Controlling Factors on Condensate Production from the Eagle Ford Shale

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Controlling Factors on Condensate Production from the Eagle Ford Shale

by

Yi Wang

A THESIS
SUBMITTED TO THE FACULTY OF GRADUATE STUDIES
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Abstract

This thesis examines the impact on recovery from shale condensate reservoirs of key properties such as porosity and permeability as well as other controlling factors that include the horizontal wells length, liquid drop out and liquid loading around the wellbore. It also addresses the possibility of lean gas injection. It is found that production of heavy ends (C5, C6 and C7) remains low with time but at an approximate constant rate. The dual permeability model shows larger production of C5, C6 and C7 as compared with the dual porosity model. A higher natural fracture permeability results in an increased production and recovery. The preliminary conclusion is reached that lean injection is not feasible when shale permeability is within the range considered in this study (0.0001 md). However, there might be sweet spots within condensate shale reservoirs amenable to enhanced oil recovery. It is recommended to investigate this possibility.
Acknowledgements

I would like to express my sincere gratitude and appreciation to my supervisor Dr. Roberto Aguilera for his tremendous guidance and support, for providing the opportunity to conduct this research, and for his excellent advice during my project. Also to the members of the GFREE research team in the Chemical and Petroleum Engineering Department. I am very grateful to Talisman Energy Inc. that provided help and data for completing this study. I would also thank Dr. Sudarshan A Mehta; Dr. Robert Gordon Moore and Dr. Laurence R Lines for serving on my examination committee.
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List of Symbols, Abbreviations and Nomenclature

Symbols

\( \phi \) = Porosity, fraction
\( \mu \) = Fluid viscosity

Abbreviations

BOPD = Barrels of Oil per Day
BHP = Bottom hole pressure
CGR = Condensate gas ratios
ERCB = Energy Resources Conservation Board (Alberta, Canada)
EUR = Estimated Ultimate Recovery
GFREE = Integrated geoscience (G), formation evaluation (F), reservoir drilling, completion and stimulation (R), reservoir engineering (E), economics and externalities (EE). Research Team at the University of Calgary
KBD = Karnes, Bee, and DeWitt counties (Texas)
MSHF = Multi-stage hydraulically fractured
OGIP = Original gas in place (MMscf)
OPIP = Original petroleum in place (bbl)
POVO = Pore Volume Average Pressure (psi)
SC = Standard Condition at 20 °C and 1 atm
SRV = stimulated reservoir volume
TOC = Total Organic Carbon (%) 

Nomenclature

Bg = Gas formation volume factor
c_t = Total compressibility
D = Knudsen diffusion constant, m2/s
D = Pore diameter (\( \mu \)m)
HZ = Horizontal
K = Permeability (md)
K_n = Knudsen number
M = Molecular mass, kg/kmol
P = Pressure, (psi)
Ro = Vitrinite reflectance (%)
r_p = Throat Aperture (microns)
SC = Standard Condition
T = Temperature (°F)
Z = Compressibility factor
Subscripts

2 = Natural fractures
ad = Absorbed
hf = Hydraulic fractures
m = Matrix
org = Organic matter (kerogen)
sh = Shale
CHAPTER ONE: EAGLE FORD GEOLOGY OVERVIEW

1.1 General Description

Two wells drilled in 2006 by Conoco and Apache started the Eagle Ford play, but these were not true Eagle Ford wells, as more perforations were made in Austin Chalk (DrillingInfo, 2010). The first Eagle Ford well was drilled in 2008 by Petrohawk in the Hawkville Field. Initially, the play was discovered as dry gas. Later, wet gas and oil were discovered up-dip. The northern part of Eagle Ford is the up-dip oil window with lower pressure and higher oil volumes. The southern part of the play is down-dip and mainly dry gas. In the middle is the wet gas or condensate window. As of the end of 2010, there were over 1,000 Eagle Ford completions with another 3,000 permitted wells. The current play is approximately 50 miles wide and 400 miles long, spanning over 23 counties in Texas (Fig. 1-1).

U.S. Oil production grew more in 2012 than any other year in the history of the domestic oil industry. Daily crude output averaged 6.47 million barrels of oil per day (BOPD) in 2012, up a record 826,000 BOPD from 2011. Within the incremental 826,000 BOPD, more than a quarter of it comes from Eagle Ford Shale oil production, increasing by 252,698 BOPD from 128,619 BOPD in 2011 to 381,317 BOPD in 2012. The drilling activities in the Eagle Ford Shale were as exciting as the production increase. During 2012, the average rig count in the Eagle Ford was 269, compared with 1,809 in the United States and 3,461 in the world (DrillingInfo, 2010).

1.2 Geologic Distributions and Characteristics

Geographically, the Eagle Ford play in Texas is 50 miles wide and 400 miles long, and covers 23 counties in South-Central Texas. The Eagle Ford area is bounded by the U.S.–Mexico border, the Sligo Shelf Margin, and the San Marcos Arch. Geologically, the Eagle Ford Shale consists of
Cretaceous mudstone and carbonate that are the source rock for the Austin Chalk formation. The depth of the productive Eagle Ford formation ranges from 2,500 to 14,000 ft., while the thickness ranges from 120 to 350 ft. The Eagle Ford Shale has high carbonate content and low clay content, which makes it more brittle and easier to stimulate through hydraulically fracturing compared with other shale plays (Pope et al., 2012). Eagle Ford Shale has been developed play-wide since 2008 using horizontal wells with multi-stage hydraulic-fracturing treatments. The hydrocarbons being produced from Eagle Ford range from dry gas through gas condensate through volatile oil to black oil.

Figure 1-1. Map of the Eagle Ford Play. After the Railroad Commission of Texas (2012).
Lithologically, Eagle Ford is comprised of laminated organic-rich marls, bioturbated limestone, and interbedded limestone and marls. The predominant mineralogy of the sediments is carbonate (55-65%), where quartz (~15%), clay (~15%), kerogen (~10%) and lesser minerals comprise the remaining matrix. The rock type is a calcareous Marl to argillaceous limestone. Fossilized planktonic foams are present along with shelled molluscan fragments, such as Inoceramus. Total organic carbon is dispersed both vertically and geographically and ranges from 1-8%. Vitrinite reflectance (Ro) has been measured to range from 0.5% to 2% across the Eagle Ford trend. Two main pores types have been described within the Eagle Ford: organic-matter related pores and non-organic matter related pores. Organic pores are created by thermal maturation of organic material and by the generation of hydrocarbons. The nonorganic pores predominate. These are commonly inter-granular in nature and are controlled by mechanical and chemical diagenesis. Total porosity is in the range of 3-12%, while hydrocarbon filled porosity ranges from 2-9%.

In South-Central Texas, areas of three counties (Karnes, Bee, and DeWitt, abbreviated by KBD Group) make up the Eagle Ford condensate window. This has a mixed siliciclastic/carbonate unit thickness (~60m/200 ft.) that records the mid-Cenomanian through Turonian transgression of the western Gulf Plain of the United States (Donovan & Staeker, 2010). The underlying Lower Cretaceous Sligo and Edwards formations record a time of major reef development and carbonate margin progradation that had a significant effect on the East Texas Basin physiography during Eagle Ford deposition. In South-Central Texas (KDB Group), the Edwards Margin prograded on top of the Sligo margin creating a sharp break between the continental shelf and the continental slope.

Traditionally, the Eagle Ford Shale has been divided into two intervals: the Lower Eagle Ford transgressive systems tract and the Upper Eagle Ford high stand systems tract representing a
single 2nd order depositional sequence. The upper Eagle Ford is interpreted to be pro-gradational within a high stand systems tract and the lower Eagle Ford is interpreted to be retro gradational within a transgressive systems tract (Donovan and Staerker, 2010).

It is critical to evaluate the reserves and resources early for optimal development. McKinney (2002) stated that suboptimal development plans could result in potential losses of 50% of the asset value. Permeability in the Eagle Ford Shale is normally tens or hundreds of nanodarcies and yields long transient-flow periods, which complicate production forecasting and estimation of reserves. In addition to the extremely low matrix permeability, there are other challenges associated with forecasting production and estimating reserves from hydraulically fractured horizontal wells in shale gas reservoirs. First, multistage fracture treatments in shale reservoirs do not create conventional single bi-wing planar cracks; instead, they create a complex fracture network that exhibits long and wide fracture fairways. Second, there are also natural fractures in shale, which can play an important role in the formation of hydraulic fracture geometry and reservoir depletion. Third, adsorbed gas contributes a significant fraction of total original gas in place (Leahy-Dios et al., 2011), although the impact on EUR and production is not well understood. Fourth, the history of drilling horizontal wells in the Eagle Ford Shale is relatively short, with first production from these wells starting in 2008. Therefore, long-term production performance and decline characteristics are not clear for hydraulically fractured horizontal wells in this shale reservoir. As a result, there are significant uncertainties associated with resources estimation in the Eagle Ford Shale reserves. These need to be reliably quantified.

1.3 Oil and Gas Resource Pyramids

Aguilera (2008) introduced a world oil and gas resource pyramid including global endowment for conventional gas, tight gas, shale gas, coalbed methane, conventional oil, and tight oil, shale,
and oil sands reservoirs. The pyramid presents clearly the shale gas and oil shale positions in the overall oil and gas resources and the other factors that impact development.

Figure 1-2. Estimate of Global Natural Gas and Oil Endowment (Aguilera, R.F., 2006; Aguilera et al., 2008; SPE132845; SPE162717; GFREE Team, University of Calgary).
1.4 Overall Porosity Scale Distributions and The Pore Throat Aperture (rp35)

Figure 1-3. Pore Sizes Distribution (Nelson, 2009).

Nelson (2009) presented the above diagram that categorizes the diameter, width, and size of the different materials. The graphic shows the x axis as the diameter, width or size (um) scales and the y axis is only for visual categories. There is a consistency between porosities and permeabilities from core analysis for conventional, tight gas and shale gas reservoirs as well as porosities and permeabilities calculated from pore scale modeling. Figure 1-3 shows the sizes of molecules and pore throat sin silici elastic rocks on a logarithmic scale covering seven orders of magnitude. Five measurement methods are shown at the top of the graph, and the scales used for solid particles are shown in the lower right. The symbols show pore-throat sizes for four
sandstones, four tight sandstones, and five shales. Ranges of clay mineral spacing, diamondoids, and three oils are shown, as are the molecular diameters of water, mercury, and three gases. The sources of data and measurement methods for each sample set are discussed in the text.

Aguilera introduced a cross plot of permeability vs. porosity for various pore size classes, including conventional tight and shale petroleum reservoirs, and potential rates as in Figure 1-4. The lines of constant rp35 were developed with the use of the pore throat aperture (rp35) equation. From this graph, we can see that the Eagle Ford shale reservoir permeability as the red star mark in the graphic is in the range of 1e-4 to 1e-3 md, and porosity is in the range of 6-12%. This is aligned with the pore throat aperture rp35 in the range of 0.025 to 0.04 microns at the nanoports classification.

Figure 1-4. Porosities and Permeabilities for Pore Throat (r_{p35}) Ranges. (Aguilera 2013).
The graph also shows the groups on the basis of pore throat (port) apertures as megaports (rp35>10 microns), macroports (2.5—10 microns), mesoports (0.5 to 2.5 microns), microports (0.1 to 0.5 microns), and nanoports (0.01 to 0.1 microns).

### 1.5 Shale Gas, Condensate, Oil Definitions

The term “unconventional reservoirs” covers a wide range of hydrocarbon-bearing formations and reservoir types that generally do not produce economic rates of hydrocarbons without stimulation. Common terms for such “unconventional” reservoirs include: Tight-Gas Sandstones, Gas Hydrates, Oil Shale Formations, Heavy Oil Sandstones, and Shale Gas. Shale is a term that has been applied to describe a wide variety of rocks that are composed of extremely fine-grained particles, typically less than 4 microns in diameter, but may contain variable amounts of silt-size particles up to 62.5 microns.

Hydrocarbon reserves are defined and categorized by the total porosity scale, permeability, and formation of fluids. The liquid can contain a great deal of C1-5 vapor, and the vapor can also contain a large quantity of C6+. The initial Gas Oil Ratio can be an indicator to define hydrocarbon reserves as shown in Table 1-1.

<table>
<thead>
<tr>
<th>CGR (Condensate Gas Ratio)</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Dry</td>
<td>&lt;20</td>
</tr>
<tr>
<td>Lean</td>
<td>20 to 80</td>
</tr>
<tr>
<td>Rich</td>
<td>80 to 200</td>
</tr>
<tr>
<td>Near critical</td>
<td>&gt;200</td>
</tr>
</tbody>
</table>

Table 1-1. Reservoir Type Definitions.
CHAPTER TWO: EAGLE FORD SHALE CONDENSATE COMMON

CHARACTERISTICS

2.1 Introduction

Structurally, the Eagle Ford Shale dips to the SE. Faulting (Figure 2-1), which is related to presence of salt domes and the proximity to the shelf slope break. For example, areas of the three KBD counties are impacted the greatest by these faults, resulting in an increased risk to drilling and land utilization. However, along with the presence of these faults, an increase of fracture density and conductivity may have a positive effect on stimulation and production.

