opening wing valve and upstream of the choke, prevent ball sealers from being carried down the flow lines to plug chokes or impair the operation of separation equipment[27]. Ball catchers, however, are not usually needed if controlled density ball sealers are used. Controlled density ball sealers are balls that are designed to be buoyant in the treating fluids but are nonbuoyant in any subsequently produced or injected fluids[27]. Here, the ball sealer is manufactured to narrow density specifications i.e. lighter than typical stimulation fluids (1.07-1.14 g/cm^3) but heavier than water or brine (1.00-1.04 g/cm^3)[27]. Also, the density of the balls must be maintained at downhole conditions. Syntactic foam-cored ball sealers are ideally suited for this technique because their densities increase by less than 0.01 g/cm^3 at downhole treating conditions up to 200^{0}F and 20,000 psi[27].

Buoyant ball sealers perform better with high BHP wells while controlled density ball sealers are better used for low BHP wells. Rising velocity is an important consideration when designing treatments conducted at low flow rates with buoyant ball sealers. It is absolutely necessary that the injection rate be sufficient to cause the balls to be transported down the tubing and the casing to the perforations. Calculating the relative velocity in the largest casing of the completion will guarantee that the balls are moved to the perforations.

2.4.6 Hydra-Jet Fracturing with Coiled Tubing

The hydra-jet assisted fracturing technique engages the services of a hydraulic jetting assembly on coiled tubing (CT) to erode perforation. This is immediately followed by pumping a fracture-stimulation treatment through the annulus between the casing and CT[29]. Fig. 2.14 shows an example of a CT hydra-jet bottomhole assembly. This technique uses tubing to deliver high velocity fluids to the formation or casing wall through jets at up to 700 ft/sec[30]. Due to the fact that the jetted erosive fluid contains sand or other abrasive proppants, it can cut a cavity in the casing or wellbore wall. The high pressure energy of the fluid in the tubing is transformed into kinetic energy by the jets thus making the high velocity erosive slurry to quickly produce a perforation hole in the casing and the formation[29]. The fluid velocity through the jets is actually a function of the pressure energy provided by the pumps. A 1.75-in. or 2-in. CT string provides adequate rate for the process. The creation of the perforation tunnels takes approximately 5-15 minutes, depending on the specific parameters[29].

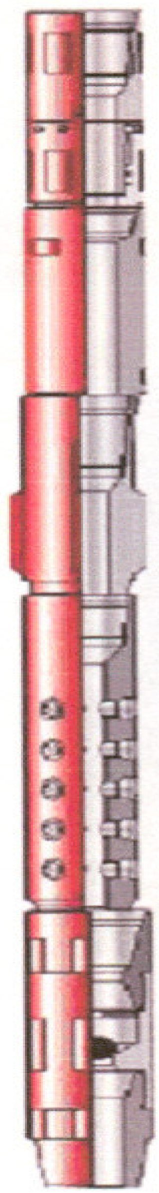


Fig. 2.14: A hydra-jet coiled tubing bottomhole assembly[29]

This process, which is still new in the industry for vertical well completions, does not need bridge plugs or packers for isolation between fractured zones. This method enables it to be used in a wide range of casing sizes and configuration. At the completion of the first fracturing stage, small volume, high proppant concentration slurry is left in the wellbore to provide isolation of the just stimulated zone for subsequent targets[29]. The process is repeated until all the desired zones are treated. The well is cleaned out with CT following the final stimulation stage and then turned over to production.

The casing is not designed to handle the fracturing pressures near the well head in some wells. In this case, the hydra-jet fracturing treatments can be done through tubing with a packer at the end of the large ID tubing workstring, thereby isolating the casing. Fig. 2.15 illustrates the through-tubing deployment of the hydra-jet fracturing method[29].

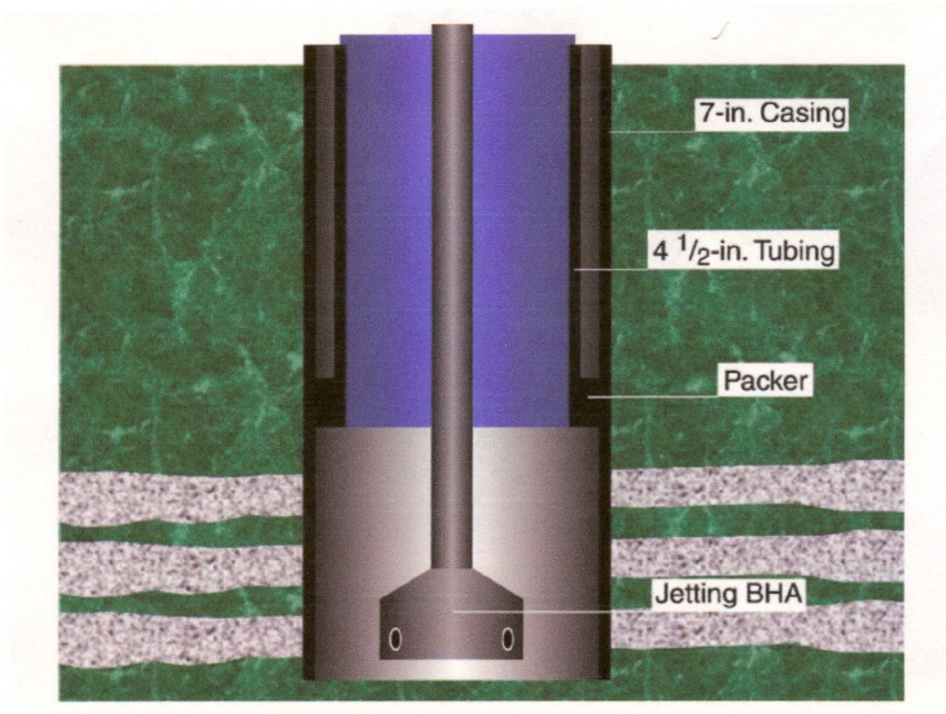


Fig. 2.15: An illustration of through-tubing deployment of the hydra-jet technique, which allows the isolation of a section of the casing annulus if needed[29]

The hydra-jet fracturing technique has its various advantages and disadvantages. The technique's primary disadvantage is that the tubing wall takes away a considerable portion of the wellbore area that under other circumstances could be used by the fracturing fluid flow. Also, the impact from proppant-laden slurry at the wellhead may result in abrasion damage to the CT. One of its advantages is that it is able to place the fracture where desired. Also, the technique will completely remove the pressure spike of formation breakdown from the pressure record[29]. In addition, tortuosity problems (which can result in premature screenouts because of insufficient fracture width at the perforations) that frequently occur in hard formations will seldom be present when fracturing using the hydra-jet technique.

2.4.7 Packer and Bridge Plug

The Packer and Bridge Plug technique refers to the use of a bridge plug to mechanically isolate a lower zone from the uphole fracture treatment[31].A packer is used to completely isolate the zone to be treated. It is a step-by-step process that involves perforating a lower zone, performing a fracture treatment of that zone, setting a bridge plug above that interval, setting a packer above the interval, and then perforating and fracture treating the next zone. It is regarded as a very reliable technique for diverting multi-stage fracture treatments. Its advantage lies on the fact that it is the most positive way to divert a fracture treatment. However, a workover rig is needed to move the packer and bridge plugs in the well, thus, making the method very time consuming. This inadvertently makes this technique the most expensive method when compared to the other diverting techniques. Mechanical problems can occur with the bridge plugs used to isolate the zones.

Hinn[31], in his study, reported that the Packer and Bridge Plug technique was the most economical and successful diverting technique in the Blocker Cotton Valley field in east Texas on the basis of wells completed in the late 1970's and early 1980's. He put forward a comparison between 4 wells diverted with the packer and bridge plug method and 3 similar wells diverted with the Pine Island technique. Two intervals were completed in each of the wells: the yellow zone which is over pressured and the normally pressured uphole blue zone. The results of his study, as seen in Table 2.3, showed that the Packer and Bridge Plug technique proved as the most economical method due to the fact that it assessed uphole Cotton Valley potential (i.e. zones other than the lowermost zone) and optimized production from all identified productive intervals. Amongst the 3 wells stimulated using the Pine Island technique, only one of the wells (well A) had verifiable uphole (Blue zone) production accounting for 13% of the total commingled well stream[31]. On the other hand, in each of the 4 wells stimulated using the Packer and Bridge Plug technique, the blue zone contributed a percentage of the total well stream ranging from 32% in well G to 54% in well D. Consequently, the packer and bridge plug technique, although involved additional expense, showed positive diversion.

Table 2.3: A summary of the Hinn's results in the Blocker Cotton Valley Field, East Texas[31]

Well	Diversion Technique	Zone	Interval	Estimated Sand Face Pressure (psia) Blue Zone	Production Log Results	
					% Blue	% Yellow
A	Pine Island	Blue	9025 - 9100	2756		
		Yellow	10040 - 10216	-		
		Commingled	-	-	13	87
B	Pine Island	Blue	8823 – 8951	1809		
		Yellow	10000 – 10204	-		
		Commingled	-	-	0	100
C	Pine Island	Blue	8782 – 9125	1470		
		Yellow	9882 – 10124	-		
		Commingled	-	-	0	100
D	Bridge Plug	Blue (Upper)	8815 - 8844	-		
		Blue (Lower)	9018 – 9118	1487		
		Yellow	9980 – 10184	-		
		Commingled	-	-	54	46
E	Bridge Plug	Blue	8890 – 9170	2855		
		Yellow	10088 – 10130	-		
		Commingled	-	-	61	39
F	Bridge Plug	Blue	8730 – 9005	3999		
		Yellow	9881 – 10140	-		
		Commingled	-	-	26	64
G	Bridge Plug	Blue	8925 – 9061	2372		
		Yellow	9838 – 10108	-		
		Commingled	-	-	32	68

2.4.8 Pine Island

The Pine Island diversion method involves the use of a sand plug to isolate the fracture treated zones. According to Hufft's study[32], the stimulation technique initially used in the Caspiana Field, Cotton Valley formation was the Pine Island method. When two zones are to be stimulated, the process involves fracture treating the lowermost interval, then setting a sand plug across the lower zone to isolate the fracture treated interval. Setting the sand plug is achieved by pumping sand into the tubing and allowing it to settle to the bottom[32]. The sand plug is pressure treated to make sure that it would not allow the re-fracturing of the lower interval. The upper interval is then perforated and fracture treated. The process is repeated, depending on the number of zones to be fraced. After the last interval is fracture treated, the wellbore is cleaned out, usually with coiled tubing. Fig. 2.16 shows a diagrammatic representation of the Pine island technique.

There are limitations associated with the Pine Island technique. Hufft[29] concluded from his study that the major drawback with this method was that shale members within the Cotton Valley section did not control fracture growth, and that as a result of this growth, the desired fracture penetration was not achieved. Hufft[32] went ahead to say that the productivity of the wells was found to be directly related to the fracture penetration. Also, it is sometimes difficult to place the sand plug precisely where it is needed[33]. Putting in too much sand into the borehole could end up covering up the next interval to be perforated and fracture treated. The Pine Island technique is not recommended when the perforations are closely spaced. A sand mixture of 20/40- and 100- mesh sand was recommended in order to minimize permeability of the sand in the wellbore[33]. This maximizes the efficiency of the Pine Island technique.

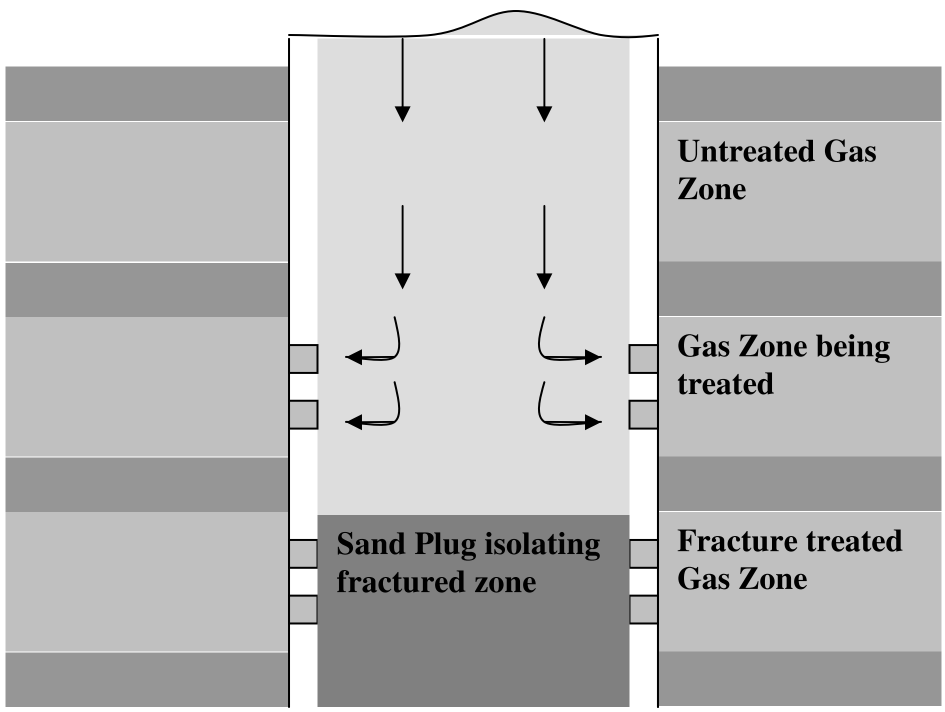


Fig. 2.16: The Pine Island technique

CHAPTER III

METHODOLOGY

The primary purpose of this research is to evaluate the diversion techniques involved in completing tight gas sands with thick, multiple pay zones. We developed decision charts and computer programs which will assist engineers in determining the best ways for diverting fracture treatments. These programs were tested using best practices as documented in the petroleum literature.

In this research, we have done the following:

1. Performed a complete literature review of the different diversion techniques involved in completing tight gas sands with thick, multiple pay zones;
2. Evaluated each of these diversion techniques, documenting their technologies, advantages, limitations and applications;
3. Developed decision charts to aid decisions being made in choosing diversion techniques and injection methods over various alternatives;
4. Developed programs, using the VBA programming language, encompassing the decision charts. This program, which provides recommendations, would require the user to input certain reservoir data to get the desired output. This serves as an “advisor”. We have also developed a limited entry design program; and

5. Tested and validated the developed programs by comparing our solutions with various case studies from the petroleum literature.

Fig. 3.1 represents the process flow chart showing the research procedure.

1. Literature Search: technologies, descriptions, limitations

⇓

2. Best Practices

⇓

3. Decision charts for diversion techniques

⇓

4. Build TGS Advisor modules for diversion techniques and injection methods

⇓

5. Programming limited entry design using VBA

⇓

6. Tested and validated the developed programs

Fig. 3.1: Process flow chart showing the research procedure

3.1 Literature Search / Documentation

The literature review formed an important part of this research effort. The review was divided into two parts. The first part was to identify, using published papers, the various types of diversion / placement techniques used when fracture treating thick, multilayered tight gas pay zones. The second part of the review was to use the information from the literature to evaluate each of these diversion techniques. The TGS Advisor computer program will provide the logic required to make decisions concerning which diversion technique(s) should be used in fracture treating a multilayered, tight gas reservoir. This logic is a function of the reservoir parameters such as depth, net pay, and bottom-hole pressure.

We obtained most of the information from publicly available technical reports and from other sources such as papers from the SPE elibrary, AAPG, USGS, DOE, and IHS Energy. The papers downloaded from these sources were documented using the EndNote X software. Appendix A shows all of these papers as arranged in EndNote X.

3.2 Evaluation / Analysis of Diversion Techniques

The literature search brought to light a number of diversion techniques used in completing these thick, tight gas pay zones. These techniques are as stated below:

1. Limited Entry Fracturing;

2. External Casing Perforating System (ExCAPE);
3. Flow Through Composite Frac Plugs (FTCFP);
4. Coiled Tubing Fracturing;
5. Pseudo-Limited Entry;
6. Hydra-Jet Fracturing with Coiled Tubing;
7. Packer and bridge Plug; and
8. Pine Island

Studying the information in the petroleum literature enabled us further understand the technologies, advantages, limitations as well as the applications of these techniques. Table 3.1 shows details on all the different diversion methods.

