TASK 1 DELIVERABLE D2 – PLAINS CO_2 REDUCTION (PCOR) PARTNERSHIP (PHASE III) – SITE CHARACTERIZATION OF THE DICKINSON LODGEPOLE MOUNDS FOR POTENTIAL CO_2 ENHANCED OIL RECOVERY

(For the period October 1, 2007, through September 30, 2009)

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Cooperative Agreement No. DE-FC26-05NT42592

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2010-EERC-03-02

May 2009
Approved

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PLAINS CO_2 REDUCTION (PCOR) PARTNERSHIP (PHASE III) – SITE CHARACTERIZATION OF THE DICKINSON LODGEPOLE MOUNDS FOR POTENTIAL CO_2 ENHANCED OIL RECOVERY

INTRODUCTION

Carbon dioxide capture and storage (CCS) in geological media has been identified as a technically and economically viable approach for significantly reducing anthropogenic greenhouse gas emissions into the atmosphere. One of the PCOR Partnership's goals is to identify and evaluate CCS opportunities in the central interior of North America. Several means for geological storage of carbon dioxide (CO_2) are available, such as storage in deep saline formations and depleted oil and gas reservoirs or enhanced recovery methods where CO_2 is stored in the process of recovering resources, such as CO_2 enhanced oil recovery (EOR) and enhanced coalbed methane (ECBM) recovery. The use of CO_2 for simultaneous enhanced resource recovery and geological storage provides operators with an economic benefit as a result of producing additional oil or methane and is the focus of this work.

Several research and development (R&D) issues will be addressed during the PCOR Partnership Phase III tasks, specifically focusing on modeling, monitoring, capture, and injection operations to demonstrate that large-scale storage of CO_2 in oil fields is a safe and permanent solution for storing significant amounts of CO_2 emissions from the PCOR Partnership region (Figure 1). The Dickinson Lodgepole Mounds (DLM) in southwestern North Dakota have been identified as possible targets for CO_2 storage and CO_2 EOR activities because of the high recovery factor and very successful waterflooding operations as well as their proven ability to trap oil and gas for millions of years (Gorecki et al., 2008). Many of the oil fields that encompass the DLM are operated by PCOR Partnership partners and, as a result, the entire mound complex has been selected for additional site characterization activities. Characterization of the DLM was accomplished using modern stochastic geostatistical techniques to create a model of these features, with the goal of describing the DLM to a greater degree, including macrofacies and microfacies analysis. This model was used for calculations of EOR potential as well as for CO_2 storage volume analysis.

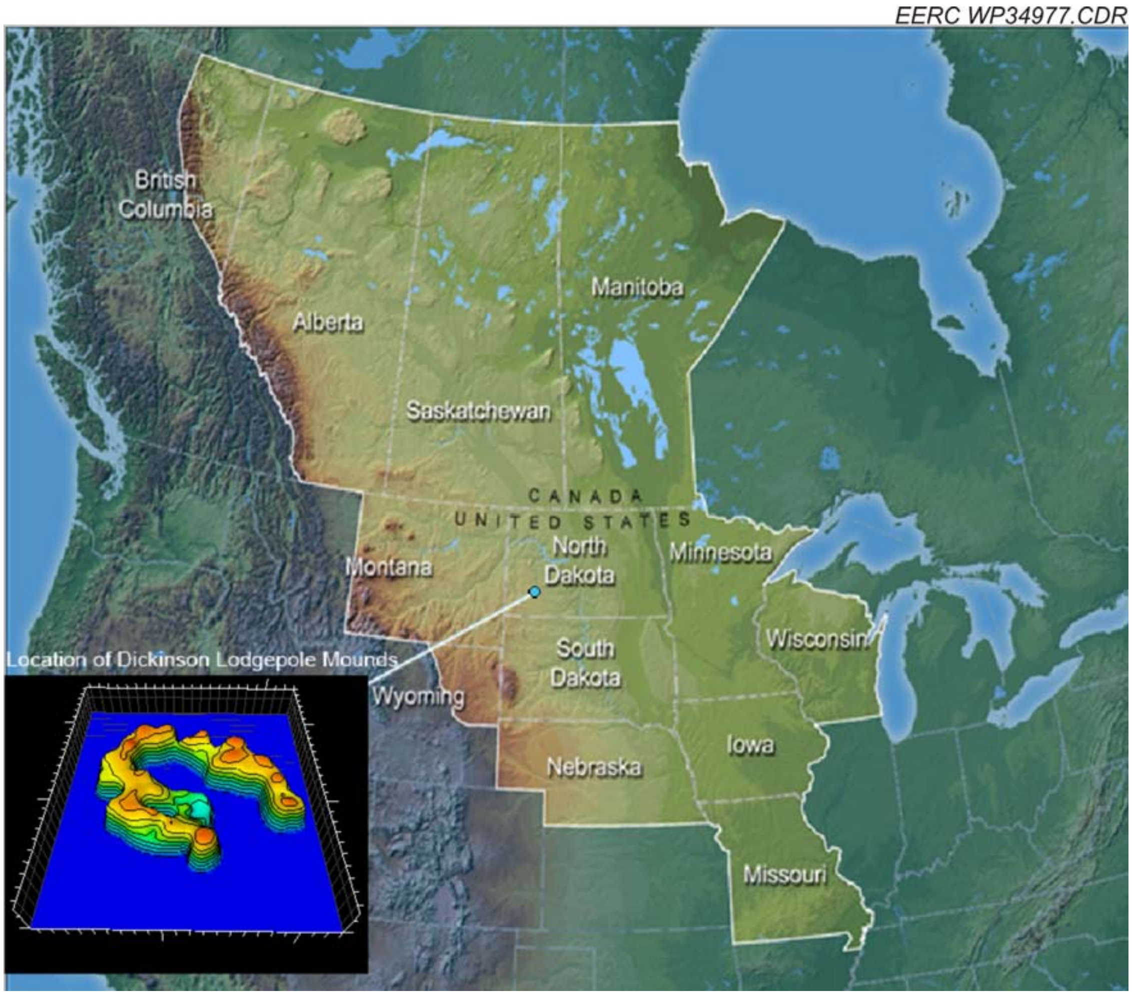

Figure 1. PCOR Partnership region.

PROJECT OBJECTIVES

The activities described in this report were conducted as part of the Regional Characterization task of Phase III of the PCOR Partnership. The objective of the Regional Characterization task is to identify, evaluate, and characterize locations in the PCOR Partnership region that may have potential to serve as sites for large-scale storage of CO_2. Detailed subsurface mapping and characterization must be conducted prior to large-scale injection of CO_2 for the purpose of secondary or tertiary oil production techniques. As part of the PCOR Partnership's Phases I and II Regional Characterization activities, evaluations of potential geological storage targets were completed on a reconnaissance level using readily available public sources of data. These investigations have resulted in the evaluation of the theoretical storage capacity for oil fields throughout the PCOR Partnership region and provide the basis for further, more detailed evaluation.

Early in Phase III activities, the PCOR Partnership identified three target areas for detailed evaluation with regard to the utilization of CO_2 for EOR: 1) Eland oil field, which is part of the DLM located in western North Dakota; 2) Rival oil field in northwestern North Dakota, which is proximal to a gas-processing plant that currently disposes of acid gas into the subsurface; and 3) Sleepy Hollow oil field in southwestern Nebraska. Each of these site investigations will address unique opportunities to utilize CO_2 obtained from a myriad of industrial applications and provide valuable information with regard to the economic impact of CO_2 EOR.

Phase III characterization activities, including those focused on the DLM, will generally be completed in greater detail than those conducted in Phases I and II. All sources of data available through the PCOR Partnership will be employed for characterization, including wireline well logs, core analysis, production decline curves, drill stem tests, and produced fluid analyses. Site characterization results are fed into predictive models using industry standard software that addresses three critical issues to determine the ultimate effectiveness of the target formation, including 1) the CO_2 storage capacity of the target formation, in this case an oil reservoir within an established oil field; 2) the overall potential for enhanced resource recovery from the identified target; and 3) the mobility and fate of the CO_2 at near-, intermediate-, and long-term time frames. Key site characterization parameters that will be addressed include properties of the reservoir and seal rocks, properties of the fluids in the reservoir and overlying fluid-bearing formations, and production and operational history of the target oil reservoir.

The basis of our focus on CO_2 storage and utilization in oil fields is that oil fields are generally much better characterized than saline formations; are already legally established for the purpose of safe, large-scale manipulation of subsurface fluids; and offer a means to offset the considerable costs of CO_2 capture, compression, transportation, and implementation through the sale of incrementally produced oil. These attributes make oil fields the most cost-effective, near-term choices in the PCOR Partnership region for large-scale CO_2 storage projects.

