Bakken CO$_2$ Storage and Enhanced Recovery Program – Phase II Final Report

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ABSTRACT

The Bakken Formation has enormous oil resource, but low recovery factors (4% to 10%). The need to improve the productivity of a world-class oil resource and a desire to manage CO₂ emissions has led to interest in the use of CO₂ for enhanced oil recovery (EOR) and associated storage in the Bakken Formation. From 2012 to 2018, the Energy & Environmental Research Center (EERC) conducted the Bakken CO₂ Storage and Enhanced Recovery Program. The program was carried out over two phases. The Phase I results suggested that a better understanding of the fundamental mechanisms controlling the interactions between CO₂ and Bakken rock and reservoir fluids is necessary to develop accurate assessments of CO₂ storage and EOR potential. Therefore a series of laboratory-, modeling-, and field-based activities were conducted from 2014 to 2018 under Phase II of the program.

The Phase II lab- and modeling-based studies demonstrate CO₂ can permeate the Bakken matrix, largely through diffusion, to mobilize oil. The studies also showed that CO₂ will preferentially mobilize lower-molecular-weight hydrocarbons. In 2017, an injection test was conducted in a vertical Bakken well. The objectives of the test were to determine the injectivity of an unstimulated Bakken reservoir (i.e., a reservoir that had not been hydraulically fractured) and the ability of injected CO₂ to permeate the matrix and mobilize oil. Based on modeling and simulation work, a predicted radius was determined to be as much as 140 ft. Field testing showed injectivity of the unstimulated Middle Bakken matrix was found to be low, with stable CO₂ injection rates between 6 and 12 gallons per minute. Approximately 99 tons of CO₂ was injected over 4 days, followed by a 15 day soak period. Preinjection and postinjection oil samples were analyzed for oil composition to determine the molecular weight distribution of the hydrocarbons. Analyses of those samples indicated the composition of the postinjection oil samples had shifted toward the lower-molecular-weight hydrocarbons, suggesting the injected CO₂ penetrated the Bakken matrix and mobilized oil.

Simulation modeling work indicated that a alternating huff ‘n puff approach can more than double the oil recovery factor of a well. Those efforts also showed the presence of water in a Bakken reservoir can have negative impacts on EOR and CO₂ storage. A refined methodology was developed for estimating the CO₂ storage potential of the Bakken. Those estimates show the organic rich Bakken shales may have up to three times more storage resource on a kg CO₂/m³ rock basis than the nonshale Middle Bakken. Bakken Formation storage estimates were 5.8 to 26.3 kg CO₂/m³ rock for the shales and 1.9 to 12.4 kg CO₂/m³ rock for the nonshale rocks.

The overall results of this project provide field-based validation of previous laboratory- and modeling-based studies. Lessons learned provide valuable guidance toward the design and execution of future pilot tests in unconventional tight reservoirs. New insight into the potential CO₂ storage resource of the Bakken was also generated.

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EXECUTIVE SUMMARY

The Bakken Formation in the Williston Basin is a world-class unconventional tight oil play with oil-in-place estimates in the hundreds of billions of barrels. Matrix permeability in the Bakken is typically on the order of micro- to nano-Darcies, and hydraulically induced fractures are necessary to produce oil from the reservoir. Despite the enormous resource, recovery factors are typically low, ranging from 4% to 10%. The Williston Basin also holds world-class lignite coal reserves. Several large lignite coal-fired power plants in North Dakota and Saskatchewan operate within 100 km of the most oil-productive areas of the Bakken Formation. The juxtaposition of a need to improve the productivity of a world-class oil resource with a desire to manage CO₂ emissions from nearby power plants has led to an interest in the potential to use CO₂ for enhanced oil recovery (EOR) and associated storage in the Bakken Formation.

From 2012 to 2018, the Energy & Environmental Research Center (EERC) has conducted the Bakken CO₂ Storage and Enhanced Recovery Program. The U.S. Department of Energy (DOE) and industry consortium-funded program was carried out over two phases. Phase I, which ran from 2012 to 2013, used new and existing reservoir characterization and laboratory analytical data coupled with state-of-the-art modeling to examine the viability of injecting CO₂ in the unconventional tight Bakken Formation for simultaneous carbon storage and EOR. The Phase I results suggested that a better understanding of the fundamental mechanisms controlling the interactions between CO₂ and Bakken rock, oil, and other reservoir fluids in these unique, tight formations is necessary to develop accurate assessments of CO₂ storage and EOR potential. To address those knowledge gaps, a series of laboratory-, modeling-, and field-based activities were conducted from 2014 to 2018 under Phase II of the program.

The Phase II lab- and modeling-based studies demonstrate CO₂ can permeate the Bakken matrix, largely through diffusion, to mobilize oil. Those studies also showed that CO₂ will preferentially mobilize lower molecular weight hydrocarbons. In 2017, an injection test was conducted in a vertical well completed in the Middle Member of the Bakken. The objectives of the test were to determine the injectivity of an unstimulated Bakken reservoir (i.e., a reservoir that had not been hydraulically fractured) and the ability of injected CO₂ to permeate the matrix and mobilize oil. The test was conducted in a virgin Bakken reservoir. The well completion program did not include the use of hydraulic fracturing and proppant. Upon perforation, the well did not flow to surface, but oil samples were collected from the well before injection. Approximately 99 tons of CO₂ was injected over 4 days. The CO₂ was allowed to soak for 15 days. Reservoir pressure and temperature were monitored during all stages of the test using downhole gauges. During the flowback period, gas composition was monitored, and fluid samples were collected. Preinjection and postinjection oil samples were analyzed for oil composition to determine the molecular weight distribution of the hydrocarbons. Pulsed-neutron logs were also run before and after injection to evaluate the vertical distribution of the CO₂ in the near-wellbore environment.

Injectivity of the unstimulated Middle Bakken was found to be low, with stable CO₂ injection rates between 6 and 12 gallons per minute and bottomhole pressure during continuous injection from 9400 to 9470 psi. The CO₂ penetration radius was calculated to be 50 to 70 ft. However,
simulation indicated it may be as much as 140 ft. During flowback, oil flowed to the surface briefly, during which time fluid and gas samples were collected. Analyses of the preinjection and postinjection oil showed that the composition of the postinjection oil samples had greater amounts of lower molecular weight hydrocarbons than the pretest oils. Interpretation of the results from the field test suggests that although matrix injectivity is low, injected CO₂ can penetrate the Middle Bakken to mobilize oil from the matrix.

The data from the field test have also been used in simulation modeling exercises to gain further understanding of the flow characteristics of CO₂ in unconventional tight oil formations. The simulations indicated that the alternating huff ‘n’ puff approach showed the best performance in terms of EOR. In the best cases, the alternating huff ‘n’ puff scheme was predicted to increase the oil recovery factor of a well. These results support the conclusions of previous Phase I modeling work that indicate alternating huff ‘n’ puff approaches may be an effective and economic means of implementing CO₂ EOR and associated storage. The modeling efforts also indicated the presence of water in a Bakken reservoir can have serious impacts on the EOR and CO₂ storage potential of a well. The results suggest that mobile water may tend to accumulate in the lower portions of hydraulically induced fractures, which can impede the contact of injected CO₂ with the lower portions of the Bakken reservoir. As the geographic area of production has expanded, more Bakken wells have been drilled into areas of relatively higher water saturation. The results of these Phase II modeling efforts make an important contribution to furthering the understanding of the role that formation water may have in CO₂ EOR and associated storage.

The Phase II laboratory experimental data and field testing results were applied to develop a refined methodology for estimating the CO₂ storage potential of a tight oil formation, based on the National Energy Technology Laboratory method developed by Goodman and others (2016). This work yielded estimates of the long-term storage of CO₂ in the Bakken using a revised analytical expression informed by laboratory, literature, and simulation data. Application of the refined method indicates that the organic-rich Upper and Lower Bakken shales may have two to three times more storage resource on a kg CO₂/m³ rock basis than the nonshale Middle Bakken. The range of storage estimates for the Bakken shale units is 5.8 to 26.3 kg CO₂/m³ rock, as compared to the nonshale Middle Bakken storage estimates which ranged from 1.9 to 12.4 kg CO₂/m³ rock. The Three Forks storage estimates ranged from 5.6 to 19.9 kg CO₂/m³ rock.

The results of this project provide field-based validation of previous laboratory- and modeling-based studies. They also provide valuable guidance toward the design and execution of future pilot tests in unconventional tight reservoirs. The results also provide insight about how laboratory-, modeling-, and field-based data can be transformed into plausible descriptors of larger-scale field observations, which in turn will yield improved understanding of the potential CO₂ storage resource and EOR opportunities associated with unconventional tight oil reservoirs. The knowledge gained from the Phase II laboratory, modeling, and field-based activities provides new information and data regarding the ability of tight oil-bearing formations to store CO₂ and realize improvements in oil productivity through CO₂ injection.

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SUBTASK 2.20 – BAKKEN CO₂ STORAGE AND ENHANCED RECOVERY PROGRAM – PHASE II

INTRODUCTION

In recent years, the largest booms in oilfield development are in unconventional tight formations (matrix permeability <10 mD), such as the Bakken Formation in North Dakota and Montana and the Eagle Ford Formation in Texas, where fluid flow is dominated by natural and artificially induced fractures. The tight oil resources in the United States are massive, with several hundreds of billions of barrels of oil in place in the Bakken petroleum system (a system that includes the Bakken and Three Forks [TF] Formations but is hereby referred to as simply “the Bakken”) alone (Energy Information Administration, 2013). The Eagle Ford resource appears to be of comparable magnitude, and emerging tight oil plays such as the Niobrara and Tuscaloosa further underscore the growing importance of unconventional oil production to America’s energy portfolio. Given their size and broad geographic distribution, tight oil formations may be great opportunities to simultaneously store large amounts of CO₂ while increasing the recoverable reserves of oil by injecting CO₂ for enhanced oil recovery (EOR). Current methodologies for estimating the potential for CO₂-based EOR and CO₂ storage resource in oil reservoirs are based on knowledge gained over the last 40 years from commercial CO₂ EOR operations in moderate-to high-permeability conventional reservoirs (Jarrell and others, 2002; U.S. Department of Energy, 2008, 2010, 2012; IEA Greenhouse Gas R&D Programme, 2009). However, there is a lack of understanding as to the CO₂ storage and EOR potential in unconventional tight formations which has thus far precluded them as primary targets for EOR or storage. The widespread exploitation of tight oil resources is a relatively recent development (within the last 8 to 10 years); thus the current level of knowledge of mechanisms and factors affecting oil production from, and injection of CO₂ into, tight formations is relatively low when compared to knowledge of conventional reservoirs.

To address those knowledge gaps, a multidisciplinary research project called “Bakken CO₂ Storage and Enhanced Recovery Program” was conducted by the Energy & Environmental Research Center (EERC). The project was designed to take a phased approach. Phase I was conducted from 2011 to 2014, and Phase II was conducted from 2014 to 2018. In early 2014, a final report was published that described the approach, methods, and results of the Phase I activities (Sorensen and others, 2014). The methods, results, and key findings of Phase II are presented and discussed in this report. The Phase II program received funding from the U.S. Department of Energy (DOE), the North Dakota Industrial Commission (NDIC) through the North Dakota Oil & Gas Research Program (OGRP), and a consortium of Bakken operators that included XTO Energy (XTO) – ExxonMobil, Hess, Continental Resources, and Marathon Oil. In-kind support was provided by XTO, Schlumberger, Computer Modelling Group (CMG), and Baker Hughes. Additional cooperation was provided by Kinder Morgan, the North Dakota Department of Mineral Resources Oil and Gas Division, the North Dakota Geological Survey, and the North Dakota Petroleum Council.
**Overview of Phase I Results**

Over the course of 2012 and 2013, Bakken CO₂ Storage and Enhanced Recovery Phase I technical activities were conducted, with a final report presented to DOE in 2014. The objective of that program was to use new and existing reservoir characterization and laboratory analytical data (e.g., core analyses, well logs, oil analyses, etc.) coupled with state-of-the-art modeling to determine the viability of injecting CO₂ into the Bakken Formation for simultaneous carbon storage and EOR.

Generally speaking, the results of the Phase I activities suggest that the CO₂ storage resource of the Bakken Formation in North Dakota ranges from over 160 Mt to as high as 3.2 Gt. The results also indicate that CO₂ may be effective in enhancing the productivity of oil from the Bakken. However, there is no clear, straightforward answer regarding the most effective approach for using CO₂ to improve productivity and facilitate long-term storage. The results generated by Phase I demonstrate that an unconventional resource will require unconventional approaches. With that in mind, it was clear that additional knowledge was necessary to make informed decisions regarding the design and implementation of potential injection, storage, and production schemes. In particular, a better understanding of the fundamental mechanisms controlling the interactions between CO₂ and reservoir (and source) rock, oil, and other reservoir fluids in these unique formations is necessary to develop accurate assessments of potential CO₂ storage. Also, existing modeling and simulation software packages did not adequately address or incorporate the unique properties (e.g., microfractures, high organic carbon content, combined diffusion, adsorption, and very low darcy flow, or the physical interactions between the injected CO₂ and formation fluids) of these tight, unconventional reservoirs in terms of their impact on CO₂ behavior.

**Overview of Phase II Goals and Program Structure**

The knowledge gaps identified in Phase I were targeted by conducting scaled-up laboratory activities integrated with improved modeling and simulation techniques. The ultimate goal of the Phase II Program was to develop knowledge to support the deployment of commercially viable CO₂ injection operations to simultaneously enhance oil recovery and geologically store CO₂ in tight oil-bearing formations. To achieve that goal, the EERC conducted a series of laboratory-, modeling-, and field-based activities to quantitatively determine the effects of injecting CO₂ into the Bakken Formation in North Dakota from the perspectives of CO₂ storage and EOR.

The Phase II activities were organized into two distinct parts: Phase II-A and II-B. The objectives of Phase II-A were to verify and validate the phenomena and mechanisms identified in Phase I, as well as the integration of those laboratory results to more accurately model and simulate the complex processes that occur in these tight, fractured formations. The results of the Phase II-A efforts were designed and conducted to directly support the Phase II-B activities. The objectives of Phase II-B were to apply the insight gained from the Phase I and Phase II-A results toward the design and monitoring of a pilot-scale injection test into a Bakken reservoir.

The end results of the Phase II program, which are presented in this report, yielded a robust characterization data, modeling, and field experience package to enable stakeholders to more accurately assess and predict the ultimate CO₂ storage resource of tight, organic-rich rock
formations. The knowledge gained will also support industry efforts to recover a larger percentage of the oil resources known to exist in unconventional tight reservoirs. Considering the fact that such formations are known to exist in numerous basins throughout the United States and Canada, the impact of this research to the overall North American carbon capture, utilization, and storage (CCUS) portfolio will be substantial.

TECHNICAL BACKGROUND

The Bakken petroleum system (hereafter referred to as “the Bakken”) in the Williston Basin comprises five distinctive geologic rock units. From the shallowest to deepest, those units are the Upper Bakken Shale (UBS), Middle Bakken (MB), Lower Bakken Shale (LBS), and Pronghorn Members of the Bakken Formation and the Three Forks Formation. Traditionally, these units are characterized by ultralow matrix permeability, especially in the organic-rich shales of the Upper and Lower Bakken Shale Members, which causes hydrocarbons to be trapped in localized pore spaces and obstructs their flow to the wellbore without stimulation (Kurtoglu and others, 2013; Aguilera, 2014). The MB and Pronghorn Members of the Bakken Formation and the Three Forks Formation are nonshale reservoir rocks, the lithologies of which are highly variable, including a mix of carbonates and fine-grained clastics. Despite their nonshale classification, they are characterized by low porosity and low permeability and are also considered to be tight oil formations. However, advances in horizontal well drilling and multistage hydraulic fracturing make it possible to economically produce the oil and gas trapped in these unconventional tight rocks (Ozkan and others, 2012). The Pronghorn Member covers a much smaller area than the other units of the Bakken (Johnson, 2013) and was not a primary target for drilling and production in any of the study wells that provided samples for this project, so it will not be discussed further in this report.

Bakken production occurs in a large area of western North Dakota and eastern Montana (Figure 1). So far, over 1 billion barrels of oil have been produced from the Bakken (Helms, 2018). Although the number is encouraging, the long-term sustainability of Bakken production faces a number of challenges (Ran and Kelkar, 2015). One of the most intractable problems is the fast production decline in individual producers, which forces operators to continuously drill new wells or refracture existing wells to maintain their production rate (Baihly and others, 2012). While the Bakken resource is currently in the primary stage of production, investigating secondary or tertiary recovery operations is necessary to increase efficiency and capitalize on existing wells.

One of the primary goals of the EERC’s program is to generate data to support the development of improved CO2 storage capacity estimates for the Bakken Formation. When this project was initiated in 2011, there was no globally accepted method to describe and systematically estimate the CO2 storage capacity, also commonly referred to as CO2 storage resource, of a given geologic sink. Over the past decade, separate efforts to develop an overarching classification system for CO2 storage have been conducted by the United Nations Economic Commission for Europe (UNCE) and the Society of Petroleum Engineers (SPE). The UNCE effort resulted in a section of the United Nations Framework Classification (UNFC) for Fossil Energy and Mineral Reserves and Resources 2009 (United Nations Framework Classification, 2009) that addressed the
assessments of CO$_2$ storage, while the SPE work resulted in the CO$_2$ Storage Resources Management System (SPE-SRMS) published in 2016 (Society of Petroleum Engineers, 2016). To maintain consistency between the two systems, the SPE Carbon Dioxide Capture, Utilization, and Storage Technical Section is working with UNECE to ensure that key definitions and approaches are globally accepted. According to the SPE-SRMS (2016), “Capacity refers to those storable quantities anticipated to be commercially stored by application of development projects to known storable quantities from a given date forward under defined conditions. Capacity must further satisfy four criteria: they must be discovered, storable, commercial, and remaining (as of a given date) on the basis of the development project(s) applied.”

Based on this definition, estimates of CO$_2$ storage potential in the Bakken Formation have not yet met the threshold of being classified as “capacity” because, to date, there are sparse data from the field demonstrating that CO$_2$ can be stored in the Bakken and no data to support the commercial viability of such storage. The SPE-SRMS (2016) states that the term “resources” is “intended to encompass all storable quantities (accessible and inaccessible) within geologic formations – discovered and undiscovered…. Given the relatively early stages of determining the

Figure 1. Map showing productive areas of the Bakken and Bakken wells that have been examined in different EERC studies.
technical and economic viability of CO₂ storage in tight oil formations such as the Bakken, the findings and discussions presented in this report will, therefore, refer to CO₂ storage in the Bakken in terms of “resource” or “potential,” rather than “capacity.”

As mentioned above, the Bakken is characterized by several distinctive lithofacies, each with its own unique properties that may (or may not) significantly affect the mobility and ultimate fate of CO₂ within the formation. The lithofacies of the Bakken Formation can be broadly divided into two groups: the shale group, which includes the Upper and Lower Bakken Shale Members, and the nonshale group, which includes the many lithofacies of the MB Member. The fine-grained clastics and carbonates of the MB Member are representative of a tight, fractured reservoir rock that is capable of transmitting fluids once it has been hydraulically fractured. In North Dakota and Montana, the Middle Member typically comprises between three and seven distinctly different lithofacies that range from silty carbonates to calcite/dolomite cemented siltstones. In most areas of the Bakken Formation, the Middle Member of the formation is bounded above by the UBS and below by the LBS. Both shale members are organic-rich, typically oil-wet shales that are the source rocks for the productive areas of the Bakken (Figure 2). Some of the key challenges associated with characterization of the Bakken include low porosity (typically <10%), low permeability (typically <1 mD), very fine grain minerals (4 to 60 µm) and clay-size particles (<4 µm) that are hard to resolve both chemically and physically, and a high degree of rock heterogeneity. Figure 3 shows a series of photographs of slabbed core samples from the two shale members and key lithofacies of the Middle Member (designated MB L1–L5), illustrating the range of heterogeneity that can be present in Bakken Formation rocks in a single well. These factors directly influence the potential of tight oil formations to transport and store CO₂. They also affect the ability of the injected CO₂ to mobilize oil from the matrix into the fracture network and, ultimately, increase oil production. Inadequate identification of these features poses serious challenges to the development of effective injection and production strategies for CO₂ EOR and storage in tight, fractured reservoirs.

The viability of injecting CO₂ into the Bakken for simultaneous CO₂ storage and EOR has been the focus of previous research activities of the EERC. The results of that work suggest that 1) CO₂ does have the ability to mobilize oil from Bakken shale and MB reservoir rocks; 2) diffusion of CO₂ appears to be an important mechanism for moving oil from the reservoir matrix into the fracture network; and 3) the oil production response of a Bakken reservoir to CO₂ injection may be delayed, but the increase in oil production rates could be as high as 50% (Kurtoglu and others, 2013; Hawthorne and others, 2013; Sorensen and others, 2014). However, pilot-scale field injection tests using CO₂ have not yielded the results predicted by modeling (Sorensen and Hamling, 2016). The disparity between the laboratory and modeling results and the field tests reflects the large degree of uncertainty when it comes to understanding the mechanisms controlling fluid movement and phase behavior in the Bakken. With respect to CO₂ storage, the results of the EERC’s previous efforts suggest that the storage potential of the Bakken ranges from over 160 Mt to as high as 3.2 Gt, with the large degree of uncertainty due, again, to the data gaps in the understanding of fluid-phase behavior in tight, organic-rich, fractured formations (Sorensen and others, 2014). Because fractures and microfractures are the primary fluid flow paths in the Bakken it is critical to understand the nature and distribution of fracture networks within the formation. It is also crucial to understand the phase behavior of CO₂ and oil under reservoir conditions.
Figure 2. Major oil-producing lithofacies of the Bakken petroleum system. The system also includes the Lodgepole Formation (including the Scallion and False Bakken members), which overlies the Bakken Formation (Sorensen and others, 2014).
CO₂, as an oil recovery agent, has been widely applied in conventional oil reservoirs for many years with great success. As much as 60% of original oil in place (OOIP) can be recovered in some oil fields (Aryana and others, 2014). In an unfractured, conventional oil reservoir, CO₂ recovers oil by vaporizing hydrocarbon components and reducing oil viscosity, interfacial tension, and residual oil saturation, etc. (Holm and Josendal, 1974; Afonja and others, 2012). In fractured reservoirs, CO₂ may directly flow from injectors to producers via fractures without sweeping through the matrix (channeling), which reduces sweep efficiency. Cyclic CO₂ injection (also referred to as CO₂ huff ‘n’ puff) is used to mitigate the negative impact of fractures in this circumstance, as the process involves injecting gas and producing oil via the same well at different time intervals. The channeling effect is effectively eliminated and the high conductivity of the fractures becomes an advantage, which helps to extend the area affected by CO₂ (Hawthorne and others, 2014; Wan and others, 2015; Eide and others, 2015). Recent studies show that concentration gradient-driven diffusion is a critical mechanism in oil and gas mobilization and recovery in the extremely tight unconventional reservoirs. Such diffusion controls the hydrocarbon transfer in the matrix where viscous flow is restricted by the strong capillary resistance (Javadpour and others, 2007; Ozkan and others, 2010; Sakhaee-Pour and Bryant, 2012; Wan and Sheng, 2015).

While water and gas flooding are the most widely used techniques to improve oil production after primary recovery in conventional reservoirs (Jin and Wojtanowicz, 2010, 2011a, b), their application in unconventional reservoirs might be quite limited because of low permeability caused by the nanometer-scale pores, which are difficult to flood even at the core-scale (Dacy, 2010; Wan and others, 2015). Several laboratory studies have been conducted on different approaches to improve the oil transportability in tight rocks, including low salinity water and surfactant imbibition, N₂ cyclic injection, CO₂ exposure, etc. (Kovscek and others, 2008; Tovar and others, 2014; Wan and others, 2015; Zhang and others, 2015). However, many of these experiments were carried out in low-pressure, low-temperature conditions not representative of actual reservoirs. Also, fluid properties were seldom reported, or tests were conducted with fluids of simple composition (e.g., mineral oil) in many cases. Therefore, Phase II activities included investigations to evaluate the performance of CO₂ in Bakken rocks and fluids under representative reservoir conditions.
PHASE II TECHNICAL APPROACH

Phase II included innovative laboratory-based experimental and characterization efforts, field-based testing, the integration of the results from those activities into Bakken reservoir models, and advances in the estimation of CO₂ storage resource and EOR potential for the Bakken Formation in North Dakota. These activities were organized into five distinct, but complementary, activities that are described below.

**Characterization of Natural Fractures and Matrix Pore Geometry**

Laboratory examinations of rock samples were conducted to systematically characterize microfractures and matrix pore geometry, yielding data that could be integrated into improved static geologic models of a selected reservoir. The laboratory activities were focused on developing semiquantitative and quantitative data on mineralogy, microfractures, and matrix pore geometry in key Bakken shale and nonshale lithofacies. The scanning electron microscopy methods used in Phase I were applied to quantify matrix pore geometry and microfracture attributes of aperture, length, and orientation. Those data were then correlated to well log data. Detailed presentations of the methods and results of those activities have been presented in papers presented at major conferences (Sorensen and others, 2015, 2016; Hawthorne and others, 2016, 2017; Jin and others, 2016). The data generated by these activities are provided in Appendix A. The data were integrated into the reservoir modeling activities.

**Examinations of CO₂ Interactions with Tight Oil Formations**

A series of laboratory experiments were conducted to quantify the ability of CO₂ to permeate Bakken shales and nonshale rock samples and extract hydrocarbons from those rock samples at reservoir conditions. The rock samples were collected from core from six Bakken wells in North Dakota. The samples represent key selected lithofacies within the Bakken. Studies of CO₂ interactions with Bakken oil were also conducted using representative oil samples from Bakken wells in North Dakota. Detailed presentations of the methods and results of those activities have been presented in papers presented at major conferences (Sorensen and others, 2015, 2016; Hawthorne and others, 2016, 2017; Jin and others, 2016). The data generated by these activities are provided in Appendix A. Selected findings were used in the modeling and CO₂ storage resource estimation efforts.

**Development of Improved Modeling Techniques for Tight Reservoirs**

The results of the CO₂ permeation/hydrocarbon extraction experimental activities conducted in Phase I and Phase II and the data generated from the pilot-scale CO₂ injection testing were incorporated into static and dynamic modeling exercises. Those exercises were designed and executed to result in geomodels that more accurately reflect the true nature of tight oil-bearing formations, which in turn supported improved dynamic simulations, yielding more accurate predictions of CO₂ injectivity, EOR, and storage. Many of the modeling results developed in the early stages of Phase II were integrated into papers presented at conferences (Jin and others, 2015, 2016). Because of confidentiality considerations for the operating partner of the field test, the modeling exercises that were focused on supporting the development of the field test injection and
monitoring schemes, and subsequent modeling-based efforts to evaluate of the results of the field test were not the subject of previously published papers. Now that the injection test has been conducted, the confidentiality considerations are no longer a concern, and descriptions and results from the modeling efforts can be publicly presented. Those efforts are presented and discussed in detail in later sections of this report.