Table 3.1: Details on all the different diversion techniques

Diversion Technique	Advantages	Disadvantages	Limitations
Limited Entry	- Cost effective in deep wells - Multiple layers can be treated simultaneously - More layers can be stimulated with relatively low pumping rates	- Runs the risk of leaving some zones unstimulated - Accurate design maybe difficult because of unpredictable variation of the fracturing pressure - Perforation erosion could result in a reduction in the perforation friction	- Fracturing pressure in all zones should be relatively similar - High perforation differential is needed to exceed the highest fracturing pressure of the perforated zones - Decrease of perforation friction due to proppant erosion
ExCAPE	- Enhances the stimulation of bypassed or unstimulated intervals - Individual zones can be completed in a rapid, cost effective manner - Direct measurement of the BHP - Positive isolation devices to isolate lower intervals during fracture treatment	- Extra time is required to run casing - Hole must be in excellent condition to be certain casing can be run to total depth - Obtaining an excellent primary cement job is essential	- Larger borehole size is required to accommodate ExCAPE hardware - Isolation devices can only be removed using special tools on coiled tubing

Table 3.1 (Continued)

Diversion Technique	Advantages	Disadvantages	Limitations
Flow Through Composite Frac Plugs (FTCFP)	- No zones are shut in for long periods of time - FTCFPs can be easily drilled out after treatment - The wells are completed without the need of a workover rig - Greater well productivity and reduced completion time since well killing operations are eliminated - All previously treated zones help clean up each subsequent treatment	- It is not used if a zone is to be abandoned for any length of time - Have to drill out plugs to have a usable wellbore	- FTCFPs are not used whenever it is desirable to test individual sands. - High pressure differential from below to above can result in a problem with crossflow and this can possibly compromise the integrity of the FTCFP
Coiled tubing Fracturing	- Multistage fracturing can be pumped in a single trip - Provides a more precise placement of proppants in pay zones - Less environmental impact by performing one trip treatment - Elimination of work over rig costs, bridge plugs, and well head isolation tools.	- Can not be used in deep wells - Cost of coiled tubing can be excessive	- Limited depth (cannot be used beyond 10,000ft) - Limited Injection rate

Table 3.1 (Continued)

Diversion Technique	Advantages	Disadvantages	Limitations
Packer and Bridge Plug	- Regarded as the most reliable technique - It is the best way to ensure treatment diversion - Allows for the clean up of uphole intervals with a minimum of mechanical problems	- A workover rig is required - The method is time-consuming and expensive - In deep wells, milling up the bridge plugs after treatment becomes a problem	- Is not considered in very deep wells because of the problems associated with milling up. - Using the bridge plug exclusively for the separate treatment of each zone may not be practical because of the number of stages necessary for effective treatment of the pays.
Pine Island	- Cost effective compared to the Packer and Bridge Plug technique - Can divert treatments without need of a rig - Easy to clean out with coil tubing	- Problems of placing the sand plug precisely where it is needed - Movement of the isolating sand plug while attempting flowback of the uphole interval can result in damage to surface equipment - Can result in stuck coiled tubing resulting from sand plug movement during cleanout attempts	- Fluid may initially leak through the plug, thus, requiring the addition of fluid-loss additives to seal the plug

Table 3.1 (Continued)

Diversion Technique	Advantages	Disadvantages	Limitations
Hydra-Jet Fracturing with Coiled Tubing	- Can be used in a wide range of casing sizes and configurations - Tortuosity problems can be minimized - Clean out excess proppant by reverse circulation - Fracture stimulation time reduced	- Can not be used in deep wells - Oval jetted perforations are difficult to seal using ball sealers - Cost of coil tubing can be excessive	- Impingement from a proppant laden slurry at the wellhead may result in abrasion damage to the coiled tubing - Can not achieve long propped fractures - Jets wear out after repeated use
Pseudo-Limited Entry using ball sealers	- Multiple pays of approximately equal fracturing pressure can be stimulated effectively with one fracture stage - Reduced perforation differential at reasonable horsepower compared to the limited entry technique	- Less economic than the limited entry technique - One can not control the location of the ball sealers in the well bore	- Unseating of balls as soon as pumping stops - Sufficient injection rate to transport the ball down the tubing and casing to the perforation

3.2.1 Decision Charts for Choosing a Diversion Technique

As stated earlier, the information we obtained from the petroleum literature was used to develop several decision charts. These decision charts were developed by looking at the depth ranges and bottom-hole pressures under which these various diversion techniques can be effectively operated. The depth was classified as shallow or deep. We regarded a shallow well as one with a depth less than 10000 ft. A deep well is greater than 10000 ft. Figs. 3.2a, 3.2b and 3.2c present the decision chart that was developed. The bottom-hole pressure was classified as normal/low or geo-pressured. The normal/low pressured formation was regarded as one with a gradient less than or equal to 0.5 psi/ft while the geo-pressured or over-pressured formation was regarded as one with a gradient greater than 0.5 psi/ft. Another parameter involved in developing the decision charts was the net pay. The net pay was categorized into small or large. These were further categorized into multiple thin zones or thick zones. We represented the thin zones as intervals with less than 75 ft of pay while the thick zones were intervals with greater than 75 ft of pay. Using these decision factors as a base, the diversion techniques were able to be classified and grouped as shown in Figs. 3.2a, 3.2b and 3.2c.

We realize our definitions of high or low pressure, deep or shallow depth, and thick or thin pay zones are somewhat arbitrary. However, in the software, these values can be altered and we plan on continually testing our logic with published field case histories to improve our methodology and “the numbers” we use to make decisions

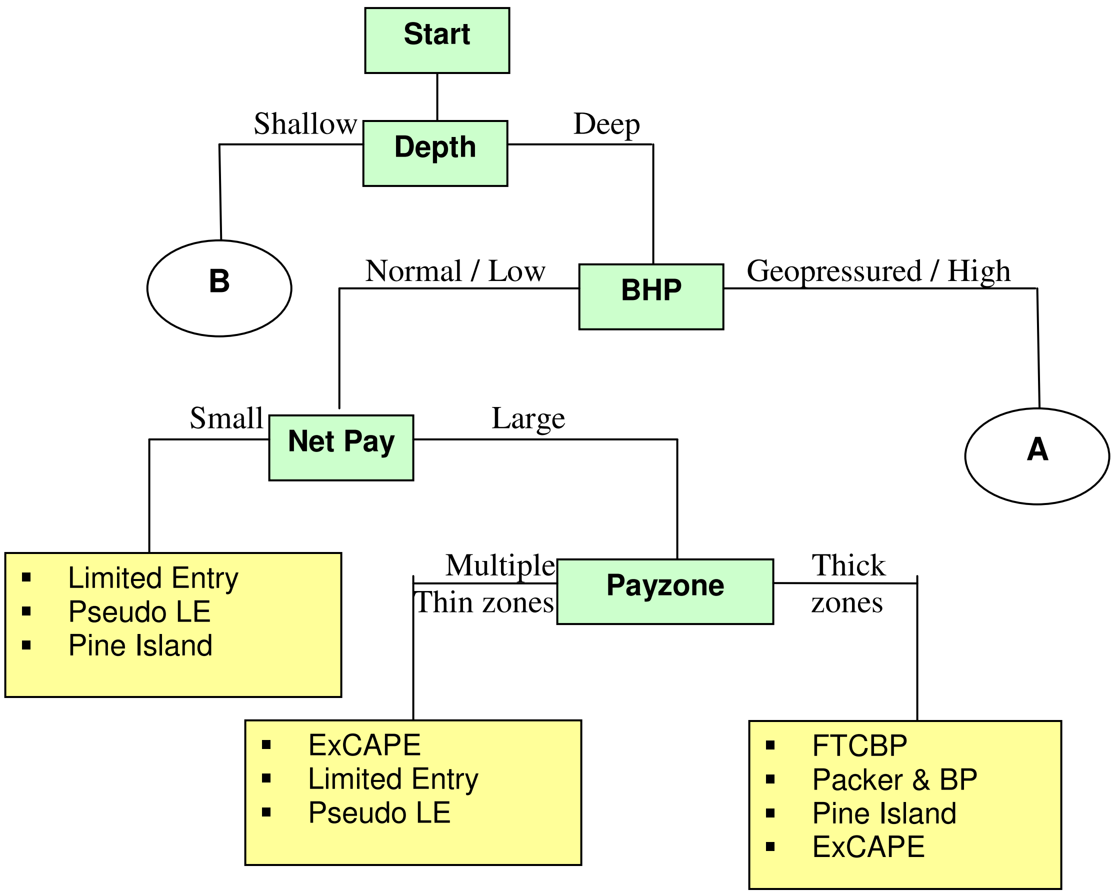


Fig. 3.2a: Flow charts showing decisions being made in choosing the various diversion techniques

KEY	
Deep: >= 10000ft	Small Net Pay: <= 75 ft
Shallow: < 10000ft	Large Net Pay: > 75ft
Normal BHP: < 0.5 psi/ft	Multiple Thin Payzones: <= 75 ft
Geopressured: >= 0.5 psi/ft	Thick Payzones: > 75ft

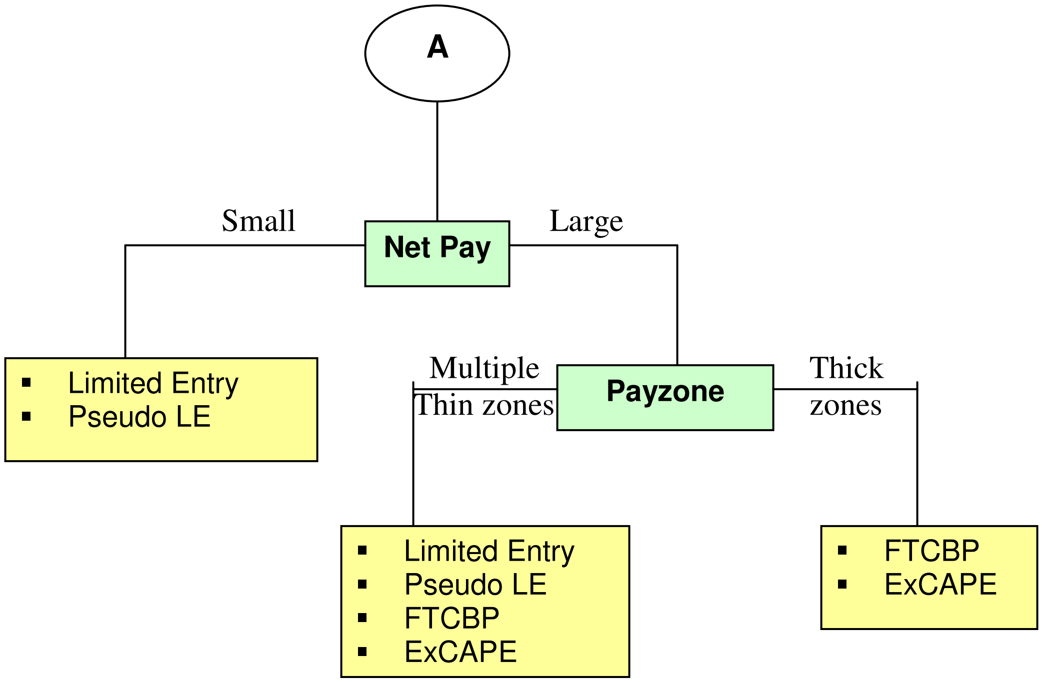


Fig. 3.2b: Flow charts showing decisions being made in choosing the various diversion techniques based on a deep well

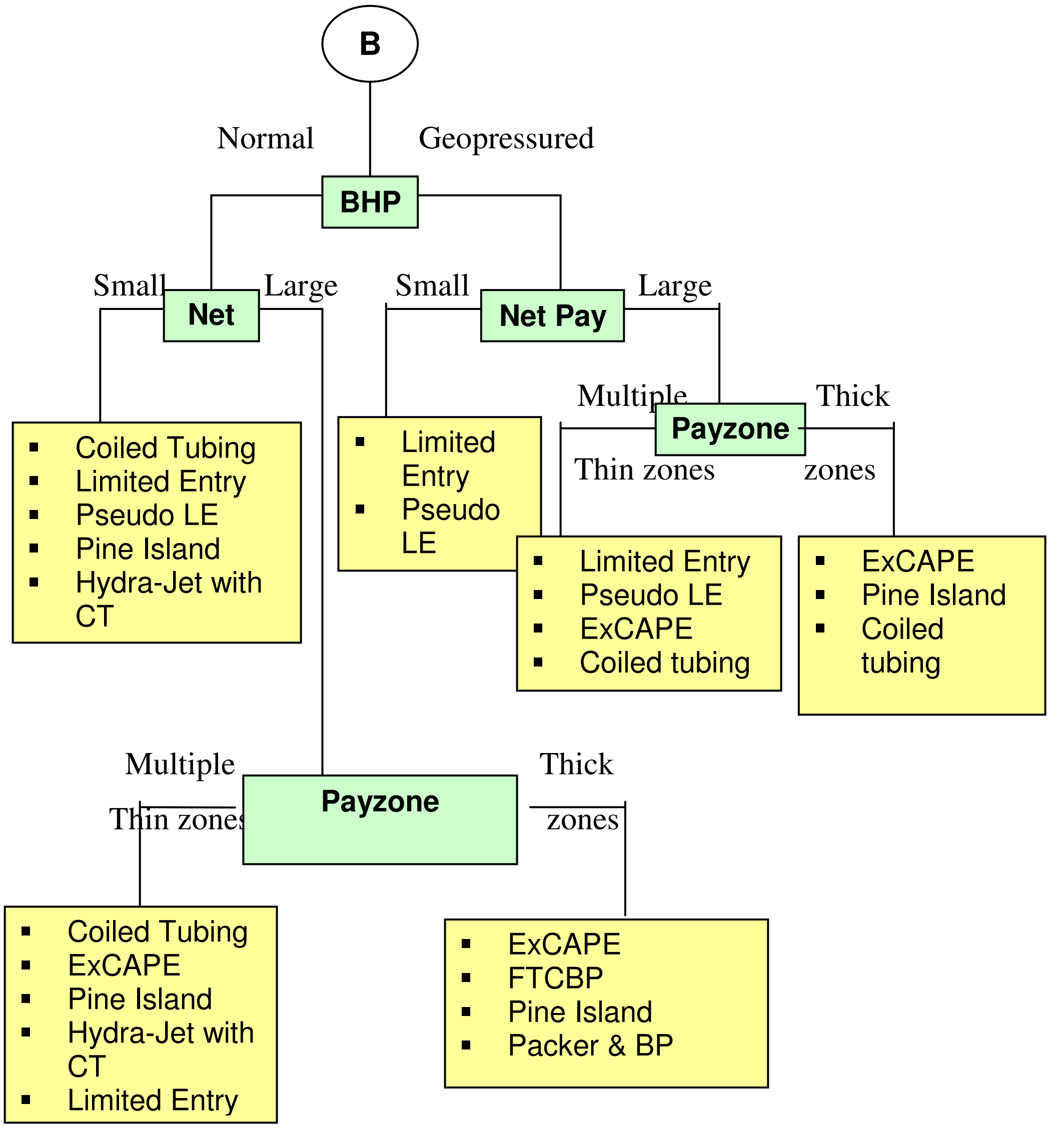


Fig. 3.2c: Flow charts showing decisions being made in choosing the various diversion techniques based on a shallow well

3.2.2 Decision Charts for Choosing the Injection Method

The decision charts drawn for the injection methods were derived from the stimulation expert rules book prepared by Xiong, H.[34]. Figs. 3.3a and 3.3b show a representation of these charts. These charts were further programmed using VBA.

The three injection methods considered were:

1. Injecting the treatment fluid down casing;
2. Injecting the treatment fluid down tubing and;
3. Injecting the treatment fluid down the annulus

Performing the fracture treatment down casing involves flushing the treatment with a clean, solids-free fluid, and then running in with the packer and tubing before the fracture fluids are produced back. This injection method is quite beneficial because a viscous fluid can be pumped at high injection rates with low surface injection pressures[33]. The high injection rates can be useful to the success of the stimulation treatment. As seen in Fig. 3.3a, during the fracture treatment, when there is no need to measure the bottom-hole pressure (BHP), the fluids can be injected down the casing.

