STRESS DEPENDENT COMPACTION IN TIGHT RESERVOIRS AND ITS IMPACT ON LONG-TERM PRODUCTION

by

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ABSTRACT

Stress dependent compaction in low permeability reservoirs and its impact on long term reservoir recovery were investigated in this work. The research was inspired by the observation of steep production decline in many shale wells. The objectives of this research are in the following aspects:

1) To measure pore pressure and confining stress dependent tight rock permeability, which is rarely documented in the literature;
2) To identify permeability decline characteristics at various effective stress conditions of different types of tight rocks;
3) To generate pressure dependent permeability decline models for numerical simulation study;
4) To evaluate the impact of stress dependent compaction on tight reservoir recovery by integrating permeability decline models into traditional reservoir simulation;
5) Last but not least, to provide practical suggestions for production enhancement in shale wells; more importantly, to inspire more research and field pilots in this area to further validate the viability of the potential EOR/IOR approaches.

This work consists of two parts: laboratory sample measurements and numerical simulations. In the first part, two core measurement assemblies were utilized to calibrate stress dependent tight sample permeability. Pressure transmission test method was employed and three different types of tight samples were used for the experiments. Multiple combinations of pore pressure and confining stress were applied to each sample to cover different stages during reservoir depletion. The interpretation of measured permeability decline as well as the change in sample downstream equilibrium time for all three samples confirms the stress dependent compaction phenomenon. The data also suggest that the tight rock permeability change does not follow monotonic trend in a specific reservoir, as the algorithm changes from linear to power law increase with the increase of applied pore pressure. The critical confining stress to pore pressure window was identified for different samples which indicate the starting point of
permeability decline signature changes. Using the data of pressure transmission tests, the Biot
coefficient was determined using trial and error technique such that the effective stress can be
obtained. The effective stress dependent permeability model was then built for the numerical
simulation.

Coupled permeability decline numerical simulation was conducted after the experimental work.
Multiple simulation scenarios were run to study the production response due to compaction.
The following aspects were investigated with the non-injection, horizontal producer only model.

First of all, the compaction model was compared with the traditional non-compaction model. It
was found that the non-compaction model would overestimate the 20 years cumulative oil
recovery by more than 20%. The overestimation with non-compaction models is proportional
to the stress sensitivity of the reservoir rocks.

Secondly, different well constraints with the compaction model were investigated. Multiple
realizations were run for each compaction model with different bottom-hole pressure. Unlike
the speculation that the stress dependent compaction would dominate long-term production,
the results showed that pressure drawdown is still the key production mechanism in stress
sensitive tight reservoirs and the hydrocarbon recovery would not be enhanced by bottom-hole
pressure maintenance. Therefore, another possible approach for improved recovery was
investigated with numerical simulation.

The potential IOR method is thought to be related to pressure maintenance, as severe
permeability decline was observed from the laboratory measurements when the pore pressure
was depleted. Gas injection simulations were run for four compaction models with different
injection rates. The results indicate that approximately 20% - 60% incremental oil would be
produced comparing to the non-injection models as long as the desired injectivity can be
achieved. Nevertheless, the injectivity could be a critical issue in extremely low permeability
reservoirs. In such cases, essentially no incremental oil would be produced with low volume of
injected gas.
Although the preliminary results of experiment based gas injection simulation showed EOR potentials in tight reservoirs, it is recommended that further field scale tests to be conducted in order to validate the laboratory and simulation works. Since improved recovery in unconventional tight reservoirs is a huge project and each research approach reveals only a small portion of the big picture, continuous efforts in different aspects and integrated research strategies are keys to success.
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CHAPTER 1 INTRODUCTION

Unconventional tight reservoirs are an integral part of hydrocarbon resources worldwide. Since the initial success in the Barnett shale formation, numerous shale and other tight hydrocarbon reservoirs have been developed in the U.S. in the last 15 years with the advanced horizontal drilling and, multi-stage completion and hydraulic fracturing technologies. Oil and gas production is booming in the U.S in recent years as a result of the increasingly mature exploration and development in unconventional tight formations.

The development and application of long lateral horizontal wells led to the revolution of hydrocarbon production in unconventional basins. The fluid flow mechanism in low permeability reservoirs is distinguishably different from that commonly observed in conventional reservoirs. Generally, the drainage area of a horizontal well in tight reservoirs is thought to be the stimulated reservoir volume (SRV), which is essentially the area surrounded by the hydraulic fracture tips and the horizontal wellbore. High initial production rate can usually be expected in shale wells, benefiting from massive hydraulic fractures and the secondary fracture networks created by the stimulation work. While infill wells are being drilled in developed reservoirs and the field recovery keeps increasing, the production in existing wells is actually decreasing rapidly as reported by public data from multiple tight formations. The ultimate recovery and long-term economics will be substantially affected if no effective measures are taken to alleviate the production decline.

Unfortunately, the mechanism of steep production decline in tight reservoirs is very complicated and it varies depending on different geological and reservoir conditions. Currently, no clear conclusion had been drawn to account for the sharp decline. However, some experiment and simulation based speculations are commonly accepted by scholars. For one thing, since the drainage area of shale well is confined by the hydraulic fracture networks, the pore pressure drop within this area is much faster than other parts of the reservoir. Meanwhile, the energy in the depleted zone cannot be easily compensated due to extremely low reservoir conductivity. In order to maintain well productivity, the bottom-hole pressure has to be lowered continuously. It is common to see 50% or higher bottom-hole pressure drop within six
months of completing a new horizontal well. Ultimately, the pore energy in the SRV is
dissipated and the production drops significantly.

Gas expansion can be another possible reason for the initial production boom in shale gas
reservoirs. In this scenario, the combined effects of massive fracture networks and gas
compressibility generate very high reservoir conductivity and fluid mobility. Therefore, large
volume of gas can be produced within a short period of time after opening the well. As can be
anticipated, substantial production rate drop will be observed shortly as the fracture
conductivity is diminished and the natural energy is exhausted.

Another possible explanation of the steep production decline is reservoir properties
degradation caused by pore pressure dissipation. One of the main geological characteristics of
tight reservoir is the thin and layered rocks with high clay contents. These reservoir rocks are
very sensitive to the pore fluid effects, such as saturation and pressure changes. It turns out
that significant pore pressure changes are usually observed during a tight reservoir depletion;
therefore, the changes of stress dependent reservoir properties (i.e., permeability and
conductivity) must be taken into account in reservoir characterization. The degree of reservoir
degradation is closely related to the production decline.

There are some other possible reasons for the high initial production and subsequent sharp
decline, such as multi-component adsorption. In fact, the phenomenon can be caused by
multiple mechanisms with different weighting factors. Moreover, some of the mechanisms are
related to the intrinsic properties of the fluid and rock, and are therefore difficult to be
eliminated, such as gas expansion effect; whereas others are possible to be altered by
improved engineering design, such as reservoir pressure depletion.

While each of the above mentioned explanations has its merit, only stress dependent
compaction phenomenon will be investigated in this work. The work contains two parts:
laboratory measurements and numerical simulations. In the first part, different types of tight
rocks were used and the sample permeability was measured at various pressure and stress
conditions. Next, the experiment-based stress dependent permeability models were generated.
The models were incorporated into traditional numerical simulation to study the effects of compaction on long-term reservoir recovery in stress sensitive reservoirs. Different simulation scenarios were conducted, including preliminary EOR tests. Based on the experimental works and simulation realizations, field application and other future works were suggested in order to alleviate the sharp production decline while improving ultimate recovery.
2.1 Effective stress

The effective stress law of a solid material describes the relationship between external applying forces, normally known as confining stress and internal counteracting forces, the pore pressure. The combined effects of confining stress and pore pressure exert various impacts on the rock properties, including, but not limited to deformation, permeability, acoustic impedance and rock mechanical properties. From the perspective of reservoir engineering, monitoring reservoir properties variations (i.e., rock matrix and fracture permeability, reservoir conductivity and etc.) due to changing effective stress is crucial for optimizing well production and making reasonable long term depletion strategy.

The concept of effective stress was first introduced by Terzaghi (1943) in soil mechanics analyses. He showed that the average effective stress carried by soil skeleton can be evaluated by measuring two other parameters: the total stress ($\sigma$) and the pore water pressure ($p$). The expression was given in the form of

$$\sigma' = \sigma - p$$

For soil, essentially 100% of pore pressure is used to counteract the applied total stress. Therefore, no multiplier was applied to the pore pressure term in soil mechanics. However, it appears that the pore pressure support in hydrocarbon reservoirs is usually offset by certain magnitude due to the porous-elastic nature of sedimentary rocks; and therefore, another empirical parameter was developed by Biot (1941) to account for the partial pore pressure effect. The effective stress equation then becomes

$$\sigma' = \sigma - \alpha p$$

Where $\alpha$ is an empirical coefficient named after Biot which value depends highly on the pore size and structure, throat deformation and rock mechanical properties. Experimentally, the Biot coefficient can be determined by measuring the bulk modulus from an unjacketed...
compressibility test ($K'_a$) and the bulk modulus of the rock ($K$) (Biot and Willis 1957; Geertsma 1957) using the expression of

$$\alpha = 1 - \frac{K}{K_s}$$

(2-3)

For ideal sedimentary rocks, the Biot coefficient can be determined by measuring the bulk modulus of the skeletal material ($K_s$) and the bulk modulus of the rock ($K$) (Nur and Byerlee 1971) in the form of

$$\alpha = 1 - \frac{K}{K_s}$$

(2-4)

In general, the ideal rock conditions refers to a homogenous and isotropic rock with no obvious unconnected porosity, chemical effects (i.e., water sensitive clay effects) or capillary pressure discontinuities, hysteresis and other time-dependent effects (Rice and Cleary 1976).

Therefore, Equations 2-2 and 2-4 hold true only for sedimentary rocks with good pore throat connection and phase continuity, as well as limited percentage of clay contents. However, the ideal conditions are often non-existent in shale and other tight reservoirs. For most tight reservoirs, the variation in the Biot coefficient can be significant due to sensitivity of rock properties to the confining stress and the pore pressure, therefore making the evaluation of effective stress more difficult than for conventional reservoir rocks.

Various authors studied the effective stress in different types of tight reservoirs. Warpinski and Teufel (1992) investigated the effective stress law for sandstone and chalks. Their permeability inverse responses suggested that the change in the Biot coefficient is mostly linear for sandstones; however, non-linear behaviors were often observed for chalks. They also found that experimentally derived Biot coefficient can differ significantly from the theoretical values, with the errors highly dependent on the non-homogeneity, pore throat structure and anisotropy. Based on these findings, one could infer that the use of conventional method-
derived Biot coefficient for effective stress dependent rock properties evaluation would be inaccurate and misleading.

He and Ling (2014) reported an experimental setup to determine the Biot coefficient for tight rock samples. While the pore pressure was set to increase with time, the volumetric strain of the rock sample was held constant by controlling the confining stress. The sample permeability was then measured and plotted against the averaged Biot coefficient. Thus, the relationship of the two variables was obtained by regression. Although this method has the ability to directly quantify the Biot coefficient, it actually requires sufficient accuracy in confinement control and strain measurement. Otherwise, the experimental errors would accumulate and significantly affect the final results.

A more straightforward trial-and-error method for determination of the experimental Biot coefficient was proposed by Abass et al. (2009). In this approach, the rock sample permeability is first measured at various pore pressure and confining stress combinations. The measured permeability series are then plotted versus net confining stress by assuming an initial Biot coefficient value. Then, the trial and error approach is applied to tune the Biot coefficient value until a reasonable permeability-effective stress relationship is obtained. Detailed discussion and experimental application of this method will be presented in Chapter 3.

2.2 Unconventional reservoir resources

Commercial exploration and development of conventional hydrocarbon resources have been conducted for more than a century. In past decades, a significant amount of unconventional hydrocarbon resources all around the world were discovered and proved to be economically producible. In general, unconventional hydrocarbon resources refer to all new types of reservoirs, including, but not limited to shale gas, shale oil, heavy oil, coal-bed methane, hydrate and etc. The unconventional reservoirs vary in geologic environment and reservoir characteristics; however, none of them can be economically produced without the assistance of novel techniques. In this work, unconventional hydrocarbon resources will be used to indicate
shale and other types of tight reservoirs (i.e., tight sandstone and tight carbonate). This research will focus on the effective stress dependent compaction in these tight reservoirs.

It has been recognized for a long time that tight reservoirs are widespread in the world. However, commercial exploration and production were not achieved until recently, when the idea of long lateral horizontal wells and multiple stages of hydraulic fractures were conceptually combined and technically applicable in the field. The foremost influential success in shale play production is attributed to Mitchell Energy and their pioneering works in the Barnett Shale Formation in the Bent Arch-Fort Worth Basin. Although discovered in 1981, the early production was not inspiring due to the technical difficulties in well completion. It was not until the late 1990s that Mitchell Energy combined horizontal wells with slickwater fracturing fluid, and the next few years witnessed the booming gas production from the Barnett Shale (Martineau 2007).

With the lessons learned from the Barnett Shale drilling and production, operators started making successes in many other unconventional gas and oil reservoirs in the US. Currently, the Bakken Formation and the Eagle Ford Formation are the most prolific tight oil resources, while the Barnett, Haynesville, Fayetteville and Marcellus formations are recognized as the top plays for shale gas production. Rapid growth in hydrocarbon production is also observed in some other tight formations, such as the Permian Basin and the Niobrara Shale play, which hold potential to be giant producers in the near future (Figure 2-1).
A wide variety of differences between conventional reservoirs and unconventional tight reservoirs have been observed. From the perspective of reservoir development stage, 5-10 years of hydrocarbon natural flow is expected for conventional reservoirs. In this period, the internal reservoir energy is spent to drain the hydrocarbon towards the producing wells. After the natural energy is depleted, the reservoir pressure maintenance stage proceeds, with the most common technique of water flooding to sweep the trapped oil in the reservoir. Finally, depending on the reservoir pressure, water cut, remaining oil and other PVT properties, various enhanced oil recovery (EOR) methods can be used to extract an additional of 10-15% hydrocarbon from the reservoirs (Taber et al. 1997). In tight oil and gas reservoirs, however, the commercial natural flow will not occur unless multiple stages of massive hydraulic fractures are
created to intersect the horizontal wellbore. The stimulated reservoir volume (SRV) is considered to be the drainage area of a horizontal well, and the induced fracture network within SRV provides additional flowing channels between the rock matrix and hydraulic fracture surface, therefore allowing commercial production from the tight rocks. Currently, most of the tight reservoirs are in the primary depletion stage and none of the existing EOR/IOR techniques have been proved to be effective for the unconventional formations.

There are also fundamental distinctions between conventional and shale reservoirs in terms of reservoir properties. The porous media within conventional reservoirs are generally considered as well connected pore throat system with the average diameter of micron level. Pore throat in shale reservoirs can be as small as 1nm, with the median value of 10nm – 200nm, according to the scanning electron microscope (SEM) (Adesida et al. 2011, Lewis et al. 2013). The permeability in the two types of reservoirs is also significantly different. By convention, a cut-off value of 0.1 md is widely accepted to distinguish conventional reservoirs from unconventional tight and shale reservoirs. Permeability values of 100 nd to 0.01 md (10000 nd) are the most common range for the major shale plays in the US (Whitson et al. 2014). Furthermore, the rocks in the target zone/pay zone of conventional reservoirs are generally more homogeneous and the pay height is relatively thick; whereas thinner, layered reservoir rocks are often found in unconventional reservoirs, with impermeable shale and clay contents embedded in between the layers.

### 2.3 Depletion performance of tight and conventional reservoirs

In conventional reservoir wells, the depletion behavior can be correlated with volumetric average reservoir pressure, with little or no dependence on the reservoir permeability and flowing bottom-hole pressure (BHP). Nevertheless, the characterization of depletion performance in tight reservoirs becomes notably complicated, because the concept of volumetric average reservoir pressure and hydrocarbon recovery factors present little value herein (Whitson et al. 2014). The work of Whitson and Sunjerga (2012) showed that the
depletion behavior of unconventional wells depends on reservoir permeability, and therefore different type of unconventional reservoirs will be governed by different depletion performances. They also suggested that producing gas oil ratio (GOR) is a strong function of flowing BHP and the degree of under-saturation, which is differs significantly from conventional sandstone or carbonate reservoirs.

Although the mechanisms of shale reservoir depletion are not fully understood, the field production data in recent years suggest somewhat unique production behavior, as noted by various authors (Baihly et al. 2010, Whitson et al. 2014). Figure 2-2 shows the overlay of gas production rate of several shale and tight sandstone reservoirs in the first 5 years (Baihly et al. 2010). It can be seen that the initial production rate climbed rapidly until the peak is achieved in the first several weeks (or months). However, the high productivity period was terminated shortly after the peak production and is then followed by a sudden and steep decline. It shows that an average of 70 percent of the gas production rate was diminished at the end of the first year. Figure 2-3 shows the study from Standard & Poor’s Credit Week (2011) which illustrates the first year production decline rate for major US shale oil and gas wells. A lower bound of 65% holds true for all shale plays, while some Haynesville and Eagle Ford dry gas wells had experienced 80% annual production reduction. As producing data and simulation results suggested in Figure 2-2, the production continues to decline after the first year until a very low rate is reached and stabilized. This decline trend is not uncommon for shale oil wells although the production decline may appear less sharp for oil production.
Figure 2-2 Overlay of gas production rate from various tight sandstone and shale gas basins in the US.

Figure 2-3 Typical production decline rate of major US shale wells. Data source: Standard & Poor’s Credit Week Dec.14, 2011.
With the information provided by the production decline rate and percentage, one could infer that the overall recovery factor for shale plays is significantly lower than for conventional reservoirs. This is quite true as suggested by field cumulative production profile and cumulative reserve estimation. Several authors have evaluated the recovery factor in both shale gas and oil reservoirs. Clark (2009) used material balance method and decline curve analysis to evaluate the recovery factor for the Bakken Shale in Mountrail County. The analyses of the two methods showed good agreement with each other, and the result of 7% recovery factor was suggested and adopted by some companies for probable reserve re-evaluation. Another illustration of low recovery factor is the Barnett shale. Although massive exploration and production activities are being conducted in the past two decades, with a total free original gas in place (OGIP$^{\text{free}}$) estimated at 444 Tcf, only 7%-10% of the reserve could be extracted by the year of 2050 as estimated by Browning et al. (2013) and Ikonnikova et al. (2014).