The following report summarizes the detailed characterization activities recently completed for the first of the three target areas, the DLM region (including the Eland oil field) near Dickinson, North Dakota.

BACKGROUND

The DLM were a prolific oil discovery in the mid-1990s around and beneath the city of Dickinson, North Dakota (Figures 1 and 2). The DLM contain some of the best oil-producing wells in the history of North Dakota (Burke and Diehl, 1993). The Lodgepole Formation is typically a tight, shaly limestone cap rock which overlies the organic and oil-rich Bakken Formation; however, the DLM comprise a clean lime mud with higher porosity and substantially higher permeability than average Lodgepole rock. Because of the unique characteristics of the DLM, they were chosen early on in the PCOR Partnership characterization activities as a possible target for CO_2 EOR and CO_2 storage.

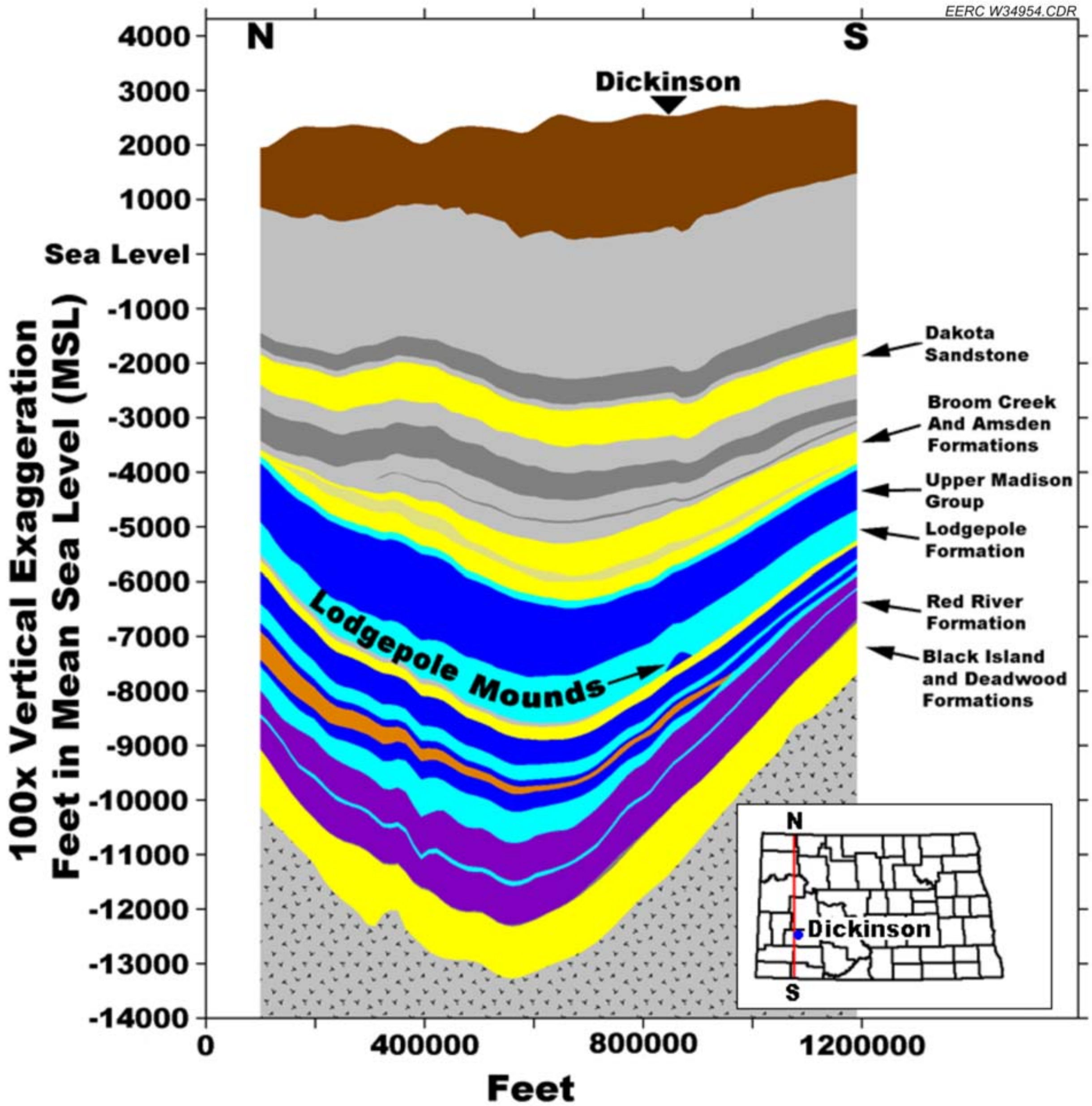

Figure 2. North-to-south cross section through North Dakota and the DLM.

The DLM oil fields cover an area of approximately 36 square miles in Stark County, North Dakota (Young et al., 1998). The fields are operated by various oil companies, some of which are members of the PCOR Partnership. Encore Operating specifically manages production of the Eland, Stadium, Livestock, and Subdivision Fields (Figure 3). The DLM contains unitized fields, which means that regulatory approval by the North Dakota Department of Mineral Resources to conduct large-scale fluid injection activities (including CO_2) as part of the reservoir's operation has been given. The fact that the mounds are already an established injection-oriented

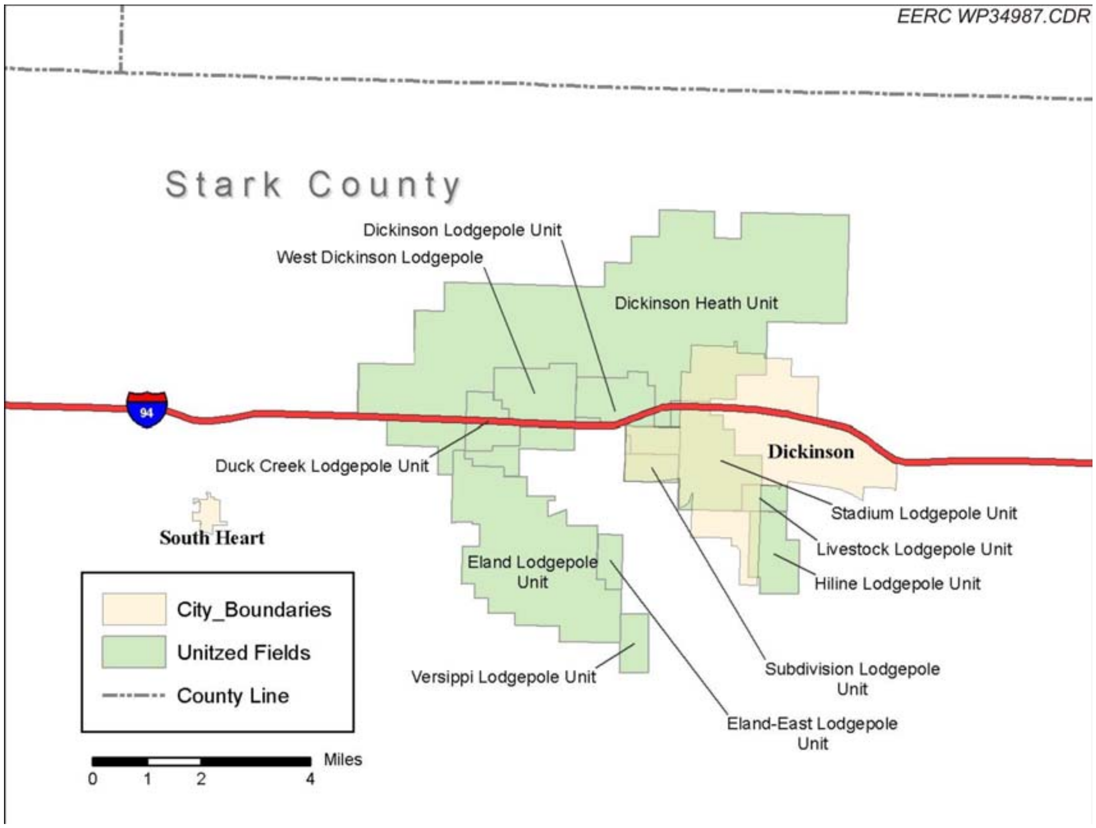

Figure 3. Unitized fields and Dickinson.

interval will provide the project with flexibility regarding the selection of well sites and the construction of CO_2 injection wells and attendant infrastructure. It will also significantly streamline the permitting process.