Performing the fracture treatment down tubing involves flushing the treatment through tubing with a packer isolating the tubing from the annulus. This method is used especially when the casing condition is bad i.e. when there are any weak spots existing in the casing as a result of corrosion, erosion or a weak liner top. Fig. 3.3b shows that when the casing condition is bad, injection down tubing should be the major option. Fig. 3.3b also shows that when the casing condition is bad and the tubing string cannot be replaced or run, fracturing the well is not recommended. Injecting down tubing is also useful in highly over-pressured or extremely under-pressured formations. Well control can be maintained at all times. This is because the well is produced back after the stimulation treatment and a brief shut-in time, thus, minimizing the amount of time the fracture fluid stays in the formation[33].

Performing the fracture treatment down the annulus involves having a tubing string in the well without a packer to pack off the annulus. With this method, there is a direct measurement of the fracturing bottom-hole pressures (BHPs). The knowledge of the BHP during the fracture treatment can be used to determine whether fracture containment is being maintained or to foresee possible screenouts before they actually occur[33]. Injecting the treatment down the annulus is considered the best method of injection due to its numerous advantages over fracturing the well whether down casing or down tubing with a packer in the well.

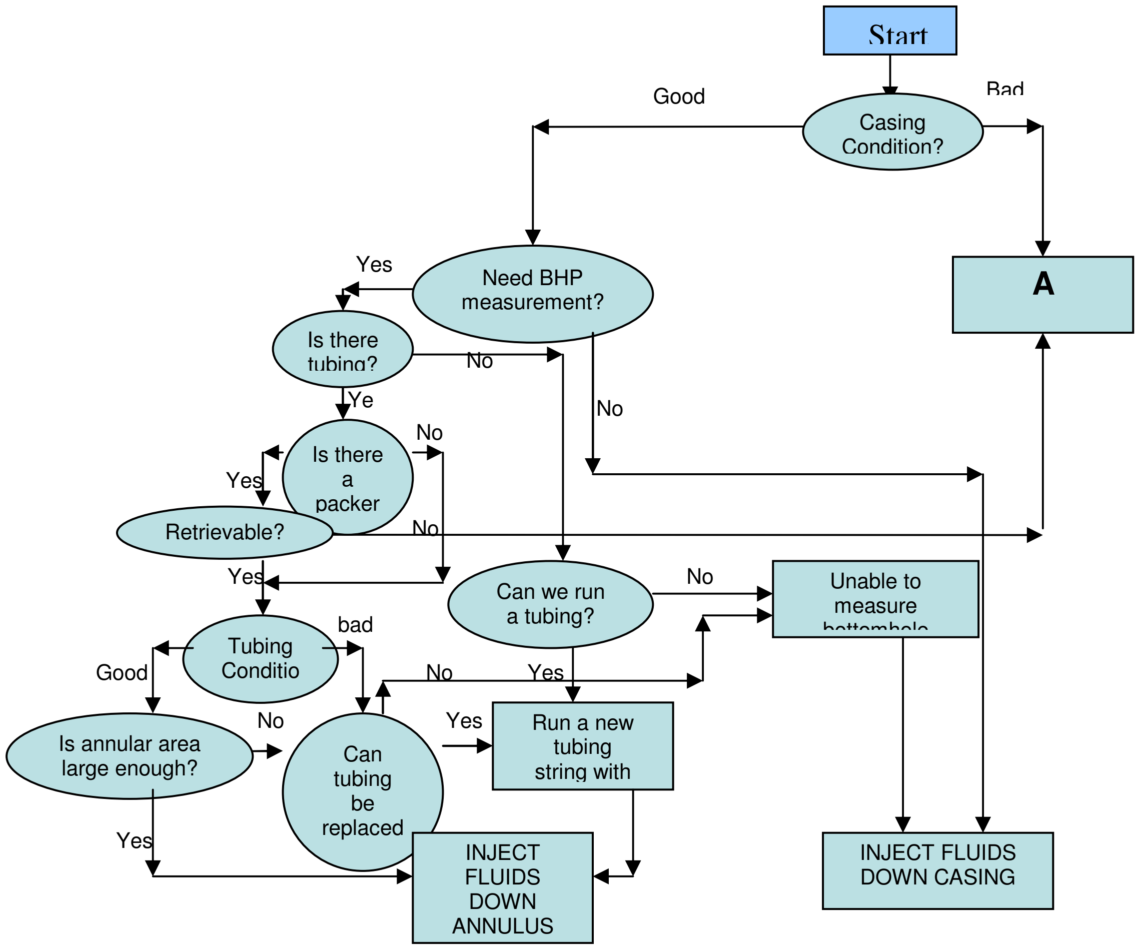


Fig 3.3a: Flow charts showing decisions being made in choosing the appropriate injection method[34]

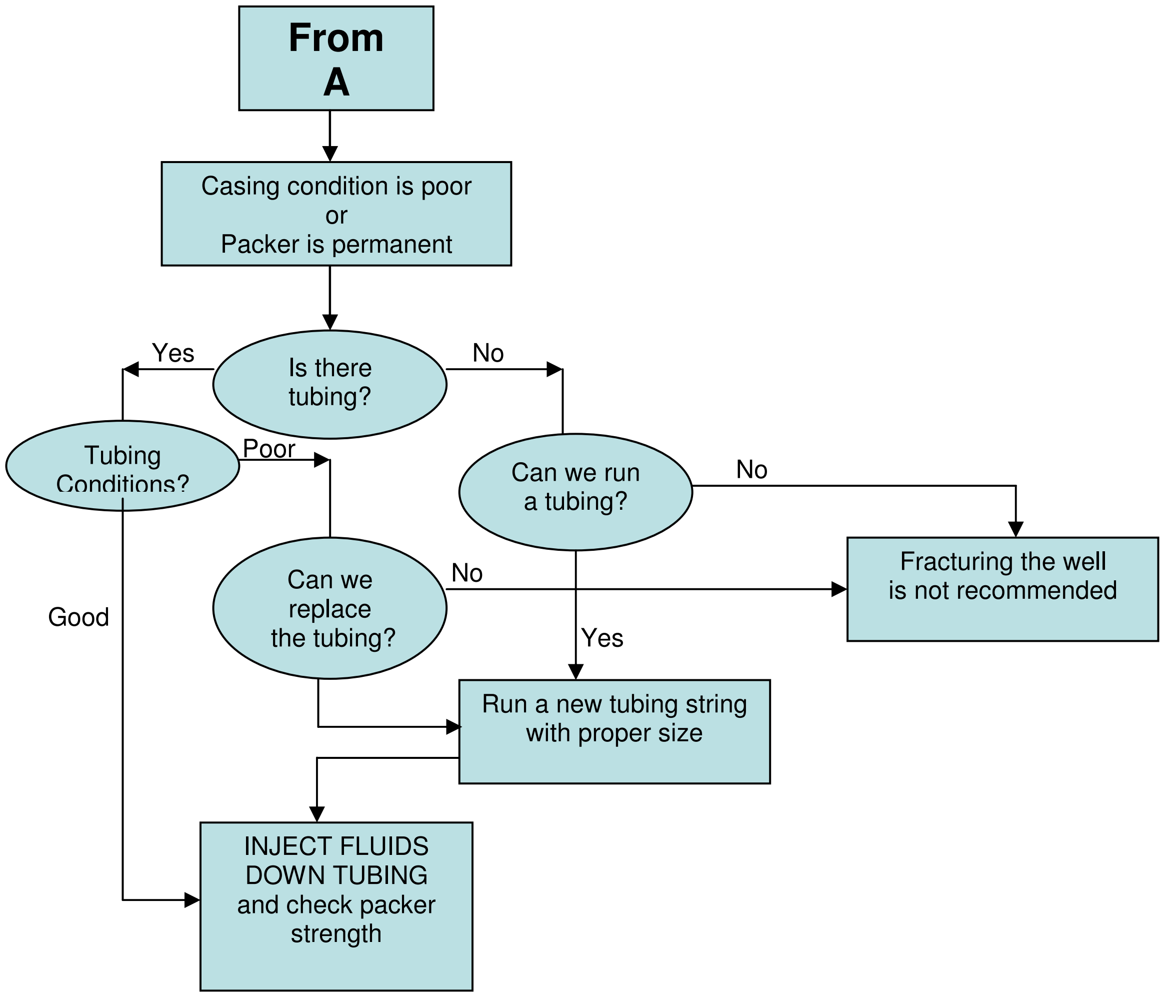


Fig 3.3b: Decision charts showing decisions being made in choosing the appropriate injection method[34]

3.2.3 Advisor Development

Stand-alone programs ("advisors") were developed based on the decision charts. The programs were written using the visual basic application (VBA) programming language. The purpose of the programs is to program the decisions that are required to design the completion and stimulation of a well in a tight gas reservoir.

Fig. 3.4 represents the advisor for the selection of the diversion techniques. The subroutine for this program is included in Appendix B. The user inputs values for parameters such as depth, net pay thickness, pay zone thickness and bottomhole pressure into the yellow rows. After this is done, the recommendation button is clicked to provide recommendations on the diversion technique based on the input information. Clicking the optimum diversion technique button ranks the techniques based on a ratio between revenue and cost thus providing the optimum diversion technique

Fig. 3.5 represents the advisor for the selection of the appropriate injection method to be used. The subroutine for this program is included in Appendix C. Using the drop box, the user answers the proposed "yes" or "no" questions. When the questions are answered, the recommendation button is clicked, thus, allowing the program to recommend the appropriate injection method.

Fig. 3.6 represents a spreadsheet program written to design a limited entry treatment. The program serves three main purposes, which are:

1. To calculate and provide the amount of treatment fluid that would go into the individual zones;
2. To calculate the injection rate per zone; and
3. To calculate the surface injection pressure.

A fluid type is chosen, along with other specifications such as the fluid quantity and gradient. Other general parameters such as the number of zones and injection rate are also specified and inputted in the brown columns. In the blue columns, the depth to the top of each zone is specified, along with the net pay thickness and number of holes to be perforated per zone.

The calculations used behind the program were made using the following equations:

Perforation friction (P_{ppf}) = $\dfrac{(0.2369) \times {i_{p_f}}^2 \times \ell_f}{{d_{pf}}^4 \times \alpha^2}$ .... Eq. 1

Injection rate per zone (i_{pf}) = $\sqrt{\dfrac{P_{ppf} \times {d_{pf}}^2 \times \alpha^2}{(0.2369) \times \ell_f}}$ .... Eq. 2

Bottomhole treatment pressure (BHTP)

= in-situ stress * TVD (top).. Eq. 3

Hydrostatic Pressure (P_h) = TVD (top) * fluid gradient......................... Eq. 4

Surface injection pressure (P_{surf}) = BHTP - P_h + P_{pf} + P_{ppf}.....................Eq. 5

Pipe friction (P_{pf}) = TVD of the packer * friction pressure gradient.......... Eq. 6

TGS ADVISOR FOR DIVERSION TECHNIQUE SELECTION

Input Parameters	
Total depth (ft)	7000
Average netpay (ft)	40
Average payzone thickness (ft)	76
Pressure Gradient (psi/ft)	0.45

Default Parameters	
Small Net Pay <=	75
Thin Pay zone <=	75
Normal Pressure Gradient <=	0.5

Info:	
Small Net Pay <=	75
Large Net Pay >	75
Thin Pay zone <=	75
Thick Payzone >	75
Normally Pressured <=	0.5
Geo Pressured >=	0.5

Recommended Diversion Techniques:	*Coiled Tubing or limited entry or Pseudo Limited Entry or Pine Island or HydraJet*

Fig. 3.4: TGS advisor for the selection of diversion techniques

Input Data

Number of Layers	5
Drilling Cost ($)	2500000
Net Revenue Interest (%)	0.875
Gas Price ($/MMBTU)	6.36
Gas Price ($/Bcf)	6430738
Recovery Efficiency (RE)	0.5
Number of Intervals to be diverted	4
Total Gas - in - place (Bcf)	3.5
Total Fracture cost ($)	360000

RESET

Recommended Diversion Techniques

Optimum Diversion Technique

Layer	1	2	3	4	5
Depth to Top Layer (ft)	7000	7400	7800	8200	8600
Depth to bottom Layer (ft)	7200	7600	8000	8400	8800
Net Pay Thickness (ft)	20	40	60	40	20
Effective Porosity	0.074	0.083	0.069	0.059	0.049
Water Saturation	0.35	0.39	0.41	0.58	0.3
Drainage Area (acres)	40	40	40	40	40
Layer Pressure (psia)	4300	4500	4650	5490	4000
Layer Temperature (F)	240	245	250	260	300
Layer Temperature (R	700	705	710	720	760
Psc (psia)	14.7	14.7	14.7	14.7	14.7
Tsc (R)	520	520	520	520	520
Z	0.8	0.8	0.8	0.8	0.8
Fracture costs ($)	40000	80000	120000	80000	40000
Gas formation volume factor (Bg)	0.0037	0.0035	0.0035	0.0030	0.0043
Gas - in - place (Bcf)	0.5	1.0	1.2	0.6	0.3

No. of recommended techniques	5

Output

Diversion Techniques	Diversion Efficiency Factor	Diversion Cost per Layer ($)	Total Completion Cost ($)	Total Cost (10^6) $	Reserves (Bcf)	Gross undiscounted revenue (10^6) $	Revenue - to-Investment ratio
Pseudo Limited Entry	0.4	10000	400000	2.90	0.7	4.0	1.38
Pine Island	0.5	30000	480000	2.98	0.9	5.0	1.67
HydraJet	0.6	50000	560000	3.06	1.1	6.0	1.96
Coiled Tubing	0.75	50000	560000	3.06	1.3	7.5	2.44

Fig. 3.4 (Continued)

