PRAIRIE HORIZON CARBON MANAGEMENT HUB

Final Report

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EXECUTIVE SUMMARY

The Energy & Environmental Research Center (EERC), with support from the North Dakota Industrial Commission and the U.S. Department of Energy, evaluated the potential for the development of a large-scale carbon management hub (CMH) in Stark County, North Dakota. The objective of the Prairie Horizon CMH project is to build public confidence to benefit and accelerate commercial carbon capture, utilization, and storage (CCUS) deployment. Findings from this investigation can facilitate project development by informing early-stage decision-making related to site selection, stakeholder engagement, understanding risks, and permitting readiness.

Project objectives were accomplished by identifying and addressing technical and nontechnical challenges, evaluating legal and regulatory frameworks, and facilitating stakeholder engagement. Countywide screening included an evaluation of legacy wellbores, potential carbon dioxide (CO_2) pipeline routing using existing rights-of-way (ROWs), a high-level risk assessment using a township-level spatial criteria approach, and a public opinion survey on CCUS. Regulatory implications were also considered with an emphasis on the federal subsurface leasing process and North Dakota's policies and regulations related to competing subsurface pore space use.

To assist project planners, operators, and other stakeholders, a framework was developed to evaluate four essential project feasibility categories: technical, financial, regulatory, and social. By using this framework, project risks can be identified within each feasibility category. A high-level risk assessment of these categories in the context of a potential future Stark County CMH can inform CCUS site selection with technical and nontechnical risks being identified. Risk scoring across Stark County shows relatively little variation, with southern and eastern Stark County townships showing favorable conditions for dedicated storage and central Stark County showing a prime opportunity to advance CCUS through CO_2 enhanced oil recovery (EOR). Project development advantages across the county include an active carbon capture and storage (CCS) project, low population density, existing ROWs, active oil and gas development, and proximity to infrastructure, all of which may reduce permitting and public engagement issues. A comprehensive analysis of the public opinion survey across Stark County reveals that, although there are some concerns with dedicated storage, the overall perspective is neutral to positive with overwhelming support for CO_2 EOR.

Site screening and feasibility activities were structured into an assessment table to help project developers determine project maturity in terms of site readiness. For this project, site readiness is based on development progress toward final project design and submission of a compliant injection permit application. This site readiness assessment is a guide for developers to track progress and identify gaps in the early stages of project development to facilitate CCUS deployment.

In Stark County, the Inyan Kara and Broom Creek Formations present strong prospects for dedicated storage in deep saline formations. To date, the Gevo North Dakota ethanol plant near

Richardton, North Dakota, has injected 577,485 tonnes of captured CO_2 into the Broom Creek Formation for dedicated storage. The Dickinson Lodgepole Mounds (DLM), a horseshoe-shaped series of oil fields in central Stark County, offer an intriguing opportunity for CO_2 EOR, with estimated incremental recovery of 21–34 million barrels of oil and associated storage of 6–15 million tonnes of CO_2. These positive factors for future CCUS and the active CO_2 storage project associated with the Gevo North Dakota ethanol plant in the county's northeast corner suggest ideal conditions to advance future additional CO_2 storage site development in Stark County. Project planners and developers can use lessons from this project to inform early-stage decision-making and facilitate CCUS deployment in Stark County.

The key lessons learned and knowledge gaps addressed from the Prairie Horizon CMH are:

- Stark County is well-positioned for future CCUS deployment, all that remains are the commercial drivers and private sector investment to bring CO_2 to this region.

- Timelines for site selection, feasibility, and permit development can be improved by following established methodologies for CCUS evaluation.

- Stark County has infrastructure advantages with existing pipeline ROW that may expediate the regulatory siting and permitting, offering existing transportation corridors for CO_2 delivery to a future dedicated storage location or the DLM.

- Dedicated CO_2 storage project planners should avoid geologic formations near active oil and gas development that may compete with subsurface pressure space, specifically saltwater disposal in the Inyan Kara Formation.

- The U.S. Bureau of Land Management (BLM) has two distinct regulatory procedures for CO_2 storage on public lands, utilizing a ROW grant process for dedicated storage and a leasing process for associated storage. However, rent schedules for pore space use have not yet been defined, delaying the issuing of final ROW approvals.

- Public opinion survey participants in Stark County are generally divided in their opinion on CCS for dedicated storage; however, those participants indicate strong (greater than 80%) support for CO_2 EOR.

PRAIRIE HORIZON CARBON MANAGEMENT HUB

INTRODUCTION AND OBJECTIVES

The Energy & Environmental Research Center (EERC) at the University of North Dakota, along with support from North Dakota Industrial Commission (NDIC) through the North Dakota Renewable Energy Program and the U.S. Department of Energy (DOE) National Energy Technology Laboratory, evaluated the potential for the development of a prospective regional carbon management hub (CMH) in Stark County, North Dakota (Figure 1). The objective of the Prairie Horizon CMH project is to build public confidence to benefit and accelerate commercial development of carbon capture, utilization, and storage (CCUS) in the region.

The project team conducted three main activities to 1) address technical and nontechnical challenges by investigating key issues influencing project feasibility, risk, legacy well integrity, carbon dioxide (CO_2) pipeline right-of-way (ROW), and site readiness; 2) evaluate legal and regulatory frameworks, with an emphasis on the federal subsurface leasing process and North Dakota's policies and regulations related to competing subsurface pore space use; and 3) engage stakeholders and develop outreach and education materials related to carbon management. Project developers can use the products from these efforts to facilitate and inform early-stage decision-making related to site selection, stakeholder engagement, risk management, and permitting readiness.

For this project, the storage portion of a regional CMH is defined as a localized geographic area of interest (ideally <300 mi^2) with sufficient geologic storage resource in one or more geologic formations to store up to 50 million tonnes (MMt) of CO_2 in a 30-year period. "Hub" is used in this context to mean that the CO_2 could be supplied by more than one capture source. However, no specific source or group of sources was identified or contemplated other than an assumed cumulative CO_2 mass of 50 MMt to be stored.

STORAGE RESOURCE

Stark County lies within the southern portion of the Williston Basin, a large, well-studied sedimentary basin containing several formations suitable for long-term storage of CO_2 (Peck and others, 2021). Two prime examples are the Inyan Kara and Broom Creek Formations, both deep saline sandstone formations with no hydrocarbon accumulation. Based on prior characterization work performed by the EERC on the Broom Creek Formation, 50 MMt of CO_2 could likely be stored in Stark County in an area no larger than 15 mi^2 over an injection period of 30 years. In addition, the Dickinson Lodgepole Mounds (DLM) in central Stark County were identified in 2008 as having a high potential for CO_2 enhanced oil recovery (EOR), with associated storage of 6–15 MMt of CO_2 (Knudsen and others, 2009).