**Pilot-Scale Field Test of CO₂ Injection into a Tight Oil Reservoir**

A pilot-scale field test of CO₂ injection into a Bakken reservoir in North Dakota was conducted in 2017. The EERC efforts in the test included supplying CO₂ to the site for injection, providing reservoir characterization and modeling support to the operator partner (XTO), conducting laboratory-based studies of oil/CO₂ interactions on site-specific samples of oil and rock, working with oilfield service providers to design and implement a test monitoring program for the test (including Schlumberger for well logging and perforations), and assisting the operator in both design and implementation of the test. The approach, execution, and results of the pilot testing activities have not been the subject of previously published papers but are presented and discussed in detail in later sections of this report.

**Evaluation of the Potential for Long-Term Storage of CO₂ in Tight Oil Formations**

The results of the laboratory-, modeling-, and field-based efforts conducted over the course of the project have been considered in terms of their implications to the long-term storage of CO₂ in tight oil formations. To that end, the data generated in this project have been used to develop an improved methodology for estimating CO₂ storage resource potential for the Bakken. The results of this activity are presented for the first time in this report.

**PRESENTATION AND DISCUSSION OF KEY ACTIVITIES**

The Phase II technical efforts were carried out over the course of 3½ years. An exhaustive presentation of all of the laboratory-, modeling-, and field-based characterization and experimental activities conducted as part of this project are beyond the scope of this report. As mentioned above, the detailed descriptions of methods, results, and lessons learned from the laboratory-based work and the early modeling efforts have been the subject of previously published technical papers and presentations. References for those products are provided in the “Project Products” section of this report. The following sections are organized to present relatively abbreviated discussions of the activities and results from the laboratory-based efforts that are considered to be key in terms of furthering the understanding of the physical and chemical mechanisms that control the behavior of CO₂ in the tight rocks of the Bakken. Because of their more recent timing and lack of previous publication, the sections on the field test, integrated modeling, and CO₂ storage resource estimation are presented and discussed in more detail.
Laboratory Studies of CO₂ Interactions with Bakken Oil and Rocks

Reservoir Fluid Characterization – Minimum Miscibility Pressure Studies

Having a quantitative understanding of the phase behavior of multiphase fluids (e.g., oil and CO₂) in a reservoir is essential to predicting the effectiveness of an EOR scheme. Such data are necessary inputs for simulation modeling that informs the design and operational parameters of any EOR project. Minimum miscibility pressure (MMP) is considered to be the pressure at which an injected fluid (CO₂, hydrocarbon gases, etc.) obtains “multiple contact miscibility” with reservoir oil at reservoir temperatures and is a critical component for the design of miscible displacement EOR processes in conventional reservoirs (Stalkup, 1983). The slim-tube test has been the industry standard to determine MMP for decades but has received criticism from many investigators for being slow, expensive, having no consistent and widely accepted operating parameters, and lacking a fundamental physicochemical definition of MMP (Elsharkawy and Poettmann 1996; Thomas and others, 1994; Hudgins and others, 1990; Ayiral and Rao, 2011; Zhang and Gu, 2015; Johnson and Pollin, 1981; Abdurrahman and others, 2015; Yellig and Metcalfe, 1980). The rising bubble method has also been used for rapid estimates of MMP but is subject to operator interpretation since the MMP is determined by visual operation (Elsharkawy and others, 1996; Dong and others, 2001; Adekunle and Hoffman, 2014; Christiansen and Haines, 1987). In contrast, the more recent, vanishing interfacial tension (VIT) test is more rapid (less expensive) than the slim-tube test and has a rigid definition of miscibility; i.e., MMP is the pressure at which the interfacial tension between two phases approaches zero (Thomas and others, 1994; Ayiral and Rao, 2011; Teklu and others, 2014; Rao, 1997). Although some investigators have criticized the method since it does not mimic all of the interactions of flow and phase interactions that occur in a slim-tube (Orr and Jessen, 2007; Jessen and Orr, 2008), more recent work using measured IFT (interfacial tension) values (rather than calculated VIT estimates of miscibility) showed good agreement with those determined using the slim-tube test (Ayiral and Rao, 2011). Two approaches can be used to measure IFT, including the pendant drop and the capillary-rise methods (Ayiral and Rao, 2011; Rao, 1997; Cao and Gu, 2013; Ayiral and others, 2006; Saini and Rao, 2010; Tathet and others, 2010; Abedini and Torabi, 2014). While the equations to determine IFT with both methods are well defined, the pendant drop is difficult to use at low IFTs between the two fluids; thus the capillary-rise method is preferred to determine at which pressure the IFT approaches zero (i.e., MMP) (Ayiral and Rao, 2011).

The capillary-rise VIT approach to determine MMP requires measuring the IFT between the bulk oil and the injected test fluid at each of several different pressures. Determining the IFT at each pressure (at reservoir temperature) requires measuring the density of both upper and lower phases at each injection pressure, measuring the contact angle (θ) of the meniscus that occurs at the top of the oil column in the capillary tube at each pressure, and having an accurate measurement of capillary tube inner diameter (Ayiral and Rao, 2011). However, simple manipulation of the equation for calculating IFT from these values and the height of the oil column shows that if one is not concerned with actual IFT values at each pressure, but is only concerned with determining when IFT goes to zero, then a simple extrapolation of the oil height vs. pressure yields a linear plot that intercepts the pressure axis at the MMP (Hawthorne and others, 2014; Hawthorne and Miller, 2017). Thus the need for determining fluid densities, contact angle, and an exact capillary inner diameter vanishes, which substantially reduces the cost of the instrumentation and time...
required to measure MMPs. This modified capillary-rise VIT approach was used to conduct MMP studies as part of the Phase II program. The specific details of the experimental approach used in the Phase II studies are presented in Hawthorne and others (2017). Figure 4 is a series of photos looking into the pressurized chamber within which the height of oil in three glass capillary tubes is shown under three different pressure conditions.

The changes in capillary height that occur with successive pressure increases with the injected fluid are shown in Figure 4 at the beginning of the injected fluid pressurization steps (left), at a pressure approximately one-half of the MMP (middle), and as the pressure approaches the MMP (right). Typical plots of the measured capillary heights for the three different diameter capillaries are shown in Figure 5. Depending upon the size of the pressure steps and the MMP for a particular system, the plot for each capillary contains ca. 10 to 25 measured data points, in contrast to the five or six data points typically determined in slim-tube determinations of MMP (Yellig and Metcalfe, 1980; Metcalfe, 1982). In addition, the use of the three capillaries in each experiment yields three measurements of MMP, thus reducing the chances of sporadic a particular system, the plot for each capillary contains ca. 10 to 25 measured data points, in contrast to the five or six data points typically determined in slim-tube determinations of MMP (Yellig and Metcalfe, 1980; Metcalfe, 1982). In addition, the use of the three capillaries in each experiment
yields three measurements of MMP, thus reducing the chances of sporadic measurement errors influencing the final MMP value. Activities to optimize the method, including the application of the method to very high pressure regimes, were conducted and presented in detail in Hawthorne and others (2017).

The Phase II MMP studies used the capillary-rise VIT method to evaluate the effect of temperature on Bakken MMP, as well as the differences in MMP measurements that occur between the use of “live” or “dead” oil samples. The MMP studies included testing of an oil sample from a conventional oil reservoir in Montana for comparative purposes. Results were also compared to a slim-tube-derived MMP performed on the same Bakken oil.

RESULTS AND DISCUSSION OF MMP STUDIES

Measured MMPs for the two crude oils (Bakken and Montana conventional) with pure CO₂ are given in Table 1. The relative standard deviations (RSD) presented are based on the MMPs from each of the three capillaries and are typically 5% or less. However, the reproducibility of replicate experiments (i.e., a fresh load of crude oil and a new set of capillary tubes) was significantly better with the MMPs from three experiments with the Montana crude oil with CO₂ (42°C) having an RSD of 0.5% and the three experiments with Bakken crude oil with CO₂ (110°C) having an RSD of 1.1% (Table 1).
Table 1. MMPs for the Montana Conventional and Bakken Crude Oils with Pure CO₂

<table>
<thead>
<tr>
<th>Crude Oil</th>
<th>Fluid</th>
<th>Temp., °C</th>
<th>Density, g/mL&lt;sup&gt;a&lt;/sup&gt;</th>
<th>MMP, MPa&lt;sup&gt;b&lt;/sup&gt;</th>
<th>SD, %</th>
<th>RSD</th>
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<tr>
<td>Montana</td>
<td>CO₂</td>
<td>42</td>
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<td>9.67</td>
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<td></td>
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<td></td>
<td></td>
<td>9.65</td>
<td>0.47</td>
<td>4.9</td>
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<tr>
<td>Bakken</td>
<td>CO₂</td>
<td>110</td>
<td>0.37</td>
<td>17.38</td>
<td>0.37</td>
<td>2.1</td>
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<td>17.64</td>
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<td></td>
<td></td>
<td>17.26</td>
<td>0.14</td>
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<tr>
<td>Bakken</td>
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<td>0.366</td>
<td>8.86</td>
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<td>2.9</td>
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<td>8.77</td>
<td>0.16</td>
<td>1.8</td>
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</table>

<sup>a</sup> Average fluid densities for the replicate MMP values are listed for the pure fluids at the stated pressures and temperatures.

<sup>b</sup> Mean MMPs and standard deviations are based on the MMP values from each of the three capillary tube used for each determination.

The long-term stability of the capillary-rise VIT method was also tested by repeating MMP experiments with both crude oils three times over a 10-month period. As shown in Table 1, neither the Montana oil (42°C), nor the Bakken oil (110°C), showed significant changes in the measured MMPs over ca. 10 months.

**CO₂ MMP Values**

MMP for pure CO₂ in Bakken crude under the expected reservoir conditions of the field test well in Dunn County, North Dakota, ranged from 17.26 to 17.64 MPa (2503 to 2558 psi). The virgin reservoir pressure of the Bakken at the test well is over 8000 psi, so the injected CO₂ was miscible. The profound effect reservoir temperature has on determining MMP is shown in Table 1. Although the effect of higher temperatures on raising MMP is known, it is often not recognized as a significant factor in EOR project designs. For example, Bakken crude oil is considered to have a high MMP considering it is a fairly light (API [American Petroleum Institute] 41.5) oil. However, as shown in Table 1, lowering the temperature from 110°C to 42°C reduces the MMP by one-half for CO₂. These results support those from earlier investigators that reservoir temperature can be more important than oil characteristics in determining MMP (Yellig and Metcalfe, 1980). These results are also directly relevant to the Bakken, where Hester and Schmoker (1985) report reservoir temperatures are found to range from 50° to 120°C and operating members of the project consortium report temperatures as high as 129°C. What is found in common for MMPs at the two temperatures is that the densities (of the pure fluids) at MMP are remarkably similar. For example, the MMP density of CO₂ for Bakken crude is 0.37 g/mL at both 110°C (MMP = 17.4 MPa) and at 42°C (MMP = 8.8 MPa) (National Institute of Standards and Technology, 2016).

**Comparison of Capillary-Rise VIT to Slim-Tube and Equation-of-State MMP Values**

Two live oil samples from the Bakken reservoir were supplied by a Bakken producer and reconstituted to reservoir compositions as described above. A replicate sample was retained by the
contract PVT lab that prepared both live oil samples. MMP values using the capillary-rise VIT method were measured and reported to the producer without prior knowledge of the slim-tube results provided by the contract PVT lab. MMP determinations for each sample were performed in five replicate experiments, each with three different diameter capillaries as before.

The mean MMP for the five capillary-rise VIT determinations of live Crude Oil A (129°C) was 21.92 ± 0.79 MPa (3.6% RSD) which was in good agreement with the slim-tube value reported by the PVT lab of 21.79 MPa, and the equation-of-state (EOS) value reported by the producer of 22.20 MPa. Although the slim-tube MMP was not available for the live Crude Oil B (126°C), the measured value using capillary-rise VIT was 22.04 ± 0.99 MPa (4.5% RSD), which is in reasonable agreement with the producer’s EOS value of 21.72 MPa. RSDs for the three capillaries in each individual experiment were ≤5% as they were for the dead oils. These results and Ayirala and Rao’s earlier reports showing good agreement between capillary-rise VIT and slim-tube results support the use of this technique instead of (or in conjunction with) the slim-tube method.

**Summary of Key Findings from MMP Studies**

Simple modifications to Ayirala and Rao’s capillary-rise VIT method that were conducted as part of the Phase II efforts greatly decrease the apparatus cost and complexity of doing MMP studies by eliminating the need to measure both fluid densities and contact angle at each test pressure, as well as the need for capillaries with accurately known internal diameters. The simple, yet thermodynamically rigid definition of MMP as the pressure where the IFT between two fluid phases goes to zero makes the capillary-rise VIT method less susceptible to operational differences and operator interpretations among different labs that affect methods such as the rising bubble and slim-tube techniques. The method developed and used as part of the Phase II efforts is reproducible, only requires 3 mL of crude oil per determination, and can be performed with live oil (one or two determinations per day) or dead oil (three or four determinations per day) with one experimental apparatus. The previous reports showing good agreement between the slim-tube and the capillary-rise VIT method, as well as the good agreement presented in the present study for live oil, support the use of capillary-rise VIT as a supplement for and/or replacement to the slim-tube method.

The profound effect reservoir temperature has on determining MMP is shown in Table 1. Although the effect of higher temperatures on raising MMP is known (Yellig and Metcalfe, 1980), it is often not recognized as a significant factor in EOR project designs. For example, Bakken crude oil is considered to have a high MMP, considering it is a fairly light (API 41.5) oil. However, as shown in Table 1, lowering the temperature from 110° to 42°C reduces the MMP by one-half for CO₂. These results support those from earlier investigators that reservoir temperature can be more important than oil characteristics in determining MMP (Yellig and Metcalfe, 1980). These results are also directly relevant to the Bakken, where reservoir temperatures are found to range from 50° to 129°C.
RESERVOIR AND ROCK–FLUID PROPERTIES

The UB and LB are organic-rich shales which act as source rocks for the system. Five major lithofacies, ranging from silty sands to siltstones and tight carbonates, have been identified in the MB, which is the main target for horizontal drilling (Pitman and others, 2001; Kurtoglu and others, 2013). The Three Forks Formation also has multiple lithologies, including interbedded dolostone/limestone, siltstone/mudstone, shale, and evaporites. The geologic sequence of these members is shown in Figure 6 (Klenner and others, 2014).

Figure 6. Schematic of Bakken petroleum system stratigraphy (Klenner and others, 2014).

Reservoir properties are very heterogeneous within the Bakken. Petrophysical data for samples from all of the Phase II study wells are provided in Appendix A. As an example of the petrophysical properties from a “typical” Bakken well, Figure 7 shows the reservoir property distribution based on analysis of core samples from one of the study wells, referred to here as Well A. Porosity varies around 0.06 with ±50% difference in the UBS, MB, LBS, and Upper Three Forks rock units. Permeability spans a much wider range: from 0.0005 to 0.2 mD in the MB and from 0.001 to 2 mD in the Upper Three Forks. The UBS and LBS Members are much less permeable (typically less than 0.01 mD) than the other intervals. The zonation of the formation is clearly demonstrated by water saturation: about 10% in the shale zones and 20%–50% elsewhere.

The relatively low values of measured oil saturation may be misleading because of the large pressure change from reservoir to the surface. Short-chain hydrocarbons are a substantial fraction of the Bakken oil (Hawthorne and others, 2014), and these light components escape from the pore space when pressure drops (when core is brought to surface conditions), reducing laboratory-measured oil saturation. The oil is in liquid state under reservoir conditions where pressure is
greater than 3000 psi; however, it separates into oil and gas components when the core is under atmospheric conditions, where gas has already escaped and only residual oil is left in the core (Jin and others, 2016). UBS and LBS samples have higher oil saturations than those from the MB and Three Forks, possibly related to both lower initial oil saturation and an increase of volatile escape enabled by the higher permeability of the MB and Three Forks samples in comparison to the shales. Total organic carbon (TOC or kerogen) content and pore-size distribution (PSD) play important roles in residual oil trapping in the shale samples.

Figure 8 shows the distribution of TOC and average pore throat radius in the selected samples which correlates to the oil saturation distribution very well. The UBS and LBS samples have significantly higher TOC and smaller pore throat radii than those of the MB or Three Forks zones. Kerogen is usually oil-wet, and the generally smaller pore throat induces a larger capillary force, confining oil inside of the pore space (Nojabaei and others, 2013; Jin and others, 2015; Kazil and others, 2015). Therefore, oil preferentially remains more in the shale samples in comparison to the MB and Three Forks samples.
Figure 8. TOC and average pore throat radius in the Bakken and Upper TF (Well A) (Jin and others, 2016).

**Experimental Investigation of CO₂ and Bakken Rock Interactions**

Although CO₂ flooding has been successfully applied in conventional reservoirs for more than 40 years (Aryana and others, 2014), applicability in unconventional reservoirs remains uncertain because of the different flow mechanisms. The recovery mechanism by which CO₂ EOR appears to operate in unconventional tight oil formations includes the physical changes of lowered oil viscosity and increased oil swelling but is ultimately dominated by concentration gradient-driven diffusion, that is, diffusion of CO₂ from the bulk CO₂ into the oil in the rock matrix and diffusion of the oil in the rock into the bulk CO₂ (Hawthorne and others, 2013). Accurate determination of pure molecular diffusion flow in the field is difficult due to the complex geologic and reservoir conditions, facilitating a need for experimental laboratory investigations before conducting field tests. In order to determine the diffusion flow accurately, it is desirable to eliminate the viscous, slip and transition flows in the experiments. Therefore, an experimental setup was designed as shown in Figure 9, which intends to answer the following questions:

1. Can CO₂ extract oil from unconventional cores by way of diffusion?
2. If so, what is the extraction rate?
3. How does the extraction rate relate to the rock properties?
Compared to flow in other regimes, diffusion flow is a slow process which requires much more time to observe the oil recovery response than the traditional core flooding experiments. Thus small sample dimensions were selected in order to observe the extraction response in a reasonable time. Each rock core sample was used as it was received; i.e., the oil recovered during the experiments was present in the core sample in the reservoir and not added to the core in the laboratory. Each core sample (1.1-cm diameter and ca. 4 cm length) was put inside the extraction vessel (1.5-cm diameter and 5.7 cm length), which was placed into an ISCO Model SFX-210 supercritical extractor which was thermostatically controlled at 230°F (110°C). The pressure throughout the entire system was maintained at 5000 psi by an ISCO Model 260D syringe pump operated in the constant pressure mode. Initially, the outlet control valve (8) on the extraction vessel was closed. CO₂ was injected at the top of the extraction vessel to fill the space around the core and let CO₂ penetrate into the core. At certain intervals (hourly for the first 7 hours of exposure and an additional exposure up to 24 hours), the recovered hydrocarbons were collected by opening the outlet control valve. The flow rate of CO₂ was controlled at 1.5 mL/min by the flow restrictor (9) and about 2 cell void volumes (ca. 15 mL total) of CO₂ were purged into ca. 15 mL of methylene chloride to collect the hydrocarbons recovered during each exposure time. It is important to note that pressure changes throughout the sample cell were minimized by the small flow rate; thus pressure-gradient-dependent flow was essentially eliminated across the rock core sample. As CO₂ was able to move freely around the core rather than being forced through the core (in contrast to a conventional core flooding experiment), the pressure in the core was constant during the experimental process, and oil was recovered primarily by way of concentration gradient-driven diffusion.

Following the 24-hour CO₂ exposure, the rock core sample was crushed to a fine powder and extracted with the aid of sonication three times in 20 mL methylene chloride to recover the remaining hydrocarbons. Percent recoveries are defined as the quantity of crude oil hydrocarbons
found in the CO2 extracts as compared to the methylene chloride extracts of the rock sample after CO2 exposure. It is important to note that recovery values do not include kerogen organics.

**Results and Discussion of Bakken CO2 Extraction Experiments**

The extraction results presented below are from experiments conducted on 21 samples from two wells (Well A and Well B) representing four of the oil-bearing zones (UBS, MB, LBS, and Three Forks) to determine the behavior of CO2-enhanced diffusion flow throughout the strata of the system. The detailed rock properties and percent recovery of hydrocarbon from each sample after 7 hours of exposure to CO2 can be found in Table 2. The samples were representative of the reservoir intervals from which they were taken.

<table>
<thead>
<tr>
<th>Well No.</th>
<th>Unit</th>
<th>Depth, ft</th>
<th>φ, %</th>
<th>K, mD</th>
<th>TOC, %</th>
<th>r35, nm</th>
<th>Sw, frac</th>
<th>7-hr Recovery, %</th>
</tr>
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<tr>
<td>A MB-A1</td>
<td>MB</td>
<td>11,141.5</td>
<td>2.81</td>
<td>0.0550</td>
<td>0.10</td>
<td>–*</td>
<td>0.23</td>
<td>70</td>
</tr>
<tr>
<td>MB-A2</td>
<td>MB</td>
<td>11,145.5</td>
<td>4.56</td>
<td>0.0041</td>
<td>0.20</td>
<td>–</td>
<td>0.12</td>
<td>86</td>
</tr>
<tr>
<td>MB-A3</td>
<td>MB</td>
<td>11,155.5</td>
<td>2.37</td>
<td>0.0040</td>
<td>0.30</td>
<td>15</td>
<td>0.37</td>
<td>88</td>
</tr>
<tr>
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<td>MB</td>
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<td>2.37</td>
<td>0.0020</td>
<td>0.22</td>
<td>13</td>
<td>0.20</td>
<td>80</td>
</tr>
<tr>
<td>MB-A5</td>
<td>MB</td>
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<td>0.0100</td>
<td>0.35</td>
<td>8</td>
<td>0.07</td>
<td>64</td>
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<td>0.0098</td>
<td>14.66</td>
<td>5</td>
<td>0.08</td>
<td>29</td>
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<tr>
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<td>0.0105</td>
<td>15.00</td>
<td>–</td>
<td>0.08</td>
<td>28</td>
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<tr>
<td>MB-B3</td>
<td>MB</td>
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<td>0.0200</td>
<td>0.20</td>
<td>66</td>
<td>0.12</td>
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<td>UB</td>
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<td>11.00</td>
<td>–</td>
<td>0.13</td>
<td>37</td>
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<td>0.0085</td>
<td>10.66</td>
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<td>0.13</td>
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<td>–</td>
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<td>–</td>
<td>0.18</td>
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<td>67</td>
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<td>0.0650</td>
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<td>–</td>
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<td>0.0040</td>
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<td>0.0080</td>
<td>0.18</td>
<td>27</td>
<td>0.58</td>
<td>94</td>
</tr>
</tbody>
</table>

* Measurement is not available.

Note: φ, porosity; K, permeability; r35, pore throat radius; Sw, water saturation. Porosity, permeability, and pore throat radius were determined by high-pressure mercury injection (HPMI) testing.

Figure 10 and Figure 11 show the oil recovery over a 24-hour time frame for samples from Wells A and B, respectively. Both figures demonstrate two distinct recovery behaviors, with the MB and Three Forks samples exhibiting higher recovery percentages than those from the UB and LB. The highest and lowest oil recovery values for UB, MB, and LB samples were plotted for Well B in Figure 11. High oil recovery percentage (95%–99%) was observed from Three Forks and MB samples from both wells at the end of 24 hr. The difference of 24-hr oil recovery for the UB and LB samples was small, most samples having recoveries around 60%, which was much lower than the MB and Three Forks.
Figure 10. Oil recovery performance of core samples from Well A (Jin and others, 2016).

Figure 11. Oil recovery performance of core samples from Well B. Two curves are plotted for the LB, MB, and UB Members showing the highest and lowest recoveries measured for each (Jin and others, 2016).
The effect on hydrocarbon molecular weight on recovery rates with CO₂ were also examined. Bulk effects of CO₂ dissolving into the oil in the rock matrix (i.e., swelling and lowered viscosity) would be expected to show little molecular weight preference in the recovered hydrocarbons. In contrast, recovery processes that involve mobilizing hydrocarbons into the CO₂ would favor lighter hydrocarbons because they have higher solubility than higher molecular weight hydrocarbons. Also, lower molecular weight hydrocarbons diffuse more rapidly and are more soluble in CO₂. Therefore, it is useful to observe the molecular weight distribution in the hydrocarbons recovered during the CO₂ exposures. As shown in Figure 12 for the round rod samples, there is a great degree of preference for CO₂ recovery of lighter versus the heavier hydrocarbons, as is especially evident from the tighter UB and LB shales. For example, the C7 hydrocarbons are recovered ca. 10-fold faster than the C20 hydrocarbons from the UB and LB shales. Although the same range of hydrocarbons could not be observed from the Middle Bakken sample (because of their loss during transport and storage of the core sample), some preference for lighter hydrocarbons is also observed for the Middle Bakken sample.

To examine the relationship between oil recovery and rock properties, a statistical analysis of variance (ANOVA) based on a linear regression was implemented to investigate the significance of control parameters. ANOVA is particularly useful for studying statistical relationships between dependent variables and individual or groups of independent variables (Montgomery and Runger, 2010; Jin and Wojtanowicz, 2013). This method was used to determine the sensitivity of the oil recovery to porosity, permeability, TOC, pore throat radius, and water saturation as shown in Figure 13. In order to include the oil recovery performance from both MB and Three Forks units in the linear regression model, 7-hr recovery results were used. Only those samples with pore throat radius measurements were used in Figure 13a. Preliminary ANOVA using well (A or B) and lithologic unit as factors indicated that although the 7-hr recovery results do not differ between wells, they do differ according to unit. Post hoc tests show that the MB and Three Forks nonshale rocks form one group and the organic-rich shales of the UBS and LBS another. Two linear regression ANOVAs were performed, one with only the MB and Three Forks samples (Figure 13b), and one with all samples (Figure 13c) the latter to attempt to explain the effect of the shales.

The results clearly indicate the two most important variables correlating with oil recovery in the MB/Three Forks model \( R^2 = 0.9998 \) are pore throat radius and water saturation, and in the all-units model \( R^2 = 0.9902 \), the most important variables are TOC and pore throat radius (contributing about 70% of variability). Water saturation and TOC were observed to correlate negatively to oil recovery, while pore throat radius correlated positively (Jin and others, 2017). Porosity has a minimum positive effect on recovery, less than 5%. However, recent work reported in Sorensen and others (2018), which took a closer examination of the role of TOC in CO₂ mobility in Bakken shales, showed that when only shale samples are compared, higher TOC values within shales correlated to higher hydrocarbon recoveries. The result of a negative correlation between TOC and oil recoveries identified in this study is an artifact of the inclusion of both Bakken shale and MB nonshale samples in the ANOVAs. The Bakken shales inherently contain an order of magnitude more TOC than the nonshale MB and Three Forks (TOC ≥10% for the shales compared to ≤1% for the nonshales), whereas the largest pore throat sizes for the shales are generally similar
Figure 12. Recovery rates of different molecular weight alkanes under dynamic CO₂ exposures (5000 psi, 110°C) from ca. 11 mm diameter × 40 mm long round rods of UB, MB, and LB source and reservoir rocks from a single borehole (Hawthorne and others, 2013). “7” indicates the total C7 alkanes as defined by chromatographic retention times. The same definition applies to the other carbon numbers shown. “total HC” indicates the total hydrocarbon mass recovered regardless of molecular weight.
in size to the smallest pore throat sizes of the nonshales (Sorensen and others, 2018). When considered in the context of the results reported in Sorensen and others (2018), the more appropriate interpretation of the ANOVA results may be that it is not the high TOC that is causing the significantly lower recoveries in the shales, as compared to the nonshales, but rather the smaller pore throat sizes.