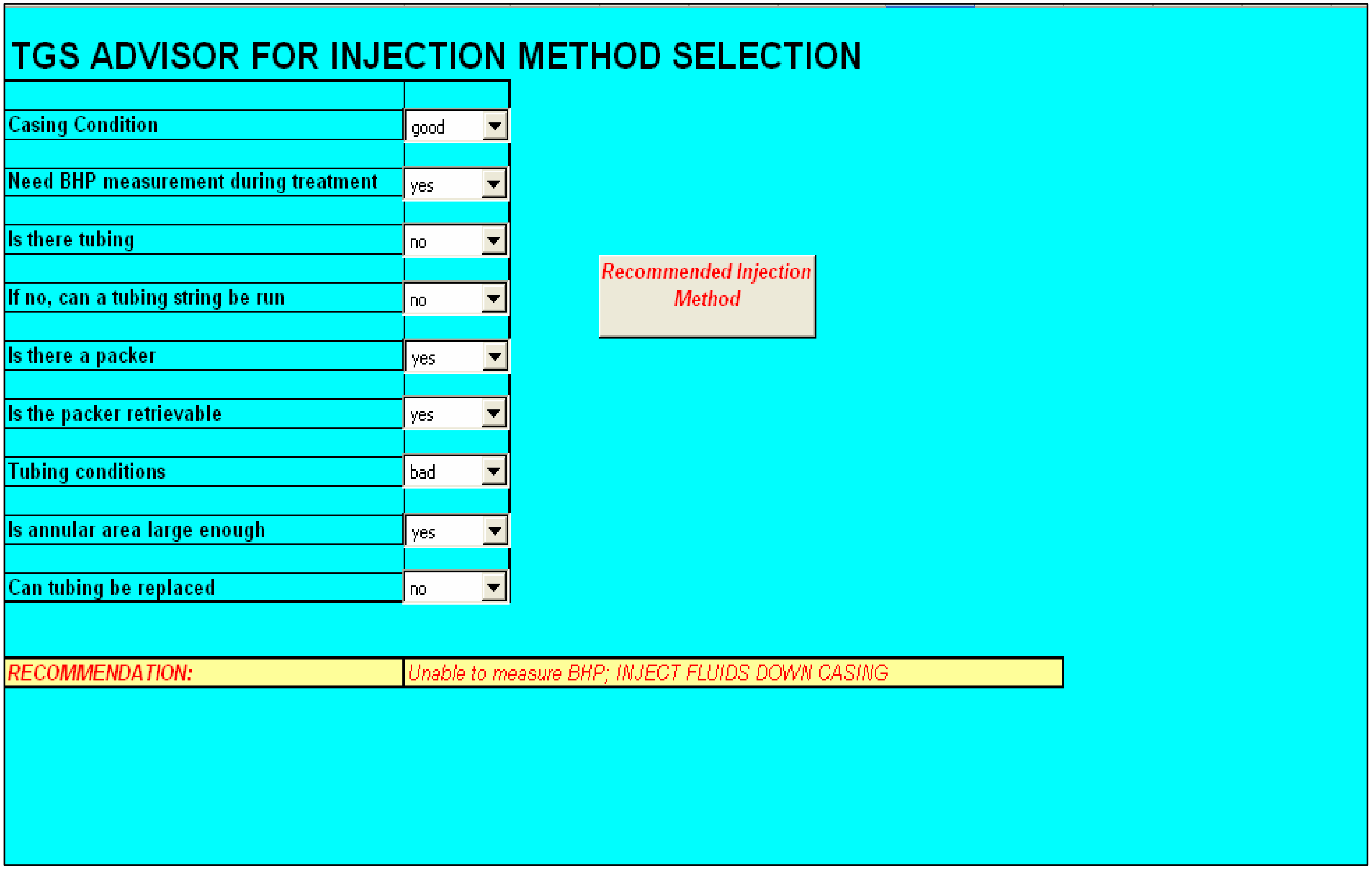


Fig.3.5: TGS advisor for the selection of the appropriate injection method

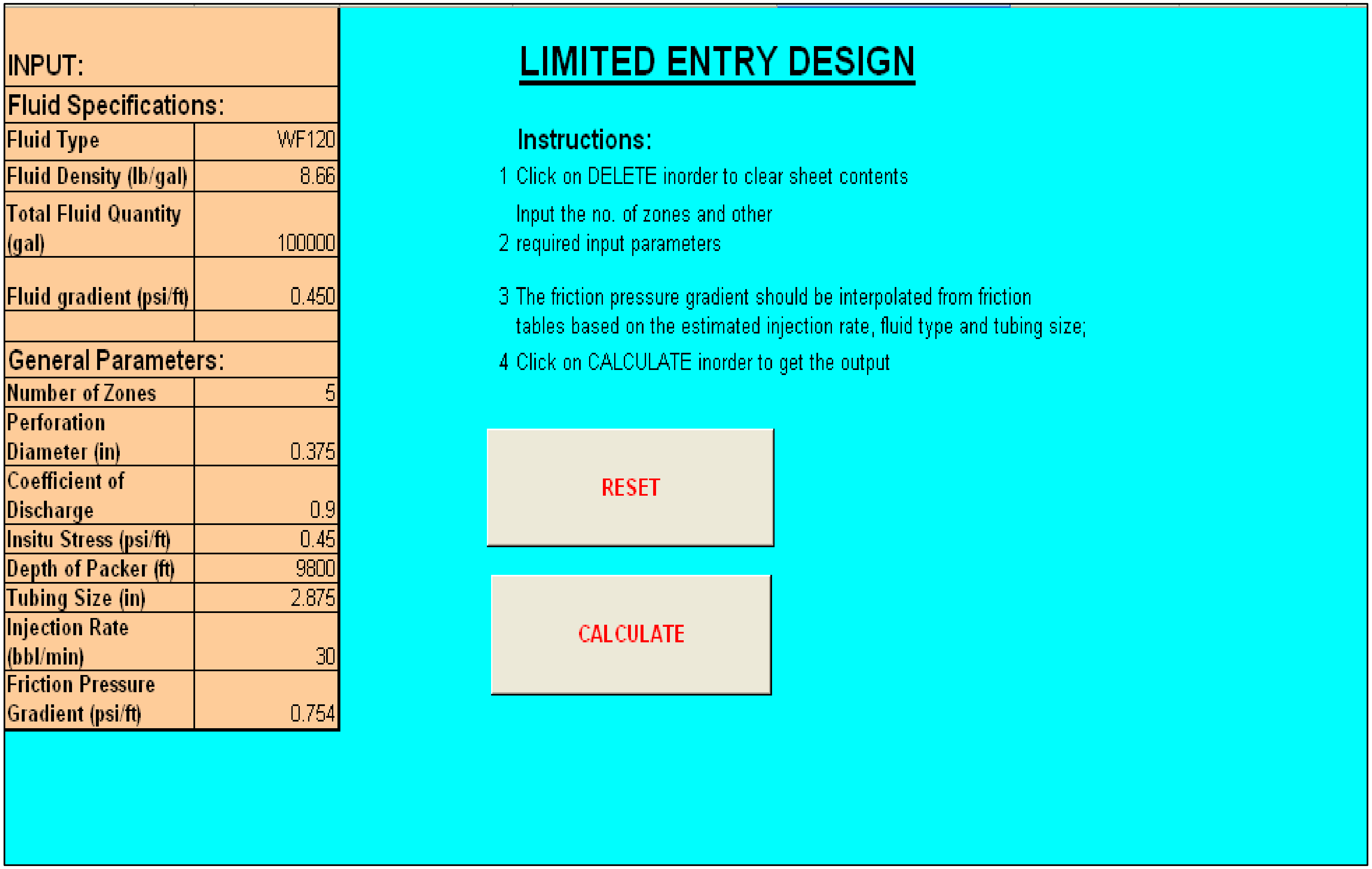


Fig. 3.6: Limited entry treatment design

Coefficient of Discharge	0.9
Insitu Stress (psi/ft)	0.45
Depth of Packer (ft)	9800
Tubing Size (in)	2.875
Injection Rate (bbl/min)	30
Friction Pressure Gradient (psi/ft)	0.754

RESET

CALCULATE

	INPUT:			OUTPUT:		
Zones	Net Pay Thickness Per Zone (ft)	Number of Holes per Zone	Depth to top of Zone (ft)	Injection Rate (bbl/min/perf)	Fluid distribution (%)	Fluid Distribution (gal)
1	20	3	8000	3.9	13.0	13048.4
2	40	5	8500	6.5	21.7	21743.2
3	60	7	9000	9.1	30.4	30434.8
4	40	5	9500	6.5	21.7	21735.0
5	20	3	10000	3.9	13.0	13038.6

Surface Injection Pressure (psi) =	7607

Fig. 3.6 (Continued)

The friction pressure gradient was calculated by interpolating between injection rates in the friction tables. Table 3.2 shows rate vs. friction pressure gradient for fluid type WF120. With an estimated injection rate of 30 bbl/min, the friction pressure gradient was interpolated to get 754 psi/1000ft. Fig. 3.7 shows a log-log plot of the friction pressure vs. the flow rate.

Table 3.2: Friction pressure vs. rate data for WF120

	Rate (bbl/min)	Friction Pressure (psi/1000ft)
Low	1.6	10
Pivot	13	200
High	39.3	1000

The subroutine for the limited entry design is expressed in Appendix D. The programs, upon completion, were tested and validated using various case studies from the petroleum literature.

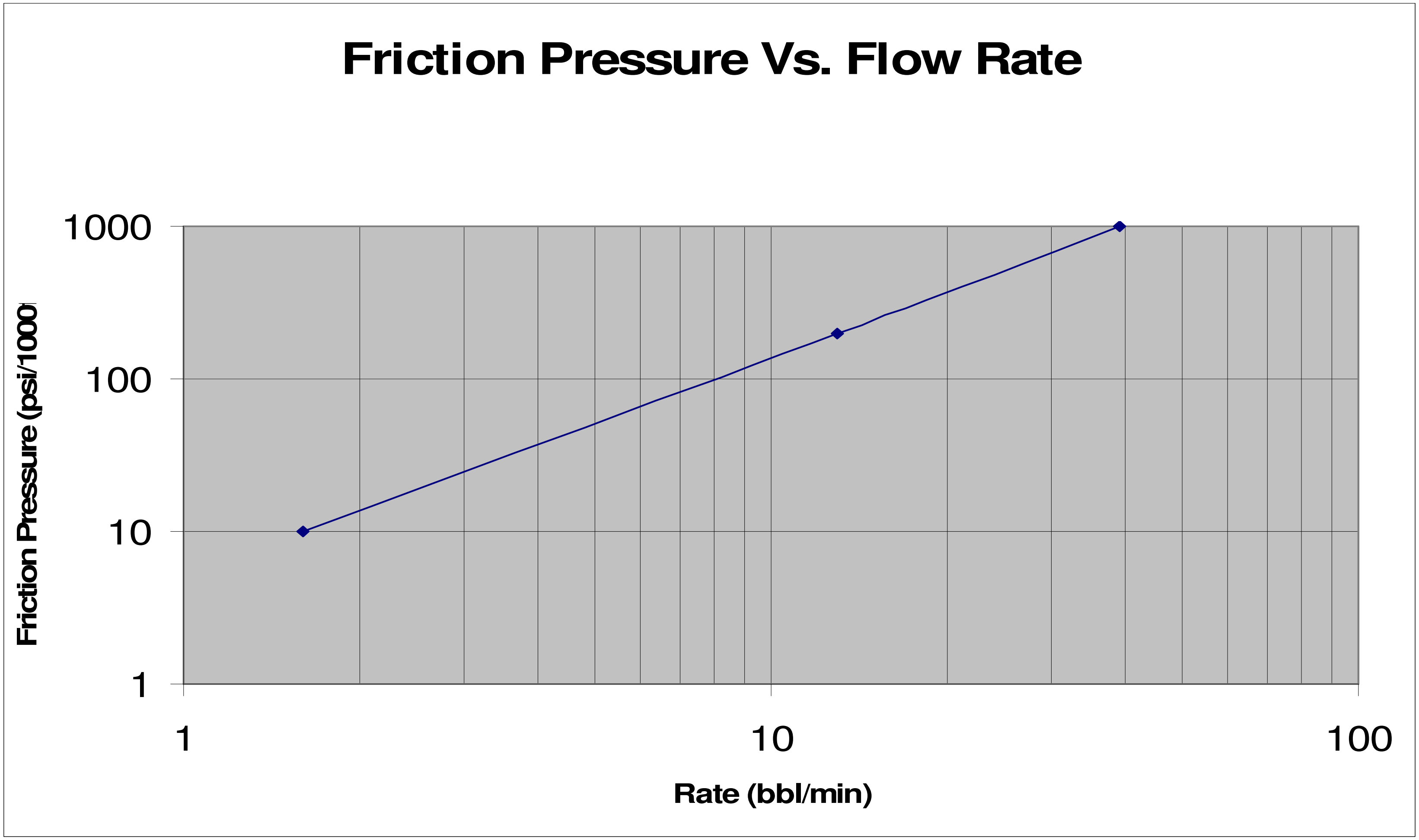


Fig. 3.7: Log-log plot of friction pressure vs. rate for WF120

CHAPTER IV

RESULTS AND DISCUSSION

In this research, we have used the petroleum literature to determine the best practices concerning how to complete wells in tight gas sands reservoirs where fracture treatment diversion methods are required. Using the information in the literature, we have derived “knowledge” that can be programmed into a computer program that we call TGS Advisor. In this chapter, we will explain how we developed the module on diversion techniques and how we verified the module using case histories in the literature.

4.1 Diversion Technique Module for TGS Advisor

In building the flow charts and subroutine for the selection of diversion techniques, we determined the most important parameters one must consider are as follows:

1. Number of layers;
2. Depth;
3. Net pay thickness;
4. Effective porosity;
5. Water saturation;
6. Drainage area;
7. Layer pressure and temperature; and
8. Gas gravity.

The process was divided into two parts. In the first part, we developed the flow charts which succeeded in grouping the diversion techniques as a function of the depth, net pay thickness and bottomhole pressure, as seen in Figs. 3.2a, 3.2b and 3.2c. The program developed from this flow chart, as seen in Figs. 3.4, will enable the user input reservoir data to obtain a list of the appropriate diversion techniques based on the input data. This list will give the user an idea of the techniques he/she can use as diversion for the fracture treatment.

After developing the subroutine, we validated the method using data from case histories published in the petroleum literature. We developed comparisons between actual case studies in the literature and results from our programs. If the actual best practice provided by the case study corresponded with our program's recommended options, the test was successful. If there was no match, we would probe to find out the cause for the mismatch. The main reason why the best practice did not correspond with any of the program's recommendations was that we did not include all the critical parameters during the flow chart development. Whenever we encountered a mismatch, we modified our decision charts in order to produce a match. These adjustments both improved and validated our methodology. Table 4.1a presents a list of the actual case studies and input data we considered while validating our program.

Coiled tubing fracturing was the declared best practice in Cases 1 and 2. Recommendations from our advisor indicated Coiled Tubing, ExCAPE, Pine Island, HydraJet as options for Case 1; and Coiled Tubing, Limited Entry, Pseudo Limited Entry, Pine Island, HydraJet as options for Case 2, as shown in Table 4.1b. For Cases 3 and 4, ExCAPE was the best practice in the case study. Our advisor recommended ExCAPE, Coiled Tubing, Pine Island, HydraJet as options to pick from. For Case 5, limited Entry was the recommended best practice by the case study. Our advisor recommended Limited Entry, Coiled Tubing, Pseudo Limited Entry, Pine Island and HydraJet. The Packer and the Bridge Plug technique was the stated best practice in Case 6. The advisor recommended the Packer and Bridge Plug, ExCAPE, Flow through Composite Frac Plug, and Pine Island as alternatives. Finally, the Flow through Composite Frac plug was recorded as the best practice in Case 7. Flow through Composite Frac plug, Limited Entry, Pseudo Limited Entry, ExCAPE techniques were recommended by the TGS advisor. The above analysis shows that field data and the TGS advisor's recommendations are in reasonable agreement, as seen in Table 4.1b.

Table 4.1a: Input data for the validation of diversion techniques selection subroutine

Case	SPE Paper / Journal #	Location	Formation	Well	TVD (ft)	Net pay thickness (ft)	Pay zone thickness (ft)	Formation pressure gradient
1	71656	Uintah	Fort Union; Wasatch		3647	175	33	Normally Pressured
2	60313	Rocky Mountains, Alberta Canada	Viking sands, Wild Cat Hills	3-3-27-5W5M	8200	45	10	Under pressured
3	90722	Alaska	Beluga sands, Kenai gas Field		7500	175	18	Normally pressured
4	64526	Oklahoma	Stephens County		7800	262	42	Normally pressured
5	JPT, July 1963	Permian	TXL Tubb field, Ector County		6300	73	18	Under pressured
6	6868	East Texas	Cotton Valley		9000	175	76	Normally pressured
7	59790	Green River	Lance		11000 – 12500	300 – 600	5 – 50	Over pressured

Table 4.1b: Results from the validation of diversion techniques selection subroutine

Case	Best Practice from Literature	Subroutine Options
1	Coiled Tubing Fracturing	Coiled tubing, ExCAPE, Pine Island, HydraJet
2	Coiled Tubing Fracturing	Coiled Tubing, limited entry, Pseudo Limited Entry, Pine Island, HydraJet
3	ExCAPE	ExCAPE, Coiled tubing, Pine Island, HydraJet
4	ExCAPE	ExCAPE, Coiled tubing, Pine Island, HydraJet
5	Limited Entry	Limited entry, coiled tubing, Pseudo Limited Entry, Pine Island, HydraJet
6	Packer and bridge plug	Packer and bridge plug, ExCAPE, FTCBP, Pine Island
7	FTCBP	FTCBP, Limited Entry, Pseudo Limited Entry, ExCAPE

In Table 4.1b for each case history, the advisor gives the user a list of possible diversion method. However, in every case, at least four cjoices are suggested. As such, we decided that we needed to included additional information concerning the economics behind each method to help narrow down the choice of which diversion method is most appropriate for a given well and reservoir situation. Thus, we have further developed an economic analysis method to rank the alternatives on the basis of total cost and gross revenue. For these calculations, we also have to input value of the following parameters:

1. Gas price;
2. Drilling cost to total depth (T.D);
3. Net Revenue Interest (NRI); and
4. Recovery Efficiency (RE).

The user has to input the completion cost per stage for each of the selected techniques. The program then calculates the completion cost (all the stages involved) and total cost for each technique using the equations below:

Completion cost =

Completion cost per stage * Number of stages ……………………….Eq. 7

Total Cost =

Completion cost + Drilling cost to T.D………………………………….Eq. 8

The following equations are used in calculating the gross undiscounted revenue:

Gross undiscounted revenue = $G \times NRI \times Gasprice$ ………………….Eq. 9

Reserves (G) = $\sum GIP \times RE \times DEF$ …………………………………….Eq. 10

Gas – in – place (GIP) = $\dfrac{\varphi \times (1 - S_w) \times A \times h_{net}}{B_g}$ ……………………………Eq. 11

The recovery efficiency is a function of the permeability, fracture length and the drainage area. We used the production forecast software, Promat, to develop data to obtain a quick estimate of recover efficiency.