### 2.4 Pressure and stress dependent permeability decline

The rapid production decline and low recovery factor in tight reservoirs are indications of losing reservoir and fracture conductivity. For a particular reservoir, the radius of investigation (or ROI, which is the propagation distance of the peak pressure disturbance induced by an impulse source or sink) can be described in the form of Equation 2-5 given by (Lee 1982)

$$r_i = \frac{kt}{\sqrt{948\phi\mu c}}$$  \hspace{1cm} (2-5)

Where

- $r_i$ – Radius of investigation, ft;
- $k$ – Average reservoir permeability in the investigated zone, md;
- $t$ – Elapsed time, hours;
φ – Porosity, dimensionless;

μ – Viscosity, cp;

c_t – Total compressibility, psi⁻¹.

In low permeability reservoirs, the radius of investigation is significantly smaller than that of conventional reservoirs. High initial production rates in tight reservoirs are accomplished by highly conductive fracture networks and high pressure differential between the reservoir and the wellbore. There, the pore pressure drop is significantly higher in tight reservoirs for the same production rate, and most pressure drops happen within the stimulated reservoir volume (the reservoir sector surrounded by the horizontal well and hydraulic fractures), resulting in rapid depletion in these area.

In stress sensitive reservoirs, the pore pressure dissipation during depletion would exert impacts on the conductivity of reservoir flow components. Several authors have investigated effective stress sensitivity of porosity and permeability for conventional sandstones and tight rocks. Reyes and Osisanya (2000) found the effective stress dependence of shale physical and chemical properties by measuring different types of shale samples from Wapanuka, Wilcox, Atoka and Catoosa Formations. They reported empirical relationships which correlate shale porosity and permeability based on series of laboratory compaction tests. Although some of the curves can be fitted with both polynomial and exponential expressions, the authors suggested the use of exponential function for best representation of the underlying physics. Mokhtari et al. (2013) measured the permeability of fractured shale samples from different US shale plays under increasing confining stress. They showed that the permeability decreases exponentially with the applied effective stress. The authors also reported the trend of intrinsic permeability anisotropy of Mancos shale samples as a function of bedding angles. Wasaki and Akkutlu (2014) investigated permeability of shale matrix with organic and inorganic pores. Their results indicated that stress dependency has the greatest impact on permeability at high pore pressure, while surface diffusion and sorption effect become the dominant factor as the pore pressure
goes down. Lei et al. (2015) reported a novel analytical model for porosity, permeability and two-phase relative permeability correlation with effective stress variations in tight sandstone. Their results demonstrated that normalized porosity and permeability decrease with the increase of applied effective stress, and the wetting phase relative permeability is a complex function of effective stress, microstructural parameters and initial irreducible water saturation. However, none of the authors listed above considered the variations in the Biot coefficient for different tight rock samples, nor did they relate the stress sensitive porosity and permeability to tight reservoir depletion performance. This research will also investigate these two aspects in addition to the stress dependent permeability measurement.

2.5 Tight rocks sample permeability measurement

Laboratory measurement and well testing are the two major approaches to obtain rock permeability. Traditionally, both well testing and steady-state experimental studies could provide reliable permeability for conventional high permeable rocks. In tight reservoirs, however, it takes an extremely long period of time for the wells to reach pseudo-steady state flow, and therefore the practice of well testing becomes less meaningful. Likewise, the feasibility of steady-state laboratory permeability measurement is also lowered by the long pressure equilibrium time, although the testing media in the laboratory can be 1 inch in diameter or even smaller. There is a long existing debate in the literature regarding the use of crushed samples (i.e., quarter inch-long sample) or core chips (Luffel et al. 1993) versus traditional dimension core samples for tight rock permeability measurement. Although the crushed core may render a much faster measurement, the accuracy and the representation of the measured permeability is suspicious because the geologic texture and preexisting natural fractures are likely to be destroyed (Sinha et al. 2013, Rosen et al. 2014).

Unsteady state methodology is accepted by more researchers to calibrate shale and other tight rock permeability. In field scale application, the impulse testing technique was introduced by Ayoub et al. (1988) to characterize wells with undesirable extended flow. In their work, a rate
impulse was generated by briefly flowing the well or injecting into the formation. The authors showed that the pressure response to an instantaneous rate impulse is given by the derivative of pressure response to the differential flow rate. This technique is very useful for delineating reservoir characteristics in conjunction with some common field practices, such as drill-stem test (DST) and tubing-conveyed perforation (TCP). Gu et al. (1993) introduced an impulse-fracture injection technique to determine gas reservoir permeability. In their tests, a small fracture was created by water injection and the pressure falloff was recorded during shut-in period. The permeability and reservoir pressure can be interpreted from the pressure response after fracture closure.

Laboratory unsteady state permeability tests have been conducted for several decades. Rudd (1966) reported permeability measurement using pressure decay technique. The methodology is similar to pressure buildup test in many aspects. The sample cell was initially subjected to a sudden pressure increase, and the decaying pressure in the cell was recorded and timed until it equalized with chamber pressure, from which the permeability can be estimated. The author also suggested that more core characteristics in addition to permeability could be inferred from the pressure decay curve. Bourbie and Walls (1982) derived an analytical solution for laboratory pulse-decay permeability measurement of tight gas sandstone and shale samples. van Oort (1994) established a novel experimental method to measure in-depth permeability of shale wells. Unlike traditional steady-state approach, this methodology requires measurement of upstream and downstream pressure response, pore pressure and downstream reservoir volume to interpret shale permeability using pressure transmission technique. Their methodology was adopted in this research and the applications will be discussed in detail in Section 4-1. Rosen et al. (2014) optimized the standard design for unsteady-state to measure gas permeability of unconventional rock samples with small pore volume. They interpreted the experimental results by considering various fluid transport mechanisms and concluded that taking into account Klinkenberg and Forchheimer effects will not help improve the accuracy of results, but rather introduce more mathematical uncertainties and complexities.
2.6 Stress dependent permeability of various porous media in tight rocks

A reliable permeability is very important for reservoir exploration and development. First of all, the permeability range determines whether a particular reservoir section in tight formations should be developed. Second, rock permeability and its heterogeneity are key factors in designing the horizontal well and hydraulic fractures. Thirdly, the reservoir management requires accurate permeability estimation to keep optimizing development strategies, such as infill drilling, re-stimulation and gas flooding.

A great amount of efforts have been put on measuring absolute (or static) permeability, both in laboratory and in the field. Stress dependent (or dynamic) permeability, on the other hand, caught much less attention though it may exert significant impact on tight and stress sensitive reservoir production. Abass et al. (2007) evaluated the stress dependent permeability behavior of different porous components in carbonate formation. Their findings indicated that poroelastic signature of matrix and different types of fractures (i.e., shear, tensile and propped) varies significantly more than was commonly thought and various porous components in stress sensitive reservoirs should be recognized individually for a better reservoir simulation work. Addis and Yassir (2010) reported the permeability reduction of rock matrix and natural fractures in tight gas reservoirs and the associated impact on the well productivity. It can be inferred that poorly connected pore throat and heterogeneous pore size distribution are the main factors that cause stress sensitivity. Yao et al. (2013) discussed the importance of stress dependent matrix permeability and hydraulic fracture conductivity and how they could assist in pressure transient analysis. By applying their stress dependent fracture conductivity model to Haynesville Shale wells, the authors could match the type curve much better than using model with constant permeability.

In summary, current research indicates that stress dependent rock permeability is a common phenomenon in tight reservoirs. However, the magnitude of stress sensitivity could vary significantly in different reservoirs. Detailed reservoir rock characterizations and laboratory measurements are needed to uncover the effective stress - permeability relationship of different flow components in these reservoirs.
2.7 Coupled permeability decline flow simulation

Considering the difficulties in tight rock sample preparation and laboratory measurement, numerical modeling serves as a practical tool for tight reservoir characterization. It enables better understanding of well performance through history matching process and provides more insight into the reserve and estimated ultimate recovery through future production prediction. However, establishing an accurate numerical model that describes subsurface flow behaviors can be very difficult, especially when the target reservoir is by nature geologically complicated. First of all, most of the tight reservoirs are stimulated with massive multi-stage hydraulic fractures. The fluid flow behavior for a multi-stage fractured horizontal well is dominated by a long period of transient flow which is difficult to model. Secondly, the dimension and conductivity parameters of a single fracture are essentially unknown. Some fracture stages or clusters may experience crushing or bridging and lose their conductivity. These fractures provide only partial contribution to take the fluid and transport to the wellbore, leaving the rest trapped in the formation. It is very difficult, if not completely impossible, to realize the subsurface conditions in the simulator. Furthermore, the flow media of tight reservoirs are significantly different from conventional high conductivity reservoirs, and the fluid flow mechanisms are still under investigation. The production in tight reservoirs can be attributed to various sweet spots within the SRV connected by the created fracture networks, while the other porous components (i.e., slot pores and dead pores) may not contribute at all. Modeling various porous media requires detailed rock characterization and multi-disciplinary cooperation. For these reasons, the grid block size needs to be fine enough to capture the pressure drop near the wellbore and at the fracture surface. In addition, localized variation in porosity and permeability needs to be specified to represent different flowing components. Finally, the time step needs to be small enough to capture the characteristics of transient flow in the fractures and in the matrix.

Many authors have reported their work on modeling shale and other type of tight reservoirs for different research and practical purposes. Based on the literature survey, two broad categories for shale reservoir simulation research are identified: flow component oriented and fluid flow
mechanism oriented. Although there is no clear cut between the two directions and some authors explored both fields, the former is more concentrated on identifying different porous media, and how their storage capacity and conductivity affect the ultimate production from the wellbore. The latter, on the other hand, focuses more on identifying the exact flow mechanism in tight reservoirs and the combined effects of viscous flow and other types of flow (i.e., diffusion). Dual porosity, dual permeability (DP/DP) model is adopted by a few researches for modeling tight-fractured formations (Segatto and Colombo 2011; Sun et al. 2014; Fuentes-Cruz and Valko 2015). Although some researchers believed that DP/DP model is the best approach to simulate fractured shale reservoirs (Sun et al. 2014), there is ongoing debates regarding the use of DP/DP versus other models, such as local grid refinement, discrete fracture model (Li et al. 2011; Darishchev et al. 2013), or the most common single porosity model. Molecular diffusion is an important mechanism for hydrocarbon movement in shale gas media. The Knudsen diffusion was conceptually accepted by most researches and was formulated into some research simulators (Shabro et al. 2011; Sun et al. 2014). However, controversy does exist on the question of whether Knudsen diffusion is suitable for modeling shale gas production. For illustration, Shi et al. (2013) suggested to use a new diffusion-slippage-flow model combined with gas transport mechanism to replace Knudsen diffusion for shale gas production forecasting.

Among the papers in the literature discussing shale reservoir simulation, there is hardly any focus given on the stress-dependent rock properties change and the subsequent productivity response. Since numerical simulation is the most feasible approach to upscale laboratory results to field production problems, this research will attempt to combine experimental work and numerical modeling to investigate how stress-sensitivity of rock permeability could affect shale well production.

2.8 Enhanced hydrocarbon recovery in tight reservoirs

As has been discussed in the previous sections, the hydrocarbon production in tight reservoirs is always characterized by rapid decline. One of the objectives in this thesis is to investigate
possible approaches to alleviate the sharp depletion and enhance the ultimate recovery. In recent years, the topic of improving oil recovery (IOR) in shale and tight reservoirs has received increasing attention from researchers and field operators. However, the research in this area is still in the preliminary stage as the rock physics and fluid flow mechanisms in these reservoirs are not well understood. Moreover, most of the studies are either numerical simulation or laboratory rock sample measurement. Very few field scale injection or flooding tests were reported, probably because of the prohibitive cost and lack of fundamental understanding of the potential EOR mechanism.

Sheng et al. (2015) evaluated different EOR schemes for a Wolfcamp Formation reservoir. Their result showed that cyclic gas injection has the best potential to improve oil recovery. Pu and Li (2015) identified the capillarity and adsorption as the key production factors in some Bakken oil reservoirs. Their simulation study showed that CO$_2$ huff-n-puff process would substantially increase the well production. The results also indicate that CO$_2$ soaking time and injection cycles, as well as the injection volume are important factors for production improvement. Hoffman (2012) evaluated the EOR potential of shale reservoirs with different gas injection schemes in numerical simulations. The analyses suggested that miscible hydrocarbon or CO$_2$ flood appear to be an effective method to improve oil recovery in the Bakken Formation as the economics seemed promising. However, the recent studies of seven injection pilot tests in the Bakken Formation revealed that none of these trials produced incremental oil from the shale wells and yet the mechanisms for the unsuccessful injection tests are not well understood (Hoffman and Evans 2016). It appears that early breakthrough occurred in most cases probably due to the massive hydraulic fractures. Nevertheless, the complex fracture network can hardly be understood by numerical simulation and laboratory measurements; it was suggested that additional pilots to be conducted in the Bakken Formation in order to better understand the mechanisms and to further evaluate the EOR potential.

Although most researches are concentrated on gas injection, there are also ongoing researches of other EOR approaches in tight reservoirs. Neog and Schechter (2016) investigated the potential of using surfactants in stimulation fluid to improve oil recovery in tight oil reservoirs
such as the Wolfcamp Formation. Their experiments showed that nonionic surfactant has the potential to alter the wettability from intermediate wet to the preferentially water-wet conditions and hence hold potential for future EOR applications. Ziegler (2016) developed analytical models of stream flooding in fractured tight shale and dolomite reservoirs in California. The models were validated against field tests and thermal simulations. Significant production improvement has been observed after stream flooding and the economic review showed favorable profit under the current market oil price. Although the conclusion of using steam flood looks promising, close examination revealed that the reservoir permeability in the study is in millidarcy level whereas the major tight oil resources such as the Bakken and the Eagle Ford Formation have much lower permeability. Thermal EOR might encounter more challenges in such low permeability reservoirs.
CHAPTER 3 EXPERIMENTAL SETUP

In this research, laboratory core measurements and numerical simulations are combined to investigate the stress dependent rock permeability and its impact on reservoir recovery. The contents in Chapters 3 – 5 include the experimental setup, methodology and measurement procedures followed by results interpretation and discussion. Chapter 6 discusses numerical simulation using the experimentally determined permeability data. This chapter introduces the equipment and device used during laboratory measurement.

In early stage of the experimental work, the CMS-300 instrument designed by Core Lab was used to measure stress dependent tight rock permeability. The CMS-300 instrument uses pressure decay technique to measure sample permeability under a variety of confining stress. The measurement for shale samples can be finished within a reasonable time (i.e., several hours). However, the major drawback of CMS-300 is that it doesn’t have the capability to apply varying pore pressure. It has been widely recognized that the effective stress variations during field depletion cannot be represented by solely varying confining stress. In fact, changing pore pressure under a specific geological condition is the key to investigate the permeability decline behaviors. Therefore, another permeability measurement system was acquired which has the capability to apply both varying confining stress and pore pressure. Both the CMS-300 instrument and the new core holder assembly will be introduced in this chapter. The measurement results from the CSM-300 instrument will be briefly discussed to illustrate the stress sensitivity of tight reservoirs rocks; while the core holder assembly serves as the main equipment for the effective stress dependent permeability measurement. The methodology used to calibrate rock permeability with the core holder assembly will be described in detail.
3.1 The CMS-300 instrument

3.1.1 The CMS-300 assembly

The CMS-300 instrument was designed by Core Lab and acquired by Petroleum Engineering Department. The most outstanding feature of this assembly is that the measurement and data interpretation are integrated and automatic. The system is readily available for rock sample permeability and porosity measurements at various confining stress conditions.

Figure 3-1 is the configuration of the CMS-300 assembly. The housing of the equipment consists of six panels mounted on a welded steel frame as shown in Figure 3-2. The interior part has two sections: the front section where the measurement take place contains Sample Holder, the Confining Pressure System and the Helium System; and the rear section in which the Heat-generating electric and electronic components are installed. The schematic diagram of core holder assembly is shown in Figure 3-3 and Figure 3-4 illustrates how it is mated to the helium manifold. Two interchangeable Hassler-type core holders (Figure 3-5) can be equipped with the CMS-300: one fits 1-inch diameter cores and the other accommodates 1.5-inch diameter samples. Both core holders require the sample length to fit into 0.75-inch to 3.00-inch. Multiple samples can be placed into the sample slots and the photosensor system controls the sequential insertion and removal of samples in and out of the Hassler Holder. The Confining Pressure System provides up to 10,000 psi confining stress axially by the Axial Intensifier (Figure 3-6), and radially by pressurized hydraulic oil surrounding the sample holder. The pore pressure, nonetheless, can only be held at low level (i.e., approximately 100 psi) throughout the measurement. The CMS-300 instrument uses standard industrial grade dry helium gas for pore volume and permeability measurements.
Figure 3-1 Configuration of the CMS-300 instrument.
Figure 3-2 CMS-300 instrument frame and panel assembly (CMS-300 core measurement system operation and maintenance manual. Core Lab. October 1992).
Figure 3-3 Sample holder assembly (CMS-300 core measurement system operation and maintenance manual. Core Lab. October 1992).
Figure 3-4 Core holder to helium manifold mating (CMS-300 core measurement system operation and maintenance manual. Core Lab. October 1992).
Figure 3-5 Hassler type core holder (CMS-300 core measurement system operation and maintenance manual. Core Lab. October 1992).
3.1.2 Confining stress dependent permeability measurement

The porosity and permeability of six shale samples were measured at different confining stress conditions using the CMS-300 instrument. The four Niobrara samples are considered matrix dominant while the two Woodford samples contain obvious fractures. The results for the Niobrara samples are in Figure 3-7 and Figure 3-8. It can be seen that while the porosity shows moderate decline, the permeability drops more than 10 times with confining stress going from 500 psi to 2,000 psi. Figure 3-9 and Figure 3-10 show confining stress dependent permeability measurements of fractured Woodford samples. The first sample has axial fractures across the core and severe permeability decline can be observed. The second sample was parted due to excessive fractures and was wrapped before measurements. Moderate permeability decline can be seen which shows great contrast to the first Woodford sample which does not contain opening fracture system. This comparison indicates that intensified fractures in tight reservoirs would trend to lessen the permeability decline.
Figure 3-7 Porosity decline of four Niobrara shale samples with increasing confining pressure.

Figure 3-8 Permeability decline of four Niobrara shale samples with increasing confining pressure.
Figure 3-9 Permeability decline of Woodford shale sample #1 with increasing confining pressure.

Figure 3-10 Permeability decline of Woodford shale sample #2 with increasing confining pressure.
It should be noticed that the duration for each measurement of the above mentioned micro to nano Darcy shale samples is only a few hours as the CMS-300 instrument uses pressure decay method to determine the tight sample permeability. This advantage, along with its relatively straightforward and user friendly operation, makes this instrument an ideal assembly for initial porosity and permeability characterization. Nevertheless, the standalone confining stress condition cannot be used to represent the effective stress conditions during field depletion as the pore pressure plays an important in the compaction and dilation process. The CMS-300 instrument maintains the pore pressure at a very low level (i.e., approximately 100 psi on average) and the pore pressure cannot be changed throughout the measurement. Therefore, it is necessary to build a new set of equipment which has the ability to apply both varying confining stress and pore pressure to the sample holder.