The middle window shows the region of gas wells with high condensate gas ratios (CGR) that contribute the most to economic reserve recovery. The identification of the strategy for how the wells will be produced is based on the well fluid type and the subsurface pressures required to achieve optimal production of the reservoir fluids.

At the middle condensate window, fluids exhibit retrograde behavior. Retrograde condensate wells constitute over 90 percent of all wells in the KDB group field. Most wells experience minor liquid dropout, and the retrograde effects are considered to be inconsequential. However, in the KDB counties, 12% or more of the wells may experience considerable liquid dropout and require a different production strategy. Theoretically, the production characteristics of these retrograde wells are such that if the wells are flowed with a low bottom hole pressure (BHP) (likely less than 4,000 psi), the reservoir fluid will separate into gas and liquids in the reservoir. When this happens, the liquids remain in the reservoir, which creates a significant value loss to the project. In addition, these liquids could start blocking the gas flow through the low
permeability rock and cause significant reductions in well production. In extreme cases, this blockage may damage the well and cause premature abandonment.

Figure 2-1. Eagle Ford Shale Petroleum Window Interpretation Map within the USA (DrillingInfo, 2012).

Understanding the nature of the shale condensate well fluids, the impact of retrograde behavior on well production, and their best well production strategy is necessary to achieve optimal economic recovery for each of the well types. In addition, it is also necessary to conduct the analysis of the fluid characteristics and the expected production of these shale condensate wells.
2.2 Eagle Ford Shale Condensate Reservoir Petrophysics

The Eagle Ford Shale Condensate Reservoir cored interval in the KDB Group is 124.7 ft. thick. The lower 110 ft. of the core consists of cyclic interbedded medium gray skeletal packstone and dark gray laminated, foram marl. Locally, the limestone contains scour surfaces and gutter casts. The upper 15 ft. of Eagle Ford consists of skeletal wackestone, with glauconite and phosphatic clasts, and pyrite nodules. Skeletal conglomerates, packstone to grainstone, occur at the base and top of this upper interval. Alternating marl and limestone beds are interpreted to represent parasequences. Marls, at the parasequence base, reflect hemipelagic suspension during transgression, whereas the limestones represent more proximal, high energy, aerobic environments.

Deposition is understood to have occurred in alternating outer shelf and storm-dominated/distal inner shelf environments. Planktonic foams constitute the most abundant fossil group and their accumulation on bedding planes locally highlights lamination. Sparse molluscan fragments (including Inoceramus) also occur.

Calcite is the most abundant mineral and averages 60 vol%. Calcite occurs as fossils, as part of the matrix, and as clusters of crystals due to recrystallization. Quartz (avg. 16.4 vol%), clay (avg. 10.5 vol%) and kerogen (avg. 8.6 vol%) are additional components, with lesser plagioclase (avg. 3% vol%) and pyrite (avg. 1.5 vol%). Marcasite, dolomite, and apatite are locally present (avg. <1% vol%). Illite/smectite and illite are the principal clay species (avg. 5.8 and 2.5 vol%, respectively), with lesser amounts of kaolinite (avg. 1.7 vol%) and chlorite (avg. 0.9 vol%).

TOC ranges from 1.14% to 6.02%, and averages 3.93%. Ro varies between 1.38% and 1.46%. Tested samples straddle the boundary between condensate-wet gas and the dry gas window. The total measured porosity averages 8.39% (5.9-10.73%). Average gas-filled porosity is 5.81% (2.2-
Matrix permeability ranges from $7.59 \times 10^{-7}$ md to $1.8 \times 10^{-3}$ md and averages $1.73 \times 10^{-4}$ md. The matrix permeability geometric mean is $4.0 \times 10^{-5}$ md.

Average gas, oil, and water saturations are 68.46%, 4.18% and 27.36%, respectively. The average water saturation from GRI measurements is similar to the average water saturation from the petrophysical model (28.4%). The mean free gas storage capacity is 226.3 scf/ton, which equals 761.8 Mscf/acre-ft. The absorbed gas storage capacity is 45.6 scf/ton, which equals 153.5 Mscf/acre-ft. Total gas in place, is 271.9 scf/ton or 915.3 Mscf/acre-ft. With an Eagle Ford thickness of 163 feet, total gas in place is 95.0 BCF/section.

(Source: Talisman Energy Inc.)
CHAPTER THREE: KEY FACTORS CONTROLLING EAGLE FORD SHALE
CONDENSATE DEVELOPMENT

3.1 Shale Condensate Flow Mechanism and Saturation Critical Point

3.1.1 Flow Mechanism in a Nanopores System

Shale reservoirs have very low permeability, and organic material plays a key role in hydrocarbon generation and storage. The ultralow permeability, low porosity, and low natural fracturing are the main restrictions for fluid migration in the Eagle Ford Shale. Unconventional reservoir characteristics make it necessary to understand the flow mechanism in the Nanopores system. Hydrocarbon systems were grouped into five classifications according to their different length scales (Figure 3-1):

![Figure 3-1. In the Length Scales, Gas Evolution and Production in Shale Gas Sediments (Javadpour, 2009).](image-url)
Correspondingly at equilibrium, gas molecules are distributed throughout all strata, as illustrated in Figure 3-1. Javadpour (2009) stated that gas molecules exist in a hydrocarbon system in the following states: 1. Gas in the hydraulic fractures network. 2. Gas in the micro-fracture network. 3. Gas compressed in the pores as free gas. 4. Gas absorbed on the surface of the kerogen. 5. Gas dissolving from the kerogen materials to the kerogen surface.

Drilling a well or inducing a fracture disturbs this equilibrium, and gas molecules start flowing toward the zone of low-pressure: 1) The freely compressed gas in the pores is produced and flow occurs in the Macroscale network. 2) The gas flows in the large pores and the micro-fractures network. 3) The gas molecules flow through the connected nanopores. 4) The gas molecules desorbed from the surface of the kerogen walls. 5) Gas desorption changes the concentration equilibrium between the bulk of the kerogen and its surface. This concentration gradient initiates gas diffusion from the kerogen bulk to the surface at a slow rate.

Generally, gas flow happens first, followed by gas desorption, and finally, gas diffusion occurs in kerogen. There are overlaps for each of these processes, as suggested by Javadpour et al., (2009). Aguilera (2012) stated that the use of a quintuple porosity system for calculation of original petroleum in place (OPIP) in shale is important, as neglecting some of the porosities can result in pessimistic values of OPIP and production rates. Based on the concept of the Total Petroleum System (Aguilera, 2010), the word ‘Petroleum’ includes (1) thermal and biological hydrocarbon gas, (2) condensates, (3) crude oils, and (4) natural bitumen. In the case of natural gas, the gas is trapped and stored in shale in different ways: (1) gas adsorbed in the kerogen material, (2) free gas trapped in nonorganic inter-particle (matrix) porosity, (3) free gas trapped in micro fracture and slot porosity, (4) free gas stored in hydraulic fractures created during the stimulation of the
shale reservoir, and (5) free gas trapped in a pore network developed within the organic matter or kerogen. An additional storage element is provided by gas dissolved in kerogen.

Quintuple Porosity Formulation was developed by Aguilera (Aguilera, 2012):

\[
\phi_{sh} = \phi_m + \phi_{org} + \phi_2 + \phi_{ad} + \phi_{hf}
\]

Where:

\( \phi_m = \) nonorganic matrix porosity scaled to the bulk volume of the composite system, fraction

\( \phi_{org} = \) organic matrix porosity scaled to the bulk volume of the composite system, fraction

\( \phi_2 = \) natural fracture porosity scaled to the bulk volume of the composite system, fraction

\( \phi_{ad} = \) adsorbed porosity, fraction

\( \phi_{hf} = \) hydraulic fracture porosity scaled to the bulk volume of the composite system, fraction

Shale matrix is composed of inorganic matter (clay, silica and other minerals) and organic matter (kerogen). Many shale gas reservoirs are characterized by natural fractures and low matrix permeability values. This fact imposes the need for multi-stage hydraulic fracturing of horizontal wells to make their production economically viable. Furthermore, gas adsorption to the internal surface of the organic pores represents an important storage mechanism of gas in shale reservoirs. Gas diffusion from kerogen (Javadpour et al., 2007; Akkutlu and Fathi, 2011; Swami and Settari, 2012; Shabro et al., 2012; Swami, 2013) is an important source of gas to be added to the quantification of total gas in place in shales. The result is a composite system in shale reservoirs made up of dissolved gas in kerogen plus the following storage mechanisms,

Adsorbed gas in the kerogen material

Free gas trapped in nonorganic inter-particle (matrix) porosity
Free gas trapped in micro fracture and slot porosity
Free gas stored in hydraulic fractures created during stimulation of the shale reservoir
Free gas trapped in an intra-particle pore network developed within the organic matter or kerogen

The above-scaled storage and transport path are aligned with the production data. Most Eagle Ford Shale Gas/Condensate productions have a peak curve in the first months and then quickly decline to a constant low production rate. Initial peak production is mainly contributed by production through the Macro and Meso scales paths. Long term, slow, constant production rates should be dominated by the Micro, Nano and Molecular scales effects.

Figure 3-2. Schematic of Gas-Molecule Locations in a Small Part of a Kerogen Grain Pore System (Javadpour et al., 2007).
3.1.2 Condensate Saturation Critical Point in Pores

After significant condensate liquid saturation builds up, some of the condensate liquid begins to flow towards the producing well (Fan, 2005). Furthermore, the lighter components are likely to occupy the center of the nanopore, while the heavier components lie closer to the pore wall (Altman, R., et al., 2014).

The shale gas condensate fluid consists of C1 to C7+ at different fractions in the nanopores. Not only does the length of the C7+ molecules begin to approach the pore size, but also it is thermodynamically more favorable for longer chain molecules such as C7+ to interact and sorb with the pore wall of organic sites than for C1 molecules, as in Figure 3-3.

As the reservoir starts to produce and the pressure in the pore spaces decreases, a dynamic may be created between the desorption of C7+ molecules from the kerogen (with pressure decrease) and the formation of liquid condensate from the C7+ of the condensate fluid in the middle of the pores (as pressure decreases to below dew point). The nanopores (with their very high surface to volume ratios) could reduce the affinity for C7+ to coalesce and form liquid condensate in the case where it is energetically more favorable for C7+ to exist in an adsorbed state on the organic pore surfaces (Altman, R. et al, 2014).
Additionally, a suppressed phase envelope results in a lower critical pressure. This implies an increase in the compressibility factor (Z), an increase in the gas formation volume factor (Bg), and a decrease in the gas in place (or an overestimation of the previously calculated gas in place). Because the gas condensate fluid inside the production string will have bulk properties, this underestimation of Bg would only apply over the pressure range defined by the pressure gradient experienced by the fluid flowing through the nanopores of the reservoir. Failing to account for the pore proximity effects of gas condensate fluids in nanopores (causing suppression of the phase envelope) will lead to reserves being underestimated because in reality, conditions for liquid condensate banking are likely to be delayed (Altman, R. et al, 2014).

3.2 Process or Delivery Speed

The process or delivery speed (i.e., the ratio of permeability and porosity) as introduced by Aguilera (Aguilera, 2013) provides a relative indication of storage and how quickly fluids can move through porous media. This concept has been shown to be a powerful tool for
characterizing conventional oil and gas reservoirs in various lithologies (Chopra et al., 1987, Gunter et al., 1997), for predicting recoverable hydrocarbon volumes (Pickett and Artus, 1970), and for determining flow units in tight gas and shale gas reservoirs (Aguilera, 2010).

Aguilera stated that the flow unit (a function of permeability and porosity) is thus a useful concept for linking geology, petrophysics, and reservoir engineering as permeability and porosity are studied in detail and used by all of these disciplines (Aguilera, 2004). The process speed \( \frac{k}{\phi} \) is an important part of the diffusivity equation:

\[
\nabla^2 p = \frac{\mu c_t}{\left( \frac{k}{\phi} \right)} \frac{\partial p}{\partial t}
\]

Where \( \mu \) is fluid viscosity and \( c_t \) is total compressibility. The above equation is at the heart of fluid flow calculations in porous media by reservoir engineers. Thus, it is extremely important to have knowledge of the process speed (\( \frac{k}{\phi} \)) and hydraulic diffusivity (\( N = \frac{\mu c_t}{\left( \frac{k}{\phi} \right)} \)).