Using the input data shown in Tables 4.2a and 4.2b, 900 computer runs were made using Promat, which is a single phase, analytical, reservoir simulator. The results from those 900 computer runs were put into an excel spreadsheet and are used to determine a reasonable value to recovery efficiency for any given set of reservoir data and fracture length. The results are also included graphically in Appendix E.

Table 4.2a: Data used for recovery efficiency

P_i (psia)	**P_{wf} (psia)**	**K (md)**	**L_f (ft)**	**A (acres)**
2500	250	0.001	100	40
5000	500	0.005	250	80
7500	750	0.01	500	160
		0.05	750	320
		0.1	1000	

Table 4.2b: Reservoir data used for Promat runs

Porosity	7.5%
Gas Gravity	0.65
Bottom hole Temperature	200^0F
Net pay	100 ft
Cumulative Time	20 years

We developed the graphs by changing the fracture length with respect to variations in the permeability, drainage area, initial reservoir pressure and the wellbore flowing pressure. The 40 acre drainage area could not accommodate the 750 ft and 1000 ft fracture lengths. This was because the fracture length must be less than 725.8 ft for a drainage area of 40 acres.

A list of diversion efficiency factors (DEF) for each technique, as shown in Table 4.3[35], was a part of the subroutine. We came up with the DEF values upon various discussions with experts in the industry.

Table 4.3: Diversion techniques with their corresponding efficiency factors[35]

Diversion Technique	Diversion Efficiency Factor (DEF) RANGE	Diversion Efficiency Factor (DEF) Recommended value
Limited Entry	0.25 – 0.5	0.33
Pseudo-Limited Entry	0.33 – 0.67	0.40
Pine Island	0.33 – 0.75	0.50
Coiled Tubing with Packer	0.5 – 0.9	0.75
Flow Through Composite Frac Plugs	0.6 – 0.9	0.80
Packer and Bridge plug	0.8 – 1.0	0.90
External Casing Perforating (ExCAPE)	0.75 – 1.0	0.85
HydraJet with Coiled Tubing	0.5 – 0.7	0.60

The diversion technique, amongst other alternatives, with the largest revenue to investment ratio emerges as optimum. Figure 4.1 shows a diagrammatic representation of the process.

The final phase of the subroutine, which involved ranking the alternatives, was enabled using the equation below:

$$\text{Revenue to Investment Ratio} = \frac{Revenue}{Cost}$$

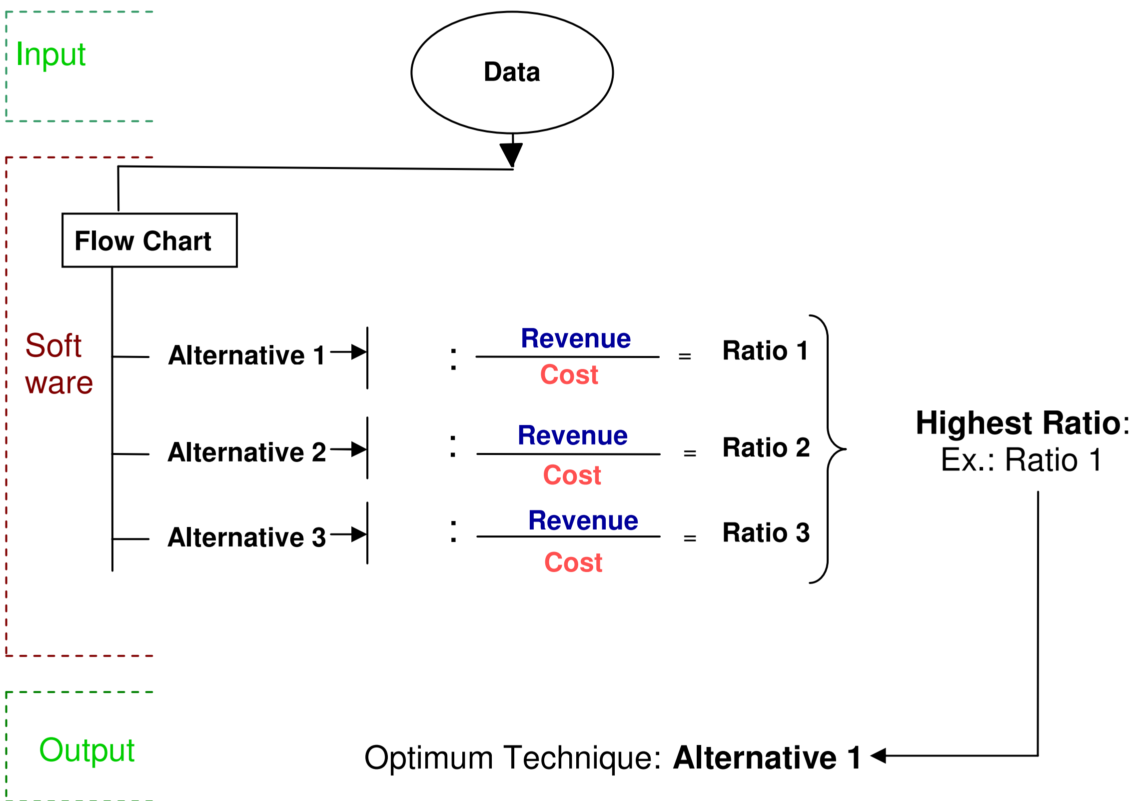


Fig. 4.1: A representation of the optimum diversion technique selection process

4.2 Limited Entry Treatment Design

As explained in Chapter III, the limited entry computer program was developed to calculate the amount of treatment fluid that will go into the different layers; the injection rate per layer; and the surface injection pressure. When the user alters parameters such as the injection rate, the program automatically outputs the amount of treatment fluid going into each zone, the injection rate per zone and the surface injection pressure, as shown in Fig. 3.6b. Equations surrounding these calculations are presented in Chapter III of this thesis.

Upon completion of the computer program, the subroutine was checked for accuracy by comparing the results obtained from hand calculations with the results obtained from the program. The data in Table 4.4a are the input data for the first verification example:

Verification 1:

INPUT PARAMETERS

Table 4.4a: Input parameters for limited entry design program verification (1)

Fluid Type	WF 120
Fluid density (lb/gal)	8.66
Fluid gradient (psi/ft)	0.45
Total Fluid Quantity (gal)	100000
Number of zones	3
Perforation diameter (in)	0.35
Coefficient of discharge	0.9
Insitu stress (psi/ft)	0.8
Depth of packer (ft)	9800
Tubing size (in)	2.875
Injection rate (bbl/min)	20
Friction pressure gradient (psi/ft)	0.412

RESULTS

Table 4.4b: Design program results for example (1)

	Input			**Output**		
Zone	**Net Pay thickness per zone (ft)**	**Number of holes per zone**	**Depth to top of zone (ft)**	**Injection Rate (bbl/min/perf)**	**Fluid Distribution (%)**	**Fluid Distribution (gal)**
1	10	3	10000	**6.3**	**31.4**	**31401**
2	15	5	10200	**9.9**	**49.8**	**49772**
3	5	2	10400	**3.7**	**18.8**	**18828**

Surface injection Pressure = **8272 psi**

Table 4.4c: Hand calculation results for example (1)

	Input			Output		
Zone	**Net Pay thickness per zone (ft)**	**Number of holes per zone**	**Depth to top of zone (ft)**	**Injection Rate (bbl/min/perf)**	**Fluid Distribution (%)**	**Fluid Distribution (gal)**
1	10	3	10000	**6.0**	**31.3**	**31250**
2	15	5	10200	**9.6**	**50.0**	**50000**
3	5	2	10400	**3.6**	**18.8**	**18750**

Surface injection Pressure = **8222 psi**

Verification 2:

INPUT PARAMETERS

Table 4.5a: Input parameters for limited entry design program verification (2)

Fluid Type	WF 120
Fluid density (lb/gal)	8.66
Fluid gradient (psi/ft)	0.45
Total Fluid Quantity (gal)	100000
Number of zones	3
Perforation diameter (in)	0.375
Coefficient of discharge	0.9
Insitu stress (psi/ft)	0.45
Depth of packer (ft)	9800
Tubing size (in)	2.875
Injection rate (bbl/min)	30
Friction pressure gradient (psi/ft)	0.754

RESULTS

Table 4.5b: Design program results for example (2)

	Input			Output		
Zone	**Net Pay thickness per zone (ft)**	**Number of holes per zone**	**Depth to top of zone (ft)**	**Injection Rate (bbl/min/perf)**	**Fluid Distribution (%)**	**Fluid Distribution (gal)**
1	10	3	8000	**9.0**	**30.0**	**30001**
2	15	5	8500	**15.0**	**49.9**	**49999**
3	5	2	9000	**6.0**	**19.9**	**19999**

Surface injection Pressure = **8536 psi**

Table 4.5c: Hand calculation results for example (2)

	Input			Output		
Zone	**Net Pay thickness per zone (ft)**	**Number of holes per zone**	**Depth to top of zone (ft)**	**Injection Rate (bbl/min/perf)**	**Fluid Distribution (%)**	**Fluid Distribution (gal)**
1	10	3	8000	**9.0**	**30.0**	**30000**
2	15	5	8500	**15.0**	**50.0**	**50000**
3	5	2	9000	**6.0**	**20.0**	**20000**

Surface injection Pressure = **8542 psi**

Verification 3:

INPUT PARAMETERS

Table 4.6a: Input parameters for limited entry design program verification (3)

Fluid Type	WF 240
Fluid Density (lb/gal)	8.66
Fluid gradient (psi/ft)	0.45
Total Fluid Quantity (gal)	150000
Number of zones	3
Perforation diameter (in)	0.375
Coefficient of discharge	0.9
Insitu stress (psi/ft)	0.8
Depth of packer (ft)	9800
Tubing size (in)	2.875
Injection rate (bbl/min)	40
Friction pressure gradient (psi/ft)	0.491

RESULTS

Table 4.6b: Design program results for example (3)

	Input			**Output**		
Zone	**Net Pay thickness per zone (ft)**	**Number of holes per zone**	**Depth to top of zone (ft)**	**Injection Rate (bbl/min/perf)**	**Fluid Distribution (%)**	**Fluid Distribution (gal)**
1	10	3	8000	**12.4**	**31.2**	**46725**
2	15	5	8500	**19.9**	**49.8**	**74712**
3	5	2	9000	**7.6**	**19.0**	**28563**

Surface injection Pressure = **9813 psi**

Table 4.6c: Hand calculation results for example (3)

	Input			**Output**		
Zone	**Net Pay thickness per zone (ft)**	**Number of holes per zone**	**Depth to top of zone (ft)**	**Injection Rate (bbl/min/perf)**	**Fluid Distribution (%)**	**Fluid Distribution (gal)**
1	10	3	10000	**12.4**	**31.2**	**46727**
2	15	5	10200	**19.9**	**49.8**	**74680**
3	5	2	10400	**7.6**	**19.1**	**28593**

Surface injection Pressure = **9810 psi**

The first verification was made using 100,000 gallons of WF 120 treatment fluid. The fluid was pumped at an injection rate of 20 bbl/min. Other input parameters are as shown in Tables 4.4a, 4.4b, and 4.4c. As indicated in Table 4.4b, the program recorded a fluid distribution of 31401 gals, 49772 gals, and 18828 gals into the first, second and third zones respectively. It also recorded a surface injection pressure of 8272 psi. When verified by hand calculation, we arrived at 31250 gals, 50000 gals, and 18750 gals into the first, second and third zones respectively. The hand calculations resulted in a surface injection pressure of 8213psi. The differences between the results of the fluid distribution recorded by the design program and our hand calculations were 151 gals, 228 gals, and 78 gals for zones 1, 2, and 3 respectively, while the difference between the results for the surface injection pressure was 50 psi.

These differences in the comparisons resulted from decimal errors in the hand calculations.

The second verification was also made using 100,000 gallons of WF 120 treatment fluid. In this case, the fluid was pumped at an injection rate of 30 bbl/min. Parameters we altered included the perforation diameter and in-situ stress. The friction pressure gradient also changed due to the change in injection rate from 20 bbl/min to 30 bbl/min. These are shown in Table 4.5a. The depths to the top of each zone were also altered as seen in Tables 4.5b and 4.5c. As indicated in Table 4.5b, the program recorded a fluid distribution of 30001 gals, 49999 gals, and 19999 gals into the first, second and third zones respectively. It also computed a surface injection pressure of 8536 psi. When verified by hand calculation, we arrived at 30000 gals, 50000 gals, and 20000 gals into the first, second and third zones respectively. The hand calculations resulted in a surface injection pressure of 8542 psi. The differences between the results of the fluid distribution recorded by the design program and the hand calculations were insignificant. As seen from our comparisons, there were little or no differences between the results computed by the program and the hand calculations. This verified that the equations behind the program were correct and that the program was working effectively.

A third verification was made using 150,000 gallons of WF 240 treatment fluid. The fluid was pumped at an injection rate of 40 bbl/min and the in-situ stress was changed to 0.8 psi/ft. After interpolating between 2 rates and 2 pressure gradients for WF 240 as expressed in Table 4.7 and Fig. 4.2, we computed a friction pressure gradient of 0.491 psi/ft.