PREVIOUS WORK

Mississippian-aged mud mounds were first discovered via outcrop in the Montana portion of the Williston Basin in the mid-1970s, where they were described as crinoid and bryozoan buildups with micritic cores and were postulated to exist elsewhere within the Williston Basin (Bjorlie, 1979). The DLM were discovered in 1993 with the completion of the Conoco No. 74 Dickinson State well and have received considerable attention since. Throughout the mid-1990s, dozens of additional exploratory oil wells were drilled in the area. A report documenting the DLM discovery and early interpretation was published in 1995 (Lefever et al., 1995). Several publications pertaining to the mounds followed as the play developed and information became available (Burke and Diehl, 1993, 1995; Burke and Lasemi, 1995), and a very in-depth review of the mounds was conducted by Young et al. (1998). Most recently, Gorecki et al. (2008) proposed that the mounds, like most oil accumulations in the Williston Basin, have great potential as a CO_2 EOR target and CO_2 storage sink based on the success of the secondary waterflooding operations and the assumption that since the mounds have proven the ability to trap substantial quantities of hydrocarbons for millions of years, they should be able to trap and contain any injected CO_2 for the foreseeable future.

Worldwide Mound Summary

"Waulsortian," "Waulsortian-type," and "Waulsortian-like" mud mounds such as the DLM are enigmatic reef structures found around the world from the Cambrian to the Jurassic (Bosence and Bridges, 1995) after the type locality near Waulsort, Belgium. The term mud mound is rather discrete, being defined by Bosence and Bridges (1995) as "carbonate buildups having depositional relief and being composed dominantly of carbonate mud, peloidal mud, or micrite." This leaves a single term representative of deep- and shallow-water mounds consisting of sediment piles, microbial tufas or, in some instances, giant stromatolites or thrombolites (Pratt, 1995). Other authors, including early work by Lees and Miller (1985, 1995) reserve the term for a series of mud developments that contain specific, defined biologic assemblages and are of early to middle Mississippian age (Bridges et al., 1995). Lees and Miller (1995) report that mud mounds discovered in North Dakota are Waulsortian-type; however, several documents label them Waulsortian proper (Ahr, 2008; Young et al., 1998) or Waulsortian-like (Burke and Diehl, 1993, 1995; Longman, 1996). Because of the ambiguous nature of the term, this document will continue to use Waulsortian to describe the mounds, regardless of the subtle and implicit technicalities.

Worldwide, it is estimated that there are over 1000 Mississippian-aged mud mounds (Krause et al., 2004), characterized as small mounds of clean carbonate mud which are nodal to sinuous in shape and exhibit high vertical relief; at times deposits are several hundred feet thick, with flanks up to 50 degrees identified (Lees and Miller, 1985). No solid determination has been made as to the exact depositional requirements, so mud mounds are usually characterized based on sediment size, fossil assemblages, and structure alone. Although there is no known universal origin for Waulsortian mud mounds, it is known that they preferentially occur on structural highs (Johnson, 1995) near the shelf or shelf margin (Flügel, 2004; Bjorlie, 1979), are often found in subsidence zones, and begin forming below wave base and the photic zone (Boulvain, 2001). Individual mud mounds are typically smaller than 1 square mile in size and are found in groups; at some locations, over 200 mounds and composite mound ridges cluster into geographical regions such as the Ahnet Basin of Algeria (Wendt et al., 1997), and in Belgium, where more than 69 individual mounds are located and mined for stone (Boulvain, 2001). Waulsortian mud mounds are not generally considered source rocks for oil; however, under certain conditions, they make excellent structural traps. Notable oil plays have been observed in mud mounds all over North America, in the North Sea Basin, and in Poland (Zywecki and Skompski, 2004).

Idealized Mounds

A typical Waulsortian mud mound (Figure 4) consists of a micritic limestone mud core dominated by stromatactic and bryozoan fabrics, a fossiliferous grainstone flank made mostly of skeletal debris, and a crinoid apron (Al-Aasam and Vernon, 2007). A much more complicated explanation was developed by Frédéric Boulvain during his years studying similar, proximal Frasnian (Late-Devonian) mounds in southern Belgium. He suggests different types of mounds

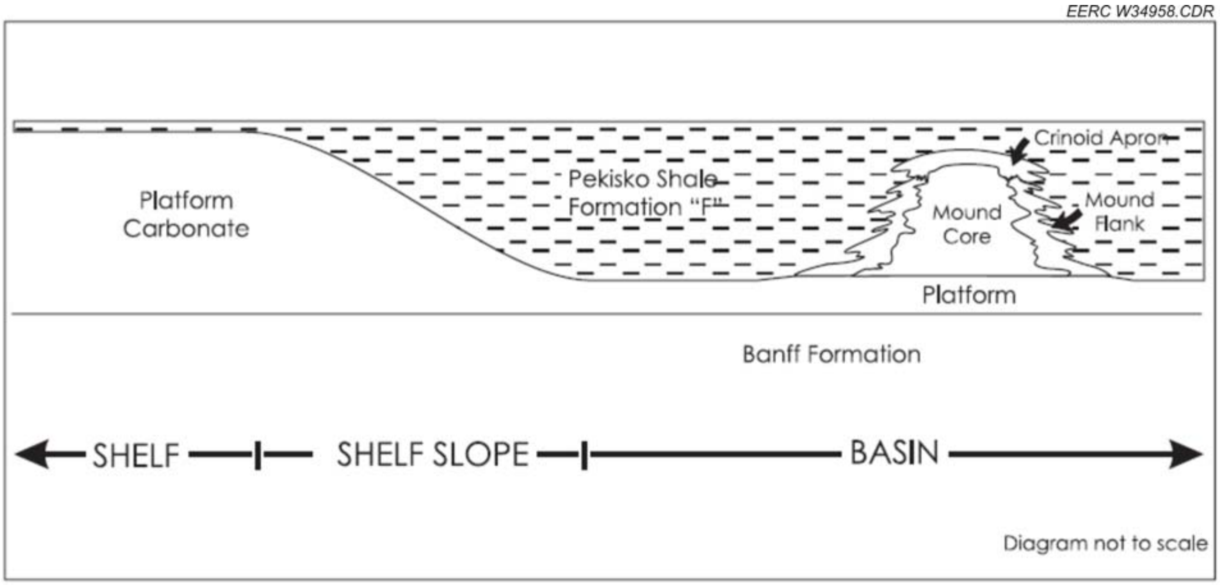

Figure 4. Al-Aasam's generalized mud mound.

which have adapted to their specific depositional environment, namely, St. Rémy, Lés Wayons, and Lés Bulants (Figure 5).

St. Rémy mud mounds are very small mounds that contain significant amounts of iron and manganese, interpreted as deep-water mounds made mostly of iron-fixing bacteria and sponge which thrive in anoxic or near-anoxic conditions. The mounds never reach photosynthetic or wave action levels, which limits their growth.

Lés Wayons mud mounds begin in deeper water, similar to St. Rémy mud mounds, but build into the oligophotic zone, grading from anoxic to oxidized conditions where the limestone changes color from red and black (anoxic) to pink and gray (oxidized). These mounds tend to grow tall, have steep relief, and are surrounded by biogenic detritus. Lés Wayons are interpreted to have developed midslope.

The third type of mud mound described by Boulvain is the Lés Bulants. This type of mud mound develops in shallower water and reaches a maximum height, be it wave base, surficially exposed, or otherwise too shallow to continue accumulating sediment. The mud mound then begins to grow laterally. These mud mounds are, therefore, the largest diameterwise but tend to be shorter in height than Lés Wayons-type mud mounds.

