Interpretation of Well Test Data from Two Hydraulically Communicating Reservoirs

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Abstract

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Naturally fractured reservoirs (NFR) have been receiving more attention than ever since the beginning of the last decade due to various reasons. The current understanding is not sufficient to achieve a favorable recovery factor due to the complexity associated with the fracture characterization and the dynamic behavior of the fractured system. The majority of the fractured reservoirs are developed. Therefore, before proceeding into secondary or possibly tertiary recovery processes a thorough understanding must be reached to avoid undesirable results. The huge reserve volume present in fractured oil and gas reservoirs motivate engineers, researchers, and geoscientists to exert additional efforts to economically exploit these reserves. The fact that they are widely distributed and found in many countries around the globe in almost every lithology is another justification for more interest.

Fracture characterization is the first building block in any NFR study. Therefore, the primary focus of this study is to show the effectiveness of data integration of various dynamic and static data. The study considers a NFR field which consists of two reservoirs that are hydraulically communicating. The reservoirs have prolific porosity and permeability separated by a non reservoir formation. The field well test data was analyzed to identify fractures, and a simulation model was constructed to predict the type of response that would be observed in communicating reservoirs. A unique shape on the derivative was seen due to the communication through fractures. In addition, this study demonstrates the impact of a well, several reservoirs, and fracture attributes on the derivative.
Dedication

I would like to dedicate my effort to my mother and father who have been the reason, after God, behind every success that I achieve in life. I would also like to dedicate it to my lovely wife, Haya, for her sacrifice to stop and postpone her education to come along with me to the United States of America to support me. I would like to thank her for her sacrifice, patience, understanding and support. I would also like to dedicate this work to my first kid, Bailasan, may God help me to make her a happy, educated, knowledgeable and successful person. This thesis is also dedicated to my sisters. I am grateful to all of them for their love, advice, spiritual emotions and encouragement to perform the impossible. I love you all.
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Chapter 1. Introduction

1.1 Problem Statement

Naturally fractured reservoirs (NFR) have been explored and exploited worldwide. They are found with different characteristics in terms of their storage capacity and conductivity. Today, the oil industry is producing oil and gas from all types of NFR. Some of these reservoirs are prolific with high production rates, and some are marginal with limited or intermittent production. It has been noticed that more attention is paid to NFR due to various reasons. The current understanding is not sufficient to achieve high recovery factors due to the complexity associated with the fracture characterization and the dynamic behavior of the fractured system. The majority of the fractured reservoirs are developed. Therefore, before proceeding into secondary or possibly tertiary recovery processes a thorough understanding must be reached to avoid undesirable results. The huge reserve volume present in fractured oil and gas reservoirs motivate engineers, researchers, and geoscientists to exert additional efforts to exploit these reserves economically. The fact that NFR are found in many countries around the globe in almost every lithology is another justification for more interest.

The complexity of NFR is on the heterogeneity of system and determining whether or not fractures are present with sufficient quantity to have a significant impact on reservoir dynamics can be challenging. In the case of tight geologic prospects, NFR are discovered because the exploratory well intersected a natural fracture which is very seldom because the well is vertical and the fracture is either vertical or slightly oblique. Therefore, there could be some hydrocarbon potentials, which is plugged and abandoned, and these have been considered uneconomical because the well did not intersect fractures. On the other hand, a prolific or modest NFR could be mistakenly considered a non-fractured reservoir because drilled wells did not encounter any fracture as a result of vertical drilling. Thus, reservoir characterization is very essential and a vital component in reservoir life cycle because it impacts reservoir development scheme and recovery. Unfortunately, it is not always known before development starts that the reservoir
contains fractures, and sometimes it can take years which may not lead to achieving the optimum productivity. It is always wise to consider any reservoir a fractured reservoir until proven otherwise.

Fractures can have a positive or negative impact on reservoir performance. It all depends upon the level of understanding of their existence, interaction with matrix, and how engineers deal with them. If these were well established and understood fractures can boost the recovery of the field and make marginal fields economically attractive. To understand these aspects, the earth model should be constructed with all available data to mimic the presence of fracture as close as possible. The flow dynamics including capillary-viscous and gravity-viscous forces are studied thoroughly in that particular reservoir. The reservoir engineer should make these forces act for the benefit of the well productivity and recovery by designing the horizontal well’s location, direction and placement in addition to the allocation of production and injection rates.

The primary focus of this study is on fracture characterization which is the first building block of constructing a robust understanding of fractures. Reservoir characterization has evolved over decades of research and field observations. The oil industry has developed many ways of detecting fractures. There is no unique method or procedure, and it involves more than one discipline such as geology, geophysics, petrophysics and petroleum engineering. Each source of data would provide some information; some are direct and some are not. However the effectiveness comes when all this multisource information is integrated. It strengthens the observation and raises the level of confidence in the characterization. The study also considers a case of two reservoirs that are in hydraulic communication by building a reservoir simulation model to generate test data. The test data was analyzed to predict the behavior of pressure data during the test and study different well, reservoir and fracture attributes effects on the test data\textsuperscript{1&2}. 
Chapter 2. Literature Review

2.1 Natural Fracture

Natural fracture is a macroscopic planar discontinuity that results from stresses that exceed the rupture strength of the rock. It can also be defined as a mechanical discontinuity or partings caused by brittle failure\(^1\). Nelson included the physical diagenesis in the definition of natural fracture, so it can be created by physical and/or chemical reaction. Fractures vary on their size, and they can be small scale fractures such as microcracks or multikilometer long features. Fractures are also described as open, partially open, deformed, mineralized or cemented, and vuggy. It is very important to distinguish these types from drilling induced fractures which are created near wellbore due to drilling or core acquisition operations. Figure 1 shows various types of fracture morphology.

![Fracture Morphology](image)

**Figure 1** Shows different types of fracture morphology

(a) Mineralized fracture (b) The dark is open fracture while the bright is closed and the blue is partially open fracture (c) Drilling induced fracture (d) deformed fracture (e) Vuggy fracture.

(After Saudi Aramco)
There are many classifications of natural fractures. Generally, fractures are classified into two types, joints and faults. They are distinct features of fractures with different origins, characteristics, occurrence, and impacts on reservoir fluid flow\textsuperscript{1}. However, the most comprehensive and yet simple classification was presented by Nelson. The classification divides the fractures into two groups:

\subsection*{2.1.1 Tectonic Fractures}

As the name implies tectonic fractures are created by tectonic forces which include joints, fracture swarms, fault-related fractures, and fold related fractures.

\textbf{2.1.1.1 Joints} are parallel or sub parallel set of fractures with its wall pulled away from each other during formation with no involvement of shearing displacement while faults are characterized by shearing displacement of one or possibly two walls of the fracture. Figure 2 shows a reverse fault with many joints.