The bulk of the TOC in the shales is kerogen, which has smaller pore size and more complex pore structure than nonorganic matter (Kuila, 2013). Nanometer-scale pores induce high capillary pressure between phases when oil, gas, and water coexist in the core. The smaller the pore throat size, the more difficult it is to overcome capillary resistance.

In the MB/Three Forks analysis, pore throat radius is also important. This reasoning was confirmed by the results: the Three Forks TF-A1 and MB-B3 nonshale cores have the largest pore throat radii and thus yield the best oil recovery while the least oil recovery was observed from LB-A1 and LB-B1 shale cores, which have the smallest pore throat radii. The importance of porosity and permeability is not as significant as other parameters investigated, which is quite different to what is observed in normal flow-through experiments for conventional reservoir rocks (Monger and others, 1991; Afonja and others, 2012).

The results show that CO₂ greatly enhances hydrocarbon transport through concentration gradient-driven diffusion in unconventional tight oil reservoirs. This has significant implications, especially so for densely fractured tight oil formations (high surface area-to-volume ratio) where CO₂ would have greater contact with the reservoir. This would enable CO₂ diffusion into the matrix and hydrocarbon diffusion out of the matrix to occur more efficiently (increasing recoverable
reserves). Also, the fracture networks would assist in alleviating potential injectivity challenges as CO₂ does not need to be flooded through the tight matrix. These observations indicate the mechanisms of CO₂ EOR in unconventional tight reservoirs could be substantially different from those of conventional reservoirs. With these observations in mind, the Phase II CO₂ injection field test was designed, in part, to scale up the laboratory CO₂ permeation/hydrocarbon extraction experiments from the core plug scale to the reservoir scale to determine if CO₂ could permeate the tight matrix under real-world virgin reservoir conditions. This was an important step to verify and validate the results and interpretations from the laboratory tests to determine if those results truly have any applicability to a real-world tight oil reservoir.

FIELD INJECTION TESTING IN THE BAKKEN

Previous Injection Tests in the Bakken

While common in conventional reservoirs in the Rocky Mountains and areas such as West Texas, CO₂ EOR in unconventional tight oil reservoirs is a relatively new concept. If successful, large-scale CO₂ injection into the Bakken petroleum system could not only dramatically increase oil productivity and recovery factors but also result in the geologic storage of significant amounts of carbon dioxide.

The ultimate goal of the Phase II program is to provide guidance in designing a commercially viable injection/production scheme for CO₂ EOR and storage in tight oil formations. The program seeks to determine what makes a good candidate site; which types of injection/production schemes are most effective; what site-specific data need to be collected prior to, during, and after the injection test; and what the expected time frame is for CO₂ to enhance production. As part of the effort to address those questions, the task focused on the field injection test included an examination of publicly available data from Bakken wells in which injection tests have been conducted. The data include a pilot-scale CO₂ injection test in the Elm Coulee Field in Montana as well as four water, CO₂, and/or produced field gas injection projects in North Dakota. A description of each of those tests and key observations from them are presented below. The locations of those tests are shown on the map in Figure 14.
Elm Coulee CO₂ Pilot Test in Montana

The Elm Coulee Field pilot test was conducted jointly by Continental Resources, Enerplus, and XTO in the Burning Tree-State No. 36-2H well in Richland County, Montana. This horizontal well was completed in the MB and was stimulated using a single-stage hydraulic fracturing operation. The test used a huff ‘n’ puff approach, with injection beginning in early 2009.

Figure 15 shows oil production for the Burning Tree well. Before injection testing, oil production ranged from 30 to 40 bbl/d. Over the course of a 45-day test in January and February, approximately 45 million cubic feet (2570 tons) of CO₂ was injected at rates as high as 3.0 MMcf/d. After injection, the well was capped, and the CO₂ was allowed to soak for 64 days. The well then was opened and allowed to flow freely. After climbing to peak production of 160 bbl/d 8 days after opening the well, oil production settled into an average of 20 bbl/d during the first 30 days after the soak period. By the end of June 2009, the well was no longer flowing and was put on pump. Daily oil production returned to the preinjection range in late 2009, nearly 8 months after the well was opened.
Oil production continued to rise slowly in early 2010, reaching a peak postinjection high approaching 44 bbl/d in March 2010 (a higher rate than was achieved during any of the 14 months immediately prior to the injection test). Discussions with the operators indicate the higher production rate may be related to well workover activities as opposed to delayed CO₂ effects. Other than in the first few days, which saw an initial spike in fluid production that was likely the result of pressure buildup as opposed to miscibility-related CO₂ effects, the Burning Tree well did not see a dramatic production increase. CO₂ was injected successfully, and reservoir fluids subsequently were produced.

Taking a longer view, there was a period (January to March 2010) that saw a gradual oil productivity increase, and although it was delayed and certainly not dramatic, this improved productivity might be at least partially attributable to injection. Unfortunately, the nature of the available data makes it difficult to determine how much of the improvement could be related to the CO₂ or whether it actually was associated with other operational factors. Gaps in the injection monitoring data were perhaps the most significant limitation to fully assessing the effect of CO₂ on the Burning Tree well. While gas analysis data show that approximately 50% of the CO₂ injection volume was recovered between May and August 2009, there were no further testing results from the well. Furthermore, it appears that during the test period, no offset producing wells were monitored in a way that could shed light on possible CO₂ migration. Testing for CO₂ in offset wells provides the mass balance calculations necessary to fully evaluate the movement of both injectant and mobilized oil within the reservoir.
North Dakota Bakken Injection Tests

NDIC’s well file database includes information on four injection tests in Bakken wells conducted between 1994 and 2014 that could provide insights on Bakken CO₂ EOR.

The first was a water injection test by Meridian Oil in the NDIC 9660 well, a horizontal well in the UBS in the Bicentennial Field in McKenzie County. This well was not hydraulically fractured but had evidence of a high degree of natural fractures which provided the flow pathways for the well to produce oil. In 1994, approximately 13,200 barrels of freshwater was injected for 50 days. The well was shut in for 2 months, after which oil production remained below pretest rates for the rest of the well’s operational life. This test demonstrated a reasonable degree of fluid injectivity was possible in a Bakken horizontal well.

In late 2008, EOG Resources conducted a CO₂ injection test in the NDIC 16713 well in the Parshall Field in Mountrail County. This horizontal well was drilled into the MB and was completed using a six-stage hydraulic fracture treatment. Based on incomplete well file data, an estimated 30 MMcf of CO₂ was injected using a Huff ‘n’ Puff approach. No data on pre- or posttest reservoir conditions were available. However, after 11 days of injection, CO₂ breakthrough was observed in offset well NDIC 16768, located 1 mile west of NDIC 16713 well.

Figure 16 shows oil and gas production data for both the test and offset wells used in the 2008 test. The Parshall Field has a high degree of natural fracturing (Nordeng and others, 2010), and the high mobility of CO₂ in this fractured system indicates that conformance control is likely a major factor in designing EOR operations. Also of interest is the fact that three other offset wells located within 1 mile of the injector did not see CO₂ breakthrough, suggesting that understanding the local natural fracture system is key to EOR planning.

EOG Resources conducted a produced water injection test in another well in the Parshall Field, the NDIC 17170. Injection began in the spring of 2012 with plans to operate the well in a Huff ‘n’ Puff scheme according to a 30-day injection and 10-day soak schedule. Data in the well file indicate that 10,000 barrels of water was injected in April and 29,000 barrels injected in May 2012. Again, no data on pretest or posttest reservoir conditions are publicly available. There was no observable incremental improvement in oil production attributable to water injection.

A third Parshall Field well operated by EOG, the NDIC 16986, has been the subject of both produced water and field gas injection testing. Water injection was conducted periodically from April 2012 to February 2014 in a “waterflood pilot.” Figure 17 shows fluid production data for the injection well and nearby offset well NDIC 16461. Nearly 439,000 barrels of water was injected before the well was returned to production in March 2014.

Starting in June 2014, EOG Resources began injecting field gas (an undefined mixture of methane, ethane, and other hydrocarbon gases) mingled with produced water injection. According to statements in the well file, water was used to “manage effects of gas mobility in the fracture system” or, if needed, “build system pressure with less gas volume.” Through August 20, 2014, a total of 88,729 MMcf had been injected. No data on pre- or posttest reservoir conditions are available, and there is nothing in the well file to suggest that the testing activities were considered successful by the operator. Changes in fluid production rates were observed in two offset wells, demonstrating that communication between wells can occur rapidly.
Figure 16. CO₂ injection results for the NDIC 16713 well (top) and NDIC 16768 offset well (bottom).
Figure 17. Produced water and field gas injection results for NDIC 16986 (top) and NDIC 16461 offset well (bottom).
Lessons Learned from Previous Bakken Field Tests

The information available in the NDIC well file database provides only limited details about pre- or posttest reservoir conditions, injection schemes, or effects on offset wells. Geologic data, operator notes and activity logs, and information on natural and induced fracture networks are severely limited as well. This lack of information limits the ability to draw authoritative conclusions about potential EOR schemes. Generally speaking, however, the tests do suggest that injectivity is not a limiting factor in the MB and even UBS. This is likely due to the presence of extensive fracture networks, which in the case of the Middle Bakken wells are hydraulically induced and completed with proppant to maintain fracture conductivity. Also, examining monthly oil, gas, and water production data for the test wells and neighboring offset wells indicates that communication was observed in some offsets. However, in all cases, the specific objectives of each pilot test were unclear, and a lack of information on operational aspects of the injection and offset wells make it difficult to independently evaluate the success of the tests.

Most Bakken injection tests have used a huff ‘n’ puff approach. Successful CO₂ huff ‘n’ puff operations in conventional wells typically see dramatically improved oil production shortly after soaking for several weeks, or even months (Haskin and Alston, 1989; Mohammed-Singh and others, 2006). While these Bakken tests would not be considered successful compared with huff ‘n’ puff tests in conventional reservoirs, it is important to keep in mind that the Bakken is an unconventional tight oil play. When viewed through a conventional lens, a reservoir that is highly fractured with a tight matrix is not a good candidate for any conventional CO₂ EOR approach. That is why these early tests should be viewed in the context of pioneering efforts and judged accordingly. The findings strongly suggest that a conventional huff ‘n’ puff approach will not be effective in unconventional formations.

However, some important lessons have been learned. Water and gas injectivity into various lithofacies, including the UBS, has been demonstrated. Production responses to injection were observed, and while those responses were not necessarily related to higher oil production, they do suggest that fluid mobilization can be influenced. If CO₂ or other gases that enhance oil mobility can be injected and fluid mobilization can be influenced, developing an effective means of EOR in unconventional formations is possible. That said, developing an effective EOR approach will require more field work, and another key lesson learned from the Bakken tests is that detailed pre- and posttest data on reservoir conditions and fluids production are essential for test and offset wells. Robust reservoir characterization provides information that is crucial to creating realistic geomodels and conducting valid dynamic simulations of potential EOR scenarios. This knowledge is essential to designing the operational parameters of injectivity tests and interpreting the results. Detailed data on the reservoir pressure and temperature conditions and composition of reservoir fluids prior to and after the injection test are essential to thoroughly and quantitatively evaluate the effects of injection. Baseline conditions should be determined for both injection well and neighboring wells that may be affected by the injection test. Wherever possible, offset wells should be monitored before, during, and after injection as part of the injection test program, especially in large-scale tests. These lessons and concepts were carried forward and applied to planning and execution of a Bakken CO₂ injection test in 2017 that was conducted by XTO as part of its contribution to the Phase II program.
Goals of the 2017 Bakken CO₂ Injection Test

In 2016 XTO Energy entered into an agreement with the EERC to provide a well and conduct all field-based operations necessary to conduct a pilot-scale CO₂ injection test into a Bakken reservoir. Schlumberger also entered into an agreement to provide discounted well completion and logging services as in-kind cost share to the project. The overarching ultimate goal of the 2017 field-based Bakken investigations was to develop fundamental data to provide a technical foundation for the design and operation of future gas-driven EOR. The laboratory and modeling work described above (Hawthorne and others, 2014; Jin and others, 2016) indicates that diffusion, solubility, and sorption may be primary mechanisms controlling CO₂ permeation and oil mobility in Bakken rocks. The results of the MMP studies which show miscibility achieved at the pressures greater than 2540 psi in a 110°C reservoir indicate the injected CO₂ will almost certainly be miscible in the test well, which has a virgin pressure of 8600 psi at 120°C. The experiences and results gained from the 2017 field test provide new insight regarding the role that those mechanisms may play in the ability of CO₂ to permeate and mobilize oil from within the matrix of the Bakken.

Hypothesis

As described earlier, a series of EERC laboratory experiments have demonstrated that CO₂ can permeate the rocks of the Middle Member and Shale Members of the Bakken Formation and cause an increase in oil mobility (Hawthorne and others, 2014, 2016). However, past pilot-scale CO₂ injection tests into horizontal Bakken wells have shown little to no effect on oil mobilization (Sorensen and Hamling, 2016). This is most likely due to fractures in the reservoir system serving as fast-flow pathways that disperse the CO₂, minimizing the contact time between the injected CO₂ and the matrix in which stranded oil resides. With respect to the potential for CO₂ storage and EOR in the Bakken, there is clearly a gap in what laboratory-scale experiments suggest may be possible and what the application of conventional approaches to CO₂-based EOR in the field has shown to be possible. In an effort to close this knowledge gap, the EERC conducted a set of field-based experimental activities to test a two-pronged hypothesis: 1) that CO₂ can be injected into an unstimulated Bakken reservoir and 2) the injected CO₂ can interact with the in-place fluids, resulting in subsequent mobilization of hydrocarbons and storage of CO₂.

A field test to evaluate the injectivity of the unstimulated Bakken reservoir is an important step to determine if the observations in the lab can truly be applied to the field. One of the problems with the laboratory CO₂ permeation/hydrocarbon extraction experiments is that the act of core collection inherently changes a couple of key sample characteristics, namely, the composition of the hydrocarbon content and the pore pressure of the rock. Bakken core in North Dakota is collected from depths between 9000 and 11,000 feet, and the process can take several hours to bring the core to surface. During that time, unless unusual (and expensive) precautions are taken to maintain pressure on the sample, the core will undergo significant depressurization, going from an in situ pressure of anywhere from 7000 to 9000 psi to atmospheric (approximately 14 psi). A result of the uncontrolled depressurization of the core is that new fractures will be induced by the release of pressure. The depressurization also causes lighter hydrocarbons, which are in the liquid state in the high-pressure, high-temperature conditions of the reservoir, to volatilize and escape from the core. There are also questions about whether or not the pore structures seen in core
samples are truly representative of the pore structures that exist in the reservoir, with the notion being that the loss of pore pressure that occurs during core collection will cause a relaxation of the rock fabric that allows preexisting pore throats and microfractures to open further than they are when in the reservoir. All of these phenomena imply that the results of the laboratory-scale tests represent the most optimistic case with respect to CO₂ permeation and oil mobility. The field injection test provides the opportunity to essentially scale up the laboratory CO₂ permeation/hydrocarbon extraction tests. Conducting the tests in a virgin Bakken reservoir (i.e., a reservoir that has not been stimulated by hydraulic fracturing and proppant placement and which has not undergone pressure depletion due to prolonged production) would arguably represent the most pessimistic case for CO₂ permeation and oil mobility. Results from such a pessimistic case provide a valuable end member data set that essentially brackets the range of possibility when considering the potential to inject CO₂ for EOR and associated storage in tight unconventional oil reservoirs such as the Bakken.

The effect of CO₂ on a reservoir is typically judged by changes in fluid production observed after injection as compared to preinjection production history (e.g., changes in parameters such as oil production rate, water cut, GOR [gas-to-oil ratio], etc.). Because a virgin well does not have prior production history to which test results can be compared, the effects of the injected CO₂ must be evaluated by different means. One of the key findings of the laboratory testing was that in both shale and nonshale Bakken rocks CO₂ was observed to preferentially mobilize lighter hydrocarbons. With that in mind, in the absence of historical production data, the primary means of addressing the second aspect of the hypothesis is to compare preinjection oil compositional data to postinjection data. According to the lab results, a shift in the molecular weight distribution toward the lighter end would be an indicator that the injected CO₂ was able to permeate the matrix and mobilize oil.

To test both aspects of the hypothesis, an existing horizontal well would not be ideal because 1) due to the heterogeneity of the various Bakken lithofacies (Figure 3), the petrophysical properties of a Bakken reservoir are not uniformly distributed and 2) the length of the wellbore (anywhere from 5000 to 15,000 feet) and existence of extensive hydraulically stimulated and propped fractures would require over 1000 tons of CO₂ to overcome the pore pressure of the reservoir. To reduce the uncertainty in petrophysical property distribution that is associated with a long horizontal wellbore and reduce the amount of CO₂ that would be needed to pressure up the wellbore, a vertical well was considered to be a better choice for achieving the goals of the Phase II injection test.

**Experimental Design**

The field-based experimental activities included the following sequence of events in an existing vertical well that penetrates the Bakken and Three Forks Formations but has not previously produced fluids from any units in those formations. The formal name of the well is Knutson–Werre 34-3WIW (also referred to in this report as the Knutson–Werre well). The well was originally drilled and completed into the underlying Duperow Formation in 1985. The well is located in northern Dunn County, North Dakota, one of the most highly productive areas of the Bakken (Figure 18). This offered a unique opportunity to test the injectivity of CO₂ into the
unstimulated matrix of the Bakken in a virgin reservoir in the heart of the Bakken play, thereby making the lessons learned from the test directly applicable to hundreds, if not thousands, of wells that could be candidates for future EOR efforts. The stratigraphy of the Bakken Formation in the Knutson–Werre well and a well completion diagram for the injection are shown in Figure 19. The original experimental design called for using an offset vertical well, the Knutson–Werre 34-1 well, located 600 ft from the injection well, as an observation (OBS) well. Like the injection well, the OBS well was a legacy vertical conventional well completed in a deeper formation than the Bakken and would require workover activities, including new perforations at the depth of the Bakken, to allow for monitoring of pressure and temperature and possible fluid sample collection. Unfortunately, unanticipated costs and delays associated with preparing the Knutson–Werre 34-3WIW injection well for the test led to the decision to forego converting the Knutson–Werre
Figure 19. Stratigraphy of the Bakken Formation in the Knutson–Werre well based on gamma ray (GR) and density (DT-TGS) logs. A well completion diagram showing the perforated (perf) zone at a depth of 10,940 to 10,950 ft and the location of packers to isolate the injection zone is also provided.
34-1 well into an observation well. The well preparation and experimental design for the test included the elements listed below:

- Perforation of the injection zone in the Middle Member of the Bakken Formation.
- Collection of preinjection reservoir fluids to establish baseline conditions.
- Collection of preinjection reservoir pressure and temperature data using downhole gauges.
- Well workover activities to prepare the well for high-pressure CO₂ injection.
- Small-scale CO₂ injectivity test, referred to as the “pretest.”
- Main CO₂ injection test.
- Soak period.
- Flowback period during which postinjection reservoir fluids (gas, oil, water) are collected.
- Preinjection well logging to determine wellbore integrity and reservoir properties, including fluid distribution in the formation.
- Postinjection well logging to determine any changes that may have occurred in the near wellbore environment, including potential evidence of vertical CO₂ migration out of the injection zone.
- Compositional analysis of fluids collected prior to pretest and after the main test, particularly to determine any changes in the hydrocarbon composition.

Each of these elements of the test is described in more detail below.

Extensive well workover activities were required to convert the test well from a legacy vertical production well in a conventional oil-bearing formation into a CO₂ injection well. This included the removal of the production wellhead and installation of a CO₂-rated high-pressure injection wellhead. All well preparation work was planned and conducted by XTO Energy. Photos of the well preparation work are presented in Figure 20.

Maintaining wellbore integrity is necessary to ensure that injected fluids go into the target formation and that the wellbore does not serve as a conduit for injected fluids to move out of the intended zone. Determination of wellbore cement and casing conditions prior to injection is, therefore, critical to the success of an injection test. The Schlumberger ultrasonic imager (USI) log was run to determine the condition of the casing and cement bond and provide guidance in the selection of perforation points and the final design of the perforations. The USI logging indicated the presence of a channel in the cement that appeared to cut across the injection zone in the MB
Figure 20. Photos of well preparation activities. The wellhead on the far left is the original production wellhead. The wellhead on the far right is the injection wellhead used in the test.

(Figure 21). This channel could possibly serve as a leakage pathway, so the decision was made to deploy a “zero degree” perforation configuration. A “zero degree” configuration means that all of the perforation charges are oriented in a straight line on one side of the perforation tool (Figure 22). The goal of this perforation configuration is to create a straight line of perforations on one side of the well, ideally opposite of the side with the channel. The results of another USI logging run made after perforation were inconclusive as to whether or not the perforations missed the channel. No fluids flowed to surface, and swabbing operations in which a cup is lowered into the well and brought back to surface were used to collect baseline reservoir fluids. Bottomhole gauges were installed to monitor pressure and temperature in real time during all major stages of the test (pretest baseline, injection, soak, and flowback). Pressure was monitored in the wellbore of the injection well in the perforated zone and above the MB at all phases of the testing.

A pulsed-neutron log (PNL) was run to determine baseline preinjection fluid (oil, gas, and water) saturations in the zones of interest. The PNL logging also yielded lithology and estimates of reservoir porosity through integration of the logging data with Schlumberger’s ELAN petrophysical analysis software (Figure 23).

Injection testing was conducted in two distinct phases: the first being a small-scale injectivity test, referred to as the “pretest,” and the second being a larger-scale “main test.” Because the Bakken in this well was a virgin reservoir, there were many questions about reservoir conditions (e.g., injectivity of the nonstimulated matrix, native pressure, temperature). The uncertainty surrounding those conditions made injection scheme design difficult. The purpose of the pretest was to use the results from this short-duration, low-volume injectivity test to cost-effectively inform the design of the larger-scale main test. For both tests, the injection zone in the well was isolated by two packers, as shown in Figure 19.
The pretest was conducted on April 13, 2017. Figure 24 is a photo of the pumping unit and wellhead during the pretest. While plans called for 60 tons of CO₂ to be injected, the amount of CO₂ injected in the well during the pretest was approximately 16 tons, which is enough to fill the tubing and build pressure on the perforations. However it is thought that very little of that CO₂ went into the formation because the upper packer that isolated the injection zone experienced mechanical failure shortly after the injection reached the BHP (bottomhole pressure) needed to overcome the native reservoir pressure. Despite the inability to inject substantial CO₂ into the formation during the pretest, valuable downhole data were obtained that enabled the technical team...
to redesign the packer configuration and design the main test in a cost-effective way that reduced the risk of packer failure. This included evidence that CO₂ was not bleeding off through the channel in the cement that had been observed in the USI data. The pretest also provided a definitive determination of reservoir conditions prior to the primary test. Key lessons learned from the pretest included the following:

- Analysis of BHP data indicated the native reservoir pressure is 8668 psi.
- Maximum BHP achieved was 9113 psi.
- Analysis of pressure data indicated that the maximum BHP did not induce a fracture.
- Initial bottomhole temperature (BHT) was 255°F.
- Minimum injection rate of the equipment was 4.5 to 5 gallons/minute.
- Tubing held up to the injection pressure.
- Downhole gauges functioned as expected and were critical to effectively operate and monitor the injection.
- Fluid influx into the well was low, but consistent.
- A packer failed before stable injection into the reservoir could be established.

Figure 22. Perforation tool with a “zero degree” configuration.
Figure 23. Interpreted PNL display with annotations for Bakken Members. The well logs included in this display, from left to right, are gamma ray (GR), wellbore temperature (WTEP) and manometer fluid density (MWFD), salinity (ASAL_F_), borehole sigma (SIBH), porosity (POR/TPHI) and formation sigma (SIGM), fast-neutron cross section (FNXS_MATR_INCP/FNXS), volumes for various minerals and fluids, total and effective porosity (PHIT and PIGN, respectively), and invaded zone water saturation (S XO).
Prior to the main test, the well was swabbed, during which approximately 62 barrels of fluid was recovered and sampled for later analysis. The initial BHP after swabbing and before the start of the main injection test was approximately 7500 psi. At approximately 7:00 p.m. Mountain Daylight Time (MDT) on June 24, 2017, the main injection test was initiated into the Middle Member of the Bakken. The main test injection was concluded at approximately 5:00 a.m. MDT on June 28. Figure 25 is a Gantt chart showing the timing and duration of each activity conducted during the main CO₂ injection test. The main test injection period included periods of cyclic injection and continuous injection, as well as a brief shut-in period (ca. 5 hours) on June 27 to conduct a pressure falloff test, which was then followed by a period of continuous injection until the test conclusion. BHP and temperature data were collected continuously. Those data were crucial components of the efforts to interpret the results of the test and are described in more detail in the modeling section below. A total of 98.9 tons of CO₂ were injected during the main injection test. The well was then shut in to allow a period of several days during which the injected CO₂ would soak into the reservoir. The plans called for the well to be opened at the end of the first week of July or early in the second week of July, depending on the BHP behavior observed during the shut-in period. Table 3 presents statistics for the main injection test. Key operational parameters of the main injection test include:

- Initial BHP was approximately 7500 psi. This pressure is lower than the estimated virgin reservoir pressure of approximately 8670 psi because of the sporadic removal of fluids by swabbing (less than 200 bbl) and degassing that occurred during the well preparation activities.

- Stable injection rates were between 6 and 12 gallons per minute (gpm).
Figure 25. Gantt chart showing timing and duration of each activity for the main test.

Table 3. Main Test Injection Statistics

<table>
<thead>
<tr>
<th>Day</th>
<th>Date</th>
<th>Volume, gal</th>
<th>Mass, tons</th>
<th>Period</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>June 24</td>
<td>2236.7</td>
<td>10.4</td>
<td>Filling</td>
</tr>
<tr>
<td>1</td>
<td>June 24</td>
<td>50.8</td>
<td>0.2</td>
<td>BHP from 8200 to 8600</td>
</tr>
<tr>
<td>1</td>
<td>June 24</td>
<td>207</td>
<td>1.0</td>
<td>Cyclic inj. – Part 1</td>
</tr>
<tr>
<td>2</td>
<td>June 25</td>
<td>1160.5</td>
<td>5.4</td>
<td>Cyclic inj. – Part 1</td>
</tr>
<tr>
<td>2</td>
<td>June 25</td>
<td>904.5</td>
<td>4.2</td>
<td>Cyclic inj. – Part 2</td>
</tr>
<tr>
<td>2</td>
<td>June 26</td>
<td>1009.4</td>
<td>4.7</td>
<td>Cyclic inj. – Part 2</td>
</tr>
<tr>
<td>3</td>
<td>June 26</td>
<td>1752.6</td>
<td>8.1</td>
<td>Cont. inj.</td>
</tr>
<tr>
<td>4</td>
<td>June 27</td>
<td>11,131</td>
<td>51.8</td>
<td>Cont. inj.</td>
</tr>
<tr>
<td>5</td>
<td>June 28</td>
<td>2806.2</td>
<td>13.0</td>
<td>Cont. inj.</td>
</tr>
<tr>
<td></td>
<td>Total</td>
<td></td>
<td></td>
<td>Total 98.9</td>
</tr>
</tbody>
</table>

- Maximum BHP was approximately 9480 psi.
- BHP during continuous injection ranged from approximately 9400 psi to approximately 9470 psi.
- BHT ranged from 251° to 257°F (Figure 26).