DLM Mound Interpretation

Their tall height and steep relief suggest that the DLM are similar to the Lés Wayons variety; however, the consistent height of the DLM is indicative that they reached a similar maximum height, a trait of Lés Bulants mud mounds. Additionally, there is no evidence of anoxic conditions at any place in the mounds. This sets the depositional origin of the mounds

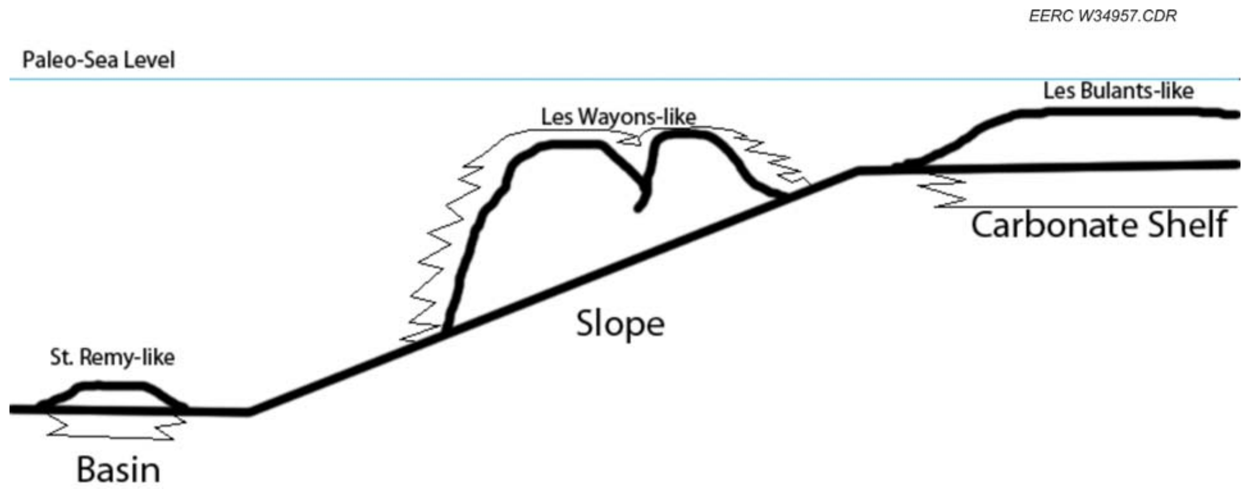

Figure 5. Interpretation of Boulvain's mound types.

within a shallow enough environment to retain oxygen within a zone on the broad regional slope directed into the basin at sufficient depth to produce and capture lime mud. The wave base was likely shallower than expected in the open sea because of a restricted embayedlike environment. During the Mississippian time period, water depths in the Williston Basin may have been chaotic because of sea level fluctuations, basin subsidence, and growth patterns of the mud mounds. The mud mounds, therefore, grew in alternating phases similar to the upper anoxic portions of the Lés Wayons type and the lateral accumulation of the Lés Bulants type. This combination fits the nodular shape of the mounds as well as the composite mound-ridge-like behavior and the associated depositional depths. DLM fossil evidence of disarticulated crinoids shows that the environment was agitated at times, and thick beds of stromatactis and clean lime mudstones are interpreted to accumulate in calmer or sheltered environments dominated by algae within the photic zone.

Microfacies Classification

Porosity and permeability distribution within Waulsortian mounds is strongly correlated to microfacies within the mounds. Understanding the nature of microfacies within the mounds is a key component to developing a realistic model of the DLM reservoirs. DLM facies were identified based on core examinations (Figure 6) and a clean gamma ray signature on geophysical logs (Figure 7). They alternate between a bryozoan–crinoid microfacies (Figures 6A, 7, and 8), the dominant stromatactis microfacies (Figures 6B, 7, and 8), and a flank/debris microfacies (Figures 6C, 7, and 8) (modified from Burke et al., 1995). The bryozoan–crinoid microfacies is a diverse limestone, with whole disarticulated crinoid segments showing minimal weathering and agitation. The stromatactis microfacies is an algal- and microbial-dominated buildup with greatest occurrence in the mound nuclei. The large-grained flank debris microfacies accumulated in an agitated state and contain large partial segments of mostly unrecognizable crinoids, bryozoans, and corals at normal magnification.

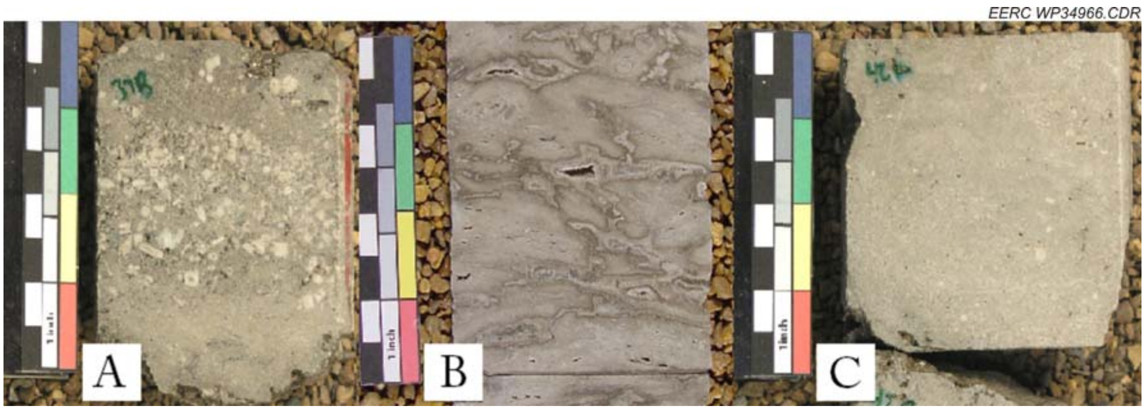

Figure 6. Microfacies photos: A) bryozoan–crinoid, B) stromatactis, and C) flank/debris.

A common feature identified in worldwide Mississippian mud mounds is that they contain stromatactis (Figure 6B) (Bourque and Boulvain, 1993), which are features of controversial origin. Stromatactis are cemented or partially cemented cavities in otherwise clean lime mud that may be a trace fossil of an unpreserved organism or recrystallized patches of the host rock, but it is within reasonable agreement that they are formed by cementation occurring within a cavity of unclear origin (Bourque and Boulvain, 1993). Regardless of the method of formation, the DLM possess stromatactis cavities at a microfacies level, which are among the most productive reservoir rocks in the system.

Field Summaries

Prior to this study, the DLM were mapped as a series of nodal, domelike structures, as is common with other mud mounds from around the world, although composite mounds, mud mound ridges, and mud atolls (continuous rounded ridges surrounding a central lagoon) are not uncommon (Wendt et al., 2001). This, among other factors, such as the nature and time frame of discovery (Table 1), the generally confusing nature of carbonate reservoirs, and likely compartmentalization in the DLM, led to the complex being unitized into several producing fields (Figure 9). Initial pressures and early oil–water contacts (OWCs) were also used as evidence to unitize the fields. Later data on oil production volumes, water injection volumes, pressure response, and the mound heights give evidence that the mounds are actually a larger coalesced ridgelike structure, as the present model shows and has been suggested by numerous authors (Gordon, 1995; Wendt et al., 1997; Ahr, 2008).

The mounds are considered separate, discrete structures in their unitization documents even though the fields are directly adjacent to each other and some of the contours overlap on field maps. This is most likely due to the wildcat nature of the mound's individual discovery wells and the nucleuslike behavior exhibited by mud mounds. Field differentiation most likely resulted from legal issues, and the structures were regarded as close, or touching, but below the OWC, or separated by other means (North Dakota Industrial Commission [NDIC] Cases 6922, 6139, and 7219, 2009). This unitization created oil fields that were confined to the OWC exclusively and, since this study is considering CO_2 storage in addition to EOR, all available