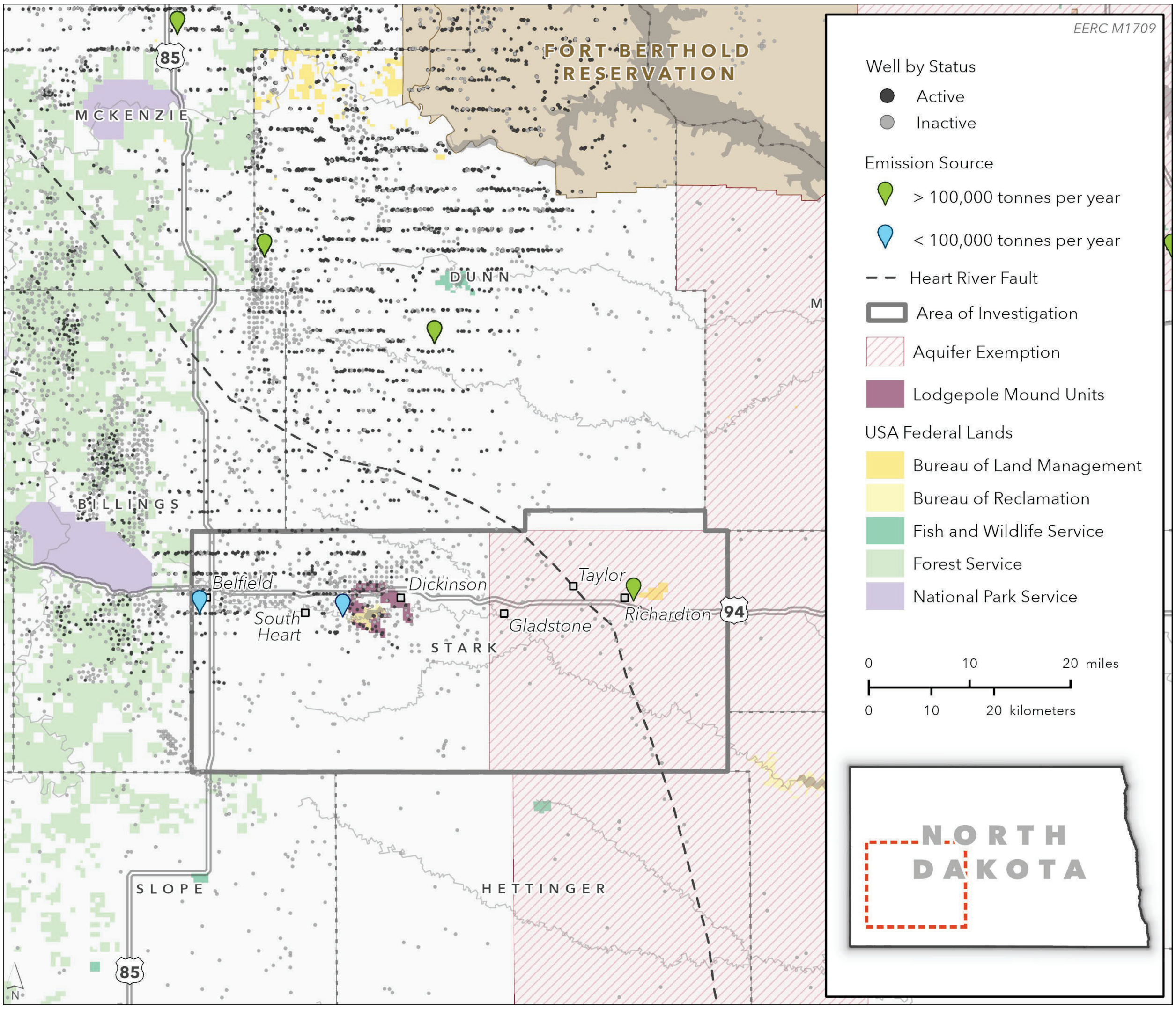

Figure 1. Map of the carbon management hub area of interest in Stark County, southwestern North Dakota.

Target Storage Complexes in Stark County

The stratigraphy of the Williston Basin, particularly in relation to CO_2 storage, has been extensively studied through research led by the Plains CO_2 Reduction (PCOR) Partnership. Figure 2 shows a generalized stratigraphic column representative of the geology underlying Stark County. This work focused on three target storage complexes—the Inyan Kara Formation, Broom Creek Formation, and Lodgepole Mounds—as strong candidates for long-term CO_2 storage. Their suitability is due to a thick sequence of clastic and carbonate sedimentary rocks, subtle structural

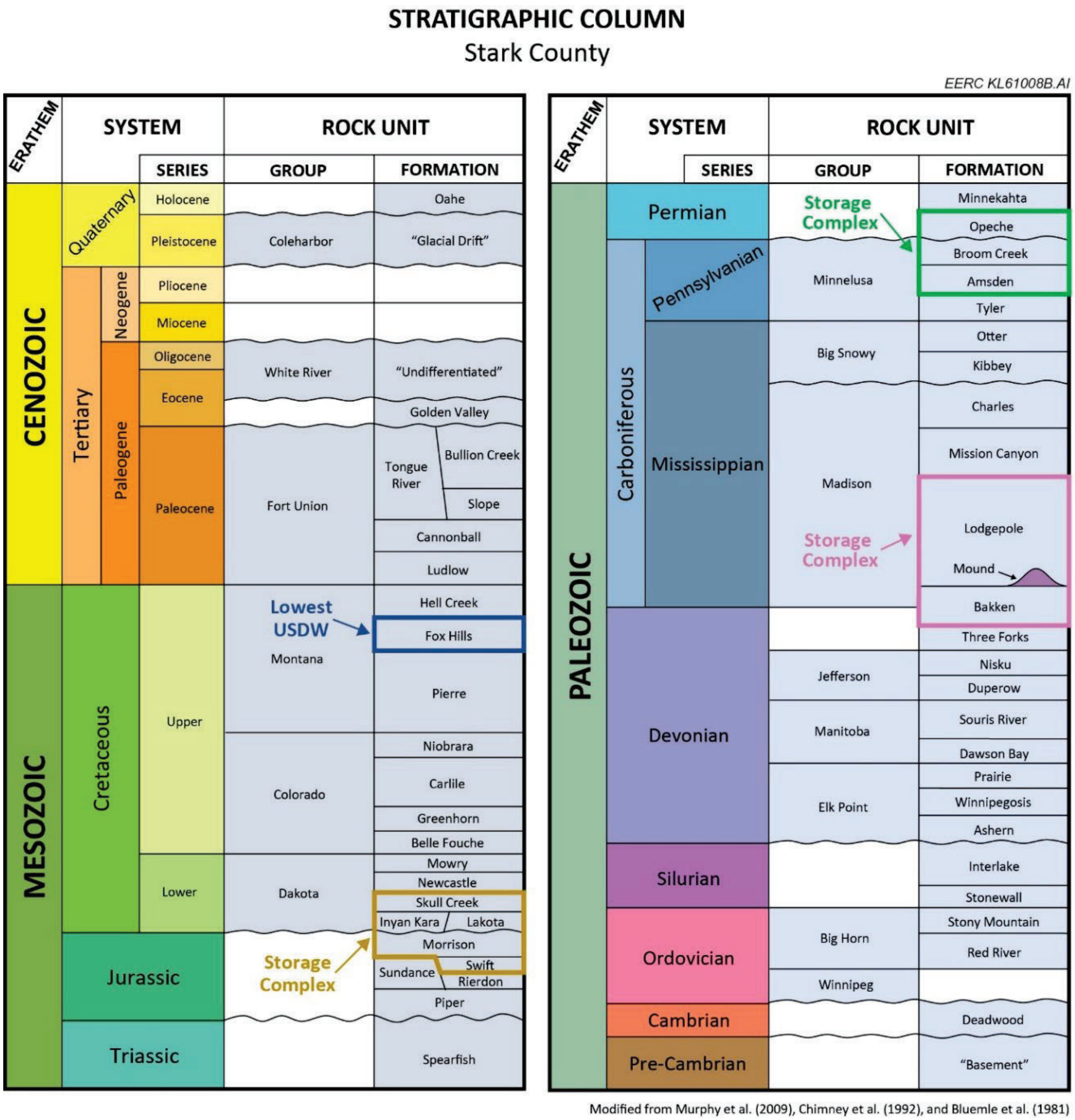

Figure 2. Generalized stratigraphy for Stark County illustrating storage complexes around the Inyan Kara Formation, Broom Creek Formation, and Lodgepole Mounds injection zones.

features, and regional tectonic stability (Peck and others, 2024). The three CO_2 storage complexes are defined as follows:

- **Inyan Kara Storage Complex:** Includes the Skull Creek Formation as the primary confining layer, the Inyan Kara Formation as the injection zone, and the Swift Formation as the underlying confining zone.

- **Broom Creek Storage Complex:** Includes the Opeche Formation as the primary confining layer, the Broom Creek Formation as the injection zone, and the Amsden Formation as the underlying confining zone.

- **Lodgepole Mounds Complex (Madison Group):** Includes the Lodgepole Formation as the primary confining layer, the Lodgepole Mounds as the injection zone, and the Bakken Formation as the underlying confining zone.

The region's lowermost underground source of drinking water (USDW) is Fox Hills Formation. Key features of these three storage complexes that make them ideal for CO_2 storage include:

- Approximately 3000 feet of successive shale intervals provide impermeable rock formations between the Inyan Kara Formation and the Fox Hills aquifer (lowermost USDW).

- Approximately 1200 feet of impermeable rock formations overlying the Opeche Formation before the next porous zone.

- The domelike configuration of the various Lodgepole Mounds, which provides exceptional storage efficiency and containment.

Active Carbon Capture and Storage

Notably, the first Underground Injection Control (UIC) Class VI (dedicated storage) project in North Dakota is in northeastern Stark County near Richardton, North Dakota. The Gevo North Dakota ethanal plant began carbon capture and storage (CCS) operations in June 2022 and has since captured and stored, via Class VI injection well, 577,485 tonnes of CO_2 into the Broom Creek Formation.