The soak period for the injection test extended into the first 2 weeks of July. Reservoir pressure and temperature were monitored using the downhole gauges. The test procedure called for opening the well after the soak period to conduct a flowback period, during which pressure, temperature, and gas composition would continue to be monitored while fluid samples were collected at the surface. The well was first opened on July 7, 9 days after injection ceased. The initial BHP on July 7 was at 8740 psi, which is back to very near the estimated pretest reservoir pressure. Gas flowed for 8.5 hours, after which time the BHP had dropped to 100 psi. The composition of the gas started out as essentially 100% CO₂ and, since this was the residual fluid in the tubing after injection, showed some traces of hydrocarbons in the last 2 hours of the first flowback period. The decision was made to shut the well in again and extend the soak period for another 6 days. The second flowback period began on July 13. The BHP at the start of the second flowback period was 3116 psi. After a mix of CO₂ and hydrocarbon gas was produced for 10.5 hours, the well started flowing oil to surface at a rate of approximately an eighth of a
Figure 26. Postinjection PNL results. The well logs included in this display, from left to right, are gamma ray (GR_RST/HSGR/HCGR/GR), volumes for various minerals, formation sigma (SIGM_PNX) and porosity (TPHI_PNX/PIGN/PHIT), baseline sigma measurement (SIGM_MAIN/SIGM REP), repeat sigma measurement (SIGM MAIN/SIGM REP) both baseline and repeat sigma and perforated interval (SIGM_2017_04, SIGM_2017_07, and PERFS, respectively), water saturation change (SAT CHANGE), manometer well fluid density (MWFD) and well temperature (WTEP), filtered near-borehole sigma (SBNA_FIL_RST) and filtered far/near inelastic count ratio (IRAT_FIL_RST), and a wellbore schematic at the far right.
barrel/minute. The well flowed for a total of 45 minutes, producing a total of 9 barrels of oil. Oil, gas, and water samples were collected. The BHP when the oil started flowing to the surface was approximately 1890 psi. An explanation for the delayed response and flow at low-BHP conditions is that the MB reservoir is so tight. An explanation for the delayed response and flow at low-BHP conditions is that the MB reservoir is so tight that continuous flow from the matrix could not be sustained during the first flowback period. The very low BHP indicates that the high saturation of CO$_2$ in the near-wellbore area vaporized, further reducing liquid permeability. However, a considerable fraction of the injected CO$_2$ was voided from the reservoir during the first flowback period. The subsequent 6-day shut-in and pressure buildup period allowed mobilized reservoir oil to return to the near-wellbore area. During the second flowback period, gas was again cleared from the wellbore but some mobilized oil was able to enter the well and be produced under the more controlled, but still below saturation pressure, BHP condition of 1890 psi. At the same time, the small tubing size of the wellbore caused higher gas velocities, which temporarily enhanced the transport of fluids from the bottomhole to the wellhead. This beneficial effect of increased production was short-lived, as the gas expansion does not propagate into the far-reservoir region, which is controlled by the tight matrix compressibility and the virgin reservoir high pressure (Owusu and others, 2013). A PNL was run in the injection well after all other field activities were complete to determine any changes in oil, water, or gas saturation that may have occurred as a result of the injection tests. The results of the postinjection PNL run are provided in Figure 26, showing no evidence of CO$_2$ occurring out of the MB injection zone. The well was then shut in, and the field-based portion of the main injection test was considered to be completed.

The samples collected during the oil flowback period were sent to the EERC where the hydrocarbon composition (as defined by molecular weight distribution and hydrocarbon species) were determined. Figure 27 shows the results of the compositional analysis of oil samples collected before the pretest and after the main test soak period. The data shown in Figure 27 are shown in a mass percent basis. The red dots represent “typical” Bakken crude composition, based on analysis of oil samples from a different Bakken well in northern Dunn County. The green and yellow dots represent the preinjection oil from the Knutson–Werre 34-3 well. The gold and purple dots represent the oil collected during the flowback period on July 13 (i.e., the postinjection/postsoak oil). The data points represent the mass percent of hydrocarbon molecules in the sample that have a carbon number smaller than or equal to the carbon number on the x-axis. For example, the purple dot at the intersection of $x = C9$ and $y = 75\%$ means that 75% of the hydrocarbons in that postinjection sample are in the C9 and lighter range. Compare that to the preinjection sample represented by the green dot at $y = 75\%$ where $x = C13$. These data indicate that there was an observable shift toward the lower molecular weight hydrocarbons as a result of the CO$_2$ injection. These observations are consistent with observations from the laboratory rock extraction experiments, which showed that CO$_2$ preferentially mobilizes lower molecular weight hydrocarbons from the MB matrix (Figure 28). The phenomenon of preferential mobilization of lighter molecular weight hydrocarbons by CO$_2$ is observed to be even more pronounced in the Bakken shales, as shown in Figure 29. These pre- and posttest oil compositional data from the field test suggest that the CO$_2$ did indeed penetrate the matrix of the MB, interacted with the oil therein, and mobilized lighter oil.
Figure 27. Comparison of preinjection oil composition and a representative Bakken oil sample from another Dunn County well to postinjection oil composition (HC stands for hydrocarbon).
Figure 28. Results of CO$_2$ extraction tests on two samples of MB rock showing that lower molecular weight hydrocarbons were mobilized faster and more completely by CO$_2$. 
Figure 29. Results of CO₂ extraction tests on a sample of LBS showing that lower molecular weight hydrocarbons (represented here by carbon numbers C8 and C12) were preferentially mobilized by CO₂ over higher molecular weight hydrocarbons (represented here by carbon numbers C20 and C24).

**Analysis of the Injection Test BHP and BHT Data**

Because of the low matrix permeability, the injection rate and pressure during the test were controlled carefully to prevent fracturing around the wellbore. Figure 30 shows the injection rate, BHP, and BHT response during the test. CO₂ injection rates (6–12 gallons per minute [gpm]) caused an increase of the BHP to 9468 psi and decreased the BHT to about 250°F in just under 16 hours.

Analysis of BHP response during the test played a vital part in understanding the reservoir. The pressure response resulting from fluid flow in the matrix can be interpreted using well testing principles, including continuity of flow (mass balance), fluid flow resistance, and rock/fluid compressibility, providing insights into the physical mechanisms involved in the process (Smith and Montgomery, 2015). Figure 30b shows the BHP during and after CO₂ injection. The continuous increase of pressure indicates that the pressure needed to initiate fractures was not exceeded; however, the opening of an existing pre-existing fracture(s) was interpreted.
Figure 30. Injection rate (top), BHP (middle), and BHT (bottom) response during the test.
The pressure response in the shut-in period also provided important information for the reservoir. Various flow regimes (Figure 31) may be observed from a shut-in pressure decline period. Different analysis techniques have been proposed to analyze the pressure decline period, which is usually referred to as fracture diagnostics (Barree and others, 2009). Equation 1 shows the Bourdet derivative (also termed as the “pressure derivative”), which is usually used in such analysis (Bourdet and others, 1983):

\[
BPD = \frac{d(\Delta P)}{d(ln(\Delta t))} = \Delta t \frac{d(\Delta P)}{d(\Delta t)} \tag{[Eq. 1]}
\]

where \( BPD \) is the Bourdet (or pressure) derivative, psi; \( P \) is the pressure, psi; \( t \) is the time, hour.

Together with pressure difference and BPD, the classic log-log plot used in well test analysis provides a powerful tool for fracture diagnostics in unconventional reservoir testing. Figure 32 shows the log-log plot for the shut-in pressure analysis. The initial slope in the log-log plot indicates wellbore storage. Immediately after the injection stops, there follows a period of “after flow” as injectate continues flowing from the wellbore into fractures. At the end of wellbore storage period, fluid loss from the opened natural fractures begins to control the pressure decline.

Figure 31. Typical flow regimes diagnosed from the pressure decline curve during the shut-in period (Smith and Montgomery, 2015).
behavior. The flow regime in the fractures is linear when the fractures remain open. This flow regime is observed where the curve’s slope = \( \frac{1}{2} \) of BPD in the diagnostic plot. During the test, natural fractures remained open for about 4 hours. With the energy of the injected fluid decreasing, the fractures began gradually closing, shown where the curve’s slope = \( \frac{3}{2} \) of BPD vs. \( \Delta t \) (Marongiu-Porcu and others, 2011). The plot indicates that fractures closed after 10 hours. Fluid flow in the matrix dominated the system when the fractures were closed. Because the permeability in the MB matrix was very low, the \(-\frac{1}{2}\) slope remained after 170 hours, meaning linear flow lasted through the well shut-in period.

**CO₂ PENETRATION DISTANCE BASED ON WELL FLOW AND MATERIAL BALANCE ANALYSES**

When CO₂ is injected into the Bakken Formation, the distribution of the CO₂ plume is strongly correlated to reservoir properties and fluid flow pattern. The CO₂ injection rate and well BHP response during the test demonstrated that the formation matrix of the Middle Bakken is too tight to maintain a stable injection rate at 12 gpm; the rate fluctuated between 6 and 12 gpm through the test process. In contrast to the instability of the injection rate, the well BHP increased stably: the pressure did not decrease when the injection rate dropped from 12 to 6 gpm, which indicates that the injected CO₂ accumulated around the wellbore faster than it could penetrate into the formation matrix. The shut-in pressure analysis showed that natural fractures were opened in the near-wellbore region during injection, and they were closed after 10 hours when injection ceased. Therefore, it is necessary to analyze the CO₂ flow behavior in both fractures and matrix in order to determine the CO₂ penetration depth.
Based on pore throat radius, porosity, and permeability, different flow units can be distinguished in conventional and unconventional reservoirs, as shown in Figure 33 (Aguilera, 2014; Jin and others, 2017). Conventional reservoirs are usually highly permeable and characterized by relatively large pore throat size (mega-, macro-, and mesopores). Viscous (darcy) flow is the main flow regime in conventional reservoirs; flow in fractures also belongs to this category. In Bakken reservoirs, permeability ranges are in the microdarcy or nanodarcy levels, with pore throat sizes at the nanometer scale (micro- and nanopores). Fluid flow is very slow in such tiny pores, and diffusion-dominated flow becomes the main flow regime in the matrix of unconventional reservoirs. Detailed discussion of flow regimes in the Bakken Formation can be found in Jin and others (2017), which is another publication resulting from this project.

Figure 33. Flow units division for various oil reservoirs.
During the CO₂ injection test, the pre-existing natural fractures (or microfractures) are open, so CO₂ flows from the wellbore to the Bakken Formation via these fractures in viscous flow, as shown in Figure 34a. Viscous flow ceases when the fractures are closed, which, in the case of the Knutson–Werre test, required 10 hours after shutting down the injector. CO₂ continues penetrating into the formation matrix by means of diffusion flow, as shown in Figure 34b. The diffusion flow is much slower than the viscous flow. Assuming CO₂ diffuses into the formation symmetrically around the fractures, the CO₂ penetration radius can be estimated based on the material balance equation (Equation 2) shown below:

\[ r = \sqrt{\frac{V_g}{\pi h \phi \Delta S_{g}}} \]  

[Eq. 2]

Where \( V_g \) is the injected CO₂ volume under reservoir conditions (ft³), and it can be determined by the equation of state for real gases; \( h \) is the formation thickness (ft); \( \phi \) is the porosity (fraction); \( \Delta S_{g} \) is the change of CO₂ saturation in the CO₂ penetrated region (fraction).

Because of the lack of measured values of porosity and CO₂ saturation around the wellbore, a sensitivity study was conducted to investigate the CO₂ penetration radius based on the possible ranges of porosity and CO₂ saturation, as shown in Figure 35. The shaded area in the figure indicates that the CO₂ penetration radius may fall between 50 and 70 ft around the wellbore based on the most possible ranges of matrix porosity at 0.06–0.08 and CO₂ saturation at 0.4–0.6, respectively. Pressure transient analysis and reservoir simulation were also applied to evaluate the CO₂ penetration radius. A discussion of that work is presented on page 58.

Figure 34. Schematic of CO₂ flow around the injector during and after injection. Figure 34(a) is a cross-sectional view showing the vertical wellbore and a cartoon representation of CO₂ flow during injection. Figure 34(b) is a map view depiction of the CO₂ flow, with the darker red inner circle representing viscous flow during injection and the lighter red outer circle representing diffusion flow.
Figure 35. Sensitivity study of CO₂ penetration radius around the wellbore. The shaded area represents the most likely possible range of the radius.

LESSONS LEARNED FROM THE 2017 BAKKEN CO₂ INJECTION TEST

- The test demonstrated that CO₂ can be injected into an unstimulated MB reservoir rock (i.e., no use of hydraulic fracturing fluids or proppant to open and maintain complex induced fracture networks).

- Fluid compositional data before and after the test indicate that CO₂ did penetrate into the matrix of the MB and mobilize lighter molecular weight hydrocarbons.

- Robust reservoir pressure (including pore pressure) and temperature data were generated and used to fine-tune the geocellular and simulation models that were used to evaluate CO₂ storage resource and EOR potential in the Bakken Formation.

- Log data provide detailed information regarding pre- and posttest fluid saturation in the Middle Member of the Bakken as well as the Upper and Lower Shale Members of the Bakken Formation, which in turn support the development of a more accurate geocellular model.

- The data generated by the main test serve to verify and validate the previously generated laboratory experimental data from the CO₂-based permeation and hydrocarbon extraction studies conducted on MB core samples.

- When combined and considered in the context of the previously generated laboratory data and modeling activities, these field-based data will provide stakeholders with previously unavailable technically based insight regarding the fundamental physical and chemical
mechanisms controlling 1) the ability of CO\textsubscript{2} to mobilize oil from the matrix of tight oil formations and 2) the potential storage resource of tight oil formations.

DEVELOPMENT OF IMPROVED MODELING TECHNIQUES FOR THE BAKKEN

The modeling efforts conducted by the EERC under Phase II focused on integrating data generated by the laboratory- and field-based activities to support the field CO\textsubscript{2} injection test; develop an approach yielding more accurate representations of unconventional tight, oil-bearing formations; and provide the basis for numerical simulations which could predict CO\textsubscript{2} injectivity, EOR, and storage with increased accuracy. Models were created using CMG’s Builder module (Computer Modelling Group Ltd., 2016a) and Schlumberger’s Petrel software (Schlumberger, 2017). A small field-scale model was constructed to inform the design of the CO\textsubscript{2} injection test. A drill spacing unit (DSU) dual porosity–dual permeability model was created in an attempt to transfer knowledge gained from the CO\textsubscript{2} injection test (which used a vertical well) in estimating reservoir response along horizontal wellbores. The location of the wells used in these modeling efforts is shown in Figure 36. To follow the sequence of events leading up to, through, and following the pilot CO\textsubscript{2} injection test, the injection site model is discussed next, as it was used in the planning of the injection test, while the DSU model is discussed in later sections of this report, as this model was used to integrate the results of the test and generate long-term predictions of reservoir performance.

Injection Site Model

During the 2017 field operations the vertical Knutson–Werre well selected to conduct the CO\textsubscript{2} injection test was completed in the MB. While the Knutson–Werre 34-1 well was ultimately not used as an observation well, it was included as part of the injection site modeling exercises and is referred to in this section of the report as the “OBS well.” The selected test location was in a virgin reservoir where the reservoir pressure was not depleted prior to the CO\textsubscript{2} injection. Consequently, both the reservoir’s matrix and natural fractures were preserved in their original conditions. Figure 37 shows the well log data from the Knutson–Werre 34-3 test well. The logs illustrate the main rock components in the MB, including illite, dolomite, calcite, and quartz. The formation exhibited low porosity (<0.04 v/v) around the wellbore. The initial reservoir pressure was estimated between 8400 and 8700 psi, and the formation breakdown and fracture closure pressures were estimated at 9500 and 9200 psi, respectively.

In preparation for the CO\textsubscript{2} injection test, a simplified stratigraphic (“layer cake”) model was created. This model was constructed to provide the basis for initial simulation work needed to estimate injection pressure limits, the volume of CO\textsubscript{2} required for the injection operation, the response from the reservoir in terms of mobilized hydrocarbons, and the time required to conduct the test. Petrophysical and reservoir fluid properties were obtained from other activities within this study and previous Bakken related works by Jin and others (2016), Kurtoglu and others (2012), and Sorensen and others (2015). The well constraints (production rates and BHP) were defined using typical Bakken operational values (Patterson, 2017; Hoffman and others, 2016). The model
size (square sector with a side length of 20,000 ft) was selected to accommodate the dynamic changes during the injection operation, including changes in pressure and fluid saturations. Open boundary conditions were defined with an infinite-acting boundary. Two vertical wells were included in the model (one injection well [Knutson–Werre 34-3] and one observation/production well [Knutson–Werre 34-1]), with approximately 600 feet in separation. Grid refinement near the wellbores allowed changes in pressure and saturation to be accurately captured.

The model contained eight different layers, including the UBS, individual MB lithofacies (MB L1 to L5), the LBS, and the uppermost bench of the Three Forks (TF5). Figure 38 shows different graphical displays of this model, including a map view of the grid, an image of the permeability distribution, and a cross section through the grid showing relative thicknesses and depths of model subunits. Table 4 shows the properties used to populate the static model, although
Figure 37. Well logs acquired in the Knutson–Werre 34-3 showing the basic reservoir/rock properties in the Bakken and Upper Three Forks Formations. The well logs included in this display, from left to right, are gamma ray (HCGR/HSGR/GR), well temperature (WTEP), and manometer well fluid density (MWFD), salinity (ASAL_F), borehole corrected sigma (SIBH), porosity (POR/TPHI), and formation sigma (SIGM), fast neutron cross section (FNSX_MATR_INCP/FNXS), and dry weights for various minerals.

uncertainty cases were run varying some of these parameters. The effective permeability for the L3 lithofacies is recorded in Table 4 as 3 mD, which is significantly higher than the matrix permeability expected (0.3 mD). This was done to account for the presence of natural fractures in the reservoir. Table 5 lists the different scenarios considered. Cases 1 and 3 considered injection only. In Cases 2 and 4, the OBS was converted to production as a means to offset limited injectivity caused by the injection pressure constraint. The goals for each of the cases were to determine the amount of time required for CO₂ breakthrough to occur at the OBS well and the amount
of CO₂ able to be injected. For Cases 1 and 3 with the OBS well closed (no production), the time for pressure communication at the OBS well was also inspected. Additionally, the amount of produced reservoir fluids was examined in Cases 2 and 4 with the OBS well open (acting as a production well).
Table 4. Reservoir Properties Used to Populate the Layer Cake Model

<table>
<thead>
<tr>
<th></th>
<th>Thickness, ft</th>
<th>Top Depth, ft</th>
<th>Pressure, psi</th>
<th>Permeability, mD</th>
<th>Porosity, %</th>
</tr>
</thead>
<tbody>
<tr>
<td>UBS</td>
<td>18</td>
<td>10,908</td>
<td>8399</td>
<td>0.085</td>
<td>7.2</td>
</tr>
<tr>
<td>MB L5</td>
<td>7</td>
<td>10,926</td>
<td>8413</td>
<td>0.572</td>
<td>5.6</td>
</tr>
<tr>
<td>MB L4</td>
<td>7</td>
<td>10,933</td>
<td>8418</td>
<td>0.067</td>
<td>6.3</td>
</tr>
<tr>
<td>MB L3</td>
<td>12</td>
<td>10,940</td>
<td>8424</td>
<td>3.000</td>
<td>6.5</td>
</tr>
<tr>
<td>MB L2</td>
<td>15</td>
<td>10,952</td>
<td>8433</td>
<td>0.337</td>
<td>6.2</td>
</tr>
<tr>
<td>MB L1</td>
<td>2</td>
<td>10,967</td>
<td>8445</td>
<td>0.001</td>
<td>2.3</td>
</tr>
<tr>
<td>LBS</td>
<td>21</td>
<td>10,969</td>
<td>8446</td>
<td>0.008</td>
<td>8.4</td>
</tr>
<tr>
<td>TF5</td>
<td>12</td>
<td>10,990</td>
<td>8462</td>
<td>0.07</td>
<td>9.8</td>
</tr>
</tbody>
</table>

Table 5. List of Operational Scenarios Considered

<table>
<thead>
<tr>
<th>Case</th>
<th>Scenario1</th>
<th>Injected CO₂, tpd²</th>
<th>MB L3 Permeability Assumed, mD</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1</td>
<td>100³</td>
<td>3</td>
</tr>
<tr>
<td>2</td>
<td>2</td>
<td>100</td>
<td>3</td>
</tr>
<tr>
<td>3</td>
<td>1</td>
<td>100</td>
<td>Sensitivity analysis: 4.5, 9, 18</td>
</tr>
<tr>
<td>4</td>
<td>2</td>
<td>100</td>
<td>Sensitivity analysis: 4.5, 9, 18</td>
</tr>
</tbody>
</table>

Note: 1 Scenario 1: OBS well (no production); Scenario 2: OBS well converted to production well.
² Maximum injection rate, tons per day.
³ Maximum injection pressure, 8900 psi.

For the sake of simplicity, only end member results are discussed. Figure 39 shows the pressure and global CO₂ fraction observed at CO₂ breakthrough times. Breakthrough time was reduced from 720 days in Case 1 to 140 days in Case 2 just by opening the OBS well to production. The best result (referred to as the “Best-Case Scenario” in Figure 39), in terms of shortest expected time to breakthrough following injection of 100 tons per day, was observed when the effective permeability was improved to 18 mD, resulting in breakthrough in less than 60 days. Oil production rate from the OBS well ranged from 200 to 1500 bpd.

The simulation results indicated the presence of fractures is a key factor when looking for more favorable scenarios in terms of CO₂ injection in virgin tight oil reservoirs. In the absence of flow contribution from natural or induced fractures, CO₂ injection rates in tight reservoirs at virgin conditions, such as the Bakken Formation, are expected to be extremely low. Fractures play an important role by increasing the contact area with the reservoir. In reviewing the simulation scenarios evaluated, it was recommended to 1) plan for a small-scale injection test using a total CO₂ volume of approximately a hundred tons, and 2) have no need to collect fluid samples in the observation well as the injection period would not exceed 1 week. The recommendation regarding the use of the observation well was rendered to be moot when the decision was made to remove the use of that well from the experimental design monitoring plan.
CO₂ PENETRATION DISTANCE BASED ON PREDICTIVE MODELING

A reservoir simulation model was built to predict the distance that the mass of injected CO₂ would penetrate into the MB reservoir. The results of pressure-transient analysis indicated that during the injection period with high pressures, the formation exhibited characteristics of 1) high
leak-off regime; i.e., the CO2 penetrated into the matrix, and 2) pressure-transient signature typical of complex fractures (fracture height recession and transverse storage). The “after-closure analysis” was inconclusive regarding flow regimes, fracture properties, and fracture dimensions. Given the lack of information for representing more accurately the complex fractures opened by CO2 injection at high pressure, the model chosen for these simulations uses a relatively simple dual-permeability model. The model is simple in the sense that it does not require the exact geometrical description of the fracture dimensions and their exact location. However, the model still is able to capture relevant mechanisms such as flow contribution from the opening of the fractures during the injection period, and posterior severe reduction of the fracture permeability due to the fracture closure during the shut-in period. The objective of this exercise was to estimate the area influenced by the CO2 injection in terms of the CO2 saturation and pressure plumes.

The layer cake model built for this study used information from the well logs (thickness and depth of the different lithofacies) and core analysis (initial fluid saturations). Both the relative permeability table and the PVT table were taken from the simulation study shown in a previous section (Horizontal Wells’ Production Analysis section). The matrix properties are listed in Table 6. Fracture properties were manually tuned, in several sensitivity analysis iterations, such that the model is able to reproduce key field observations recorded during the injection test. Rock compaction tables were used to model the mechanism of fracture opening (high effective permeability at pressures higher than the fracture opening pressure, 9200 psi approximately) and fracture closing (effective permeability behaves as the original matrix permeability at pressures lower than 9200 psi). There is no hysteresis in the rock compaction tables. Relative permeability of the fractures follow a simple linear function with saturation.

<table>
<thead>
<tr>
<th>Member</th>
<th>Depth, ft</th>
<th>Matrix Porosity, %</th>
<th>Matrix Permeability, μD</th>
</tr>
</thead>
<tbody>
<tr>
<td>UBS</td>
<td>10910</td>
<td>7.2</td>
<td>0.8</td>
</tr>
<tr>
<td>MB-L5</td>
<td>10925</td>
<td>5.6</td>
<td>0.3</td>
</tr>
<tr>
<td>MB-L4</td>
<td>10933</td>
<td>6.3</td>
<td>20</td>
</tr>
<tr>
<td>MB-L3</td>
<td>10945</td>
<td>6.5</td>
<td>50</td>
</tr>
<tr>
<td>MB-L2</td>
<td>10951</td>
<td>6.2</td>
<td>40</td>
</tr>
<tr>
<td>MB-L1</td>
<td>10960</td>
<td>2.3</td>
<td>13</td>
</tr>
<tr>
<td>LBS</td>
<td>10965</td>
<td>8.4</td>
<td>0.5</td>
</tr>
<tr>
<td>TF5</td>
<td>10983</td>
<td>9.8</td>
<td>60</td>
</tr>
</tbody>
</table>

The model was run in prediction mode, covering a period of approximately 10 days, corresponding to the following sequence of events: 1) 1.33 days (32 hours) of cyclic injection with a maximum injection pressure of 9200 psi, 2) another 1.33 days (32 hours) of continuous injection with a maximum injection pressure of 9400 psi, and 3) one week of soaking. The well was constrained to honor the maximum BHP measured during both cyclic and continuous injection tests while the injection rate is calculated. Figure 40 shows the BHP pressure on the right axis and the cumulative CO2 injection volume on the left axis vs. time. Figure 40 confirms that the values
of the parameters chosen for the fracture properties and the rock compaction table are capable of reproducing, with a reasonable degree of confidence, field-measured values (BHP and CO₂ injection rates). Figure 41 shows top views, zooming in, around the area of influence (near-wellbore area, centered around the injection well and located at the perforation depth on the Knutson–Werre well) at a time equivalent to the end of the injection (after a total of 64 hours of injection). Figure 41a shows the simulated CO₂ saturation plume, and Figure 41b shows the results at the end of the injection period, the pressure plume has a radius of influence approximately 400 ft; while the CO₂ plume has a maximum radius of approximately 140 ft.

It is important to note that the modeling of the CO₂ saturation plume assumes CO₂ flowed exclusively in fractures, and therefore likely overestimates the role of fractures. This modeling also assumes CO₂ fills all fracture spaces, but the reality would be that oil and water fill substantial portions of the fracture space, further adding to the overestimation of the saturation plume size. Therefore the saturation plume sizes from the predictive modeling should be considered to be a theoretical maximum. As described above in the presentation of material balance and well test analysis, the data collected in the field indicate that the tight nature of the formation matrix resulted in a saturation plume that is much smaller than predicted.
Figure 41. Maps showing the simulation-based predicted area of influence near the injection well at a time equivalent to the end of the injection (after 64 hours of injection): a) simulated CO$_2$ saturation plume, and b) simulated pressure plume. The difference in shape is due to the influences of fracture flow on the saturation model.
MODELING-BASED EVALUATION OF THE POTENTIAL FOR LONG-TERM CO₂ STORAGE AND EOR

Introduction

A variety of modeling activities were conducted using the data generated by the field test to evaluate the potential for EOR and long-term associated CO₂ storage in the Bakken. The work is presented in two different sections: 1) preparation of the simulation models and 2) simulation of CO₂ EOR scenarios using horizontal wells perforated in the area surrounding the vertical Knutson–Werre 34-3 injection test well.