The empirical flow units represented by rp35 lines (Kolodzie, 1980; Aguilera, 2010) are supported by pore scale modeling calculations for pore throats (r_p) ranging between 1-4, 0.1-1.5, 0.005-0.5 and 0.009-0.1 microns. Pore throat aperture (r_{p35}) in microns can be calculated from the following (Aguilera, 2002-2004):

\[
r_{p35} = 2.665 \left[ \frac{K}{(100\phi)} \right]^{0.45}
\]
Figure 3-4. Permeability vs. Porosity Cross Plot for Eagle Ford (Walls et al. 2011; Freeman and Eller 2010; Aguilera 2013).

Walls et al. (2011) shows permeability and porosity data in Figure 3-4 for the Eagle Ford Shale in Texas. There is also a data point for the Eagle Ford Shale (a green triangle followed by a question mark) taken from Freeman and Eller (2010). Aguilera stated that the question mark indicates that the validity of the data point is not certain. If the data point is correct, comparison with other tight oil reservoirs discussed in this paper would suggest very rapid production declines for those wells with this poroperm characteristic, even if the wells are drilled horizontally and hydraulically fractured in multiple stages. As there are wells that perform much better, it is likely that there are areas with better rock characteristics as indicated by Walls et al., (2011). The Eagle Ford Shale and the Austin Chalk are considered to be a total petroleum system
(Martin et al., 2011) because the Eagle Ford Shale is the source for the naturally fractured Austin Chalk.

The process or delivery speed provides a continuum between conventional, tight gas, shale gas, tight oil, and shale oil reservoirs. This surprising result, based on core data from North American basins, leads to distinctive flow units for each type of reservoir. Viscous flow is present when the architecture of the rock is dominated by megaports, macroports, mesoports, and sometimes microports. Diffusion flow on the other hand is sometimes observed during gas production at the nanoport level. The approximate boundary between viscous and diffusion dominated flow is estimated with the dimensionless Knudsen number \( \text{Kn} \). This number is defined as the ratio of the molecular mean gas mean free path length and pore diameter \( d \) (Aguilera, 2013).

Aguilera (2013) indicates in Figure 3-5 that the flow unit is a function of pore throat radii \( \text{rp35} \) in microns, porosities (%) and permeabilities (md). The results give possible ranges of oil rates (thousands of bopd) for vertical wells (Martin et al., 2011) and gas flow rates (millions of scfd) for vertical wells (Deng et al., 2011). This graph also shows the possible range of oil and gas rates for multi-stage hydraulically fractured (MSHF) horizontal wells. The Knudsen number (as built into the graph) distinguishes the viscous and diffusion-like flow in tight and ultra-tight gas reservoirs. The characteristics of Eagle Ford Shale condensate wells are consistent with the shale curve in the graph.
Figure 3-5. Flow Units as a Function of Pore Throat Apertures (Rp35), Porosities and Permeabilities, and Possible Oil and Gas Flow Rate (Aguilera, 2013). Source: GFREE Research Team, U of Calgary, 2013.

3.3 Fluid Migration and Communications in Eagle Ford Shale Oil, Condensate, and Gas

Aguilera (2014) proposed that a geological challenge in the Eagle Ford Shale is the unconventional distribution of fluids: shallow in the structure there is black oil; deeper and to the south condensate appears; and at the bottom, dry gas can be found. Differences in burial depth, temperature, and vitrine reflectance are used to explain this unique distribution. A similar fluid distribution occurs in other reservoirs (e.g., Duvernay Shale in Canada). These above observations and analyses identify the main factors that control fluid migration (due to buoyancy
of gas in oil) from one zone to another. Results show that low natural fracturing, reflected in the higher distances between adjacent fractures is probably the feature that has the greatest control on fluid migration in the Eagle Ford Shale. High values of fracture spacing allow a slow and uniform fluid flow as shown by the results, while low values of fracture spacing show quick and erratic flow. The research results show that an increase in permeability by one order of magnitude leads to very rapid flow towards the upper region. Porosity does not seem to have a significant impact on the fluid flow. Cases with different values of porosity showed similar results.

3.4 Organic Pores and TOC wt% vs. vol% in Shale Sediment

![SME Image-Orgaenic Pores](source: Helios NanoLab)

Figure 3-6. SME Image-Organic Pores. Source: Helios NanoLab.
Passey et al. (2010) discussed how TOC in wt% corresponds to approximately double that in terms of vol%, due to the lower grain density of the organic matter (e.g., 1.1-1.4 g/cc, compared to 2.6-2.8 g/cc for common rock minerals). The occurrence of pores within the organic matter further amplifies how a relatively small amount of TOC (in wt%) can impact a much larger volume %, as shown in Figure 26. If 50% of the original organic matter volume is now pores, the volume impacted by the current 5 wt% TOC is approximately 20 vol% of the rock; thus, the current 5 wt% TOC may impact a volume up to four times its current wt%. Because well logs respond primarily to volume percentage of the rock, it is important to understand the difference between current TOC wt% and original TOC vol%.

Figure 3-7. Schematic Illustrating How Current 5 wt% TOC Corresponds to Current 10 vol% TOC. However, if much of the volume of the original organic matter volume is now occupied by pores within the organic matter, then the current 5 wt% TOC impacts a volume up to 20 vol% of the current rock. (Modified from Passey et al. 2010).
3.5 Shale Maturity of Eagle Ford Shale

Most current shale-gas reservoirs had their origin as organic-rich mud. These sediments could have been deposited in a marine environment, in lakes (lacustrine), or in associated swamps and mires along the margins of lakes or seas. The type of organic matter deposited, and ultimately preserved in the mud, depends on the original deposition environment. Organic geochemists (e.g. Tissot and Welte, 1984) have used hydrogen to carbon and oxygen-to-carbon ratios to describe the various types of organic matter (or kerogen) in organic-rich mudstones that have generated much of the oil and gas that resides in conventional reservoirs worldwide. Type 1 and Type 2 kerogen are from algal and herbaceous material, have high H:C ratios, and will typically generate oil during the thermal maturation phase associated with burial, time, and temperature. Type 3 kerogen is largely composed of woody/coaly material and will generate mostly gas during thermogenic maturation. If hydrocarbons are generated from these rocks, they are termed “source rocks”.

The critical parameters related to whether or not a given rock will be a good source rock is the organic richness (generally recorded at wt% of Total Organic Carbon—TOC), the current and past maturity level of the formation (generally referenced as Vitrinite Reflectance, Ro), and the organic matter type (whether the primary thermogenic product will be oil, gas, or a mixture).

During the deposition of these organic-rich muds, a variety of geologic and biologic processes contribute to the concentration of organic matter ultimately preserved in the rock.

During the exploration phase for hydrocarbons, the location (depth and lateral extent) of these organic-rich formations is critical for understanding the complete hydrocarbon system that may, or may not, be present in a sedimentary basin. The current and past depth of burial and heat flow history provides critical information on the timing of generation and expulsion of hydrocarbons...
to conventional traps. The principal generation windows for oil-prone kerogen (Type 1 and Type 2) ranges from Ro=0.5 (for early generation) through peak generation Ro=0.8, to over-mature Ro>1.1. Above Ro=1.1, any residual oil or oil-prone kerogen will likely be cracked to gas. The current targets for shale-gas reservoir exploration are over mature oil-prone source rocks; thus, unconventional shale-gas reservoirs are simply highly mature organic-rich rocks that have gone through primary thermogenic maturation, but have retained sufficient residual gas to be of economic interest. The key may be how and where that gas is stored.

The Eagle Ford Shale is classified as a petroleum system in that it is a self-sourced reservoir with seals, where type I, II, and III kerogens have been identified. Maturation, expulsion, and migration took place as the Eagle Ford Shale dipped south, where it went through three maturation windows: Oil, Gas Condensate, and Dry Gas, as shown in Figure 3-8.

**Figure 3-8. Eagle Ford Shale Maturation Structure Map (Modified from Corelab).**
Map showing the maturation window as the blue arrow for Eagle Ford Reservoirs. The maturation window boundary between gas condensate and dry gas was present by the colors: green-oil, yellow-retrograde oil, orange-condensate/wet gas and red-dry gas (Source: Corelab).
At the elevations to the top of the Eagle Ford in the NW area, the difference in the hydrocarbon content is due to the kerogen type. Types II and II/III are found in the North West areas, and type II is found primarily in areas of the North East (Tuttle, 2010).

3.6 Flow Regions

As the pressure decreases in the reservoir, more condensate will drop out until the condensate saturation reaches a critical saturation. At this event, condensate will start to mobilize in the reservoir. The three-zone flow model (first introduced by Fevang, 1995) captures this phenomenon. The three flow regions around the wellbore assumed by this model are presented in Figure 3-9. The following is a summary of what is going on around the wellbore:

Region 1: condensate dropouts

A near-wellbore region where condensate and gas are present and mobile.

Region 2: Hydraulic and Natural Fracture network – surface for contact with matrix support, flow relative permeability, slippage effect.

A condensate build-up region where the condensate phase is immobile and only gas is flowing.

Region 3: High capillary pressure 1,000 psi plus – Suppression phase envelope. Gas adsorption, Condensate / Heavier adsorption on the wall, Condensate Critical Saturated degree.

An outer region where only gas is present.
Maytham (Maytham et al., 2014) stated that in gas-condensate systems, the gas composition varies along the direction of flow during depletion. The change in gas composition is due to the combination of condensate dropout and relative permeability effects. The phase behavior is affected by the additional fluid-rock interaction expected for the shale due to flow through nanometer-sized pores.

An analysis was conducted by Hashemi et al. (2004) on the horizontal wells in gas-condensate reservoirs and indicated that the condensate build-ups in production tests should be due to the condensate bank increasing over the test duration as the production tests were performed at pressures significantly below the dew point pressure. This could also be interpreted into the pressure change radius around the well bore.

**Figure 3-9. Gas-condensate Three-Flow Regions (Roussennac, 2001).**
Figure 3-10. Condensate Saturation Distribution over Production Time (Hashemi et al., 2004).
In recent years, in line with a favorable commercial environment, liquid hydrocarbon production from tight organic shales has increased. However, the industry still lacks in its understanding of hydrocarbon fluid flow in the nanopores of these reservoirs because of the many factors controlling flow behavior. The complexity of fluid flow and fluid properties in unconventional reservoirs has led to technological challenges in nanoscale measurements and modeling.

4.1 Eagle Ford Shale Condensate Phase Envelope

Production from the gas-condensate window (liquid-rich) shale plays in Eagle Ford has increased dramatically during the past decade. Such increased production increased the requirement on understanding the flow behavior of gas-condensate shales when the flowing bottom-hole pressure falls below the dew point pressure and the very lower permeability and porosity. Theoretically, the condensate dropout below the dew point pressure leads to variations in the composition of the vapor and liquid hydrocarbons. Phase behavior prediction is further complicated by the nanometer-sized pores of the shale formations where fluid-rock interaction is significant at the molecular level (Maytham et al., 2014).

At original reservoir conditions, such as the Eagle Ford Shale condensate reservoir in KDB areas, the fluid in the original reservoir is a single-phase fluid before the pressure declines lower than the dew point pressure. The fluid consists of a large amount of methane (CH$_4$) and other short-chain hydrocarbons. As in gas-condensate wells, this fluid also contains a large percentage of long-chain hydrocarbons (Heavy ends). Figure 4-1 compares the composition of gas-condensate systems with other categories of hydrocarbon systems. It is reported that a lower heptane-and-heavier (C7+) content occurs in gas-condensate systems than for crude oil systems.
Most known gas-condensate reservoirs have been discovered in formation with pressures and temperatures within the ranges of 3,000 to 8,000 psi and 200 to 400 F (Moses and Danohoe, 1962). These wide ranges of pressures and temperatures, along with wide composition ranges, provide a large variety of conditions for gas-condensate phase behaviors. This increases the challenge for reservoir engineers, when studying gas-condensate systems, to devise strategies for achieving optimal development and operation plans.
Fan et al. (2005) presented gas-condensate reservoir flow behavior, as depending on the phase envelope of the fluid system and reservoir conditions. The phase envelope consists of the bubble-point line and the dew-point line meeting at a critical point as shown in Figure 4-2. During isothermal expansion, the first bubble of gas is vaporized from the liquid at the bubble-point line. In contrast, the first droplet of liquid condenses from vapor at the dew point line. At this critical juncture, the vapor and liquid phases cannot be distinguished because the composition and all other intensive properties of these two phases become identical.

Figure 4-2. Phase Diagram of a Gas-Condensate System (Fan et al., 2005).
Gas and gas-condensate reservoirs are characterized by the phase envelope in initial reservoir conditions. In the reservoir, an A-A’ path will be followed during isothermal expansion. The two-phase region will not be entered if the reservoir temperature is above the cricondentherm.
temperature. Therefore, the single phase as a gas fluid will remain in the reservoir, and the fluid composition will remain constant during depletion.