CO_2 EOR Opportunity

The DLM, a horseshoe-shaped series of oil fields in central Stark County, offers an intriguing opportunity for CO_2 EOR (UIC Class II), with estimated incremental recovery of 21–34 million barrels of oil and associated storage of 6–15 MMt of CO_2. The DLM represent one of the most significant oil plays within the Lower Mississippian Lodgepole Formation of the Williston Basin. Among the various fields developed in this play, the Eland Field stands out as the most productive, yielding tens of millions of barrels of oil since its discovery. Production at the Eland Field went through primary depletion and, later, an extensive waterflooding program which maintained reservoir pressure and supported recovery. Previous studies have identified the DLM as having high potential for CO_2 EOR and associated storage (Gorecki and others, 2008; Knudsen and others, 2009; Zhao and others, 2020). Given the long production history and current waterflood maturity, the Eland Field is a strong candidate for CO_2 EOR.

The project team assessed the feasibility and potential effectiveness of EOR using CO_2 injection in the Eland Field. The investigation combined reservoir characterization analysis, historical production and waterflood performance analysis, and early-stage predictive simulation by developing a section model in a highly productive area within Eland Field where a potential new well will be drilled. The incremental oil recovery, CO_2 utilization efficiency, and amount of CO_2 stored associated with EOR were estimated. The results of this work are in Appendix A of this report.

TECHNICAL AND NONTECHNICAL CHALLENGES

Risk Assessment

Identified as the primary targets for dedicated storage in Stark County, the Inyan Kara and Broom Creek Formations were the basis for a high-level risk assessment. The project team applied a structured risk management framework to evaluate how these formations could support a storage hub. A screening-level risk assessment was designed to identify technical and nontechnical challenges that could influence the development of large-scale CCUS in Stark County as part of a regional feasibility study.

The project team developed a set of criteria that could influence the Class VI permitting process for CO_2 storage (Table 1). These criteria reflect factors that may add significant cost or time to the storage facility permit (SFP) application or reduce the likelihood of permit approval. Subject matter experts helped establish the criteria based on experience with similar projects in North Dakota. The team gathered and analyzed available data at different spatial scales to inform criteria scoring. Because the data varied in resolution, the team aggregated the information and mapped it across Stark County townships. This approach provided a consistent framework for comparing criteria across the county and identifying where permitting challenges may be more likely.

Table 1. Selected Risk Criteria

Distance from a City	Inyan Kara Storage Resource
Landowner Count/Diversity	Broom Creek Legacy Well Penetrations
Existing ROWs	Broom Creek Control Well Availability
Inyan Kara Legacy Well Penetrations	Broom Creek Storage Resource
Inyan Kara Saltwater Disposal Well Density	Seismic Data Availability
Inyan Kara Aquifer Exemption Area	Faults and Fractures
Inyan Kara Control Well Availability	

This assessment generally followed the risk management framework outlined in International Organization for Standardization (ISO) 31000 (International Organization for Standardization, 2009), which includes establishing the risk assessment context and identifying, analyzing, and evaluating risks. However, we adapted the process to broadly identifying permitting challenges across the county. Instead of scoring individual risks in detail, we identified the key criteria most relevant to the SFP process, assessed their importance, and applied a ranking score. This approach remains consistent with ISO principles and adaptations specific to conducting subsurface technical risk assessments of geologic CO_2 storage projects (Canadian Standards Association, 2012; Azzolina and others, 2017; International Organization for Standardization, 2017; Finnigan and others, 2022) while tailoring the method to the practical needs of this project.

For the CMH project, neither specific industrial CO_2 sources nor exact storage sites were identified. As a result, detailed injection scenarios were not evaluated in this screening-level risk assessment. Instead, township-level data for the three target storage complexes—the Inyan Kara Formation, Broom Creek Formation, and Lodgepole Mounds—were aggregated and mapped across Stark County to highlight areas with relatively higher or lower storage potential. These high-level assessments informed the scoring criteria used in the risk evaluation.

The Inyan Kara and Broom Creek Formations were treated as continuous storage resources across the county. In contrast, the Lodgepole Mounds are limited to four townships near the city of Dickinson and were evaluated separately as a localized storage complex.

Stark County is subdivided into townships 137–140 and ranges 91–99, creating 36 square-mile polygons for the risk assessment. Risk criteria scores were mapped to each township, and heat maps were generated to visualize how individual criteria and their unweighted and weighted sums varied across the county. Based on the available data, the risk criteria were scored 1 (worst), 3 (moderate), or 5 (best). Therefore, the lowest possible score was 13 (13 × 1), and the highest was 65 (13 × 5).

Figure 3 shows the composite scores across all 13 nontechnical and technical risk criteria. Composite scores across Stark County show relatively little variation, with all townships falling between 33 and 55. The highest-scoring township (T138R98, score of 51) is in the southwest portion of the county, while the lowest (T140R93, score of 33) is in the northwest.

The northwest quadrant consistently ranks lowest, driven by dense legacy wells, clusters of saltwater disposal (SWD) wells, and lower storage resource. The eastern edge also shows lower scores, reflecting geologic risks tied to the Heart River Fault. In contrast, the central corridor and southeastern townships score the highest (approaching 55 out of 65), benefiting from fewer legacy wells and greater storage resource.

The composite scores and heat maps assume that all 13 risk criteria equally influence permitting cost, timelines, and approval. In reality, some factors may matter more than others. For example, SWD well density or whether a site lies inside the Inyan Kara aquifer exemption may have a greater impact than data availability or storage resource quartile. In future assessments, weights could reflect these differences based on the operator's risk tolerance and site-specific

Figure 3. Heat maps showing Stark County and the 36 townships (Townships 137–140, Ranges 91–99) used in the risk assessment. Top map color-coded worst (1, dark blue), moderate (3, yellow), or best (5, dark orange) based on the composite scores incorporating all 13 nontechnical and technical risk criteria. Bottom map color-coded green for the top 10 composite scores and red for the bottom 10 composite scores.

conditions. This assessment presents only unweighted composite scores because no project-specific priorities are defined.

Not all criteria contribute equally to these patterns. The most influential factors are legacy well density, SWD density, and aquifer exemption status, which sharply distinguish high- and low-scoring areas. Moderate differentiation comes from storage resource and nontechnical risk criteria like landowner diversity and distance from cities, while seismic coverage and existing ROWs add relatively little variation because they are favorable across most of the county.

Together, these results point to the central and southeastern portions of Stark County as the most promising candidates for Class VI permitting and long-term CO_2 storage, while development in the northwest and eastern edges would require additional data, potential corrective measures, and possibly more complex permitting strategies, potentially adding cost and time to the SFP process. The Lodgepole Mounds, because of their long history of hydrocarbon trapping, multiple proven sealing formations, strong injectivity, and extensive prior characterization, represent a well-understood and geologically secure option for CO_2 EOR and long-term CO_2 storage.

Legacy Well Integrity

Wellbores created during oil and gas exploration and production represent one of the primary risks for CO_2 migration out of a storage formation. To address this risk and as part of the regulatory permitting process, developers must define an area of review (AOR) and evaluate the integrity of all wellbores that penetrate the reservoir or its upper seal within that boundary.

A formal AOR for Class VI permitting is typically established through dynamic simulation of CO_2 injection, which predicts the region surrounding the injection site where free-phase CO_2 may migrate or where reservoir pressure could rise above a critical threshold. Such pressure increases can create pathways for brine to move upward through a wellbore to the lowest USDW. Wells within or near these zones are considered higher risk and may require remediation. In many cases, remediation must be completed before injection to meet permitting requirements. However, wells not expected to be affected for several years may be addressed later through a staged remediation approach. During the early stages of a regional feasibility study, however, the framework for dynamic simulation is often not yet in place, meaning that no formal AOR has been defined. To avoid confusion with the regulatory term, this report instead uses the phrase area of investigation (AOI).

