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Multiscale Modeling to Evaluate the Mechanisms Controlling CO_2-Based Enhanced Oil Recovery and CO_2 Storage in the Bakken Formation

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Abstract

This work presents the main findings of a research project conducted to integrate well logs and advanced laboratory-based data from Bakken core samples into geocellular and simulation models at multiple scales. The objective of this effort was to improve the accuracy of modeling approaches for predicting potential incremental oil production through carbon dioxide (CO_2)-based enhanced oil recovery (EOR) in unconventional tight oil reservoirs and to evaluate the ability of organic-rich shales to store CO_2 and, possibly, produce incremental oil.

Unique data sets applied to the modeling included results from advanced scanning electron microscopy (SEM) techniques, computerized tomography (CT) scanning, and CO_2 permeation and oil mobility experiments. Plug- and core-scale models were used to simulate and history-match the CO_2 permeation and oil mobilization experiments. Larger-scale models, such as near-wellbore and drill spacing unit (DSU)-scale models, were used to simulate and predict CO_2 behavior under conditions that are more representative of what might be expected in the field. Reservoir pressure, temperature, and injectivity data from a CO_2 injection field test in a Bakken well were also applied to the reservoir-scale modeling.

The plug- and core-scale modeling efforts were able to reasonably reproduce the oil recovery results observed in the lab. Results from models with and without CH_4 adsorption settings suggest that integration of CH_4 adsorption and core CT data allowed simulations to better reproduce the experimental results. However, perfect matches were never achieved, and a lack of data on capillary pressure effects and relative permeability were identified as being potential reasons for the imperfect matches. The larger-scale simulations included modeling of different huff 'n' puff scenarios with both single-fracture stage model and DSU models. The single-fracture stage model showed incremental recovery factors ranging from 0.6% to 5.4%. This number could be increased by conducting more huff 'n' puff cycles over the lifespan of an operating well and/or by optimizing the operational parameters and well placement. At the DSU scale, the simulations indicated that alternating wells with the huff 'n' puff showed the best performance in terms of EOR. In the best-case scenario, the alternating huff 'n' puff scheme was predicted to more than double the oil recovery factor of a well.

These results will ultimately be used to better estimate the EOR potential and associated CO_2 storage resource of unconventional tight oil formations. While a 5% improvement in ultimate recovery may be perceived as a relatively small increase over primary production, the implications for an incremental recovery of 5% for production throughout the Bakken play is enormous. With estimated Bakken OOIP (original oil in place) estimates ranging from 300 billion to 900 billion barrels, realization of even this small improvement would yield billions of incremental barrels of oil and extend the lifetime of the play by decades.

Introduction

According to the International Energy Agency (IEA), the United States is expected to become a net exporter of oil in the late 2020s thanks to the shale revolution (World Energy Outlook, 2017). This scenario could not be possible without the contribution from unconventional tight oil resources like the Bakken petroleum system (BPS). In effect, during the last decade, more than 10,000 wells have been drilled in the Bakken and Three Forks Formations in North Dakota and Montana, which resulted in an oil production increase from about 200 thousand barrels a day before 2009 to more than 1.2 million barrels a day by March 2018 (U.S. Energy Information Administration, 2018). Despite the inarguable success reached with primary production from hydraulically fractured horizontal wells, two factors are drawing the attention of operators to different technologies, such as EOR. First, while the hydrocarbon in-place estimates are in the order of hundreds of billions of barrels, most primary recovery factor estimations in the Bakken range in the single digits (<10%) (Sorensen et al., 2015). Second, recent reports from newer wells have shown that well performance has deteriorated, as both gas-oil ratios and water cut have increased and decline rates seem to be accelerating (Berman, 2017).

CO_2 is an excellent hydrocarbon extraction solvent, making it an attractive option for EOR. It has been successfully employed for more than 40 years in conventional reservoirs, mainly in regions with abundant CO_2 sources such as the Permian Basin (Alvarado and Manrique, 2010). In addition, associated CO_2 storage could help to reduce carbon emissions from power plants and industrial facilities located in the vicinities. While the implementation of CO_2 EOR projects is well understood in conventional reservoirs, its application to tight oil formations is relatively new (Sorensen et al., 2015; Jia et al., 2017). Design of effective CO_2 injection and EOR schemes in tight oil formations requires understanding fluid permeation and transport occurring in low-porosity, low-permeability, tight rocks.

Recently, the Energy & Environmental Research Center (EERC) conducted an extensive set of Bakken-centered EOR research activities, including lab experiments, reservoir characterization studies, modeling and simulation exercises, and a field test. Without being exhaustive, the main findings are summarized in the reminder of this section. More detailed explanations can be found elsewhere (Sorensen et al., 2014, 2015, 2018a, 2018b; Jin et al., 2017b; Hawthorne et al., 2017).

Early laboratory work indicated that tight oil formations such as the Bakken might be suitable targets for CO_2 EOR opportunities (Hawthorne et al., 2014) and confirmed that hydrocarbon recoveries in core plugs were unexpectedly high when exposed for sufficient time to CO_2. In addition, results indicated that the microporous structure in the shale seems to be accessible to CO_2 for storage. Core plug CO_2 permeation and oil extraction experiments using Bakken rocks have shown that supercritical CO_2 enables extraction of a considerable portion (15%–65%) of hydrocarbons from the Bakken shales within 24 hours. Additionally, measurement of CO_2 adsorption isotherms showed that Bakken shale has a considerable capability to trap CO_2 (up to 17 mg/g) under a wide range of pressures (Jin et al., 2017a).

A variety of reservoir characterization activities have been conducted as an attempt to advance the current understanding of the tight oil formations (Jin et al., 2017b; Sorensen et al., 2015, 2016; Klenner et al., 2014; Kurtoglu, 2013). These studies have shown that the Bakken is characterized by several distinctive lithofacies, each with its own unique properties that may significantly affect the mobility and ultimate fate of CO_2 within the formation. The lithofacies of the Bakken 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 Middle Bakken Member. The fine-grained clastics and carbonates of the Middle Bakken Member are representative of a tight, fractured reservoir rock that is capable of transmitting fluids once it has been hydraulically fractured. The Middle Bakken Member typically comprises between three and seven distinctly different lithofacies that range from silty carbonates to calcite/dolomite-cemented siltstones. Both shale members are organic-rich, typically oil-wet shales that are the source rocks for the productive areas of the Bakken (Figure 1). 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. High-pressure mercury injection tests showed that pore throat radii are less than 10 nm for most pores in both the upper and lower Bakken samples, and with small pore sizes, high capillary entry pressure is expected to make CO_2 permeation into the rock matrix difficult (Jin et al., 2017b).

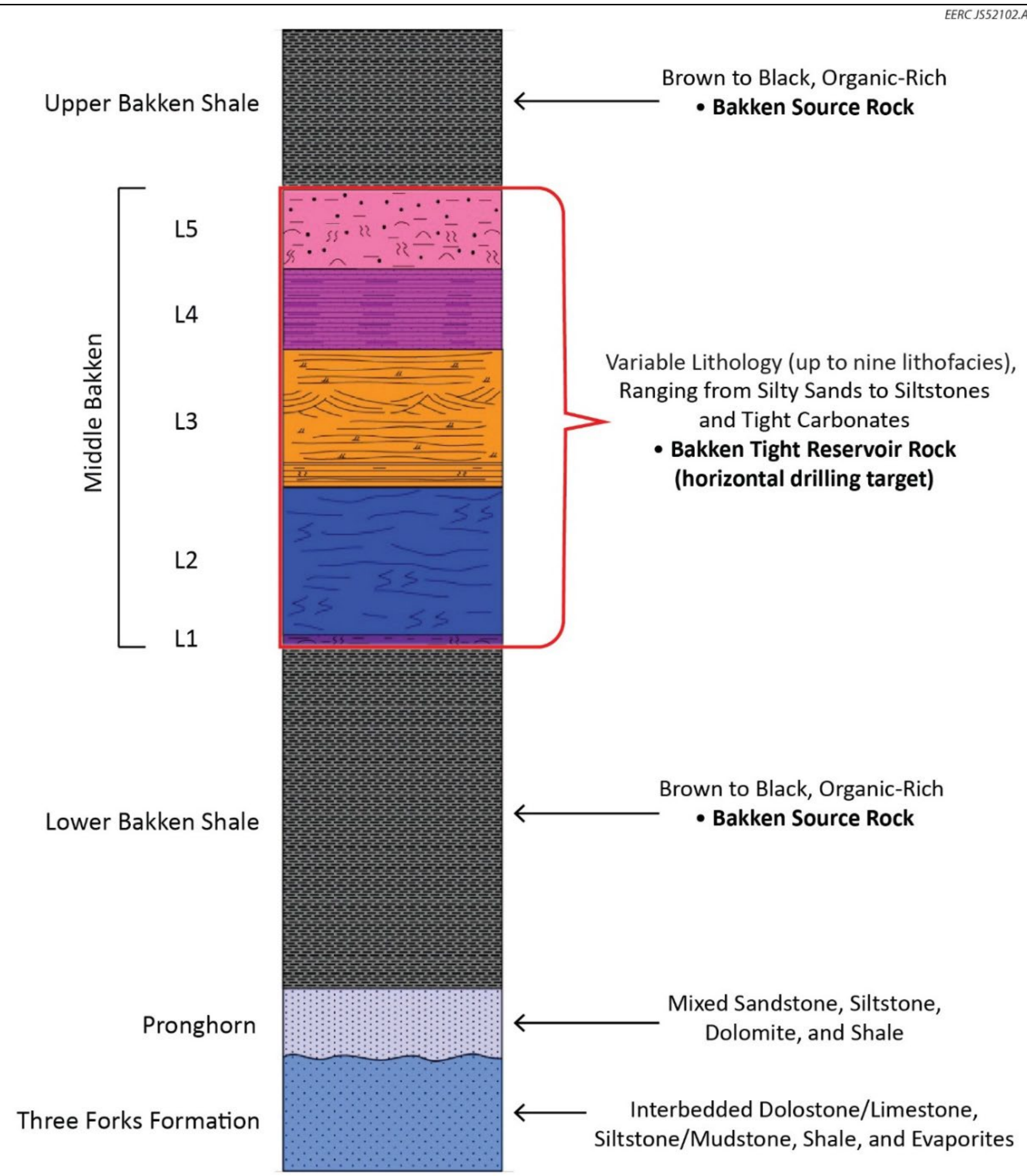

Figure 1: Major oil-producing lithofacies of the BPS. The system also includes the Lodgepole Formation (including the Scallion and False Bakken members) which overlies the Bakken Formation.