Alternately, the B-B’ path will be followed during isothermal expansion if the reservoir temperature is between the critical and the cricondentherm temperatures. Condensation will drop out at the reservoir when the B-B’ path enters the dew-point line. When the reservoir fluid path is in the 2-phase zone, the fluid will be mixed with gas and liquid. However, below the critical condensate saturation point in the nanoports, condensate mobility may be zero and only gas will flow. When the condensate saturation in the nanoports is above the critical point, the flowing fluid composition will consequently change and the dropout condensate will move toward the fracture pathway to the wellbore.

Eagle Ford Shale Condensate areas have an initial pressure of approximately 5,200 psi with an initial temperature of approximately 335 F and a reservoir depth of roughly 11,000 ft. In the development of condensate/retrograde oil, the fluid components are composed of C1-C7+ with a large percentage of long chain hydrocarbons (heavy ends), when compared to lean gas and dry gas. In Eagle Ford Shale Condensate in the KDB, the PVT indicates that the critical point is around 4,000 psi. After initial development, the bottom hole pressure quickly decreases to below 4,000 psi.

According to the theoretically phase envelop analysis, liquid drop out around the bottom hole may appear when the reservoir pressure delinked lower than the 4,000 psi which is the critical point for pressure, and this changes the components of the fluid up to surface. However, there are also other factors affecting the fluid properties.
4.2 Capillary Pressure and Hypothesis Suppression

4.2.1 Capillary Controlled Displacement Drainage

Theoretically, phase envelopes exhibit fluid behaviors when the reservoir pressure changes with development. However, such phase envelopes have been developed mainly from lab PVT results. For a very low permeability and low porosity reservoir such as Eagle Ford plays, the in-situ fluid behaviors are complicated and the actual fluid components, flow regime, and behaviors may not be revealed by an analysis of PVT samples. Another complicating factor is the capillary controlled displacement drainage, which controls the flow in a very low permeability shale reservoir.

The effects of hydraulic fracture degradation with drawdown and liquid dropout in the production string are shown in Figure 4-3.

**Figure 4-3. Capillary Controlled Displacement Drainage. Source: Core lab.**

Capillary pressure is related to pore size, size distribution, and wettability. Capillary boundary effects can lead to phase trapping and a limited flow capacity for any gas-liquid system. The pressure difference between two or more immiscible phases contained in a restricted cavity control the flow. Capillary pressure controls the saturation distribution within a porous medium.
Initially, the flow will take the “easy” drainage path, which is connected by large effective permeability and the pore throat apertures (rp35). After the fluid has drained, the pressure difference will increase between the “easy” path and the “secondary” path (original lower permeability), and the connection surfaces between the matrix and the “easy” path increase. This produces more liquids as such liquids trapped in the matrix become more mobile due to the increased number of exposed surfaces and the pressure differences.

The findings of Abdolnabi et al. (2010) have pointed to a decrease in the PVT phase envelopes of hydrocarbon fluids confined in nanopores. As a result, the presence of nanopores in tight, rich-gas-condensate wells may hold long-term gas/oil ratio (GOR) trends constant over time as has been observed in the production data for Eagle Ford shale wells. This finding contrasts with the theoretical analysis of phase envelopes based on bulk laboratory PVT data. This would delay the onset of dew point pressure and condensate liquid dropout and could be one of the causes of the constant production of GOR in the wells studied by Altman et al. (2014).

The behavior of gas condensates is contrary to what would be expected from “normal” gases: an isothermal decrease in pressure that causes liquid to form at the condensate dew point because of interactions between heavier molecules in the gas condensate fluid. (McCain, 1990)

As the pressure in the near-wellbore region drops below the dew point during production, liquid condensate droplets are formed that tend to remain in the reservoir rock. Such droplets are not productive because of the relative permeability effects. This generally causes GOR production to increase with time. A ring of condensate liquid may form around the wellbore and reduce the deliverability of gas (Deng, 2013) and, hence, well productivity. After significant condensate liquid saturation builds up, some of the condensate liquid will begin to flow towards the producing well (Fan 2005). The decline in productivity of shale gas condensate wells may be
more severe because the pressure drawdown gradients are large. However, a number of shale gas condensate wells are still in production in North America at constant GOR years after their first production began. This suggests that the productivity of these wells may not be dramatically declining or may be controlled and influenced by other factors.

4.2.2 Suppression Phase Envelope

An understanding of fluid properties in nanopores is fundamental in predicting the onset of condensate dropout in shale reservoirs. Vapor pressure may be suppressed in nanopores while capillary pressures are high (Du 2012). These high pressures will cause more light components to be dissolved in the oil phase and suppress bubble point pressure.

The phase envelope of hydrocarbon vapor/liquid fluids decreases from an original “bulk” state to confinement inside the nanopores (Didar and Akkutlu 2013). Furthermore, the lighter components are likely to occupy the center of the nanopore while heavier components lie closer to the pore wall.

Figure 4-5 shows that the decreasing nano pore sizes suppress the phase envelope, and Figure 4-6 shows that the phase envelope flattens under confinement.
Figure 4-4. Decreasing Nano Pore Sizes Suppress the Phase Envelope (Didar and Akkutlu, 2013).
Figure 4-5. Shifts in Phase Envelopes of the Gas Mixture with Varying Composition (Didar and Akkutlu, 2013).

Figures 4-4 and 4-5 present changes in the phase envelopes that occur with variations in the composition and confinement in bulk state and when confined to different sizes of pore widths. Critical points are shown by black dots. The production path is also shown. The red dot in these figures displays when surface conditions have reached standard pressure and temperature conditions (Didar and Akkutlu, 2013).

It is possible that the lower mobility of oil (when compared with gas) in nanopores causes changes in the composition of the flowing fluid along the transport path (Xiong et al. 2013). Slippage and diffusion may further complicate the picture.
Additionally, Altman et al. (2014) state that a suppressed phase envelope results in a lower critical pressure. This implies an increase in the compressibility factor (Z) and an increase in the gas formation volume factor (Bg). The bulk testing properties of a PVT laboratory may not accurately represent the fluid properties at original reservoir conditions. Therefore, there may be some pessimistic estimations on the nanopores of the reservoir. Failing to account for the pore proximity effects of gas condensate fluids in nanopores may cause the suppression of the phase envelope. This may result in incorrect predictions of liquid condensate banking and the pore proximity effects may delay liquid dropping out.
CHAPTER FIVE: SHALE CONDENSATE PRODUCTION CHARACTERISTICS AND HISTORICAL DATA

5.1 Eagle Ford Shale Condensate Production Type Curves in the KDB Group

The Eagle Ford Shale horizontal wells in the KDB group were broken down into three types of fluid produced (wet gas, retrograde gas, and volatile oil) according to the gas oil ratio (Source: Talisman Energy Inc.). This was done to compare the wells’ production characteristics within a localized area. Wet gas wells in Figure 5-1 are located to the Western area of Live Oak County. Retrograde Gas (Condensate) wells in Figure 5-2 are located in the middle of the Karnes County. Volatile oil wells in Figure 5-3 are mainly in DeWitt County.

Figure 5-1. Wet Gas Type Curve (Courtesy of Talisman Energy).
Figure 5-2. Retrograde Gas Type Curve (Courtesy of Talisman Energy).

Figure 5-3. Volatile Oil Type Curve (Courtesy of Talisman Energy).
When applied to the current well drilling program, these type curves form the basis for the aggregate rates that can be expected from the KDB area. Because of limited historical production data available when the type curves were generated by Talisman, the figures only showed the initial months’ production rates and a forecasted production curve (Green curve). If more historical data were available, then, a more objective prediction could have been produced. Other wells’ CGR (Condensate Gas Ratio) were generated by Talisman as shown in Table 5-1.

<table>
<thead>
<tr>
<th>Well</th>
<th>County</th>
<th>#stages</th>
<th>Clean up</th>
<th>Water Recovery</th>
<th>Sand control</th>
<th>CGR</th>
</tr>
</thead>
<tbody>
<tr>
<td>McClanahan #1-1</td>
<td>DeWitt</td>
<td>16</td>
<td>3,640</td>
<td>1</td>
<td>1/16</td>
<td>83.2</td>
</tr>
<tr>
<td>Johnston GU 2-2</td>
<td>Bee</td>
<td>12</td>
<td>700</td>
<td>8</td>
<td>light</td>
<td>10.8</td>
</tr>
<tr>
<td>Wessendorff #5-2</td>
<td>Karnes</td>
<td>12</td>
<td>6,260</td>
<td>4.1</td>
<td>light</td>
<td>73.5</td>
</tr>
<tr>
<td>Three Rivers GU 1-1</td>
<td>Live Oak</td>
<td>14</td>
<td>5,440</td>
<td>4</td>
<td>1/8</td>
<td>35</td>
</tr>
<tr>
<td>Regmund FT 1-1</td>
<td>Karnes</td>
<td>14</td>
<td>4,400</td>
<td>1.8</td>
<td>1/16</td>
<td>35</td>
</tr>
<tr>
<td>Regmund GU 1-1</td>
<td>Karnes</td>
<td>14</td>
<td>3,888</td>
<td>1</td>
<td>trace</td>
<td>20</td>
</tr>
<tr>
<td>Matejek GU 1-1</td>
<td>DeWitt</td>
<td>13</td>
<td>3,415</td>
<td>1</td>
<td>1/16</td>
<td>23</td>
</tr>
<tr>
<td>Gano GU 1-1</td>
<td>Dewitt</td>
<td>13</td>
<td>4,660</td>
<td>1</td>
<td>none</td>
<td>60</td>
</tr>
<tr>
<td>BlackWell 2-2</td>
<td>Dewitt</td>
<td>15</td>
<td>5,779</td>
<td>1</td>
<td>trace</td>
<td>104</td>
</tr>
<tr>
<td>Stolte GU 1-1</td>
<td>Karnes</td>
<td>14</td>
<td>5,200</td>
<td>1</td>
<td>trace</td>
<td>30</td>
</tr>
</tbody>
</table>

Table 5-1. Eagle Ford KDB CGR (Condensate Gas Ratio) (Courtesy of Talisman Energy).

The overall KDB production forecast (Figure 5-4) was developed by Talisman in 2012 which showed the gross raw gas (Mcf/d) and the gross condensate (BBL/D).
Figure 5-4. Eagle Ford KDB Production Forecast (Raw Gas and Condensate) (Courtesy of Talisman Energy).

The locations of the above wells are shown in Figure 5-5 in areas represented by the red star.
5.2 Eagle Ford Shale Condensate Production Characteristics and Historical Data

Production derives from two systems characterized by Tran et al. (2011). One is a “fast” or higher permeability system such as natural fractures, hydraulic fractures, or higher permeability layers. These systems typically have small pore volumes and are usually depleted very quickly during the early production period. This aligns well with the quick decline in initial production rates for Eagle Ford shale condensate wells in the KDB group. The other system is a “slow” system or a lower permeability matrix system. The production rate is much lower than the “fast”
or higher permeability system but lasts a long time at a constant rate. The reason for this is that the majority of the hydrocarbons are initially stored in the matrix and this contributes to longer-term production. The high permeability system provides surface area for a low permeability system, connecting it through the pathways to the horizontal wellbore. After the initial peak production period when hydrocarbons in the larger, “easy” channel are developed the pressure difference between the matrix system and the higher permeability system encourages hydrocarbons in the matrix to flow to the higher permeability system and to the wellbore.

Tran et al. (2011) researched a group of Eagle Ford shale wells, which included the shale condensate wells, located in the KDB areas as shown in Figure 5-6.

![Figure 5-6. Eagle Ford Shale Horizontal Well Group Locations. (Modified from Tran et al. 2011).](image)

The typical oil average curve of the 20 wells are presented in Figure 5-7.
Figure 5-7. Eagle Ford Shale Study Group Oil Decline Curve. (Modified from Tran et al. 2011).

Figure 5-7 shows that initial peak production occurred in the first 2-3 months and quickly declined after 12 months. The sharp slope of the decline decreases from 12 to 30 months and then enters a constant lower production rate of 30-40 bbl/D.

Figures 5-8 to 5-11 show monthly GOR curves of Eagle Ford Shale condensate wells (Altman et al., 2014). These wells can be further categorized as rich gas condensate wells and lean gas condensate wells. Altman et al. retrieved the data from the North American Public database (IHS). This data is current to the end of 2014.