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{image.png}
\caption{Figure 2 Shows a reverse fault and many joints \hspace{1cm} (After Narr, Schechter & Thompson)}
\end{figure}
2.1.1.2 Fracture Swarms are areas where fracture density is high and fractures are preferentially oriented. They are large-scale objects (several hundred meters). Usually fractures cross layers’ boundaries. Figure 3 shows fracture swarms in a sandstone formation.

![Figure 3 Shows fracture swarms in a sandstone formation (After IFP)](image)

2.1.1.3 Fault planes are planes of shear and characterized by shearing offset. The majority of fractures associated with faults are parallel to the fault. The intensity of fracturing associated with faulting appears to be a function of lithology, distance from fault plane, amount of displacement along the fault, total strain in the rock mass, depth of burial, and possibly the type of fault. Micarelli (2003) was able to demonstrate the frequency of fault related fractures in the vicinity of a fault. It clearly shows that fracture density decreases away from the fault. Figure 4 shows a histogram of fracture occurrence relative to fault distance. A common type of fault related fracture is called fracture corridor which is defined as sub-vertical tabular bodies of fractures which traverse vertically the entire reservoir thickness and extend laterally for tens to hundreds of meters.
2.1.4 Fold Related Fractures are created by stresses that generated the structure. It is often described as fracture lineaments. The stress history during initiation and growth of fold is very complex and hence the fracture patterns that develop within the fold are also complex. Folding usually generates three sets of fractures which are parallel, oblique or perpendicular to maximum horizontal stress direction. Figure 5 shows a diagram of a block showing the geometry of the major conjugate fracture patterns observed in folds in rock.
The three sets of fractures are the following:

- Stylolitic joints and contractional faults are oriented orthogonal to the maximum stress axis, $\sigma_1$.
- Fissure veins, extensional fractures and extension faults are oriented parallel to the maximum stress axis, $\sigma_1$.
- Conjugated shear joints are oriented oblique to the maximum stress axis, $\sigma_1$.

Figure 6 depicts the possible fold related fractures by Price (1967).

2.1.2 Diagenetic Fractures

The diagenetic fractures are mainly bed-parallel stylolites or Stylolite-related features. 

*Stylolites* are discontinuities caused by pressure solution of rock. They are surfaces marked by the accumulation of insoluble residual minerals and commonly occur in carbonate rock. Stylolites can be a problem because it could act as a permeability barrier to flow. Figure 7 shows a Stylolite in a limestone formation.
2.2 Natural Fracture Characteristics

It is very essential after the knowledge of fracture existence to describe its geological characteristic. Fracture characteristics are a vital part of any fracture study since they are used to generate fracture maps which are eventually provided to the geologic model for fluid flow simulation.

2.2.1 Location is the first thing to know about fractures from whatever source has been used. The location could be exact or predicted and sometimes is regionally determined. Fracture location might be lithologic based or based on some seismic attributes. If fracture location is not certainly determined, then multiple scenarios can be generated and simulated for field performance prediction under uncertainty.

2.2.2 Azimuth is the direction of the fracture relative to the north. In an image log, direction of fracture is represented by the rose diagram. The fracture direction can also be predicted to some extent by in-situ stresses. However, in some cases and due to geological complexity, current stresses are not responsible for fracture creation or the fracture might be generated due to local stress rather than regional ones.
2.2.3 Length and Height uncertainty associated with fracture length is very high. High resolution seismic data can help in tracing fracture length. Another source of data would be well test data if only the well intersected the fracture. The same level of uncertainty is also applicable to fracture height. Sometimes fractures traverse the whole formation while in other cases are layered controlled fractures.

2.2.4 Dip is the magnitude of the inclination of a fracture from horizontal. True, or maximum, dip is measured perpendicular to strike. Apparent dip is measured in a direction other than perpendicular to strike.

2.2.5 Aperture basically is the fracture opening or width and it can be determined by core or borehole image.

2.2.6 Fracture Morphology it is very important to know if the fracture is open, partially open, mineralized (cemented or closed), deformed due to secondary stresses, or vuggy. It impacts reservoir dynamics so it is a critical characteristic to know.

2.2.7 Density and Intensity fracture density is the reciprocal of fracture spacing. It is a characteristic of fracture network in a specific formation while fracture intensity is the number of fractures in a specific lithology or layer.

2.2.8 Porosity and Permeability fracture porosity can be considered within the fracture and in this case the porosity might be extremely high. However, if the fracture porosity is considered relative to the bulk volume of the rock, then it is usually small in the neighborhood of 1%. Fracture permeability is usually high which makes low permeability reservoirs producible. Aguilera (1995) developed a mathematical equation for determining fracture permeability as a function of fracture width.

2.2.9 Pressure Dependency some fractures are pressure dependant and they heal or close as the reservoir is depleted. The main cause of fracture closure is the increase of effective stress due to reduction in reservoir pressure. There are occasions where some fracture mineralization could help in preventing fracture closure because it could act as a natural proppant agent.
2.3 Naturally Fractured Reservoirs

Nelson (1985) defined a fractured reservoir as a reservoir in which naturally occurring fractures either have, or are predicted to have, a significant effect on reservoir fluid flow either in the form of increased reservoir permeability and/or porosity or increased permeability anisotropy. Aguilera (1995) defined a naturally fractured reservoir as a reservoir which contains fractures created by natural forces. Most geoscientists believe that every reservoir has some degree of fracturing but not all of them can be considered fractured reservoirs. A reservoir may have some fractures but no impact on fluid flow, so this case cannot be considered a fractured reservoir. It is critical to know at early time whether or not the reservoir is fractured, but a lot of data is needed to classify a reservoir as a NFR. In some cases it takes years before classifying a reservoir as a fractured reservoir. Fracture’s impact can be in favor of the reservoir by enhancing reservoir permeability or help in achieving good sweep efficiency if perfectly managed. On the other hand, fractures can compartmentalize the reservoir which could lead to poor sweep efficiency or could cause rapid water production and short well life. Therefore, the key is to characterize fractures and make them work in favor of the reservoir. It is wise to treat newly discovered reservoir as if it was fractured until proven otherwise.