The first step in a wellbore review is to gather essential information about all wellbores within the assessment area, including their locations and status—active, temporarily abandoned, or plugged and abandoned. Figure 4 shows the distribution of existing wellbores in Stark County. For each wellbore, additional details are collected and analyzed, such as total depth drilled, completion type (open hole or cased hole), casing sizes and lengths, cementing records, and plugging data. In North Dakota, this information is typically compiled from reports available through the North Dakota Department of Mineral Resources. Plugging data receives particular attention, with the review focusing on formation tops, wellbore type, bit sizes, the number of cement sacks per plug, plug depth intervals, perforations, and the use of plugging tools such as cast-iron bridge plugs and cement retainers. Understanding the vintage of wells is also important when evaluating risks in an AOI. For example, regulatory changes in North Dakota mean that wells drilled after 1980 are more likely to have surface casing depths extending below the USDW, creating an important barrier that prevents fluid migration between the proposed injection zone and the USDW. Figure 5 illustrates the age distribution of wellbores in Stark County based on spud date (the year drilling began).

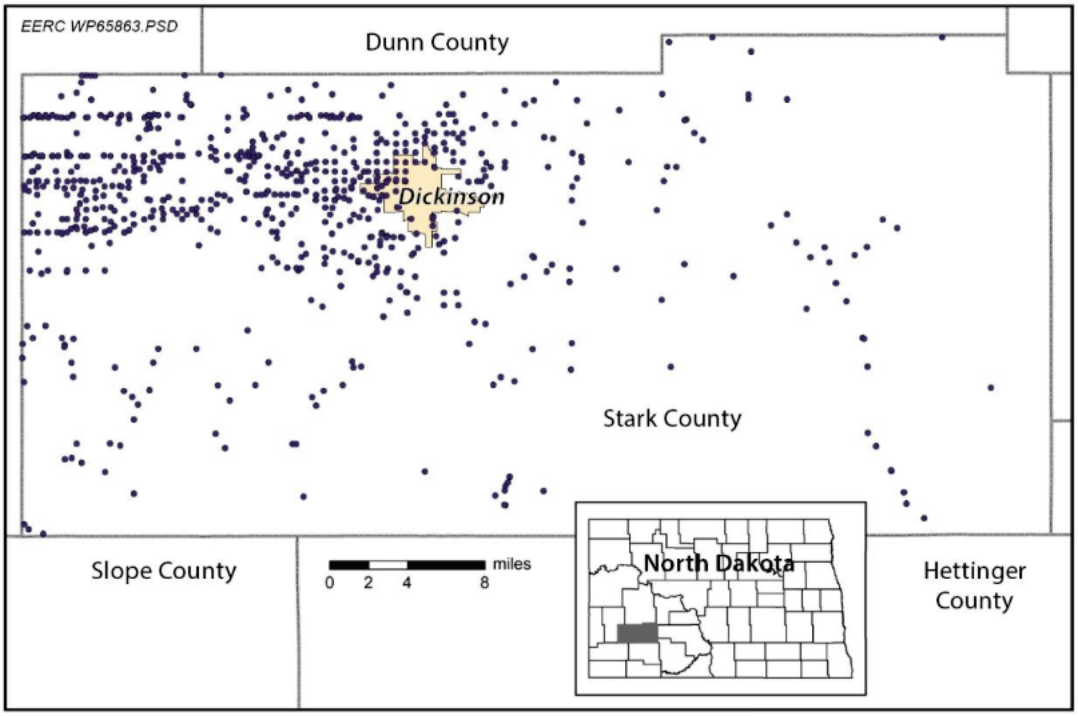

Figure 4. Distribution of existing wellbores in Stark County, North Dakota.

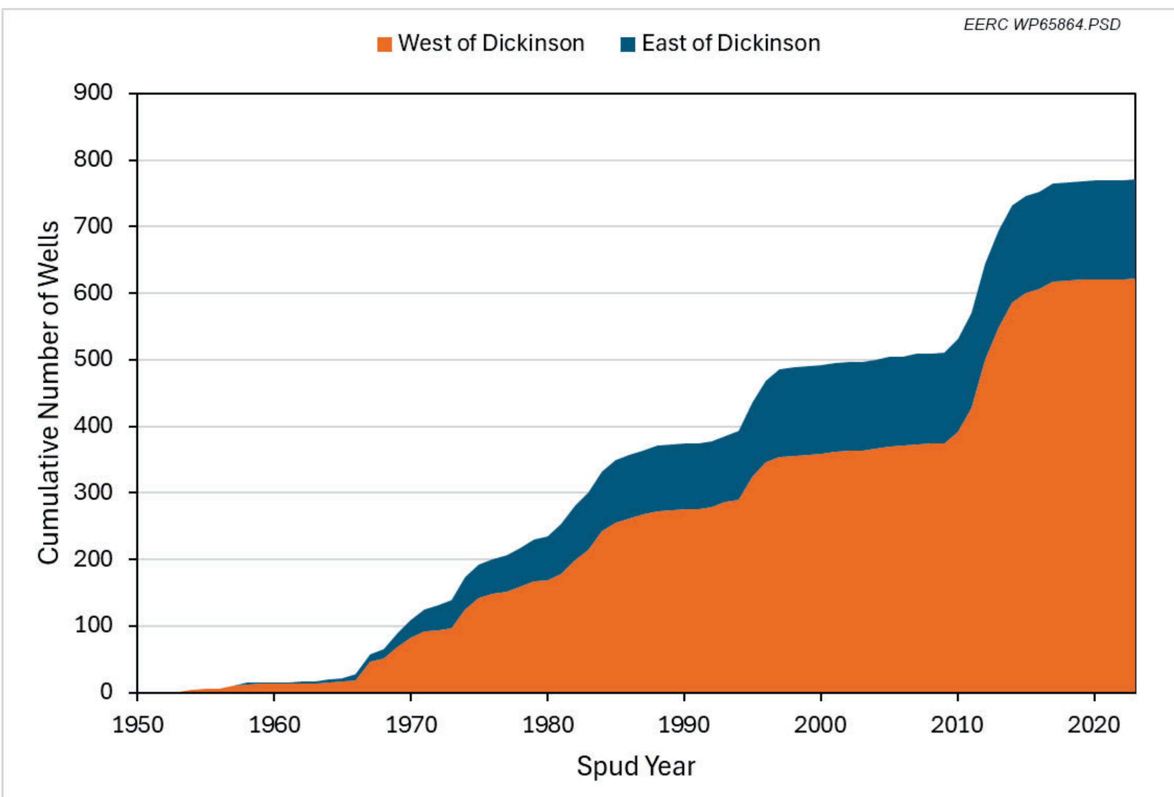

Figure 5. Vintage distribution of wells in Stark County, North Dakota.

Once plug top and bottom depths are identified or calculated, well logs are reviewed to confirm the formations in which plugs are set and the zones they isolate. With plug intervals verified, the review applies a three-tier stoplight ranking to highlight potential risks of fluid migration outside the proposed injection zone (Figure 6). A low-risk qualification is green to indicate mitigation of fluid migration from injection outside of the injection reservoir and into the USDW. A moderate-risk qualification is yellow to indicate the risk of fluid migration outside of the injection reservoir, but fluid is isolated from entering the USDW. Finally, a high-risk qualification is red to indicate the risk of fluid migration to the USDW.