3.2 The new core flooding system

3.2.1 Instrument assembly

The new core flooding system was acquired in the middle of 2015. The new assembly consists of Core Lab HCH series biaxial sample holder, nitrogen supplying system, hydraulic oil supplying system and data recording system. With the Core Lab sample holder, the axial and radial confining stress can be applied through the body wall, along the outer diameter and the end of the core holder. Two confining pressure ports are provided so that the annulus space can be filled with hydraulic oil and the air easily displaced. The distribution plug is connected to a quarter-inch tube which floats inside the end cap. This design allows the distribution plug to move inside the core holder and remain in constant contact with the core sample while the confining stress is applied to the core holder.

The schematic diagram of the Core Lab sample holder is in Figure 3-11 and the cross-sectional view is shown in Figure 3-12. The HCH series core holder accommodates rock samples of 1.0-inch and 1.5-inch and the minimum sample length is 1.0-inch. Figure 3-13 shows the assembly ready to conduct experiment. Three pressure measurements take place during the experiment:
the confining stress provided by hydraulic oil, the inlet (upstream) pressure and outlet (downstream) pressure provided by the nitrogen. The pressures are converted into electrical signals via pressure transducers and recorded by the data collecting system.

### 3.2.2 Permeability measurement methodology

Laboratory pressure transmission test technique is used for permeability measurements under different confining stress and pore pressure conditions. This methodology consumes small amount of pore fluid and takes relatively short time to measure the tight samples.

The procedures of pressure transmission test are described as follow. The 1.5-inch-diameter tight rock samples are prepared and plugged into a rubber sleeve biaxial core holder. The confining stress is provided hydrostatically by hydraulic oil. The upstream of core holder is connected to the pore pressure fluid supplying system and a constant pressure is applied to saturate the entire sample until the initial equilibrium condition is reached. Nitrogen gas is selected as the pore fluid in consideration of its physical and chemical properties as well as the relatively low cost. When the entire core is saturated, the upstream nitrogen pressure is kicked to a higher pressure instantaneously while the downstream pressure still holds. As a response to the increased upstream pressure, the pressure build-up at the downstream would be observed. The upstream and downstream of the core holder, as well as the annulus space are connected to the pressure transducers and the pressures are recorded by computer data acquisition system during the pressure transmission test. The downstream equilibrium time is also recorded for each test as an indicator of permeability change due to different pore pressure and confining stress conditions. The permeability of the rock sample can be interpreted using the following formula (van Oort 1994):

\[
\Delta \ln \left[ \frac{P_u - P_p}{P_u - P(l,t)} \right] = k \frac{A \Delta t}{\mu c V l}
\]

Where:
\( P_u \) — upstream pressure, Pa;

\( P_p \) — initial pore pressure, Pa;

\( P(l, t) \) — pore pressure at given position as a function of time, Pa;

\( \Delta t \) — time interval, sec;

\( k \) — permeability, Darcy;

\( \mu \) — pore fluid viscosity, Pa s;

\( c \) — pore fluid compressibility, \( \text{Pa}^{-1} \)

\( V \) — downstream reservoir volume, m\(^3\);

\( l \) — sample length, m

\( A \) — core sample cross-sectional area, m\(^2\)

In this work, \( P(l, t) \) is measured at the outlet of core holder to represent the downstream pore pressure.

The downstream reservoir volume is the summation of flow line volume from the sample downstream to the pressure transducer. The measured downstream reservoir volume of the assembly is \( 4.2 \times 10^{-6} \text{ m}^3 \) (or 0.256 in\(^3\)).

It should be pointed out that the calculated sample permeability depends highly on the pore fluid properties as indicated from the equation above. For nitrogen, the gas compressibility and viscosity are strong functions of applied pore pressure. Therefore, pressure dependent nitrogen properties at laboratory condition are essential for reliable sample permeability interpretation. Jones (1997) suggested the compressibility and viscosity values for ideal nitrogen gas at 72°F laboratory temperature and different pressure conditions. The pressure dependent nitrogen properties used in this work are illustrated in Figure 3-14 and Figure 3-15 respectively, up to 5,000 psi.
The experiments were conducted under four confining stress conditions; and each of them contains a series of pore pressure sequence. Each individual combination represents a unique reservoir condition and the overall data trend will illustrate the stress-dependent compaction during tight reservoir depletion. Chapter 4 shows the tight rock samples used in the experiments, followed by examples of measured pressure build-up data. Chapter 5 presents the interpretations of the experiment data first; then, the importance of stress-dependent compaction and potential application in tight reservoir development is discussed.

Figure 3-11 Sketch of Core Lab HCH series biaxial sample holder (Standard core holder - HCH series. http://www.corelab.com/cli/core-holders/standard-core-holder-hch-series. From Core Lab).

Figure 3-12 Cross-sectional view of the new core holder (Standard core holder - HCH series. http://www.corelab.com/cli/core-holders/standard-core-holder-hch-series. From Core Lab).
Figure 3-13 Core lab sample holder assembly.

Figure 3-14 Nitrogen compressibility at 72°F laboratory condition, modified from Jones (1997).
3.3 Summary

In order to investigate effective stress dependent permeability for the tight rock samples, two sets of laboratory instruments were used. The CMS-300 instrument was first employed since the instrument is readily available and the data interpretation modulus is integrated into the data measurement system. Furthermore, the system uses unsteady-state pressure decay technique which significantly shortens the measurement time for low permeability rock samples. Several Niobrara shale samples were tested to illustrate the importance of stress dependent compaction phenomenon and the necessity of conducting further measurements. The experiment with the CMS-300 instrument was terminated due to its inability to apply varying pore pressure in addition to confining stress. A new core holder system which is compatible with both changing confining stress and pore pressure conditions was acquired to
build the new core flooding assembly. The schematic diagram of the new system was shown and the methodology used to calibrated stress dependent sample permeability was discussed. Chapter 4 discusses the tight rock samples, measurement conditions and examples of measurement results.
CHAPTER 4  ROCK SAMPLES AND MEASUREMENT RESULTS

4.1  Rock samples

4.1.1  Sample acquisition

The samples used for laboratory were acquired from Niobrara Formation shale outcrops in Lyons Quarry, northern Colorado. Figure 4-1 is the photo of Niobrara Formation outcrops. Approximately twenty shale blocks with different dimensions were gathered and stored in the laboratory for multiple research purposes. For shale rock stress dependent permeability experiments, a series of 1.0-inch and 1.5-inch diameter vertical and horizontal core plugs with variable length were drilled in the laboratory. The shortest core is 0.8 inch while the longest one is approximately 2.0 inch. Several 1.0 inch diameter cores (Figure 4-2) were measured with the CMS-300 instrument and the results were provided in Section 3.1.

Figure 4-1 Niobrara Formation outcrops at Lyons Quarry.
Figure 4-2 Niobrara shale samples tested by the CMS-300 instrument.

Figure 4-3 Woodford shale sample #1 with axial fractures.
Figure 4-3 and Figure 4-4 show the Woodford shale samples that were also measured using the CMS-300 instrument. Both samples had axial fractures along the core upon acquisition and therefore the samples were wrapped before conducting measurements. Figure 3-9 and Figure 3-10 have demonstrated the confining stress dependent permeability of the two Woodford samples. The measured permeability was considered as fracture permeability. Because the insertion and removal process of the CMS-300 instrument have further lowered the core stability, the Woodford samples were no longer integral after the measurements. Therefore, these two samples were not selected for effective stress dependent permeability measurement with the new core flooding assembly. Nonetheless, the permeability behaviors of different types of tight rocks would be studied using different Niobrara shale samples and tight carbonate sample.
4.1.2 Sample used for pressure dependent permeability measurements

The Core Lab HCH series core holder uses samples of 1.5-inch diameter and the ideal sample length is between 1.0-inch and 1.5-inch. This is to ensure a reasonable testing time for each measurement. Among these cores, three most representative samples were selected to conduct the confining stress and pore pressure dependent permeability measurements. Figure 4-5 is a horizontal Niobrara sample with the length of 1.88 inches and Figure 4-6 shows a vertical 1.0-inch-long Niobrara sample with sealed fractures filled with calcite minerals. While the fractures of the second sample can be easily identified, close examination of sample # 1 shows no obvious fracture system. A tight carbonate sample shown in Figure 4-7 was also measured as to compare with the shale samples.

Figure 4-5 Rock matrix dominated Niobrara shale sample #1.
Figure 4-6 Niobrara shale sample #2 with sealed fractures.

Figure 4-7 Carbonate sample.
4.2 Experiment conditions

The experiments were conducted in the laboratory with the Core Lab HCH series core holder assembly (as discussed in Section 3.2) at approximately 70°F - 75°F (or 21°C - 24°C) room temperature conditions. Different confining stress and pore pressure combinations were applied to measure the effective stress dependent permeability of the samples. The confining stress was provided hydrostatically by the hydraulic oil and the pore pressure was provided by the nitrogen gas.

Table 4-1 summarizes the confining stress and pore pressure condition of each measurement. Four groups of permeability measurements were conducted using pressure transmission test technique under confining stress of 5,000 psi, 4,000 psi, 3,000 psi and 2,000 psi, respectively. For each confining stress scenario, several pairs of upstream and downstream nitrogen pressure were applied while the pressure differential is held constant at 400 psi for all the tests. The average pore pressure for each individual confining stress is a representation of the status of reservoir depletion. Low pore pressures indicate highly depleted reservoir conditions while high pore pressures correspond to the original states of the reservoir. The maximum upstream pore pressure was set at 4,900 psi, 3,900 psi, 2,900 psi and 1,900 psi, respectively, such that a minimum net pressure (i.e., the difference between confining stress and pore pressure) of 100 psi was left for each confining stress case. The purpose of this is to prevent the potential leakage and the undesired fluid communications inside and outside the core holder. The duration of each permeability measurement was also recorded. Unlike the interpreted permeability which is an indirect measurement from the pressure the transmission tests, the measured equilibrium time would be used as a direct indicator of the pressure dependent compaction in shale and tight reservoirs. The analyses of permeability measurement from pressure build-up test and the recorded sample downstream pressure will be discussed in detail in Chapter 5.
4.3 Pressure transmission test

The rock samples permeabilities were determined through the pressure transmission test under different pore pressure and confining stress combinations. The confining stress was applied first, followed by the soaking period through core holder inlet until the entire sample reaches the preset upstream pressure. The pressure transmission test started by setting upstream pressure 400 psi higher than the downstream pressure, and the downstream
pressure were recorded until it equalizes with the upstream pressure. The pressure build-up data were used to determine sample permeability using the methodology described in Section 3.2.2 and Equation 3-1. The measurements continued by following the pore pressure sequence shown in Table 4-1, until the highest pore pressure is reached. Figure 4-8 and Figure 4-9 show examples of the pressure build-up behaviors of Niobrara sample # 1 as a function of time at 5,000 psi confining stress and different pore pressure conditions. It can be seen that the downstream equilibrium time is more than 30 hours at very low pore pressure; while the duration is reduced to approximately 6 hours when the average pore pressure is 4,300 psi. The downstream equilibrium time reduction as a function of applied pore pressure can be found from naturally fractured Niobrara and carbonate samples as well, indicating the permeability decline. The results of pressure transmission test of the Niobrara sample # 2 at 700 psi and 4,300 psi are shown in Figure 4-10 and Figure 4-11, respectively; while Figure 4-12 and Figure 4-13 are selected results of the carbonate sample measurement.

To calculate the sample permeability using pressure data shown in Figure 4-8, the nitrogen compressibility and viscosity at 700 psi were selected, which is $0.0013 \text{ psi}^{-1}$ and $0.0185 \text{ cp}$, respectively. For all other build-up measurements, the nitrogen properties were obtained from Figure 3-14 and Figure 3-15 at $(P_{\text{upstream}}+P_{\text{downstream}})/2 \text{ psi}$. The detailed interpretations of pressure transmission tests are presented in chapter 5.
Figure 4-8 Pressure transmission test of Niobrara sample #1 under 5,000 psi confining stress and 500 psi – 900 psi pore pressure.

Figure 4-9 Pressure transmission test of Niobrara sample #1 under 5,000 psi confining stress and 4100 psi – 4500 psi pore pressure.
Figure 4-10 Pressure transmission test of Niobrara sample #2 under 5,000 psi confining stress and 500 psi – 900 psi pore pressure.

Figure 4-11 Pressure transmission test of Niobrara sample #2 under 5,000 psi confining stress and 3700 psi – 4100 psi pore pressure.
Figure 4-12 Pressure transmission test of the carbonate sample under 5,000 psi confining stress and 500 psi – 900 psi pore pressure.

Figure 4-13 Pressure transmission test of the carbonate sample under 5,000 psi confining stress and 4500 psi – 4900 psi pore pressure.
CHAPTER 5 EXPERIMENT DATA ANALYSIS AND DISCUSSION

5.1 Permeability interpretation

In this section, the stress dependent permeability measurements for the three tight rock samples are interpreted. The change in permeability and sample downstream equilibrium time under various conditions are discussed in detail.

5.1.1 Niobrara shale sample #1 (matrix)

The matrix dominated Niobrara shale sample was measured under different confining stress and pore pressure combinations sequentially and the results are in Figure 5-1. The interpreted permeability is approximately 45 nD at the highest pore pressure condition whereas the lower bound can be less than 20 nD while the pore pressure is low. For each individual confining stress, the change in permeability is almost linear below certain pore pressure window while a significant improvement can be observed as the critical pore pressure value is exceeded. The kick-off pore pressure varies in different confining stress scenarios. Therefore, the critical pore pressure window is different for different subsurface conditions.

In order to provide a general indication of the critical condition, the applied pressure conditions were normalized and expressed as a ratio of confining stress to average pore pressure as shown in Figure 5-2. The horizontal axis in the figure is an indication of reservoir depletion status as small numbers correspond to the initial reservoir conditions while the increasing numbers imply continuous reservoir depletion. The typical initial confining stress to pore pressure ratio (Pc/Pp ratio) falls into the range of 1.2 to 1.6. For illustration of the pore pressure effects on tight rock permeability, the x-axis includes the Pc/Pp ratio between 1 and 8. It shows that the critical Pc/Pp window lies between 1.5 and 2 where significant permeability improvement can be obtained as the ratio moves towards the original reservoir conditions. To the contrary, as the pore pressure drops below the critical range in a given reservoir, smooth and linear reduction in permeability would be seen as the depletion continues.
The depletion effect on shale rock permeability can be illustrated from another perspective. Figure 5-3 shows the sample downstream pressure equilibrium time for each pore pressure and confining stress combination. It took more than 30 hours for the core downstream to equalize with the upstream pressure in case of highest effective stress (i.e., under 5,000 psi confining stress and 700 psi average pore pressure condition). However, the equilibrium time was shortened to 3 hours under 4,000 psi confining stress and 3,700 psi average pore pressure. As stated above, the nitrogen pressure differential between sample upstream and downstream was held constant for all the tests; therefore, the continuous decline of sample downstream pressure equilibrium time is a strong evidence of permeability improvement with the increase of applied pore pressure. Once again, the critical pore pressure window exists for any specific reservoir from where the rock permeability is considerably enhanced. To illustrate the critical point, the downstream pressure equilibrium time as a function of confining stress to average pore pressure ratio is provided in Figure 5-4. As the equilibrium time is a reciprocal function of rock permeability, the trend in Figure 5-4 is similar to that of Figure 5-2 but the shape of curve is flipped 180 degree through x-axis. The variation in equilibrium time for each individual confining stress cases follows approximately logarithmic increase trend until the crucial pore pressure window is reached and the separation in data points are observed. Interpretation of the data series suggests the critical Pc/Pp ratio of approximately 2, where significant change of the slope can be identified.

Figure 5-5 illustrates the time downstream pressure reaches the average pore pressure ((Pupstream+Pdownstream)/2). Same conclusion of critical Pc/Pp ratio can be drawn from the data which shows similar behavior to Figure 5-4. Because the recorded equilibrium time is a direct evidence of the rock permeability, it affirms the previous discussions from the permeability interpretations. Overall, the experiments imply that by maintaining the pore pressure above 50% of the confining stress condition, the reservoir rock permeability will be significantly improved and hence better reservoir conductivity can be obtained. As the well productivity is closely related to the in-situ permeability and reservoir conductivity, effective reservoir pressure maintenance practices hold the potential to alleviate the sharp production in shale well.
Figure 5-1 Niobrara shale sample #1 permeability as a function of average pore pressure under different confining stress conditions.

Figure 5-2 Niobrara shale sample #1 permeability as a function of ratio of confining stress to average pore pressure.
Figure 5-3 Niobrara shale sample #1 downstream pressure equilibrium time as a function of average pore pressure under different confining stress conditions.

Figure 5-4 Niobrara shale sample #1 downstream pressure equilibrium time as a function of confining stress to average pore pressure ratio.
5.1.2 Niobrara shale sample #2 (with sealed fractures)

The second core sample is the naturally fractured Niobrara shale (Figure 4-6). Both the first and second samples are drilled from the same Niobrara Formation outcrop block acquired from the Lyons Quarry. The major distinction between the two is the axial sealed fractures across the second sample, and thus the sample permeability is considered to be dominated by the natural fractures. Laboratory measurements show that the permeability of this fractured sample is several orders of magnitude higher than the first one (Figure 5-6). The entire series of permeability values fall into the range between 0.2 md and 2.5 md, which is the preferable commercial exploration and production condition. Similar to the first sample, the pressure dependent permeability of the fractured sample also show different trends within different pore pressure intervals. For instance, at 5,000 psi confining stress condition, the permeability change is mostly linear while the pore pressure is below 2,500 psi. Keep increasing the pore pressure results in rapid increase of the rock permeability. Different confining environments
have different critical pore pressures and the kick-off point can be found from the relationship between rock permeability and normalized reservoir depletion status (Pc/Pp ratio).

Figure 5-6 Niobrara shale sample #2 permeability as a function of average pore pressure under different confining stress conditions.

Figure 5-7 Niobrara shale sample #2 permeability as a function of ratio of confining stress to average pore pressure.
As discussed above, the ratio of confining stress to average pore pressure was utilized to quantify the depletion status of a reservoir. The horizontal axis in Figure 5-7 illustrates reservoir pressure reduction process while the vertical axis shows the measured rock permeability at different stages during reservoir depletion. The data series show that the turning point corresponds to \( \frac{P_c}{P_p} \approx 2 \), which is consistent for all confining stress conditions. This implies that the reservoir would experience significant permeability impairment once the pore pressure drops below this critical pressure window. The relationship under different confining stress conditions also indicates that for various tight reservoirs, the original reservoir permeability is at least two times higher than the permeability at critical pore pressure conditions. Therefore, it can be inferred that pore pressure maintenance in tight reservoirs could benefit reservoir conductivity and well productivity.