Fracture networks can be identified at the macroscale through visual core descriptions and visualized with whole-core CT scanning (Sorensen et al., 2014). Also, naturally occurring microfractures have been characterized in terms of their aperture, length, and orientation using SEM techniques (Sorensen et al., 2014).

Factors mentioned above influence the potential of tight oil formations to transport and store CO_2 and are expected to affect the ability of the injected CO_2 to mobilize oil from the matrix into the fracture (natural or induced) networks and, ultimately, increase oil production. Inadequate understanding of these features poses serious threats to the development of effective injection and production strategies for CO_2 EOR and storage in tight, fractured reservoirs.

The next sections of this paper present a systematic modeling and simulation approach that incorporates multiple data sets from the Bakken Formation. Special consideration was given to integrate key findings from varied investigations performed at diverse scales. Each task was performed at the adequate scale to discern the relative importance of plausible flow and/or phase behavior mechanisms expected to influence CO_2 EOR and associated storage. The goal of integrating these varied efforts using modeling and simulation techniques was to improve understanding on the interplay of the distinct mechanisms and their implications in terms of 1) CO_2 injection, 2) CO_2 storage efficiency, 3) oil mobilization and sweep efficiency, and 4) the potential for incremental oil recovery through various huff ‘n’ puff scenarios. While many activities were successfully conducted at different levels, including submicroscopic-scale (SEM resolution [nanometer-scale]) and CT resolution (micrometer-scale), core plug-scale, and well-scale, for the sake of simplicity only a subset will be presented in detail in the following sections. Further details can be found elsewhere (Sorensen et al., 2018b). The suite of analysis integrated into the modeling and simulation efforts is summarized in Table 1; while Figure 2 graphically illustrates the multiple scales integrated into macroscopic models.

Table 1: Suite of Advanced and Classical Analyses Integrated into the Modeling and Simulation Efforts

Advanced Analysis	Information Derived
Sorption Experiments	CO_2 sorption isotherms
CO_2 Hydrocarbon Extraction and Permeation	CO_2 and CH_4 diffusion coefficients (from history matching)
VIT* Capillary Rise	Minimum miscibility pressure
CT Scan	Natural fracture density, length, and orientation
Classical Analysis	**Information Derived**
Well Logging	Petrophysical properties: initial fluid saturations, matrix porosity, formation thickness and lithology, reservoir temperature, etc.
PVT Reports	Reservoir fluid characterization
Production Analysis During Primary Production	Used to adjust the static model property distribution (porosity and permeability), and the relative permeability function end points
Field Test	Injectivity of CO_2 in tight formations, maximum injection pressure

* Vanishing interfacial tension.

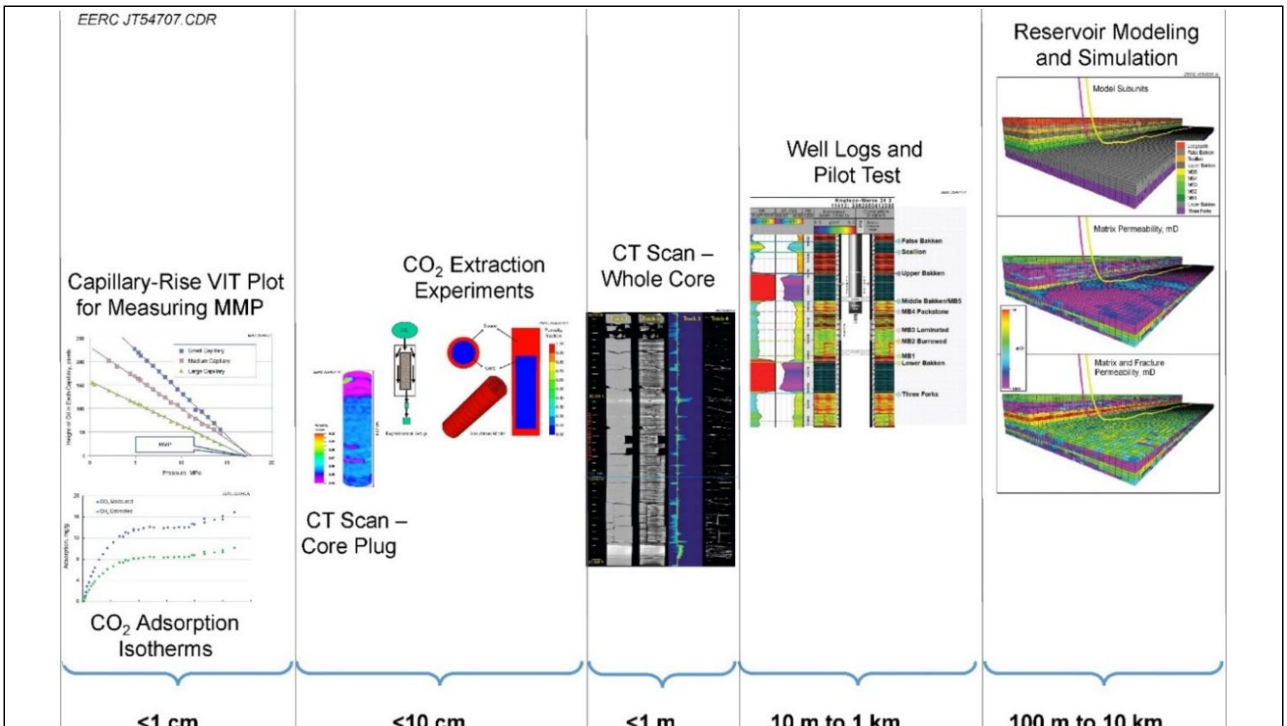

Figure 2: Scheme showing the multiple scales integrated in this study, incorporating acquired advanced laboratory and novel field data sets from the Bakken Formation. From left to right, the diagram shows 1) lab-scale experiments (minimum miscibility pressure, [MMP] and adsorption isotherms), 2) core plug-scale measurements (CT scan and CO_2 extractions), 3) core analysis using CT scans and visual inspection to measure natural fracture density, orientation, and length; 4) well logs and field-scale data sets collected during a pilot test; and 5) reservoir modeling and simulation at near-well and DSU scale.

The modeling and simulation approach followed in this work assumes that the governing equations at the (macroscopic) Darcy scale are valid to represent the multiphase flow of fluids occurring in tight oil reservoirs subject to CO_2 EOR operations. While the connections between microscopic (pores and pore throats smaller than 2 nm) and macroscopic (pores larger than 50 nm) scales is still subject of scientific debate (Falk et al., 2015), the models presented in this work assume that the geologic uncertainties can be represented with a sufficient degree of accuracy that permits evaluation of the relative merits of different operational scenarios. State-of-the-art software has been used; Schlumberger's Petrel software (SLB, 2016) was the platform for creating the geologic models and Computer Modelling Group's (CMG's) GEM reservoir simulator (Computer Modelling Group, 2016b) served as the platform for numerical simulations.

Creation of Geocellular Models

Geocellular models at two different scales (small- and larger-scales) were developed. Field-based data sets acquired during a pilot test that was executed on July 2017 (targeting the Bakken Formation) have been integrated into the static models (Sorensen et al., 2018a). Small-scale models include plug- and core-scale models. These were used to simulate and history-match laboratory experiments of CO_2 permeation and oil mobilization. Larger-scale models, such as near-wellbore- and reservoir-scale models, were used to simulate and predict CO_2 behavior under conditions that are more representative of what might be expected in the field. Figure 3 provides an example of a plug-scale model, and Figure 4 provides an example of a core-scale model, which were created using core characterization data generated as part of this project. Near-wellbore-scale petrophysical models of the Middle Bakken (MB) were also created using rock characterization data and well logs. A small reservoir-scale model has been created for the entire BPS, with site-specific data from an area located in Dunn County, North Dakota. The model includes the strata from the Lodgepole Formation to the Three Forks Formation (Figure 5). This model has been developed to capture overpressure in the BPS associated with hydrocarbon generation (Figure 6). The model also included a discrete fracture network within the MB Member (Figure 6) in an attempt to better understand fluid flow and pressure response to production/injection within the tight reservoir.