Classical reservoir engineering analysis of the data obtained during the flowback period advised against conducting sophisticated history-matching exercises using production data from the actual field test. In the first place, the small amount of fluids collected and the phase changes that those fluids experienced raised some concerns about their suitability for history matching. As a large drawdown was required to compensate for the low permeability of the tight formation, the BHP dropped below the saturation pressure during the flowback period. This caused a phase separation, with much of the liquid phase dropping out of solution and staying trapped in the reservoir, while the gas phase was pushed into the wellbore. Because of the near-wellbore multiphase behavior observed in this low-permeability reservoir and without the collection and analysis of downhole pressurized in situ fluids (essentially “live” oil), both the EOS fluid characterization and the history-matching validation have limited applicability (Fevang and Whitson, 1994). In the second place, the flow rate-measured values at the wellhead may not directly apply to the near-wellbore scale model assumptions. Because the field test was designed to determine injectivity in a virgin reservoir without fracturing the formation, the well was operated under low injection and production rate conditions. These low rates pose a major challenge for performing accurate computations with history-matching methods. For instance, while the total wellbore volume was estimated to be approximately between 60 to 70 bbl, the flowback production cumulative volume was less than 10 bbl. With this relatively small production volume, early time transient effects (such as liquid holdup and velocity fluctuations due to multiphase flow conditions in the wellbore) are expected to have a significant role, obscuring the interpretation of the history matching results. Therefore, history-matching of the flowback period was not attempted. In its place, production analysis techniques were carried out, and results were shown in the Analysis of the Injection Test BHP and Temperature Data section.

A DSU model was prepared using Schlumberger’s Petrel Software. Numerical simulations were performed with CMG’s compositional reservoir simulator, GEM (Computer Modelling Group Ltd., 2016b). CMG’s CMOST module was used to perform sensitivity analyses and history-matching studies (Computer Modelling Group Ltd., 2016c). Different reservoir simulation scenarios were prepared to investigate the implications of injecting CO₂, CO₂ storage efficiency, sweep efficiency, oil mobilization, and the potential for incremental oil recovery through huff ‘n’ puff operational schedules.
Integration of Laboratory- and Field-Based Test Results into DSU-Scale Modeling

As mentioned above, the injection site model was created to provide the basis for initial simulations needed to inform the injection test design and operational constraints. The DSU model was constructed to more accurately capture the heterogeneity present in the subsurface, provide a mechanism for integration of the test results, and develop long-term predictions of the reservoir response in horizontal wells.

Data compilation began with an initial area of interest 10 miles in diameter and centered on two wells, the NDIC 30829 and the NDIC 30831 wells, located east-southeast of the injection test site at a distance of approximately 1.7 miles. This initial area included nearly 1200 wells useful in developing structural surfaces to construct the model’s structural framework. Digital well log data from the available wells were used to interpret petrophysical properties of the various Bakken and Three Forks lithofacies.

From the gathered data, a heterogeneous, dual porosity–dual permeability DSU model was constructed, intending to capture the anticipated variability within the overall Bakken petroleum system. It is important to note that while this model is referred to in this report as a DSU model, the model covered 2 miles in length and 0.6 miles in width, which represented approximately 60% of the typical DSU size in North Dakota fields. This model differed from the injection test model in the following ways: 1) aside from the Bakken Formation (UBS, MB, and LBS), the structural framework for the heterogeneous model contained the Lodgepole and Three Forks Formations, the units directly overlying and underlying the Bakken Formation, respectively; 2) a range of petrophysical properties were distributed within each model subunit, based upon the spectrum of measurements acquired in the Phase II laboratory efforts described above, whereas the injection site model was populated with only average values for each subunit; 3) model properties were computed using porosity and permeability properties from core and well logs, generated based upon learnings the Phase II laboratory work and previously constructed modeling efforts from Phase I reported in Sorensen and others (2014); and 4) proprietary data and confidential insight provided by XTO regarding reservoir pressure were incorporated to better capture the vertical heterogeneity in the pressure distribution. The resulting distribution of pressure better matched the expected pressure distribution, which is described by Meissner (1991) as a zone of overpressure in the shales due to hydrocarbon generation, slightly lower pressure in the MB Member, with decreasing pressure upwards in the Lodgepole Formation and downwards into the upper portion of the Three Forks Formation. Figure 42 shows the stratigraphic units contained in the model and the wellbore trajectories. Figure 43 shows the resulting matrix and fracture permeability, the discrete fracture network, and initial pressure distribution. Figure 44 shows the matrix and fracture permeability.
Figure 42. DSU model (top) and cutaway view (bottom) showing the horizontal wells’ trajectories. Vertical exaggeration (V.E.) = 10×.
Figure 43. Subunits contained within the DSU model (top), the discrete fracture network constructed within the MB Lithofacies (middle; yellow fracture planes), and the initial pressure distribution (bottom). Note the overpressured nature of the Bakken.
Figure 44. Cutaway view of the model showing well trajectories and subunits contained within the DSU model (top), matrix permeability (middle), and the combined matrix and fracture permeability (bottom).
**Discrete Fracture Network**

A discrete fracture network was created for the MB Member of the DSU model. This fracture network was constructed to replicate the effects of natural fractures in the MB Lithofacies. Fractures were not populated in the UBS and LBS units, as the shales’ plasticity is thought to result in the healing of initiated fractures. Data generated in laboratory analyses of this project, as well as previous work by Sorensen and others (2014), was used to guide the distribution of fracture properties.

Two fracture sets, differing in dip orientation (horizontal versus vertical), were created for each MB lithofacies. Each set was assigned a fracture intensity, aperture, and length. Fracture intensity and aperture were informed by macroscopic core analyses and scanning electron microscopy (SEM) imagery. Little information was available for fracture length, as this was unable to be observed in SEM imaging. An assumed length of 5 ft was used for each fracture set. Additionally, very little information was available for the MB1 lithofacies, as this is a generally thin unit (few available samples). Therefore, the characteristics for the MB2 fracture sets were duplicated in the MB1 lithofacies. The discrete fracture network characteristics for each of the MB lithofacies is included in Table 7.

After these characteristics were input, secondary porosity and permeability were calculated. These properties were used in the creation of a dual porosity–dual permeability simulation model. Early simulation activities using this DSU model identified challenges in using the discrete fracture network. The model size and the relatively large number of fractures used in the simulations resulted in loss of computational efficiencies and convergence problems, causing long simulation run time. Thus the fracture porosity and permeability were upscaled and combined with the matrix properties. The augmented porosity and permeability properties were used in a revised version of the DSU model (single porosity–single permeability), which enabled simulation results to be achieved with increased efficiency. Because of this, only the single porosity–single permeability model was used in the simulation activities discussed in the following sections.

<table>
<thead>
<tr>
<th>Lithofacies</th>
<th>Horizontal Intensity, N/ft</th>
<th>Vertical Intensity, N/ft</th>
<th>Avg. Aperture, ft</th>
</tr>
</thead>
<tbody>
<tr>
<td>MB L5</td>
<td>0.53</td>
<td>0.08</td>
<td>0.000019</td>
</tr>
<tr>
<td>MB L4</td>
<td>0.35</td>
<td>0.76</td>
<td>0.000589</td>
</tr>
<tr>
<td>MB L3</td>
<td>0.92</td>
<td>0.59</td>
<td>0.00253</td>
</tr>
<tr>
<td>MB L2</td>
<td>0.37</td>
<td>0.07</td>
<td>0.001753</td>
</tr>
<tr>
<td>MB L1*</td>
<td>0.37</td>
<td>0.07</td>
<td>0.001753</td>
</tr>
</tbody>
</table>

*MB L1 fracture characteristics were unable to be assessed with confidence because of the paucity of samples; therefore, the fracture characteristics for the MB L2 lithofacies were duplicated in the MB L1 lithofacies.
Use of Rock Compaction Table to Evaluate Field Test Fracture Flow

Rock compaction tables are used to represent nonlinear relations between the CO₂ injection rate and the BHP at the injector wells. This effect was observed in the field test and was analyzed in previous sections. Figure 45 shows the rock compaction table used in the model that represents the dynamic effect caused by the fracture opening on the maximum injection rate. The assumption is that the reservoir could accept a constraint on maximum injection rate below the fracture opening pressure, i.e., in the range from 3000 to 9000 psi. Once the pressure reaches 9000 psi, preexisting fractures will start to open, which will significantly reduce the flow resistance inside the reservoir. In the model, the flow resistance is parameterized in terms of the permeability multiplier, \( k_{mult} \), which is defined as follows:

\[
k_{mult} = \frac{k_{eff}}{k_i}
\]

[Eq. 3]

Where \( k_{mult} \) is the permeability multiplier, later on computed by the reservoir simulator based on table lookup and linear interpolation methods (CMG GEM, 2016), \( k_{eff} \) is the effective permeability of the rock as a result of the combined flow contribution from both matrix and fractures, and \( k_i \) is the initial permeability defined in the original static model. Thus once the pressure reaches 9000 psi, the effective permeability starts to increase exponentially as the injection pressure approaches the fracture opening pressure of 9200 psi. After the fracture opening pressure (9200 psi) is reached, the well is constrained by the maximum injection pressure. By switching the well constraint, the purpose is to reduce the injection rate to avoid fracture

Figure 45. Plot of the rock compaction table used in the model to represent the dynamic effect caused by the fracture opening on the maximum injection rate.
propagation. Rock compaction table was defined in a way that the rock behavior is reversible, meaning that there is a single relationship between permeability and pressure; i.e., there is no hysteresis on the function (CMG GEM, 2016).

Figure 46 shows the response of the model to the rock compaction table in terms of the evolution of the injectivity index vs. BHP. While the injectivity index, $II$, is commonly defined as the ratio of the total injection flow rate to the injection pressure increase, in this document $II$ is defined as follows:

$$II = \frac{Q_g}{(P_{inj} - BHP)} \quad [\text{Eq. 4}]$$

Where $P_{inj}$ is the maximum injection pressure (psi), $Q_g$ is the CO$_2$ injection rate (MMscf/day), and BHP is the well bottomhole pressure (psi). $II$ is a measure of the well performance and reflects the ability of the reservoir to take a given CO$_2$ injection rate, which is primarily a function of the reservoir properties and the BHP.

CO$_2$ injectivity is dominated by the matrix permeability when the injection BHP is significantly below the fracture opening pressure (9200 psi), shown in Figure 41 as the path from Point A to Point B. The injection well is constrained by the maximum injection rate along the AB path. A flow regime transition starts to happen when pressure increases up to 9000 psi (Point B); as the fractures start to open, the flow contribution from fractures progressively dominate over the matrix contribution, and the injectivity increases because the CO$_2$ moves through both the matrix and the fracture. Finally, as the injection pressure reaches or exceeds the fracture opening pressure,

Figure 46. Plot of the injectivity index vs. pressure observed in the injector Well INJ-01 as a result of using the rock compaction table (Figure 40) to represent the dynamic effect caused by the fracture opening on the maximum injection rate.
the flow regime changes to fracture flow (Path BC). Therefore, there is a step increase on injectivity and the well constraint need to be changed to maximum injection pressure (9200 psi) to avoid fracture propagation. Once the BHP is constrained by the maximum injection pressure, CO₂ rates could be reduced up to two orders of magnitude.

**Horizontal Wells’ Production Analysis**

The two horizontal wells included in the DSU model were drilled in 2016 in Dunn County, North Dakota. These wells were selected because they existed in close proximity to the injection test site. Separated by approximately 600 ft, both wells’ hydraulically fractured horizontal segments were completed in the MB Member. The horizontal leg of each production well was 2 miles in length and had 30 completion stages. The first production occurred in June 2017, and production tests were performed in July. Following the production tests, the wells were opened to primary production. Six months of reported production data were obtained from NDIC and used in history-matching efforts during numerical simulation.

Figure 47 shows the average oil and water production (barrels per day) and gas-oil ratio (GOR; cubic feet per barrel) during the first 6 months of production (from June 2017 until December 2017). Statistical analysis showed both wells continued to be prolific producers, averaging more than 11 and 15 cumulative barrels of oil per foot of completed lateral length (bbl/ft) after 6 months of production. For comparison, an analysis of over 10,000 wells completed in the MB Member and Three Forks Formation by Lolon and others (2016) found the 180-day cumulative oil barrels per feet typically ranged between 0.4 to 20 bbl/ft. Table 8 shows statistics from 296 Bakken wells by Dalkhaa and others (2018). The median for Dunn County was 2.8 bbl/ft at 90 days. The maximum at 90 days was 12.4 bbl/ft, and the 75th percentile was only 4.5 bbl/ft. Both of the wells used in the DSU model fell between the 75th percentile and the maximum value, particularly at 180 days with 11.87 bbl/ft (about the 91st percentile) and 15.32 bbl/ft (about the 96th percentile), which suggests that these wells are in a class with other top-ranking wells.

One important aspect noted for this work was the sustained water production rate during the first months in these two wells. While a fraction of this mobile water was likely fluid introduced during reservoir stimulation, other results from the characterization efforts of this project have shown the MB Member, the Lodgepole, and the Three Forks may contain significant mobile water. The LBS impedes movement of mobile water from MB toward deeper formations by gravitational forces, making the initial water content available for production as soon as production is started. The presence of mobile water has important consequences for CO₂ EOR operations. This has not been a focus of many previous Bakken-related studies (Yu and others, 2015; Zuloaga and others, 2017).
Figure 47. Chart showing the average oil and water production (barrels per day) and GOR (cubic feet per barrel) during the first 6 months of production.
Table 8. Comparison of 90- and 180-day Production Statistics from 296 Bakken Wells in Nine North Dakota Counties (bbl oil per foot of completed lateral length). The two columns at the right show the estimated values for the two wells selected for this study (labeled as PROD-01 and PROD-02).

<table>
<thead>
<tr>
<th>County</th>
<th>N</th>
<th>Minimum</th>
<th>Q1</th>
<th>Mean</th>
<th>SD</th>
<th>Median</th>
<th>Q3</th>
<th>Maximum</th>
<th>PROD-01</th>
<th>PROD-02</th>
</tr>
</thead>
<tbody>
<tr>
<td>90-day Cumulative Oil per foot of Lateral Length (bbl/ft)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Dunn</td>
<td>57</td>
<td>0.493</td>
<td>1.431</td>
<td>3.492</td>
<td>2.724</td>
<td>2.802</td>
<td>4.458</td>
<td>12.36</td>
<td>6.74</td>
<td>5.23</td>
</tr>
<tr>
<td>Billings</td>
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<td>0.013</td>
<td>0.602</td>
<td>1.978</td>
<td>1.809</td>
<td>1.260</td>
<td>2.967</td>
<td>7.139</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Burke</td>
<td>1</td>
<td>1.3230</td>
<td>*</td>
<td>1.3230</td>
<td>*</td>
<td>1.3230</td>
<td>*</td>
<td>1.323</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Divide</td>
<td>5</td>
<td>0.960</td>
<td>1.242</td>
<td>2.580</td>
<td>1.563</td>
<td>2.020</td>
<td>4.197</td>
<td>4.696</td>
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<tr>
<td>Golden Valley</td>
<td>6</td>
<td>1.927</td>
<td>1.948</td>
<td>2.934</td>
<td>1.118</td>
<td>2.654</td>
<td>3.877</td>
<td>4.867</td>
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</tr>
<tr>
<td>McKenzie</td>
<td>58</td>
<td>0.283</td>
<td>2.413</td>
<td>4.582</td>
<td>2.804</td>
<td>4.016</td>
<td>6.466</td>
<td>14.373</td>
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<tr>
<td>Mountrail</td>
<td>64</td>
<td>0.835</td>
<td>2.538</td>
<td>5.530</td>
<td>3.586</td>
<td>4.873</td>
<td>7.575</td>
<td>15.02</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Stark</td>
<td>9</td>
<td>0.525</td>
<td>0.974</td>
<td>2.937</td>
<td>2.436</td>
<td>2.365</td>
<td>4.358</td>
<td>8.082</td>
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<tr>
<td>Williams</td>
<td>68</td>
<td>0.660</td>
<td>2.033</td>
<td>3.499</td>
<td>1.819</td>
<td>3.358</td>
<td>4.967</td>
<td>8.421</td>
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<td></td>
</tr>
<tr>
<td>180-day Cumulative Oil per foot of Lateral Length (bbl/ft)</td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Dunn</td>
<td>57</td>
<td>0.926</td>
<td>2.532</td>
<td>5.801</td>
<td>4.227</td>
<td>4.694</td>
<td>7.293</td>
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<td>15.32</td>
<td>11.87</td>
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<td>4.551</td>
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<td></td>
</tr>
<tr>
<td>Burke</td>
<td>1</td>
<td>2.3547</td>
<td>*</td>
<td>2.3547</td>
<td>*</td>
<td>2.3547</td>
<td>*</td>
<td>2.3547</td>
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<tr>
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<td>5.33</td>
<td>7.33</td>
<td>8.5</td>
<td></td>
<td></td>
</tr>
<tr>
<td>McKenzie</td>
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<td>0.854</td>
<td>4.570</td>
<td>7.657</td>
<td>4.462</td>
<td>7.151</td>
<td>9.883</td>
<td>23.8</td>
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<td></td>
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<tr>
<td>Mountrail</td>
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<td>6.479</td>
<td>8.447</td>
<td>14.529</td>
<td>32.156</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Stark</td>
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<td>1.31</td>
<td>2.10</td>
<td>5.24</td>
<td>4.13</td>
<td>4.02</td>
<td>6.78</td>
<td>14.68</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Williams</td>
<td>68</td>
<td>0.969</td>
<td>3.877</td>
<td>5.999</td>
<td>2.698</td>
<td>6.142</td>
<td>7.679</td>
<td>13.624</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
**History-Matching Validation**

Figure 48 shows 3-D images of the DSU model with the two wells’ trajectories and hydraulic fractures. Symmetrical planar fractures were created with CMG’s Builder module, representing 56 single fracture stages (28 for each well). While the actual number of stages is 30, the cell size employed did not allow accommodating the well trajectories in the model without overlapping between the two remaining hydraulic fractures. Sensitivity analyses showed results tend to have little sensitivity when varying fracture spacing and the two fractures per well discrepancy. History-matching exercises confirmed the selected number of planar fractures provided a reasonable choice for the model.

Production data, shown in Figure 47, were used to calibrate the matrix properties (porosity and permeability) and hydraulic fracture properties (fracture permeability, fracture length, and fracture height). Fluid composition and fluid properties were obtained from existing PVT reports (Kurtoglu and others, 2012; Jin and others, 2017). The Peng-Robinson EOS model was calibrated with saturation pressure and oil viscosity data from laboratory experiments and GOR from separator tests. Figure 49 shows plots of the oil viscosity vs. pressure (Figure 49a) and the pressure-temperature phase diagram (phase envelope; see Figure 49b). Table 9 presents the fluid composition and fluid properties used in this study. Relative permeability end points were parameterized and used on the history-matching procedure. The initial set of relative permeability curves was obtained from lab results publicly available (Cho and others, 2016). Initial and final relative permeability curves are shown in Figure 50.

CMOST was used to perform sensitivity analyses and history-matching efforts. Factors used to evaluate the history-matched model quality were cumulative oil, cumulative water, and GOR. Several rounds of history matching were performed to adjust the model parameters, including relative permeability end points and hydraulic fracture properties. Figure 51 presents a chart with the global error vs. history-matching simulation number. Cumulative oil vs. time (Figure 52a) and cumulative water (Figure 52b) resulted in excellent agreement. The history-matched model resulted in a weighted average global error of 7.4%, composed of 1.3% error from the cumulative oil, 4.1% from the cumulative water, and 8.7% from the GOR. As expected, cumulative water and GOR had greater uncertainty. For the purpose of this study, the level of error was considered acceptable given the unknowns surrounding operational parameters. In particular, a relatively high degree of uncertainty was present regarding the BHP and instantaneous rate measurements.
Figure 48. Porosity a) and permeability b) distributions with the wells’ trajectories and hydraulic fractures.
Figure 49. Oil viscosity and fluid pressure/temperature phase diagram (phase envelope) after calibration of EOS using lab results and WINPROP.

Table 9. Fluid Composition and Fluid Properties Used in This Study

<table>
<thead>
<tr>
<th>ID</th>
<th>Component</th>
<th>P_c, atm</th>
<th>T_c, K</th>
<th>Acentric Factor</th>
<th>Molecular Weight</th>
<th>Volume Shift</th>
<th>Composition</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>CO₂</td>
<td>72.8</td>
<td>304.2</td>
<td>0.2250</td>
<td>44.0</td>
<td>0.005653</td>
<td>0.03219</td>
</tr>
<tr>
<td>2</td>
<td>N₂</td>
<td>33.5</td>
<td>126.2</td>
<td>0.0400</td>
<td>28.0</td>
<td>−0.22838</td>
<td>0.00320</td>
</tr>
<tr>
<td>3</td>
<td>CH₄</td>
<td>45.4</td>
<td>190.6</td>
<td>0.0080</td>
<td>16.0</td>
<td>−0.25386</td>
<td>0.26865</td>
</tr>
<tr>
<td>4</td>
<td>C₂H₆</td>
<td>48.2</td>
<td>305.4</td>
<td>0.0980</td>
<td>30.1</td>
<td>−0.22401</td>
<td>0.10798</td>
</tr>
<tr>
<td>5</td>
<td>C₃H to NC₄</td>
<td>39.9</td>
<td>392.2</td>
<td>0.1675</td>
<td>49.9</td>
<td>−0.18033</td>
<td>0.13087</td>
</tr>
<tr>
<td>6</td>
<td>IC₅ to C₇</td>
<td>32.1</td>
<td>513.1</td>
<td>0.2810</td>
<td>86.6</td>
<td>−0.11924</td>
<td>0.13677</td>
</tr>
<tr>
<td>7</td>
<td>C₈ to C₁₂</td>
<td>22.1</td>
<td>663.7</td>
<td>0.4157</td>
<td>152.7</td>
<td>0.100631</td>
<td>0.16517</td>
</tr>
<tr>
<td>8</td>
<td>C₁₃ to C₁₉</td>
<td>21.7</td>
<td>784.2</td>
<td>0.6591</td>
<td>254.0</td>
<td>0.222675</td>
<td>0.08558</td>
</tr>
<tr>
<td>9</td>
<td>C₂₀ to C₃₆</td>
<td>9.4</td>
<td>1021.9</td>
<td>1.0123</td>
<td>435.6</td>
<td>0.129949</td>
<td>0.06959</td>
</tr>
</tbody>
</table>
Figure 50. Water/oil (a) and liquid/gas (b) relative permeability curves.

Figure 51. Global and local error for the history-matching efforts.
Figure 52. Comparison of the simulated and recorded (field-observed) cumulative oil (a) and simulated and recorded (field-observed) cumulative water (b) during history matching.
Simulation of CO₂ EOR Scenarios

Case 1: History-Matched Simulation Model

The history-matched simulation model (Case 1) was used as starting point to examine injection and production schemes that may be effective in maximizing the long-term storage of CO₂ in the Bakken Formation. Different scenarios were prepared to investigate the long-term storage of CO₂ through continuous CO₂ injection (CCI) and huff ‘n’ puff (alternating CO₂ injection and production) schemes. While many configurations were studied, only results from a few cases are discussed in detail below.

The CO₂ EOR results from Case 1 were relatively modest (<2%) or suboptimal. The contributing factors included a relatively low fracture–matrix surface contact area, combined with poor vertical communication (low vertical-to-horizontal permeability ratio) and a higher-than-expected water saturation. These factors will be explained in the next section comparing the performance of two additional variants (Cases 2 and 3), which were prepared to assess uncertainty in MB Member permeability (due to flow contribution by natural fractures). Table 10 includes assumed values for minimum, maximum, and arithmetic average permeability and the vertical-to-horizontal permeability ratio for the MB layers for three cases.

Figure 53 shows a comparison of oil production estimates, assuming primary production conditions, from simulations lasting 60 months for Cases 1 and 2 in comparison to a moderate-type curve obtained from decline curve analysis (DCA) of the 296 Bakken wells mentioned above, as explained in Table 8. As expected, the history-matched model performed much better than the other two cases. Recovery factor estimates after 30 years of primary production, using 3000 psi as a BHP constraint, were 6.9% for Case 3, 4.1% for Case 2, and 6.8% for Case 1. Case 1 and Case 3 performed in a similar way after 30 years of production.

<table>
<thead>
<tr>
<th>Table 10. History-Matched Model (Case 1) and Its Variants (Case 2 and Case 3)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Permeability, μD</td>
</tr>
<tr>
<td>Min.</td>
</tr>
<tr>
<td>Case 1</td>
</tr>
<tr>
<td>Case 2</td>
</tr>
<tr>
<td>Case 3</td>
</tr>
</tbody>
</table>
Table 11 summarizes the operational parameters assumed with Case 2 (low vertical-to-horizontal permeability ratio). A comparison of oil production with and without CO₂ injection for the scenarios studied with Case 2 is presented in Figure 53. Oil production remained above the baseline case (reference case) for all three huff ‘n’ puff cases. The CCI cases entailed conversion of one production well into an injection well. This resulted in lower recovery than the reference case (Reference case; primary production with constant BHP) where both wells operated as production wells throughout their operational life. Similarly, a huff ‘n’ puff variant where CO₂ was injected in both wells at the same time resulted in relatively modest incremental recovery (<1%). On the other hand, the alternating huff ‘n’ puff results (one well injecting CO₂ while the other was producing) indicated this operational strategy was a more attractive option. The alternating huff ‘n’ puff variant consisted of the following steps:

1) After 3 years of primary production, one well was converted to a CO₂ injection well while the other well remained under production.

2) After an injection period, the injection well was shut in to start a “soaking” period, allowing the injected CO₂ to interact with the matrix while keeping the other well on production.

Figure 53. Comparison between Cases 1 and 2 and the moderate-type curve obtained from DCA techniques using a database of 296 wells in the area.

**Case 2: Tight Matrix with Low Vertical-to-Horizontal Permeability Ratio**

Table 11 summarizes the operational parameters assumed with Case 2 (low vertical-to-horizontal permeability ratio). A comparison of oil production with and without CO₂ injection for the scenarios studied with Case 2 is presented in Figure 53. Oil production remained above the baseline case (reference case) for all three huff ‘n’ puff cases. The CCI cases entailed conversion of one production well into an injection well. This resulted in lower recovery than the reference case (Reference case; primary production with constant BHP) where both wells operated as production wells throughout their operational life. Similarly, a huff ‘n’ puff variant where CO₂ was injected in both wells at the same time resulted in relatively modest incremental recovery (<1%). On the other hand, the alternating huff ‘n’ puff results (one well injecting CO₂ while the other was producing) indicated this operational strategy was a more attractive option. The alternating huff ‘n’ puff variant consisted of the following steps:

1) After 3 years of primary production, one well was converted to a CO₂ injection well while the other well remained under production.