Table 4.7: Friction pressure vs. rate data for WF 240

	Rate (bbl/min)	Friction Pressure (psi/1000ft)
Low	1.6	10.8
Pivot	5.8	32
High	77.9	1000

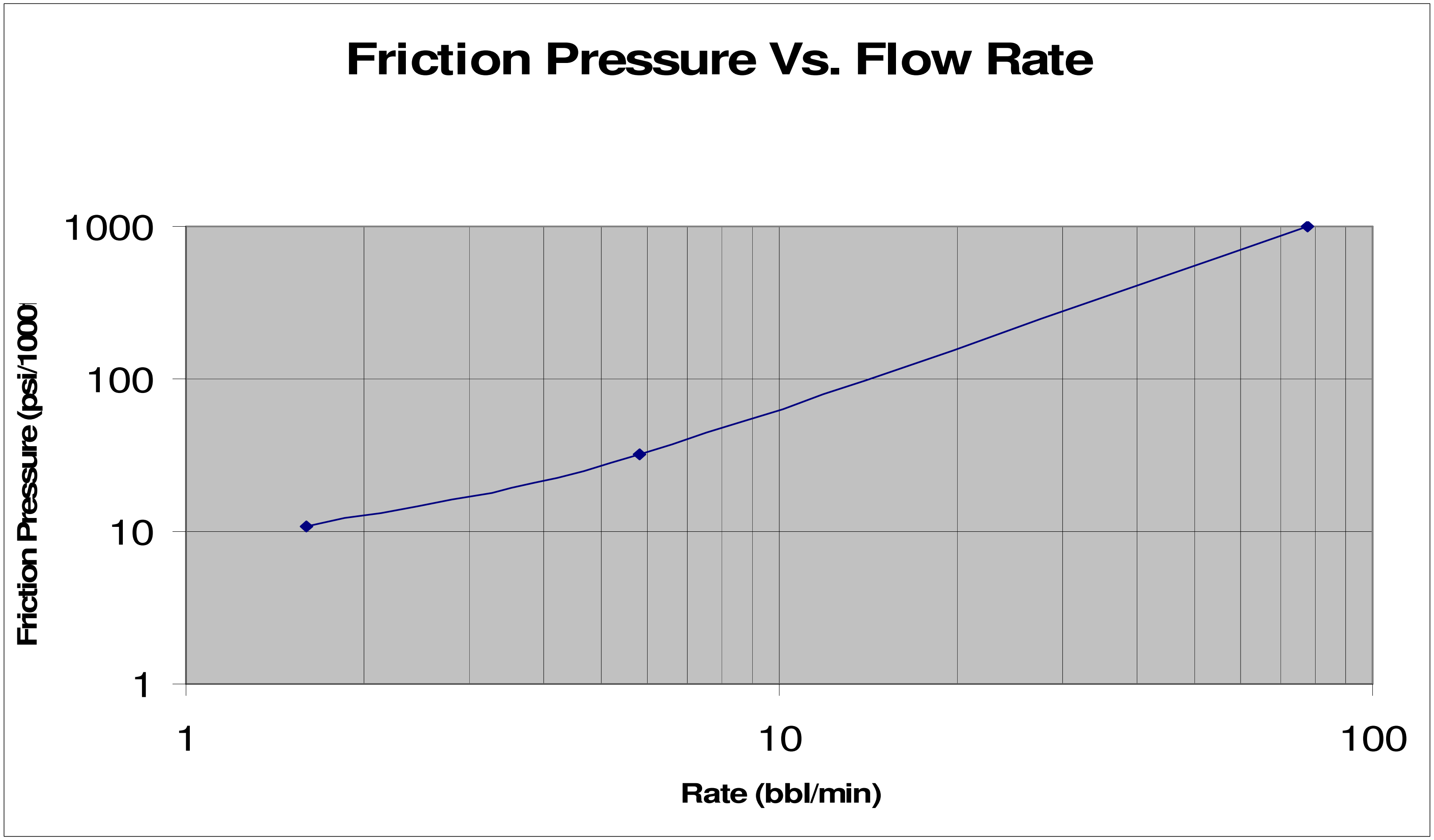


Fig. 4.2: Log-log plot of friction pressure vs. rate for WF 240

As indicated in Table 4.6b, the program computed a fluid distribution of 46725 gals, 74712 gals, and 28563 gals into the first, second and third zones respectively. It also computed a surface injection pressure of 9813 psi. When verified by hand calculation, we recorded 46727 gals, 74680 gals, and 28593 gals into the first, second and third zones respectively. The hand calculations resulted in a surface injection pressure of 9810 psi. The differences between the results of the fluid distribution recorded by the design program and the hand calculations were again insignificant. In this comparison, there were also little or no differences between the results from the program and hand calculations. This verification also showed that the equations behind the program were correct and the program was working effectively.

CHAPTER V

CONCLUSIONS

The following conclusions were gathered from the research project:

1. The eight methods commonly used in the oil and gas industry to divert hydraulic fracture treatments are as follows:
   - Limited Entry;
   - Packer and Bridge Plug;
   - Coiled Tubing Fracturing;
   - Pine Island;
   - Flow Through Composite Bridge Plug;
   - Hydra-Jet Fracturing with Coiled Tubing;
   - Pseudo-Limited Entry; and
   - External Casing Perforating System (ExCAPE).
2. Not all of the methods can be used in every well. The selection of the optimum diversion methods must be based on values of:
   - Depth;
   - Net Pay;
   - Layer Pressure and Temperature;
   - Effective Porosity;
   - Water Saturation;
   - Drainage Area; and
   - Gas Gravity.

3. A decision chart and computer program has been developed to allow the completions engineer to determine which of the 8 diversion methods are feasible for a given well stimulation.
4. After narrowing down the possible diversion methods for a specific well stimulation, the completions engineer must conduct detailed economic studies to choose the optimum diversion method.
5. The computer program developed to provide advice concerning the appropriate diversion methods was verified using case histories from the literature. However, the program should be improved and modified as additional case histories warrant.
6. The limited entry design program can be used to calculate the fluid distribution into different layers when fracture treating multilayered tight gas reservoirs using the limited entry technique.
7. The limited entry design program can also be used to compute the surface injection pressure when using the limited entry technique.

NOMENCLATURE

Tcf = Trillion cubic feet

mD = Milli darcy

bbl = Barrels

bbl/min = Barrels per minute

Sw = Water saturation

Swc = Critical water saturation

Sgc = Critical gas saturation

Swirr = Irreducible water saturation

in. = Inch

GR = Gamma ray

CCL = Casing collar log

m = Meter

mm = Milli meter

ft = Foot

g/cm^3 = Grams per cubic centimeter

ft/sec = Feet per second

psi = Pound square inch

psi/ft = Pound square inch per foot

P_{ppf} = Perforation friction

i_{pf} = Injection rate per zone

ℓ_f = Fluid density

d_{pf} = diameter of perforated hole

α = Coefficient of discharge

BHTP = Bottomhole treating pressure

P_h = Hydrostatic pressure

P_{surf} = Surface injection pressure

P_{pf} = Pipe friction

T.D = Total depth

TVD = Total vertical depth

G = Reserves

NRI = Net revenue interest

RE = Recovery efficiency

DEF = Diversion efficiency factor

h_{net} = Net thickness

B_g = Gas formation volume factor

φ = Porosity

GIP = Gas – in – place

gals = Gallons

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APPENDIX A

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APPENDIX B

SUBROUTINE FOR DIVERSION TECHNIQUE SELECTION

```
Option Explicit

Public depth, netpay, small, payzone, BHP, thin, Normal, layers,
DivertedIntervals, drillingcost, RecoveryEfficiency, TotalGIP, Totalfraccost, NRI,
Gasprice As Double

Public ans, output, ans1, ans2, ans3, ans4, ans5 As String

Public diversioncost(5), totalcompletioncost(5), totalcost(5), DEF(5), reserves(5),
revenue(5), ratio(5) As Double

Public i, n As Integer


Sub Obie()

With ThisWorkbook.Worksheets("Sheet1")

n = .Cells(33, 5)

depth = .Cells(3, 2)

netpay = .Cells(4, 2)

payzone = .Cells(5, 2)

BHP = .Cells(6, 2)

small = .Cells(9, 2)

thin = .Cells(10, 2)

Normal = .Cells(11, 2)

layers = .Cells(17, 2)

DivertedIntervals = .Cells(23, 2)

drillingcost = .Cells(18, 2)
```

```
NRI = .Cells(19, 2)
Gasprice = .Cells(21, 2)
RecoveryEfficiency = .Cells(22, 2)
TotalGIP = .Cells(24, 2)
Totalfraccost = .Cells(25, 2)

For i = 1 To n
diversioncost(i) = .Cells(35 + i, 3)
DEF(i) = .Cells(35 + i, 2)
Next i
End With
End Sub

Sub Process()
Call Obie
If depth <= 10000 Then
Call BHP1
End If

If depth >= 10000 Then
Call BHP2
End If
```

```
Call output_ans
End Sub

Sub BHP1()
If BHP <= Normal Then
Call Netpay1
ElseIf BHP >= Normal Then
Call Netpay2
End If
End Sub

Sub BHP2()
If BHP <= Normal Then
Call Netpay3
ElseIf BHP >= Normal Then
Call Netpay4
End If
End Sub

Sub Netpay1()
If netpay <= small Then
```

```
ans = "Coiled Tubing or limited entry or Pseudo Limited Entry or Pine Island or HydraJet"
ans1 = "Pseudo Limited Entry"
ans2 = "Pine Island"
ans3 = "HydraJet"
ans4 = "Coiled Tubing"
ans5 = "Limited Entry"
ElseIf netpay > small Then
Call Payzone1
End If
End Sub

Sub Netpay2()
If netpay <= small Then
ans = "Limited Entry or Pseudo Limited Entry"
ans1 = "Limited Entry"
ans2 = "Pseudo Limited Entry"
ElseIf netpay > small Then
Call Payzone2
End If
End Sub
```

```
Sub Netpay3()
If netpay <= small Then
ans = "Limited Entry or Pseudo Limited Entry or Pine Island"
ans1 = "Limited Entry"
ans2 = "Pseudo Limited Entry"
ans3 = "Pine Island"
ElseIf netpay > small Then
Call Payzone3
End If
End Sub

Sub Netpay4()
If netpay <= small Then
ans = "Limited Entry or Pseudo Limited Entry"
ans1 = "Limited Entry"
ans2 = "Pseudo Limited Entry"
ElseIf netpay > small Then
Call Payzone4
End If
End Sub
```

```
Sub Payzone1()

If payzone <= thin Then

ans = "ExCAPE or Coiled Tubing or Pine Island or HydraJet or Limited Entry"

ans1 = "ExCAPE"

ans2 = "Coiled Tubing"

ans3 = "Pine Island"

ans4 = "HydraJet"

ans5 = "Limited Entry"

ElseIf payzone > thin Then

ans = "ExCAPE or Bridge Plug and Packer or Flow thru Composite Bridge Plug
or Pine Island"

ans1 = "ExCAPE"

ans2 = "Bridge Plug and Packer"

ans3 = "Flow thru Composite bridge Plug"

ans4 = "Pine Island"

End If

End Sub


Sub Payzone2()

If payzone <= thin Then

ans = "ExCAPE or Limited Entry or Pseudo Limited Entry or Coiled Tubing"

ans1 = "ExCAPE"
```

```
ans2 = "Limited Entry"

ans3 = "Pseudo Limited Entry"

ans4 = "Coiled Tubing"

ElseIf payzone > thin Then

ans = "Pine Island or ExCAPE or Coiled Tubing"

ans1 = "Pine Island"

ans2 = "ExCAPE"

ans3 = "Coiled Tubing"

End If

End Sub


Sub Payzone3()

If payzone <= thin Then

ans = "ExCAPE or Limited Entry or Pseudo Limited Entry"

ans1 = "ExCAPE"

ans2 = "Limited Entry"

ans3 = "Pseudo Limited Entry"

ElseIf payzone > thin Then

ans = "Flow thru Composite Bridge plug or Bridge Plug and Packer or ExCAPE
or Pine Island"

ans1 = "Flow thru Composite bridge Plug"

ans2 = "Bridge Plug and Packer"
```

```
ans3 = "ExCAPE"
ans4 = "Pine Island"
End If
End Sub

Sub Payzone4()
If payzone <= thin Then
ans = "Limited Entry or Pseudo Limited Entry or Flow Thru Composite Bridge
Plug or ExCAPE"
ans1 = "Limited Entry"
ans2 = "Pseudo Limited Entry"
ans3 = "Flow thru Composite bridge Plug"
ans4 = "ExCAPE"
ElseIf payzone > thin Then
ans = "Flow thru Composite Bridge Plug or ExCAPE"
ans1 = "Flow thru Composite bridge Plug"
ans2 = "ExCAPE"
End If
End Sub
```

```
Sub Delete()

Range("A36:H40").Select

Selection.ClearContents

End Sub


Sub ratio1()

Call Obie

With ThisWorkbook.Worksheets("Sheet1")

For i = 1 To n

totalcompletioncost(i) = (diversioncost(i) * DivertedIntervals) + Totalfraccost

.Cells(35 + i, 4) = totalcompletioncost(i)

totalcost(i) = totalcompletioncost(i) + drillingcost

totalcost(i) = totalcost(i) * 10 ^ -6

.Cells(35 + i, 5) = totalcost(i)

reserves(i) = TotalGIP * RecoveryEfficiency * DEF(i)

.Cells(35 + i, 6) = reserves(i)

revenue(i) = reserves(i) * Gasprice * NRI

revenue(i) = revenue(i) * 10 ^ -6

.Cells(35 + i, 7) = revenue(i)

ratio(i) = revenue(i) / totalcost(i)

.Cells(35 + i, 8) = ratio(i)

Next i
```

```
End With
End Sub

Sub output_ans()
With ThisWorkbook.Worksheets("Sheet1")
.Cells(13, 2) = ans
.Cells(36, 1) = ans1
.Cells(37, 1) = ans2
.Cells(38, 1) = ans3
.Cells(39, 1) = ans4
.Cells(40, 1) = ans5
End With
End Sub
```

APPENDIX C

SUBROUTINE FOR INJECTION METHOD SELECTION

```
Option Explicit

Public Casingcondition, BHPmeasurement, Istubingpresent, Canweruntubing,
Packerpresent, Tubingcondition, Packerretrievable, Largeannulararea,
Tubingreplacement, good, bad, no, yes, recommendation, output As String

Sub Tweezy()
With ThisWorkbook.Worksheets("Sheet2")
Casingcondition = .Cells(3, 2)
BHPmeasurement = .Cells(5, 2)
Istubingpresent = .Cells(7, 2)
Canweruntubing = .Cells(9, 2)
Packerpresent = .Cells(11, 2)
Packerretrievable = .Cells(13, 2)
Tubingcondition = .Cells(15, 2)
Largeannulararea = .Cells(17, 2)
Tubingreplacement = .Cells(19, 2)
End With
End Sub

Sub Start1()
Call Tweezy
If Casingcondition = 1 Then
```

```
Call BHPmeasurement1
End If
If Casingcondition = 2 Then
Call Istubingpresent2
End If
Call output_recommendation
End Sub

Sub BHPmeasurement1()
If BHPmeasurement = 1 Then
Call Istubingpresent1
ElseIf BHPmeasurement = 2 Then
recommendation = "INJECT FLUIDS DOWN CASING"
End If
End Sub

Sub Istubingpresent1()
If Istubingpresent = 1 Then
Call Packerpresent1
ElseIf Istubingpresent = 2 Then
Call Canweruntubing1
End If
```

```
End Sub

Sub Packerpresent1()
If Packerpresent = 1 Then
Call Packerretrievable1
 ElseIf Packerpresent = 2 Then
Call Tubingcondition1
End If
End Sub

Sub Canweruntubing1()
If Canweruntubing = 1 Then
recommendation = "Run new tubing with proper size;then INJECT FLUIDS
DOWN ANNULUS"
ElseIf Canweruntubing = 2 Then
recommendation = "Unable to measure BHP; INJECT FLUIDS DOWN CASING"
End If
End Sub

Sub Packerretrievable1()
If Packerretrievable = 1 Then
Call Tubingcondition1
```

```
ElseIf Packerretrievable = 2 Then
Call Istubingpresent2
End If
End Sub

Sub Tubingcondition1()
If Tubingcondition = 1 Then
Call Largeannulararea1
ElseIf Tubingcondition = 2 Then
Call Tubingreplacement1
End If
End Sub

Sub Largeannulararea1()
If Largeannulararea = 1 Then
recommendation = "INJECT FLUIDS DOWN ANNULUS"
ElseIf Largeannulararea = 2 Then
Call Tubingreplacement1
End If
End Sub
```

```
Sub Tubingreplacement1()
If Tubingreplacement = 1 Then
recommendation = "Run new tubing with proper size;then INJECT FLUIDS
DOWN ANNULUS"
ElseIf Tubingreplacement = 2 Then
recommendation = "Unable to measure BHP; INJECT FLUIDS DOWN CASING"
End If
End Sub

Sub Istubingpresent2()
If Istubingpresent = 1 Then
Call Tubingcondition2
ElseIf Istubingpresent = 2 Then
Call Canweruntubing2
Call output_recommendation
End If
End Sub

Sub Tubingcondition2()
If Tubingcondition = 1 Then
recommendation = "INJECT FLUIDS DOWN TUBING; and check packer
strength"
```

```
ElseIf Tubingcondition = 2 Then
Call Tubingreplacement2
End If
End Sub

Sub Canweruntubing2()
If Canweruntubing = 1 Then
recommendation = "Run new tubing with proper size; then INJECT FLUIDS
DOWN TUBING"
ElseIf Canweruntubing = 2 Then
recommendation = "FRACTURING THE WELL IS NOT RECOMMENDED"
End If
End Sub

Sub Tubingreplacement2()
If Tubingreplacement = 1 Then
recommendation = "Run new tubing with proper size; then INJECT FLUIDS
DOWN TUBING"
ElseIf Tubingreplacement = 2 Then
recommendation = "FRACTURING THE WELL IS NOT RECOMMENDED"
End If
End Sub
```

```
Sub output_recommendation()

With ThisWorkbook.Worksheets("Sheet2")
.Cells(22, 2) = recommendation
End With
End Sub
```