Plug- and Core-Scale Model

In an attempt to experimentally quantify the ability of CO_2 to permeate tight Bakken rocks and mobilize oil from them, a set of laboratory experiments were conducted on small core plugs, using 11.2-mm-diameter rods. While similar experiments on Bakken rocks had been conducted and presented in previous work (Hawthorne et al., 2013, 2014), the generation of additional CO_2 permeation and oil extraction data from samples obtained from other wells was necessary to confirm those earlier studies. Also, the new experiments were designed to specifically generate permeation and extraction data on the key lithofacies that were the subject of advanced characterization. A total of 34 samples representing all of the major lithofacies from eight wells in three North Dakota counties were used in these experiments. The results of the CO_2 permeation and oil extraction experimental tests clearly demonstrated, at the core plug scale, the ability of CO_2 to permeate both organic-rich shales and tight nonshale rocks to subsequently mobilize oil from those rocks. In fact, most of the hydrocarbon mobilization occurred within the first 8 hours of the experiment, with between 85% and 99% of the oil being removed from the MB samples and between 15% and 65% being removed from the shales in that initial time period.

The experiments were not confined flow-through experiments, but rather the core plug was loosely contained inside the vessel, surrounded by empty space to allow for flow of CO_2 around the sample. This setup was designed to replicate the ability of CO_2 flowing in a fracture to permeate the matrix and mobilize oil from it (Hawthorne et al., 2013). The CO_2 was injected through the empty space of the top of the vessel, and fluids (including CO_2 and hydrocarbons) were produced via the empty space at the bottom of the vessel. However, because the plug was not confined, the CO_2 did not flow through the plug but rather surrounded it and permeated the matrix through concentration gradient-driven diffusion (Hawthorne et al., 2013; Jia et al., 2018). The dimensions of the simulation model were set to mimic those of the experimental setup (described in detail in Jin et al., 2017b). Properties of Bakken oil were measured and used as input data to the simulation model to ensure the results were representative of fluid behavior in the Bakken reservoir. Initial oil saturation was representative of the residual oil used in the experiments (live oil). The basic rock and fluid properties used in the model can be found in Table 2.

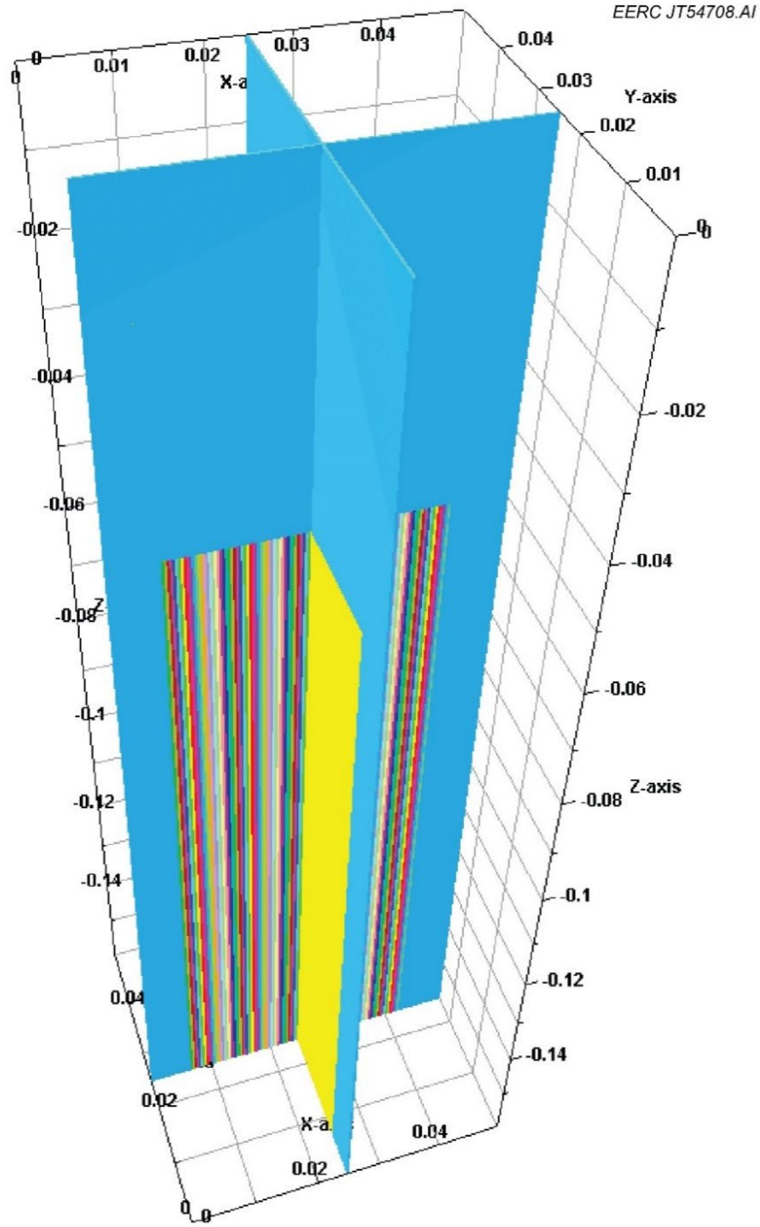

Figure 3: Perpendicular cross sections within a core plug-scale model of a horizontal plug from the Middle Bakken, MB3 (laminated) lithofacies, used in numerical simulations replicating hydrocarbon extraction experiments using CO_2. The dimensions of the model are 15 × 15 × 50 mm. The dark blue surrounding the core plug represents the void volume within the sample vessel. Individual laminae are indicated with different colors.

The values of the rock parameters in this plug model were based on the measured property values for Lower Bakken Shale core samples (see Figure 7). Iterative modifications of the model, varying input parameters slightly, were simulated until a reasonable match of the extraction results was achieved. As in the laboratory experiments, simulations were run with all sides of the shale sample exposed to CO_2 during the permeation and extraction process. Here diffusion played an important role in mobilizing oil from the sample because pressure drawdown was eliminated during the extraction. Figure 8 shows the comparison of experimental and simulation results for a Lower Bakken Shale core sample. The results indicate the model was able to reproduce the laboratory-measured hydrocarbon extraction results; however, the final recovery factor was slightly underestimated. The simulation model was also able to imitate the CO_2 penetration process during the extraction (Figure 8). The history-matching exercise resulted in a calibrated shale plug model that provided experimental-based estimated values for the CO_2 molecular diffusion coefficients and maximum adsorption (Table 3).

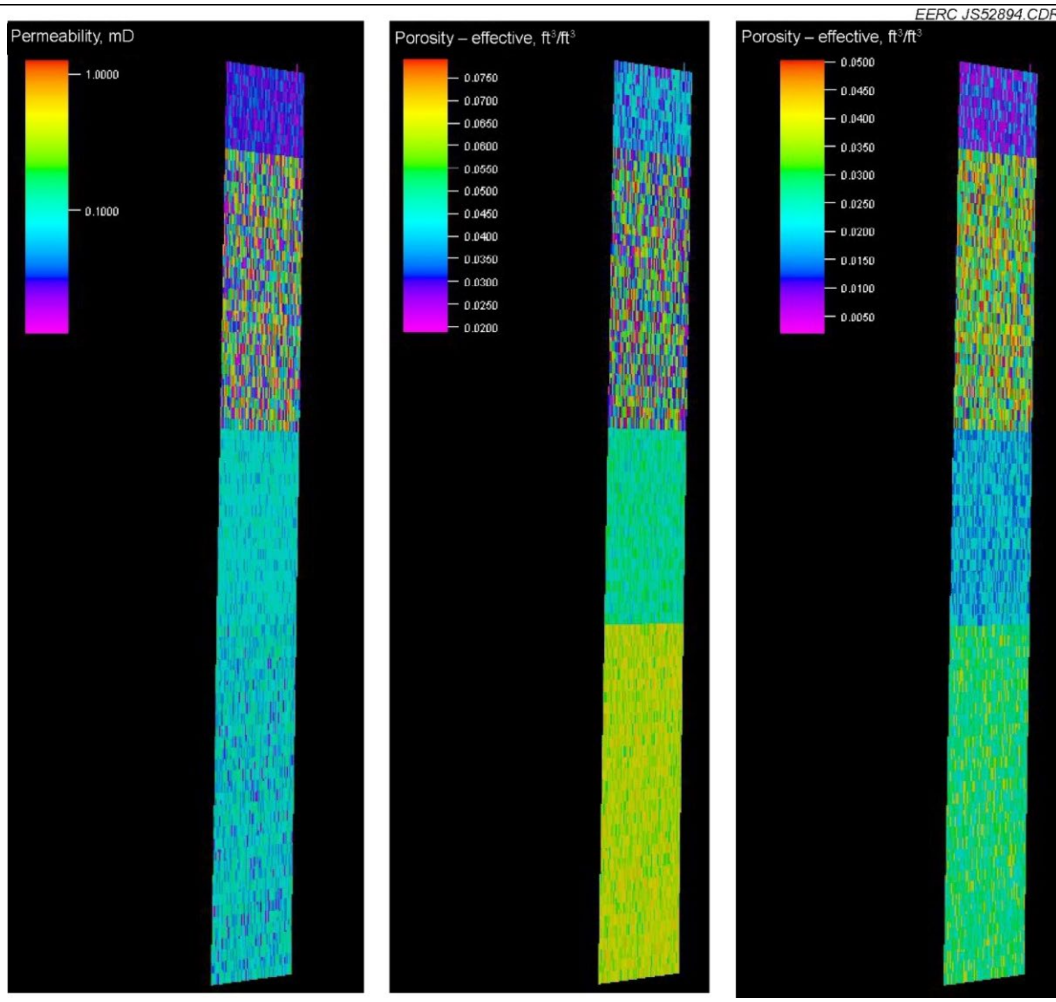

Figure 4: Middle Bakken core-scale model (lithofacies MB2 through MB5; MB1 is not present) showing distribution of permeability (left), porosity (center), and effective porosity (right). The dimensions of the model as shown in this image are not to scale, as the width of the core is 4 inches, while the length is approximately 45 ft.