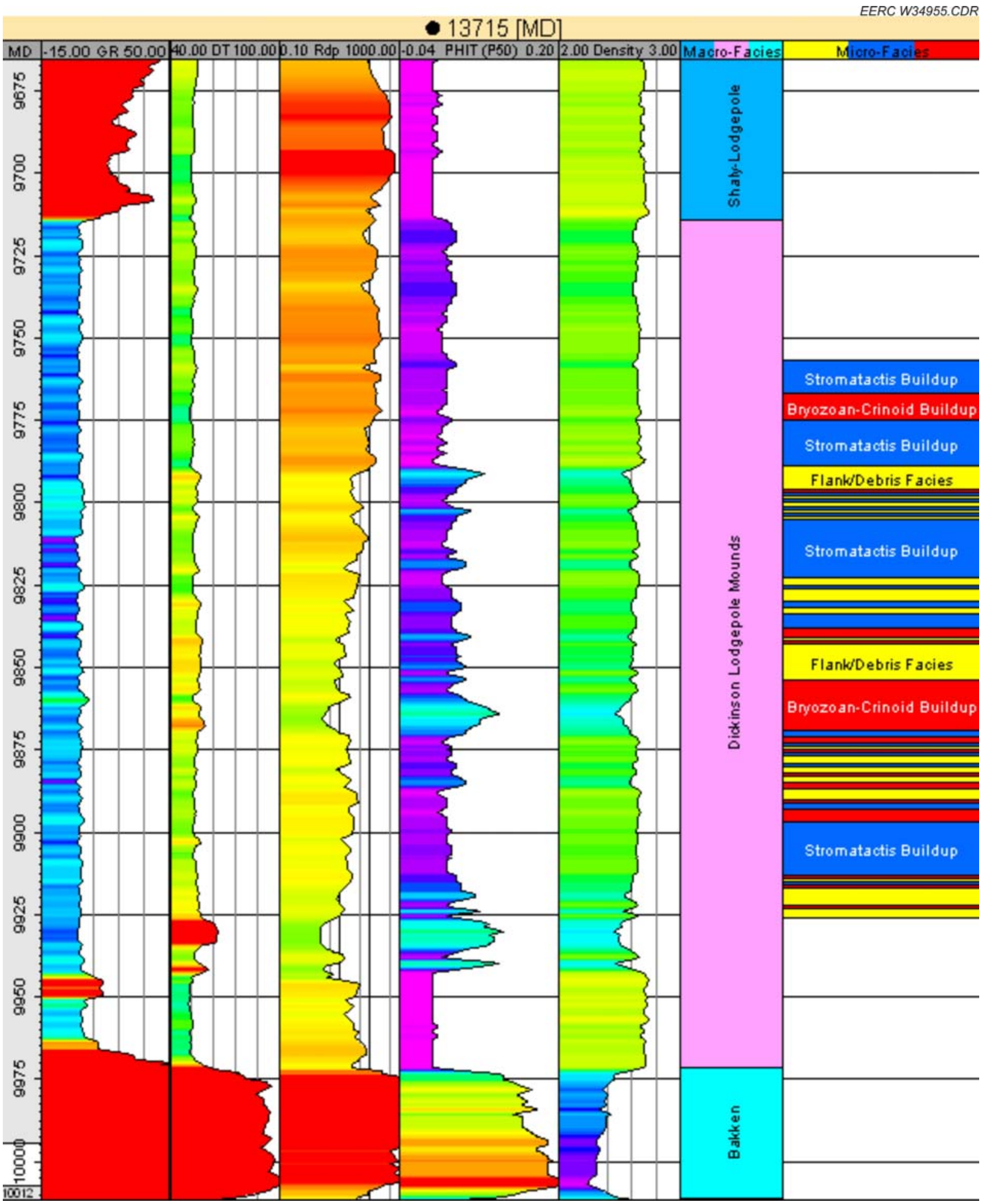

Figure 7. Type log of DLM with macrofacies and microfacies indicated. DLM are indicated by clean gamma ray signature.

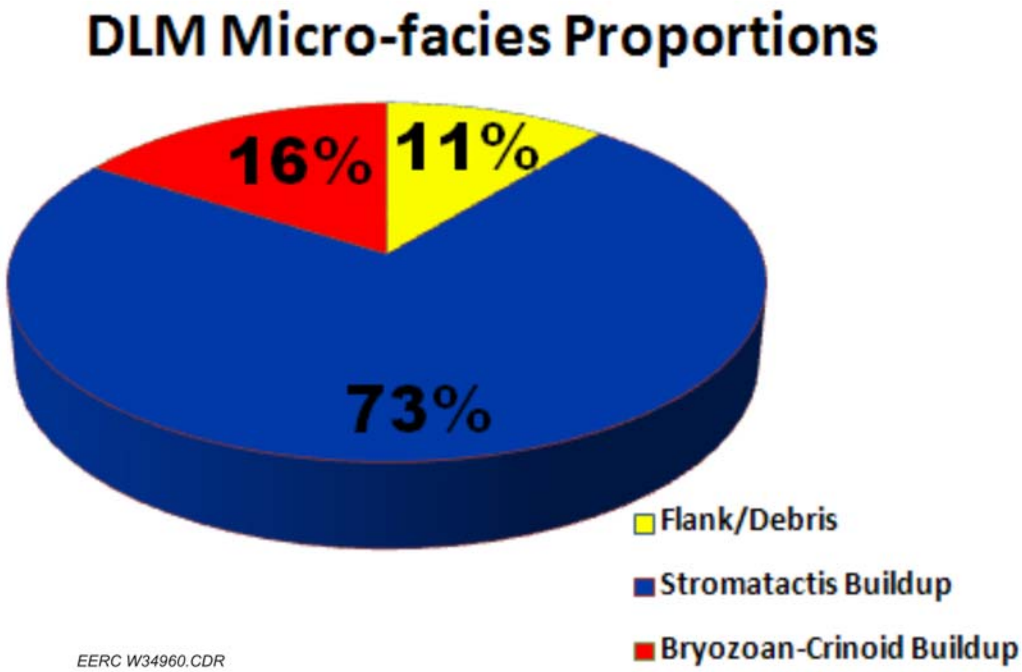

Figure 8. DLM microfacies proportions.

Table 1. Discovery and Unitization Time Line

Field	Activity
2/3/1993	Dickinson Lodgepole play discovered by Conoco
6/16/1994	Dickinson Lodgepole field unitized
2/2/1995	Eland play discovered by Duncan Oil
4/28/1995	Duck Creek play discovered by Armstrong Operating
9/6/1995	Versippi play discovered by Armstrong Operating
10/5/1995	Hiline play discovered by Armstrong Operating
6/1/1996	Duck Creek Field unitized
8/22/1996	West Dickinson play discovered by Conoco
8/22/1996	Subdivision play discovered by Conoco
10/10/1996	Versippi pool unitized
11/8/1996	Eland Field unitized
12/31/1996	Stadium pool discovered by TransTexas
11/1/1997	West Dickinson Field unitized
4/21/1997	Hiline Field unitized
4/27/1997	Eland Field expanded
8/21/1997	Livestock play discovered by Duncan Oil
6/1/1998	Stadium Field unitized
2/1/1999	Subdivision and Livestock Fields unitized

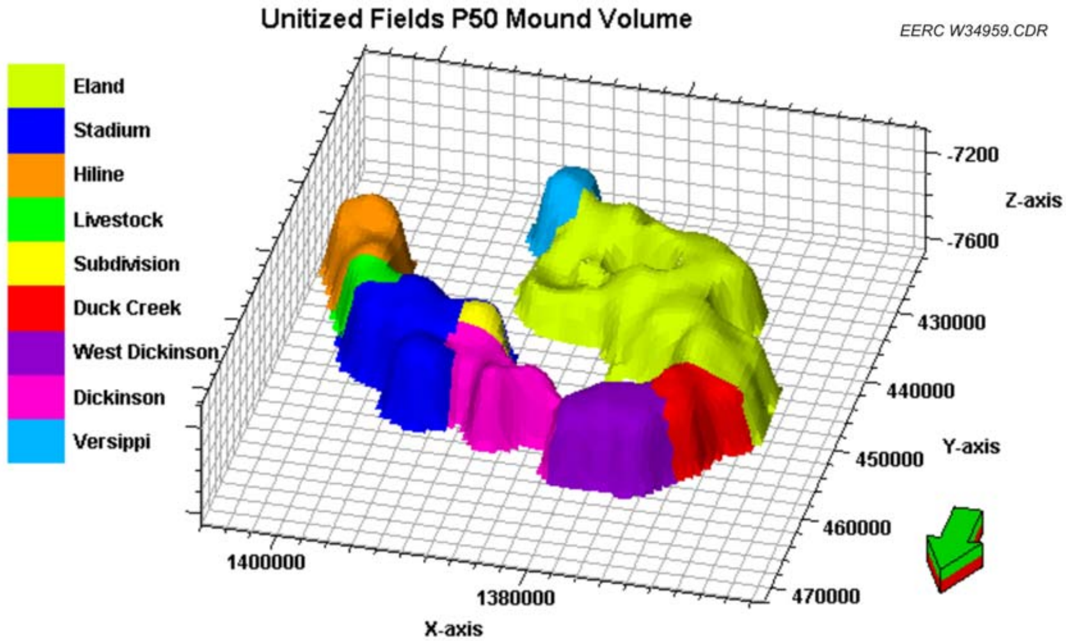

Figure 9. Production units.

pore space and gross volume should be considered. This will require the original unitized fields to be resized for this study.

METHODS AND ANALYSIS

Core data, core images, and wireline logs were collected from the NDIC Oil and Gas server. It was determined that macrofacies and microfacies sequential indicator simulation (SIS) modeling in Schlumberger Petrel was needed for the special geometry, shape, and steep flanks exhibited by the DLM. For this project, an experimental design-based methodology was undertaken. This means that apparent uncertainty extremes were accounted for. Core porosity to wireline porosity and core porosity to core permeability transforms gave initial uncertainty. These variables and associated uncertainty were stochastically distributed into a DLM volume. The DLM deterministic volume (Figure 9) was formed from a most probabilistic indicator model generated from 200 simulations. Normal deterministic surface modeling did not accurately reproduce the DLM geometry. Macrofacies logs were approximated from gamma ray wireline logs by using the zones above the Bakken Shale with generally less than 15 gAPI (American Petroleum Institute units) units. Microfacies logs were created by identifying them on core images and in thin section. Highest total porosities appeared to be moderately biased to the flank/debris and bryozoan–crinoid microfacies. Microfacies modeling was used to define permeability in the DLM exclusively because each microfacies had different nonoverlapping porosity–permeability reduced major axis (RMA) regression transforms (Lucia, 2007). Porosity and pore volume modeling in Petrel used the sequential Gaussian simulation (SGS) algorithm, which produces multiple stochastic realizations of porosity, pore volume, and permeability. Stochastic modeling is an advanced predictive method that produces not one single model but multiple equiprobable realizations that, after summation of each realization, fit a Gaussian distribution. This helps rank P10 (low case or proven), P50 (midcase or probable), and P90 (high case or possible) models. It is industry standard practice in dynamic fluid simulation to use SGS, which produces models that fit the true heterogeneity seen in core, wireline logs, seismic, and semivariogram.