The permeability of Niobrara shale sample # 2 is significantly higher than sample #1 as a result of the sealed fractures across the core; the improvement is also reflected on the downstream nitrogen pressure equilibrium time as Figure 5-8 shows. For the same confining stress and pore pressure, the equilibrium time for the fractured sample is generally reduced to less than 10% of the matrix dominated sample, indicating significant permeability improvement. The equilibrium time is approximately 2 hours with the highest effective stress and it decreases with the increase of applied pore pressure. Similar to the Niobrara sample # 1, the reduction of downstream pressure equilibrium time is nonlinear with the decrease of the effective stress conditions. Further quantification of the critical pore pressure window for this sample can be found in the relationships between equilibrium time and \( \frac{P_c}{P_p} \) ratio (Figure 5-9 and Figure 5-10). In this case, the critical confining stress to average pore pressure ratio is between 2.5 and 3, above which the curve starts turning flat.

Comparing the critical pore pressure of the two Niobrara samples, one could identify that the latter generally yields higher confining stress to average pore pressure ratio. This is an implication of pore pressure sensitivity of different types of tight reservoirs. For the areas that are predominated by rock matrix, a smaller depletion effect could lead the permeability dropping below the critical value; while for the fractured tight rocks, further pore pressure
depletion is allowed before reaching the closure condition of the major flowing components. The critical pressure analyses can be also utilized to guide the pressure maintenance practices in different tight reservoirs. The measured permeability and equilibrium time suggest that the fractured reservoirs in general require less pore pressure support to break through the low permeability region. On the other hand, larger amount of the injection fluid is probably required to enhance the reservoir rocks permeability if little trace of fractures exists in the tight reservoir.

Figure 5-8 Niobrara shale sample #2 sample downstream pressure equilibrium time as a function of average pore pressure under different confining stress conditions.
Figure 5-9 Niobrara shale sample #2 sample downstream pressure equilibrium time as a function of confining stress to average pore pressure ratio.

Figure 5-10 Niobrara shale sample #2 downstream pressure build-up time to (Pupstream+Pdownstream)/2 as a function of confining stress to average pore pressure ratio.
5.1.3 Carbonate sample

Following the same interpretation procedures, the pressure dependent permeability measurements for the carbonate sample were analyzed and the results are shown in Figure 5-11 - Figure 5-14. Similar to the shale samples, the rock permeability as a function of applied pore pressure follows a constant slope below the critical pressure window and the kick-off point for the complex rapid increase varies for different confining stress conditions (Figure 5-11). The critical Pc/Pp ratio for the carbonate sample was interpreted from Figure 5-12, rendering an approximate range of 2 - 2.5 which is similar to the fractured shale sample. In addition, the measured permeability ranges between approximately 100 nD and 900 nD, suggesting that the tight carbonate sample is primarily matrix dominated. The decrease in downstream equilibrium time with increasing pore pressure shown in Figure 5-13 and Figure 5-14 confirms the stress dependent compaction in the tight carbonate sample.

Overall, the stress dependent permeability and equilibrium time of the carbonate sample behaves more like the fractured Niobrara shale sample and less like the matrix dominated one. Both the fractured shale and carbonate samples have high critical Pc/Pp ratio compared to the shale matrix sample, allowing higher pressure drop before reaching the critical compaction condition. This indicates that even tiny or sealed fractures have the potential to improve the stress-dependent conductivity in the shale reservoirs.

From Figure 5-14 and Figure 5-15, we can see that the trend of the carbonate sample downstream pressure build-up is more linear comparing to that of the two Niobrara samples. The possible explanation of this phenomenon is that the carbonate sample is more homogenous than the Niobrara shale samples which are considered to have a significant amount of clay contents. In addition, the comparison indicates that the pore structure of this carbonate sample is more regular whereas the shale samples have more irregular porous systems.
Figure 5-11 Carbonate sample permeability as a function of average pore pressure under different confining stress conditions.

Figure 5-12 Carbonate sample permeability as a function of ratio of confining stress to average pore pressure.
Figure 5-13 Carbonate sample downstream pressure equilibrium time as a function of average pore pressure under different confining stress conditions.

Figure 5-14 Carbonate sample downstream pressure equilibrium time as a function of confining stress to average pore pressure ratio.
5.2 **Biot Coefficient determination**

The Biot poroelastic coefficient determines how efficient the pore fluid pressure is counteracting the stress applied by the sedimentary rocks. Theoretically, the Biot coefficient can be determined experimentally by measuring dry rock bulk modulus and mineral bulk modulus. In many conventional basins, the dry rock bulk modulus is usually significantly lower than the bulk modulus, rending the Biot coefficient close to unity. Nonetheless, this can be completely different situation in tight reservoirs because of compaction effect and complex minerology. Because the Biot coefficient can be directly measured only if the ideal rock conditions are present (i.e., homogeneous and isotropic sedimentary rocks with good porous media continuity and no phase discontinuities or chemical effects (Rice and Cleary 1976), the complexities associated with unconventional reservoir rocks make direct laboratory
measurement of the Biot coefficient very difficult. However, it is wise to recognize that indirect measurement approach is available for the Biot coefficient determination and the method is applicable to the tight reservoir rocks.

In addition to determine tight rock permeability, the laboratory pressure transmission test at various pressure pairs can also be employed to determine the Biot coefficient. In this research, a trial and error methodology proposed by Abass et al. (2009) was applied to determine the coefficient using the interpreted stress dependent permeability measurement.

First of all, the pressure dependent permeability was plotted against the effective stress, where the initial Biot coefficient was assigned arbitrarily. Theoretically, one permeability value should always correspond to one effective stress for the same rock if the reasonable Biot coefficient is given. Based on this principle, the tentative effective stress was updated by tuning the Biot coefficient while the distributions of the scatters were observed until the desired shape was obtained. Ideally, the scatters are supposed to collapse into a single curve (or band) if sufficient amount of data points are available.

Several plots are presented in Figure 5-16 to illustrate the trial and error procedure to determine Biot coefficient of Niobrara sample # 1. Figure 5-16 (a) is the initial trial of the Biot coefficient equals to 0.2. In this case, great horizontal separations are observed where a single permeability corresponds to several effective stress values. This is against the one sample premise and therefore the Biot coefficient is updated accordingly. Figure 5-16 (b) shows another attempt of Biot coefficient equals to 0.5. It shows that the horizontal separations are attenuated and certain portions of the data fall together; however, further collapsing of the data points requires increasing the Biot coefficient. Figure 5-16 (c), the factor is adjusted to 0.8 and the majority of the data points collapse into a band. Therefore, this value was determined to be the approximate Biot coefficient for this core. To further illustrate the trial and error methodology, Figure 5-16 (d) is shown with the Biot coefficient of 1. Comparing it with Figure 5-16 (c) one could identify the greater vertical separation between data points in Figure 5-16 (d), which is also in contradiction of the one permeability-one effective stress rule.
Similarly, the Biot coefficient for the Niobrara shale sample # 2 was determined experimentally following the trial and error procedure described above. Figure 5-17 shows the cross plot of measured permeability and effective stress while the Biot coefficient is set to be 0.2, 0.5, 0.8 and 1, respectively. The data fitting suggest that 1 is the most appropriate value of the Biot coefficient for the fractured Niobrara sample as smaller values lead to greater separations between measured permeability under different confining stress conditions.
Using the same technique, the Biot coefficient for the carbonate sample was determined and illustrated in Figure 5-18. Figure 5-18 (a)-(d) show the permeability vs. effective stress behavior with the Biot coefficient equals to 0.2, 0.5, 0.7 and 1, respectively. It can be seen that perfect data fitting was obtained in the case where Biot coefficient equals to 1; otherwise, the one permeability-one effective stress principle would be violated.
5.3 Stress dependent permeability models for tight rocks

The pressure transmission tests demonstrate significant permeability decline during tight reservoir depletion. The next step is to evaluate the influence of permeability decline on well productivity during short term and long term depletion. This objective can be achieved by numerical reservoir simulation. The next chapter contains details about the modelling procedure and results discussion.

In order to incorporate laboratory measurements with flow simulation, the stress dependent permeability models for different flow components must be generated. Because the Biot coefficient of three different types of tight samples was already obtained from Figure 5-16,
Figure 5-17 and Figure 5-18, the normalized permeability - effective stress cross plot can be determined. Three types of regression were used to match the cross plot. Figure 5-19 to Figure 5-21 have the data fitting of the matrix dominated Niobrara sample by selecting exponential regression, logarithmic regression and power law regression, respectively. The regression equation and coefficient of determination $R^2$ are also displayed on each plot. Initially, it seems that all three methods provide acceptable matching to the measured data with slightly different $R^2$ values. However, close examination suggests that the power law fitting is superior to the other two methods. In addition to matching the data in the middle of the trend, the power law regression also captures more data points towards the end of each side. These observations hold true for the naturally fractured Niobrara sample and the carbonate sample as well. Therefore, the power law equations were selected to describe the relationship between tight sample permeability and applied effective stress.

The general form of power law permeability decline model is shown in Equation 5-1, where $C_1$ and $C_2$ are coefficient depending on different rock types. Figure 5-22 and Figure 5-23 demonstrate power law fitting on the fractured Niobrara shale and carbonate sample permeability measurement data, respectively. Equation 5-2, Equation 5-3 and Equation 5-4 provide the normalized permeability models as a function of effective stress for the two Niobrara shale samples and tight carbonate sample measured in this work.

$$k = C_1 \sigma_{eff}^{C_2}$$  \hspace{1cm} (5-1)

$$k_{normalized\_matrix} = 25.64 \sigma_{eff}^{-0.49}$$  \hspace{1cm} (5-2)

$$k_{normalized\_fractured} = 91.43 \sigma_{eff}^{-0.83}$$  \hspace{1cm} (5-3)

$$k_{normalized\_carbonate} = 233.69 \sigma_{eff}^{-0.959}$$  \hspace{1cm} (5-4)
Figure 5-19 Niobrara sample #1 permeability vs effective stress data fitting by exponential regression.

Figure 5-20 Niobrara sample #1 permeability vs effective stress data fitting by logarithmic regression.
Figure 5-21 Niobrara sample #1 permeability vs effective stress data fitting by power law regression.

Figure 5-22 Niobrara sample #2 permeability vs effective stress data fitting by power law regression.
5.4 Conclusive remarks for the experimental work

The laboratory instruments, rock sample preparation as well as the entire process of stress dependent permeability measurements and interpretations were presented in Chapter 3, 4 and 5. Two instrument assemblies were used to conduct the experiments. The CMS-300 instrument was initially employed to measure confining stress dependent sample permeability while only low, constant (approximately 100 psi) pore pressure can be applied in this system. Since effective stress is the key for to investigate stress dependent compaction, multiple combinations of pore pressure and confining stress are required for the measurements. Therefore, the CMS-300 assembly was replaced by the new core holder assembly. Nevertheless, the results from the CMS-300 system truly demonstrate the stress sensitivity of tight rock permeability and the data also imply that further efforts are required to unveil the permeability decline behaviors in tight reservoirs. Inspired by the results, a new sample holder assembly was acquired within which both pore pressure and confining stress can be applied. Three different
tight rock samples were measured using the new instrument under a variety of pore pressure and confining stress conditions. The measured data (permeability and sample downstream equilibrium time) were interpreted to illustrate the pressure dependent compaction during tight reservoir depletion. The Biot coefficient of different samples was interpreted using laboratory trial and error method. Finally, the experiment derived permeability decline models were established for numerical simulation study to be discussed in Chapter 6. The main findings from the experiments are summarized as follow:

1) The reduction in recorded sample downstream equilibrium time and the increase in measured rock permeability as a function of applied pore pressure at any specific confining stress condition suggest that the pressure dependent compaction is a significant phenomenon in tight formations;

2) The tight rock permeability is not a monotonic function of average reservoir pressure for a specific reservoir. At low reservoir pressure conditions, increasing pore pressure results in a smooth and linear increase in tight rock permeability; while continuously increase of pore pressure leads to the transition from linear increase to more complicated algorithm (i.e., logarithmic or power law) as the critical pore pressure condition is exceeded;

3) The critical pressure window was defined as the pressure conditions where the trend of permeability decline is significantly changed. Based on the pressure transmission test data, the critical confining stress to pore pressure ratio was identified for different samples. The critical pressure window is a complex function of rock properties and porous components. For the matrix dominant Niobrara shale sample, the critical confining stress to pore pressure ratio is approximately 1.5 - 2, whereas this ratio is 2 - 2.5 for the fractured Niobrara shale sample and the carbonate sample;

4) Continuous depletion in the tight reservoir below the critical Pc/Pp ratio would induce significant compaction and permeability degradation while efficient pressure maintenance has the potential to revitalize tight formations and enhance ultimate recovery. Therefore, gas injection is a possible approach to improve liquid rich basin oil recovery. Nonetheless, a series
of flow simulations and field pilots are needed to test the viability of the possible EOR/IOR schemes.

5) The Biot coefficient $\alpha$ for the tight rock samples were determined experimentally using trial and error methodology. The analyses showed that tight rocks with different dominant porous media hold different Biot coefficients. The data fitting suggested that the Biot coefficient is close to 0.8 for the matrix dominated shale sample, while the fractured shale sample and the carbonate sample render a reasonable $\alpha$ value of approximate 1. The Biot coefficient and effective stress are incorporated into flow simulation.

6) The permeability decline models were established using experimental data. Power law algorithm was used to describe the relationship between effective stress and rock permeability.
6.1 Introduction

In the previous chapters, the phenomenon of stress dependent compaction in tight reservoirs were raised and investigated by measuring rock sample permeability alterations. The main purpose of running flow simulations are in the following aspects:

(1) To study the impacts of permeability decline on long-term production;
(2) To learn the magnitude of production overestimation with traditional non-compaction models;
(3) To investigate the influential factor of pressure draw down versus permeability decline in stress sensitive reservoirs;
(4) To evaluate the viability of gas injection enhanced recovery in stress sensitive tight reservoirs;
(5) If numerical simulation shows potential of gas injection for recovery enhancement, what is the underlying mechanism for the production improvement?

The new simulation models use multiple sets of effective stress dependent permeability models developed in this thesis and from literature. The magnitude of permeability covered in the study ranges from nanodarcy level to millidarcy level. Multiple realizations of well constraints were conducted to study the combined effects on long-term recovery.

6.2 Model setup

6.2.1 Geological model

Both the geological model and the flow simulation model were built using CMG reservoir simulation package. A general geological sector model was built first. The size of the sector
model was chosen to be 5,280 ft by 4,000 ft by 360 ft such that multiple wells could be placed and reasonable well spacing could be obtained. The entire model was gridded to include 29,700 (66 × 50 × 9) gridblocks. The size of gridblocks in both horizontal directions is 80 ft and the thickness of each vertical gridblock is 40 ft. The total thickness of 360 ft is considered moderate for a typical tight formation. The reservoir top is set at 6,000 ft. It is assumed that no fault or pinch out exists in the modeled geological formation and homogeneous conditions dominate the reservoir. Therefore, only regular gridblocks were used to generate the entire reservoir model. Figure 6-1 shows 3D visualization of the base case geological model in CMG.

Figure 6-1 3D visualization of the base model.
6.2.2  Rock and fluid model

The main reservoir properties used in the simulation are summarized in Table 6-1. The reservoir rock porosity was set at 7% as the pore properties were considered as fixed parameters for control and comparison purposes. This value agrees in range with the CMS-300 porosity measurement shown in Figure 3-7 and was considered reasonable for major commercial tight reservoirs. The permeability was primarily obtained from the previously discussed laboratory measurements. To compare different stress dependent features, published permeability decline data from literature was also utilized (Davies and Davies 2001). The range of the horizontal permeability is between 0.00005 mD (50 nD) and 0.6 mD, whereas the vertical permeability was calculated from the horizontal permeability by applying a multiplier of 0.1. This permeability range is considered to include different magnitude of tight rocks with and without natural fractures.

For most reservoir rocks, the compaction effects on porosity are less significant than that on permeability. This can also be seen from Figure 3-7. Therefore, the porosity remains the same at different stress conditions whereas the permeability changes follow experimentally derived models.

Table 6-2 and Table 6-3 summaries the permeability multipliers used in different simulation models. The two Niobrara models (matrix dominated one and the one with natural fracture) and the carbonate model were obtained from the measurement discussed in Chapter 5, whereas the data in Table 6-3 are from a peer review SPE paper. The four models show good agreement on the trend of permeability decline as a function of applied pore pressure and confining stress, but each individual model shows unique magnitude which represents different rock and fluid properties in different reservoirs. The initial pore pressure was set at 5,000 psi for all models. It can be seen that up to 90% of the original permeability can be lost when the pore pressure is depleted to 1,000 psi.
Table 6-1 Reservoir properties for simulation.

<table>
<thead>
<tr>
<th>Property</th>
<th>min</th>
<th>max</th>
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</thead>
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<td>Porosity (%)</td>
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<td>Horizontal permeability (md)</td>
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<tr>
<td>Vertical permeability (md)</td>
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<td>0.06</td>
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<td>Rock compressibility (1/psi)</td>
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<td></td>
</tr>
<tr>
<td>Water compressibility (1/psi)</td>
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<td></td>
</tr>
<tr>
<td>Water phase viscosity (cp)</td>
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<tr>
<td>Water formation volume factor (RB/STB)</td>
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<tr>
<td>Pressure dependence of water viscosity (cp/psi)</td>
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<td>Water density (lb/ft3)</td>
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<tr>
<td>Gas density (lb/ft3)</td>
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<tr>
<td>Reservoir temperature (°F)</td>
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</tr>
<tr>
<td>Initial reservoir pressure (psi)</td>
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<td>5000</td>
</tr>
<tr>
<td>Initial oil saturation</td>
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</tr>
<tr>
<td>Initial water saturation</td>
<td></td>
<td>0.3</td>
</tr>
<tr>
<td>Reservoir bubble point pressure (psi)</td>
<td></td>
<td>3000</td>
</tr>
</tbody>
</table>
Table 6-2 Permeability multiplier as a function of pore pressure in simulation model, from laboratory measurement.