Larger-Scale Models

In addition to plug-scale simulations, a series of larger-scale models were prepared to investigate the role of natural or induced fractures on different CO_2 injection strategies using models with two adjacent hydraulically fractured horizontal wells. Symmetrical planar fractures were created with CMG's Builder module (CMG, 2016a). Sensitivity studies were performed to quantify the effect of key parameters. Several scenarios were examined in detail, including varied well schedules and targeted injection/production rates.

Reservoir fluid properties and rock–fluid properties were obtained from public literature (Kurtoglu, 2013; Sorensen et al., 2015; Jin et al., 2017b; Hawthorne et al., 2017; Cho et al., 2016). Production data were used to calibrate the matrix properties (porosity and permeability) and hydraulic fracture properties (fracture permeability, fracture length, and fracture height) to imitate primary depletion from a prolific producer well in the North Dakota sector of the Bakken Formation. Two wells in Dunn County located near the location of the July 2017 injection test were chosen for reservoir-scale simulation modeling. For instance, the wells simulated with the larger-scale model had an average 180-day cumulative oil production, in terms of barrels per foot of horizontal lateral, above the third quartile (11.87 and 15.32 bbl/ft) of a data set comprising 297 wells. For comparison, an analysis of over 10,000 wells completed in the MB member and Three Forks Formation by Lolon et al., (2016) found the 180-day cumulative oil barrels per foot typically ranged between 0.4 to 20 bbl/ft. Field-based injectivity data acquired during a pilot test executed on July 2017 have been integrated into the large-scale simulations (Sorensen et al., 2018a).

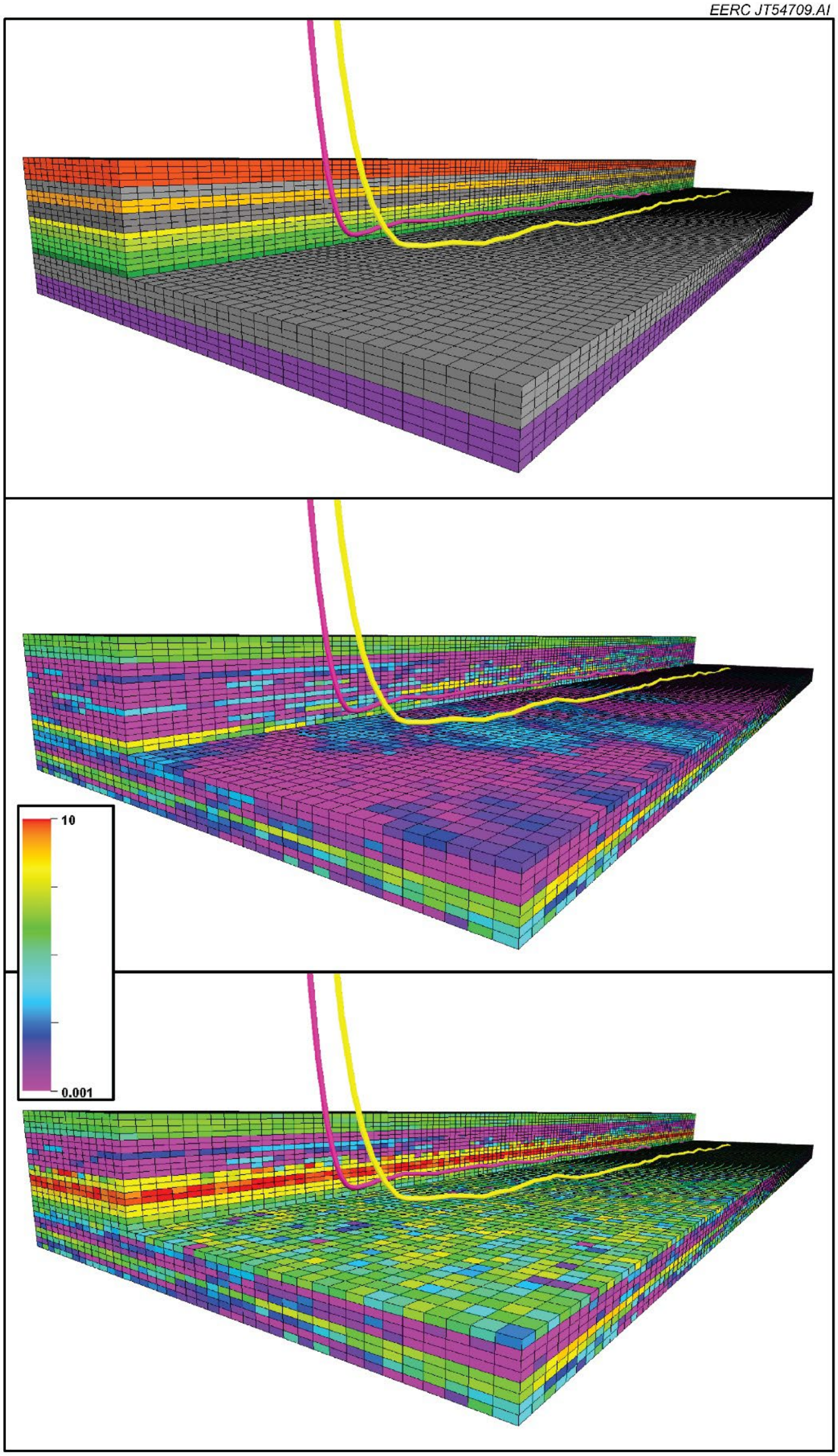

Figure 5: Cutaway view of the model showing well trajectories and subunits contained within the DSU model (top), matrix permeability (middle [mD]), and the combined matrix and fracture permeability (bottom [mD]).

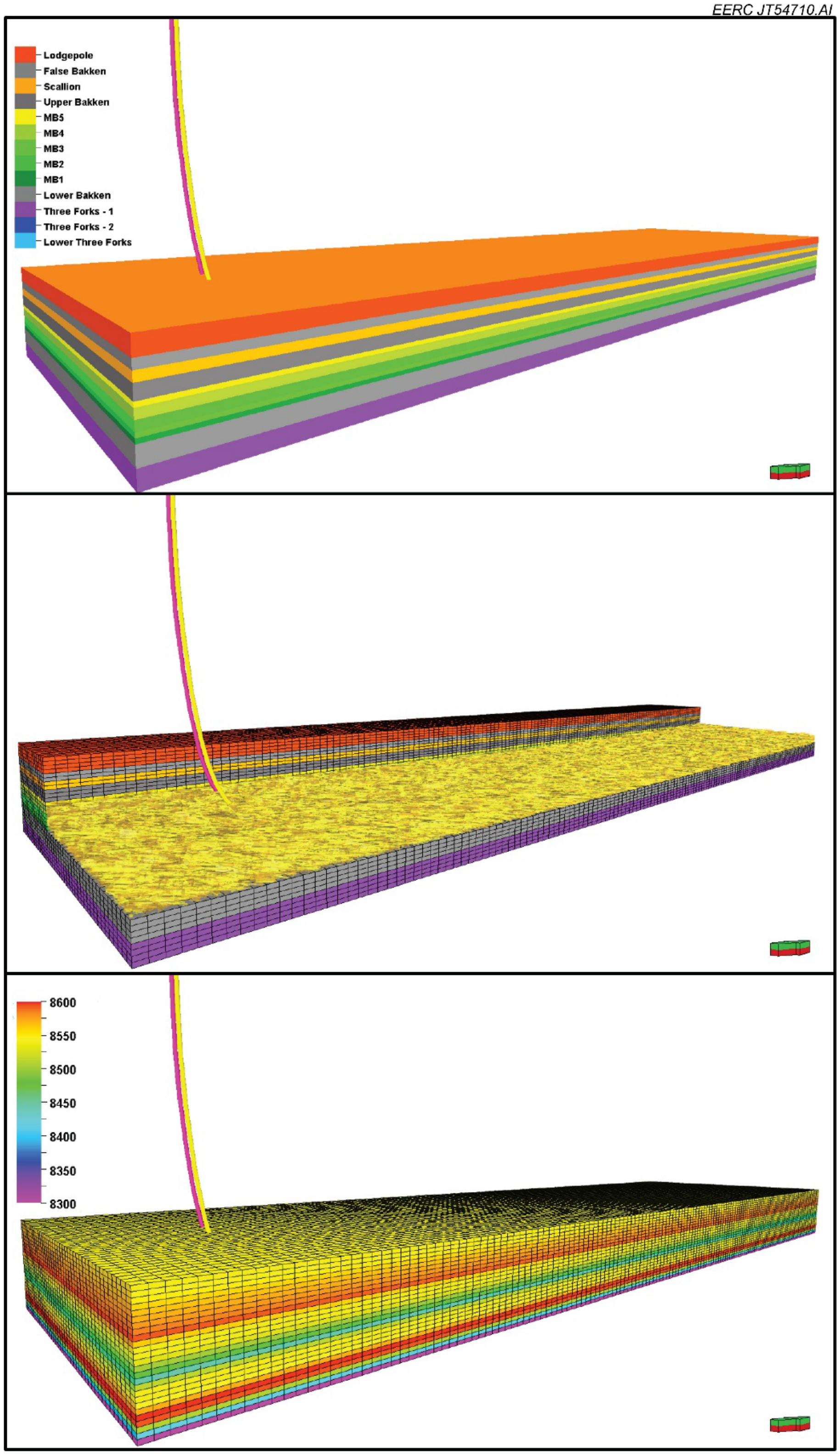

Figure 6: Subunits contained within the DSU model (top), the discrete fracture network constructed within the Middle Bakken lithofacies (middle, yellow fracture planes), and the initial pressure (psi) distribution (bottom). Note the overpressured nature of the Bakken shales.