APPENDIX D

SUBROUTINE FOR LIMITED ENTRY DESIGN

```
Option Explicit
Public density, totalquantity, dp, pc, ph, psurf, stress, tubeid, totalrate, head,
gradient, packerdepth, pipefriction, fricpressuregradient As Double
Public i, n As Integer
Public netpay(100), nohole(100), depth(100), P(100) As Double
Public flow(100), BHTP(100), Pppf(100), actual_flow(100), totalflow,
percentage(100), fraction_flow(100), quantity(100) As Double

Sub read()
With ThisWorkbook.Worksheets("Sheet3")
density = .Cells(4, 2)
totalquantity = .Cells(5, 2)
gradient = .Cells(6, 2)
n = .Cells(9, 2)
dp = .Cells(10, 2)
pc = .Cells(11, 2)
stress = .Cells(12, 2)
packerdepth = .Cells(13, 2)
tubeid = .Cells(14, 2)
totalrate = .Cells(15, 2)
fricpressuregradient = .Cells(16, 2)
```

```
For i = 1 To n
netpay(i) = .Cells(22 + i, 2)
nohole(i) = .Cells(22 + i, 3)
depth(i) = .Cells(22 + i, 4)
Next i
End With
End Sub



Public Sub calculate()
Call read
For flow(1) = 0.001 To totalrate Step 0.001
BHTP(1) = stress * depth(1)
Pppf(1) = (0.2369 * flow(1) ^ 2 * density) / (dp ^ 4 * pc ^ 2)
P(1) = BHTP(1) + Pppf(1)

For i = 2 To n

head = gradient * (depth(i) - depth(i - 1))
P(i) = P(i - 1) + head
BHTP(i) = stress * depth(i)
Pppf(i) = P(i) - BHTP(i)
```

```
On Error Resume Next
flow(i) = Sqr(Pppf(i) * dp ^ 4 * pc ^ 2 / (0.2369 * density))

Next i

totalflow = 0
For i = 1 To n
actual_flow(i) = flow(i) * nohole(i)
totalflow = totalflow + actual_flow(i)
Next i

If (totalrate - 0.1) < totalflow And totalflow < (totalrate + 0.1) Then
GoTo exit1
Else
GoTo continue1
End If
continue1:
Next flow(1)

exit1:
With ThisWorkbook.Worksheets("Sheet3")
For i = 1 To n
```

```
.Cells(22 + i, 1) = i
.Cells(22 + i, 5) = actual_flow(i)
fraction_flow(i) = actual_flow(i) / totalflow
percentage(i) = fraction_flow(i) * 100
.Cells(22 + i, 6) = percentage(i)
quantity(i) = fraction_flow(i) * totalquantity
.Cells(22 + i, 7) = quantity(i)

Next i

ph = gradient * depth(1)
pipefriction = packerdepth * fricpressuregradient
psurf = P(1) - ph + pipefriction

.Cells(31, 5) = "Surface Injection Pressure (psi) ="
.Cells(31, 6) = psurf

End With
End Sub
```

```
Sub Delete()

Range("A23:G31").Select

Selection.ClearContents

End Sub
```