The model produced during this study (Figure 10) shows a single, sinuous composite ridge, as suggested by Gordon (1995) and Wendt et al. (1997), where individual growth centers join together to form one composite system, and this is supported strongly by the available well control. Previous model contours of the Eland Field initially showed a series of separate mounds; however, after additional wells were drilled, it was determined that these individual mounds form a sinuous, ridgelike structure, which could be the case with the entire mound complex. However, because of the complex depositional setting and local and regional faulting, discrete compartments may have formed within the complex, justifying the division of the entire complex into a series of separate compartments. There is evidence of two-phase permeability (fracture and intergranular), which allowed for fluid conduit activity between separate fields within the mound complex, as measured through pressure transient tests, which reported response in wells 2–3 miles apart within minutes (Young et al., 1998).

Based on core and permeability studies, the DLM are also expected to be a highly fractured reservoir, with fracturing assumed to be greatest along the flanks of the mounds because of their steep nature and differential compaction rates. This is supported by the fact that porosities in the mounds are very low (4%–5%) but permeabilities are very high, reaching 2000 mD. By using a combination of macrofacies mud mound delineation, mud mound microfacies rock fabric classification, and a dual porosity and permeability system, a more representative reservoir model was produced. For this report, only intergranular effective porosity is used, because above the OWC, water saturation is confined to separate vugs. This is verified by the production of water-free oil for many years, even though core and wireline analysis show water saturations as high as 50%. In some cases, wells produced 2 million barrels of oil before producing any water. Porosity distribution in the DLM is highly variable and discontinuous, the porosity of the reservoir rock is not less than 4% (Figures 11 and 12), and permeability ranges from 2–2000 mD (Young et al., 1998).

Seals for Injected CO_2

The Williston Basin is a fairly symmetrical intracratonic sedimentary basin, so differently oriented cross sections display similar geometry (Figure 2). Thus, in the absence of a trapping mechanism, the migration of a low-gravity fluidlike CO_2 would be expected to occur updip, toward the flanks of the basin. However, accumulation of hydrocarbons in the DLM provides evidence for the presence of a trapping mechanism in the area.

The trapping mechanism is stratigraphic and is created by the interaction of reservoir porosity and paleostructure associated with the formation of Waulsortian mounds. The primary sealing interval is the upper, or “normal,” shaly Lodgepole, a thick sequence of alternating argillaceous limestones and shales, directly above and laterally beside the mud mounds.

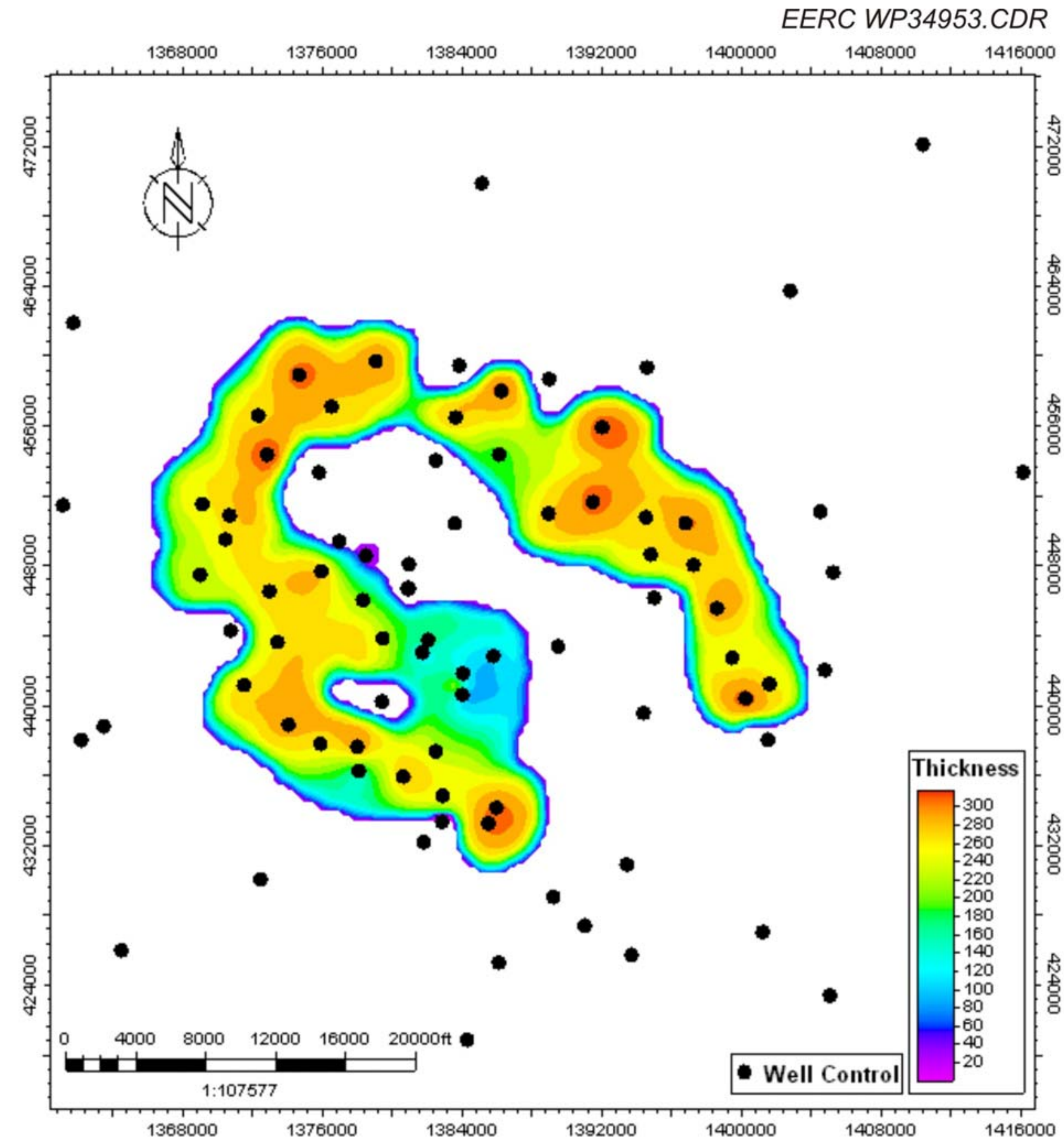

Figure 10. P50 thickness map of the DLM in North Dakota.

If CO_2 were to migrate out of the mounds through an unidentified path, it would be required to permeate through several hundred feet of low-permeability limestone of the Madison Formation and massive evaporites of the Charles Formation. Above the Charles lies productive oil fields in the Tyler/Heath Formation, which, as shown by hydrocarbon accumulation, must also possess a competent seal that has limited fluid flow for millions of years. A study of the hydrocarbon compositions from different horizons in the Williston Basin (Jarvie, 2001) indicates that no mixing of Madison Group (including Lodgepole) hydrocarbons with hydrocarbons