For rich gas condensate wells (3,300—10,000 scf/STB), 14 wells are characterized by about constant GOR as shown in Figure 5-8 (most likely the result of shrinking 2-phase envelopes in smaller pores) whereas three wells show increasing GOR with time as shown in Figure 5-9.
Figure 5-8. Monthly GOR Behavior of Rich Gas Condensate Wells (3,300-10,000 scf/STB) in Eagle Ford Shale. Both graphs (a total of 14 wells) show approximate constant GOR through time. (Altman et al., 2014).

Figure 5-9. Monthly GOR Behavior of Three Rich Gas Condensate Wells (3,300—10,000 scf/STB) in Eagle Ford Shale. GOR increases with Time (Altman et al., 2014).
The GOR plots in Figure 5-9 show the results that align with the conventional bulk liquid rich phase envelope analysis.

For lean gas condensate wells (10,000-30,000 scf/STB), 9 wells show a subtle increase of GOR with time (Figure 5-10), whereas only 4 wells show a constant GOR (Figure 5-11).

Figure 5-10. Monthly GOR Behavior of Nine Lean Gas Condensate Wells (10,000-30,000 scf/STB) in the Eagle Ford Shale. Increasing GOR with the time. (Altman et al., 2014).

Figure 5-11. Monthly GOR Behaviors of Four Lean Gas Condensate Wells (10,000-30,000 scf/STB) in Eagle Ford Shale. Constant GOR with the time. (Altman et al., 2014).
The results in Figure 5-8 and Figure 5-11 are contrary to what would be expected based on the phase envelopes analysis of shale condensate liquid dropout (Chapter 4). As wells produce and pressures decline, rich gas condensate wells are expected to reach dew point sooner than lean gas condensate, assuming that other factors remain constant. Therefore, the corresponding GOR would be expected to increase more readily for rich gas condensate wells because the condensate liquid is initially immobile in the reservoir rock and/or because of condensate liquid loading in the wellbore.

As indicated in Chapter 4, there are many factors controlling flow behavior, including pore proximity effects in shale nano-pores. These may cause a greater change in hydrocarbon fluids if there is a larger proportion of heavier components in the fluid. The constant GOR in Figure 5-8 and Figure 5-11 could have resulted from the stronger suppression in smaller pores of phase envelopes in rich gas condensates, which have a greater proportion of heavier components. This would delay the onset of the liquid condensate dropout and keep GOR constant for longer period, compared with the lean gas condensate.

The degree of condensate liquid dropout in the reservoir and the resulting GOR behavior depend on the combined effects of the matrix and fracture systems. As discussed in Section 3.6 dealing with flow regions, the pressure in the fracture system near the wellbore goes below the dew point much sooner than that of the matrix system. This should cause GOR production to increase. When the fluid flow from the matrix is weak, the GOR increases earlier and continues to rise because of the pressure depletion in the fracture system. On the other hand, if the fluid flow from matrix is strong, then the GOR soon flattens to a constant value even after an initial increase in producing GOR due to pressure depletion in the hydraulic fracture system. The GOR can remain as constant for quite a long time until the matrix system in the reservoir depletes. Furthermore, a
large hydraulic fracture surface area will effectively enhance the matrix flow to the fracture path. Generally, a strong fluid flow from the matrix and a large surface area hydraulic fracture system will contribute to a constant GOR.

Another situation was presented by Altman et al. in Figure 5-12. Four horizontal shale gas condensate wells were plotted and show a variation in daily GOR production data with time. All wells show a relatively constant GOR initially. After approximately 2 years of production, the GORs increased dramatically. This spiky behavior was shown in all four wells. This is the result of the condensate liquid loading inside the production string or the liquid dropout that may occur in a non-stimulated matrix system which is far from the wellbore but the pressure declined with the production over a period.

![Figure 5-12. Constant GOR with Time for Shale Gas Condensate Wells. The spiky behavior after 700 days is associated with liquid condensate loading in the wellbore. (Altman et al., 2014).](image-url)
5.3 Discussion

In conclusion, the expected liquid dropout does not occur at the initial production period. Some wells that produce with a constant GOR appear to be rich condensate wells while the other graphs that show a larger increase in GOR with time belong to lean gas wells. The permeability and the stimulated surface areas through hydraulic fracture enhanced the fluid flow from the matrix as the support to fill in the hydraulic fracture network. This helped to maintain GOR as a constant for a longer period. However, after a certain production interval, the GORs show an increase as spikes on the graph, and liquid loading occurs. The dramatic upward curves for GOR in some wells can be explained by the liquid dropout around the wellbore.
CHAPTER SIX: EAGLE FORD SHALE CONDENSATE MODELING

6.1 Introduction

Unconventional shale gas reservoirs require stimulation by hydraulic fracturing. The reservoir, in general, includes pre-existing fracture networks. The idea is to create a stimulated reservoir volume (SRV) for producing reservoir fluids economically. Through the SRV, gas flow runs from the matrix to the complex stimulated fracture network and to the well bore. Reservoir simulators use a variety of techniques from reservoir engineering. In this paper, numerical modeling was carried out by using the latest commercial compositional reservoir simulator, GEM, as released by the Computer Modeling Group (CMG).

The conceptual model focused on the effects of changes to sensitive variables. The simulation results are compared with the typical Eagle Ford shale condensate well production type curves to ensure that the simulation results are reasonable.

6.2 Modeling Description

A simplified 3-D conceptual model (Figure 6-1) of two producing wells was created for this study. The model was set with average reservoir and fluid properties of the shale condensate compartment in the Eagle Ford deposit. One-third (2,000 ft.) of the real HZ well length (6,000 ft) was simulated initially to perform sensitivity analyses. Elapsed computation running times of the conceptual models varied, but normally 24 hours were required to produce each solution with the GEM simulator in the desktop computer with 4 Processor CPU at 3.60 GHz and RAM 16.0 GB.

Among the cases conducted for the sensitivities analysis, one typical case was selected in the end to build a full horizontal well length of 6,000 ft. to replicate a real Eagle Ford shale condensate well. This was simulated to reflect practical results.
The size of the grid blocks are minimized, as this allows for capturing the effects of the sensitivities controlling change factors. In addition, using homogenized grid blocks allows the model to better simulate the changes of reservoir flow, fluid saturation and pressure, as well as changes in the fluid composition. The average model block size of the various cases is as follows, I: 2,450 ft.; J: 2,700 ft.; and K: 110 ft. This is represented by Cartesian grid block sizes of 50X50X8 ft. in i-j-k directions, respectively.

Figure 6-1. Base Case, 3-D View of the Reservoir Model.
6.3 Base Inputs to the Eagle Ford Shale Condensate Well Model

The conceptual Eagle Ford shale condensate model was built using selected reservoir properties. The initial gas saturation was composed of C1-C7 chemical components with a water-gas bearing bottom.

6.3.1 Reservoir Properties

The base case model represents an Eagle Ford shale condensate reservoir with net pay equalling 110 ft. (Lower Eagle Ford), Depth 10,000 ft., Permeability Matrix 100 nd, Porosity 7%, Initial Pressure 5,200 psi, Initial Temperature 335 °F, and Rock Compressibility 1e-6 1/psi.

6.3.2 Fluid Properties

The fluid chemical components included in the reservoir model are as follows:

<table>
<thead>
<tr>
<th>Components</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>C1</td>
<td>40%</td>
</tr>
<tr>
<td>C2</td>
<td>20%</td>
</tr>
<tr>
<td>C3</td>
<td>20%</td>
</tr>
<tr>
<td>IC4</td>
<td>2%</td>
</tr>
<tr>
<td>NC4</td>
<td>2%</td>
</tr>
<tr>
<td>IC5</td>
<td>1%</td>
</tr>
<tr>
<td>NC5</td>
<td>1%</td>
</tr>
<tr>
<td>C6</td>
<td>4%</td>
</tr>
<tr>
<td>C7</td>
<td>10%</td>
</tr>
<tr>
<td>Total</td>
<td>100%</td>
</tr>
</tbody>
</table>

Table 6-1. Chemical Components and Fractions.

Under original reservoir pressures and temperatures, the fluid exists as a gas phase in the model.

6.3.3 Initial Condition

The reservoir model’s top layer is located at a depth of 10,000 ft. and an initial temperature of 335 °F. The water saturation is 25% and the initial chemical components mole fractions of gas are as shown in Table 6-1. The water gas contact level is at 10,350 ft.
6.3.4 Modeling

CMG-GEM provides two different formulations for horizontal wellbore modeling: (1) Dual Porosity (2) Dual Permeability.

The Dual Porosity approach allows flow from matrix to fractures and fractures to fractures as Figure 6-2.

![Figure 6-2. Dual Porosity Approach. Source: CMG.](image)

The Dual Permeability approach permits flow from matrix to fractures, fractures to fractures, and matrix to matrix as Figure 6-3.

![Figure 6-3. Dual Permeability Approach. Source: CMG.](image)

In this paper, the base case and most investigation cases selected the Dual Permeability formulations. One case was constructed by using Dual Porosity formulations for comparison purposes. Both Dual Porosity and Dual Permeability models were built with the same inputs as the base case. This provides the possibility of capturing changes due to the different formulations.
6.3.5 Well Constraint

The production wells are constrained to operate at a variable minimum bottom hole pressure and at the maximum surface gas rate of 2 E6 scf/d. The corresponding temperature at the bottom-hole pressure is 335 °F.

6.3.6 Operating Period

Each numerical case was run for 5 years. The main production periods are approximately 2 years while the peak production period declined fast and took only 1 year.

6.3.7 Well Configurations

Numerous simulations were conducted for different well configuration cases in search for those sensitive controlling factors impacting shale condensate formation in the Eagle Ford reservoir. The base modeling well pattern is a conceptual well model with a horizontal well length of 2,000 ft. (1/3 of the practical, real, horizontal well length average in Eagle Ford shale condensate wells). The wells interval is 1,050 ft at the surface and the end of the hydraulic fracture has 500 ft. intervals for the base study cases. The base case was built by using input data representative of the real Eagle Ford shale condensate parameters. Furthermore, the performances of the sensitivity cases were compared against the base case and results were crosschecked.

6.3.8 Natural Fracture Permeability

Natural fractures play an important role in productivity of Eagle Ford. In the base case, natural fracture permeability was input as follows: I, J 4 e-5 md and K 8 e-5 md. A comparable case was built by selecting: I, J 2 e-4 md, and K 4 e-4 md. The simulation results are compared in this thesis.

6.4 Cases investigated

This thesis investigates a base case and various sensitivities as follows:
Base case:

BHP 1500 psi

Natural fracture permeability, I: 4e-5 md; J: 4e-5 md and K: 8e-5 md

The wells step out intervals 500 ft.

Hydraulic Fracture Spacing: 25 ft.

Investigation cases remain the input data same as the base case except for the parameters changed as the below descriptions:

**Case 1:** Change BHP (Bottom Hole Pressure) to the following values:

500 psi

3,000 psi

**Case 2:** Change natural fracture permeability to the following values:

I: 4e-5 md; J: 4e-5 md and K: 8e-5 md

I: 2e-4 md; J: 2e-4 md and K: 4e-4 md

**Case 3:** Develop the model by changing to Dual Porosity

**Case 4:** Change the wells intervals to the following values:

700 ft.

900 ft.

**Case 5:** Change hydraulic fracture spacing to the following values:

25 ft.

50 ft.

**Case 6:** Develop a full horizontal well length as Eagle Ford actual well length (6,000 ft.) to compare with the base case.
6.4.1 Base Case

The configuration of the base case used typical porosity, matrix permeability, and reservoir properties from the Eagle Ford shale condensate wells as Table 6-2. The actual horizontal well length is approximately 6,000 ft., but in this study, 2,000 ft. was selected for the conceptual horizontal well length in order to reduce processing time and still capture reasonable results. The hydraulic fractures perforations are at 400-500 ft. intervals. The distance between parallel wells (step out) is 500 ft.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reservoir Temperature</td>
<td>335 °F</td>
</tr>
<tr>
<td>Reservoir Depth</td>
<td>10,000 ft.</td>
</tr>
<tr>
<td>Reservoir Pressure</td>
<td>5,200 psi at 10,000 ft.</td>
</tr>
<tr>
<td>Fluid Chemical Components</td>
<td>C1—C7 with variable fractions as Table 6-1</td>
</tr>
<tr>
<td>Matrix Permeabilities</td>
<td>4e-4 md</td>
</tr>
<tr>
<td>Fracture Permeabilities</td>
<td>I &amp; J Direction: 4e-5 md; K Direction: 8e-5 md</td>
</tr>
<tr>
<td>Primary Hydraulic Fracture Permeability</td>
<td>10,000 md</td>
</tr>
<tr>
<td>Matrix Porosity</td>
<td>7%</td>
</tr>
<tr>
<td>BHP Pressure</td>
<td>1,500 psi</td>
</tr>
</tbody>
</table>

Table 6-2. Modeling Base Case Input Parameters.
Base case simulation results at BHP 1,500 psi:

Figure 6-4. Base Case. BHP 1,500 psi. Reservoir Pressures Changes around the Hydraulic Fractures and Well Bores.