2) After an injection period, the injection well was shut in to start a “soaking” period, allowing the injected CO₂ to interact with the matrix while keeping the other well on production.
Table 11. List of Operational Scenarios Considered with Case 2, Characterized by Relatively Low Vertical Matrix Permeability (assumed 0.1 as K_v-to-K_h ratio)

<table>
<thead>
<tr>
<th>Scenario ID</th>
<th>Number of Cycles</th>
<th>Cum CO₂ Injected, MMscf</th>
<th>Incremental Recovery Factor</th>
<th>Operational Constraints¹</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reference²</td>
<td>0</td>
<td>–</td>
<td>–</td>
<td>• Minimum BHP (3000 psi) at producers</td>
</tr>
<tr>
<td>HP-01</td>
<td>28</td>
<td>4445</td>
<td>1.3%</td>
<td>• Maximum BHP (9200 psi) at injectors</td>
</tr>
<tr>
<td>HP-02</td>
<td>18</td>
<td>4424</td>
<td>1.3%</td>
<td>• Maximum gas rate (10 MMscfd) injected</td>
</tr>
<tr>
<td>HP-03</td>
<td>14</td>
<td>3907</td>
<td>1.2%</td>
<td></td>
</tr>
<tr>
<td>HP-04 Paired³</td>
<td>7</td>
<td>3609</td>
<td>0.4%</td>
<td></td>
</tr>
</tbody>
</table>

¹ Alternating huff ‘n’ puff cycle lengths: 3-month (HP-01), 5-month (HP-02), or 9-month (HP-03) injection, followed by 4 weeks of soaking and 1 year of production.
² Reference case refers to primary production without CO₂ injection.
³ Paired huff ‘n’ puff cycle lengths: 11-month (HP-04) injection, followed by 4 weeks of soaking and 1 year of production. Results after 30-year of production (huff ‘n’ puff, starting on the third year after primary production).

3) After the “soaking” period, the function of the wells was reversed, where the injection well was converted to production (and vice versa).

4) Steps 1–3 were repeated with the new configuration.

The injection well needed to be operated for several weeks to months to inject a meaningful volume of CO₂ into the tight formation. Having one production well operating simultaneously mitigated production loss during each injection and soak period, as shown in Figure 54. This operational procedure appeared effective when there was little or negligible direct communication between the pair of wells. GOR was monitored to detect CO₂ breakthrough in the production well to detect interwell communication.

MMP is an important factor in oil mobilization during CO₂ EOR. Laboratory experiments have shown that when CO₂ injection is accompanied by pressure at or above MMP, oil mobilization is more effective. When pressure lowers below MMP, oil mobilization decreases. The simulation results indicated CO₂ injection was most effective when BHP was kept above MMP. When BHP is below the MMP and saturation pressure, fractures are filled with three fluid phases (water, oil, and gas). Water progressively accumulates at the bottom of fractures during production. Gravitational forces trap some of the water, blocking a significant section of the fracture. At the same time, a gas cap may accumulate at the top of the fracture. This effect may become more pronounced as production progresses, potentially reducing the surface area available for oil transport. When CO₂ is injected at a BHP higher than MMP, the water volume accumulating in the lower part of fractures is decreased. At the same time, another factor affecting the CO₂ EOR effectiveness is water coming from out of the targeted reservoir zones (Figure 55) (top unit – Lodgpole- and/or Three Forks having higher initial water saturation). These effects may have significant influence over both the oil recovery rate and the associated CO₂ storage. The BHP during production was constrained to 3000 psi, with a dual purpose: 1) maintain a pressure high enough to allow miscible conditions, and 2) to keep reservoir pressure above the saturation pressure. The later factor will simplify the analysis of the results by removing compositional effects happening during fluid-phase changes.
Figure 54. Oil production in Wells PROD-01 (a) and PROD-02 (b) vs. time for the huff ‘n’ puff alternating variant (HNP-01). Reference case refers to primary production without CO\textsubscript{2} injection.
Figure 55. 2-D cross-section view at the center of the model showing the spatial distribution of the pressure and the fluid-phase saturations at a time equivalent to the end of the first injection cycle: a) pressure map and b) ternary saturation map (with BHP higher than MMP).

**Case 3: Base Case Matrix Permeability with Higher Vertical-to-Horizontal Permeability Ratio**

As shown by the rock extraction studies described above and discussed in more detail in Hawthorne and others (2013) and Jin and others (2017), diffusion is thought to play a key role in the production of hydrocarbons in ultralow permeability rocks during CO$_2$ EOR, allowing otherwise trapped hydrocarbons to migrate to fractures. With that in mind, the role of natural fractures and vertical communication was evaluated in Case 3, which used a vertical-to-horizontal permeability ratio (Kv/Kh) of 0.4. Figure 56a shows the recovery factor in Case 2, which had lower effective permeability in the MB (Table 10, up to one order of magnitude lower), meant to simulate lower contribution from natural fractures. The operational scenarios for Case 3 are listed in Table 12. Figure 56b shows the recovery factor in Case 3 (with higher effective permeability and higher vertical-to-horizontal permeability ratio due to greater contribution from natural fractures).
Figure 56. Recovery factor with time for different models and operational scenarios: a) Case 2 (tight matrix with poor vertical communication) and b) Case 3 (base case matrix permeability with fluid contribution from natural fractures in the MB and good vertical communication). Reference case refers to primary production without CO$_2$ injection. Continuous case refers to continuous CO$_2$ injection using one well as injector and the other as producer during the 30 years.
Table 12. List of Operational Scenarios Considered with Case 3 Having a Relatively High Vertical Matrix Permeability (assumed 0.4 as Kv-to-Kh ratio)

<table>
<thead>
<tr>
<th>Scenario ID</th>
<th>Number of Cycles</th>
<th>Cum CO₂ Injected, MMscf</th>
<th>Incremental Recovery Factor</th>
<th>Operational Constraints*</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reference</td>
<td>0</td>
<td>–</td>
<td>–</td>
<td>• Minimum BHP (3000 psi) at producers</td>
</tr>
<tr>
<td>HP-05*</td>
<td>28</td>
<td>21521</td>
<td>6.3%</td>
<td>• Maximum BHP (9200 psi) at injectors</td>
</tr>
<tr>
<td>HP-06*</td>
<td>28</td>
<td>21079</td>
<td>7.3%</td>
<td>• Maximum gas rate (10 MMscfd) injected</td>
</tr>
<tr>
<td>HP-07**</td>
<td>7</td>
<td>21056</td>
<td>7.5%</td>
<td>** Paired huff ‘n’ puff cycle length: 11-month (HP-07) injection; followed by 4 weeks of soaking and 3 years of production. Results after 30 years of production (huff ‘n’ puff, starting on the third year after primary production).</td>
</tr>
</tbody>
</table>

* Alternating huff ‘n’ puff cycles’ length: 3-month (HP-05) injection or 9-month (HP-06) injection, followed by 4 weeks of soaking and 1 year of production.
** Paired huff ‘n’ puff cycle length: 11-month (HP-07) injection, followed by 4 weeks of soaking and 3 years of production. Results after 30 years of production (huff ‘n’ puff, starting on the third year after primary production).

Conclusions of Modeling Activities

In this study, data generated by the field test were integrated into a second round of dynamic simulation modeling to examine injection and production schemes that maximize the long-term storage of CO₂ in tight oil formations. For that purpose, a geologic model was built and calibrated using field- and lab-scale data sets acquired in the area surrounding the vertical Knutson–Werre 34-3 injection test well. Production data for horizontal wells in the study area, collected from the NDIC site, were incorporated into the analysis for a better representation of the site-specific characteristics of local Bakken wells. Collected data indicate that, after 180 days of primary depletion, the two horizontal wells performed above average in terms of water and oil cumulative production compared to other Bakken wells. Initial in situ saturations from well logs collected in the injector well revealed that the MB Member and the Lodgepole and Three Forks Formations might contain significant amounts of mobile water.

Simulation models provided a means to improve the understanding of the physical mechanisms affecting the CO₂ storage efficiency in tight oil reservoirs. Simulation results at the DSU scale confirmed the potential benefits of using alternating CO₂ huff ‘n’ puff injection in adjacent hydraulically fractured horizontal wells. Stimulation of the near-wellbore region by changing the distribution of the fluid phases present in the hydraulic fractures has been identified as a favorable mechanism from CO₂ injection in Bakken tight members.

In the two horizontal study wells that were modeled, the simulations indicated that the alternating huff ‘n’ puff injection approach showed the best performance in terms of EOR. In the best cases, the alternating huff ‘n’ puff scheme was predicted to more than double the oil recovery factor of a well. These results support the conclusions of previous Phase I modeling work that indicate alternating huff ‘n’ puff approaches may be an effective and economic means of implementing CO₂ EOR and associated storage.

The modeling efforts indicated the presence of water in a Bakken reservoir can have serious impacts on the EOR and CO₂ storage potential of a well. The production history of the two horizontal study wells that were modeled showed both wells having a higher water saturation than previous EERC-modeled Bakken wells. The modeling results suggest that mobile water may tend
to accumulate in the lower portions of hydraulically induced fractures, which can essentially block or impede the contact of injected CO₂ with the lower portions of the Bakken reservoir, including the relatively oil-rich LBS. Previous EERC Bakken modeling exercises in Phase I and other Bakken research projects were conducted using reservoirs with very low water saturation, which are typical of many of the highly productive areas of the Bakken. However, as the geographic area of production has expanded, more Bakken wells have been drilled into areas of relatively higher water saturation. The results of these Phase II modeling efforts make an important contribution not only in furthering our understanding of the role that formation water may have in CO₂ EOR and associated storage, but also in expanding the applicability of the program’s results to include a wider variety of Bakken reservoir types.

In this project, production data used to calibrate the history-matched model were limited to the well reports obtained from the NDIC Oil and Gas Division Web site. Reported data for both PROD-01 and PROD-02 wells included some well parameters (such as number of stages, well trajectory, wellbore diameter, etc.) and production records (which consisted of monthly cumulative production volumes for each fluid phase: water, oil, and gas). Reservoir fluid compositions were obtained from the open literature (Kortuglu, 2012), and the separator conditions were obtained from previous studies (Lord and others, 2015). Unfortunately, wellhead pressure and bottomhole pressure measurements from PROD-01 and PROD-02 wells were not available at this time. The dynamic reservoir simulation model could greatly benefit from having actual pressure and flow rate measurements. In particular, analysis of higher-frequency production data (such as daily pressures and rates) would provide valuable information about the total fracture-matrix surface area, the total number of hydraulic fractures, the stimulated reservoir volume, and the total drainage area (Wang and Wu, 2014).

While an accurate history match could only be performed using field-measured values, in the absence of actual measurements, the model presented above relied on calculated flow rates and BHP. Therefore, the model that was built as part of Phase II could be seen as a relatively simple model that is consistent with the nature of the study, which provides a means to capture trends and helps to understand the behavior of the reservoir and injected fluids based on the data available. Given the model assumptions, the simulation results provide an approximate answer to the real problem. In that sense, the simulation results provide some guidance about the relative merits of the different scenarios evaluated but are not intended to be perceived as representing an accurate or perfect model.

POTENTIAL FOR LONG-TERM STORAGE OF CO₂ IN THE BAKKEN

The results of the Phase I and II laboratory- and simulation-based efforts, as well as data from other EERC Bakken-focused research projects, were applied toward an evaluation of the long-term CO₂ storage potential of the Bakken. To that end, a refined method for estimating the CO₂ storage resource on a kg CO₂ stored per kg of rock basis for both the Bakken shales and nonshale rock units was developed. The development and application of the method and the resulting storage resource estimates for the Bakken shales, MB, and Three Forks are presented below.
CO₂ Storage Resource Equation

The basis for estimating the long-term storage of CO₂ in the Bakken is a variation of DOE’s National Energy Technology Laboratory (NETL) volumetric-based methodology for calculating the prospective CO₂ storage resource of organic-rich shale formations (Goodman and others, 2014; Levine and others, 2016). The DOE NETL formula quantifies the mass of CO₂ stored as either free gas within fractures and pores or as a sorbed component on organic matter and clays:

\[ G_{CO₂} = A_t E_A h_g h_h \left[ \phi \rho_{CO₂ res} \phi_E + (1 - \phi) \rho_{sCO₂} E_m E_{sorb} \right] \]  

[Eq. 5]

Where:

- \( G_{CO₂} \) = Mass CO₂ storage resource of the organic-rich shale formation, M
- \( A_t \) = Total area of the organic-rich shale formation being assessed for CO₂ storage, L²
- \( E_A \) = Fraction of formation total area available for CO₂ storage, L²/L²
- \( h_g \) = Gross thickness of organic-rich shale formation being assessed for CO₂ storage, L
- \( E_h \) = Fraction of shale formation gross thickness available for CO₂ storage, L/L
- \( \phi \) = Percentage of bulk volume that is void volume (porosity), L³/L³
- \( \rho_{CO₂ res} \) = Density of CO₂ at formation pressure and temperature, M/L³
- \( \rho_{sCO₂} \) = Maximum mass of CO₂ sorbed per unit volume solid rock, e.g., the asymptotic value of an appropriate isotherm, M/L³
- \( E_\phi \) = Fraction of shale porosity within the effective formation volume, Ve, available for CO₂ storage. This is a reservoir-scale efficiency factor that is meant to address the probability that CO₂ will never reach some of the pore space because of transport heterogeneities associated with fracture networks and low matrix permeability, L³/L³
- \( E_m \) = Fraction of the shale matrix within the effective formation volume, Ve, available for CO₂ storage. This is a reservoir-scale efficiency factor that is meant to address the probability that CO₂ will never reach some of the shale matrix rock because of transport heterogeneities associated with fracture networks and low matrix permeability, L³/L³
- \( E_{sorb} \) = Fraction of \( \rho_{sCO₂} \) due to reductions in sorptive packing at reservoir pressure and temperature conditions. This is a reservoir-scale efficiency factor that is meant to address the inefficiency of sorptive packing on shale matrix rock because of competitive sorption (sorption/desorption with other species) and nonideality of sorption surfaces (reduction of surface coverage) in the shale matrix, L³/L³

The green-highlighted text in Equation 5 (\( A_t E_A h_g h_h \)) calculates the effective formation volume, \( V_e \), of the formation being assessed for CO₂ storage (i.e., area × height after eliminating acreage due to social or physical restrictions and formation-scale characteristics that change as a function of depth). The blue-highlighted text in Equation 5 (\( \phi \rho_{CO₂ res} \phi_E \)) calculates the portion of the effective formation volume associated with the mass of CO₂ stored as free gas within fractures and pores. Lastly, the red-highlighted text in Equation 5 (\( (1 - \phi) \rho_{sCO₂} E_m E_{sorb} \)) calculates the solid portion of the effective formation volume and the mass of CO₂ stored as a sorbed component on organic matter and clays.
The red-highlighted text in Equation 5 assumes that the input is an isotherm representative of the pressure–sorption relationship and uses an isotherm volume constant at standard conditions. However, this study does not use an isotherm of this form and instead directly incorporates laboratory measurements of CO₂ sorption collected under reservoir pressure and temperature conditions (approximately 110°C [230°F] and 400 bar [5800 psi]) (Sorensen and others, 2018). These laboratory measurements provide results in units of mass of CO₂/mass of TOC and clay in the rock sample; therefore, ρ_{sCO₂} is not necessary, and Equation 5 becomes Equation 6:

$$G_{CO₂} = A_t E_{h_g} [\Phi \rho_{CO₂res} E_\phi + \rho_{bulk} F_{TOC+clay} C_S E_s]$$

[Eq. 6]

Where:

- \(\rho_{bulk}\) = Bulk density of the formation, kg rock/m³ rock
- \(F_{TOC+clay}\) = Mass of TOC and clay in the rock sample, kg (TOC + clay)/kg rock
- \(C_s\) = Mass of CO₂ sorbed per mass of (TOC + clay) in the rock at reservoir pressure and temperature conditions, kg CO₂/kg (TOC + clay)
- \(E_S\) = Combined efficiency of the volume of matrix rock contacted by gas (E_m), i.e., reductions due to transport processes and the efficiency of sorptive packing of gas at reservoir conditions (E_sorb)

Equation 6 is the primary equation used in this section to estimate the prospective CO₂ storage resource of the Bakken. Advanced core characterization of Bakken rock samples shows that the organic matter in the UBS and LBS largely consists of kerogen and bitumen and that there is little organic matter in the MB Member; therefore, sorption of CO₂ in the shales primarily occurs in the organic matter, while in the MB, sorption occurs largely on clays (Sorensen and others, 2017). This study does not distinguish among different types of organic matter or between organic matter and clays and simply relates \(C_s\) as a function of the TOC and clay content of the rock matrix. The effects of different types of organic matter and clays on CO₂ sorption are currently being investigated in more detail at the EERC as part of other Bakken-related projects.

The Phase II laboratory analyses conducted on Bakken rock samples described in previous sections provide measurements that improve estimates of \(\Phi\), \(F_{TOC+clay}\), and \(C_s\), which help to provide improved estimates of \(G_{CO₂}\) for the Bakken and the variability inherent in these estimates. Values for the efficiency terms in Equation 6, \(E_\phi\) and \(E_m\), use literature estimates obtained from Curtis (2002), Jarvie (2012), and Levine and others (2016). The Phase II modeling and simulation efforts, in particular the DSU-scale 3-D Corner-Point Grid Model, provide additional information about \(E_\phi\), integrating knowledge gained from the Knutson–Werre CO₂ injection test to predict the reservoir response along horizontal wellbores. These DSU-simulation results provides additional information about the ability of injected CO₂ to displace other pore fluids and remain stored in the Bakken.

As described above in the section on the rock and fluid characterization studies, the Bakken is not solely a shale formation. The distinctive lithofacies of the Bakken each have their own unique properties that may significantly affect the mobility and ultimate fate of CO₂ within the formation. Consequently, this work applies Equation 6 to each lithofacies and then sums these individual components to derive an estimate of the total mass CO₂ storage resource for the Bakken, i.e., the shale and nonshale groups.
\[ G_{CO2,TOTAL} = G_{CO2,UBS} + G_{CO2,MB-L5-L1} + G_{CO2,MB-L4} + G_{CO2,LBS} + G_{CO2,TF} \]  [Eq. 7]

Where:
- \( G_{CO2,TOTAL} \) = Total mass CO\(_2\) storage resource of the Bakken petroleum system
- \( G_{CO2,UBS} \) = Mass CO\(_2\) storage resource of the UBS
- \( G_{CO2,MB-L5-L1} \) = Mass CO\(_2\) storage resource of the MB Member, including Lithofacies 5 (MB-L5) through Lithofacies 1 (MB-L1)
- \( G_{CO2,LBS} \) = Mass CO\(_2\) storage resource of the LBS
- \( G_{CO2,TF} \) = Mass CO\(_2\) storage resource of the Three Forks Formation

The remainder of this section describes estimates of \( \phi \), \( C_s \), and \( F_{TOC+clay} \) for the different Bakken lithofacies, as informed by the current study and available published references, and implements Equations 6 and 7 to estimate the total mass CO\(_2\) storage resource of the Bakken.

**Porosity (\( \phi \)) Examinations**

The average porosity measured in rock samples collected from the UBS and LBS ranged from 3.4\% to 4.2\%, and the average porosity of rock samples collected from the MB Member ranged from 2.7\% to 4.4\% (Table 13). Therefore, both the shale and nonshale groups have comparable total porosity. However, while the measured porosity (void space) is similar between the shale and nonshale groups, the size and distribution of the pore throats that contribute to that porosity will have an important effect on the ability for fluids to move through the pore space.

The porosity measurements in Table 13 account for matrix porosity and some natural fractures present in the rock core samples. However, these rock core samples may not account for the natural fracture networks known to be present within the broader MB Member. These types of laboratory measurements are known to be scale-dependent, particularly when natural fracture networks are involved, with values increasing as the scale of the measurement increases (Neuman, 1990). Thus these porosity measurements are likely biased low for the MB Member. In addition, the porosity measurements in Table 13 do not account for the increased porosity attributable to drilling and completion (i.e., hydraulic fracturing) of the MB Member.
Table 13. Summary Statistics of Porosity, Bulk Density, TOC, and Clay Measurements for Bakken Rock Core Samples Grouped by Lithofacies. The P25 and P75 are the 25th and 75th percentiles, respectively, and define the interquartile range (IQR).

<table>
<thead>
<tr>
<th>Lithofacies</th>
<th>N</th>
<th>Minimum</th>
<th>P25</th>
<th>Mean</th>
<th>SD</th>
<th>Median</th>
<th>P75</th>
<th>Maximum</th>
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<tr>
<td>Porosity, %</td>
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<td></td>
<td></td>
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<tr>
<td>UBS</td>
<td>4</td>
<td>0.3</td>
<td>0.3</td>
<td>3.4</td>
<td>3.7</td>
<td>3.1</td>
<td>6.9</td>
<td>7.2</td>
</tr>
<tr>
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<td>0.5</td>
<td>1.5</td>
<td>3.7</td>
<td>2.2</td>
<td>4.1</td>
<td>5.7</td>
<td>6.1</td>
</tr>
<tr>
<td>MB-L4 (packstone)</td>
<td>9</td>
<td>0.3</td>
<td>0.9</td>
<td>2.7</td>
<td>2.8</td>
<td>2.0</td>
<td>3.3</td>
<td>9.4</td>
</tr>
<tr>
<td>MB-L3 (laminated)</td>
<td>22</td>
<td>1.3</td>
<td>3.0</td>
<td>4.4</td>
<td>1.7</td>
<td>4.5</td>
<td>5.5</td>
<td>7.4</td>
</tr>
<tr>
<td>MB-L2 (burrowed)</td>
<td>9</td>
<td>1.3</td>
<td>3.5</td>
<td>4.0</td>
<td>1.3</td>
<td>4.3</td>
<td>4.7</td>
<td>6.0</td>
</tr>
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<td>MB-L1</td>
<td>8</td>
<td>1.5</td>
<td>1.8</td>
<td>4.1</td>
<td>3.8</td>
<td>3.2</td>
<td>4.1</td>
<td>13.1</td>
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<tr>
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<td>0.2</td>
<td>0.2</td>
<td>4.2</td>
<td>2.8</td>
<td>5.6</td>
<td>6.5</td>
<td>6.5</td>
</tr>
<tr>
<td>TF-L5</td>
<td>2</td>
<td>7.1</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>7.4</td>
<td>5.7</td>
<td>–</td>
</tr>
<tr>
<td>Lithofacies</td>
<td>N</td>
<td>Minimum</td>
<td>P25</td>
<td>Mean</td>
<td>SD</td>
<td>Median</td>
<td>P75</td>
<td>Maximum</td>
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<tr>
<td>Bulk Density, g/cm³</td>
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<tr>
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<td>2.19</td>
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<td>2.54</td>
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<td>2.58</td>
<td>2.64</td>
<td>2.71</td>
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<td>2.42</td>
<td>2.57</td>
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<td>2.63</td>
<td>2.67</td>
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<td>2.51</td>
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<td>2.55</td>
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<td>2.55</td>
<td>2.57</td>
<td>0.03</td>
<td>2.57</td>
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<td>2.60</td>
<td>2.63</td>
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<tr>
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<td>2.27</td>
<td>2.32</td>
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<td>2.54</td>
<td>–</td>
<td>2.55</td>
<td>0.00</td>
<td>2.55</td>
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<tr>
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<tr>
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<td>0.1</td>
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<td>0.3</td>
<td>0.3</td>
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<td>0.2</td>
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<td>0.2</td>
<td>0.3</td>
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<td>–</td>
<td>0.4</td>
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<tr>
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<td>6.1</td>
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<td>11.6</td>
<td>14.6</td>
<td>15.1</td>
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<td>TF-L5</td>
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<td>0.2</td>
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<td>0.2</td>
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<td>Minimum</td>
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<td>Mean</td>
<td>SD</td>
<td>Median</td>
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<td>Maximum</td>
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<tr>
<td>Clays, wt%</td>
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<td></td>
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<td></td>
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<tr>
<td>UBS</td>
<td>10</td>
<td>12.2</td>
<td>15.4</td>
<td>19.9</td>
<td>5.9</td>
<td>19.8</td>
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<td>11.0</td>
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<td>18.5</td>
<td>19.1</td>
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<td>0.2</td>
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<td>3.0</td>
<td>2.2</td>
<td>3.7</td>
<td>9.0</td>
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<td>MB-L2 (burrowed)</td>
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<td>4.2</td>
<td>6.9</td>
<td>3.6</td>
<td>7.1</td>
<td>8.9</td>
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<td>9.9</td>
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<td>–</td>
<td>13.9</td>
<td>5.8</td>
<td>13.9</td>
<td>–</td>
<td>17.9</td>
</tr>
</tbody>
</table>

* The summary statistic could not be computed from the available data.
Pore Throat Size Distribution

Pore throat size distribution based on mercury capillary entry pressure testing provides additional information about the nature of the porosity in a rock sample. Figure 57 shows pore throat size distributions for rock samples collected from the UBS, MB, LBS, and Three Forks units and approximate thresholds for nano-, micro-, and meso-sized pore throat radii. These figures illustrate that the UBS and LBS samples have a greater percentage of pore throat radii ≤0.005 μm, while the MB and Three Forks samples have pore throat radii more evenly distributed across the nanopore range and into the micropore range.

Figure 58 translates the frequency distributions of pore throat radii into an expected value (average) using the expectation for a discrete random variable (Baron, 2007). Figure 58 clearly illustrates the change in average pore throat radius between shale and nonshale groups, with UBS and LBS samples having average pore throat radii of 0.005 to 0.012 μm and MB and Three Forks samples having average pore throat radii of 0.010 to 0.089 μm.

The relatively low porosity (<5%) and small pore throat radii (nano- to microscale range) for both the shale and nonshale groups indicate that the volume of pore space that can be filled with CO₂ is significantly less than 100% of the product of porosity and effective formation volume, because a fraction of the CO₂ will never reach the pore space because of transport heterogeneities associated with fracture networks and low matrix permeability (Levine and others, 2016). However, these measurements of pore throat radii support the conclusion that the efficiency factors for CO₂ stored as free gas within fractures and pores (Eφ) would be greater for the MB and Three Forks lithofacies than for the UBS and LBS.

Mass of CO₂ Sorbed to Organic Matter (Cs)

Laboratory Sorption Experiments

Figure 59 shows a compilation of CO₂ adsorption/desorption experiments conducted on Bakken rock samples at approximately 110°C (230°F) and increasing pressure up to approximately 400 bar (5800 psi) (Sorensen and others, 2018). These sorption isotherms were generated from ongoing complementary DOE-funded efforts conducted by the EERC in collaboration with Hitachi.

These results include three rock samples collected from the UBS, two rock samples collected from the MB-L3, and two rock samples collected from the LBS. The laboratory reported the isotherm results in units of mg CO₂/g sample. However, Figure 59 shows these results reexpressed in units of Cs = kg CO₂/kg (TOC + clay), which provides a more tractable set of units for implementing Equation 5. These laboratory results suggest that under reservoir conditions, the lower and upper values for Cs in the UBS and LBS are approximately 0.04 to 0.05 kg CO₂/kg (TOC + clay), respectively, and in the MB-L3 are approximately 0.02 to 0.03 kg CO₂/kg (TOC + clay), respectively.
Figure 57. Distributions of measured pore throat radii for rock samples collected from the UBS (A), MB Member (B), LBS (C), and TF Formation (D), showing approximate thresholds for nano-, micro-, and mesosized pore throats.
Figure 58. Expected value (E[Y]) of measured pore throat radii for rock samples collected from the UBS (A), MB Member (B), LBS (C), and TF Formation (D).
Figure 59. Compilation of CO\textsubscript{2} adsorption/desorption experiments conducted at approximately 110°C (230°F) and increasing pressure up to approximately 400 bar (5800 psi) (Sorensen and others, 2018) expressed in kg CO\textsubscript{2}/kg (TOC + clays) for rock samples collected from the UBS (top), MB Lithofacies 3 (laminated) (middle), and the LBS (bottom).
The asymptotic behavior of the sorption isotherms for the UBS and LBS rock samples are consistent with a Langmuir-type isotherm, where the solid surface possesses a finite number of sorption sites which, once filled, will no longer sorb additional CO₂. In contrast, the sorption isotherms for the MB-L3 rock samples suggest two line segments, which is more consistent with a two-surface sorption isotherm reflecting two types of sorption sites. The significance of these different isotherm behaviors on CO₂ storage is still being investigated as part of the EERC–Hitachi collaborative project.