Table 2: Basic Parameters Used in the Simulation Model

Category	Parameter	Value	Unit
Rock	Porosity	4.8	%
	Permeability	0.008	mD
	Density	2400	kg/m^3
	Compressibility	1×10^{-6}	1/psi
Oil	Density	794.6	kg/m^3
	Viscosity	1.336	cP
Condition	Initial core pressure	150	psi
	Injection pressure	5000	psi
	Temperature	110	°C

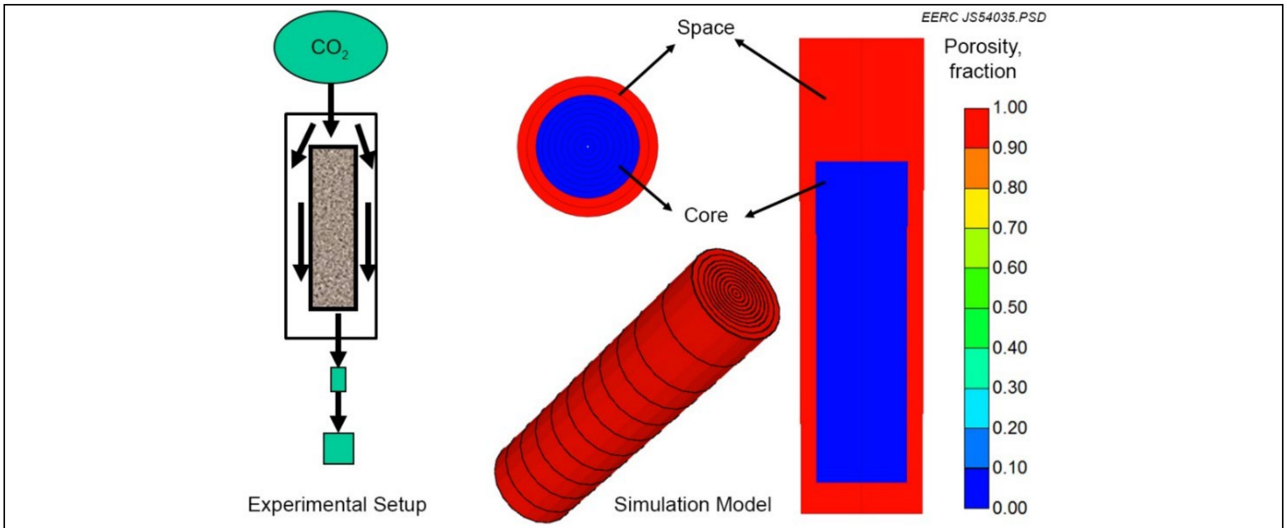

Figure 7: Schematic of plug-scale simulation models (right) in comparison to the experimental setup (left) (Jin et al., 2017b).

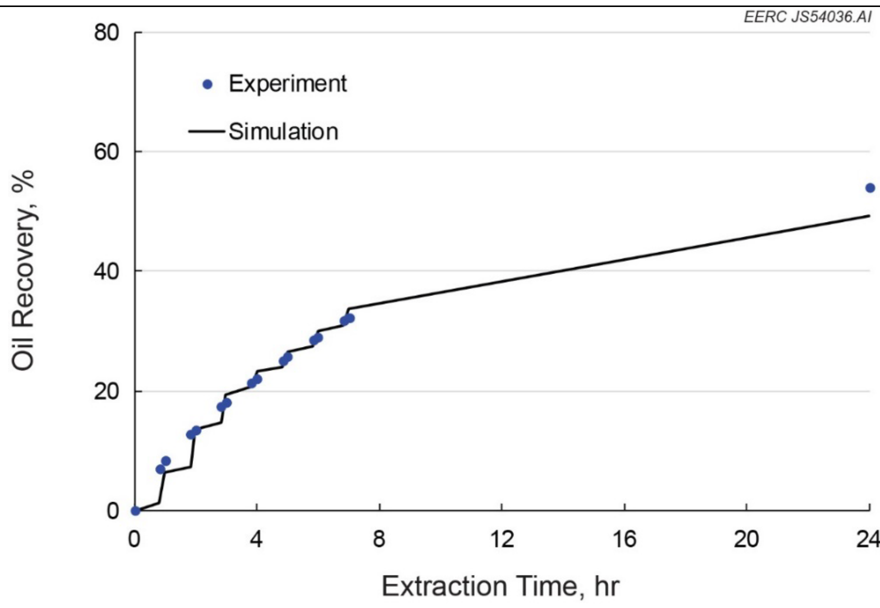

Figure 8: Simulated hydrocarbon extraction reproducing experimental results in a Lower Bakken Shale sample.

Table 3: Values for Each of the Parameters Used in the Lower Bakken Shale Plug Simulation (results shown in Figure 8)

Parameter	Value	Unit
Pressure	4995	psi
Porosity	0.0611	fraction
Permeability	0.0113	mD
Water Saturation	0.11	fraction
Diffusion Coefficient	1.67×10^{-5}	cm^2/s
Maximum Adsorption	0.1624	gmole/lb

The single-stage and DSU models were created to investigate different situations (Table 4). On one hand, the single-stage model represents a horizontal well that is connected to dense (induced and/or natural) fracture network(s), with the hydraulic fracture surface contact area reaching three members (LBS, MB, and UBS). On the other hand, the DSU model represents a horizontal well placed in a region with relatively lower fracture network density. In addition, the DSU wells have undulating well trajectories such that the hydraulic fractures are in contact with the UBS and MB in the first section of the well, while extending from the MB down into the upper section of the Three Forks in the second section. Another major difference is that the initial saturation conditions for the single-stage model are such that there is no mobile water in the MB, while for the DSU model, there is mobile water in the MB.

Table 4. List of assumptions used on the single stage and DSU models

Assumptions	Single Stage Model	DSU Model
Modeling Approach	Dual Porosity/Dual Permeability Model	Single Porosity Model
Domain	Element of symmetry (1300 ft × 150 ft)	Sector covering the full wells length (10400 ft × 3120 ft)
Well Trajectory	Centered around MB-L3	Undulating trajectory: first section is centered in MB-L3; second section is centered in MB-L5
Fracture Height	Surface contact area reaching three members (LBS, MB and UBS)	Surface contact area in contact with the UBS and MB in the first section of the well, while extending from the MB down into the upper section of the Three Forks in the second section
Initial Water Saturation (MB)	Critical water saturation (0.3)	Mobile water saturation (0.486)

Single-Fracture Stage Model

The models built for the near-well-scale studies were heterogeneous models, single-fracture stage symmetry elements, which were used to investigate different injection strategies with two contiguous, hydraulically fractured, horizontal wells. Table 5 shows the properties, inputs, and assumptions used to build the model. Elements of symmetry were used to reduce the simulation time.

Dual continuum models were created to estimate the role of natural fractures on CO_2 storage efficiency, CO_2 sweep efficiency, and the potential for incremental oil recovery through huff 'n' puff schemes. The model has 15 layers (layer thickness ranged from 4 to 9 feet), encompassing seven different units including (descending order) the False Bakken, Scallion, Upper Bakken Shale, Middle Bakken, Lower Bakken Shale, and Three Forks (Benches 1 and 2).

The model contained two horizontal wells separated by 490 feet. Symmetrical artificial fractures were created, representing a single fracture stage. Fracture half-length and height were fixed at 200 and 94 feet, respectively. The hydraulic fractures propagated from the Upper Bakken Shale through the Lower Bakken Shale units. Figure 9 shows select displays of the geologic model (9a) with two contiguous single-stage elements of symmetry (Figures 9b to 9f).

Table 5 shows the model parameters (well constraints, relative permeability end points, and hydraulic fracture parameters). Table 6 shows the operational parameters of the six production scenarios, consisting of one reference case undergoing primary production (baseline) and five variants of huff 'n' puff cycles, each cycle containing an injection period of 3 weeks, a soak interval of 1 week, followed by a year of production. This configuration has

Table 5: Model Properties, Inputs, and Assumptions

Well Constraints	
• Maximum BHP, injector well	3000 psi
• Minimum BHP, producer well	1000 psi
End Points for Relative Permeability (after Cho et al., 2016)	
• k_{ro} End Point at Residual Water, at S_{wc}	0.4
• Critical Water Saturation, S_{wc}	0.3
• k_{rw} End Point at Irreducible Oil, at $1\text{-}S_{orw}$	0.05
• Saturation of Irreducible Oil, S_{orw}	0.3
• Exponent for Calculating k_{row}, n_{ow}	5
• Exponent for Calculating k_{rw}, n_{ow} n_w	1.3
• Trapped Oil Saturation of Irreducible Oil, S_{om}	0.05
Elements of Symmetry and Hydraulic Fractures	
• Number of Fractures per Element of Symmetry	2 per 150 ft
• Distance Between Fracture Tips and Model Boundary in X-Direction	191 ft
• Distance Between Fractures and Model Boundary in Y-Direction	41.7 ft
• Distance Between Fracture Tips from Another Well	76.4 ft
• Hydraulic Fracture Permeability	1 Darcy

two potential benefits: 1) CO_2 could help reduce the viscosity of the liquid in the high-permeability channels (either natural or artificial fractures) and adjacent tight pores and 2) CO_2 has been shown tobe effective at extracting hydrocarbons from tight rocks, as reported in the lab results discussed above. BHP (bottomehole pressure) well constraint in the producer well was chosen to keep the producer downhole conditions near CO_2 supercritical conditions.