<table>
<thead>
<tr>
<th>Pore Pressure (psi)</th>
<th>Niobrara matrix</th>
<th>Matrix fracture</th>
<th>Carbonate</th>
</tr>
</thead>
<tbody>
<tr>
<td>300</td>
<td>0.519</td>
<td>0.236</td>
<td>0.188</td>
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<td>600</td>
<td>0.531</td>
<td>0.247</td>
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<tr>
<td>900</td>
<td>0.544</td>
<td>0.259</td>
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</tr>
<tr>
<td>1200</td>
<td>0.559</td>
<td>0.272</td>
<td>0.222</td>
</tr>
<tr>
<td>1500</td>
<td>0.574</td>
<td>0.287</td>
<td>0.236</td>
</tr>
<tr>
<td>1800</td>
<td>0.592</td>
<td>0.304</td>
<td>0.253</td>
</tr>
<tr>
<td>2100</td>
<td>0.610</td>
<td>0.323</td>
<td>0.271</td>
</tr>
<tr>
<td>2400</td>
<td>0.631</td>
<td>0.345</td>
<td>0.293</td>
</tr>
<tr>
<td>2700</td>
<td>0.654</td>
<td>0.371</td>
<td>0.318</td>
</tr>
<tr>
<td>3000</td>
<td>0.680</td>
<td>0.402</td>
<td>0.349</td>
</tr>
<tr>
<td>3300</td>
<td>0.709</td>
<td>0.438</td>
<td>0.386</td>
</tr>
<tr>
<td>3600</td>
<td>0.742</td>
<td>0.484</td>
<td>0.432</td>
</tr>
<tr>
<td>3900</td>
<td>0.780</td>
<td>0.540</td>
<td>0.491</td>
</tr>
<tr>
<td>4200</td>
<td>0.825</td>
<td>0.614</td>
<td>0.569</td>
</tr>
<tr>
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<td>0.879</td>
<td>0.714</td>
<td>0.678</td>
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<tr>
<td>4800</td>
<td>0.946</td>
<td>0.860</td>
<td>0.840</td>
</tr>
<tr>
<td>5000</td>
<td>1.000</td>
<td>1.000</td>
<td>1.000</td>
</tr>
</tbody>
</table>

Table 6-3 Permeability multiplier as a function of pore pressure in simulation model, from Davies and Davies (2001).

<table>
<thead>
<tr>
<th>Pore Pressure (psi)</th>
<th>Perm. Multiplier</th>
</tr>
</thead>
<tbody>
<tr>
<td>500</td>
<td>0.08</td>
</tr>
<tr>
<td>1000</td>
<td>0.10</td>
</tr>
<tr>
<td>1500</td>
<td>0.12</td>
</tr>
<tr>
<td>2000</td>
<td>0.15</td>
</tr>
<tr>
<td>2500</td>
<td>0.21</td>
</tr>
<tr>
<td>3000</td>
<td>0.25</td>
</tr>
<tr>
<td>3500</td>
<td>0.37</td>
</tr>
<tr>
<td>4000</td>
<td>0.50</td>
</tr>
<tr>
<td>4500</td>
<td>0.80</td>
</tr>
<tr>
<td>5000</td>
<td>1.00</td>
</tr>
</tbody>
</table>
The PVT model is shown in Table 6-4. Since the objective of flow simulation in this work is to investigate stress dependent compaction and its long-term impacts on production, a general black oil fluid model was generated and utilized. Another reason for not choosing a compositional model is that the fluid sample data are unavailable to build an accurate model. Moreover, a black oil model would serve the research goal while saving additional run time.

Table 6-4 PVT table for simulation model.

<table>
<thead>
<tr>
<th>p</th>
<th>rs</th>
<th>bo</th>
<th>eg</th>
<th>viso</th>
<th>visg</th>
</tr>
</thead>
<tbody>
<tr>
<td>1674</td>
<td>367</td>
<td>1.300</td>
<td>505.1</td>
<td>0.529</td>
<td>0.016</td>
</tr>
<tr>
<td>2031</td>
<td>447</td>
<td>1.336</td>
<td>617.3</td>
<td>0.487</td>
<td>0.017</td>
</tr>
<tr>
<td>2530</td>
<td>564</td>
<td>1.389</td>
<td>769.2</td>
<td>0.436</td>
<td>0.018</td>
</tr>
<tr>
<td>2991</td>
<td>679</td>
<td>1.443</td>
<td>900.9</td>
<td>0.397</td>
<td>0.020</td>
</tr>
<tr>
<td>3553</td>
<td>832</td>
<td>1.514</td>
<td>1042.8</td>
<td>0.351</td>
<td>0.021</td>
</tr>
<tr>
<td>4110</td>
<td>1000</td>
<td>1.594</td>
<td>1169.6</td>
<td>0.310</td>
<td>0.023</td>
</tr>
<tr>
<td>4544</td>
<td>1143</td>
<td>1.663</td>
<td>1257.9</td>
<td>0.278</td>
<td>0.024</td>
</tr>
<tr>
<td>4935</td>
<td>1285</td>
<td>1.732</td>
<td>1331.6</td>
<td>0.248</td>
<td>0.026</td>
</tr>
<tr>
<td>5255</td>
<td>1413</td>
<td>1.795</td>
<td>1388.9</td>
<td>0.229</td>
<td>0.027</td>
</tr>
</tbody>
</table>

The relative permeability functions used in the simulations are shown in Figure 6-2 and Figure 6-3. The curves were not obtained from laboratory calibrations such as SCAL (Special Core Analysis); as such measurements are generally inapplicable for tight reservoir rocks. In fact, measuring absolute permeability is already a difficult task for some tight samples as described in the previous chapters. The measurement takes a long time to finish, and its accuracy can be easily affected by experimental conditions and other factors. Furthermore, the sample structure and physical properties will be altered by the end of the experiments which makes repeat test even more difficult. The relative permeability determination suffers from all these and more limitations. In addition, because history match is not the purpose of this work, a fixed set of relative permeability for all models is thought to be reasonable.
The initial oil saturation and water saturation were set at 0.6 and 0.3, respectively for all gridblocks. The reservoir bubble point was set at 3,000 psi. The rock matrix compressibility is $3.0 \times 10^{-6}$ 1/psi, and the oil and water compressibility is $1.31 \times 10^{-5}$ and $3.15 \times 10^{-6}$ 1/psi, respectively.

Figure 6-2 Oil-Water relative permeability curve.

Figure 6-3 Gas-Oil relative permeability curve.
6.2.3 Numerical methods control

The numerical method and controlling parameters were fixed for all the simulation cases. The minimum time-step size (DTMIN) was set to $10^{-6}$ days and the well change first time-step size is $10^{-4}$ days. The maximum number of orthogonalization (NORTH) allowed is 40. The maximum number of iteration (ITERMAX) allowed in Jacobian matrix solution routine is 100. The number of cuts in a single time-step (NCUTS) was chosen to be 10. The rest of numerical method control parameters were remained at default value. The gridblocks that represent rock matrix were set to an initial implicit pattern (AIMSET equals to 1).

6.2.4 Wells

There are two horizontal producers in the base model. Both of them were transversely fractured and each of them has ten stages. Planar fracture model was chosen to simulate the hydraulic fractures. The fracture half-length is 400 ft (five horizontal gridblocks) and the fracture height is 200 ft (five vertical gridblocks). The horizontal wellbore is located in the fifth layer from the top and staggered fracture structure was utilized. Standard well spacing of 1,280 ft was selected and the fracture spacing is 400 ft. The distance between fracture tips from the two wellbores is 480 ft. Local Grid Refinement (LGR) was applied at the gridblocks containing hydraulic fractures. The total numbers of active gridblocks in the model is approximately 98,600. In order to enhance computing speed, the fracture width (the innermost gridblock in the LGR zone) was set equals to 2 ft. Therefore, equivalent fracture permeability was utilized in the fracture model so that the effective fracture conductivity remains at 20 md-ft. Figure 6-4 and Figure 6-5 illustrates the fractured horizontal wells and their dimension. All the fractures shown were considered open and have equal potential for the fluid inflow throughout the entire duration of production. A third well will be added to the model subsequently which will be discussed in the next sections.

The well element geometry parameters were set to calculate the well index internally. For all the producers, the well radius (rad) was specified to be 0.25 ft. The geometric factor (geofac) is
0.39 and the well fraction of a circle (wfrac) is 1 as all wells were modeled at the center. Zero well skin factor was assumed for all producers.

Several well control strategies were applied to the producers. Because well bottom-hole pressure (BHP) or well head pressure constraints (WTHP) are more common in the field than well producing rate constraints, the BHP control was used in the simulation models. Four BHP values from 1,000 psi to 3,000psi were used to constrain the horizontal wells in different models. The objective of simulating different well control scenarios is to evaluate the long-term well production with the presence of stress-dependent compaction phenomenon.

The simulation starts from January 1, 2010 when the horizontal wells start producing. The duration of simulation run lasts for 20 years which is considered as a moderate time frame for a tight reservoir development.

Figure 6-4 2D view of the transversely fractured horizontal wells.
6.2.5 Gas injection model

The base case model contains only two producers. Currently, the natural depletion (sometimes with artificial lift) from massively fractured horizontal wells is considered the most common and cost effective depletion method in commercial tight reservoirs. Until recently, none of the EOR/IOR technique commonly used in conventional reservoirs had been proved to be a general prescription in improving tight reservoir production although increasing research and field pilots were undertaking in this area. Comparing to the expensive and complicated field trial test, numerical simulation provides a fast and efficient way to qualitatively evaluate the EOR/IOR potential in tight formations. Because the stress dependent reservoir rock compaction is the key in this research, the pressure maintenance mechanism will be emphasized mainly in the injection models. Other important mechanisms, such as gas miscible flood and sweeping
pattern will not be analyzed or discussed in this work. The objective of the simulation section is to search for the desired injector structure and spacing, as well as the fracture properties and injection plan in order to enhance ultimate recovery in stress sensitive tight reservoirs.

With the current two wells sector model, multiple injection patterns were considered and attempted with simulation runs. It was found that placing one injection well with zipper fractures on the middle line of the producing wells would provide the best results. Furthermore, the overlapping fracture pattern of injector and producers is superior to the departing fracture pattern. This is because overlapping fracture could counteract some of the negative effects caused by low matrix permeability and induce more reservoir fluid to the vicinity of producer’s wellbore. Figure 6-6 is the 2D planar view of the sector model with the inner injection well added between two producing wells.
6.3 Production wells only simulations

6.3.1 Compaction and non-compaction models

In order to show how stress dependent compaction affects the ultimate tight reservoir recovery, several pairs of simulations were run with different permeability decline models. For each case, the same simulation model was run for a second time without specifying the compaction model. Four sets of comparison will be shown to illustrate this point. Among them, the two Niobrara sample and the carbonate sample were measured in the laboratory as discussed in Chapter 4 and Chapter 5. The fourth permeability decline data was obtained from SPE 71750-PA (Davies and Davies 2001). The four rock samples represent four different tight reservoir rocks with distinguishable different permeability range and decline trend. It will be shown that these rocks display different features in long-term production corresponding to the stress dependent compaction. The constant BHP of 2,000 psi was used for all simulation cases described in the section.

6.3.1.1 The Niobrara sample #1 model

The first laboratory measured Niobrara sample has extremely low permeability (approximately 20 nD – 45 nD) and exhibit no evidence of existing fracture systems. Two simulation models were run with and without the permeability decline table. Figure 6-8 is the daily oil production rate comparison over 20 years and the cumulative oil production is plotted in Figure 6-8. It can be seen that the two curves on the cumulative plot are overlapping initially and then diverge from each other. This is because the initial rock permeability in the coupled compaction simulation model (blue curve) is the same to that of the model with no compaction (red curve). As depletion continues, sharp pore pressure decline occurs. Since rock permeability is always inversely proportional to the pore pressure due to compaction, the longer production period without pressure maintenance lasts, the lower average reservoir permeability is expected. By the end of the 20th year, the well production from the non-compaction model is approximately 53,000 bbls whereas the laboratory derived compaction model lead to the result of 43,000 bbls. The contrast indicates that, for the Niobrara sample # 1 type of rock, roughly 19% oil rate would
be over-predicted by ignoring the stress dependent compaction behavior. As Table 6-2 shows, the permeability declines approximately 40% from 5,000 psi to 2,000 psi.

Figure 6-7 Daily oil production rate of the Niobrara # 1 with and without compaction model over 20 years.

Figure 6-8 Cumulative oil production of the Niobrara # 1 with and without compaction model over 20 years.
The average reservoir pressure at the last time-step is 4,905 psi for the compaction model and 4,894 psi for the non-compaction model. Since the absolute rock permeability is extremely low, the average reservoir sector pressure was basically unaffected by the production. Figure 6-9 is the 2D pressure profile of the compaction model at the last time-step.

![Reservoir pressure profile](image)

Figure 6-9 Reservoir pressure profile at the end of simulation for compaction model of the Niobrara # 1.

### 6.3.1.2 The Niobrara sample # 2 model

The permeability of Niobrara sample with sealed fractures is notably higher than the first sample (approximately 0.15 md – 0.6 md). Experiments data show that the permeability decline signature of this sample is also quite different from that of the first sample. As the permeability multiplier table (Table 6-2) illustrates, 70% of the original permeability was lost due to pore pressure depletion from 5,000 psi to 2,000 psi. Figure 6-10 and Figure 6-11 show the daily and
cumulative oil production over 20 years. The results indicate that the non-compaction model simulates 20% more oil than could actually be if the compaction effects were recognized. Although the cumulative oil production plots in Figure 6-8 and Figure 6-11 show similar trend, the daily production rate in Figure 6-7 and Figure 6-10 looks quite different. For the Niobrara sample #1, the production from non-compaction model is always higher than that of the compaction model. The production rate difference between two curves during 20 years is almost constant and the two curves never converge. For the Niobrara sample #2, the non-compaction model produces significantly more oil than the compaction model initially. However, the difference diminished rapidly and the compaction model end up with producing more daily oil in the last several years. The reason for the different trends can be found from the completely different average reservoir pressure and drainage area. At the last time-step, the average reservoir pressure for the compaction and non-compaction models is 2,849 psi and 2,242 psi, respectively, which is significantly lower than the first simulation sets. Furthermore, unlike the Niobrara #1 models, the non-compaction model depleted much faster than the compaction model in this case, resulting in faster production drop. Figure 6-12 illustrates the pressure profile after 20 years production. In fact, the entire sector was drained shortly after the wells were turned on. This simulation suggests that, if any particular layer in the tight formation has this magnitude of permeability, early boundary effects would be seen and interferences with the wells in other sectors might be encountered. Furthermore, if the designed hydraulic fractures are located above or below the high permeability layers, it is very possible that unexpected fracture height growth happens which may affect the desired fracture length in the target zone.

6.3.1.3 The carbonate sample model

Same simulation procedures were conducted for the carbonate sample to study the production responses. The measured permeability of this sample ranges approximately between 100 nd and 900 nd. 75% of the initial rock permeability was reduced due to compaction when the pore pressure was declined from 5,000 psi to 2,000 psi. Bottom-hole pressure of 2,000 psi is fixed for both runs as before. The daily oil rate and cumulative oil production by the end of 20 years are
plotted in Figure 6-13 and Figure 6-14, respectively. The data show that the non-compaction model over-predicted oil rate throughout the simulation and the cumulative production is roughly 40% more than the compaction model. Since hundreds of nano-darcy is the common permeability range in some commercial tight reservoirs, using non-compaction model would result in significant overestimation in long-term production.

Figure 6-10 Daily oil production rate of the Niobrara # 2 with and without compaction model over 20 years.

Figure 6-11 Cumulative oil production of the Niobrara # 2 with and without compaction model over 20 years.
Figure 6-12 Reservoir pressure profile at the end of simulation for compaction model of the Niobrara #2.

Figure 6-15 is the simulated pressure profile at the last time-step. The boundary is not affected by the production in this scenario. The average pore pressure is 4,715 psi and the majority of pressure decline happened in the vicinity of wellbore and hydraulic fractures. With the current hydraulic fracture properties specification, it can be seen that hundreds of nano-darcy is the threshold value where elliptical drainage area surrounding hydraulic fractures starts forming. Although reservoir rocks several hundreds of feet away from fractures start feeding the fractures, unlike the Niobrara #2 models, the pressure interference between two horizontal wells did not occur in this case. The results suggest that well-to-well interference is unlikely to
happen in hundred nano-Darcy permeability reservoirs with the standard quarter-mile well spacing.

Figure 6-13 Daily oil production rate of the carbonate model with and without compaction model over 20 years.

Figure 6-14 Cumulative oil production of the carbonate model with and without compaction model over 20 years.
Figure 6-15 Reservoir pressure profile at the end of simulation for the carbonate model with compaction model.

6.3.1.4 Selected model from SPE-71750-PA

In order to include different low permeability reservoirs into simulation study, one permeability decline dataset from the SPE-71750-PA was utilized. The initial permeability at 5,000 psi is approximately 0.01 md. The pressure dependent decline was summarized in Table 6-3. The reasons for choosing this dataset lie in two aspects. First, 0.01 md – 0.001 md is a commonly used permeability range for tight oil reservoir simulation and this range is not covered by the above mentioned scenarios. Secondly, the permeability reduction in this case is more severe than any experimental measurement discussed in this thesis.
The daily oil rate and cumulative oil production is plotted in Figure 6-16 and Figure 6-17, respectively. The oil rate difference between the two cases is getting closer over time but the non-compaction model still overestimate production by the end of simulation. In terms of cumulative oil production, the red curve predicts approximately 38% more ultimate oil recovery without considering the stress dependent compaction effects. The average pressure is 4,300 psi. Figure 6-18 illustrates the pressure profile. Late time boundary effects appeared, but are generally negligible. Fracture to fracture interference can be seen and the area between two horizontal wells was drained.

![Figure 6-16 Daily oil production rate of dataset from SPE-71750-PA with and without compaction model over 20 years.](image)

Figure 6-16 Daily oil production rate of dataset from SPE-71750-PA with and without compaction model over 20 years.
Figure 6-17 Cumulative oil production of dataset from SPE-71750-PA with and without compaction model over 20 years.

Figure 6-18 Reservoir pressure profile at the end of simulation for compaction model of the selected dataset from SPE-71750-PA.
6.3.1.5 Summary

In this section, the compaction effects on long-term production were studied with for models with distinguishable permeability. Standard horizontal well spacing and commonly designed hydraulic fracture properties were used to constrain the simulations. It was found that the non-compaction models, as usually utilized for tight simulation, tend to overestimate the long-term production by more than 20%. The more stress sensitive reservoir rock is, the more hydrocarbon production will be over-predicted with the non-compaction models. The pressure profiles suggest that tight reservoirs with permeability of 0.01 md or less would not have severe interference between reservoir sectors under standard well configuration. Furthermore, it can be inferred from the study that the interference between wells would be weakened overtime due to permeability decline, making the central area of multiple wells less productive in the long term.