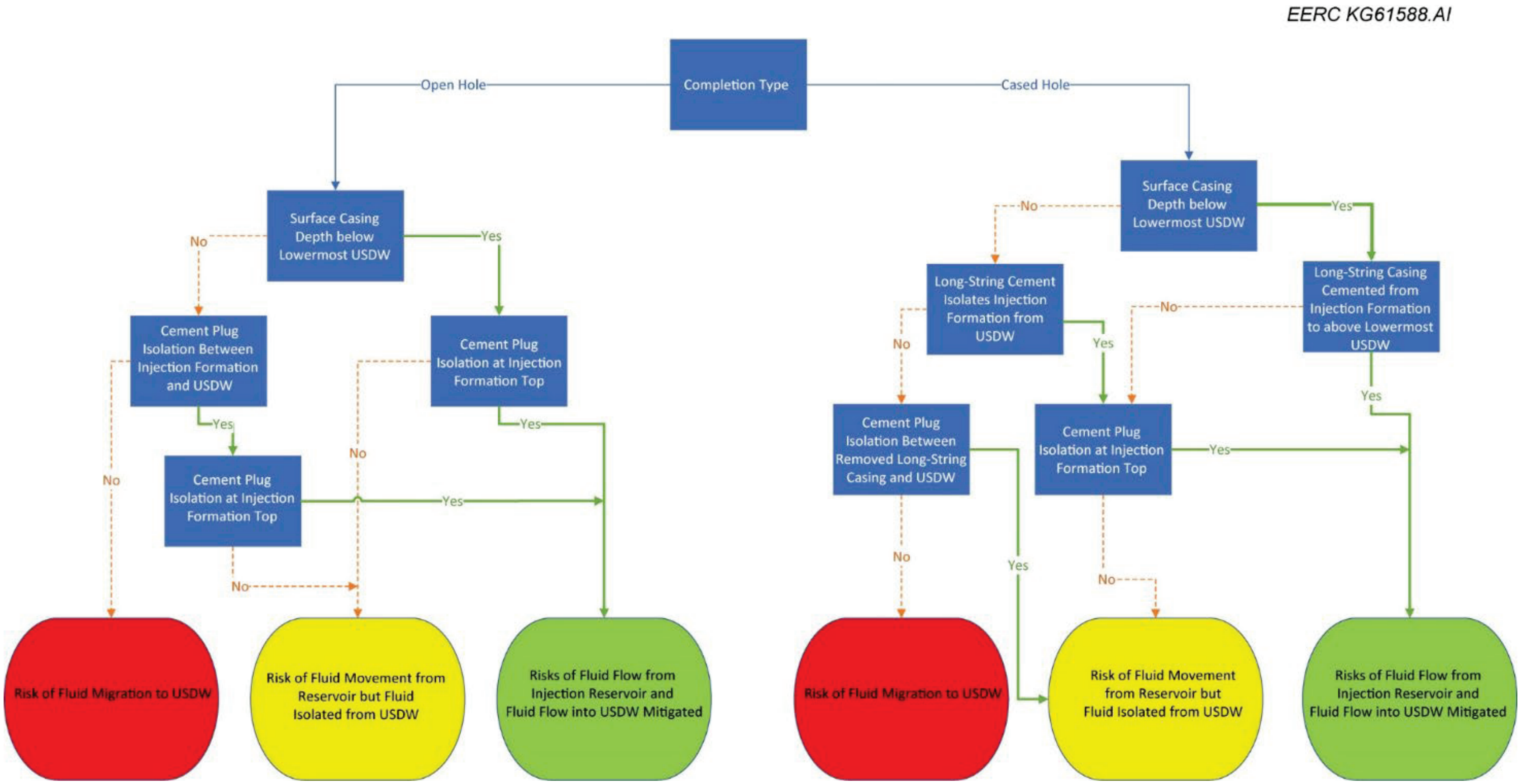

Figure 6. Wellbore evaluation and risk categorization process.

Low Risk

Wells are low-risk (green) when cement plugs are properly placed across the entire injection zone—in this case, the Broom Creek Formation—from the upper confining Opeche Formation to the lower confining Amsden Formation, as shown in Well 3 of Figure 7. In other cases, a plug across the top of the Broom Creek Formation seals its upper permeable section, preventing vertical fluid migration into overlying formations such as the Inyan Kara, illustrated as Well 1 in Figure 7.

Other features that strengthen well integrity and support isolation of the Broom Creek injection zone from the USDW include surface casing set below the base of the USDW and the presence of an intermediate casing string, which provides an additional protective barrier.

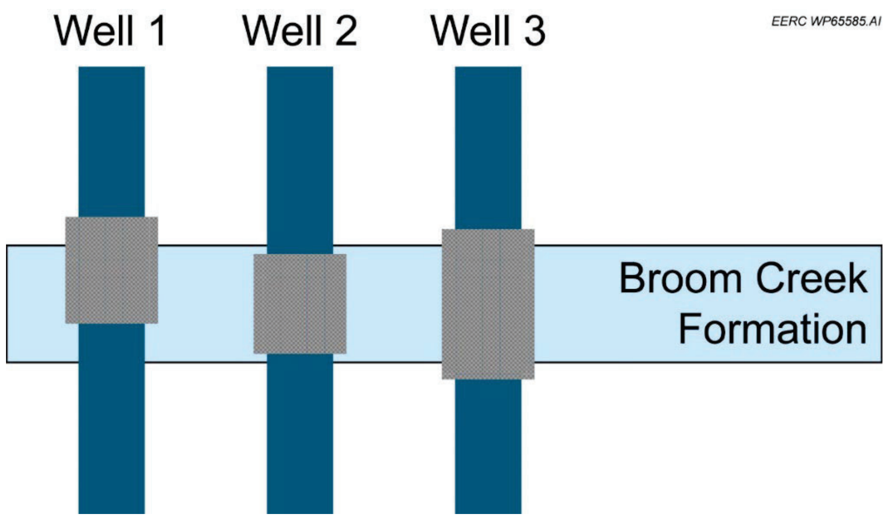

Figure 7. Schematic of three different cement-plugging configurations in wells penetrating the Broom Creek Formation—plug across the top of the formation, plug within the formation, and plug across the entire formation—illustrating varying degrees of isolation and containment of the proposed injection zone.

Moderate Risk

The primary reasons for the moderate-risk (yellow) qualification in this example include:

- Lack of isolation at the top of the proposed injection zone (Broom Creek Formation), with the first plug above the proposed injection zone set in shallower formations, such as the Inyan Kara, Rierdon, or Spearfish, potentially allowing communication with any overlying permeable zones between the Broom Creek Formation and the first plug (Well 1 of Figure 8).

- Surface casing not extending below the top of the Pierre Formation, potentially compromising the isolation of the USDW, or a plug not completely covering the top of the Inyan Kara Formation, although the permeable sections of the Inyan Kara Formation may still be isolated based on log analysis (Well 2 of Figure 8).

- Lack of plugs between the Inyan Kara and Broom Creek Formations, allowing potential communication between the two formations (Well 3 of Figure 8).

- No plug at the Broom Creek Formation and no plug between the Inyan Kara and Broom Creek Formations, allowing potential communication between the two (Well 4 of Figure 8).

- Inadequate plug coverage of the top of the Broom Creek Formation (the plug is *within* the formation, as shown in Well 5 of Figure 8). This configuration requires further confirmation to determine if the permeable portion of the formation is covered.

- Insufficient information regarding the cement top of the intermediate casing, making the Inyan Kara Formation's isolation difficult to confirm (Well 6 of Figure 8).

- No plug at or between the Inyan Kara and the Broom Creek Formations, allowing communication between the two. See NDIC Well File No. 6476 (Well 7 of Figure 8).

Wellbores with a moderate risk of fluid migration from the proposed injection zone to other permeable formations may, however, have minimal risk for direct migration of fluids into the lowest USDW. Therefore, upon further investigation, many moderate-risk wellbores will likely be low-risk. For instance, some wells may have plugs that do not extend to the top of the Inyan Kara Formation but do isolate its permeable zones. A more detailed well-log interpretation can help eliminate many of the identified issues by confirming that the permeable zones are adequately isolated with cement plugs.

High Risk

Wellbores with a high risk (red) of fluid migration from the proposed injection zone into the USDW typically do not have proper isolation in more than one area of the wellbore. This circumstance can occur when the surface casing does not extend below the lowest USDW (the Fox Hills in the examples herein) in combination with either of the following: 1) the wellbore does not have either good or full cement placement along the long-string casing section of the wellbore, or 2) no plugs are between the injection formation and the lowest USDW.

Although wellbore integrity evaluations and remediation can be complex and costly, they are essential to maintaining proper containment. Effective management of these risks ensures that CCS operations proceed safely and without environmental impacts from CO_2 injection.