**Organic Matter Content of Bakken Lithofacies (F_TOC)**

The average TOC content of rock samples collected from the UBS and LBS ranged from 10.8% to 15.1% TOC (F_TOC = 0.108 to 0.151 kg TOC/kg rock), and the average TOC content of rock samples collected from the MB Member ranged from 0.2 to 0.4 %TOC (F_TOC = 0.002 to 0.004 kg TOC/kg rock) (Table 13). Thus the TOC values in MB-L3 are approximately 50 to 70 times lower than the UBS and LBS.

**Clay Content of Bakken Lithofacies (F_clay)**

The average clay content of rock samples collected from the UBS and LBS ranged from 19.9% to 26.9% clay (F_clay = 0.199 to 0.269 kg clay/kg rock), and the average clay content of rock samples collected from the MB Member was 3.0 to 12.0 %clay (F_clay = 0.03 to 0.12 kg clay/kg rock) (Table 13). Thus clay content of the MB member is significantly lower than the clay content of the UBS and LBS.

Equation 6 combines the TOC content and clay content to define a single mass of material that can participate in CO₂ sorption (F_TOC + clay). This step simply adds the normalized values for each component. For example, the average F_TOC + clay for the UBS would be 0.151 kg TOC/kg rock + 0.199 kg clay/kg rock or 0.350 kg (TOC + clay)/kg rock. As discussed above, advanced core characterization of Bakken rock samples shows that the organic matter in the UBS and LBS largely consists of kerogen and bitumen and that there is little organic matter in the MB Member (Sorensen and others, 2017). This study does not distinguish among different types of organic matter or between organic matter and clays and simply relates CS as a function of the TOC and clay content of the rock matrix.

**Efficiency Factors**

Efficiency factors are potentially the largest source of uncertainty in estimating the prospective CO₂ storage resource of the Bakken. As stated by Levine and others (2016), “There is a great deal of uncertainty inherent in the parameters of the equation, especially the efficiency factors, due to significant complexities involved in several of the fundamental processes associated with production, injection, and storage within shales. Despite the uncertainties, the equation works as an approach to a methodology. As data are added over time to reduce the uncertainties, the utility of derived methods will improve, but the purpose for developing these equations are simply to establish the basic methodology.”
There are limited data available in the literature for either the fraction of shale porosity within the effective formation volume available for CO₂ storage ($E_\phi$) or combined efficiency of the volume of matrix rock contacted by gas and the efficiency of sorptive packing of gas at reservoir conditions ($E_S$). Moreover, published data are often specific to gas-filled shale formations rather than oil-filled shales like the UBS/LBS or nonshale tight oil reservoirs such as the MB or Three Forks. Nevertheless, this section summarizes some of the available literature for $E_\phi$ and $E_S$ for shales, recognizing that these efficiency values may differ for the Bakken.

**Fraction of Porosity Available for Free-Gas CO₂ Storage Within Fractures and Pores ($E_\phi$)**

Levine and others (2016) provide estimates of the formation-scale efficiency for CO₂ storage in shale by drawing analogy to the formation-scale efficiency of hydrocarbon production or estimated ultimate recovery (EUR) of a gas resource expressed as a recovery factor. Levine and others (2016) summarizes an average recovery factor of 25% for hydrocarbon-bearing shales in the United States (Godec and others, 2013); recovery factors of 10% to 25% for the Marcellus Shale in the Appalachian Basin (Engelder and Lash, 2008; Godec and others, 2013); and 8% to 12% for the Barnett Shale in the Fort Worth Basin (Lewis and others, 2004; Engelder and Lash, 2008).

These formations are gas-filled shale formations, not oil-filled shale formations. In addition, as previously noted, the Bakken is not solely a shale formation – only the UBS and LBS are shale members, while the MB Member consists of fine-grained clastics and carbonates. However, based on these ranges for recovery factors, low, middle, and high values of $E_\phi$ for the UBS and LBS members of the Bakken were estimated at 8%, 17%, and 25%, respectively. As noted above, the available data support higher efficiency factors for the MB and Three Forks lithofacies than for the UBS and LBS Shales. Therefore, $E_\phi$ estimates for the nonshale group (MB and Three Forks lithofacies) were increased by 10% to 9%, 19%, and 28%, respectively.

**Adjustment to Sorptive CO₂ Storage ($E_S$)**

$E_S$ is the combined efficiency of the volume of matrix rock contacted by gas ($E_m$), which includes reductions due to transport processes and the efficiency of sorptive packing of gas at reservoir conditions ($E_{sorb}$) (Levine and others, 2016). One potential method for quantifying $E_S$ is to draw analogy to the percentage of adsorbed gas versus free gas in shale reservoirs.

Adsorbed gas percentages published by Jarvie (2012) for the Marcellus, Haynesville, Barnett, Fayetteville, Woodford, and Eagle Ford shales ranged from 25% to 70%. Similarly, adsorbed gas percentages published by Curtis (2002) for the Ohio and New Albany shales ranged from 20% to 60%. A combined data set of all eight shale formations results in low, middle, and high estimates of 25%, 50%, and 60%, respectively, for $E_S$ in shales. One important distinction is that these estimates are derived for natural gas, which is predominantly methane (CH₄), not CO₂. Based on previous lab studies, the CH₄ adsorption isotherm is usually lower than the CO₂ adsorption isotherm, meaning that CO₂ is preferentially adsorbed by kerogen in comparison to CH₄ (Heller and Zoback, 2014).
Calculating Prospective CO₂ Storage Resource for the Bakken

Normalizing to Cubic Meters of Rock

There is an additional source of uncertainty in calculating the prospective CO₂ storage resource for the Bakken – the total thickness of the Bakken and relative thicknesses of the UBS, MB, LBS, and Three Forks members across the Williston Basin in North Dakota and Montana in the United States and Manitoba and Saskatchewan in Canada. For example, the total thickness of the Bakken Formation is less than 160 feet in the Williston Basin at a maximum depth of 3700 m (12,150 ft), and the maximum thicknesses of the Upper and LBS Shale Members are 7 m (23 ft) and 15 m (50 ft), respectively, whereas the MB Member is up to 26 m (85 ft) (Yan and others, 2014). However, the total thickness and relative thicknesses of these units change throughout the Bakken extent (Sonnenberg and others, 2009).

To accommodate a more dynamic solution approach that can be applied throughout the Bakken and to facilitate comparisons with other types of storage units, this section derives CO₂ storage resource estimates for each lithofacies expressed as kg CO₂/m³ of rock.

Aggregating Middle Bakken Lithofacies

While there are distinctly different lithofacies within the MB Member and the petrophysical properties differ among these lithofacies, these petrophysical differences are de minimis compared to other sources of uncertainty in the calculations. Therefore, the current CO₂ storage resource estimates aggregate the five lithofacies of the MB Member, MB-L5 through MB-L1, into one unit and apply average properties for the entire unit. Equation 7 therefore becomes 8:

\[ G_{CO₂,TOTAL} = G_{CO₂,UBS} + G_{CO₂,MB} + G_{CO₂,LBS} + G_{CO₂,TF} \]  

[Eq. 8]

Where:

- \( G_{CO₂,TOTAL} \) = Total mass CO₂ storage resource of the Bakken petroleum system
- \( G_{CO₂,UBS} \) = Mass CO₂ storage resource of the UBS
- \( G_{CO₂,MB} \) = Mass CO₂ storage resource of the MB Member
- \( G_{CO₂,LBS} \) = Mass CO₂ storage resource of the LBS
- \( G_{CO₂,TF} \) = Mass CO₂ storage resource of the Three Forks Formation

As data are added over time, future prospective CO₂ storage resource estimates may distinguish the different MB lithofacies.

CO₂ Storage Resource Calculations

Table 14 provides the low, middle, and high inputs used to derive CO₂ storage resource estimates for each lithofacies. No laboratory isotherm experiments were conducted on samples collected from the Three Forks Formation; therefore, the Cs values assume the same sorption behavior for the Three Forks Formation as the MB Member.
Table 14. Low, Middle (most likely), and High Estimates Used to Derive CO₂ Storage Resource Estimates for Each Lithofacies. Cells containing “–” indicate that the summary statistic could not be computed from the available data.

<table>
<thead>
<tr>
<th>Lithofacies</th>
<th>Porosity, %</th>
<th>Lithofacies</th>
<th>CS, kg CO₂/kg (TOC+clay)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>N  Low  Middle  High</td>
<td></td>
<td>N  Low  Middle  High</td>
</tr>
<tr>
<td>UBS</td>
<td>4  0.3  3.1  6.9</td>
<td>UBS</td>
<td>3  0.040  0.045  0.050</td>
</tr>
<tr>
<td>MB</td>
<td>54  2.1  3.8  4.9</td>
<td>MB</td>
<td>2  0.020  0.025  0.030</td>
</tr>
<tr>
<td>LBS</td>
<td>7  0.2  5.6  6.5</td>
<td>LBS</td>
<td>2  0.040  0.045  0.050</td>
</tr>
<tr>
<td>TF-L5</td>
<td>2  7.0  7.4  7.9</td>
<td>TF-L5</td>
<td>–  0.020  0.025  0.030</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Lithofacies</th>
<th>Bulk Density, kg/m³</th>
<th>Lithofacies</th>
<th>E₀, fraction</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>N  Low  Middle  High</td>
<td></td>
<td>N  Low  Middle  High</td>
</tr>
<tr>
<td>UBS</td>
<td>4  2194  2215  2368</td>
<td>UBS</td>
<td>–  0.08  0.17  0.25</td>
</tr>
<tr>
<td>MB</td>
<td>54  2536  2576  2628</td>
<td>MB</td>
<td>–  0.09  0.19  0.28</td>
</tr>
<tr>
<td>LBS</td>
<td>7  2200  2265  2317</td>
<td>LBS</td>
<td>–  0.08  0.17  0.25</td>
</tr>
<tr>
<td>TF-L5</td>
<td>2  2542  2547  2552</td>
<td>TF-L5</td>
<td>–  0.09  0.19  0.28</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Lithofacies</th>
<th>TOC, wt%</th>
<th>Lithofacies</th>
<th>E₀, fraction</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>N  Low  Middle  High</td>
<td></td>
<td>N  Low  Middle  High</td>
</tr>
<tr>
<td>UBS</td>
<td>7  11.8  13.6  15.0</td>
<td>UBS</td>
<td>–  0.25  0.50  0.60</td>
</tr>
<tr>
<td>MB</td>
<td>15  0.2  0.2  0.3</td>
<td>MB</td>
<td>–  0.25  0.50  0.60</td>
</tr>
<tr>
<td>LBS</td>
<td>8  6.1  11.6  14.6</td>
<td>LBS</td>
<td>–  0.25  0.50  0.60</td>
</tr>
<tr>
<td>TF-L5</td>
<td>2  0.2  0.2  0.2</td>
<td>TF-L5</td>
<td>–  0.25  0.50  0.60</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Lithofacies</th>
<th>Clays, wt%</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>N  Low  Middle  High</td>
</tr>
<tr>
<td>UBS</td>
<td>7  15.4  19.8  23.4</td>
</tr>
<tr>
<td>MB</td>
<td>15  3.6  8.1  11.7</td>
</tr>
<tr>
<td>LBS</td>
<td>8  19.6  26.5  33.6</td>
</tr>
<tr>
<td>TF-L5</td>
<td>2  8.1  13.9  19.6</td>
</tr>
</tbody>
</table>

The following example illustrates the calculations for estimating the most likely (middle estimate) CO₂ storage resource associated with the UBS unit. Tables 15 through 17 summarize the results for each lithofacies for the most likely, low, and high CO₂ storage resource estimates, respectively. All calculations assume a CO₂ density of 727 kg/m³ at reservoir conditions (110°C and 400 bar).
Table 15. Summary of the Most Likely CO₂ Storage Resource Estimates for Each Lithofacies. Yellow cells indicate input from Table 14.

<table>
<thead>
<tr>
<th>Input</th>
<th>Units</th>
<th>Most Likely Estimate</th>
<th>UBS</th>
<th>MB Member</th>
<th>LBS</th>
<th>TF</th>
</tr>
</thead>
<tbody>
<tr>
<td>Porosity</td>
<td>L³/L³</td>
<td>0.031</td>
<td>0.038</td>
<td>0.056</td>
<td>0.074</td>
<td></td>
</tr>
<tr>
<td>Porosity Factor for Hydraulic Fracture</td>
<td>%</td>
<td>1.0</td>
<td>1.0</td>
<td>1.0</td>
<td>1.0</td>
<td></td>
</tr>
<tr>
<td>CO₂ Density</td>
<td>kg/m³</td>
<td>727</td>
<td>727</td>
<td>727</td>
<td>727</td>
<td></td>
</tr>
<tr>
<td>Pore Space Storage</td>
<td>kg CO₂/m³ rock</td>
<td>22.7</td>
<td>27.7</td>
<td>40.8</td>
<td>54.0</td>
<td></td>
</tr>
<tr>
<td>E₀</td>
<td></td>
<td>0.17</td>
<td>0.19</td>
<td>0.17</td>
<td>0.19</td>
<td></td>
</tr>
<tr>
<td>Adjusted Pore Space Storage</td>
<td>kg CO₂/m³ rock</td>
<td>3.9</td>
<td>5.3</td>
<td>6.9</td>
<td>10.3</td>
<td></td>
</tr>
<tr>
<td>Bulk Density</td>
<td>kg/m³</td>
<td>2215</td>
<td>2576</td>
<td>2265</td>
<td>2547</td>
<td></td>
</tr>
<tr>
<td>TOC Content</td>
<td>wt%</td>
<td>13.6</td>
<td>0.2</td>
<td>11.6</td>
<td>0.2</td>
<td></td>
</tr>
<tr>
<td>TOC Content</td>
<td>kg TOC/kg rock</td>
<td>0.136</td>
<td>0.002</td>
<td>0.116</td>
<td>0.002</td>
<td></td>
</tr>
<tr>
<td>TOC Content</td>
<td>kg TOC</td>
<td>300</td>
<td>6</td>
<td>263</td>
<td>5</td>
<td></td>
</tr>
<tr>
<td>Clay Content</td>
<td>wt%</td>
<td>19.8</td>
<td>8.1</td>
<td>26.5</td>
<td>13.9</td>
<td></td>
</tr>
<tr>
<td>Clay Content</td>
<td>kg clay/kg rock</td>
<td>0.198</td>
<td>0.081</td>
<td>0.265</td>
<td>0.139</td>
<td></td>
</tr>
<tr>
<td>Clay Content</td>
<td>kg clay</td>
<td>438</td>
<td>207</td>
<td>600</td>
<td>353</td>
<td></td>
</tr>
<tr>
<td>Cₛ</td>
<td>kg CO₂/kg (TOC+clay)</td>
<td>0.045</td>
<td>0.025</td>
<td>0.045</td>
<td>0.025</td>
<td></td>
</tr>
<tr>
<td>Sorbed Storage</td>
<td>kg CO₂/m³ rock</td>
<td>33.2</td>
<td>5.3</td>
<td>38.8</td>
<td>8.9</td>
<td></td>
</tr>
<tr>
<td>Eₛ</td>
<td></td>
<td>0.50</td>
<td>0.50</td>
<td>0.50</td>
<td>0.50</td>
<td></td>
</tr>
<tr>
<td>Adjusted Sorbed Storage</td>
<td>kg CO₂/m³ rock</td>
<td>16.6</td>
<td>2.7</td>
<td>19.4</td>
<td>4.5</td>
<td></td>
</tr>
<tr>
<td>Total Storage (pore + sorbed)</td>
<td>kg CO₂/m³ rock</td>
<td>55.9</td>
<td>33.0</td>
<td>79.6</td>
<td>63.0</td>
<td></td>
</tr>
<tr>
<td>Adjusted Total Storage (pore + sorbed)</td>
<td>kg CO₂/m³ rock</td>
<td>20.5</td>
<td>7.9</td>
<td>26.3</td>
<td>14.7</td>
<td></td>
</tr>
</tbody>
</table>
Table 16. Summary of the Low CO$_2$ Storage Resource Estimates for Each Lithofacies. Yellow cells indicate input from Table 14.

<table>
<thead>
<tr>
<th>Input</th>
<th>Units</th>
<th>Low Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>UBS</td>
</tr>
<tr>
<td>Porosity</td>
<td>L$^3$/L$^3$</td>
<td>0.003</td>
</tr>
<tr>
<td>Porosity Factor for Hydraulic Fracture</td>
<td>[ ]</td>
<td>1.0</td>
</tr>
<tr>
<td>CO$_2$ Density</td>
<td>kg/m$^3$</td>
<td>727</td>
</tr>
<tr>
<td>Pore Space Storage</td>
<td>kg CO$_2$/m$^3$ rock</td>
<td>2.2</td>
</tr>
<tr>
<td>$E_p$</td>
<td>[ ]</td>
<td>0.08</td>
</tr>
<tr>
<td>Adjusted Pore Space Storage</td>
<td>kg CO$_2$/m$^3$ rock</td>
<td>0.2</td>
</tr>
<tr>
<td></td>
<td>kg/m$^3$</td>
<td>2194</td>
</tr>
<tr>
<td>TOC Content</td>
<td>wt%</td>
<td>11.8</td>
</tr>
<tr>
<td>TOC Content</td>
<td>kg TOC/kg rock</td>
<td>0.118</td>
</tr>
<tr>
<td>Clay Content</td>
<td>wt%</td>
<td>15.4</td>
</tr>
<tr>
<td>Clay Content</td>
<td>kg clay/kg rock</td>
<td>0.154</td>
</tr>
<tr>
<td>$C_s$</td>
<td>kg CO$_2$/kg (TOC+clay)</td>
<td>0.040</td>
</tr>
<tr>
<td>Sorbed Storage</td>
<td>kg CO$_2$/m$^3$ rock</td>
<td>23.8</td>
</tr>
<tr>
<td>$E_s$</td>
<td>[ ]</td>
<td>0.25</td>
</tr>
<tr>
<td>Adjusted Sorbed Storage</td>
<td>kg CO$_2$/m$^3$ rock</td>
<td>6.0</td>
</tr>
<tr>
<td>Total Storage (pore + sorbed)</td>
<td>kg CO$_2$/m$^3$ rock</td>
<td>26.0</td>
</tr>
<tr>
<td>Adjusted Total Storage (pore + sorbed)</td>
<td>kg CO$_2$/m$^3$ rock</td>
<td>6.1</td>
</tr>
</tbody>
</table>
Table 17. Summary of the High CO₂ Storage Resource Estimates for Each Lithofacies. Yellow cells indicate input from Table 14.

<table>
<thead>
<tr>
<th>Input</th>
<th>Units</th>
<th>High Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>UBS</td>
</tr>
<tr>
<td>Porosity</td>
<td>L³/L³</td>
<td>0.069</td>
</tr>
<tr>
<td>Porosity Factor for Hydraulic Fracture</td>
<td>[]</td>
<td>1.0</td>
</tr>
<tr>
<td>CO₂ Density</td>
<td>kg/m³</td>
<td>727</td>
</tr>
<tr>
<td>Pore Space Storage</td>
<td>kg CO₂/m³ rock</td>
<td>50.2</td>
</tr>
<tr>
<td>(\varepsilon_p)</td>
<td>[]</td>
<td>0.25</td>
</tr>
<tr>
<td>Adjusted Pore Space Storage</td>
<td>kg CO₂/m³ rock</td>
<td>12.5</td>
</tr>
<tr>
<td>Bulk Density</td>
<td>kg/m³</td>
<td>2368</td>
</tr>
<tr>
<td>TOC Content</td>
<td>wt%</td>
<td>15.0</td>
</tr>
<tr>
<td>TOC Content</td>
<td>kg TOC/kg rock</td>
<td>0.150</td>
</tr>
<tr>
<td>Clay Content</td>
<td>wt%</td>
<td>23.4</td>
</tr>
<tr>
<td>Clay Content</td>
<td>kg clay/kg rock</td>
<td>0.234</td>
</tr>
<tr>
<td>Clay Content</td>
<td>kg clay</td>
<td>555</td>
</tr>
<tr>
<td>(C_s)</td>
<td>kg CO₂/kg (TOC+clay)</td>
<td>0.050</td>
</tr>
<tr>
<td>Sorbed Storage</td>
<td>kg CO₂/m³ rock</td>
<td>45.5</td>
</tr>
<tr>
<td>(E_s)</td>
<td>[]</td>
<td>0.25</td>
</tr>
<tr>
<td>Adjusted Sorbed Storage</td>
<td>kg CO₂/m³ rock</td>
<td>11.4</td>
</tr>
<tr>
<td>Total Storage (pore + sorbed)</td>
<td>kg CO₂/m³ rock</td>
<td>95.6</td>
</tr>
<tr>
<td>Adjusted Total Storage (pore + sorbed)</td>
<td>kg CO₂/m³ rock</td>
<td>23.9</td>
</tr>
</tbody>
</table>
Upper Bakken Shale, Most Likely Case

The mass of CO$_2$ stored in pore space is simply the porosity multiplied by the CO$_2$ density and adjusted for efficiency (i.e., the blue-colored text in Equation 6, $\phi \rho_{CO2_{res}} E_{\phi}$). Using the middle values from Table 14 results in the following calculations:

\[
0.031 \frac{L^3}{L^3} \times 727 \frac{kg}{m^3} = 22.7 \frac{kg CO_2}{m^3 \text{ rock}}
\]

assuming an $E_{\phi}$ of 0.17 results in an adjusted mass of CO$_2$ stored in pore space of 3.9 kg CO$_2$/m$^3$ rock (Table 15).

The mass of CO$_2$ stored as a sorbed component on organic matter and clays is a function of the bulk density of the rock, the TOC content, the clay content, and the sorption isotherm, adjusted for efficiency (i.e., the red-colored text in Equation 6, $\rho_{\text{bulk}} M_{\text{TOC+clay}} C_{S} E_{S}$):

\[
\left(\frac{2215 \ kg \ CO_2}{m^3 \ rock}\right) \times \left(\frac{0.136 \ kg \ TOC+0.198 \ kg \ clay}{kg \ rock}\right) \times \left(\frac{0.045 \ kg \ CO_2}{kg \ (TOC+clay)}\right) = 33.2 \ kg \ CO_2
\]

Assuming an $E_S$ of 0.50 results in an adjusted mass of CO$_2$ stored as a sorbed component on organic matter and clays of 16.6 kg CO$_2$/m$^3$ rock (Table 15).

The most likely total mass of CO$_2$ stored in both pore space and as a sorbed component on organic matter and clays is the sum of both numbers, or 22.7 + 33.2 = 55.9 kg CO$_2$/m$^3$ rock (unadjusted) or 3.9 + 16.6 = 20.5 kg CO$_2$/m$^3$ rock (adjusted to account for efficiency factors, $E_{\phi}$ and $E_S$) (Table 15).

The most likely estimates (adjusted to account for efficiency factors) for total mass of CO$_2$ stored for the MB Member, LBS Shale, and TS are 7.9, 26.3, and 14.7 kg CO$_2$/m$^3$ rock, respectively (Table 15).

It is interesting to compare these estimates against conventional formations. For example, a fluvio-clastic deep saline formation with an average porosity of 20% and a displacement efficiency of 14% (Goodman and others, 2011) would have an estimated $0.20 \times 727 \times 0.14 = 20.4$ kg CO$_2$/m$^3$ rock. Similarly, a carbonate shelf deep saline formation with an average porosity of 15% and a displacement efficiency of 21% (Goodman and others, 2011) would have an estimated $0.15 \times 727 \times 0.21 = 22.9$ kg CO$_2$/m$^3$ rock. Thus normalized CO$_2$ storage resource estimates for the UBS and LBS of 20.5 and 26.3 kg CO$_2$/m$^3$ rock, respectively, are comparable to those for conventional deep saline formations. This result is largely attributable to the significant mass of CO$_2$ stored as a sorbed component on organic matter and clays, which constitutes approximately 70% to 80% of the total mass of CO$_2$ stored in the UBS and LBS Members. In contrast, the MB Member and Three Forks normalized CO$_2$ storage resource estimates of 7.9 and 14.7 kg CO$_2$/m$^3$ rock, respectively, are approximately one-half to one-third those for conventional deep saline formations.
Integrating CO2 Storage Resource Calculations Across the Bakken Resource

The normalized CO2 storage resource estimates can be used to estimate the total CO2 storage resource of the Bakken. For example, under the scenario where the thickness of the UBS and LBS Members are 7 and 15 m thick, respectively, and the MB and Three Forks Members are 26 and 10 m thick, respectively, the CO2 storage resource for a square meter of rock cutting through the entire Bakken (all lithofacies) would be:

\[
\left(7 \text{ m} \times \frac{20.5 \text{ kg CO}_2}{m^3 \text{ rock}}\right) + \left(26 \text{ m} \times \frac{7.9 \text{ kg CO}_2}{m^3 \text{ rock}}\right) + \left(15 \text{ m} \times \frac{26.3 \text{ kg CO}_2}{m^3 \text{ rock}}\right) + \left(10 \text{ m} \times \frac{14.7 \text{ kg CO}_2}{m^3 \text{ rock}}\right) = 892 \text{ kg CO}_2/m^2
\]

This approach can be extended to the entire Bakken by applying isopach volumes for the UBS, MB, LBS, and Three Forks units across the entire Bakken.

CO2 Storage Resource Estimated Using Modeling and Simulation Results

The modeling and simulation results of the DSU 3-D Corner-Point Grid Model (hereafter “DSU model”) were described above. Table 18 summarizes key outputs from these simulations for estimating the CO2 storage resource after 30 years of EOR and shows results for Case 2, huff ‘n’ puff Scenarios HP-01, -02, and -03 (tight matrix with relatively low vertical matrix permeability – assumed Kv : Kh = 0.1) and Case 3, huff ‘n’ puff Scenarios HP-05, -06, and -07 (tight matrix with a relatively high vertical matrix permeability – assumed Kv : Kh = 0.4).

The DSU model results provide information about porosity available for free-gas CO2 storage within fractures and pores (Eφ). The DSU model does not account for sorption of CO2 onto organic matter and clays.

The DSU model tracks injected and produced mass of CO2 and oil production for each model time-step. These values can be used to derive the following metrics:

- Gross CO2 utilization: the total volume of CO2 injected per stock tank barrel (stb) of incremental oil produced.
- Net CO2 utilization: the purchased volume of CO2 injected per stb of incremental oil produced, where the purchased volume of CO2 is approximated as (CO2 injected − CO2 produced).
- CO2 stored: the mass of CO2 retained in the reservoir, defined as (CO2 injected − CO2 produced).