Figure 10 shows illustrations of the distribution of the global CO_2 fraction at the end of the first injection cycle. The presence of the natural fractures in the Middle Bakken favors CO_2 transport in the higher permeability region (Figure 10b–c; green- and red-colored blocks ranging from 0.3 to 1 global CO_2 molar fraction). At the same time, the Upper and Lower Bakken Shale layers (Figure 10b–c; blue-colored blocks below 0.1 global CO_2 molar fraction) contain lower CO_2 concentration. However, it is important to note that adsorption behavior of CO_2 in the Upper and Lower Bakken Shale layers was not considered in these simulations. The natural fracture network acts as an extension of the hydraulic fracture, providing additional contact area, which may lead to more favorable conditions for the recovery process. As expected, the matrix blocks located near hydraulic fractures accumulated higher CO_2 concentration.

A comparison of oil production with and without CO_2 injection is presented in Figure 11. As shown, the incremental production per injection cycle remains above the baseline (reference case) for about 4 years before stabilizing at the baseline level. Figure 12 shows the oil recovery factor after 30 years of operation for the different scenarios studied.

Case 5 (nine huff ‘n’ puff cycles simulated) resulted in an incremental oil recovery exceeding 5% of the reference case. The gross CO_2 utilization number (amount of CO_2 required per incremental barrel) ranges from 6.1 to 8.9 Msfc/bbl, which indicates an excellent use of the solvent when compared with CO_2 EOR operations for conventional reservoirs (Azzolina et al., 2015).

The associated CO_2 storage potential was estimated using the methodology explained by Azzolina et al. (2015). The case with nine cycles resulted in a net CO_2 utilization of approximately 1.8 Mscf per barrel of incremental oil produced. Assuming the OOIP mentioned above, an estimated incremental oil recovery range of 0.6% to 5.4% implies additional cumulative production ranging from 1.8 billion to 16 billion barrels. Therefore, simulation results suggest a CO_2 storage volume estimate ranging from 169 Mt to 1.5 Gt for the Bakken in North Dakota.

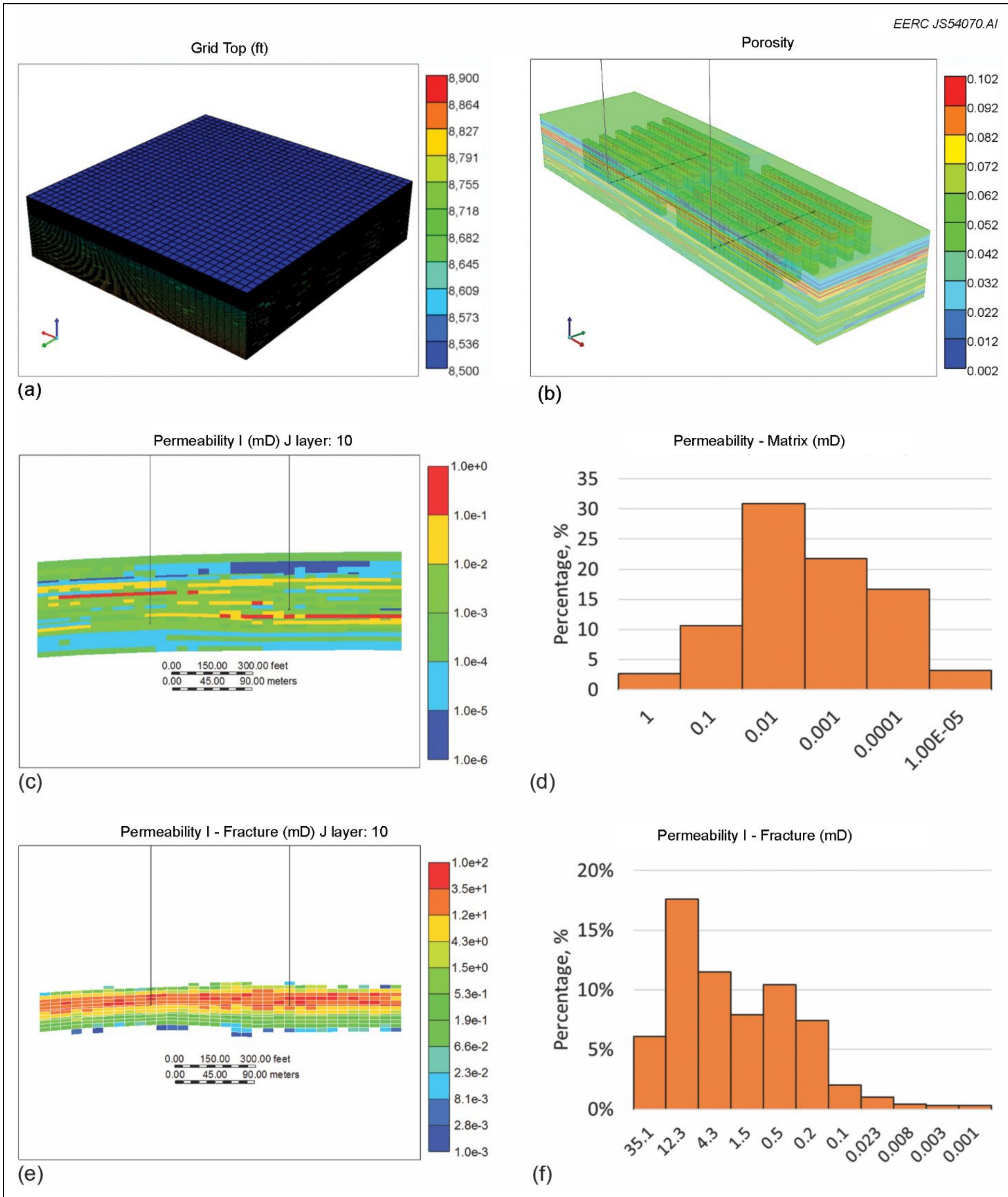

Figure 9: Displays of the geomodel (a) and the single-stage element of symmetry (b–f): 3-D view of the grid top (a), matrix porosity (b), 2-D cross section view of the matrix permeability (c), matrix permeability histogram (d), 2-D cross section view of the fracture permeability (e), and fracture permeability histogram (f). Aspect ratios are 4 (Plane XZ) and 1 (Plane XY).

Table 6: List of Operational Scenarios Considered

Case ID	Cycles	Cum. CO_2 Injected, MMscf	Recovery Factor, 30 yr	Gross CO_2 Utilization, Mscf/bbl
Reference	0	0	17.9	0
01	1	3.7	18.5	6.5
02	2	8.1	19.2	6.1
03	3	12.9	20.0	6.1
04	6	29.8	21.9	7.2
05	9	49.5	23.3	8.9

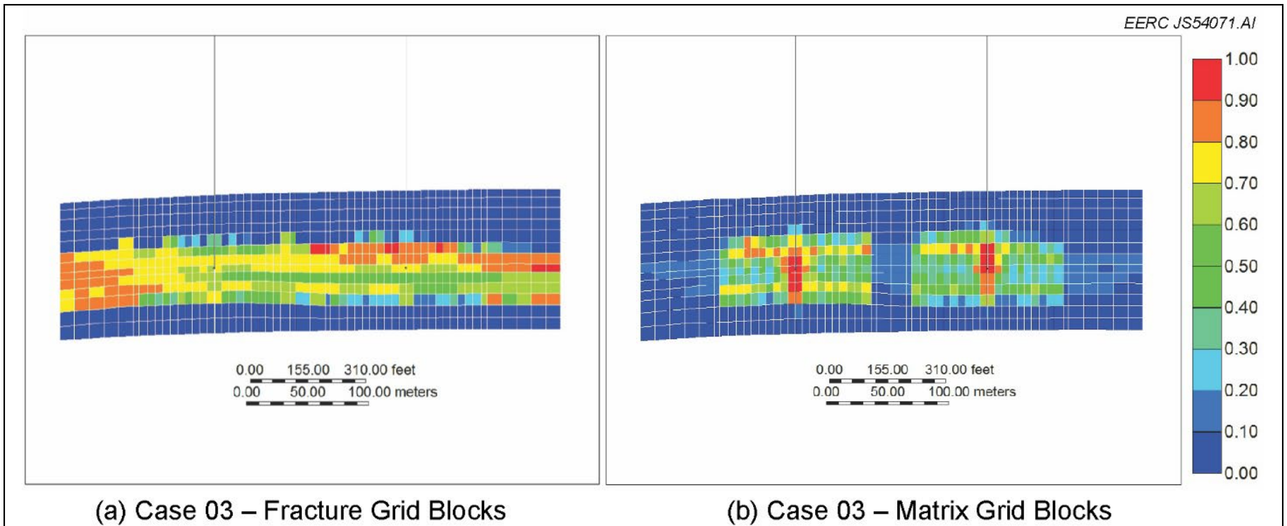

Figure 10: 2-D cross-sectional view at the center of the model showing the spatial distribution of the global CO_2 molar fraction at a time equivalent to the end of the first injection cycle for a) fracture blocks – Case 03 and b) matrix blocks – Case 03. Aspect ratio is 4 (Plane XZ).