Fracture could occur in any lithology, but theoretically speaking, the most probable fractured reservoirs are expected to occur in brittle reservoir rock of low porosity where favorable tectonic events have developed. Sinclair (1980) studied fracture intensity in carbonate rocks as a function of composition and grain size. The results showed that the dolomite has the highest fracture intensity followed by limy dolomite, then limestone. It also showed fracture intensity decreases in all types of carbonate rocks as the rock coarsened. Figure 8 shows the relationship between fracture intensity, rock composition and grain size. Montgomery & Morgan (1998) investigated fracture occurrence in both sandstone & carbonate formations which showed fracture occurrence in almost every lithology with a high percentage of fractures in brittle rocks such as Wackestone and Packstone compared to shale formation which is considered a ductile rock. Figure 9 shows fracture occurrence as a function of lithology from Bluebell oil field, Utah basin.
Figure 8 Fracture Intensity versus lithology 
(After Sinclair)

Figure 9 Fracture occurrence as a function of lithology 
(After Montgomery & Morgan AAPG © 1998)
2.3.1 Naturally Fractured Reservoirs Productivity

A unique characteristic of a NFR system is the vast range of productivity variation. This variation is attributed to the heterogeneity of the geology. For instance, a group of wells might outperform due to intersection of single or multiple highly conductive fractures while another group might show low productivity compared to the other group due to absence of fractures. An 80/20 rule of thumb is commonly mentioned for NFR well productivity which means 80% of NFR production is coming from 20% of the wells in the field\(^1\). This rule may be true for some types of NFR where fractures are the main flow contributor. A study was published in 1995 by Beliveau showing productivity improvement in horizontal wells compared to their neighboring vertical wells in a large number of reservoirs\(^7\). Beliveau studied more than 1000 horizontal wells comparing their productivity to their offset vertical wells. These wells were from conventional, naturally fractured and heavy oil fields. The study used Productivity Improvement Factor (PIF) which is defined as the stable oil or gas rate compared to the current rate of a neighboring vertical well. The study results showed a mode of 6 and a median of 9 of PIF for NFR compared to a mode of 5 and a median of 6 of PIF for conventional reservoirs. Therefore, it clearly showed the heterogeneity of NFRs and the effectiveness of horizontal wells to drain more hydrocarbon as they intersect more fractures. Figure 10 shows the comparison of PIF between conventional reservoirs to NFRs.

Figure 10 Comparison of PIF for conventional and naturally fractured reservoirs
(After Beliveau)
It is not only the productivity that distinguishes NFRs, “short circuiting” could be another phenomenon to observe where injected fluid reaches producing wells rapidly in unexpected time. This is true for some types of NFRs where a very huge conductive fracture connects producing wells to the injection wells. It is also important to keep in mind similar behavior may be observed in reservoirs with what is called “thief zones” or zones with short thickness and high conductivity.

2.3.2 Naturally Fractured Reservoirs Recovery

There are many factors affecting the recovery of NFRs, most importantly field understanding and choosing the appropriate recovery mechanism. Since NFRs are generally considered to be short-lived with possible high flow rates, rapid production decline, and low ultimate recovery factor, it is wise to review the industry history and practices on producing these assets. Jack Allan & S. Qing Sun in 2003 studied the recovery control factors of 100 NFRs. Their study indicates that the overall ultimate recoveries of the 100 NFRs are somewhat lower than those of many conventional reservoirs. However there are still some recoveries that are comparable to some conventional reservoirs. Figure 11 shows the distribution of ultimate recovery of NFRs all types.

The study showed the overall ultimate recovery factor of all NFRs types have an average of 26% while the 8 fractured gas reservoirs have an average ultimate recovery of 61%. Two thirds of the oil reservoirs have a recovery factor greater than 20% which is high enough to be commercially attractive. Three quarters of the gas reservoirs have recovery factors larger than 60%. The lower recovery factors in two of the gas reservoirs are caused by water encroachment into fractured depletion drive reservoirs. They studied the ultimate recovery for a certain type of NFRs as a function of secondary recovery and/or EOR technique. There are substantial differences in recoveries for each type which clearly show the importance of choosing the appropriate technique for each NFR type. Figure 12 & Table 1 show the ultimate recovery of a certain type of NFR against the applied secondary recovery and/or EOR technique.
Figure 11 Distribution of ultimate recovery of all NFRs types
(After Jack Allan & S. Qing Sun 2003)

Figure 12 Ultimate recovery factor versus secondary recovery/EOR technique
(After Jack Allan & S. Qing Sun 2003)
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<td>Water</td>
<td>Water injection (poor efficiency)</td>
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<td>Dolomite</td>
<td>Water</td>
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<tr>
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<td>China</td>
<td>Bohai</td>
<td>Light oil</td>
<td>Sandstone</td>
<td>Water: solution gas</td>
<td>Water injection / hydraulic fracturing</td>
<td>40.0%</td>
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<td>Philippines</td>
<td>Northwest Palawan</td>
<td>Medium oil</td>
<td>Limestone</td>
<td>Strong bottom water</td>
<td>Unassisted primary recovery</td>
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<td>Iran</td>
<td>Zagros</td>
<td>Light oil</td>
<td>Limestone/dolomite</td>
<td>Water: gas cap expansion</td>
<td>Gas injection</td>
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<tr>
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<td>Bohai</td>
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<td>Water injection</td>
<td>25.0%</td>
</tr>
<tr>
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<td>Kura</td>
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<td>Volcanics</td>
<td>Water</td>
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<td>-</td>
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<td>USA</td>
<td>Midland</td>
<td>Light oil</td>
<td>Sandstone</td>
<td>Solution gas</td>
<td>Horizontal drilling / hydraulic fracturing / water injection (poor efficiency)</td>
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<td>Cooper</td>
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<td>Sandstone</td>
<td>Solution gas</td>
<td>Gas injection / hydraulic fracturing</td>
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<td>Limestone/dolomite</td>
<td>Water</td>
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<td>Santa Maria</td>
<td>Heavy oil</td>
<td>Dolomite</td>
<td>Fluid expansion &amp; pore volume contraction / solution gas / gravity drainage</td>
<td>No data</td>
<td>-</td>
</tr>
<tr>
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<td>China</td>
<td>Bohai</td>
<td>Medium oil</td>
<td>Dolomite</td>
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<td>Water injection (poor efficiency) / gas (N2) injection</td>
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<td>Water injection (poor efficiency)</td>
<td>22.5%</td>
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2.3.3 Classification of Naturally Fractured Reservoirs

To properly develop and manage NFRs, it is crucial to classify them so the industry can lean from analogy. The knowledge of a common type can help in designing well architecture, developing an optimum depletion scheme and enhanced oil recovery methods. McNaughton & Garb (1975) classified naturally fractured reservoirs based on their storage capacity into three types (A, B and C). In NFR type A the storage capacity of the matrix is much larger than the fracture storage capacity. The matrix has significant permeability and the fracture would act as a permeability assist feature. Type B, both matrix and fractures have about the same storage capacity, but the fractures in this case provide the permeability for fluid flow. Type C, the matrix has no porosity and fractures provide both storage capacity and permeability. Figure 13 shows the classification of NFR according to McNaughton & Garb.

Figure 13 McNaughton and Garb classification of NFRs (After McNaughton & Garb)
The most well known classification of NFRs, industry wide, is proposed by Nelson (1985) and it was an expansion of that proposed by Hubbert and Willis (1955).