6.3.2 Compaction models with different production constraints

When stress dependent compaction is ignored in traditional reservoir simulations, the production is a function of the well constraints (liquid/gas rate or BHP) with all other inputs fixed. Nevertheless, the issue becomes complicated when compaction is considered. In these cases, two contradicting conditions exist for evaluating the ultimate recovery. For one thing, the reservoir permeability is positively correlated to the well BHP. Lower BHP generally means faster reservoir pressure drop, and hence lower rock permeability as depletion continues. The permeability impairment will tend to reduce long-term productivity. On the other hand, the well BHP is inversely proportional to the well production. Lower BHP introduces higher pressure differential between wellbore and reservoir and is therefore beneficial to the production rate. This section is intended to assess the combined effects of the two factors on the long-term well recovery.

The same compaction models were run with four well BHP conditions, which are 1,000 psi, 1,500 psi, 2,000 psi and 3,000psi. The cumulative oil production in 20 years was plotted and the
total production in each scenario was normalized. Figure 6-19 shows the cumulative production plot of Niobrara # 1 compaction models. The fractions to the right of each curve are normalized cumulative production. The diverging curves suggest that BHP is still the most important factor for long-term production even though permeability decline was incorporated. Based on the simulations, 22% more oil would be produced if the BHP was kept at 1,000 psi rather than at 3,000 psi, regardless of the latter render considerably higher permeability in the vicinity of the wellbore.

Simulations of Niobrara # 1 models show that the production is mainly determined by pressure draw down in extremely low permeability reservoirs. In order to assess different permeability scenarios with different degrees of stress dependent compaction, the other three compaction models were simulated following the same procedure. Figure 6-20, Figure 6-21 and Figure 6-22 list the cumulative oil production with compaction models of the fractured Niobrara sample, the carbonate sample and SPE-71750-PA, respectively. Similarly, the 1,000 psi BHP case of all three compaction models produces the most cumulative oil whereas the 3,000 psi BHP case produces the least. Even for the fourth compaction model, where the original permeability was reduced to 10% in the near wellbore region, the pressure draw down still plays the major role in overall production.

Although the low well BHP simulation cases generally lead to higher cumulative production in the producer only scenario, the normalized results indicate that the difference between 1,000psi, 1,500psi 2,000psi well BHP cases are reasonably small. For instance, the normalized production ratio of the three BHP cases is 1: 0.95: 0.9 for the first compaction model, and 1: 0.98: 0.95 for the fourth compaction model. The lowest BHP depletion strategy would produce an additional of 5% – 10% oil in 20 years while it lowers the average reservoir pressure for approximately 800psi comparing to the 2,000psi BHP scenario. It is difficult to justify the benefit of the 5% – 10% incremental production when long-term reservoir development plan is taken into account. In fact, the primary recovery (i.e., the hydrocarbon production with fractured horizontal well, and no liquid or gas is injected) is relatively low for tight reservoir wells; thus, pressure maintenance and flooding techniques are potential strategies to improve the recovery.
However, with the low well BHP used in the primary depletion, it is more difficult to implement the potential IOR/EOR practices in a cost effective manner as the average reservoir pressure becomes very low and the conductivity of various flow components were significantly impaired. Therefore, the estimated production/recovery from the primary depletion stage should not be used as the only indicator to determine the depletion strategy in stress sensitive tight reservoir; rather, additional relevant data need to be gathered and analyzed and the overall economics needs to be carefully evaluated in the early stage of tight reservoir development in order to balance the short time economics and the long-term project return while fully realizing the tight reservoir’s potential.

Furthermore, it should be noticed that the 20 years cumulative oil production in nano-Darcy permeability reservoirs are very low (Figure 6-19 and Figure 6-21) though large pressure draw down were provided (i.e., 1,000psi well BHP for 20 years). Figure 6-23 is the reservoir pressure profile of the Niobrara # 1 model (1,000 psi BHP) at last time-step. It shows that the pressure drawdown happened mainly in the close vicinity of the wellbore and hydraulic fractures. The reservoir gridblocks outside the SRV (approximately 80 ft away from the hydraulic fractures) were making little contribution to the well production. The inert fluid flow due to low matrix permeability can be observed from the oil saturation map as Figure 6-24 shows. The original oil saturation (0.6) remained almost unchanged over 20 years except for those gridblocks within or near the hydraulic fractures (or SRV) zones. It can be inferred that the drainage area would be further diminished if higher well bottom-hole pressure constraints were used.
Figure 6-19 Cumulative oil production for the Niobrara # 1 compaction model with different BHPs.

Figure 6-20 Cumulative oil production for the Niobrara # 2 compaction model with different BHPs.
Figure 6-21 Cumulative oil production for the carbonate compaction model with different BHPs.

Figure 6-22 Cumulative oil production for the compaction model selected from SPE-71750-PA with different BHPs.
The small drainage area also indicates that infill drilling in reservoirs with extremely low permeability is not a cost effective method to produce the reservoir sector. The strategy of increasing hydraulic fracture stages as can be seen in many tight oil fields is theoretically viable for production enhancement. Figure 6-25 is the updated Niobrara # 1 compaction model with 1,000 psi BHP constraint. The original 10-stage hydraulic fractures were replaced by a 23-stage design along the same wellbore. The pressure profile at the last time-step is shown in Figure 6-26. It can be seen that the areas between any two fractures were more effectively drained comparing to the original model. The cumulative oil production in the updated model is more than two times higher than the original model (Figure 6-27).

Although the use of massive hydraulic fractures to improve recovery can be validated with numerical simulation, this design is actually facing critical engineering problems. In numerical simulation, all fractures are assumed to open at all times, which is unrealistic in practice, especially when the fracture spacing is really dense (i.e., 160 ft in the above mentioned example). In such cases, some designed fractures will never open, and a great percentage of initially opened fractures may experience severe conductivity loss due to compaction and proppant degradation. For these reasons, the use of massive fractures is not always a feasible approach to improve drainage area and ultimate recovery in ultra-tight reservoirs.

Another reason for massively fractured horizontal wells alone is insufficient to improve overall recovery is that the area between two wells are essentially undrained. This problem also exists in micro-Darcy reservoir. Figure 6-28 is the pressure profile of the carbonate compaction model. Although the areas surrounded by the wellbore and fractures were stimulated, the areas between the wells were unaffected. Therefore, it is necessary to investigate other approaches to improve hydrocarbon recovery in these tight reservoirs.
Figure 6-23 Reservoir pressure profile of Niobrara # 1 model under 1,000 psi BHP.

Figure 6-24 Reservoir oil saturation profile of Niobrara # 1 model under 1,000 psi BHP.
Figure 6-25 Updated Niobrara # 1 ccompaction model with 23-stage fractures along each wellbore (1,000 psi BHP).

Figure 6-26 Pressure profile of updated Niobrara # 1 model.
Figure 6-27 Cumulative oil comparison between original and updated Niobrara # 1 model.

Figure 6-28 Reservoir pressure profile of the carbonate model (1,000 psi BHP).
In order to show the effects of well constraints on the gas reservoir production, a gas-water fluid model was built and simulated with the carbonate compaction model. The 20 years cumulative gas production is shown in Figure 6-29. The results confirm the findings from the black-oil simulation models that lower well BHP would produce more hydrocarbon in primary depletion stage despite of the permeability impairment. The main difference between black-oil model and gas-water model is that the gas rate drops much faster when high well BHP was employed. Given the same geologic model, the cumulative gas production is approximately 10% less than the cumulative oil production when the well was constrained at 3,000psi. This finding suggests that it is more difficult to balance the primary depletion and pressure maintenance in tight gas reservoirs than in liquid-rich shale reservoirs.

Figure 6-29 Cumulative gas production for the carbonate compaction model with different BHPs.
6.3.3 Summary of producer only simulations

In this section, the results of producer only simulation models with permeability decline functions were discussed. Several conclusions can be drawn based on the analyses. First, the stress dependent compaction has significant impact on long-term reservoir recovery. The simulation models covered different magnitude of permeability ranging from nano-Darcy to milli-Darcy. In each scenario, the daily rate and cumulative production in the compaction model is lower than that of non-compaction models. On the other hand, since the permeability decline functions were based on laboratory measurements, the constant permeability models were considered overestimating cumulative oil production, with an average of 25% - 30%. Therefore, it is important for the field operators to regularly calibrate the reservoir permeability or conducting laboratory depletion tests in order to accurately predict reservoir recovery.

The simulations with different well BHP constraints indicate that larger pressure draw down has more advantages than disadvantages in terms of long-term production. Maintaining well BHP is not an effective method to maintain reservoir pressure while enhancing well production. Even the permeability declines severely with pore pressure, lowering BHP still brings better combined results. Nevertheless, the difference in 20 years cumulative production between different well BHP cases is relatively small while the low BHP cases would result in much lower average reservoir pressure. In consideration of the potential pressure maintenance practices in these wells, it is important to evaluate the long-term project economics in the very early stage of reservoir development. Furthermore, as discussed in section 6.3.2, infill drilling and massively increasing hydraulic fracture stage is not a cost effective approach to improve recovery. Therefore, other potential IOR methods need to be studied. In the next section, the use of gas injection for production enhancement will be investigated based on the existing geological and reservoir models.
6.4 Gas injection simulation

The idea of running gas injection simulation is to investigate the pressure maintenance mechanism, rather than designing gas flooding scheme for tight reservoir production enhancement.

In the gas injection model, one injection well was added to the existing producer only models. The injector was placed in the center of the two producers. The distance between injector and producer is 640 ft and the three wells are in the same layer. The planar view of the injection model is in Figure 6-30. The injection well has 11 hydraulic fractures. The fracture half-length is 400 ft and the height is 200 ft. Zipper fracture structure was used such that more extensive fracture network can be created and the stimulated areas will be enlarged. Equivalent fracture conductivity of 40 md-ft was used for the injector.

Figure 6-30 Planar view of the injection model (injection well in the center of two producers).
The start date of the simulation is 1/1/2010 and the two horizontal wells were producing from 1/1/2010 to 1/1/2020 as they were in the previous models. The horizontal injector was added to the model on 1/1/2020. Methane was used as the injection gas and the daily injection rate was used to constrain the injection well. The gas injection was set to continue for 3 years. After that, the gas injector was shut-in while the producers keep producing until 1/1/2030. The 20 years cumulative oil production of the gas injection models was analyzed and compared with the producer only models. Since there is no component change or miscible flood in the injection model, the main IOR mechanism in the gas injection simulation is pressure maintenance.

Different gas injection rates were used in the simulations. Table 6-5 summarizes six different gas injection rates, from low to high order, for the gas injection simulation. Real field gas injection practices were used as the references for determining the range of gas injection rate in the simulation. Note that not all injection cases would achieve desired injectivity depending on the permeability and permeability decline function. The production wells were constrained at 2,000 psi BHP for all injection scenarios.

<table>
<thead>
<tr>
<th>Case No.</th>
<th>Gas injection rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>100 Mscf/day</td>
</tr>
<tr>
<td>2</td>
<td>500 Mscf/day</td>
</tr>
<tr>
<td>3</td>
<td>1,000 Mscf/day</td>
</tr>
<tr>
<td>4</td>
<td>1,500 Mscf/day</td>
</tr>
<tr>
<td>5</td>
<td>5,000 Mscf/day</td>
</tr>
<tr>
<td>6</td>
<td>10,000 Mscf/day</td>
</tr>
</tbody>
</table>
New permeability multiplier tables were used in the injection models to cover the high pore pressure regions induced by the gas injection. The input data shown in Table 6-6 and Table 6-7 replaced the original data provided in Table 6-2 and Table 6-3.

Table 6-6 Updated permeability multiplier as a function of pore pressure in the injection model, from laboratory measurement.

<table>
<thead>
<tr>
<th>Pore Pressure (psi)</th>
<th>Niobrara matrix</th>
<th>Matrix fracture</th>
<th>Carbonate</th>
</tr>
</thead>
<tbody>
<tr>
<td>300</td>
<td>0.519</td>
<td>0.236</td>
<td>0.188</td>
</tr>
<tr>
<td>600</td>
<td>0.531</td>
<td>0.247</td>
<td>0.198</td>
</tr>
<tr>
<td>900</td>
<td>0.544</td>
<td>0.259</td>
<td>0.210</td>
</tr>
<tr>
<td>1200</td>
<td>0.559</td>
<td>0.272</td>
<td>0.222</td>
</tr>
<tr>
<td>1500</td>
<td>0.574</td>
<td>0.287</td>
<td>0.236</td>
</tr>
<tr>
<td>1800</td>
<td>0.592</td>
<td>0.304</td>
<td>0.253</td>
</tr>
<tr>
<td>2100</td>
<td>0.610</td>
<td>0.323</td>
<td>0.271</td>
</tr>
<tr>
<td>2400</td>
<td>0.631</td>
<td>0.345</td>
<td>0.293</td>
</tr>
<tr>
<td>2700</td>
<td>0.654</td>
<td>0.371</td>
<td>0.318</td>
</tr>
<tr>
<td>3000</td>
<td>0.680</td>
<td>0.402</td>
<td>0.349</td>
</tr>
<tr>
<td>3300</td>
<td>0.709</td>
<td>0.438</td>
<td>0.386</td>
</tr>
<tr>
<td>3600</td>
<td>0.742</td>
<td>0.484</td>
<td>0.432</td>
</tr>
<tr>
<td>3900</td>
<td>0.780</td>
<td>0.540</td>
<td>0.491</td>
</tr>
<tr>
<td>4200</td>
<td>0.825</td>
<td>0.614</td>
<td>0.569</td>
</tr>
<tr>
<td>4500</td>
<td>0.879</td>
<td>0.714</td>
<td>0.678</td>
</tr>
<tr>
<td>4800</td>
<td>0.946</td>
<td>0.860</td>
<td>0.840</td>
</tr>
<tr>
<td>5000</td>
<td>1.000</td>
<td>1.000</td>
<td>1.000</td>
</tr>
<tr>
<td>5500</td>
<td>1.191</td>
<td>1.778</td>
<td>1.944</td>
</tr>
<tr>
<td>5800</td>
<td>1.378</td>
<td>3.803</td>
<td>4.681</td>
</tr>
</tbody>
</table>
Table 6-7 Updated permeability multiplier as a function of pore pressure in the injection model, from Davies and Davies (2001).

<table>
<thead>
<tr>
<th>Pore Pressure (psi)</th>
<th>Perm. Multiplier</th>
</tr>
</thead>
<tbody>
<tr>
<td>500</td>
<td>0.08</td>
</tr>
<tr>
<td>1000</td>
<td>0.10</td>
</tr>
<tr>
<td>1500</td>
<td>0.12</td>
</tr>
<tr>
<td>2000</td>
<td>0.15</td>
</tr>
<tr>
<td>2500</td>
<td>0.21</td>
</tr>
<tr>
<td>3000</td>
<td>0.25</td>
</tr>
<tr>
<td>3500</td>
<td>0.37</td>
</tr>
<tr>
<td>4000</td>
<td>0.50</td>
</tr>
<tr>
<td>4500</td>
<td>0.80</td>
</tr>
<tr>
<td>5000</td>
<td>1.00</td>
</tr>
<tr>
<td>5500</td>
<td>2.00</td>
</tr>
<tr>
<td>5800</td>
<td>2.80</td>
</tr>
</tbody>
</table>

6.4.1 Niobrara # 1 sample model

The first Niobrara sample has extremely low measured permeability and hence low cumulative oil production from the producer only models. It was expected that the gas injection would raise the pressure in the near wellbore regions and stimulate more rocks in the vicinity of the fractures. However, the simulations results were not ideal as anticipated. Simulation showed that only the first injection case with gas rate of 100 Mscf/day could achieve the designed injectivity. In other scenarios, large volume of gas was not able to be injected into the well due to low reservoir fluid mobility and relatively high regional pressure near wellbore. This implies that large volume and continuous gas injection may subject to some engineering challenges in ultra-tight reservoirs. Therefore, it is essential to evaluate the material balance and fluid flow potential when considering gas injection.

Although gas injection was successful under the rate of 100 Mscf/day, essentially no incremental oil was produced from the model. Figure 6-31 and Figure 6-32 show the pressure
profile of the injection model right after gas injection and at the end of simulation. It can be seen that the gas was not injected deep enough into the reservoirs. Because of the low matrix permeability, the injected fluid was accumulated near the hydraulic fractures. The regions between fractures of production wells remained undrained and the fracture network between injector and producers were not established.

Simulations indicate that gas injection is not an optimal approach to improve recovery in nano-Darcy reservoirs since the designed injectivity can hardly be achieved. Since the production mainly happens in the small radius of the wellbore and fractures, infill drilling and densified fractures as discussed in section 6.3.2 seems to be better approaches. Nevertheless, the effectiveness of massive wells and fractures need to be carefully evaluated in order to justify the additional cost.

Figure 6-31 Pressure profile of Niobrara # 1 model right after gas injection of 100 Mcsf/day.
6.4.2 Niobrara # 2 sample model

This model produced most oil from the production well only models (approximately 5% of OOIP under 2,000 psi BHP constraint). Nevertheless, the higher production was accompanied by much severe pressure drop. By the end of the 20th year, the average reservoir pressure had dropped to less than 3,000 psi and the pressure of near wellbore regions were very close to the bottom-hole pressure. Therefore, gas injection was utilized to assess the efficiency of pressure maintenance in the highly depleted reservoir.

Figure 6-32 Pressure profile of Niobrara # 1 gas injection model at the end of simulation.
As discussed previously, the producer only model was run for 10 years before adding the injector. The gas injection lasted for three years since 1/1/2020 and the injector was then shut in. For the Niobrara # 2 model, all five injection rates can be successfully simulated. The daily oil production rate is plotted in Figure 6-33. It shows that the improvement in oil production is not very obvious when the amount of gas injected is low (i.e., below 1,500 Mscf/day). When the gas rate was raised to 5,000 Mscf/day, the daily production enhancement can be observed in two months after the injection. In the 10,000 Mscf/day injection model, the producers responded to the gas injection within 20 days, and the peak oil rate reached 420 bbl/day, which is more than four times of the non-injection model.

Figure 6-34 shows 20 years cumulative oil production comparison of different injection schemes. Although 1,500 Mscf/day or lower injection rate models did not show much improvement, larger volume of injected gas had significantly enhanced the recovery. Comparing to the producer only model, the incremental oil production is 17% in the 5,000 Mscf/day injection model and 32% in the 10,000 Mscf/day injection model. The average reservoir pressure after 20 years was raised from 2,957 psi to 3,118 psi and 3,312 psi, respectively, when the injection rate was set at 5,000 Mscf/day and 10,000 Mscf/day.

The reservoir pressure profile at the end of the 20th year is shown in Figure 6-35. With the help of the injection well, the areas between two horizontal wells were more efficiently drained, and the pressure of the entire reservoir was maintained.