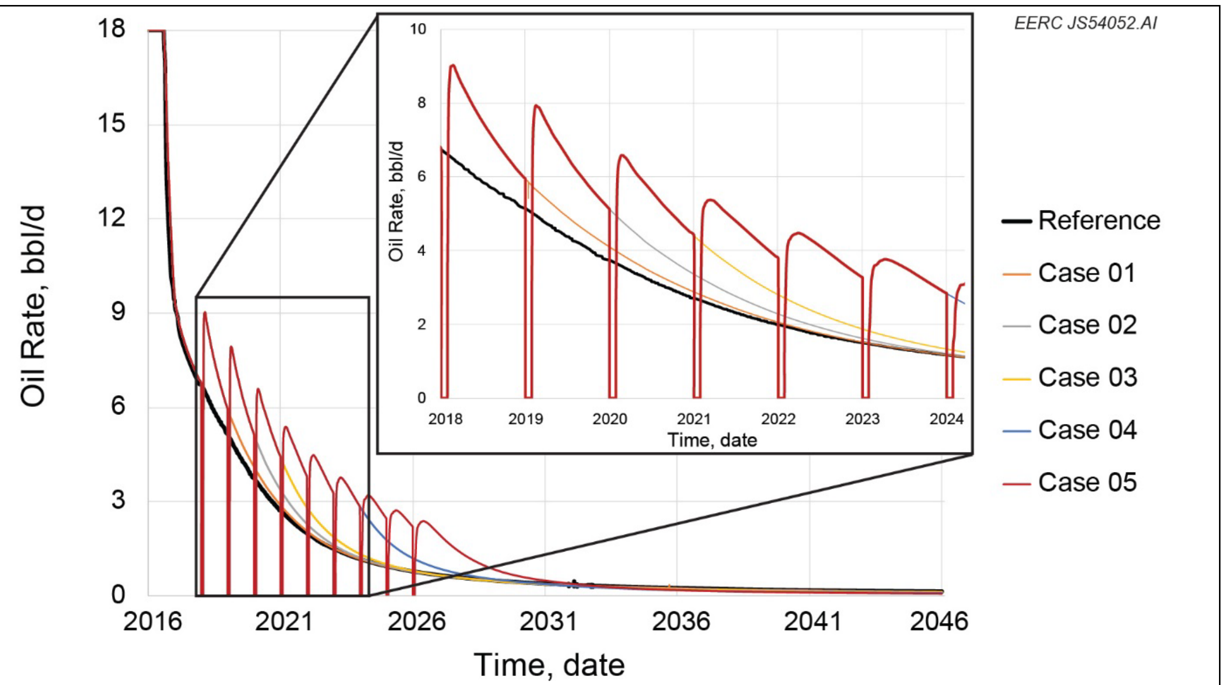

Figure 11: Oil production forecast over 30 years for the single-stage model. Inset zooms in on the time frame from 2018 to 2024.

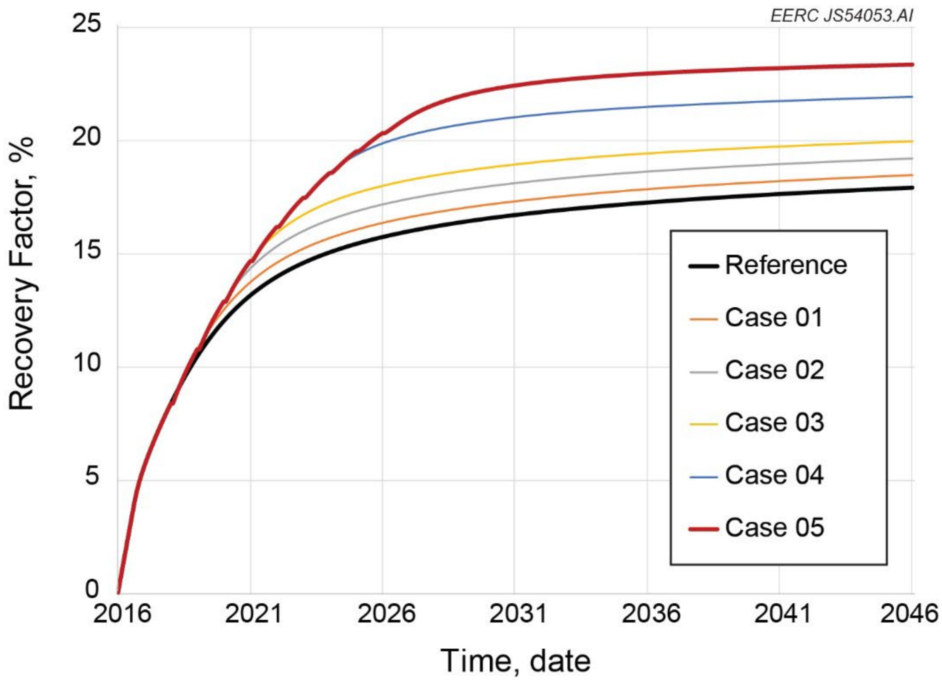

Figure 12: Recovery factor forecast over 30 years for the single-stage model.

Drill Spacing Unit Model

Figure 13 shows 3-D images of the heterogeneous 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). The base case, Case 1, represents a tight oil reservoir, with an average matrix permeability of 17 microDarcies in the MB, and with a low vertical-to-horizontal permeability ratio (Kv/Kh) of one tenth (0.1). Case 2 represents a tighter matrix with an average matrix permeability of 1 microDarcy in the MB and same Kv/Kh (0.1). The role of natural fractures and vertical communication was evaluated in Case 3, which used a Kv/Kh of 0.4 and an average matrix permeability of 13 microDarcies in the MB.

Recovery factor estimates after 30 years of primary production 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. Different scenarios were prepared to investigate the long-term storage of CO_2 through continuous CO_2 injection (CCI) and huff 'n' puff (alternating CO_2 injection and production between wells) schemes.

The CO_2 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. In the rest of this section, CO_2 EOR performance from Cases 2 and Case 3 will be compared in more detail. Figure 14a shows the recovery factor in Case 2, which had lower effective permeability in the MB (Table 7), up to one order of magnitude lower. The operational scenarios for Case 2 are listed in Table 8. Figure 14b shows the recovery factor in Case 3 (higher Kv/Kh due to greater contribution from natural fractures). The results also indicated that the wells are not fully depleted and may continue to produce for longer than 30 years. Table 9 summarizes the operational parameters assumed with Case 3.

<u>Case 2: Tight Matrix with Low Vertical-to-Horizontal Permeability Ratio</u>

Table 8 summarizes the operational parameters assumed with Case 2 (low vertical-to-horizontal permeability ratio). A comparison of oil production with and without CO_2 injection for the scenarios studied with Case 2 showed that the oil production remained above the baseline case (reference case) for all three huff 'n' puff cases. The CCI cases

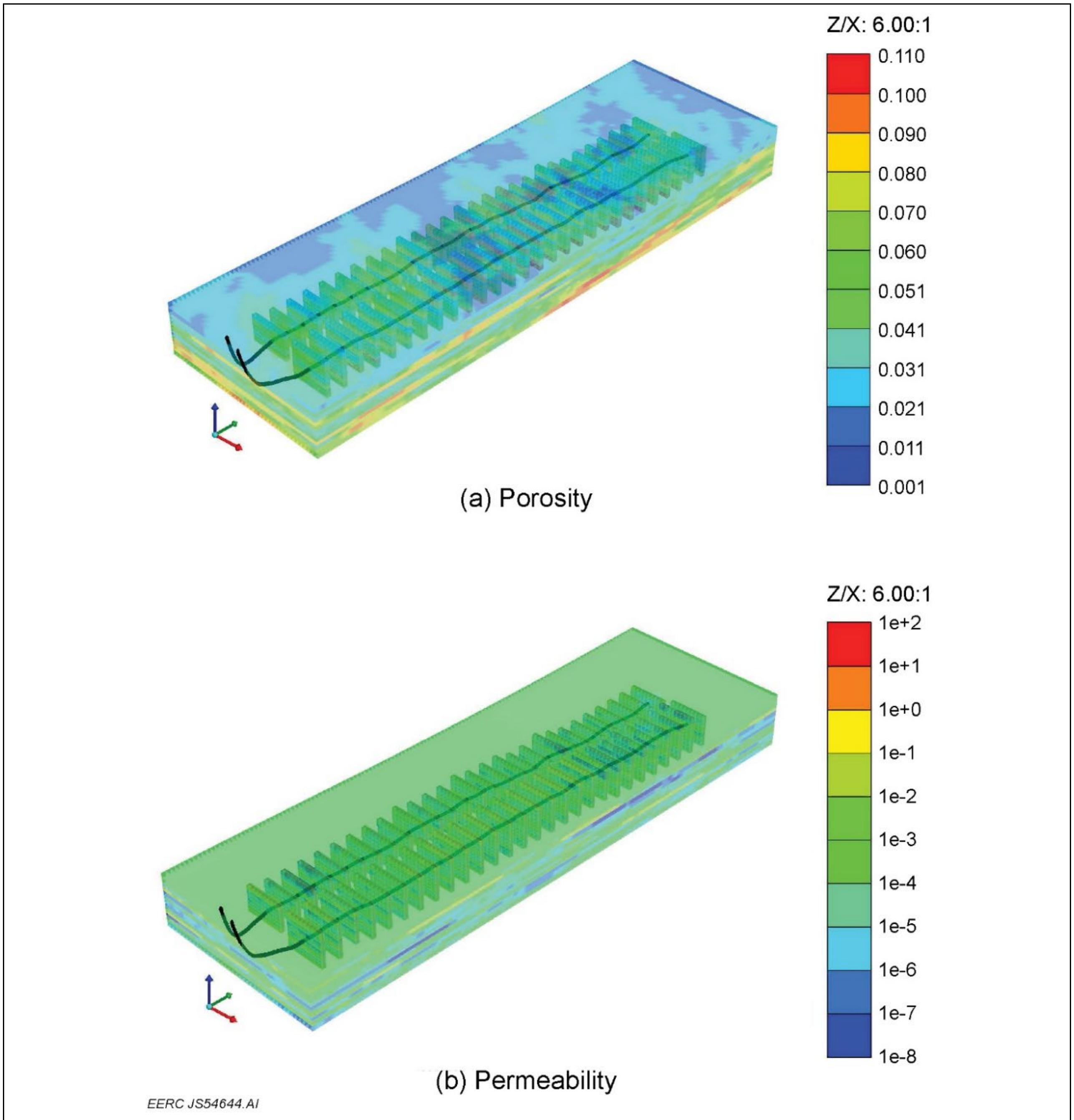

Figure 13: Porosity a) and permeability b) distributions with the wells' trajectories and hydraulic fractures.