Type 1: Fractures provide the essential reservoir porosity and permeability
Type 2: Fractures provide the essential reservoir permeability
Type 3: Fractures assist permeability in an already producible reservoir
Type 4: Fractures provide no additional porosity or permeability but create significant reservoir anisotropy (barriers)

The first three types describe positive reservoir attributes of the fracture system while type four reservoir fractures compartmentalize the reservoir which is considered a negative impact on the system.

For the first type of fractured reservoir, the fracture provides the essential porosity and permeability. It is important for reserves calculation to accurately estimate fracture porosity and spacing early on for reservoir development economics and to determine if initial high flow rates will be maintained or drop rapidly with time. This type of NFRs can present rapid decline if produced at high rates which leads some operators to produce it at low or intermittent production. Examples of this type are Basement Reservoirs in Vietnam & Kansas.

For the second and third types, the fracture provides the production pathways or assists the permeability, and the accuracy of fracture porosity determination has less significance than the first type. However, it is important to know the degree of interaction between matrix and fractures so that the engineer can know whether or not the reservoir porosity can be drained by the fracture system. Examples of type two are Sooner trend (Oklahoma), Agha Jari field (Iran), and Spraberry trend area (Texas). Type three examples include Dukhan (Qatar), Hassi Messaoud (Algeria) and Kirkuk (Iraq).

The forth type partitions the reservoir which imposes challenges in the development and management of this type. The sweep becomes an issue and may require more wells to drain a comparable area of a conventional reservoir.
In 2006 Narr, Schechter and Thompson presented a modification to Nelson’s classification which is basically the same as Nelson’s except excluding Type four. IFP has also presented a modification to Nelson’s which is excluding type four and adding a new type. The IFP new type is similar to Nelson’s type three, but this type of fracture generates a high flow anisotropy in the reservoir as compared to permeability assist in Nelson’s type 3.

Jack Allan & S. Qing Sun in 2003 studied hundred NFRs and concluded that Nelson’s type two, where fractures provide the essential reservoir permeability, has to be divided into two types. First type, the reservoir has low porosity and low permeability and the second type with high matrix porosity and low permeability. Therefore, the main difference is in the matrix porosity, one with high and the other with low porosity. They compared the recovery factors of the two types with different depletion schemes and enhanced oil recovery methods and proved that they have to be treated differently. If all modifications are integrated together Nelson’s classification will be:

Type 1: Fractures provide the essential reservoir porosity and permeability
Type 2: Fractures provide the essential reservoir permeability (Low Matrix Porosity)
Type 3: Fractures provide the essential reservoir permeability (High Matrix Porosity)
Type 4: Fractures assist permeability in an already producible reservoir
Type 5: Fractures generate a high flow anisotropy in a high porosity permeability reservoir.
Type 6: Fractures provide no additional porosity or permeability but create significant reservoir anisotropy (barriers)
Chapter 3. Objective and Methodology

3.1 Objective

The objective of this study is to detect fractures from all available data and integrate it in a meaningful way using a field example. Utilize the well test data to locate the communication between the reservoirs. A quantum leap has been reached in the area of fracture detection in recent years due to many reasons, most importantly the attention and focus given by engineers, geoscientists and researchers to increase our understanding. The methods are divided into direct and indirect and sometimes classified based on their source whether it is static or dynamic driven data.

3.2 Methodology

3.2.1 Static Data Gathering

Static data was used since it provides essential information about fractures and it can be extracted from geological, geophysical and petrophysical sources:

3.2.1.1 Core Analysis

Core analysis is among the most direct methods of fracture detection because of the ability of inspecting visually the core for fracture existence. Cores are acquired for routine and advanced geological and engineering analysis. In addition facture characterization can be performed as well. Cores provide the most detailed information about fractures such as facies and fracture relationship, fracture morphology, aperture, origin, geometry, and fracture dip relative to bedding. Core studies have some draw backs. First the core represents a tiny piece of
the reservoir that represents the immediate vicinity of the wellbore. Second, it is not economically feasible to acquire a large number of cores in an attempt to study the whole reservoir. In addition, poor core recovery could be present in NFRs. In fact it is a characteristic of highly fractured reservoir but it is not always the case because cores may be breakdown due to coring operation. With all these drawbacks core analysis is still valuable especially when is it integrated with other sources of information. During fracture characterization processes it is important to distinguish whether fractures are natural or artificially induced.

3.2.1.2 Borehole Image

It is neither economical nor practical to study formation characteristics only through core acquisition because a full core coverage may not be attainable. Wellbore image contributes in many geological studies from a simple to a very complex one such as porosity determination, permeability estimation, sequence stratigraphy, formation dipping, rock texture and facies etc. Image log becomes very powerful when it is integrated with core data. It is very uncommon to accomplish good fracture characterization without the aid of borehole images. They provide the most useful source of data about location and orientation of reservoir fractures. The water based imager can distinguish between open and closed fracture while it is challenging to know that from an oil based image. Figure 14 shows an interpreted image log with open and partially open fractures.
3.2.1.3 Seismic Anomalies

3-D Seismic technology has provided numerous advantages over the 2-D seismic which is essentially limited to vertical cross-sections. The 3D technology allows seismic data to be displayed in horizontal or “map” form. The continuous representation of the reservoir has enabled geoscientists to more accurately detect discontinuity in the geology. Impedance attributes have been used to extract geological information in many different ways. Dip, strain, curvature and coherency attributes were successfully used to detect fracture presence and constrain fracture distribution. Coherency cube is very powerful to define seismic scale fractures and faults\textsuperscript{10}. Figure 15 shows (a) a traditional 3-D seismic time slice where faults parallel to strike are difficult to see and (b) a coherency time slice where faults are clearly visible.
3.2.1.4 Open hole Logs

Open hole logs are conventionally run to define hydrocarbon pay zones which ultimately lead to completion decisions. There has been some work recently published that demonstrated identifying fracture corridors from open hole logs. Fracture corridors were identified as water saturation spikes with no corresponding change in porosity. Fracture corridors with cemented walls show bulk density spikes. Many cases revealed fracture corridors with caliper enlargement and lost circulation. The study also showed that some Middle East carbonate reservoirs have fracture corridors with gamma ray spikes.\(^5\)
3.2.1.5 Outcrops

Formation outcrops is very helpful in providing conceptual ideas about the subsurface. Geoscientists extensively study outcrops with other sources of information to produce a model that mimics subsurface reservoirs. Fractures and faults can also be studied through outcrops and can provide a pretty good idea about fracture existence. However it is very essential to keep in mind that stresses at surface are different than in situ stress which could lead to different outcomes.