APPENDIX E

RECOVERY EFFICIENCY DETERMINATION

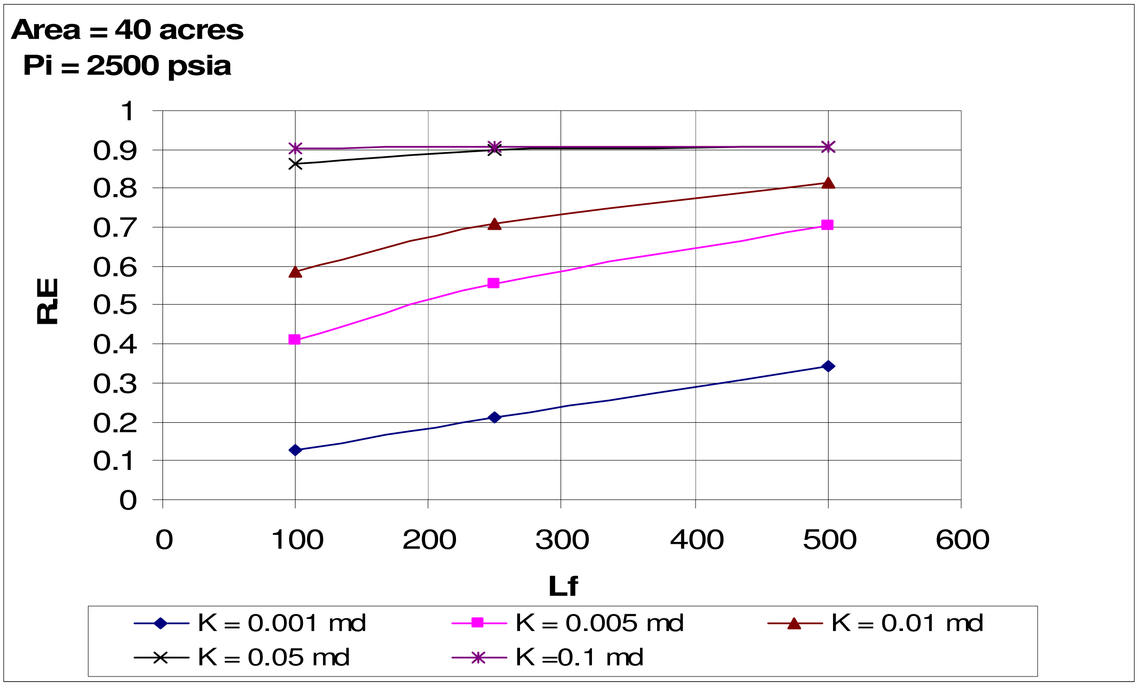

Fig. E1: Plot showing Recovery Efficiency at 40 acres and 2500 psia

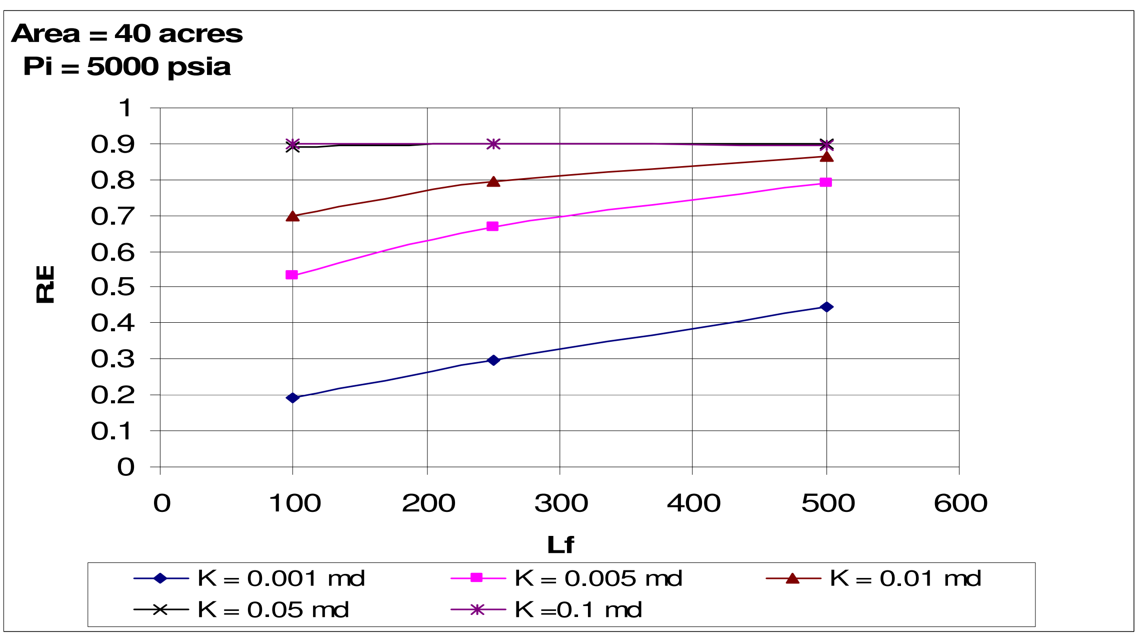

Fig. E2: Plot showing Recovery Efficiency at 40 acres and 5000 psia

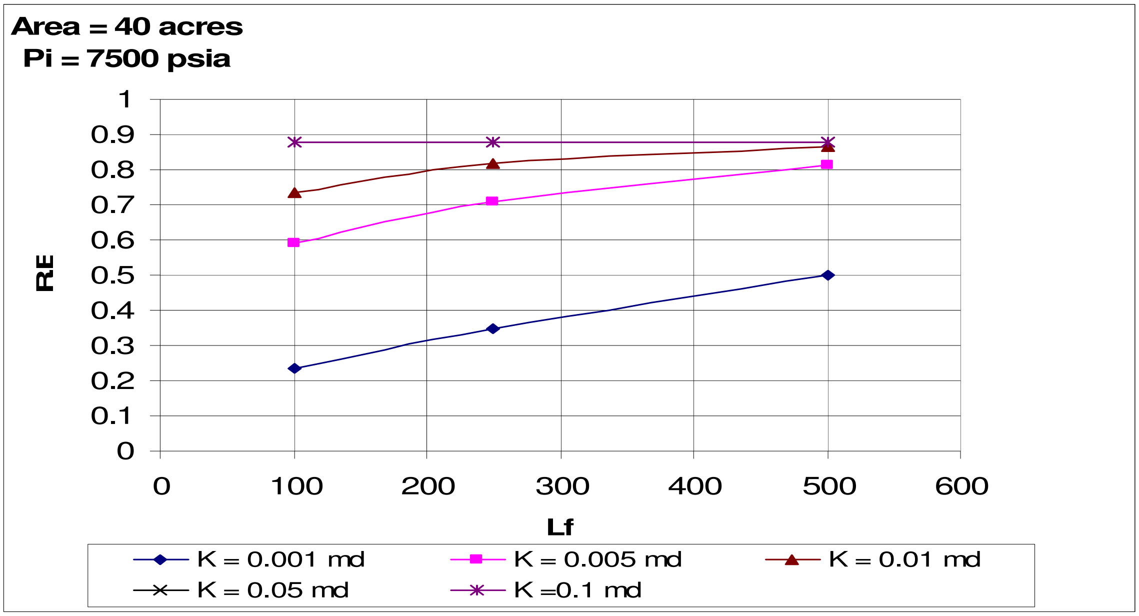

Fig. E3: Plot showing Recovery Efficiency at 40 acres and 7500 psia

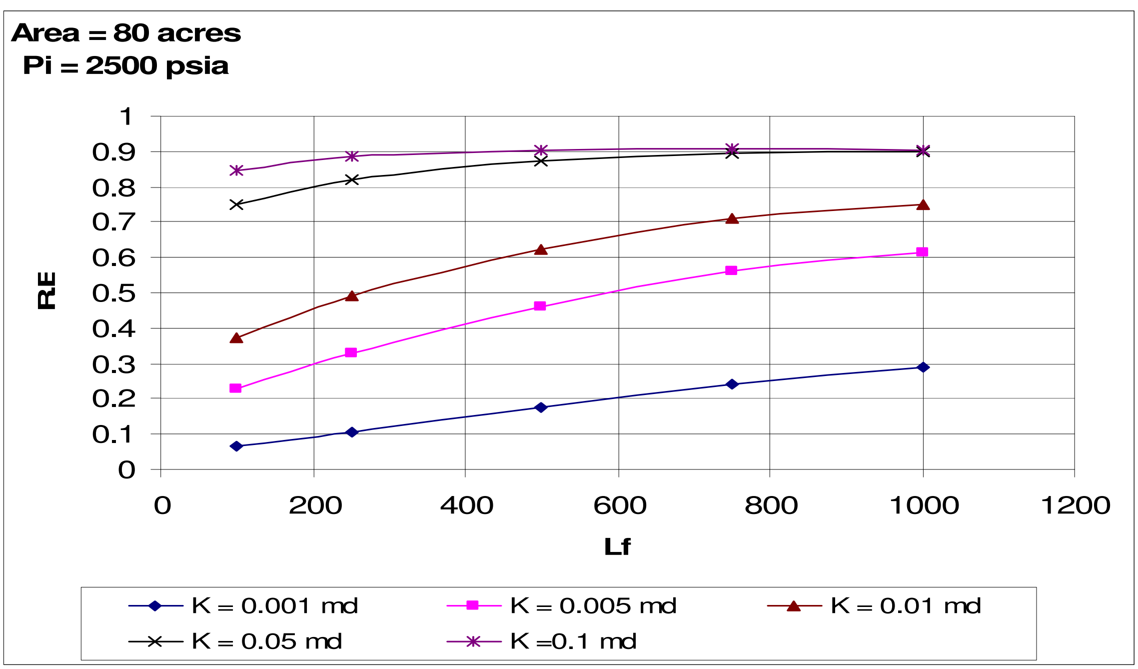

Fig. E4: Plot showing Recovery Efficiency at 80 acres and 2500 psia

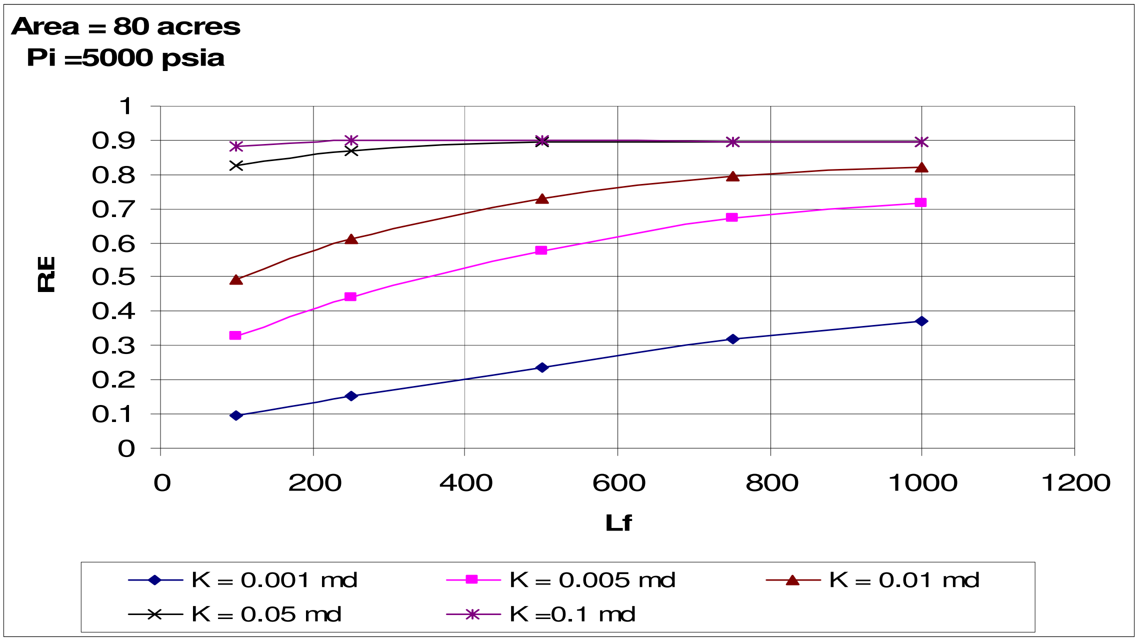

Fig. E5: Plot showing Recovery Efficiency at 80 acres and 5000 psia

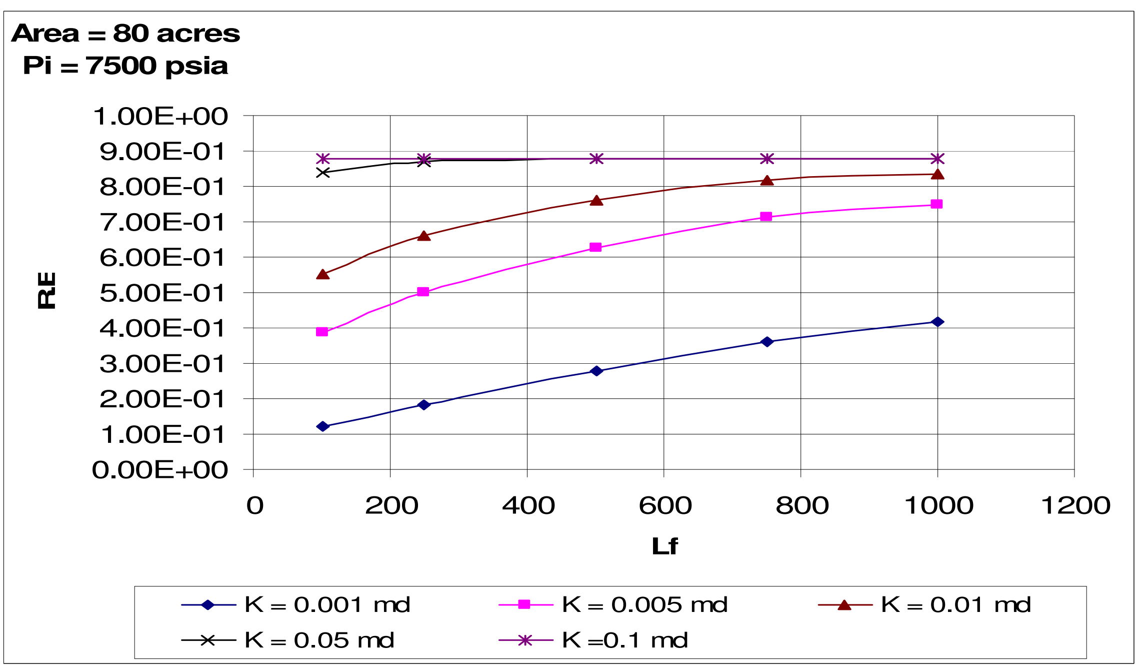

Fig. E6: Plot showing Recovery Efficiency at 80 acres and 7500 psia

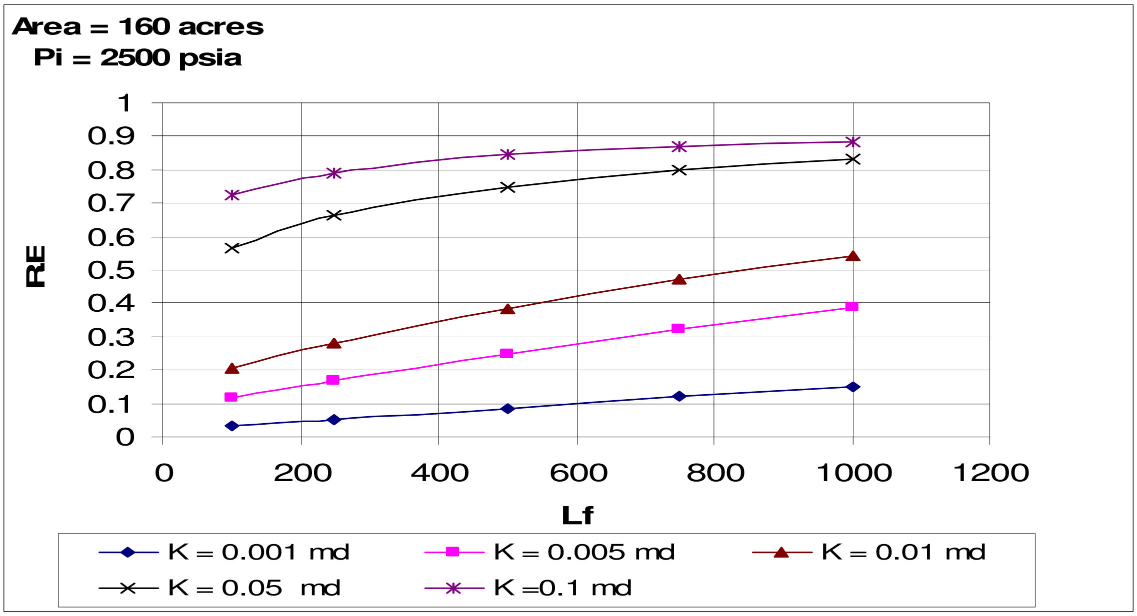

Fig. E7: Plot showing Recovery Efficiency at 160 acres and 2500 psia

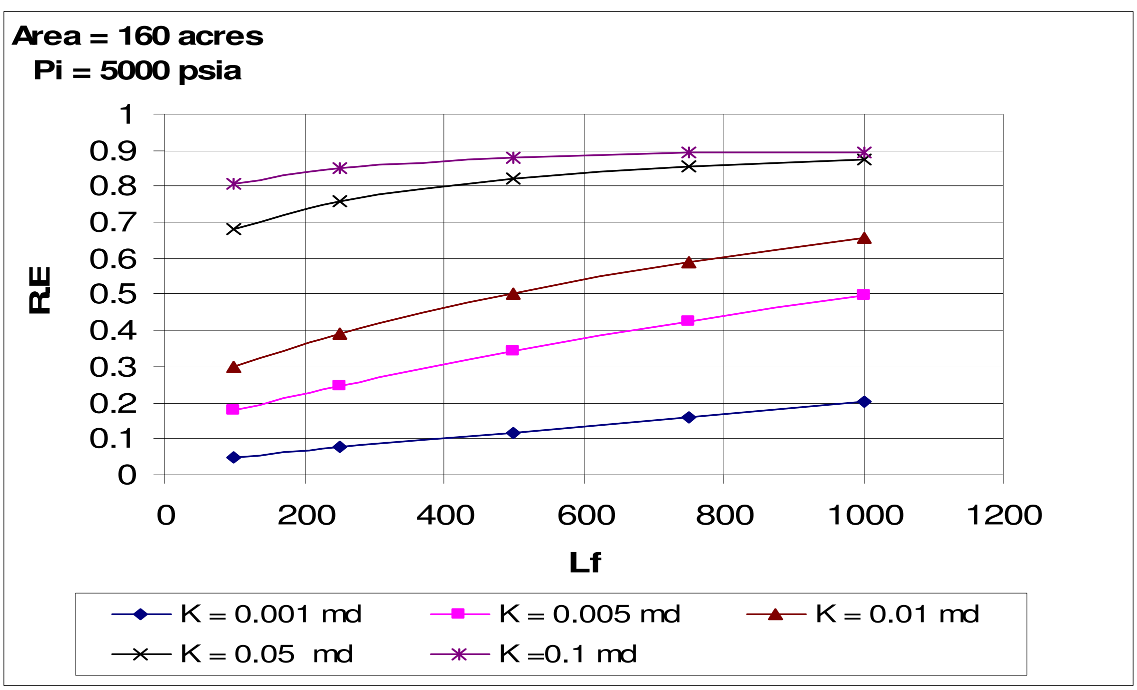

Fig. E8: Plot showing Recovery Efficiency at 160 acres and 5000 psia

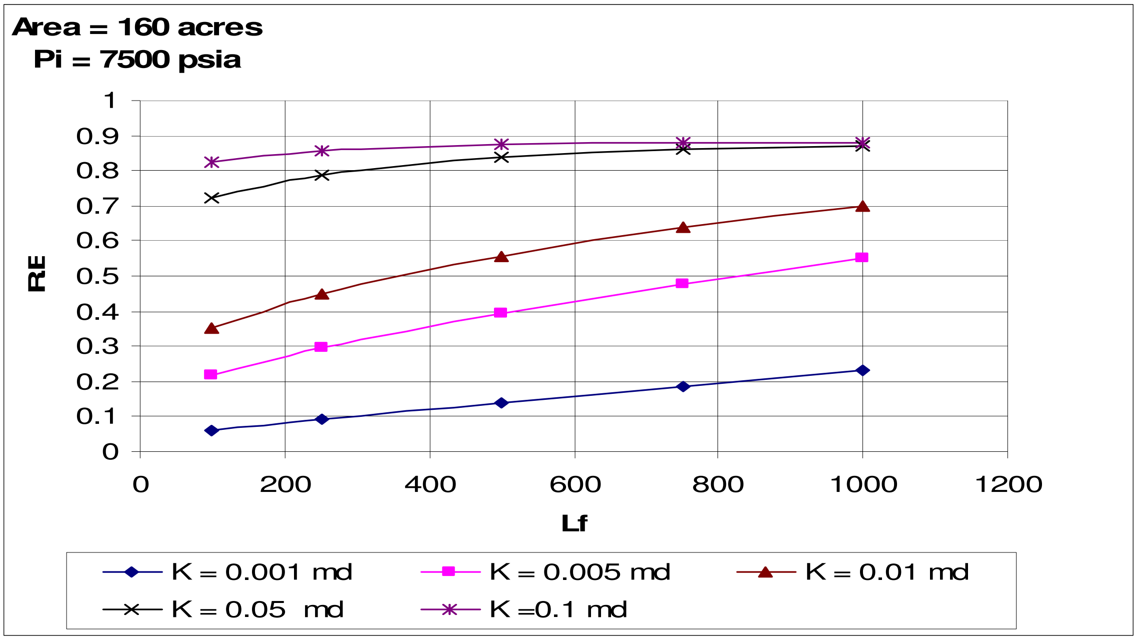

Fig. E9: Plot showing Recovery Efficiency at 160 acres and 7500 psia

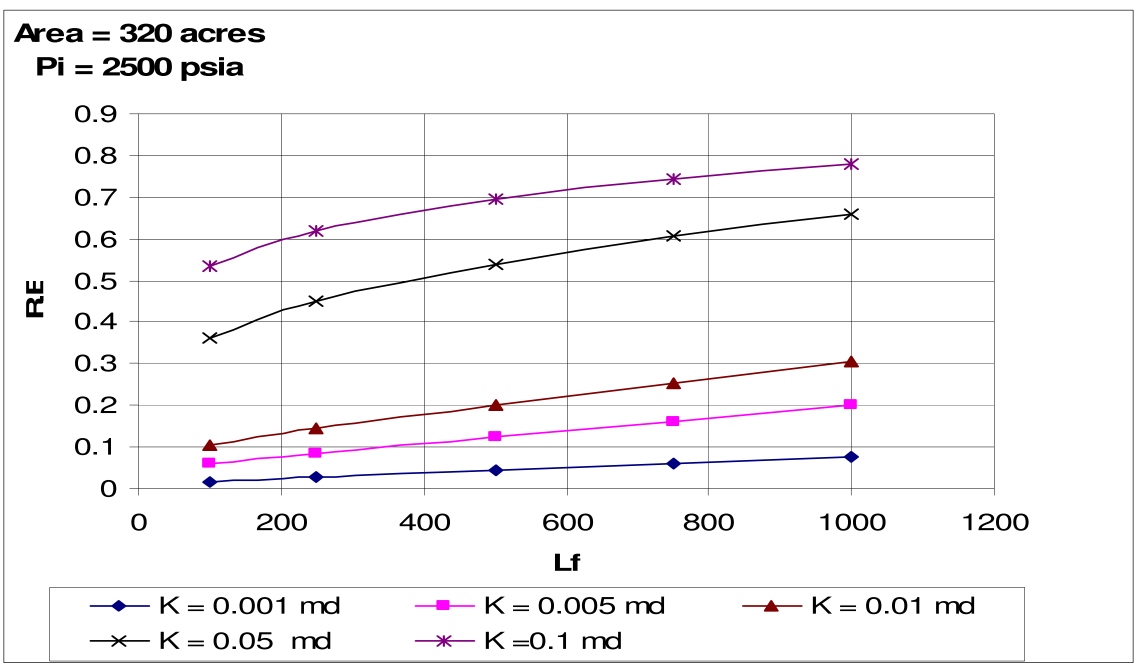

Fig. E10: Plot showing Recovery Efficiency at 320 acres and 2500 psia

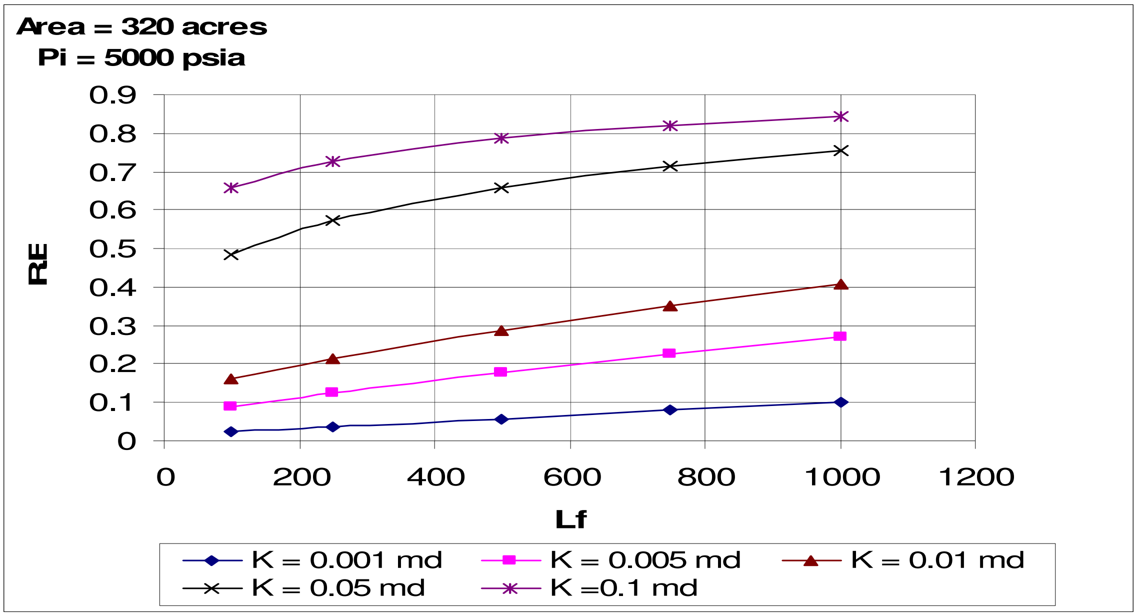

Fig. E11: Plot showing Recovery Efficiency at 320 acres and 5000 psia

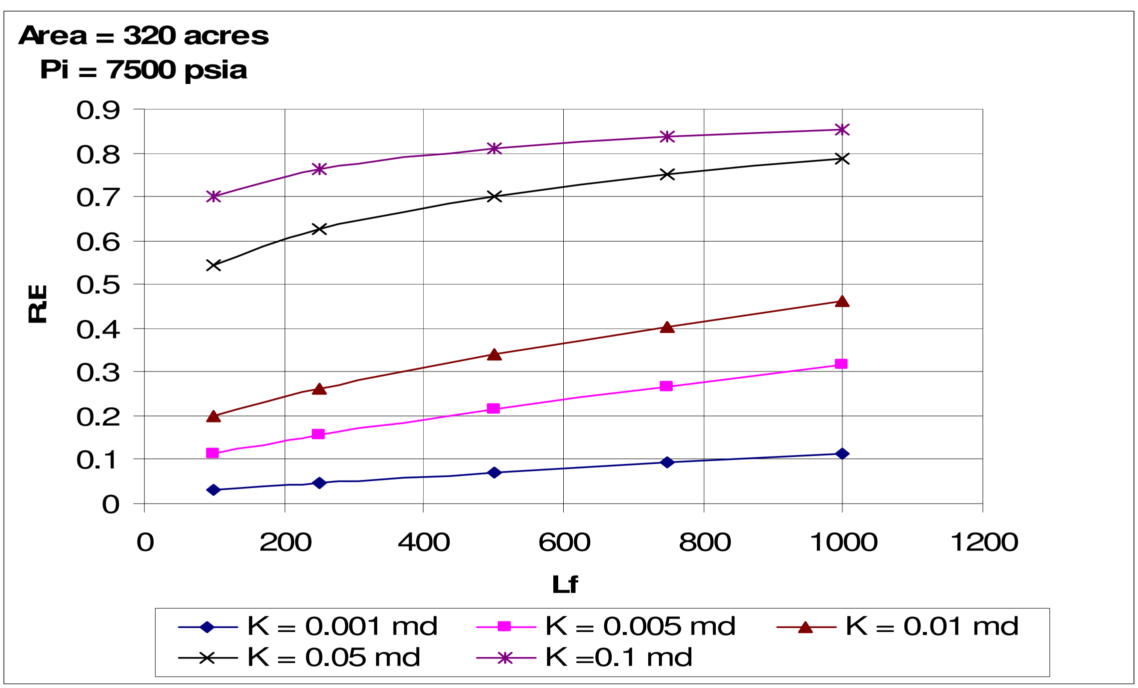

Fig. E12: Plot showing Recovery Efficiency at 320 acres and7500 psia

VITA

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