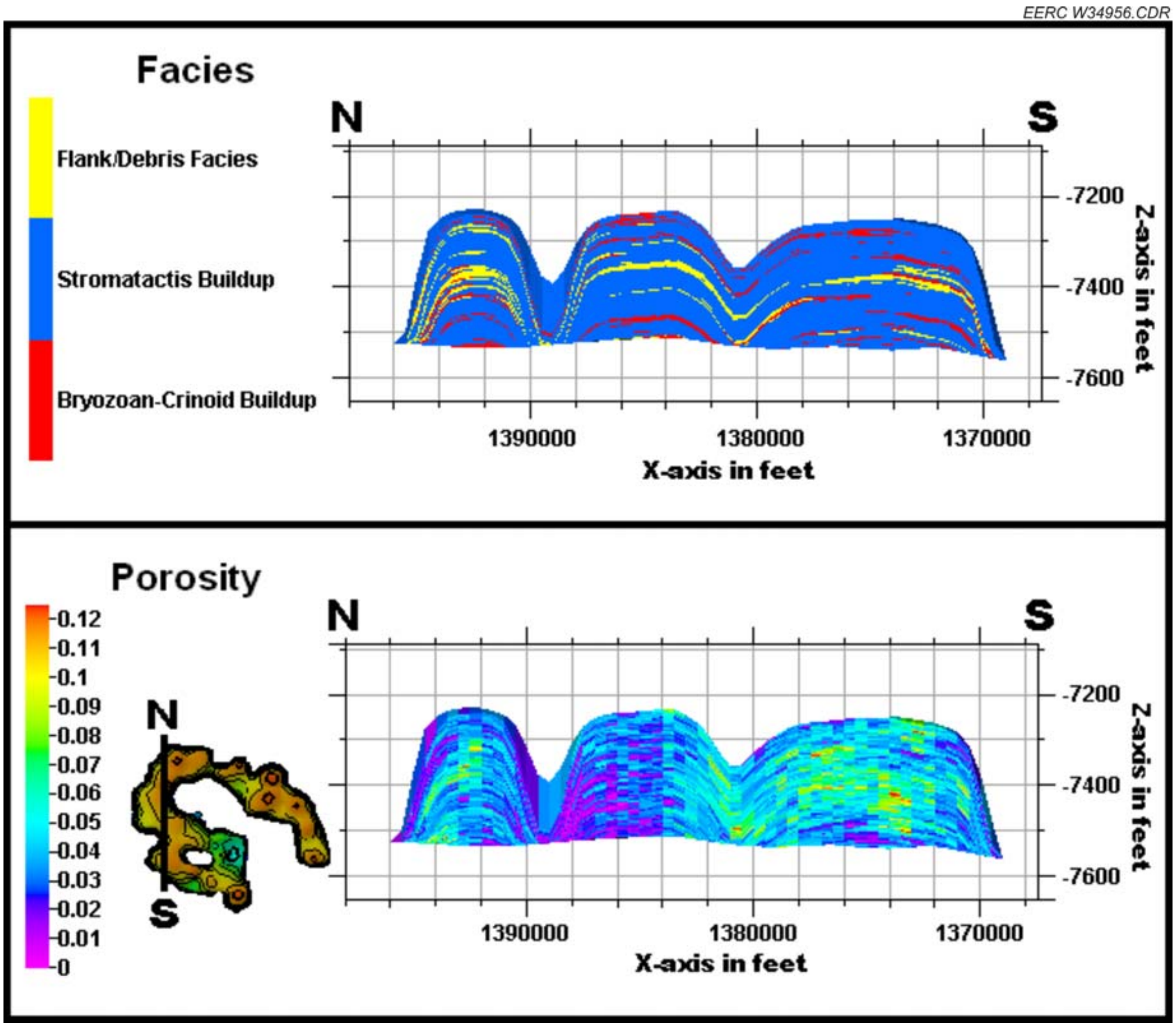

Figure 11. North–south cross sections of a single facies and porosity realization of the DLM (vertical exaggeration is 20×).

from overlying horizons has occurred. This is strong evidence that seals provided by the upper Lodgepole unit are competent enough to prevent vertical migration of fluids (Gorecki et al. 2008). Porosities in the shaly Lodgepole Formation, at least in the vicinity of the mounds, are usually below 2%, with negligible permeabilities. It is evident that the shaly Lodgepole was deposited after the mounds, based on the fact that clay is not present in the mounds, the flank contacts are sharp and clean based on core analysis, and a high degree of differential compaction is observed in the overlying sediments.

Reservoir Properties of the DLM

The base of the DLM lies directly on top of the Bakken shale formation, with porosities and permeabilities similar to the normal Lodgepole Formation. This creates a closed reservoir

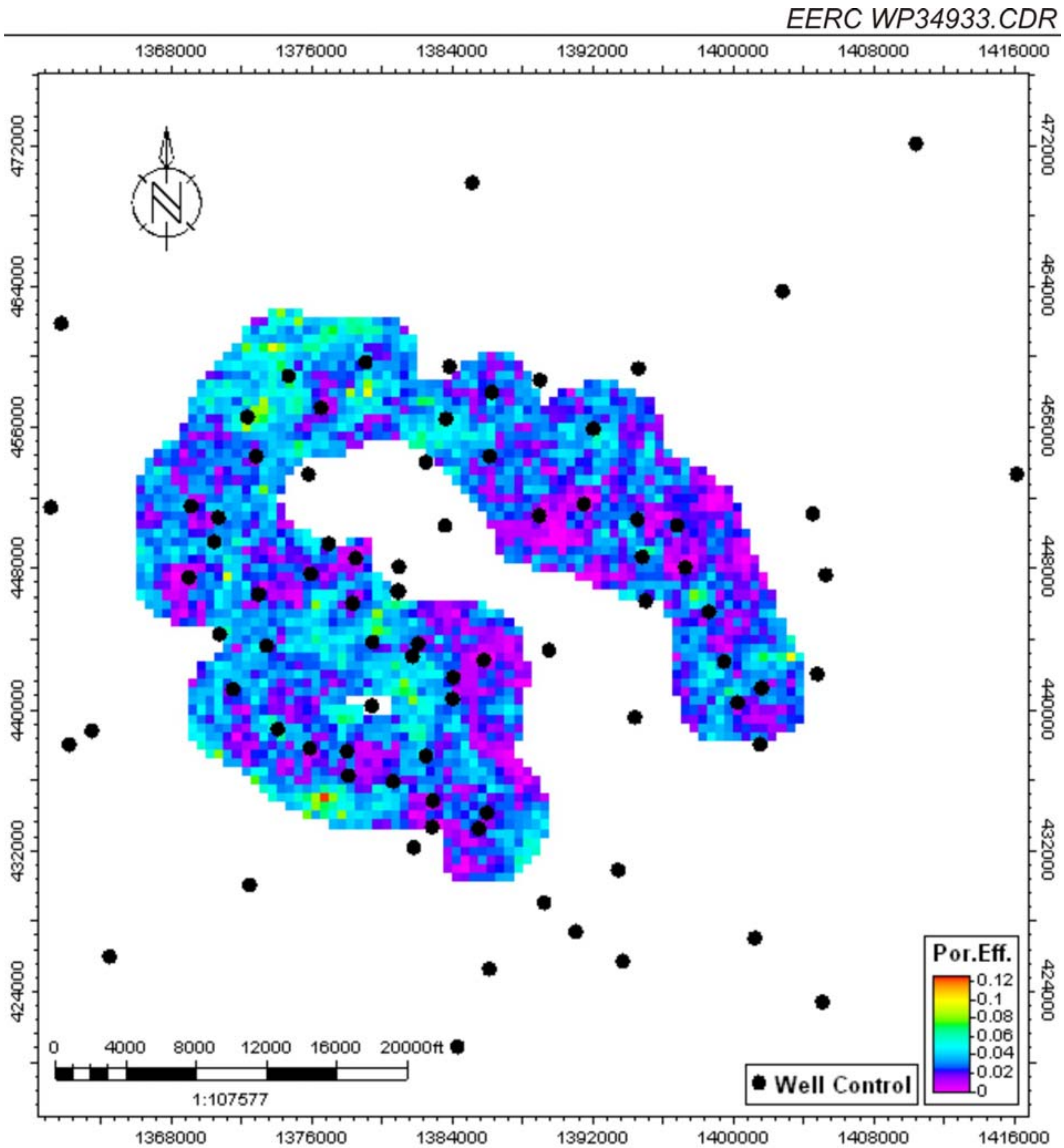

Figure 12. A single-porosity realization of the mounds.

interval or system. The average depth from surface of the DLM is 9800 feet, with the mounds reaching a maximum thickness of 316 feet (Figure 10). Initial reservoir conditions are listed in Table 2. These conditions would ensure that the CO_2 remains in the supercritical state once injected into the reservoir.

Table 2. Reservoir Conditions (rb = reservoir barrels, stb = stock tank barrels)

Play Type	DLM
Mean Initial Pressure	4400 psi
Mean Reservoir Temperature	223°F
Mean Porosity	3.50%
Permeability	2–2000 md
Mean Thickness	85 ft
Salinity of Formation Water	100,000–300,000 ppm (TDS[1])
Mean Bo at Reservoir Pressure	1.32 rb/stb
Mean Bw at Reservoir Pressure	1.04 rb/stb
Minimum Miscibility Pressure	3500 psi
Oil Gravity	44.2 API
Calculated Initial OOIP[2]	82,097,720 rb
Actual Recovery	71,502,140 rb

[1] Total dissolved solids.
[2] Original oil in place.