3.2.1.6 Structure Geology

Understanding in situ stresses and the reservoir structure helps identifying areas with possible fracture existence. As discussed in chapter 1, some fractures are fold related and others are fault related and hence knowing the presence of these structural features can lead to better insights about fracture presence.

3.2.2 Dynamic Data Gathering

Dynamic data is often classified as hard data which reflects the dynamic behavior of the reservoir. It requires reservoir engineering analysis and in most cases is very powerful despite the fact it is an indirect method of fracture detection.

3.2.2.1 Well Test Analysis

Well test analysis evolved in the last decades due to the accelerated advancement in software and reservoir modeling. This advancement has made possible a more reliable characterization of NFRs based on new flow models that properly capture NFRs heterogeneities. Well tests have proven it is effective in detecting some reservoir heterogeneities when it is
integrated with other sources of information. Flow regime that appears during well test
determines what reservoir property can be estimated. The pressure derivative is extremely
helpful in determining the present flow regime. Generally speaking, the behavior of NFRs
depends on the intensity, aperture, shape of the fracture, and the rock/matrix fluid transfer
efficiency (Cinco-ley 1996). The type of NFR plays a major role in the flow regime that takes
place during production period. Experience has shown that NFRs behave according to a variety
of reservoir flow-models: (1) homogenous reservoir (2) multiple region or composite reservoir
(3) anisotropic medium (4) single-fracture medium and finally (5) dual porosity medium. The
first proposed model to study NFRs was the dual porosity model which assumes two interacting
porous media: a high conductive fracture network and isolated matrix blocks with high storage
capacity. The basic theory of dual porosity in a NFR was first proposed by Barenblatt et al.
(1960). They assumed radial flow with slightly compressible fluid in a naturally fractured porous
medium. Later, Warren and Root (1963) presented an idealized model that assumes a connected
uniform fracture system, isolated uniform matrix system, and pseudosteady-state flow between
matrix and fracture. Kazemi (1969) and de Swaan (1976) improved the Warren-Root model and
presented theoretical solutions considering transient flow between matrix and fracture. Their
model has been characterized as a transient-interporosity flow model. In these models, similar to
the Warren-Root model, the matrix has high storage capacity and low permeability and fractures
have high permeability and low storage capacity. Figure 16 shows an idealized model of dual
porosity NFR.
Warren and Root showed that the response of buildup pressure data of the idealized dual porosity model exhibits two semilog straight lines. The first straight line corresponds to the transient flow in the fracture media and the second line to the transient flow in the total system. The slopes of those lines are related to the flow capacity of the formation. Figure 17 shows the pressure behavior of dual porosity model in a semi-log plot. The vertical separation of the two lines is related to the relative storage capacity of the fracture. They defined two parameters describing the pressure behavior in the model. The first parameter is storativity ratio ($\omega$) which is the ratio of fracture storage capacity to the total storage capacity of the system. The second parameter is interporosity flow coefficient ($\lambda$) which governs the flow from matrix to fracture and is related to heterogeneity of the system. Figure 18 shows pressure change and pressure derivative in a log-log plot with storativity ratio and interporosity flow coefficient on the derivative. In conclusion, pressure derivative behavior aids reservoir engineers to characterize NFRs through response that matches conceptual model of real reservoir.
Figure 17 Pressure behavior in a semi-log plot for dual porosity model
(After Al-Ghamdi)

Figure 18 Pressure change & derivative response of dual porosity model
(After Al-Ghamdi)
3.2.2.2 Interference Test

Multiple well tests conducted at a large volume of the reservoir provide insights about the lateral and/or vertical heterogeneities in the reservoir. To capture these heterogeneities, interference or pulse tests are designed during which a pressure pulse is created in one or many injection wells and pressure is recorded in an observation well. The recorded increase in pressure is interpreted by comparing it with a model result with different permeability values or fracture existence. Pulse and interference tests are quite similar. Pulse test is usually done with an injection followed by shut in period and sometimes more than one cycle is done to confirm obtaining good results, while interference test is done with continuous injection and monitoring. The observation well is instrumented with a down hole gauge to detect the response of pressure with time. There are many successful stories of interference tests in the petroleum industry for reservoir characterization purposes which ultimately used to fine tune reservoir simulation models.

3.2.2.3 Flow Capacity Indicator

Flow capacity indicator or index is defined as the ratio between the observed well performance to well performance predicted by matrix properties. It is calculated by dividing $k_{h_{test}}$ to $k_{h_{matrix}}$, where the $k_{h_{test}}$ value is obtained from the test data and $k_{h_{matrix}}$ is obtained from matrix permeabilities’ core data. The analysis is often done graphically by cross plotting the two $k_h$. In each well, if the value is on or near the 45° line the well performs as expected with no secondary system involved. However if the value is way above the 45° with $k_{h_{test}}$ in the y-axis, then a possible secondary system is involved such as fault or fracture, and on other hand if the well shows $k_{h_{test}}$ way below the 45° the well is underperforming. This concept was originally suggested by Riess (1980) and some authors described it as FPI (Fracture Productivity Index).
3.2.2.4 Tracer Test

Tracer test is done by injecting chemical or radioactive substances in an injection well and collecting samples from the production wells for tracer presence. They are commonly utilized in groundwater studies. However, recent statistics showed a significant increase of field tracer applications in the oil and gas industry. Figure 19 shows the trend of tracer usage in the oil and gas industry.

![Figure 19 Tracer interpretation trend in oil and gas industry](image)

(After Reidun Kleven, presented at SPE tracer workshop 2007)

Two types of tracer tests are commonly conducted based on its objective. The first type is single well tracer test (SWTT) for drilling, workover, completion, production and oil saturation purposes. The second type is an interwell tracer test (IWTT) for connectivity testing, identify barrier and fractures, sweep efficiency and reservoir management. The IWTT is extremely useful to identify fractures and fractured intervals because fractures accelerate tracer breakthrough in production wells. The results of IWTT are compared to the results of the simulation model and then guide the changes in geologic models. Fracture location, orientation and conductivity can be estimated from tracer data. Fracture conductivity is estimated by testing different conductivity values in the model to match tracer data.
3.2.2.5 Reservoir Engineering Analysis

Reservoir engineering analysis is very crucial for field performance understating. It ultimately helps in maximizing hydrocarbon recovery. The analysis of production and injection data can lead to capture some heterogeneities such as fault, fractures or high permeability streaks. The outperforming wells can be in areas with high fracture intensity or high permeability zone. Each possibility can be tested until the reservoir engineer reaches definite answers.

Injection data analysis is beneficial as well where short circuiting can indicate fracture existence. Unplanned cyclic injection can cause some rapid changes in reservoir pressure or production and in most cases can be attributed to fracture or fault presence. It is important to keep in mind that thief zones can cause similar behavior in the reservoir.