In expressing the CO2 mass storage resource in units of kg CO2/m3 of rock, the calculations in Table 18 assume that the rock volume is approximately equal to the DSU model block volumes for the portion of the model affected by drilling and completion of the horizontal wells. These values may overestimate the amount of rock volume contacted by CO2, which would reduce the estimated CO2 mass storage resource.
Table 18. Summary of Simulation Results for Case 2, Huff ‘n’ Puff Scenarios HP-01, -02, and -03 (top) and Case 3, Huff ‘n’ Puff Scenarios HP-05, -06, and -07 (bottom).

<table>
<thead>
<tr>
<th>Case 2: Tight Matrix with Relatively Low Vertical Matrix Permeability</th>
<th>Metric</th>
<th>HP-01</th>
<th>HP-02</th>
<th>HP-03</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil Recovery Factor, %OOIP</td>
<td>5.4</td>
<td>5.4</td>
<td>5.3</td>
<td></td>
</tr>
<tr>
<td>Cumulative CO₂ Injected, Mcf</td>
<td>4,445,066</td>
<td>3,907,162</td>
<td>4,424,178</td>
<td></td>
</tr>
<tr>
<td>Cumulative CO₂ Produced, Mcf</td>
<td>1,983,614</td>
<td>2,035,865</td>
<td>2,481,795</td>
<td></td>
</tr>
<tr>
<td>Cumulative Oil Produced, stb</td>
<td>209,148</td>
<td>200,837</td>
<td>182,590</td>
<td></td>
</tr>
<tr>
<td>Gross CO₂ Utilization Factor, Mcf/stb</td>
<td>21.3</td>
<td>19.5</td>
<td>24.2</td>
<td></td>
</tr>
<tr>
<td>Net CO₂ Utilization Factor, Mcf/stb</td>
<td>11.8</td>
<td>9.3</td>
<td>10.6</td>
<td></td>
</tr>
<tr>
<td>CO₂ Stored, Mcf</td>
<td>2,461,452</td>
<td>1,871,296</td>
<td>1,942,382</td>
<td></td>
</tr>
<tr>
<td>CO₂ Stored, kg</td>
<td>130,250,289</td>
<td>99,021,589</td>
<td>102,783,172</td>
<td></td>
</tr>
<tr>
<td>Rock Volume, m³</td>
<td>96,779,245</td>
<td>96,779,245</td>
<td>96,779,245</td>
<td></td>
</tr>
<tr>
<td>CO₂ Stored, kg CO₂/m³ Rock</td>
<td>1.3</td>
<td>1.0</td>
<td>1.1</td>
<td></td>
</tr>
<tr>
<td>Total Pore Volume, m³</td>
<td>5,711,165</td>
<td>5,711,165</td>
<td>5,711,165</td>
<td></td>
</tr>
<tr>
<td>CO₂ Reservoir Volume, m³</td>
<td>179,122</td>
<td>136,176</td>
<td>141,349</td>
<td></td>
</tr>
<tr>
<td>Efficiency, Eφ</td>
<td>3.1</td>
<td>2.4</td>
<td>2.5</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Case 3: Tight Matrix with a Relatively High Vertical Matrix Permeability</th>
<th>Metric</th>
<th>HP-05</th>
<th>HP-06</th>
<th>HP-07</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil Recovery Factor, %OOIP</td>
<td>14.0</td>
<td>13.1</td>
<td>14.2</td>
<td></td>
</tr>
<tr>
<td>Cumulative CO₂ Injected, Mcf</td>
<td>21,521,288</td>
<td>21,079,472</td>
<td>21,056,562</td>
<td></td>
</tr>
<tr>
<td>Cumulative CO₂ Produced, Mcf</td>
<td>13,774,799</td>
<td>15,106,655</td>
<td>14,227,887</td>
<td></td>
</tr>
<tr>
<td>Cumulative Oil Produced, stb</td>
<td>1,221,568</td>
<td>1,056,415</td>
<td>1,255,914</td>
<td></td>
</tr>
<tr>
<td>Gross CO₂ Utilization Factor, Mcf/stb</td>
<td>17.6</td>
<td>20.0</td>
<td>16.8</td>
<td></td>
</tr>
<tr>
<td>Net CO₂ Utilization Factor, Mcf/stb</td>
<td>6.3</td>
<td>5.7</td>
<td>5.4</td>
<td></td>
</tr>
<tr>
<td>CO₂ Stored, Mcf</td>
<td>7,746,489</td>
<td>5,972,817</td>
<td>6,828,675</td>
<td></td>
</tr>
<tr>
<td>CO₂ Stored, kg</td>
<td>409,913,534</td>
<td>316,057,824</td>
<td>361,346,463</td>
<td></td>
</tr>
<tr>
<td>Rock Volume, m³</td>
<td>96,779,245</td>
<td>96,779,245</td>
<td>96,779,245</td>
<td></td>
</tr>
<tr>
<td>CO₂ Stored, kg CO₂/m³ Rock</td>
<td>4.2</td>
<td>3.3</td>
<td>3.7</td>
<td></td>
</tr>
<tr>
<td>Total Pore Volume, m³</td>
<td>5,711,165</td>
<td>5,711,165</td>
<td>5,711,165</td>
<td></td>
</tr>
<tr>
<td>CO₂ Reservoir Volume, m³</td>
<td>563,718</td>
<td>434,647</td>
<td>496,928</td>
<td></td>
</tr>
<tr>
<td>Efficiency, Eφ</td>
<td>9.9</td>
<td>7.6</td>
<td>8.7</td>
<td></td>
</tr>
</tbody>
</table>
Pore space efficiency \( (E_\phi) \) was derived by dividing the reservoir volume of CO\(_2\) stored (assuming a density of 727 kg/m\(^3\)) by the DSU model output for pore space within the block volumes for the portion of the model affected by drilling and completion of the horizontal wells. For example, the reservoir volume of CO\(_2\) stored in Case 2, Scenario HP-01, is 179,122 m\(^3\), which, when divided by a pore volume of 5,711,165 m\(^3\) results in an estimated efficiency of 3.1%.

The DSU model results for Case 2 suggest a range of efficiencies from 2.4% to 3.1%, while the results for Case 3 suggest a range of efficiencies from 7.6% to 9.9% (Table 18). These efficiency values are lower than the ranges obtained from the literature for the UBS and LBS members of the Bakken (8% to 25%) and for the MB and Three Forks members of the Bakken (9% to 28%). The lower efficiency values from the DSU model results may be partially attributable to the assumption that the rock volume is approximately equal to the DSU model block volumes for the portion of the model affected by drilling and completion of the horizontal wells. However, the literature-derived efficiency values may also be too high, as they were estimated from data collected from gas-filled shale formations, not oil-filled shale formations.

Based on the results of the current DSU model, the normalized CO\(_2\) mass storage resource for the Bakken may be closer to the most likely and lower-end estimates provided in Tables 15 and 16, respectively.

**KEY LESSONS LEARNED FROM BAKKEN CO\(_2\) STORAGE AND EOR – PHASE II**

**Lessons Learned from MMP Studies**

Simple modifications to Ayirala and Rao’s capillary-rise VIT method greatly decrease the apparatus cost and complexity of doing MMP studies. The simple, yet thermodynamically rigid definition of MMP as the pressure where the interfacial tension between two fluid phases goes to zero makes the capillary-rise VIT method less susceptible to operational differences and variable operator interpretations. The method is reproducible, requires small samples of oil, and can be performed with live oil or dead oil using the same apparatus. The method is relatively rapid, with one to four tests being possible in a single day. Data showing good agreement between the slim-tube and the capillary-rise VIT method support the use of capillary-rise VIT as a supplement for and/or replacement to the slim-tube method.

MMP for pure CO\(_2\) in Bakken crude under a reservoir temperature of 110°C ranged from 17.26 to 17.64 MPa (2503 to 2558 psi). The reservoir temperature of the field test well was approximately 120°C, with a virgin reservoir pressure of approximately 59.7 MPa (8670 psi), so the injected CO\(_2\) was almost certainly miscible in the reservoir.

Reservoir temperature has been shown to have a significant effect on MMP. This is because CO\(_2\) density exerts more control over MMP than the pressure. Results from the Phase II MMP study showed that, for a Bakken oil, lowering the temperature from 110° to 42°C reduces the MMP by one-half for CO\(_2\). The Bakken oil MMP for pure CO\(_2\) at 42°C ranged from 8.77 to 8.96 MPa (1271 to 1300 psi). These results are directly relevant to oil productive areas throughout the Bakken Formation, where reservoir temperatures range from 50° to 120°C (Schmoker and Hester, 1985).
Lessons Learned from CO2 Permeation/Hydrocarbon Extraction Studies

The results of the experimental CO2 permeation and oil extraction tests clearly demonstrate, at the core plug scale, that CO2 under Bakken reservoir and temperature conditions can permeate both organic-rich shales and tight nonshale rocks and subsequently mobilize oil from those rocks. Most of the hydrocarbon mobilization occurred within the first 8 hours of the experiment, with between 65% and 95% of the oil being removed from the nonshale MB samples and between 40% and 50% being removed from the Upper and Lower Bakken Shales in that initial time period. These results are in line with other similar experiments (Hawthorne, 2013; Sorensen and others, 2014, 2018; Jin and others, 2017).

A statistical analysis of variance within the data showed the primary factors correlating to oil recovery in the nonshale MB and Three Forks were determined to be pore throat radius and water saturation, with larger pore throats and lower water saturation yielding faster, more complete oil recoveries. When considered in conjunction with findings reported in Sorensen and others (2018) for the UBS and LBS, pore throat radius was also the primary controlling factor, with smaller pore throat radii correlating to lower oil recoveries. In both shales and nonshale samples, porosity appeared to have a minimum effect on oil recovery.

The results of the Phase II work presented in Hawthorne and others (2013) and Jin and others (2017) show that the concentration gradient-driven diffusion process is a primary mechanism for CO2 permeation and hydrocarbon mobilization in tight reservoirs. This has significant implications, especially so for densely fractured unconventional tight oil formations (high surface area-to-volume ratio) where CO2 would have greater contact with the reservoir. The high surface area-to-volume ratio of the fracture networks may enable CO2 diffusion into the matrix and hydrocarbon diffusion out of the matrix to occur more efficiently, thereby increasing recoverable reserves. Also, if properly designed and managed, the hydraulically induced fracture networks would assist in alleviating potential injectivity challenges as it is not feasible to conventionally flood CO2 through the tight matrix.

Results of the laboratory experiments also show CO2 preferentially recovers lighter versus the heavier hydrocarbons from both Bakken shale and nonshale MB rocks. For example, the C7 hydrocarbons are recovered ca. 10-fold faster than the C20 hydrocarbons from the Upper and Lower Bakken Shales. Preference for removal of lighter hydrocarbons from the MB was not as strong but was also consistently observed throughout the testing. These observations were applied to the monitoring plan for the field test.

Lessons Learned from the Field Test

Analysis of the BHP data from the CO2 injection test indicated that the pressure needed to initiate fractures was not exceeded; however, the opening of an existing natural fracture(s) was interpreted. During the test, natural fractures remained open for about 4 hours. With the energy of the injected fluid decreasing, the fractures began gradually closing. The plot of the BHP data indicates that fractures had closed after 10 hours. Once the fractures were closed then fluid flow in the matrix dominated the system. The data indicate linear flow continued after 170 hours, lasting
through the well shut-in, or soak, period. Analysis of well flow and material balance data indicates that the CO₂ penetrated between 50 and 70 ft around the wellbore.

Although the injection pressure was high (approximately 65.2 MPa [9450 psi]), the injection rate was low (6 to 12 gpm). However, based on the analysis of the BHP data, the test demonstrated that CO₂ can be injected into an unstimulated, virgin MB reservoir rock. Because the test well reservoir had not undergone any prior production or stimulation, the pore pressures of the reservoir were high (estimated to be 59.7 MPa [8670 psi]), so the high injection pressure was necessary to overcome that pore pressure. Future tests in reservoirs that have been stimulated and undergone pressure depletion through production would not likely require such high injection pressures.

A comparison of pretest and posttest oil samples showed a shift in hydrocarbon molecular weight distribution in the postinjection oil toward the lighter end of the spectrum. These results indicate that CO₂ did penetrate into the matrix of the MB and mobilize lighter molecular weight hydrocarbons. The data generated by the field test serve to verify and validate the previously generated laboratory experimental data from the CO₂ permeation and hydrocarbon extraction studies conducted on MB core samples.

When combined and considered in the context of the previously generated laboratory data and modeling activities, these field-based data will provide stakeholders with previously unavailable technically based insight regarding the fundamental physical and chemical mechanisms controlling 1) the ability of CO₂ to mobilize oil from the matrix of tight oil formations and 2) the potential storage resource of tight oil formations.

**Lessons Learned from the Modeling**

Analysis of the BHP response data from the field test was vital in understanding the effects of the injection on the reservoir, which in turn were critical to the interpretation of the field test results and the design and interpretation of the simulations.

While a discrete fracture network model was created using the fracture characterization data, challenges in using the discrete fracture network as part of the DSU modeling efforts were identified. The model size and the relatively large number of fractures used in the simulations resulted in long simulation run times. To reduce the run times, the fracture porosity and permeability were upscaled and combined with the matrix properties into a single porosity–single permeability model, which enabled simulation results to be achieved with increased efficiency. Because of this, only the single porosity–single permeability model was used in the DSU-scale CO₂ EOR and associated storage simulation activities.

In the two horizontal study wells that were modeled, the simulations indicated that the alternating huff ‘n’ puff approach showed the best performance in terms of EOR. In the best cases, the alternating huff ‘n’ puff scheme was predicted to more than double the oil recovery factor of a well. These results support the conclusions of previous Phase I modeling work that indicate alternating huff ‘n’ puff approaches may be the an effective and economic means of implementing CO₂ EOR and associated storage.
The modeling efforts indicated the presence of water in a Bakken reservoir can have serious impacts on the EOR and CO2 storage potential of a well. The production history of the two horizontal study wells that were modeled showed both wells having a higher water saturation than previous EERC modeled Bakken wells. The modeling results suggest that connate water may tend to accumulate in the lower portions of hydraulically induced fractures, which can essentially block or impede the contact of injected CO2 with the lower portions of the Bakken reservoir, including the relatively oil-rich LBS. Previous EERC Bakken modeling exercises in Phase I and other Bakken research projects were conducted using reservoirs with very low water saturation, which are typical of many of the highly productive areas of the Bakken. However, as the geographic area of production has expanded, more Bakken wells have been drilled into areas of relatively higher water saturation. The results of these Phase II modeling efforts make an important contribution not only in furthering our understanding of the role that formation water may have in CO2 EOR and associated storage but also in expanding the applicability of the program’s results to include a wider variety of Bakken reservoir types.

**Lessons Learned from the Assessment of Bakken CO2 Storage Resource Potential**

The Phase II laboratory experimental data and field testing results were applied to develop a refined CO2 storage resource assessment approach for tight oil formations, based on the NETL method developed by Goodman and others (2014) and Levine and others (2016). This work yielded estimates of the long-term storage of CO2 in the Bakken using a revised analytical expression informed by laboratory, literature, and simulation data. These estimates take into account the CO2 sorption data that were generated for samples of UBS, LBS, MB, and Three Forks samples as part of another DOE-funded study conducted by the EERC (Sorensen and others, 2018) as well as the TOC and clay content data generated by both the Phase II efforts and the work presented in Sorensen and others (2018).

Application of the refined method indicates that the organic-rich UBS and LBS may have two to three times more storage resource on a kg CO2/m3 rock basis than the nonshale MB. The range of storage estimates for the Bakken shale units have the potential to store between 5.8 and 26.3 kg CO2/m3 rock, as compared to the nonshale MB storage estimates which ranged from 1.9 to 12.4 kg CO2/m3 rock. The Three Forks storage estimates ranged from 5.6 to 19.9 kg CO2/m3 rock.

The storage resource of the nonshale Three Forks Formation appears to be comparable to, though still somewhat less than, that of the shales. This is likely because the characterization results for the Three Forks Formation samples used in this study show the Three Forks as having over twice as much clay content as the MB.

**RECOMMENDATIONS FOR FUTURE RESEARCH ON CO2 STORAGE AND EOR IN UNCONVENTIONAL TIGHT OIL FORMATIONS**

To better evaluate the efficacy of CO2-based EOR and associated storage in unconventional tight oil systems, future work should focus on better understanding the factors that affect long-term injectivity, migration, and storage of CO2 in different unconventional tight oil formation rock.
types. The Phase II effort performed characterization and laboratory experiments on different rock types contained within the Bakken, including carbonate-rich clastics and organic-rich shale source rocks. The project also attempted to upscale the CO₂ permeation and hydrocarbon extraction experiments from the laboratory to the reservoir. The data generated in the laboratory and the field test were integrated into modeling efforts that were performed to evaluate the potential for CO₂ huff ‘n’ puff operations to yield improved oil recovery factors. The laboratory and field data were also used to develop a refined method for estimating the CO₂ storage resource potential of the Bakken. The results and lessons learned from these investigations enabled the identification of future work needs specific to the topic of CO₂ EOR and associated storage in tight oil formations.

Substantial progress was made toward the development of new insight on the injectivity of CO₂ in an unstimulated MB reservoir and its ability to interact with and mobilize oil from the matrix of that reservoir. The knowledge and experience gained from both the laboratory- and field-based activities can be directly applied to future pilot-scale EOR and associated storage tests. However, many challenges remain with respect to achieving the ultimate goal of commercial deployment of CO₂ storage and EOR in unconventional tight oil formations. General topic areas in which more research is needed are described briefly below:

- Within the Bakken nonshale reservoir rocks, a key question is “At what rate would CO₂ traveling within induced fractures (in the field) permeate into naturally occurring microfractures and into the unfractured rock matrix, thereby accessing hydrocarbons for EOR?” The key factors that control the rate of CO₂ permeation into the reservoir matrix should also be identified and further evaluated. For example, the acidification of formation fluid as a result of CO₂ injection could induce geochemical reactions with particular minerals within the rock matrix.

- A new paradigm is needed for assessing relative permeability and fluid behavior in unconventional tight oil formations. In particular, the role of Darcy flow versus non-Darcy flow is a topic of intense debate both in academia and industry. Both laboratory and modeling-based studies are needed to address questions of fluid/flow behavior in the context of relative permeability. Such data are essential to achieve accurate modeling of CO₂ behavior and fate in tight oil formations.

- Production of oil from, and subsequent injection of CO₂ into, tight oil formations requires hydraulic fracturing. A detailed understanding of the geomechanical properties of both shale and nonshale lithofacies in tight oil formations is another aspect of these reservoirs that is necessary to develop accurate predictive models. While the application of geomechanical modeling to design hydraulic fracturing programs is widely practiced in industry, the coupling of geomechanical models with reservoir matrix and fluid property models is not widely practiced, in large part due to model complexity and numerical execution challenges. Improvements in such coupled models are necessary to address the complexity inherent in understanding and predicting fluid behavior in flow regimes that range from macroscale hydraulically induced fracture networks down to nanoscale pore throats in organic material such as kerogen and bitumen. In addition, while study of rock mechanical constitutive equations for the solid matrix is an active area of research,
The dynamic nature of production (e.g., reservoir pressure can go from several thousands of psi to hundreds of psi during depletion and back up again when a neighboring well is hydraulically fractured) and how those dynamics may affect porosity, permeability, and fluid behavior with respect to CO₂ and hydrocarbon mobility need to be understood. Interplay between operational conditions and rock mechanical effects, such as stress-dependent permeability, may significantly influence fluid flow in the reservoir and production performance. Data are needed from lab tests, field tests specifically designed to identify and quantify stress dependent permeability, and/or observations from normal well operations to document the effects of stress dependent permeability.

In some unconventional tight oil plays, including the Bakken and Eagle Ford, there are ample supplies of low-price rich gas. Rich gas is a varying mixture of hydrocarbon gases such as methane, ethane, and propane, and studies have shown that some of these gases may be effective for EOR (Hawthorne and others, 2017; Jin and others, 2016). There may be circumstances where operators consider using both CO₂ and rich gas for EOR, either separately in sequence or as a mixture. It is also likely that the CO₂ stream produced back after the soak stage of a huff ‘n’ puff cycle would have rich gas impurities. With these scenarios being a distinct possibility, studies should be conducted to determine the effects of rich gas impurities in CO₂ on EOR and associated storage. The modified capillary-rise–VIT method used for the Phase II studies is ideal for conducting such studies.

Natural fracture systems and more representative hydraulic fracture profiles should be integrated into the simulation models to better mimic fluid flow behavior in the fracture-matrix system. Molecular diffusion, gravity segregation, sorption, and oil swelling are mechanisms that may play a principal role in naturally fractured reservoirs and need to be accounted for in the modeling and simulation studies. Physically representative models at reservoir conditions are required to model and simulate nonideal, multicomponent mixtures in the oil and gas phases.

The significance and impacts of pore-size distribution, capillary pressure, and relative permeability curves should be studied as a part of future modeling efforts. The role of the capillary pressure threshold needs to be investigated with and without the presence of water-filled pores.

More effective simulation methods and grid settings should be developed to improve simulation efficiency in order to enable the models to predict CO₂ EOR and storage performance in multiwell scenarios. Representative models need to include transport mechanisms from ultralow permeability matrix and complex fracture networks. Geomechanical effects during production must be included to account for stress-dependent properties and dynamic fracture conductivity effects. Well interference and fracture spacing require a special consideration to evaluate the long-term CO₂ EOR performance.
• More data from real-world, pilot-scale CO₂ injection tests in tight oil formations, and the lessons learned from those tests, are needed to verify and validate modeling approaches that have been developed by this and (other) projects.

• The collection and analysis of higher-frequency production and reservoir pressure and temperature data would support improved simulations of CO₂ EOR and associated storage schemes.

Recommendations for Future Pilot Tests

According to field operators (Presley, 2018), EOR in the Bakken presents three primary challenges: 1) rock–fluid interaction; 2) conformance issues; and 3) operation of the injectors, producers, and offset wells to optimize the BPS resources. Concerns about the rock–fluid interaction have been partially addressed in the laboratory investigations conducted in Phase II as described in this report, the final report from another DOE–state of North Dakota–industry-funded project (Sorensen and others, 2018), and the literature (Hawthorne and others, 2013; Sorensen and others, 2015; Jin and others, 2017). The rock extraction experiments discussed in this report and other publications (Hawthorne and others, 2017) demonstrated that injected gas (CO₂ or rich gas) can mobilize substantial amounts of hydrocarbons from tight matrix rocks. Hydrocarbon extraction observed on these experiments was driven mainly by concentration gradients, with the hydrocarbon diffusivity occurring in absence of large pressure gradients. Then, given that sufficient fracture-matrix contact area is provided, interaction between the matrix and the injected fluid should not pose major problems. In that sense, better estimations of the fracture–matrix contact area are paramount for designing successful pilot tests. Modern production analysis techniques (MPA) could provide valuable information for building more realistic reservoir simulation models. In particular, MPA could provide information about the total fracture–matrix surface area, the total number of hydraulic fractures, the stimulated reservoir volume, and the total drainage area (Clarkson, 2013).

Conformance issues have been reported in previous pilot tests, possibly caused by wells/fractures interference (Sorensen and Hamling, 2016; Hoffman, 2016). However, addressing conformance issues would require collecting site-specific data that were out of the scope of the Bakken CO₂ Storage and Enhanced Recovery project. Some tools and methods that could be applied to future pilot-scale injection tests to investigate the conformance problems include:

• MPA techniques (rate-transient and pressure transient analysis) could serve to better estimate reservoir properties in hydraulically fractured wells (Clarkson, 2013).

• Injection of chemical tracers could provide valuable information about reservoir communication and preferential flow paths inside a DSU (Salman and others, 2014).

• Horizontal well injection with distributed temperature sensing could provide valuable information about injection profiles along the lateral wells (Foo and others, 2014).

• Smart well technologies, such as multinode intelligent well technologies, could help to adjust the production or injection distribution along the wellbore (Sun and others, 2011).
Optimization of the Bakken resources by means of controlling the operational conditions of injectors, producers, and offset wells would require an integrated approach. A solid understanding of the natural systems (reservoir fluids and rocks) and their interactions with the artificial systems (hydraulic fractures, wellbores, and surface equipment) is paramount. Reservoir characterization efforts would reduce in large extent the uncertainties surrounding the natural systems. Reservoir modeling and simulation efforts would provide valuable information about the volumetric sweep efficiency and the fate of injected fluids. Process simulation would provide necessary information for an optimal operation of the surface equipment.

Finally, future simulation efforts could benefit from the collection and analysis of higher-frequency production data. Dynamic reservoir simulation modeling benefits greatly from having actual pressure and flow rate measurements. In particular, analysis of higher-frequency production data (such as daily pressures and rates) provide valuable information about the total fracture-matrix surface area, the total number of hydraulic fractures, the stimulated reservoir volume, and the total drainage area (Wang and Wu, 2014). Future injection tests should include the collection of high-frequency production and reservoir conditions data. In particular, the use of downhole monitoring systems would allow a significant reduction in the model uncertainties.

Recommendations to Improve CO2 Storage Resource Estimates for Tight Oil Formations

Further research is needed to improve the methods for estimating CO2 storage resources of tight oil formations such as the Bakken. Work should be conducted to reduce the uncertainty in the parameters used to estimate one or more aspects of the storage equation developed as part of the Bakken CO2 Storage and Enhanced Recovery Phase II efforts. Future research tasks should include:

- **Additional porosity gained in the reservoir attributable to drilling and completion:** The current porosity estimates do not account for the increased porosity attributable to drilling and completion (i.e., hydraulic fracturing). Further simulation work or field-based characterization of post-hydraulic fracturing porosity may improve the accuracy of reservoir porosity estimates following drilling and completion.

- **Efficiency factors for porosity storage (Eφ):** The literature estimates of efficiency factors for porosity storage were estimated from gas-filled shale formations, not oil-filled shale formations. Simulation results suggest that these estimates are biased high. Further simulation and field-based characterization may improve the accuracy of these efficiency factors for an oil-filled formation like the Bakken.

- **Efficiency factors for sorbed storage in the rock matrix (ES):** The literature estimates of efficiency factors for the combined efficiency of the volume of matrix rock contacted by gas and the efficiency of sorptive packing of gas at reservoir conditions were derived for natural gas. Natural gas is composed of predominantly methane (CH4), not CO2. Based on previous lab studies, the CH4 adsorption isotherm is usually lower than the CO2 adsorption isotherm, meaning that CO2 is preferentially adsorbed by kerogen in comparison to CH4. Additional laboratory and modeling studies to further quantify ES
may improve the estimates of CO2 storage potential associated with sorption. These data are particularly important for the UBS and LBS members, whose greater organic matter content will result in a greater amount of sorbed storage.

- **Additional organic matter characterization:** Advanced core characterization of Bakken rock samples shows that the organic matter in the UBS and LBS largely consists of kerogen and bitumen and that there is little organic matter in the MB Member; therefore, sorption occurs largely on clays. Further laboratory work to distinguish isotherm behavior among different types of organic matter and clays may improve the accuracy in estimates of the mass of CO2 sorbed per mass of TOC and/or clay in the rock at reservoir pressure and temperature conditions (C5). This is important to broaden the applicability of the method to other tight oil formations such as the Eagle Ford and Niobrara, which have wide variability with respect to TOC and clay content.

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APPENDIX A

METHODS AND RESULTS