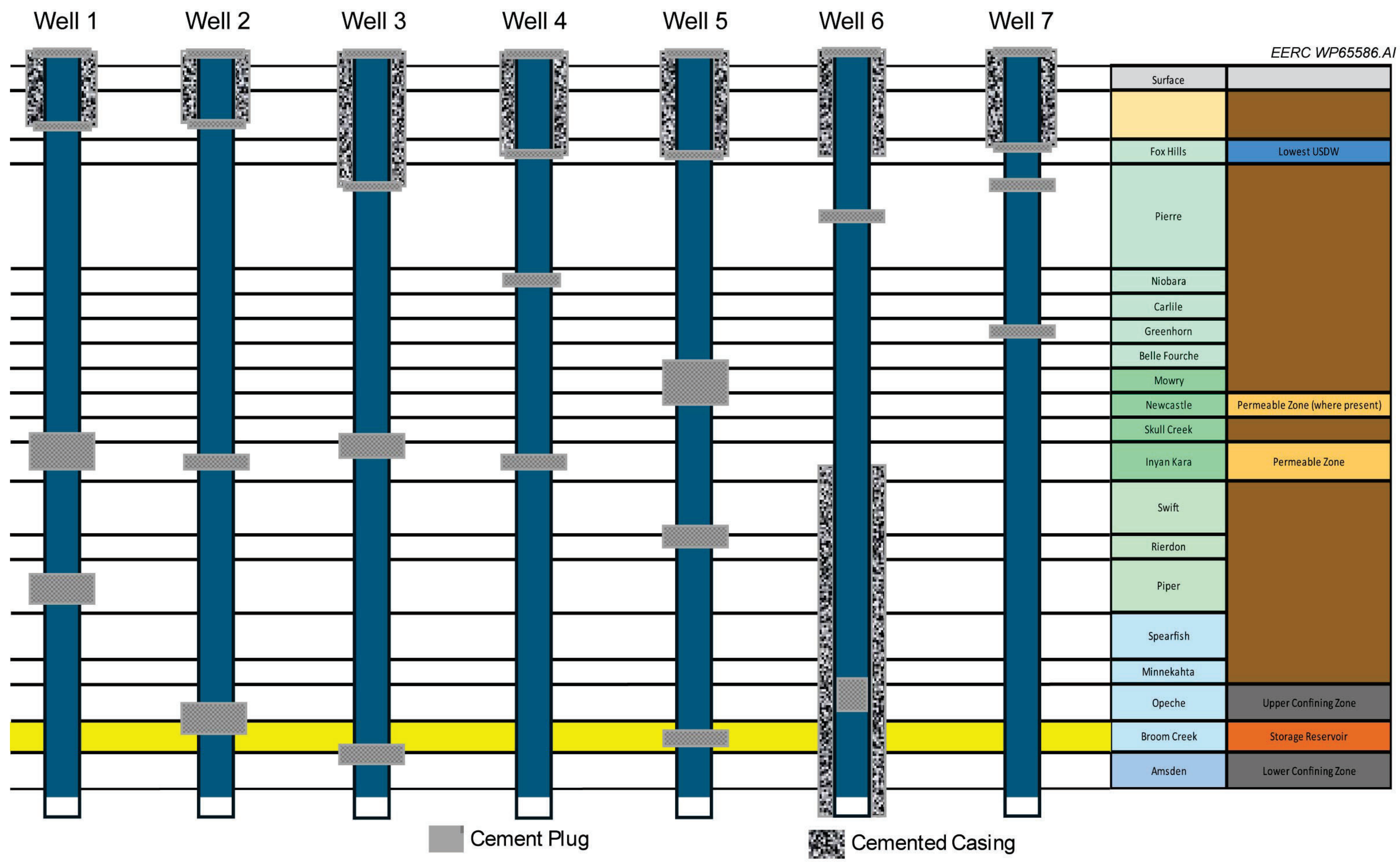

Figure 8. Schematic of seven different cement-plugging configurations in wells penetrating the Broom Creek Formation with a moderate risk: (Well 1) inadequate isolation above Broom Creek Formation, (Well 2) surface casing not extending below the top of the Pierre Formation and incomplete coverage of the top of the Inyan Kara Formation, (Well 3) no plugs between the Inyan Kara and Broom Creek Formations, (Well 4) no plug at Broom Creek Formation, (Well 5) plug within Broom Creek Formation, (Well 6) uncertain cement top of intermediate casing and surface casing not extending below the top of the Pierre Formation, (Well 7) no plug at the Broom Creek and Inyan Kara Formations. Image based on Arbad and others, 2024.

CO_2 Pipeline Right-of-Way Evaluation

As part of the regional infrastructure development task, a CO_2 pipeline ROW evaluation was completed to better understand the opportunities and constraints that may influence future CO_2 pipeline development across the study area. The evaluation focused on compiling and reviewing available information on land use, ownership, geopolitical boundaries, environmentally sensitive areas, and existing ROWs to identify factors that could limit or support future CO_2 pipeline development. The results of this effort, presented in Deliverable D3, provide a practical foundation for planning CO_2 pipeline corridors in the region.

To carry out this work, the project team performed an extensive geospatial assessment using datasets from the North Dakota Geographic Information Systems (GIS) Hub—such as land ownership, municipal boundaries, existing infrastructure, wildlife management areas, wetlands, hydrology, slopes, soils, and mapped geologic hazards. These datasets were combined with available imagery and commercial sources and analyzed using Pivvot's Aware and Route platforms to identify surface-use constraints, siting risks, and areas where colocating with existing infrastructure may help reduce impacts and streamline pipeline routing and permitting.

The evaluation also included a detailed review of the regulatory framework governing CO_2 pipelines in North Dakota. Under North Dakota Century Code (NDCC) Chapter 49-22.1, intrastate CO_2 transmission projects must obtain a transmission facility certificate of corridor compatibility (TFCCC) and a transmission facility route permit (TFRP) from the North Dakota Public Service Commission (PSC) before construction. North Dakota Administrative Code (NDAC) § 69-06-08-02 identifies several areas that must be avoided or excluded during corridor selection, including parks, wildlife areas, designated habitats, rural residences with 500-foot setbacks, water bodies, unstable geologic units, and federally controlled intercontinental ballistic missile (ICBM) sites with 1200-foot buffers. In addition, federal safety regulations under the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration hazardous liquid pipeline program (49 CFR Part 195) apply once a CO_2 pipeline is operational. Together, the regulatory and geospatial constraints formed the basis for the siting analysis.

Data Acquisition and Methodology

To support the routing feasibility analysis, the project team compiled relevant datasets from the North Dakota GIS Hub and the North Dakota Geological Survey and integrated them into the Pivvot software environment. These datasets were then evaluated within Pivvot's Aware and Route platforms to conduct broad-area screening of environmental, social, and infrastructure factors influencing potential pipeline siting.

Consistent with NDAC § 69-06-08-02 requirements, the analysis identified all relevant exclusion areas (e.g., federal and state parks, natural landmarks, wildlife refuges, critical habitats, archaeological sites, ICBM facilities) and avoidance areas (e.g., rural residences with 500-foot setbacks, unstable geology, municipal water supplies, recreational areas, wildlife management areas, and scenic rivers). Where required, protective buffer distances were applied to each dataset to comply with statutory corridor-routing constraints.

Pivvot Routes was then used to perform automated suitability modeling using a preferred-low avoidance-exclude classification system configured to match North Dakota's regulatory requirements. This enabled generation of optimal corridor segments based on terrain, land use, setback constraints, environmental features, and opportunities for colocation with existing linear infrastructure. The geospatial workflow produced detailed suitability surfaces, relative route-cost maps, colocation estimates, and slope analyses statistics for both conceptual CO_2 pipeline routes that were developed for this project.

Opportunities and Routing Potential

The evaluation identified several characteristics that could support efficient CO_2 pipeline development in the study area. These include a well-established network of existing oil and gas gathering lines associated with the DLM, a major east–west natural gas transmission corridor south of Dickinson, and multiple high-voltage power transmission ROWs. Using or paralleling these existing corridors can help minimize permitting challenges and reduce surface disturbance. The natural gas transmission corridor is of particular interest given its proximity to an existing CO_2 source, the Gevo North Dakota ethanol plant (Figure 9). The facility currently captures