Gas oil ratio (GOR) and water oil ratio (WOR) trends are also used to assess the behavior of the reservoir. Fractures can cause sudden increase in GOR and WOR if the NFR is not properly managed. It is worth mentioning that water and gas coning are phenomenon that can cause rapid increase in GOR and WOR so it is important to distinguish between the two behaviors.

Geochemical analysis and salinity maps of produced fluids indicate what is happening in the subsurface. Salinity maps have been traditionally used to track water movement, and it can be used to check for fracture existence. Injected water total dissolved solids (TDS) produced at wells that are far away from injection can be due to fracture.

Production logging is used to identify producing intervals using a flow meter. The tool provides two measurements, flow metering and temperature monitoring. Both can help to identify fractures and their flow contributions to the well. The temperature measurement helps in knowing the type of fluid entering the wellbore. High production rates from a very thin interval are usually indicative of fracture contribution yet the observation needs to be confirmed by other
sources of information. In some cases when image log is available, production log is helpful to
determine which fractures are conductive and what is their contribution to the well production.

Statistical analysis of reservoir parameters using different interpretation techniques has
proven to be useful tool to determine outperforming wells due to fractures. Productivity index
(PI), flow capacity (kh), and pressure drawdown (PDD) are well attributes commonly used to
look for wells completed in fractured areas. Bubble maps and histograms are widely used
techniques to do this type of analysis. Histograms of NFR tend to show bi-model because group
of wells are greatly affected by fractures while bubble maps provide fast visual examination of
the data.

Reservoir analogy has been used to give quick insights about productivity, recovery
factor, water influx, and reservoir heterogeneities. There are several things to keep in mind while
making the analogy. Reservoir lithology, structure and tectonic setting, depth of burial, reservoir
pressure have to be similar to some extant to make good analogy.

3.2.2.6 Lost Circulation

Drilling operation sometimes is valuable when it is accurately logged and properly
analyzed. Rate of penetration has been traditionally used for multiple purposes. Lost circulation
of drilling fluid is another piece of information which indicates fracture presence in the well or in
the well vicinity. It is indirect method of detecting fracture so it has to be confirmed with other
sources of information because some connected vugs can cause drilling fluid loss. One possible
indication of fracture caused lost circulation is high rate abrupt lost circulation.
3.2.3 Simulation Model

The second objective of this study is to investigate whether or not a distinct shape of the derivative can be seen, and that is attributed to the communication of the reservoirs. To study the effect of the communication on the test data, a detailed simulation model was constructed to mimic the communication of two reservoirs. In addition several attributes of the well, reservoir and fractures were studied. The studied attributes are fracture conductivity, fracture length, first layer permeability, third layer permeability, fracture distance from well, fracture porosity, multiple fractures, and horizontal well.

A commercial reservoir simulator (Computer Modeling Group, CMG) was used to accomplish this study. Implicit Explicit Black Oil Simulator (IMEX) software was utilized since the study is conducted on an oil field. The model main features are:

- Model dimensions (300 X 300 X 3)
- Length of each grid cell is five feet
- Model total area is 1500 X 1500 feet
- Model is a single phase flow
- Model is a single porosity-single permeability
- Porosity is assumed to be 0.18 throughout the model
- Model consists of three layers
- Second layer has no porosity except at fracture plane which is equal to the model porosity
- Second layer has no permeability
- Model has a constant bubble point pressure
- Model consists of one well located at the center of the model
- Well is completed in the first layer only
- Well is produced at a constant rate of 5000 BPD
- Model consists of one rectangular fracture plane
- Reservoirs communicate through fracture only
- Initially fracture conductivity was assumed to be 2000 md.ft
- Fracture is 50 feet away from well
Chapter 4. Results and Discussion

4.1 Data Integration and Cross Validation

Chapter 3 covers almost all fracture detection methods including the newly developed techniques and procedures. Each engineer or geoscientist has his one way of analyzing the data. No approach is ideal and applicable everywhere besides not all information is available to do most of the detection techniques. Therefore, the engineer or the geoscientist has to work with the available data and be able to integrate it in a meaningful way to drive conclusions. In addition, most of the indicators are indirect so they need to be cross validated with other indicators to generate solid conclusions\textsuperscript{1,13}.

4.2 Field Example

4.2.1 Field Overview

The purpose of this field example is to demonstrate the effectiveness of integrating the available data to define areas that are naturally fractured in the reservoir. The field consists of two carbonate reservoirs, referred to as Reservoir A and Reservoir B, stacked one on top of the other and separated by a thick non-reservoir formation. The historical production data suggests that the field is Type-5 NFR. The field pressure data that were collected from both reservoirs during the past were analyzed and showed pressure match between the offset wells in the two reservoirs. Therefore, it was concluded that the reservoirs are in hydraulic communication, but the media of the communication and the areas where they communicate were not well identified. Figure 20 shows field cross section view (a) and structure map (b).
4.2.2 Field Geology

Understanding the geologic features of the field is the first step to perform any geologic characterization. The two reservoirs in this field are asymmetrical anticline structures with a steep flank at one side and gentle slope in the other side as shown in the cross section view Figure 20 (a). The reservoirs are carbonate with excellent petrophysical properties in Reservoir A and relatively poor properties in Reservoir B. There is no drastic change in petrophysical properties of Reservoir A across the entire field. However, Reservoir B demonstrates lateral and vertical changes in facies. The reservoirs are separated by almost 300 ft of non-porous impermeable carbonate mudstone formation.

![Field cross section and structure map](image)

Figure 20 (a) Field cross section (b) structure map

Regional tectonic forces formed the anticline with a deep faulting system, which contributed to the current structure of the field. There is no definite evidence of the deep fault being propagated to penetrate these reservoirs. Therefore, the fault possibly dies before it reaches the shallow depths where these reservoirs are deposited. Natural fractures have been observed in some of the core samples, which were modeled using 3D seismic curvature analysis. The model
suggests that the dominant location of the fractures is where the most deformation of the structure occurred.

4.2.3 Geophysical Data

The interpreted 3D seismic data suggests fracture existence in the west side of the reservoir. The extracted seismic attributes for fracture study were dip, strain, and curvature. They are all in agreement on the area with the likelihood of fracture presence. Figure 21 shows different seismic attributes with areas of possible fracture presence.

![Figure 21 Seismic attributes with possible fracture presence](After John Cole and others, Saudi Aramco, 2009)

4.2.4 Borehole Images

There have been several image logs acquired across the field which show some fracture presence. The images show different type of fracture systems ranging from micro-fractures to fracture corridors but it did not show any faulting in the acquired images. The dominant location
of the fractures is at the west side of the field as shown in Figure 22. The red circles show the approximate location of the wells with images that show fractures. The green ones show the approximate location of wells with images that do not show any fractures.