Overall, the simulations indicate that gas injection is an effective approach to enhance hydrocarbon recovery in milli-Darcy permeability (or slightly less) reservoirs. The desired injectivity can be achieved with high fluid mobility. In general, larger amount of gas injection will lead to better pressure maintenance and higher recovery.
Figure 6-33 Daily oil production rate with different injection rates (Niobara # 2 sample model).

Figure 6-34 20 years cumulative oil production with different injection rates (Niobara # 2 sample model).
6.4.3 Carbonate sample model

The carbonate sample has a measured permeability range of 100 nD - 900 nD. The results of the non-injection model showed that the areas between two production wells were essentially undrained in 20 years. Well injectivity could be achieved when the gas injection rate of 100 Mscf/day, 500 Mscf/day, 1,000 Mscf/day and 1,500 Mscf/day were used. Similar to the Niobrara # 1 model, larger volume of gas could not be injected into the existing model due to low reservoir conductivity and high reservoir pressure. Nevertheless, the relatively low injection rates had proved the feasibility of gas injection IOR in this carbonate sample model. Figure 6-36 and Figure 6-37 are the daily oil rate and cumulative production over 20 years. With 1,000 Mscf daily gas injection rate, the cumulative production increased by approximately 30%. While in case of 1,500 Mscf/day injection, the daily oil rate climbed to approximately 100 bbl/day after

Figure 6-35 Pressure profile of Niobrara # 2 gas injection model at the end of simulation.
the injection, and the declined rate by the end of simulation is still two times higher than that from the non-compaction model. The cumulative production as of 2030 is 62% higher than the producer only model.

Figure 6-36 Daily oil production rate with different injection rates (Carbonate sample model).

Figure 6-37 20 years cumulative oil production with different injection rates (Carbonate sample model).
The reservoir pressure map of 1,500 Mscf/day injection case as of 1/1/2030 is shown in Figure 6-38. It shows that the pressure of entire reservoir was raised by the gas injection. As the pressure dependent permeability table indicates, the effective reservoir permeability was significantly improved due to pressure maintenance. For the production wells, the region covered by the zipper fractures received better pressure support than the other side; and accordingly, the area between injector and producers was more efficiently depleted. This information can be used to better design the injection well structure. The simulation implies that longer overlapping fractures from the injector and producers have more opportunity to enhance recovery by creating extensive fracture network and maintaining reservoir pressure. The pressure map also indicates that the 1,500 Mscf/day gas injection is unlikely to exert influence on the adjacent reservoir sectors, since the reservoir pressure outside the main drainage area is almost unaffected.

Figure 6-38 Pressure profile of the carbonate gas injection model at the end of simulation.
6.4.4 Selected model from SPE 71750-PA

The absolute permeability in the fourth compaction model is on the magnitude of micro-Darcy. It has the most severe permeability decline among the four models. The simulated oil recovery from the original production well only model is approximately 1.8% for each well. The same gas injector was placed in the center of the producers to simulate the production enhancement.

The simulation results indicate that large volume of gas (5,000 Mscf/day and 10,000 Mscf/day) could not be injected into the reservoir model for three consecutive years. If excessive gas was injected, abnormally high pressure would be accumulated near the wellbore, leading the breakdown of the reservoir rocks. In that scenario, the principle of gas injection IOR will be violated and the gas injectivity will be lost.

The daily oil rate from non-injection model and four injection models were plotted in Figure 6-39. The production enhancement is not evident in the cases of low injection rate. Nevertheless, when 1,500 Mscf daily gas was injected, the production well appeared to respond within four months. The oil rate increased rapidly and reached 110 bbl/day in 2024, which is twice higher than the non-injection model. Moreover, the declined daily rate 7 years after injection is still roughly the same to that right before the injection (approximately 55 bbl/day).

Figure 6-40 compares the cumulative oil production in non-injection model and injection models. The plot shows that 520,000 bbls oil would be produced from each well in 20 years if there was no gas injection. In general, the incremental oil production is proportional to the gas injection rate. 15% more oil would be produced with the injection rate of 1,000 Mscf/day; while the recovery will be another 8% higher if 1,500 Mscf/day gas was injected.

The pressure maps of the 1,500 Mscf/day injection model on 2023 and 2030 were shown in Figure 6-41 and Figure 6-42. The average reservoir pressure between the injector and producers were approximately 5,500 psi, which correspond to roughly two times local permeability increase. By the end of the simulation, a large percentage of the reservoir was drained while the boundary remained unaffected. The results imply that gas injection revitalized more reservoir rocks and effectively enhanced reservoir recovery.
Figure 6-39 Daily oil production rate with different injection rates (selected compaction model from SPE 71750-PA).

Figure 6-40 20 years cumulative oil production with different injection rates (Selected model from SPE 71750-PA).
Figure 6-41 Pressure profile of the 1,500 Mscf/day injection model on 2023.

Figure 6-42 Pressure profile of the 1,500 Mscf/day injection model on 2030.
6.4.5 Summary

The simulated 20 years cumulative oil production from non-injection and injection models is summarized in Table 6-8 and the incremental oil percentage of the injection models is listed in Table 6-9. The gas injection has potential to increase the production in stress sensitive reservoirs by 60%. Nevertheless, the injectivity may be difficult to achieve in low permeability reservoirs as indicated by the “NA” in the tables.

Table 6-8 Summary of 20 years cumulative oil production from different permeability models. 1 – Niobrara sample # 1; 2 – Niobrara sample # 2; 3 – Carbonate sample; 4 – selected data from SPE 71750-PA.

<table>
<thead>
<tr>
<th>No.</th>
<th>No Injection</th>
<th>Injection (Mscf/day)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>4.36E+04</td>
<td>4.37E+04</td>
</tr>
<tr>
<td>2</td>
<td>1.52E+06</td>
<td>1.54E+06 1.56E+06</td>
</tr>
<tr>
<td>3</td>
<td>1.64E+05</td>
<td>1.65E+05 1.75E+05 2.13E+05</td>
</tr>
<tr>
<td>4</td>
<td>5.20E+05</td>
<td>5.34E+05 5.59E+05 5.96E+05 6.31E+05</td>
</tr>
</tbody>
</table>

Table 6-9 Incremental cumulative oil production after gas injection, comparing to non-injection scenarios. 1 – Niobrara sample # 1; 2 – Niobrara sample # 2; 3 – Carbonate sample; 4 – selected data from SPE 71750-PA.

<table>
<thead>
<tr>
<th>No.</th>
<th>100</th>
<th>500</th>
<th>1000</th>
<th>1500</th>
<th>5000</th>
<th>10000</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>0.11%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>0.54% 1.55% 2.87% 4.19% 15.40%</td>
<td>29.91%</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>0.68% 6.72% 29.51% 62.01%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>2.68% 7.37% 14.45% 21.30%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
6.5 Gas injection enhanced recovery mechanism

The simulation study shows that gas injection has the potential to substantially improve well production from different types of tight reservoirs. Nevertheless, the mechanism of enhanced recovery in stress sensitive tight reservoirs is yet unclear. Is the incremental production a result of the common mechanism of gas displacing residual oil? Or is the pressure maintenance achieved by gas injection the key factor for enhanced recovery in tight formations? In order to answer these questions, further simulation study needs to be conducted. In this section, the compaction model and non-compaction models are compared with and without gas injection. Four simulation cases were run and categorized into two groups as Figure 6-43 shows. The comparison of incremental oil production from the two groups indicates the significance of different enhanced recovery mechanisms.

Figure 6-43 Simulation scenarios for gas flood enhanced recovery mechanism study.
The reservoir properties, pressure dependent compaction table and well injection rate used in the four models are summarized in Table 6-10. Detailed reservoir properties can be referred to Table 6-1 and Table 6-4. The original permeability was set at 5,000 psi pore pressure condition, while the pressure dependent permeability table includes higher pressure to cover the gas injection scenarios. The gas injection rate was selected to be 1,000 Mscf/day such that injectivity is not a problem in the simulation with low permeability.

Table 6-10 Simulation input for the compaction models.

<table>
<thead>
<tr>
<th>Porosity (%)</th>
<th>7</th>
</tr>
</thead>
<tbody>
<tr>
<td>Original horizontal permeability (md)</td>
<td>0.0008</td>
</tr>
<tr>
<td>Original vertical permeability (md)</td>
<td>0.00008</td>
</tr>
<tr>
<td>Gas injection rate (Mscf/day)</td>
<td>1,000</td>
</tr>
</tbody>
</table>

Table 6-10 (continued)

<table>
<thead>
<tr>
<th>Pressure dependent permeability</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pore Pressure (psi)</td>
</tr>
<tr>
<td>---------------------</td>
</tr>
<tr>
<td>300</td>
</tr>
<tr>
<td>600</td>
</tr>
<tr>
<td>900</td>
</tr>
<tr>
<td>1200</td>
</tr>
<tr>
<td>1500</td>
</tr>
<tr>
<td>1800</td>
</tr>
<tr>
<td>2100</td>
</tr>
<tr>
<td>2400</td>
</tr>
<tr>
<td>2700</td>
</tr>
<tr>
<td>3000</td>
</tr>
<tr>
<td>3300</td>
</tr>
<tr>
<td>3600</td>
</tr>
<tr>
<td>3900</td>
</tr>
<tr>
<td>4200</td>
</tr>
<tr>
<td>4500</td>
</tr>
<tr>
<td>4800</td>
</tr>
<tr>
<td>5000</td>
</tr>
<tr>
<td>5500</td>
</tr>
<tr>
<td>5800</td>
</tr>
</tbody>
</table>

The other PVT and well data are the same to those used in previous simulation cases.
The simulated daily oil rate and 20 years cumulative oil production for the four cases are shown in Figure 6-44 and Figure 6-45, respectively. It can be seen from the daily production plot that the oil rate in both non-injection cases stabilized after 5,000 days. However, the injection cases show different response to the gas injection. The production in the non-compaction and injection case slightly increases (red curve), whereas the compaction and injection shows significant improvement from 18 bbl/day to 43 bbl/day (purple curve). Although the purple curve seems to decline faster than the red curve, the cumulative oil production plot indicates that incremental oil in the compaction model is significantly higher than the non-compaction model. In fact, gas injection increase 11.5% production in non-compaction model (red curve versus blue curve); while the incremental is approximately 30% when stress dependent compaction is considered (purple curve versus green curve).

The simulation results illustrate the following points. First of all, both gas displacing oil and pressure maintenance are significant mechanisms for enhanced recovery in low permeability reservoirs. To some extent, pressure maintenance replies on the displacing effect to reactivate more reservoir rocks. Secondly, pressure maintenance can be the key mechanism in the EOR process if the permeability is a strong function of pressure and stress conditions. Thirdly, it can be inferred from the study that the weight of gas displacing oil and pressure maintenance mechanism can be altered depending on the injection scheme, stress sensitivity of reservoir rocks and other reservoir properties.

Furthermore, it should be noticed that other mechanisms might exist in the process of gas injection in tight reservoirs. However, it is very difficult to validate the existence of these factors or to quantify their effects with numerical simulation study. Therefore, further field pilots are strongly recommended to investigate the feasibility of gas injection and other EOR approaches in low permeability reservoirs. It is believed that integrated data analysis, which combines laboratory measurements, numerical simulation and field test, is the key to understand the underlying mechanisms and to improve the recovery.
Figure 6-44 Daily oil production rate for the four combination models.

Figure 6-45 20 years cumulative oil production for the four combination models.

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6.6 Gas re-utilization ratio

For any gas injection enhanced recovery project, the source of injection gas is an integral part of reservoir development planning. The CO$_2$ flooding projects, for example, rely largely on the infrastructures in a particular basin. Otherwise, undermine the project economic would be significantly undermined by the long distance transportation. For natural gas injection projects, however, the light components (i.e., methane and ethane) produced from adjacent wells can be used for re-injection such that the flaring issue can be resolved as well. The cumulative gas production of different coupled compaction simulation models are summarized as below. Since the Niobrara sample #1 did not show obvious oil production improvement with gas injection, its results are excluded from the analyses in this section.

![Cumulative gas production with different gas injection ratio](image)

Figure 6-46 Cumulative gas production with different gas injection ratio (with compaction model of Niobrara #2).
Figure 6-47 Cumulative gas production with different gas injection ratio (with compaction model of Carbonate sample).

Figure 6-48 Cumulative gas production with different gas injection ratio (with compaction model from SPE 71750).
The gas re-utilization ratios from the simulations are summarized in Table 6-11. It can be seen that for most cases, the production/injection ratio is greater than one (based on production well: injection well = 1:1, and there are two producers in the simulation model), which supports the viability of natural gas injection in the simulation scenarios.

Table 6-11 Gas production versus Injection ratio for different models and injection rates (producer: injector = 1:1).

<table>
<thead>
<tr>
<th>Injection rate (Mscf/day)</th>
<th>Niobrara # 2</th>
<th>Carbonate</th>
<th>SPE 71750</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas Production/Injection</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>100</td>
<td>72:1</td>
<td>8:1</td>
<td>19:1</td>
</tr>
<tr>
<td>500</td>
<td>15:1</td>
<td>1.5:1</td>
<td>4:1</td>
</tr>
<tr>
<td>1000</td>
<td>7:1</td>
<td>0.8:1</td>
<td>2:1</td>
</tr>
<tr>
<td>1500</td>
<td>5:1</td>
<td>0.5:1</td>
<td>1.4:1</td>
</tr>
<tr>
<td>5000</td>
<td>1.5:1</td>
<td>0.25:1</td>
<td>0.6:1</td>
</tr>
<tr>
<td>10000</td>
<td>1:1</td>
<td>NA</td>
<td>NA</td>
</tr>
</tbody>
</table>

### 6.7 Dual porosity/ dual permeability model

All the simulation models discussed above are single porosity models, in which rock matrix is considered as the only flow component. The advantages of using single porosity model can be found in the following aspects. First, the quality of simulation input data is more reliable. For instance, the rock matrix permeability used in the above realizations were directly obtained from laboratory measurements; whereas the natural fracture properties used in the dual porosity/ dual permeability models need to be assumed in most cases since direct measurement can be very difficult and the credibility of the results are often questionable. Secondly, solving single porosity problems are more straightforward and less error-prone in terms of computational performances. Unlike the dual porosity/ dual permeability model, in which complex transfer functions exist between the matrix and natural fractures, the single porosity model tend to solve the problem more smoothly while avoiding some complicated convergence problems. Meanwhile, the computational speed of the single porosity model is...
much faster than that of dual porosity models. Therefore, the general idea of conventional reservoir simulation is to use single porosity model and to keep the model as simple as possible, unless the reservoir exhibit strong dual porosity characteristics or the properties of natural fractures are accurately calibrated for special needs.

In unconventional tight reservoirs, nonetheless, the guideline for selecting flow model can be significantly different. In some cases, the dual porosity/dual permeability models are more desirable than the single porosity models. The advantages of using dual porosity/dual permeability model in tight reservoir simulation include the following aspects. First of all, most commercial shale and other type of tight reservoirs are naturally fractured. Although it is possible that the natural fractures are discrete and sparse in some particular layers or reservoir sections, the current consensus is that they are usually existed and widely distributed in the geological sweet spots. The natural fracture networks connect the impermeable pores and enable fluid flow in the tight formations.

Secondly, multi-stage and massively fractured horizontal wells are used to produce hydrocarbon from all commercial tight reservoirs. The hydraulic fractures induce large amount of secondary fractures during completion and stimulation works. The induced fractures connect with the existing natural fractures, forming more permeable conduits to accept reservoir fluids. Upon completion of the stimulation job, the newly established fracture networks still exist in the reservoir and facilitate the production.

Thirdly, tight reservoirs usually contain more flow media than conventional reservoirs. It is more practical to include fluid flow behaviors of different flow components in the simulation model. Accordingly, the dual porosity/dual permeability model is considered to better describe fluid flow in tight reservoirs.

Furthermore, gas injection enhanced recovery was simulated in this work. Large volume of gas increases the pressure around the fractures and wellbore, and the high injection rate has similar effects as hydraulic fracturing. Therefore, it is necessary to consider the secondary fractures in the gas injection simulation.
In this section, gas injection with dual permeability model will be discussed. Two dual permeability models were established with the previously mentioned rock and fluid data. It was assumed that the fracture spacing for the two horizontal directions are the same, which equal to 320 ft \((DIFRAC = DJFRAC = 320 \text{ ft})\) and the fracture spacing for the vertical direction is 200 ft \((DKFRAC = 200 \text{ ft})\). This assumption generally means that natural fractures are evenly distributed in the reservoir model and the distance between two natural fractures is 5 matrix gridblocks.

The porosity of rock matrix and fracture were assumed to be 7\% and 0.1\%, respectively. The range of matrix and natural fracture permeability for the two dual permeability models are summarized in Table 6-12. In fact, the permeability of dual permeability model \# 1 was from the Niobrara \# 1 and SPE 71750-PA, while the Niobrara \# 2 and the carbonate models were combined to build the second dual permeability model.

The rock matrix relative permeability curves are the same as in the single porosity models. Figure 6-49 and Figure 6-50 show the relative permeability functions for the natural fractures. The initial PVT data in the dual permeability models are the same as those used in the single porosity model. The same producers and injector were used in the dual permeability models and the production wells were constrained at 2,000 psi BHP. The total length of simulation was kept at 20 years.

<table>
<thead>
<tr>
<th>Initial Horizontal Permeability (md)</th>
<th>Dual Perm # 1</th>
<th>Dual Perm # 2</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Matrix</strong></td>
<td>0.00002</td>
<td>0.00007</td>
</tr>
<tr>
<td>min</td>
<td>0.00005</td>
<td>0.00008</td>
</tr>
<tr>
<td>max</td>
<td>0.0015</td>
<td>0.2</td>
</tr>
<tr>
<td><strong>Fracture</strong></td>
<td>0.01</td>
<td>0.6</td>
</tr>
<tr>
<td>min</td>
<td></td>
<td></td>
</tr>
<tr>
<td>max</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Figure 6-49 Water-oil relative permeability function for dual permeability model.

Figure 6-50 Gas-liquid relative permeability function for dual permeability model.
6.7.1 Dual permeability model # 1

The first dual permeability model was built based on the Niobrara # 1 single porosity model. Because the matrix permeability is extremely low, only small volume of gas could be injected (100 Mscf/day) in the single porosity model and essentially the cumulative production was not improved by the gas injection. In order to evaluate the feasibility of gas injection in fractured tight reservoirs, the fourth permeability model discussed above was combined in the model and utilized as the fracture permeability. The injection and non-injection model were compared in case of single porosity model and dual permeability model, respectively. Figure 6-51 shows the simulated daily oil production over 20 years. The overlapping curves (the red and dark blue ones) correspond to the single porosity models. As discussed above, the injectivity is a severe issue in reservoirs with extremely low permeability, and therefore only a small volume of gas can be injected (100 Mscf/day). As a result, no incremental oil is seen from such tight reservoir with gas injection method.