Figure 6-4 shows formation pressure changes at the layer 6 around the hydraulic fractures panels and well bores. After 5 years of production, the region near the wellbore has the lower pressure around 2,300 psi and the region around the hydraulic fracture network has a pressure in the magnitude of 3,500 psi. The matrix far away from the wellbore or the fracture network remains as the original pressure (around 5,200 psi).
The two wells with an approximate 500 ft. step out intervals between end points of hydraulic fractures did not show pressure communications within a production span of 5 years.

**Figure 6-5. Base Case. Pressure Decline Curve.**

Figure 6-5 shows that the average sector pressure declined to 4,865 psi after 5 years of production. The initial two or three months of production show a faster pressure decline, which is aligned with the peak initial production rate shown in Figure 6-14.

Figure 6-6 shows the chemical components C1, C2, C3 cumulative moles in gas phase.

Figure 6-7 shows the chemical components C1, C2, C3 cumulative moles in oil phase.

Figure 6-8 shows the chemical components C4 and C5 cumulative moles in gas phase.

Figure 6-9 shows the chemical components C4 and C5 cumulative moles in oil phase.

Figure 6-10 shows the chemical components C6 and C7 cumulative moles in gas phase.

Figure 6-11 shows the chemical components C6 and C7 cumulative moles in oil phase.
Figure 6-6. Base Case. Chemical Component C1, C2 and C3 Cumulative Gas Moles.

Figure 6-7. Base Case. Chemical Component C1, C2 and C3 Cumulative Oil Moles.
Figure 6-8. Base Case. Chemical Component C4 and C5 Cumulative Gas Moles.

Figure 6-9. Base Case. Chemical Component C4 and C5 Cumulative Oil Moles.
Figure 6-10. Base Case. Chemical Component C6 and C7 Cumulative Gas Moles.

Figure 6-11. Base Case. Chemical Component C6 and C7 Cumulative Oil Moles.
Figure 6-12. Base Case. Cumulative Gas Oil Ratio.

Figure 6-13. Base Case. Monthly Averaged Gas and Oil Daily Production Rate.
Figure 6-12 shows the cumulative gas oil ratio.

Figure 6-13 shows the monthly averaged gas and oil daily production rate.

From Figure 6-12 and 6-13, we can see the condensate gas ratio which is around 80 bbl/MMscf in the base case.

![Cumulative Gas Moles and Gas Production Rate](image)

**Figure 6-14. Base Case. Cumulative Gas Moles and Gas Production Rate.**

Figure 6-14 shows cumulative C7 and C6, and gas monthly rate. The gas monthly rate (at the standard condition) curve shows a quick decline after the initial peak production period of 2-3 months. Afterward, there is a continuous decline for the next few years of production. The Y axis unit for gas rate is Monthly (ft³/day), it means monthly averaged day rate and the day rate unit is ft³/day.
6.4.2 Case 1: Change BHP (Bottom Hole Pressure)

In Case 1, two scenarios that the BHPs were changed to 500 psi and 3,000 psi were simulated, all other input data remaining same as the base case which has the BHP as 1,500 psi. The different BHPs also control pressure decline in the different regions around the wellbore. This affects liquid dropout as discussed previously in this thesis. These pressure declines may lead to liquid banking, which will reduce the heavy end production rates of C5, C6 and C7 components. By selecting different BHPs, the simulation captures differences in flow behavior and their effects on production; especially on production of C6 and C7 heavy end chemical components.

6.4.2.1 Case 1: Change BHP (Bottom Hole Pressure) to 500 psi

Case 1 simulation results at BHP 500 psi:

Figure 6-15. Case 1. BHP 500 psi. Reservoir Pressures Changes around the Hydraulic Fractures.
In the Figure 6-15, the pressure around the well bores and the hydraulic fracture panels declined and the pressure in the matrix between the two wells remains same as the original pressure.

Figure 6-16. Case 1. BHP 500 psi. Decline in Average Pressure.
Figure 6-16 shows that average pressure declined to 4,800 psi after five years production.
Figure 6-17. Case 1. BHP 500 psi. Cumulative Productions of the Chemical Components C6 and C7 and Gas Rate.

Figure 6-17 shows the comparison of the chemical components C7 and C6 with the overall gas rate. The cumulative productions of the chemical components C6 and C7 are in the unit of moles. The Y axis unit for gas rate is Monthly (ft³/day), it means monthly averaged day rate and the day rate unit is ft³/day.
Figure 6-18. Case 1. BHP 500 psi. Cumulative Gas Oil Ratio.
Figure 6-18 shows the cumulative gas oil ratio which is in the unit of ft3/bbl. for the Case 1-BHP at 500 psi.
6.4.2.2 Case 1: Change BHP (Bottom Hole Pressure) to 3000 psi

Figure 6-19. Case 1. BHP 3,000 psi. Changes in Reservoir Pressure.
Figure 6-19 shows the BHP 3,000 psi case pressure decline map around the horizontal wells and hydraulic fracture panels at the layer 6.
Figure 6-20. Case 1. BHP 3,000 psi. Pressure Decline Curve.

Figure 6-20 shows that the average pressure declined to 5,000 psi after five years production.

The curve shows a smooth decline rate.
Figure 6-21. Case 1. BHP 3,000 psi. Cumulative Chemical Components C6 and C7 Production vs Gas Rate.

Figure 6-21 shows the cumulative productions of the chemical components C6 and C7 in the unit of moles. The Y axis unit for gas rate is Monthly (ft³/day), it means monthly averaged day rate and the day rate unit is ft³/day.
6.4.3 Case 2: Changing Natural Fracture Permeability

Natural fractures play an important role in the hydraulic fracturing process. The stimulation of pre-existing natural fractures creates the primary flow path in tight shale reservoirs. Furthermore, natural fractures in the matrix provide a path for continued flow from matrix to hydraulic fractures. The size and magnitude of natural fractures have a significant impact on well performance. However, due to a lack of experimental data on natural fractures in Eagle Ford shale condensate rocks the study relies on some approximations as follows:
Two cases were simulated. One is the same as the base case (small natural fracture) and the other case is the same input data as the base case except for the large natural fracture.

Small Natural Fracture Case: Same as the base case, I: 4e-5 md; J: 4e-5 md and K: 8e-5 md

Large Natural Fracture Case: Selected I: 2e-4 md; J: 2e-4 md and K: 4e-4 md

Figure 6-23. Case 2. Larger Natural Fracture Permeability. Reservoir Pressure Changes. Figure 6-23 shows the average pressure decline map for the case with large natural fracture permeabilities around the horizontal wells and hydraulic fracture in layer 6. At the end of the 5 year production period, the pressure declines are more obvious than in the lower natural fracture base case. Figure 6-24 shows the pressure decline for this case. Figure 6-25 shows the
corresponding cumulative productions of the chemical components C6 and C7 vs. gas rate.

Figure 6-26 shows the cumulative gas oil ratio.

Figure 6-24. Case 2. Large Natural Fracture Permeability, Pressure Decline Curve.
Figure 6-25. Case 2. Large Natural Fracture Permeability, Cumulative Chemical Components C6 and C7 Productions vs. Gas Rate.

In the Figure 6-25, it shows the cumulative productions of the chemical components C6 and C7 in the unit of moles. The Y axis unit for gas rate is Monthly (ft³/day), it means monthly averaged day rate and the day rate unit is ft³/day.
Figure 6-26. Case 2. Large Natural Fracture Permeability, Cumulative Gas Oil Ratio.

Figure 6-26 shows the cumulative gas oil ratio which is in the unit of ft³/bbl. for the Case 2 with large natural fracture permeability at 2e-4md.

6.4.4 Case 3: Dual Porosity vs. Dual Permeability in Modeling

Comparison of Dual Porosity case vs Dual Permeability case.

Both cases have the same data input as the base case (BHP 1,500psi) except for one selection is the dual permeability model and the other is the dual porosity model.

Dual Permeability Case: Same as the base case (Dual Permeability Model).

Dual Porosity Case: Selected the dual porosity modeling function and other inputs are same as in the base case. Figure 6-27 shows the pressure decline map around the wellbore and hydraulic fracture panels for the Dual Porosity case. Figure 6-28 shows the average pressure decline curve.
Figure 6-29 shows the corresponding cumulative productions of the chemical components C6 and C7 vs. gas rate and Figure 6-30 shows the cumulative gas oil ratio which is in the unit of ft³/bbl. for the Dual Porosity case.

Figure 6-27. Case 3. Dual Porosity, Reservoir Pressure Changes.
Figure 6-28. Case 3. Dual Porosity, Pressure Decline Curve.
Figure 6-29. Case 3. Dual Porosity, Cumulative Chemical Components C6 and C7 Productions vs. Gas Rate.

In the Figure 6-29, it shows the cumulative productions of the chemical components C6 and C7 in the unit of moles. The Y axis unit for gas rate is Monthly (ft³/day), it means monthly averaged day rate and the day rate unit is ft³/day.
Figure 6-30. Case 3. Dual Porosity Model. Cumulative Gas Oil Ratio.

Figure 6-30 shows the cumulative gas oil ratio which is in the unit of ft³/bbl. for the Case 3-Dual Porosity Model.

6.4.5 Case 4. Change the Wells Step Out Intervals into 500 ft.; 700 ft. and 900 ft.

Figure 6-31. Wells Step Out Intervals.
Figure 6-31 shows the well step out interval is the spacing between the end points of the two wells’ hydraulic fracture panels. To investigate the impacts of variables of the well step out intervals, two cases were constructed and compared with the base case.

Well step out interval 500 ft.: Same as the base case

Well step out interval 700 ft. Figure 6-32 shows the corresponding cumulative productions of the chemical components C6 and C7 vs. gas rate. Figure 6-33 shows the average pressure decline curve.

Figure 6-32. Case 4. The Well Step Out Interval 700 ft. ---Cumulative Chemical Components C6 and C7 Productions vs. the Gas Rate.
In Figure 6-32, it shows the cumulative productions of the chemical components C6 and C7 in the unit of moles. The Y axis unit for gas rate is Monthly (ft³/day), it means monthly averaged day rate and the day rate unit is ft³/day.

---

Figure 6-33. Case 4. The Well Step Out Interval 700 ft. --- Pressure Decline Curve.

---

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In the case of the well step out interval at 900 ft. Figure 6-34 shows the corresponding cumulative productions of the chemical components C6 and C7 vs. gas rate. Figure 6-35 shows the average pressure decline curve.

Figure 6-34. Case 4. Well Step Out Interval 900 ft. --- Cumulative Chemical Components C6 and C7 Productions vs. the Gas Rate.

In the Figure 6-34, it shows the cumulative productions of the chemical components C6 and C7 in the unit of moles. The Y axis unit for gas rate is Monthly (ft3/day), it means monthly averaged day rate and the day rate unit is ft3/day.
Figure 6-35. Case 4. Well Step Out Interval 900 ft. --- Pressure Decline Curve.

6.4.6 Case 5: Change the Natural Fracture Spacing

In the Case 5, all other input data are same as the base case (natural fracture at 25ft.) except for the variable inputs of the fracture spacing at 50 ft.

Natural Fracture Spacing at 25 ft: Same as the base case.

Natural Fracture Spacing at 50 ft: Change the fracture spacing into 50ft intervals.

Figure 6-36 shows the average pressure changes. Figure 6-37 shows the average pressure decline curve after 5 years production. Figure 6-38 shows the corresponding cumulative production of
the chemical components of C6 and C7 vs. gas rate. Figure 6-39 shows the cumulative gas oil ratio.

Figure 6-36. Case 5. Natural Fracture Spacing at 50 ft., Reservoir Pressure Changes.
Figure 6-37. Case 5. Fracture Spacing 50 ft. --- Pressure Decline Curve.
Figure 6-38. Case 5. Fracture Spacing 50 ft. --- Cumulative Chemical Components C6 and C7 Productions vs. Gas Rate.

In the Figure 6-38, it shows the cumulative productions of the chemical components C6 and C7 in the unit of moles. The Y axis unit for gas rate is Monthly (ft³/day), it means monthly averaged day rate and the day rate unit is ft³/day.
Figure 6-39. Case 5. Fracture Spacing 50 ft. --- Cumulative Gas Oil Ratio.

Figure 6-39 shows the cumulative gas oil ratio for the Case 5 which is changed the natural fracture spacing into 50ft.

6.4.7 Case 6: Typical Wells as Eagle Ford Actual Full Length Horizontal Well

One typical case was developed in the end to build wells with the full horizontal well length of 6,000 ft. to replicate a real Eagle Ford shale condensate well. The simulation data inputs are same as the base case (well length is 2,000ft.) except for the horizontal well length extended to 6,000 ft.