![Figure 22 Approximate locations of wells that show & do show not fractures](image)

The same wells that show fractures in the image, encounter drilling fluid losses during drilling with the exception of one well, which is the most southern one. Thus, two different sources of information provide the same conclusion. It showed be noted that most of them had complete losses during drilling. Figure 23 shows an example of an image log in one of these wells that encountered mud losses. The image shows a big conductive fracture in addition to many open micro-fractures.
4.2.5 Interference Testing

A field-wide interference test was conducted to delineate the hydraulic communication between the two reservoirs. The test was designed to inject into reservoir B while monitoring pressures at various parts of reservoir A. Several observation wells across the field were designated to record the pressure changes during the initial water injection stage to provide the field coverage. The test was designed to include two phases. Phase I involved the start of water injection at low rate in all Reservoir B wells simultaneously while observing pressure changes in both Reservoirs A and B wells for fifteen days. Phase II was to commence subsequently incorporating the results of Phase I and to dictate whether or not 50% increase in the injection rate would be needed. Pressure communication between these two reservoirs was seen at the southern end of the field, as this could be detected during the relatively short period of this test. Moreover, no significant pressure increase was seen in the east and west side elsewhere suggesting no communication or very weak channels of communication in that area\textsuperscript{14}. Figure 24
illustrates the tested locations with green squires showing the areas with pressure communication and other locations with the possibility of no communication.

Figure 24 Map showing the interference test areas

4.2.6 Well Test Behavior

Pressure and pressure derivative shapes have been used traditionally to detect various reservoir heterogeneities based on certain flow regimes occurrence during the test. Reservoir heterogeneities include faults, fractures, high perm layers, and barriers. The well tests of the field example have been investigated to see if they present any fracture behavior during the tests. Moreover, statistical and mapping techniques were also used to locate potential fractured areas. The data are build-up tests therefore Horner method was used to analyze the tests. The five point derivative technique was used to calculate the derivative of each test pressure data. The derivative was very helpful to define four distinct behaviors. Homogenous radial flow behavior, well intersecting conducive fracture, well near fault or fracture, and enhancement in rock properties. Figures 25, 26, 27 and 28 show examples of a typical behavior of homogenous radial flow, well intersecting conducive fracture, well near fault or fracture and enhancement in reservoir properties respectively.
Figure 25 Typical homogenous flow behavior

Figure 26 Typical intersecting conductive fracture response
Figure 27 Typical behavior of near fault or fracture

Figure 28 Typical behavior of enhancement in reservoir properties
After performing the analysis of all the test data, the calculated reservoir properties were statically analyzed. The calculated flow capacity (kh) showed a bi-model which is a typical observation in NFRs. Figure 29 shows a histogram of all the tested wells kh.

![Histogram of all wells kh](image)

**Figure 29 Histogram of all wells kh**

A bubble map was also generated to determine the locations of wells with higher flow capacity (kh) and productivity index (PI) which came in total agreement with the geophysical interpretation and lost circulation data. Both maps showed that the wells with high kh & PI are located at the west side of the field and hence the dominant location of fractures is the west side. Figures 30 &31 are bubble maps of kh & PI of all the tested well.
In addition to the bubble maps, another map was created based on the observed behaviors which are the four behaviors that are mentioned earlier. The map showed that the most of the wells at the east showed homogenous reservoir behavior while the other three are strictly located at the west where most the heterogeneity occurs. Figure 32 shows a map of the wells flow behavior during the test. The wells which intersect fractures or are in the vicinity of a fault or fracture are located at the west side as most of other sources of information indicated. Therefore, the well test data confirms the fracture existence that are suggested or interpreted by other sources of information.
Figure 32 A map shows flow behavior of the test data.
4.3 Modeling Results

As discussed in chapter 3, the objective of the modeling work is to predict the communication between the two layers using the well test interpretation. The following figure (figure 33) depicts the model layers with respects to the fracture and the well.

![Model architecture](image)

Figure 33 Model architecture

4.3.1 Model validation

The second step after constructing the model is to validate the model and ensure its ability to capture and mimic the simulated behavior. It is required from the model to produce the well at a constant rate throughout the production period. The production period should be long enough to create pressure drawdown in the first layer for the third layer to transmit fluid through fracture only into the first one. Second layer acts as a barrier between the first and third layers and it does not neither produce nor accept any fluid to go through it. The model was run several times to find the production period which is enough to allow significant amount of fluid to move
from the third layer to the first layer. Three months of continuous production was found to be the required production time. Figure 34 shows the pressure change in the model after three months of production. It clearly shows that the third layer pressure is changing while the second player pressure is still constant.

![Figure 34 Model pressure changes during production](image)

Additional well was added to the model third layer to track pressure changes. Figure 35 shows the pressure of the observation well completed in third layer versus time compared to the producing well’s pressure. The pressure of the observation well is declining even after the shut-in of the producing well indicating fluid migration to the first layer. The first run was done without the fracture to establish baseline for pressure and ensure presence of fracture effect in the model, when the fracture is added. Figure 36 shows the bottom hole flowing pressure for two cases one with fracture and the second one without fracture. The effect of fracture is clear on the model especially after 40 days of production.
The model validation process confirms the communication between the first and third layers through fracture only and ensures its reliability to study the effect of the communication on the pressure data during build up tests.
4.3.2 Model First Run

The model was run for three months of production period at a constant rate of 5000 BPD followed by one month of shut-in period to generate a test data. The data was extracted from the model and a diagnostic plot was created. The pressure data was recorded every hour to see the effect of the communication because it was believed that several hours are needed to observe the effect, which means that the effect could in pseudo-steady state period, not in the transient period. Figure 37 shows the diagnostic plot of the first run.

![Diagnostic plot of the first run](image)

The wellbore storage is not considered in this study so it is not obvious in the data. The plot shows a valley around 40 hours which is similar to the dual porosity valley in the Warren & Root model. However, their model was idealized model with flow from matrix to fracture then from fractures to the wellbore, no direct flow from matrix to well. In this study the model has only one fracture connecting the two layers. In addition both layers have enough permeability to produce at the given rate without the need for a fracture existence. The plot also showed the derivative goes up after the valley with a slope of one. Prior to proceeding any further in the study, several additional runs were made to ensure that this behavior in the diagnostic plot is due
to the fracture connecting the two layers. First run is done without the fracture in the model and a second run with the fracture exists in the first layer only. Figure 38 Shows a diagnostic plot of the three runs together.

![Diagnostic plot of no fracture, first layer fracture & base case](image)

It is so clear from the plot that the valley is a result of the fracture that connects the two layers. The no fracture case and fracture in the first layer only showed similar shape of the derivative. This is due the small contrast between fracture permeability and layer permeability. The two derivatives dive down at late time due to model boundary effect. This plot confirms the effect of the communication on the derivative plot and hence increased the confidence level and the reliability on the model to proceed with the investigation.