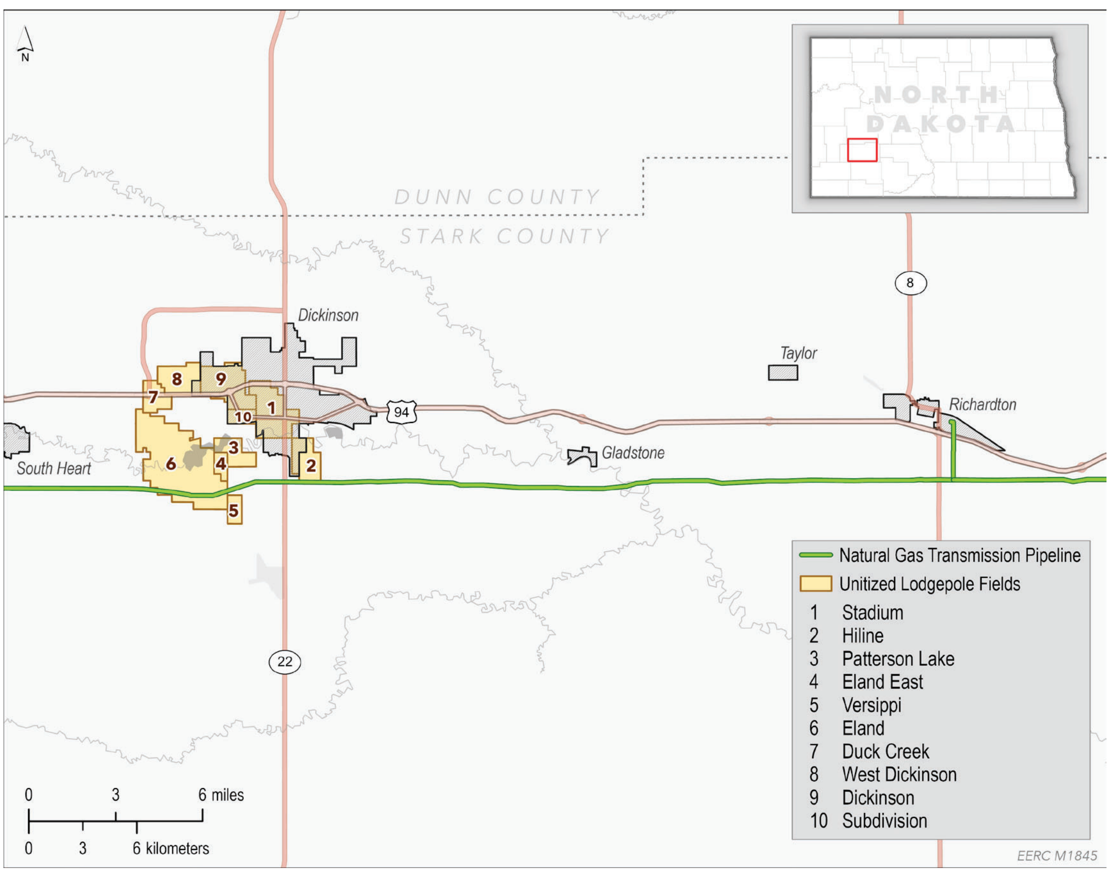

Figure 9. Major gas transmission pipeline route (green) that runs adjacent to Gevo North Dakota ethanol plant located in Richardton, North Dakota and south of Dickinson, North Dakota through southern portion of the DLM complex.

approximately 165,000 tonnes/year of CO_2 and injects and stores the CO_2 in the Broom Creek Formation. This captured CO_2 could be transported via a CO_2 pipeline colocated within the same ROW corridor for utilization in EOR at the DLM.

Large areas of low-density rural land and wide tracts of undeveloped acreage also provide flexibility for routing pipelines, particularly in areas outside the expanding Dickinson municipality. These locations generally have fewer siting conflicts and present fewer regulatory and geotechnical challenges.

Theoretical Route Evaluations

Using the regulatory and geospatial framework, the project team developed two representative CO_2 pipeline routing case studies.

The first route connects an industrial area in southwest Dickinson to the southern portion of the Eland Field (Figure 10), a field that produces from the DLM and has high potential for EOR operations and associated storage of CO_2. The route was developed utilizing Pivvot Route and accounts for statutory setbacks and exclusion areas defined under NDAC § 69-06-08-02. The modeling demonstrated that approximately 65% of the 6.8-mile route could be colocated with existing pipeline infrastructure, potentially reducing constructability risk and ROW impacts.

The second conceptual route extends approximately 21 miles from Dickinson toward a prospective dedicated storage site north of Lefor, North Dakota (Figure 11), which would target the Broom Creek Formation. Route optimization avoided the U.S. Bureau of Land Management (BLM)-managed Edward Arthur Patterson Lake (exclusion area), the Dickinson Theodore Roosevelt Regional Airport (avoidance area), and the Adam and Teresa Raab Wildlife Management Area (avoidance areas). The analysis also highlighted potential routing challenges near residential clusters north of the airport, consistent with the 500-foot residence buffer requirement (NDAC § 69-06-08-02). Alternative corridor paths were identified to comply with these constraints while preserving construction feasibility.

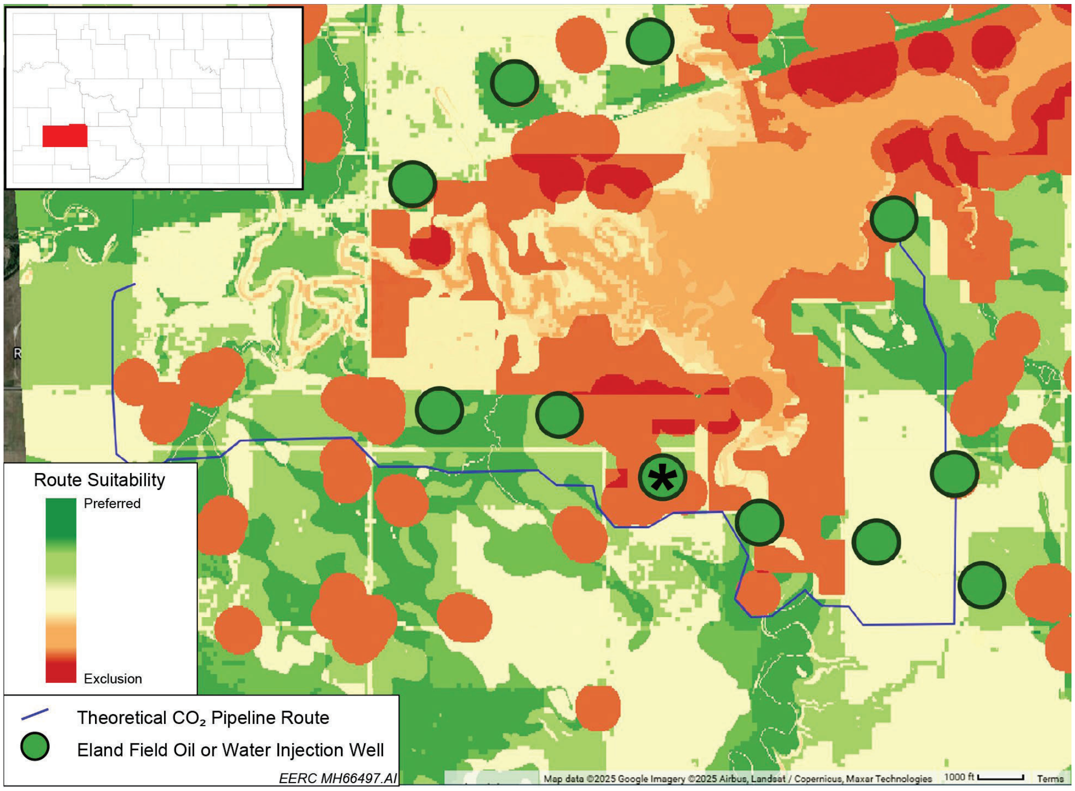

Figure 10. Pivvot-generated route suitability surface overlaid on theoretical CO_2 pipeline route that could service the southern portion of the Eland Field for CO_2 EOR activities. The circular features colored red/orange correspond to residences or businesses and the 500-ft buffer that is applied to these features. The asterisk marks a well and adjacent existing pipeline infrastructure that neighbors more recently developed residences.

As CO_2 EOR activity expands to this region, dedicated geologic storage will play an increasingly important role in managing long-term CO_2 volumes. CO_2 EOR projects can permanently store significant amounts of CO_2, but their ability to take CO_2 varies over time because of reservoir pressure limits, production cycles, and operational constraints. As a result, CO_2 EOR fields cannot always accept the full volume of captured CO_2 that may be available. Dedicated saline storage sites, on the other hand, can offer more consistent, high-volume injection capacity and can accommodate CO_2 that exceeds CO_2 EOR demand. Because of this, the study evaluated routing options to both a potential CO_2 EOR field and a dedicated storage area. Considering both pathways ensure that future CO_2 infrastructure is flexible enough to shift between CO_2 EOR and dedicated storage, supporting both near-term utilization and long-term, commercial-scale sequestration.