Table 7: Base Case Model (Case 1) and Its Variants (Case 2 and Case 3)

	Permeability, μD			
	Min.	**Max.**	**Average**	**Kv to Kh, ratio**
Case 1	0.001	342	17	0.10
Case 2	0.00001	33	1	0.10
Case 3	0.001	342	13	0.40

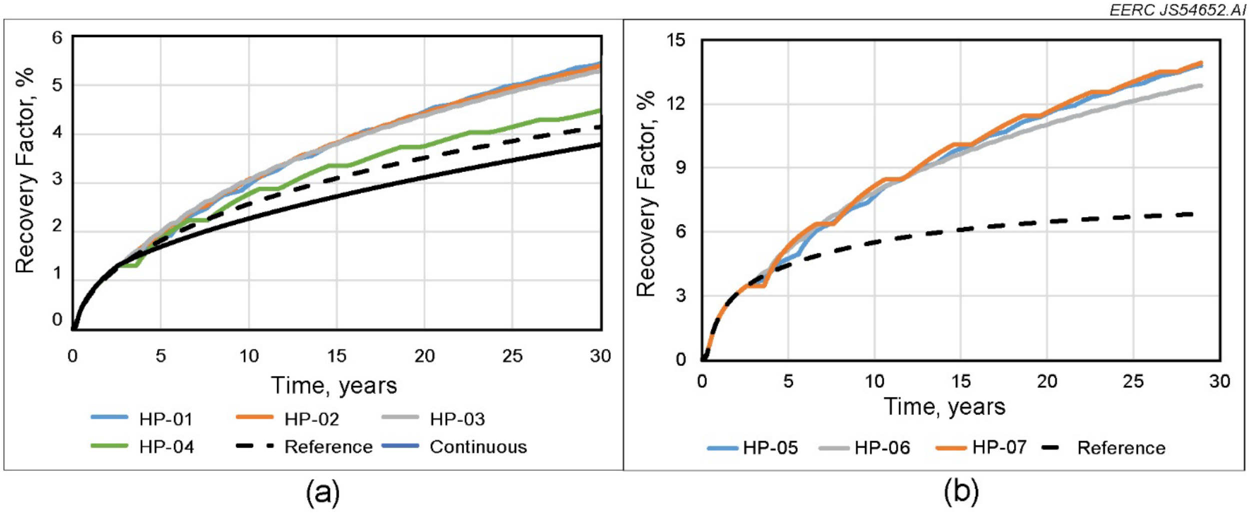

Figure 14: Recovery factor with time for different models and operational scenarios: a) Case 2 (tight matrix with poor vertical communication) and b) Case 3 (base case matrix permeability with fluid contribution from natural fractures in the MB and good vertical communication). Reference case refers 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 8: 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)

Scenario ID	Number of Cycles	Cum CO_2 Injected, MMscf	Incremental Recovery Factor	Operational Constraints[1]
Reference[2]	0	–	–	
HP-01	27	4445	1.3%	• Minimum BHP (3000 psi) at producers
HP-02	18	4424	1.3%	• Maximum BHP (9200 psi) at injectors
HP-03	14	3907	1.2%	• Maximum gas rate (10 MMscfd) injected
HP-04 Paired	7	3609	0.4%	

[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 CO_2 injection.

Table 9: List of Operational Scenarios Considered with Case 3 Having a Relatively High Vertical Matrix Permeability (assumed 0.4 as Kv-to-Kh ratio)

Scenario ID	Number of Cycles	Cum CO_2 Injected, MMscf	Incremental Recovery Factor	Operational Constraints[1]
Reference	0	–	–	
HP-05[1]	27	21521	6.3%	• Minimum BHP (3000 psi) at producers
HP-06[1]	27	21079	7.3%	• Maximum BHP (9200 psi) at injectors
HP-07[2]	7	21056	7.5%	• Maximum gas rate (10 MMscfd) injected

[1] Alternating huff 'n' puff cycles' length: each well was put on cycles comprising 3-month (HP-05) injection or 11-month (HP-06) injection, followed by 4 weeks of soaking and 2-year (HP-01), 3-year (HP-02), or 4-year (HP-03 and HP-04) of production. The start of cycle for the second well coincide with midterm cycle for the first well. Total cycle duration per well was 2-years for HP-01, 3-years for HP-02, and 4-years for HP-03 and HP-04.
[2] 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).

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 CO_2 was injected in both wells at the same time (Scenario HP-04) resulted in relatively modest incremental recovery (<1%). On the other hand, the alternating huff 'n' puff results (one well injecting CO_2 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 CO_2 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 CO_2 to interact with the matrix while keeping the other well on production.
3) After the "soaking" period, the injector well was reversed to producer well. Then, at the cycle midterm, the second producer well was reversed to injector well.
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 CO_2 into the tight formation. Having one production well operating simultaneously mitigated production loss during each injection and soak period. This operational procedure appeared effective when there was little or negligible direct communication between the pair of wells. GOR (gas-to-oil ratio) was monitored to detect CO_2 breakthrough in the production well, particularly to detect interwell communication.

Laboratory experiments have shown that higher pressure (and therefore higher CO_2 density) always gives higher/faster recoveries with CO_2, regardless of whether the pressure is below, above, or substantially above MMP. For the DSU models here considered, MMP (assumed to be on the order of 3000 psi) was used as a guidance for differentiating higher pressure from lower pressure cases. Additional work is needed to validate the lab observations with simulation models; i.e., that the CO_2 pressure (and therefore density) is what controls recoveries from tight rocks, regardless of whether the downhole conditions are below, above, or substantially above MMP. Simulation results performed in this work showed that when CO_2 is injected at higher pressure, the oil mobilization is more effective; while when CO_2 is injected at lower pressures, the oil mobilization decreases. When BHP is below the MMP and saturation pressure, fractures are filled with three fluid phases (water, oil, and gas). When CO_2 is injected at higher pressures, the gas and oil phases are miscible and water volume accumulating in the lower part of fractures is decreased. The BHP during production was constrained to 3000 psi, with a dual purpose: 1) to maintain a pressure high enough to allow miscible conditions and 2) to keep reservoir pressure above the saturation pressure. The latter factor will simplify the analysis of the results by removing compositional effects happening during fluid-phase changes.

<u>Case 3: Base Case Matrix Permeability with Higher Vertical-to-Horizontal Permeability Ratio</u>

As shown by the rock extraction studies described above and discussed in more detail in Hawthorne et al., (2013) and Jin et al., (2017b), 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 Kv/Kh of 0.4. Figure 14a shows the recovery factor in Case 2, which had lower effective permeability in the MB (Table 7), up to one order of magnitude lower. The operational scenarios for Case 3 are listed in Table 9. Figure 14b shows the recovery factor in Case 3 (with greater vertical communication from natural fractures). 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. Previous Bakken modeling exercises 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. Simulation results discussed above make an important contribution not only in furthering our understanding of the role that formation water may have in CO_2 EOR and associated storage, but also in expanding the applicability of the results to include a wider variety of Bakken reservoir types.

Conclusions

- Advanced laboratory- and novel field-based data sets acquired from the Bakken Formation have been integrated into geocellular and simulation models at multiple scales. With this approach, accuracy of the simulation models for predicting the potential incremental oil production through CO_2 EOR in unconventional tight oil reservoirs has been improved.
- The simulation results of the single-fracture stage model showed incremental recovery factors ranging from 0.6% to 5.4%. The highest incremental recovery factor observed from the simulations occurred from nine huff 'n' puff cycles was approximately 5.4%. This number could be increased by conducting more huff 'n' puff cycles over the life span of an operating well and/or by optimizing the operational parameters. And while 5.4% may still be perceived as a relatively small increase over primary production, the implications for an incremental recovery of 5.4% for production throughout the area of Bakken production is enormous, with Bakken OOIP estimated to be 300 billion barrels (LeFever and Helms, 2008).
- Results from the single stage model suggest cumulative production estimates ranging from 1.8 billion to 16 billion barrels and CO_2 storage volumes estimates ranging from 169 Mt to 1.5 Gt for the Bakken in North Dakota.
- The study with the single-fracture stage model revealed that the presence of (natural and/or induced) fracture networks could result in more favorable CO_2 sweep efficiency and oil mobilization in tight oil reservoirs. Natural fractures may significantly increase the contact area between the formation and the (artificially) stimulated region, leading to more favorable conditions for the recovery process. Consequently, reservoir characterization is a critical element in understanding the effectiveness of CO_2 storage and incremental oil recovery for tight oil formations.
- In the two horizontal study wells that were modeled at the DSU scale, 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.

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