The situation has changed in the dual permeability models. Similar to the single porosity model, the daily oil production is rapidly decreasing in the first several years (from 2010 to 2016). Despite the rapid decline, the oil rate is still significantly higher than that of the single porosity model. In this period, the major flowing component is the natural fracture system, while the contribution from rock matrix is quite limited due to low conductivity. Subsequently, the daily rate starts increasing. In this period, the matrix starts compensating the natural fractures so that the overall production is improving.

The dual permeability model also shows different behaviors as responded to the gas injection. The purple curve is one of the gas injection cases with 100 Mscf/day injection rate. Oil production jump is observed right after the gas injection. Moreover, larger volume of gas can be injected in the dual permeability model without causing injectivity issues, as seen in the 1,000 Mscf/day injection case (light blue curve). In this scenario, the production rate at the beginning of gas injection is approximately four times comparing to the non-injection model. The 20 years cumulative oil production for different cases is plotted in Figure 6-52. Again, no incremental oil was seen from the single porosity model. Nevertheless, the incremental
percentage is 6.2% for the 100 Mscf/day case, and 11.3% for the 1,000 Mscf/day case with the dual permeability models.

The simulation results imply that gas injection is actually useful for production enhancement in extremely low permeability reservoirs, as long as some natural fractures or other permeable flow components are existent and connected to each other. In such cases, the issue of injectivity is no longer critical since the reservoir is more conductive and the pressure dissipation in the entire reservoirs is much faster.

Figure 6-51 Comparison of daily oil production between injection and non-injection model, dual permeability model # 1 with corresponding single porosity model.

Figure 6-52 Comparison of 20 years cumulative production between injection and non-injection model, dual permeability model # 1 with corresponding single porosity model.
6.7.2 Dual permeability model # 2

The rock matrix and natural fracture permeability in the second dual permeability model is much higher than those used in the first model. The simulated daily oil rate and cumulative production are shown in Figure 6-53 and Figure 6-54, respectively. It can be seen that the production responses differ significantly from the single permeability model results. Although peak production is observed initially, the oil rate dropped drastically afterwards and finally equalized with the non-injection case. The overall effect is that no incremental oil being produced with gas injection, as indicated from the cumulative production comparison.

The production of the two dual permeability models is very different in respond to the gas injection. It is found that the gas breakthrough time in the second model with higher overall permeability is faster than that of the first model. A lot more injected gas was produced shortly after the injection, leaving the reservoir undrained. Therefore, the desired reservoir pressure maintenance effects by gas injection were not achieved in the second model. Moreover, since the injected gas was not effectively distributed into rock matrix, large amount of gas would occupy the natural fracture system, which would further lower relative permeability and mobility of the oil phase. For the combined reasons, gas injection showed negative impacts on the overall production.

Although the first dual permeability model showed positive results of gas injection, it should be noticed that the natural fractures are evenly distributed in the entire reservoir and are interconnected with each other. The injectivity issue could remain if the fractures are highly discrete and much less conductive. In such scenario, gas injection might be ineffective in certain part of the reservoir.

Overall, the gas injection enhanced recovery in tight reservoirs is very complicated and the results depend on a lot of factors, including well configuration, fracture properties, reservoir properties and well constraints. Field case study is a necessity to understand the viability of gas injection in a particular reservoir.
Figure 6-53 Comparison of daily oil production between injection and non-injection model, dual permeability model # 2 with corresponding single porosity model.

Figure 6-54 Comparison of 20 years cumulative production between injection and non-injection model, dual permeability model # 2 with corresponding single porosity model.
6.8 Summary

This chapter presents numerical simulation study of stress dependent compaction. Multiple simulation scenarios were run to study the production response due to permeability decline. Gas injection was tested as a potential enhanced recovery method. The base model was established on the basis of the experimental work discussed in chapter 4 and chapter 5. The simulated region is 5,280 ft by 4,000 ft laterally, with the thickness of 360 ft. The model includes two horizontal producers and one horizontal injector. Planar hydraulic fractures were applied to each horizontal well and effective fracture width and conductivity were used to define the hydraulic fracture. The simulation study in this chapter can be divided into two parts. In the first part, only two producers were included in the model and the wells were producing with natural energy. In the second part, the injector was added to the model to simulate the potential EOR method.

Several subjects were investigated in the producer only model. First of all, the compaction model was compared with the traditional non-compaction model. Four groups of simulations with different stress dependent permeability models were run to compare the daily oil rate and cumulative oil production. The results show that the non-compaction model would overestimate the 20 years cumulative oil recovery by more than 20%. Furthermore, the overestimation with non-compaction models is proportional to the stress sensitivity of the reservoir rocks.

Secondly, different well constraints were investigated with the four compaction models. Multiple realizations were run for each compaction model with different well bottom-hole pressure. It was speculated that maintaining the bottom-hole pressure at relatively high level would result in better long-term production as severe stress dependent compaction would lower the permeability significantly. However, the simulation results showed that pressure drawdown is still the key production mechanism in stress sensitive tight reservoirs and the hydrocarbon recovery would not be enhanced by bottom-hole pressure maintenance. The findings imply that it is difficult to eliminate the compaction effects on production by adjusting the production well constraint. External energy is needed in order to improve the recovery. In
addition, since the difference in cumulative production between different well BHP scenarios is relatively small while lower BHP would reduce the average reservoir pressure significantly, it is important to evaluate the overall depletion strategy in order to facilitate the potential IOR projects in tight reservoirs.

In the second part of simulation, gas injection well was added to the model to study the potential enhanced recovery method in stress sensitive tight reservoirs. The gas injector was set in the center of two producers and the lateral distance to each producer is 640 ft. Totally 11 hydraulic fractures were put on the injector with the half-length of 400 ft and height of 200 ft. Zipper fracture configuration was utilized and the J-direction overlapping between producers’ and injector’s fractures is approximately 200 ft, such that more extensive fracture networks were created to facilitate fluid flow within the stimulated area.

Gas injection simulations were run for four compaction models with different injection rates. The results indicate that approximately 20% - 60% incremental oil would be produced comparing to the non-injection models provided that the desired injectivity can be achieved. Nevertheless, the injectivity could be a critical issue in extremely low permeability reservoirs, due to low fluid mobility and accumulated pressure. In such cases, essentially no incremental oil would be produced with low volume of injected gas.

The mechanisms for gas injection EOR in tight reservoirs were investigated with further simulations. Essentially two types of mechanisms were compared in the study: the traditional flooding mechanism and pressure maintenance effects. The results show that both can be important mechanisms in tight reservoir production enhancement. When severe stress dependent compaction is encountered, the pressure maintenance would be the key factor for reservoir conductivity revitalization and hence leads to improved recovery.

Two groups of dual permeability models were run to test the gas injection in fractured tight reservoirs. The results of the two models are significant different. In case of ultra-low permeability, moderate gas injection would improve the long-term production without causing injectivity issues; whereas the model with better reservoir and natural fracture conductivity
suffered from early breakthrough of injected gas and no incremental oil can be produced. Further study is needed for the dual permeability injection model, while detailed reservoir characterization and field data are required.

The simulation study also indicates that reliable modelling work relies on extensive laboratory measurement as the rock properties in different types of reservoirs are significantly different. Additionally, field pilots are required to further validate the experimental and numerical simulation researches.
CHAPTER 7 CONCLUSIONS

In this work, stress dependent compaction in tight reservoirs was studied using laboratory core measurements and numerical simulation. The innovations of the work include the following aspects. First, extensive amount of permeability measurements were conducted on individual shale and carbonate sample to characterize the stress dependent compaction. Secondly, the permeability decline signatures were integrated with the degree of tight reservoir depletion and field application suggestions were made based on the analyses. Thirdly, the permeability decline models were generated based on the concept of effective stress law. Then, coupled stress dependent compaction simulations were run to investigate long-term reservoir recovery. Based on the experimental measurements and initial simulation results, potential enhanced oil recovery approaches were investigated with further simulation realizations. It was found that gas injection is a possible solution for production improvement in low permeability reservoirs, provided that the desired injectivity can be achieved. Although the preliminary study showed prospect for gas EOR in tight formation, further integrated research is needed to test the feasibility. The main research procedures of this work, as well as important results and findings are recapped as follow.

The research starts with experimental work of tight rock permeability measurements. The laboratory instruments, rock sample preparation and test conditions were presented in Chapter 3 and Chapter 4. Chapter 5 discussed the entire process of stress dependent permeability measurements and interpretations for the shale and carbonate samples. Two instrument assemblies were used to conduct the experiments. The CMS-300 instrument was initially employed to measure confining stress dependent sample permeability. The measurements with the CMS-300 system are fast and automatic; however, the major drawback of it is that only low, constant (approximately 100 psi) pore pressure can be applied in this system. Since effective stress is the key for to investigate stress dependent compaction, multiple combinations of pore pressure and confining stress are required for the measurements. Therefore, the CMS-300 assembly was replaced by the new core holder assembly. Nevertheless, the results from the CMS-300 system truly demonstrate the stress sensitivity of tight rock
permeability and the data imply that further efforts are required to unveil the permeability
decline behaviors in tight reservoirs. Inspired by the results, a new sample holder assembly was
acquired within which both pore pressure and confining stress can be applied. Three different
tight rock samples were measured using the new instrument under a variety of pore pressure
and confining stress conditions. The measured data (permeability and sample downstream
equilibrium time) were interpreted to illustrate the pressure dependent compaction during
tight reservoir depletion. The Biot coefficient of different samples was interpreted using
laboratory trial and error method. Finally, the experiment derived permeability decline models
were established for numerical simulation study. The results from the experimental work are
summarized as follow:

1) The reduction in recorded sample downstream equilibrium time and the increase in
measured rock permeability as a function of applied pore pressure at any specific
confining stress condition suggest that the pressure dependent compaction is a
significant phenomenon in tight formations;

2) The tight rock permeability is not a monotonic function of average reservoir
pressure for a specific reservoir. At low reservoir pressure conditions, increasing
pore pressure results in a smooth and linear increase in tight rock permeability;
while continuously increase of pore pressure leads to the transition from linear
increase to more complicated algorithm (i.e., logarithmic or power law) as the
critical pore pressure condition is exceeded;

3) The critical pressure window was defined as the pressure conditions where the
trend of permeability decline is significantly changed. Based on the pressure
transmission test data, the critical confining stress to pore pressure ratio was
identified for different samples. The critical pressure window is a complex function
of rock properties and porous components. For the matrix dominant Niobrara shale
sample, the critical confining stress to pore pressure ratio is approximately 1.5 - 2,
whereas this ratio is 2 - 2.5 for the fractured Niobrara shale sample and the
carbonate sample;
4) Continuous depletion in the tight reservoir below the critical $P_c/P_p$ ratio would induce significant compaction and permeability degradation while efficient pressure maintenance has the potential to revitalize tight formations and enhance ultimate recovery. Therefore, gas injection is a possible approach to improve liquid rich basin oil recovery. Nonetheless, a series of flow simulations and field pilots are needed to test the viability of the possible EOR/IOR schemes.

5) The Biot coefficient $\alpha$ for the tight rock samples was determined experimentally using trial and error methodology. The analyses showed that tight rocks with different dominant porous media hold different Biot coefficients. The data fitting suggested that the Biot coefficient is close to 0.8 for the matrix dominated shale sample, while the fractured shale sample and the carbonate sample render a reasonable $\alpha$ value of approximate 1. The Biot coefficient and effective stress are incorporated into flow simulation.

6) The permeability decline models were established using experimental data. Power law algorithm was used to describe the relationship between effective stress and rock permeability.

Coupled stress-dependent-compaction numerical simulation was performed after the experimental work. Chapter 6 presents model setup, simulation realizations as well as result interpretations and discussions. Multiple simulation scenarios were run to study different aspects of the models. The base model includes two horizontal producers; and one horizontal injector was added in the gas injection cases. Planar hydraulic fractures were applied to each horizontal well and effective fracture width and conductivity were used to define the hydraulic fracture. The simulation study can be divided into two parts. In the first part, several different producer only scenarios were investigated. This stage was considered as primary depletion within which the wells were producing with natural energy. In the second part, the injector was added to the model to simulate the potential EOR method.

Several subjects were investigated in the producer only models and gas injection models. The main conclusions from numerical simulation include the following aspects.
1) For the non-injection scenarios, the compaction model was first compared with the traditional non-compaction model. Four groups of simulations with different stress dependent permeability models were run to compare the daily oil rate and cumulative oil production. The results show that the non-compaction model would overestimate the 20 years cumulative oil recovery by more than 20%. Furthermore, the overestimation with non-compaction models is proportional to the stress sensitivity of the reservoir rocks.

2) Different well constraints were investigated with the four compaction models. Multiple realizations were run for each compaction model with different well bottom-hole pressure. It was speculated that maintaining the bottom-hole pressure at relatively high level would result in better long-term production as severe stress dependent compaction would lower the permeability significantly. However, the simulation results showed that pressure drawdown is still the key production mechanism in stress sensitive tight reservoirs; whereas the attempt to maintain reservoir pressure by keeping the well bottom-hole pressure relatively high is not an effective method to improve well production. The findings imply that it is difficult to eliminate the compaction effects on production by adjusting the production well strategies. Therefore, external energy is required and hence gas injection simulations were run. Furthermore, since the difference in cumulative production between different well BHP scenarios is relatively small in primary depletion stage while the lower BHP would reduce the average reservoir pressure significantly, it is important to evaluate the overall depletion strategy in order to facilitate the potential IOR projects in tight reservoirs.

3) In the gas injection scenarios, an injection well was added to the model to study the potential enhanced recovery method in stress sensitive tight reservoirs. The gas injector was set in the center of two producers such that both wells could benefit from the injection. Zipper fracture configuration was utilized and the fractures of the injector overlap with the fractures of the producers in the J-direction by approximately 200 ft, to ensure that more extensive fracture networks were created to facilitate fluid flow within the stimulated area. Gas injection simulations were run for four compaction models
with different injection rates. The results indicate that approximately 20% - 60% incremental oil would be produced comparing to the non-injection models provided that the desired injectivity can be achieved. Nevertheless, the injectivity could be a critical issue in extremely low permeability reservoirs, due to low fluid mobility and accumulated pressure. In such cases, essentially no incremental oil would be produced with low volume of injected gas.

4) The mechanisms for gas injection EOR in tight reservoirs were investigated with further simulations. The results show that both of the traditional flooding mechanism and the pressure maintenance effects are the keys for tight reservoir production enhancement. Furthermore, the pressure maintenance would be the most important factor for reservoir conductivity revitalization and recovery improvement when severe stress dependent compaction is encountered.

5) The simulation study also indicates that reliable modelling work relies on extensive laboratory measurement as the rock properties in different types of reservoirs are significantly different.
CHAPTER 8 RECOMMENDATION AND FUTURE WORK

As introduced at the beginning of the thesis, the reasons for steep production decline in unconventional low permeability reservoirs can be found in many different aspects. Reservoir compaction, as one of the possible mechanisms for the sharp decline, is by itself a broad research topic. Although comprehensive experimental measurements and multiple simulation realizations were performed, the work conducted in this research is still preliminary compared to the large amount of works to be done. There are a few limitations in this research, both in experimental work and numerical simulation. It is recommended that extensive future work be conducted based on the results and experiences learnt from this work. Some of the recommendations to improve the current work are summarized below.

1) The first possible improvement is related to the experimental apparatus. In this work, the Core Lab biaxial series core holder was utilized for the pressure transmission test. This experimental condition assumed that the core samples were confined by hydrostatic pressure. However, it is not the case in real reservoirs, where the overburden stress (vertical principle stress) is usually higher than the maximum and minimum horizontal principle stresses. The two horizontal principle stresses might be combined in the laboratory measurement, but it is better to apply different confining stress axially and radially. Therefore, it is recommended that true tri-axial core holder assembly to be used in the future experimental work, in order to better reflect real reservoir stress conditions. In addition, since the long lateral horizontal wells and massive hydraulic fractures can exert significant impact on the stress field in tight reservoirs, the variations of in-situ stress need to be obtained before conducting permeability measurements. Therefore, the stress dependent compaction experiment requires collecting sufficient field data and integration with other core sample experiments.

2) Secondly, the pressure transmission test is a useful technique for stress dependent permeability measurements. Due to time limitation, three samples from Niobrara shale and carbonate reservoirs were measured and interpreted. It is recommended that more
samples from different shale formations to be collected and tested with the method, as the compaction behavior is closely related to the intrinsic properties of the specific reservoir rock.

3) Since the composition of minerals in unconventional tight reservoirs is very complex, it is important to take measurement of rock minerology in the future work and relate it to the permeability decline.

4) For determination of the Biot coefficient, the current trial and error technique requires as many permeability measurements as possible. Since the pore pressure interval used in this work is 400 psi, this value can be lowered in future work to generate more measured data. Furthermore, since the Biot coefficient is possibly a function of changing pore pressure or effective stress, the investigation of varying Biot coefficient can be another potential research topic.

5) For numerical simulation, probably the most urgent need is the real field data. The data needed are from different aspects and stages of field development, including, but not limited to geological properties, rock and fluid sampling data, drilling and completion data and operational strategies. A practical and useful model can be built with the existence of these data. Production data are also essential for the simulation, since they are references for the history matching work, which is commonly used for prediction of production and ultimate recovery. The field data are essentially unavailable during this research, and it is the major limitation for conducting more detailed and comprehensive simulation study. It is recommended that the future work concentrate on a specific reservoir, and establish a history-matched model to investigate the potential improved recovery methods. It is essential to cooperate with the field operator and use the history-matched model to guide further development plan.

6) Since the objective of this work is to investigate the impact of stress dependent compaction on reservoir properties, the conductivity of hydraulic fractures was assumed unchanged throughout the simulation. As some researchers indicate that the degradation of hydraulic fractures is severe during depletion, it might be necessary to include hydraulic fracture conductivity decline in the simulation.
7) Planar hydraulic fracture models were used in this work since no fracture data are available. In fact, a complex fracture model has been added to the commercial simulator recently. It is commended to run the simulation with the complex fracture model if field data can be obtained.

8) Further investigation of the dual porosity/dual permeability gas injection model is suggested if the field data are available and more accurate reservoir characterization can be conducted.

9) For the sake of computational time, the simulation work in this research used a black oil model for the gas injection scenarios. For accurate results, a compositional model is suggested for future work. Meanwhile, the mechanism of CO₂ miscible/immiscible flood needs to be investigated with detailed compositional models.
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