Figure 6-40 shows the pressure decline map for the case with the actual horizontal wells length (6,000 ft.) as Eagle Ford. Figure 6-41 shows the average pressure decline for this case. Figure 6-
42 shows the corresponding cumulative productions of the chemical components C6 and C7 vs. gas rate. Figure 6-43 shows the cumulative gas oil ratio.

Figure 6-40. Case 6 Full Eagle Ford Horizontal Well Length. --- Reservoir Pressure Changes.
Figure 6-41. Case 6 Full Eagle Ford Horizontal Well Length. --- Pressure Decline Curve.
Figure 6-42. Case 6 Full Eagle Ford Horizontal Well Length --- Cumulative Chemical Components C6 and C7 Productions vs. Gas Rate.

In the Figure 6-42, it shows the cumulative productions of the chemical components C6 and C7 in the unit of moles. The Y axis unit for gas rate is Monthly (ft³/day), it means monthly averaged day rate and the day rate unit is ft³/day.
Figure 6-43. Case 6 Full Eagle Ford Horizontal Well Length. Cumulative Gas Oil Ratio.

Figure 6-43 shows the cumulative gas oil ratio which is in the unit of ft³/bbl. for the Case 6-Full Length Horizontal Well (6,000ft.).

6.5 Simulation Results and Analysis

The simulation outputs of the individual chemical components are the cumulative productions in the moles unit as the above graphics showed. The calculations were conducted and converted the cumulative productions in the unit of gmole into the volume units’ MMscf/d and bbl/d at the standard conditions (SC).
6.5.1 Case 1. Change the BHP (Bottom Hole Pressure) 500 psi, 1,500 psi, and 3,000 psi

<table>
<thead>
<tr>
<th>BHP</th>
<th>Condensate (C7+C6+C5) bbl/d</th>
<th>Gas (C4+C3+C2+C1) MMscf/d</th>
<th>Average Pressure (psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1,500 psi</td>
<td>160</td>
<td>1.94</td>
<td>4,865</td>
</tr>
<tr>
<td>500 psi</td>
<td>199</td>
<td>2.32</td>
<td>4,810</td>
</tr>
<tr>
<td>3,000 psi</td>
<td>89</td>
<td>0.9</td>
<td>5,000</td>
</tr>
</tbody>
</table>

Table 6-3. Cumulative Production and Reservoir Average Pressure at BHP Variables.

From the above cumulative production, condensate vs the gas production can be read as below:

<table>
<thead>
<tr>
<th>BHP</th>
<th>CGR (Condensate Gas Ratio) bbl/MMscf</th>
</tr>
</thead>
<tbody>
<tr>
<td>1,500 psi</td>
<td>83</td>
</tr>
<tr>
<td>500 psi</td>
<td>86</td>
</tr>
<tr>
<td>3,000 psi</td>
<td>100</td>
</tr>
</tbody>
</table>

Table 6-4. Condensate Gas Ratio at BHP Variables.

The condensate productions show differences at different BHPs and the CGRs are slight different between the cases of BHP 1,500psi and 500psi but large different from the case of BHP 3,000psi. One reason is that average reservoir pressures are still well above 4,800 psi, which is above the fluid phase’s pressure critical point around 3,500psi. This prevents liquid drop out in the matrix. However, the region near the wellbore is displayed as blue (around 2,000 psi) in the modeling of 2D pressure distribution in Figures 6-4, 6-19 and 6-26. In these regions, liquid drop out could occur but the primary hydraulic fracture permeability is 10,000 md, and the high permeability will surpass the liquid banking issue. This can also be verified through the constant and flat cumulative production CGR curve.

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Furthermore, the differences of condensate production in the three cases are obvious, we can find the BHP 3,000psi case has the lowest condensate and gas production but the highest CGR ratio among all three cases. This could indicate that the lower BHP pressure will increase the overall production but the higher BHP pressure will increase the heavier end components in the gas phase.

6.5.2 Case 2: Change the Natural Fracture Permeability

Small Natural Fracture Permeability: I: 4e-5 md; J: 4e-5 md and K: 8e-5 md

Large Natural Fracture Permeability: I: 2e-4 md; J: 2e-4 md and K: 4e-4 md

A comparison is developed by using the same data input as the base case (Small Natural Fracture Permeability) except for changing to the large natural fracture permeability. From the above two scenarios of the natural fracture permeability inputs, the simulation results show a big difference in condensate production.

<table>
<thead>
<tr>
<th>BHP</th>
<th>Inputs</th>
<th>Condensate (C7+C6+C5) bbl/d</th>
<th>Gas (C4+C3+C2+C1) MMscf/d</th>
<th>Average Pressure (psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Small Natural Fracture Permeability</td>
<td>I: 4e-5 md; J: 4e-5 md and K: 8e-5 md</td>
<td>160</td>
<td>1.94</td>
<td>4,865</td>
</tr>
<tr>
<td>Large Natural Fracture Permeability</td>
<td>I: 2e-4 md; J: 2e-4 md and K: 4e-4 md</td>
<td>208</td>
<td>2.46</td>
<td>4,700</td>
</tr>
</tbody>
</table>

Table 6-5. Simulation Results of Natural Fracture Permeability Variable Inputs.
From the above cumulative production data, the simulation results show that a higher natural fracture permeability case has 25% more production of the heavy end components and 27% more production of the gas. The average reservoir pressure remains as high as 4,700.

6.5.3 Case 3. Develop the Model by Selecting Dual Porosity or Dual Permeability

By selecting Dual Porosity or Dual Permeability, the flow mechanisms are different. Simulation results are also different with respect to production and pressure.

<table>
<thead>
<tr>
<th></th>
<th>Condensate ((C7+C6+C5)) bbl/d</th>
<th>Gas ((C4+C3+C2+C1)) MMcf/d</th>
<th>Average Pressure (psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Dual Permeability</strong></td>
<td>160</td>
<td>1.94</td>
<td>4865</td>
</tr>
<tr>
<td><strong>Dual Porosity</strong></td>
<td>99</td>
<td>1.52</td>
<td>5040</td>
</tr>
</tbody>
</table>

Table 6-6. Dual Permeability vs. Dual Porosity Simulation Results.

The Dual Porosity Model used the exact same modeling inputs (base case) as the Dual Permeability Model. Compared with Dual Permeability Model, the Dual Porosity simulation results have a lower cumulative production of condensate and a lower total production of gas. The difference between the cumulative production of condensate in the Dual Permeability model and the Dual Porosity model is about 61 bbl/d. This represents a difference of about 61.6% in condensate cumulative production in Dual Porosity. In addition, the average reservoir pressure of the Dual Porosity model is 5,040 psi, which is higher than the pressure in the Dual Permeability model. These average pressures represent a decline in pressure after 5 years production. As a result, the lower average pressure decline is aligned with a lower cumulative production of condensate and gas in the case of dual porosity case.
6.5.4 Case 4. Change the Wells’ Step Out Intervals into: 500 ft.; 700 ft., and 900 ft.

The wells’ step out intervals will change the total recovery rate and the development rate. How close the wells should be drilled and what the intervals should be in order to create the optimized distance for recovering as much product as possible while minimizing the cost of drilling the wells and their completion cost is a practical question in Eagle Ford shale condensate development. This study conducted the simulations which remain all other data inputs same as the base case (well step out interval at 500ft.) and changed the well step out intervals into 700ft. and 900ft. to compare the results in order to show differences.

<table>
<thead>
<tr>
<th>Wells Step out Intervals</th>
<th>Condensate (C7+C6+C5) bbl/d</th>
<th>Gas (C4+C3+C2+C1) MMscf/d</th>
<th>Average Pressure (psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>500 ft..</td>
<td>160</td>
<td>1.94</td>
<td>4,865</td>
</tr>
<tr>
<td>700 ft..</td>
<td>185</td>
<td>1.85</td>
<td>4,870</td>
</tr>
<tr>
<td>900 ft..</td>
<td>185</td>
<td>1.85</td>
<td>4,910</td>
</tr>
</tbody>
</table>

Table 6-7. Simulation Results of Well Step Out Intervals Variable Inputs.

The well step out intervals were set at 500 ft., 700 ft., and 900 ft. The simulation results show that cumulative production is slight different between 500 ft. and 700 ft., while 700 ft. and 900 ft. the production figures are the same. In the case of the well step out intervals is 500ft., the productions shows lower; in the case of the intervals are 700ft. and 900ft., the productions keep the same. The well step out intervals that are greater than 700ft. do not show a production advantage. However, larger well intervals may save on drilling and completion costs while still getting the same ultimate recovery and the production will take longer at a lower, constant production rate. Therefore, the well step out intervals between two wells should be an optimized at around 700ft. with respect to the overall investment return rate.
6.5.5 Case 5. Change the Fracture Spacing 25 ft. and 50 ft.

Fracture Spacing will influence overall production. Under the same base case, more intensive fracture spacing will increase the fracture networks and, hence, will provide more flow path, especially for a shale condensate reservoir with a very low permeability.

<table>
<thead>
<tr>
<th>Natural Fracture Spacing</th>
<th>Condensate (C7+C6+C5) bbl/d</th>
<th>Gas (C4+C3+C2+C1) MMcf/d</th>
<th>Average Pressure (psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>25ft. (Base Case)</td>
<td>160</td>
<td>1.94</td>
<td>4865</td>
</tr>
<tr>
<td>50ft.</td>
<td>50</td>
<td>0.6</td>
<td>5060</td>
</tr>
</tbody>
</table>

Table 6-8. Effects of Hydraulic Fracture Spacing Variable Inputs.
The simulation results show a much higher both condensate and gas productions with an intensive fracture spacing at 25 ft. compared with at 50 ft. natural fracture spacing. This is interpreted to be the contribution from networks and permeabilities increasing due to the natural fracture spacing intensive.

6.5.6 Case 6: Simulation Results of the Full Length Eagle Ford Horizontal Well

Compared with Base case, at the end of the 5 year production period, the full length wells show the accumulated production as below:

<table>
<thead>
<tr>
<th></th>
<th>Condensate Cumulative Production (C7+C6+C5) bbl/d</th>
<th>Gas Cumulative Production (C1+C2+C3+C4) MMscf/d</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Case (2,000ft) X 3</td>
<td>160</td>
<td>1.94</td>
</tr>
<tr>
<td>Full Eagle Ford Wells Length (6,000ft)</td>
<td>197</td>
<td>2.26</td>
</tr>
</tbody>
</table>

Table 6-9. Production Comparison between Base Case and Full Well Length Case.
The average pressure declines of both cases are similar as around 4,000 psi after 5 year production. The extended well length of case 6 could account for the production increase compared with base case.
CHAPTER SEVEN: MODELING OF A PAIR OF SHALE CONDENSATE WELLS
INCLUDING AN INJECTION WELL

7.1 Introduction

A shale reservoir has a low porosity and very low permeability. Normally, a hydraulic stimulation is essential to create a reservoir stimulated volume and the simulated hydraulic network that will provide the flow channel as shown in Figure 7-1.

Figure 7-1. Schematic of Multiple Horizontal Wells.
A higher original reservoir pressure is the main driver for the flow. My hypothesis is that pressure maintenance should help to improve recoveries from shales that at this time are very low (< 10%). This has not been done and for a shale condensate reservoir such as the Eagle Ford in the KDB area this could prove valuable in order to ensure that the heavy ends (C5, C6, and
C7) can be produced together with the light gas (C1, C2). It is anticipated that by keeping the reservoir at a high pressure, economic returns will be increased because of the increased production of C6, C5 and C7, which has a high market value. This will also help to avoid or improve C5, C6 and C7 liquid dropout issues.

In Texas, the Eagle Ford field is in the transition windows of dry gas, condensate, and retrograde oil as shown in Figure 3-8. The south area has down dip formations, which have higher lean gas reserves. The southern lean gas area is around 30 – 40 km away from shale condensate areas, such as KDB. In addition, the shale condensate area has also a higher gas production. Because of the lower lean gas price and the cost of processing, lean gas becomes a burdened by-product. To use lean gas effectively, my hypothesis is that it could be utilized as injection fluid to maintain reservoir pressure and to enhance the performance of shale condensate wells. In the course of this study, a simulation study was conducted to investigate this possibility.

7.2 Modeling Description

A simplified, conceptual 3-D model of gas injection paired with a production well was built. The average reservoir data and fluid properties used in the injection model are the same as the production model considered in the previous chapter. Two cases at the small natural fracture permeability but different injection well patterns and one case at the large natural fracture permeability were investigated:

Case 1. Well 1-inj-C1 started as an injection well from the beginning and paired with the continuous production Well 2-Prod-C1.