Incremental Recovery and Potential Storage

Production and injection history (Table 3) from NDIC as well as core analysis from the DLM provided a detailed understanding of the reservoir's petrographic properties, and an analysis of NDIC well files provides a good understanding of formation water quality and rock chemistry. Injection wells currently injecting water into the DLM have an average injection rate of 1900 bbl of water per day (BWPD). The maximum historical injection rate was reported to be 9150 BWPD, which provides some baseline injectivity data for the DLM.

Table 4 demonstrates that OOIP and subsequent incremental oil recovery (IOR) estimates show great potential for the fields as an EOR target. Adjusted OOIP values in Table 4 were calculated based on the modeling conducted in this study and are significantly higher than those reported in the NDIC unitization case files for DLM oil fields. This result was not unexpected because discussions with oil industry partners had indicated that the originally reported OOIP values were thought to be underestimated because of a lack of data in the early years of field development.

Ninety-five percent of the production in the DLM has been from the Eland, Stadium, Dickinson, West Dickinson, and Hiline Fields (Table 5). The average calculated recovery factors based on production history for these fields is 33%. This is a little lower than literature values for the DLM, with recovery factors of approximately 40%, but it is much closer to reality than the recovery factor based on originally reported OOIP values, which approach 87%. In fields similar to the DLM, recovery factors approaching 50% could be achievable with waterflooding, but it would require careful management of the unique structure exhibited by the DLM.

Adjusted OOIP values in Table 5 produced new recovery factors, shown in Table 6. Table 7 provides evidence that there is still much more oil that could be produced, with

Table 3. DLM Cumulative Recoveries to March 2009

	Totals
Oil	55,035,527 stb
Gas	28,443,744 mcf
Total Water	54,662,113 stb
EOR Water Injection	130,004,601 stb

Table 4. DLM Adjusted OOIP and Cumulative Recoveries to March 2009

	P10	P50	P90
Adjusted OOIP, MMrb	209	217	225
Actual Recovery, MMrb	71.5	71.5	71.5
Estimated Current Recovery Factor	0.34	0.33	0.32
Potential IOR Recovery Factor	0.10	0.125	0.15
Potential Incremental Oil Recovered, MMrb	20.9	27	33.8
CO_2 Required, Bcf	104	176	270
CO_2 Required, MM tons	6	10	16

Table 5. DLM Unitized Fields OOIP with Produced Oil per Field (log-normal distribution)

	Bo, FVF	Produced Oil, rb	P10 OOIP, rb	P50 OOIP, rb	P90 OOIP, rb
Eland	1.29	35,737,836	84,676,434	89,986,966	95,630,550
Stadium	1.3468	15,134,556	26,216,469	28,794,982	31,627,128
Dickinson	1.29	8,828,532	18,132,265	22,122,763	26,991,479
West Dickinson	1.29	6,593,364	27,592,508	30,390,859	33,473,010
Hiline	1.3468	2,284,434	20,012,720	22,793,453	25,960,565
Duck Creek	1.29	1,973,842	7,148,901	7,980,276	8,908,335
Versippi	1.347	717,141	8,500,356	9,687,400	11,040,211
Livestock	1.32	276,923	4,459,540	5,356,806	6,434,602
Subdivision	1.36	232,435	4,113,237	5,051,246	6,203,164

Table 6. Estimated Current Recovery Factor Based on OOIP and Production

	P10	P50	P90
Eland	0.42	0.40	0.37
Stadium	0.58	0.53	0.48
Dickinson	0.49	0.40	0.33
West Dickinson	0.24	0.22	0.20
Hiline	0.11	0.10	0.09
Duck Creek	0.28	0.25	0.22
Versippi	0.08	0.07	0.06
Livestock	0.06	0.05	0.04
Subdivision	0.06	0.05	0.04

Table 7. Potential Incremental Oil Recovered (rb)

	P10 @ 0.1 IOR-Rf	P50 @ 0.125 IOR-Rf	P90 @ 0.15 IOR-Rf
Eland	8,467,643	11,248,371	14,344,583
Stadium	2,621,647	3,599,373	4,744,069
Dickinson	1,813,227	2,765,345	4,048,722
West Dickinson	2,759,251	3,798,857	5,020,952
Hiline	2,001,272	2,849,182	3,894,085
Duck Creek	714,890	997,535	1,336,250
Versippi	850,036	1,210,925	1,656,032
Livestock	445,954	669,601	965,190
Subdivision	411,324	631,406	930,475

confidence in the top five producing fields, Eland, Stadium, Hiline, Dickinson, and West Dickinson, with CO_2 incremental EOR.

The estimated amounts of CO_2 required are given in millions of cubic feet (Table 8) and in tons (Table 9) necessary for CO_2-based EOR on this scale. Volume of CO_2 required was calculated for a range of recovery factors from 10% to 15%, using the equation:

$$V_{CO2r} = OOIP * R_f * \frac{V_{CO2}}{V_{oil}}$$

where V_{CO2r} is the necessary volume of CO_2 to achieve EOR potential (in Mscf), R_f is the expected recovery factor of the IOR (in %, ranging from 10% to 15%), and V_{CO2}/V_{oil} is the ratio of CO_2 injected to oil produced (Mcf/stb, ranging from 5000 to 8000).

Table 8. DLM Unitized Fields CO_2 Volume Required for EOR

	P10 CO_2 Required, Mcf	P50 CO_2 Required, Mcf	P90 CO_2 Required, Mcf
Eland	42,338,217	73,114,410	114,756,660
Stadium	13,108,235	23,395,923	37,952,554
Dickinson	9,066,133	17,974,745	32,389,775
West Dickinson	13,796,254	24,692,573	40,167,612
Hiline	10,006,360	18,519,681	31,152,678
Duck Creek	3,574,451	6,483,974	10,690,002
Versippi	4,250,178	7,871,013	13,248,253
Livestock	2,229,770	4,352,405	7,721,522
Subdivision	2,056,619	4,104,137	7,443,797

Table 9. DLM Unitized Fields CO_2 Mass Required for EOR*

	P10 CO_2 Required, tons	P50 CO_2 Required, tons	P90 CO_2 Required, tons
Eland	2,454,982	4,239,539	6,654,165
Stadium	760,081	1,356,613	2,200,679
Dickinson	525,700	1,042,266	1,878,121
West Dickinson	799,976	1,431,799	2,329,119
Hiline	580,219	1,073,864	1,806,388
Duck Creek	207,265	375,973	619,860
Versippi	246,447	456,401	768,200
Livestock	129,293	252,374	447,732
Subdivision	119,253	237,978	431,629

* Using conversion factor from U.S. Department of Energy Energy Information Administration (2000).

CONCLUSIONS

Phase I characterization activities of the PCOR Partnership concluded that approximately 550 million tons of CO_2 is emitted from large stationary sources each year in the region. The region also possesses numerous opportunities for CCS in depleted oil and gas reservoirs, deep saline aquifers, unminable coal seams, and for CO_2 EOR.

A model was produced showing the DLM as a composite mud ridge, and the mounds were examined and compared to similar structures from around the world. The model was used to calculate OOIP estimates that better represent the current and historical data available.

In order to maintain reservoir pressure within the DLM reservoirs, waterflooding was commenced soon after discovery. From 2003 to the present, only one field has reported reservoir pressures to NDIC, making it difficult to come to a conclusion regarding non-EOR bulk CO_2 storage potential; however, many of the wells are still producing quite well albeit with a high water cut.

The DLM have been identified as having a high potential for CO_2 EOR, with estimated incremental recovery in the 21-million to 34-million-barrel range, and associated storage of 6 to 15 million tons of CO_2. It is important to note that estimates of potential incremental recovery are based on the adjusted OOIP values in this study from publicly available data. Much data such as seismic and pressure history have not been released and were not used in this report. Seismic and more precise pressure history data would allow for a better history match and more accurate estimates. Based on the results of the modeling efforts in this study, and considering the fact that the oil production reported for many of the DLM fields is already in excess of 50% of the publicly available reported OOIP values, it is highly likely that the actual OOIP of these fields is much higher than previously reported. With respect to the potential value of the DLM for large-scale, long-term CO_2 storage, post-EOR storage of CO_2 within the reservoir would be sensible, as the possibility of leakage is remote because of the reservoir's closed nature and numerous proven cap rocks. It is also worth noting that water injection volumes have surpassed the volume of produced fluid, which suggests that the mounds may be larger than previously characterized. Together, these results indicate that the DLM fields are excellent targets for both CO_2-based EOR operations and associated long-term storage of large volumes of CO_2.

With respect to future work on the DLM, prior to injection, additional dynamic injection simulation with multiple point statistics (MPS) history matching should be done to maximize EOR and CO_2 storage efficiency and risk management.

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