### 4.3.3 Time Effect on the Derivative

The model was run for a longer period of time to check whether or not the raise in the derivative at late time would level out. Two runs were made one with three months of shut-in and the other one with six months of shut-in. In reality the well is not going to be shut-in for this
long period of time to perform the build-up test. However, this is purely to see the time effect only. On other hand, some wells would be equipped with downhole gauges and might be shut-in for reservoir management purposes therefore this could be helpful in this situation. Figure 39 is a diagnostic plot showing the shut-in effect on the derivative.

![Diagnostic plot showing time effect on the derivative](image)

The above plot demonstrates the effect of shut-in time on the derivative therefore if the well is shut-in for a long period of time similar behavior may be observed. Moreover, a stabilization of the derivative may appear at a later time.
4.3.4 Effect of Fracture Conductivity

The primary rock property which controls the flow in porous media is permeability therefore five runs were done using different fracture conductivities. The used conductivities are 500, 1000, 2000, 3000 and 4000 md.ft. Figure 40 shows the shape of the derivative using different conductivity values.

![Figure 40 Effect of fracture conductivity on the derivative shape](image)

The simulation run with 500 md.ft fracture conductivity did not show the valley in the derivative because the used conductivity was insufficient to establish the communication. The conductivity of 1000 md ft showed a drop in derivative values then raises but with wiggles which could be due to intermittent flow to the first layer. The other three runs with conductivities of 2000, 3000, and 4000 md ft were on top of each other with almost no differences. Once the communication is established, the magnitude of the conductivity is not affecting the shape of the derivative significantly.
4.3.5 Effect of Fracture Length

The purpose of the fracture length modification to the model is to increase the area of the communication between the layers and observe its effect on the diagnostic plot. Fracture lengths of 200, 500, 1000, and 1500 ft were used. Figure 41 shows the effect of different fracture lengths on the diagnostic plot.

The 200 ft fracture length shows a behavior similar to the behavior of no fracture case. Therefore, it has insignificant impact on the plot possibility due to no or very weak communication. The other three cases show the valley on the derivative plot however the valley goes deeper as the fracture length decreases. The 1500 ft case shows the shallowest valley or high storativity value, if it is compared to the dual porosity model. Moreover, it starts to stabilize at the end of the curve reaching the stabilization phase earlier than the other cases due to more area of communication.
4.3.6 Effect of First Layer Permeability

The effect of the first layer permeability, where the well is completed, was investigated by testing three permeability values. The used permeabilities for this investigation are 300, 500 and 700 md. Figure 42 shows the effect of the first layer permeability on the diagnostic plot.

![Figure 42 Diagnostic plot showing the effect of the first layer permeability](image)

As the first layer permeability increases the valley appears earlier in the derivative indicating faster interaction between fracture and matrix. In addition, the whole derivative curve is shifted downward as the permeability increases.
4.3.7 Effect of Third Layer Permeability

The effect of the third layer permeability was also investigated by testing three permeability values. The used permeabilities for this investigation are 100, 300 and 500 md. Figure 43 shows the effect of the third layer permeability on the diagnostic plot.

The three derivative curves are almost on top of each other meaning no significant impact of the third layer permeability on the derivative.
4.3.8 Effect of Fracture Distance from Well

The effect of the fracture distance from well was tested using three distances 50, 250 and 350 ft away from well. The objective was to keep the fracture in the well vicinity so that the whole effect of fracture in the derivative can be seen. Figure 44 is a diagnostic plot showing the effect of the distance of the fracture from well.

![Diagnostic plot showing the fracture distance from well effect](image)

The tested distances did not show any significant effect of fracture distance from well on the derivative.
4.3.9 Effect of Fracture Porosity

The effect of the fracture porosity was studied using three different porosity values 10, 18 and 25 percent. The objective was to see if high porosity values would modify the derivative valley. Figure 45 is a diagnostic plot showing the effect of the fracture porosity on the derivative.

No major effect was seen in the derivative however the minor shift of the valley upward is due to the increase of the storage capacity of the fracture.
4.3.10 Effect of Multiple Fracture

The effect of multiple fractures on the vicinity of the well instead of one fracture only was studied. The objective was to see whether or not the shape of the derivative is related to the number of fracture exist. Figure 46 shows the locations of the fractures in the model with respect to the well.

![Fractures locations on the model with respect to the well](image)

The flowing bottom hole pressure versus time of multiple fracture showed lower drawdown compared to both one fracture case and no fracture case indicating higher influx rate from third layer to the first one. Figure 47 shows the bottom hole flowing pressure versus time for the three cases. The diagnostic plot of multiple fractures in the model showed faster stabilization as opposed to the one fracture case. Moreover, the derivative valley of multiple fractures is shallower than one fracture case due to high storativity. Figure 48 shows a diagnostic plot of multiple fractures compared to one fracture.
Figure 47 Flowing bottom hole pressure versus time

Figure 48 Diagnostic plot of multiple fracture compared to one fracture only
4.3.11 Horizontal Well Case

A case was run with a horizontal well completed in the first layer instead of vertical well. The well was placed in the middle of the layer with 500 ft horizontal section. The flow regimes in a horizontal well is quite different than the vertical well flow regimes therefore this case was run to investigate the well design effect on the observed derivative shape. Figure 49 shows a comparison between two cases one with vertical well and the other case with horizontal well.

The comparison revealed two observations in the derivative. The first observation is that there are differences at early time due to different flow regimes in the two cases. Once the communication is fully established between the first and the third layer the two cases are identical. Therefore, whether the well is vertical or horizontal the communication effect on the derivative can be seen.
Chapter 5. Conclusions & Recommendations

5.1 Conclusions

- The integration of all available information including static & dynamic data has proven to be very effective in characterizing petroleum reservoirs.
- The simulation model reveals a valley, which is similar to the dual porosity valley, in the derivative during the pseudo steady state period due to the communication of the reservoirs.
- A stabilization of the derivative can be achieved if the well is shut in for a long period of time.
- First layer permeability and fracture length appears to be the properties which significantly affect the derivative while the third layer permeability did not show any impact.
- The simulated scenarios of fracture porosity, permeability, and distance from well did not show any significant impact on the derivative.
- Multiple fractures in the model show the same behavior with shorter period of time to reach stabilization.
- The horizontal well shows the same valley as the vertical well with difference at early time due to flow regime differences between horizontal and vertical well.
5.2 Recommendations

- Effect of fracture geometry or shape factor is the only thing that was not investigated in this study due to time constrain, therefore, it can be tackled in a separate study.
- The study focus was on a well completed in the first layer, therefore, a behavior of a well completed in the third layer can be investigated.
References