Case 1 is composed of one injection well (Well 1-inj-C1) and one production well (Well 2-prod-C1). The production well has the same inputs as the base case in the previous chapter, and its horizontal well length is around 2,000 ft. The injection well was built by setting the well
constraints at max BHP of 9,000 psi, which is lower than rock fracturing pressure at around 10,000psi. Outsourced lean gas was selected as the injection fluid. This is aligned with the idea that lean gas from the southern area of Eagle Ford or offset wells may be a potential resource for gas injection.

Both injection and production wells were started on the same beginning day in the simulator. The production well is continually producing while the injection well is injecting lean gas through a 4” well tube.

The injection well fracture panel is perpendicular to the production well fracture panels. The distance between the injection well fracture panels to the end point of the production well fracture panels is approximately 500 ft. This is a practical fracture end point distance between production wells.

**Case 2:** Well 1-prod-C2 started as a production well and shut down after one year. It was then converted into an injection well -Well 1-inj-C2. Its paired offset well is a continuous production Well 2-prod-C2.

In Case 2, after being in production for one year, a production well (Well 1-prod-C2) was converted into an injection well (Well 1-inj-C2) and paired with another production well (Well 2-prod-C2) in the same sector. The injection well is limited to a max BHP pressure of 9,000 psi, which is lower than the rock fracture pressure at around 10,000psi. Same as in case 1, the outsourced injection fluid is lean gas.

**Case 3:** Same as Case 2 but inputting the large natural fracture permeability at 2e-4 md.

The Case 3 was constructed at the large natural fracture permeability inputs and other data inputs are remained as same as Case 2.
The summary of the well names used in the simulations:

<table>
<thead>
<tr>
<th>Case</th>
<th>Well Name</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Case 1</td>
<td>Well 1-inj-C1</td>
<td>From the beginning, Well 1-inj-C1 is an injection well</td>
</tr>
<tr>
<td></td>
<td>Well 2-prod-C1</td>
<td>Well 2-prod-C1 is as a continuous production well</td>
</tr>
<tr>
<td>Case 2</td>
<td>Well 1-prod 1-C2</td>
<td>Well 1-prod-C2 started as an production well from the beginning till one year production</td>
</tr>
<tr>
<td>(Small Natural Fracture Permeability)</td>
<td>Well 1-inj-C2</td>
<td>After one year production, Well 1-prod-C2 was shut down and then converted into an injection Well 1-inj-C2</td>
</tr>
<tr>
<td></td>
<td>Well 2-prod-C2</td>
<td>Well 2-prod-C2 is as a continuous production well</td>
</tr>
<tr>
<td>Case 3</td>
<td>Same as Case 2</td>
<td></td>
</tr>
<tr>
<td>(Large Natural Fracture Permeability)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 7-1. Wells Names.

7.3 Cases investigated

7.3.1 Case 1: Injection Well from the Beginning- Small Natural Fracture Permeability Input).

Well 1-inj-C1 started as an injection well from day one and paired with the continuous production Well 2-Prod-C1. Figure 7-2 shows the pressure map for the Case 1 with horizontal wells and hydraulic fracture at layer 6 at the time of 2002-03-01. Figure 7-3 shows the pressure decline for this case. Figure 7-4 shows the corresponding cumulative chemical components C6, C7 vs. gas rate.
Figure 7-2. Case 1. Well 1-inj-C1 (One injection well) and Well 2-prod-C1 (One continuous production well) -- Reservoir Pressure Changes.
Figure 7-3. Case 1. Well 1-inj-C1 (One injection well) and Well 2-prod-C1 (One continuous production well) - Pressure Decline Curve.
Figure 7-4. Case 1. Well 1-inj-C1 (One injection well) and Well 2-prod-C1 (One continuous production well) --- Cumulative Chemical Components C6, C7 vs. Gas Rate.

The Y axis unit for C7 and C6 is Monthly (ft³/day), it means monthly averaged day rate and the day rate unit is ft³/day.

7.3.2 Case 2: Injection Well Converted from a Production Well - Small Natural Fracture Permeability Input).

Well 1-prod-C2 started as a production well and shut down after one year. It was then converted into an injection well Well 1-inj-C2. Its paired offset well is Well 2-prod-C2 (continuous production). Figure 7-5 shows the pressure map for the Case 2 with horizontal wells and hydraulic fracture in layer 6 at the time of 2003-6-28. Figure 7-6 shows the average pressure
changes for this case. Figure 7-7 shows the corresponding cumulative chemical components C6, C7 vs. gas rate.

Figure 7-5. Case 2. After one year in production, a production well (Well 1-prod-C2) is converted into an injection well (Well 1-inj-C2), paired with a continuous production well 2 (Well 2-prod-C2) --- Reservoir Pressure Changes.
Figure 7-6. Case 2. After one year in production, a production well (Well 1-prod-C2) is converted into an injection well (Well 1-inj-C2), paired with a continuous production well 2 (Well 2-prod-C2) Average Pressure Curve.
Figure 7-7. Case 2. After One Year in production, a production well (Well 1-prod-C2) is converted into an injection well (Well 1-inj-C2), paired with a continuous production well 2 (Well 2-prod-C2) --- Cumulative Chemical Components C6, C7 and Gas Rate.

The Y axis unit for C7 and C6 is Monthly (ft³/day), it means monthly averaged day rate and the day rate unit is ft³/day.

7.3.3 Case 3: Injection Well Converted from a Production Well - Large Natural Fracture Permeability Input.

Similar as the Case 2, in the Case 3 the Well 1-prod-C2 started as a production well and shut down after one year. It is then converted into an injection well (Well 1-inj-C2), paired with a continuous production well 2 (Well 2-prod-C2). The difference between Case 2 and Case 3 is the natural fracture permeabilities inputs. The Case 2 takes the small natural fracture permeability at 4e-5 md and the Case 3 takes the large natural permeability at 2e-4 md. Figure 7-8 shows the
pressure changes around horizontal wells and hydraulic fractures at the layer 6 at the time of 2004-12-01. Figure 7-9 shows the average pressure changes for this case. Figure 7-10 shows the corresponding cumulative chemical components C6, C7 vs. gas rate.

Figure 7-8. Case 3. Injection Case at Large Natural Fracture Permeability Inputs--Reservoir Pressure Changes.
Figure 7-9. Case 3. Injection Case at Large Natural Fracture Permeability Inputs--Average Pressure Curve.
7.4 Simulation Results and Analysis

Case 1. Well 1-inj-C1 started as an injection well from the beginning and paired with the continuous production Well 2-prod-C1.

In the simulation results, the pressure displayed figures do not show an appreciable change in the pressure at the layer 6. The enlarged figures show that the pressure at the end point of the hydraulic fracture panel kept declining with the elapsed production time. The initial pressure of ~5,227 psi (Figure 7-8) declined to 4,403 psi (Figure 7-9) when the production well shut-down...
on 2001-01-01. After the 15 months injection at the time of 2002-03-01, the production well (Well 2-prod-C1) pressure at the same grid was still declining to 3,493 psi (Figure 7-10). In addition, the matrix grids between the injections well fracture panel end points and the production well fracture panel end points still measured the original pressure as 5,227 psi. This seems to show that there is no direct pressure communication between the injections well and the production well.

Figure 7-11. Initial Pressure at the End Point of the Hydraulic Fracture Panel.
Figure 7-12. Pressure at the End Point of the Hydraulic Fracture Panel on 2001-01-01 before Shut Down.

Figure 7-13. Pressure at the End Point of the Hydraulic Fracture Panel on 2002-03-01 after 15 Months Injection.
Case 2. Well 1-prod-C2 started as a production well and shut down after one year. It was then converted into an injection well -Well 1-inj-C2. Its paired offset well is a continuous production Well 2-prod-C2.

The difference between Case 1 and Case 2 is the injection well pattern. The Case 1’s injection well fracture panel is perpendicular to the production well fracture panel and the Case 2’s injection well fracture panel is parallel to the production wells.

The simulation outputs of Case 2 are similar as Case 1, the pressure displayed figures do not show an appreciable change in the pressure at the layer 6. The enlarged figures show that the pressure at the end point of the hydraulic fracture panel kept declining with the elapsed production time. The initial pressure of $\sim 5,227$ psi declined to $3,782$ psi (Figure 7-14) when the production well shut-down on 2001-01-01. After the 31 months injection at the time of 2003-06-28, the production well (Well 2-prod-C1) pressure at the same grid was still declining to $3,238$ psi (Figure 7-15). In addition, the matrix grids between the injections well fracture panel end points and the production well fracture panel end points still measured the original pressure as $5,227$ psi. This seems to show that there is no direct pressure communication between the injections well and the production well.
Figure 7-14. Pressure at the End Point of the Hydraulic Fracture Panel on 2001-01-01 before Shut Down.

Figure 7-15. Pressure at the End Point of the Hydraulic Fracture Panel on 2003-06-28 after 31 Months Injection.
Case 3: Same as Case 2 but inputting the large natural fracture permeability at 2e-4 md.
This case followed a similar injection well pattern as Case 2 by converting a production well into an injection well and investigating whether the injection well had any pressure communication with the other production well (Well 2-prod-C2) even under large natural fracture permeability. Case 3 takes the large natural fracture permeability inputs at 2e-4 md and other data are same as the Case 2. Well 1-prod-C2 was initially a continuous production well. After one year, it was converted into an injection well (Well 1-inj-C2). During this time, Well 2 (Well 2-prod-C2) continued to retain its function as a production well.

The simulation results show the pressure displayed figures do not show an appreciable change in the pressure at the layer 6. The enlarged figures show that the pressure at the end point of the hydraulic fracture panel of the production well still kept declining with the elapsed production time. The initial pressure of ~5,227 psi declined to 3,782 psi (Figure 7- when the production well shut-down on 2001-01-01. After the 48 months injection at the time of 2004-12-01, the pressure was still declining to 3,089 psi. In addition, the matrix grids between the injections well fracture panel end points and the production well fracture panel end points still measured the original pressure as 5,227 psi. This seems to show that there is no direct pressure communication between the injections well and the production well.
Figure 7-16. Pressure at the end point of the hydraulic fracture panel on 2001-01-01 before shut down.

Figure 7-17. Pressure at the end point of the hydraulic fracture panel on 2004-12-01 after 48 months injection.
In 2012, the average Eagle Ford shale condensate well cost around $9 million to develop. Customarily, after a 2 to 3 month peak production period, most wells enter into a constant, but slow, production decline period. From this trend, one is lead to expect that shale condensate production may last longer than the reservoir engineering forecast. But because of the slow production rate, which may last an extended periods of time, operational costs reduce the economic development of these wells and results in early abandonment before all products can be extracted. If a production well can be converted into an injection well located at the middle of a group of wells within a sector as in Figure 7-1, economic returns may dramatically increase. This would be similar to a secondary recovery in a traditional oil development.

However, the simulation results from Well 2 (Well 2-prod-C2) in Case 1, 2 and 3 were compared with the base case with respect to condensate and gas productions. The pressure changes of the Well 2 (Well-prod-C2) in the three cases were also analyzed. The cumulative condensate and gas production do not show significant differences between the injection case and the production case without injection. The Well 2 (Well-prod-C2) pressure still kept declining in all three injection cases. The pressure between the injection well and the production well seems not communicate. The reason for this may be that the very tight shale reservoir blocks pressure transitions. As long as the injection pressure of 9,000 psi is lower than the hydraulic pressure of ~10,000 psi.
In this research, conceptual dual porosity and dual permeability shale condensate reservoir models with average properties of Eagle Ford reservoirs in Texas were constructed to investigate the impact of different controlling variables on (1) production capabilities and (2) lean gas injection. Six production cases of interest to companies operating in the Eagle Ford were studied including variation in bottom-hole pressures, permeability of natural fractures, performance of dual porosity vs. dual permeability reservoirs, step outs of horizontal wells, natural fractures spacing and horizontal well lengths. In addition, two lean gas injection cases were considered: (1) injection from the beginning of condensate production, and (2) conversion of one production well to injector.

Results led to the following conclusions:

1. The low but approximately constant heavy end C5, C6 and C7 production obtained in the simulation studies aligns well with typical actual performance of Eagle Ford shale wells.

2. Natural fracture permeability has a significant impact on production and pressure decline. A higher natural fracture permeability results in increased production rate and recovery.

3. The dual permeability model developed in this study shows larger production of C5, C6 and C7 as compared with the dual porosity model. This is most likely the result of flow contribution from matrix to matrix blocks and fractures, as opposed to flow from only matrix to fractures.

4. Lean gas injection is not feasible when shale permeability is of the magnitude considered in this study (0.0001 md).

5. There might be sweet spots within condensate shale reservoirs amenable to gas injection and enhanced liquids-recovery. It is recommended to investigate this possibility.
References


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