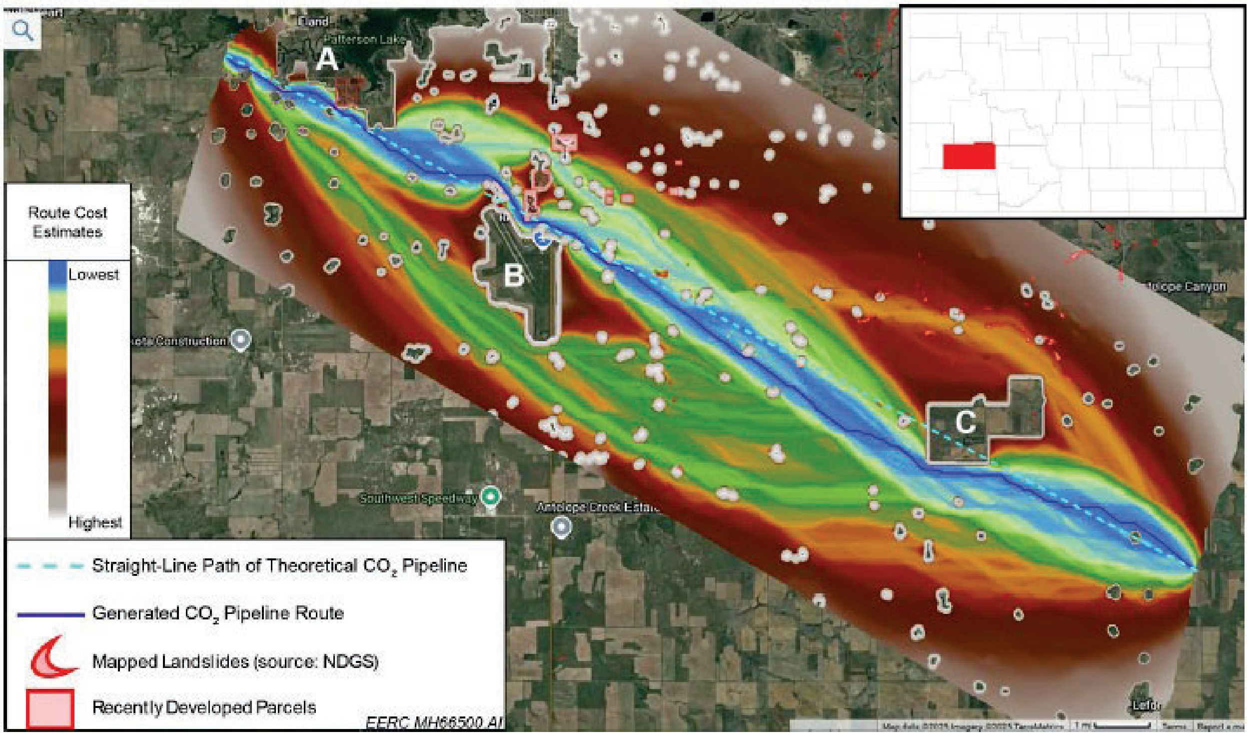

Figure 11. Pivvot-generated estimated route cost map shown along with the Pivvot-generated CO_2 pipeline route (darker blue line) derived from the straight-line path (dashed light blue line). The Edward Arthur Patterson Lake is labeled A, Dickinson Theodore Roosevelt Regional Airport is B, and the Adam and Teresa Raab wildlife management area is C. These features represent the largest siting constraints within the theoretical route area.

CO_2 Pipeline ROW Evaluation Key Findings

By integrating North Dakota's statutory and administrative requirements, particularly the corridor and routing provisions in NDCC Chapter 49-22.1 and the exclusion and avoidance criteria detailed in NDAC § 69-06-08-02, this CO_2 pipeline ROW evaluation provides a clear framework for project developers to use in early-stage site characterization, data collection, and corridor planning. This work establishes a regulatory foundation that can be directly applied during preparation of TFCCC and TFRP applications before the North Dakota PSC.

Through targeted acquisition and analysis of land-use, ownership, environmental, and infrastructure datasets, the study identified a range of opportunities that could reduce surface impacts and streamline project development. These include extensive existing pipeline and gathering-system ROWs, multiple electrical transmission corridors, large tracts of undeveloped land, and broad areas with low residential density.

At the same time, the evaluation documented several key challenges and constraints that future CO_2 pipeline developers must account for. These include municipal expansion around Dickinson, North Dakota, rural residence setback requirements, environmentally sensitive lands, wildlife management areas, BLM-managed public resources such as Patterson Lake, and landslideprone geologic settings near the Heart River and its tributaries. By identifying these constraints early, the study provides actionable intelligence that can help future projects avoid permitting delays, reduce routing conflicts, and comply with statutory requirements.

Overall, this evaluation establishes a detailed regulatory and geospatial foundation for CO_2 infrastructure planning in southwestern North Dakota. By documenting the legal requirements that govern pipeline siting and mapping the opportunities and limitations that exist across the study area, the work offers a clear path for future CO_2 pipeline development.

Site Readiness Factors

Site readiness factors presented in Peck and others (2025) established a structured framework for commercial-scale carbon storage development within North Dakota. This effort supports future development of large-scale CO_2 storage hubs by identifying the information, milestones, and data acquisition steps required to advance a prospective CO_2 storage site from early conceptualization toward UIC Class VI or Class II permit submission. The goal of this effort was to create a prototype template for documenting site readiness factors informed by a commercial deployment matrix. This was accomplished through the development of a comprehensive CCUS project readiness assessment that aligns with North Dakota's UIC Class VI and Class II permitting requirements and the SFP application process.

The assessment organizes site readiness into a clear, stepwise maturity progression that developers and stakeholders can use to evaluate how prepared a location is for carbon storage development. Central to this framework are two detailed readiness matrices:

- A Class VI project readiness assessment outlining the major data acquisition, modeling, characterization, and permitting tasks required to support development of a North Dakota SFP under North Dakota UIC Class VI regulations (NDAC 43-05-01)

- A Class II project readiness assessment summarizing the analogous readiness steps for CO_2 EOR projects regulated under North Dakota's Class II UIC program (NDAC 43-02-05)

The Class VI assessment emphasized the high data intensity and iterative nature of commercial dedicated geologic storage development, beginning with early desktop evaluations of seismic, geologic, and regulatory conditions and progressing through acquisition of new subsurface data, stratigraphic test wells, site-specific geomechanical analysis, AOR modeling, and ultimately the preparation of a complete SFP application. In contrast, the Class II assessment reflected the comparatively lower data burden for EOR projects and focuses on wellbore integrity assessments, reservoir pressure considerations, pattern design, and operational planning needed to support sustained injection and storage of CO_2 into hydrocarbon reservoirs.

Both readiness matrices distinguish between early, low-effort screening activities and higher-effort tasks—such as drilling, seismic acquisition, and full reservoir modeling—that require significant planning and investment. This structure provides a realistic view of the timelines and resources needed for each type of project and helps identify where critical data gaps may exist.

The readiness framework also highlights that CCUS project development is inherently iterative. As new geologic, geophysical, or engineering data are acquired, project teams must update models, refine interpretations, and reassess project risks. This adaptive process ensures that uncertainty is systematically reduced and that project decisions are guided by the best available information at each stage.

By creating a standardized method for evaluating both dedicated storage (UIC Class VI) and CO_2 EOR/associated storage (UIC Class II) readiness, site readiness activities provide a foundational tool for comparing the maturity of storage projects, identifying data gaps, prioritizing future characterization work, and supporting investment and planning decisions for the future development of large-scale CO_2 storage hubs.

STATE AND FEDERAL GOVERNMENT ENGAGEMENT AND TECHNOLOGY TRANSFER

Competing Pore Space Interests

The focus on the subsurface for pore space interests has blossomed and become multifaceted. The study by Peck and Regorrah (2024) evaluated factors and industries leading to competing pore space interests. Subsurface pore space use within North Dakota has gained attention in recent years as industries look to expand the development of this nontraditional resource, primarily for disposing of or storing material (waste versus nonwaste) in the deep subsurface. As this development expands, subsurface industries will begin competing for limited pore space. This competition can take the form of occupied pore space (two or more entities want to use the same pores) or competing pressure fronts (the increased pore pressure induced by one entity may interact with the increased pore pressure induced by a second entity, which may interfere with injection or production operations of one or both entities).

Management or subsequent resolution of this competition has limited legal and legislative precedence, and thus there is potential to inhibit commercial expansion into pore space use. To properly assess the economics, impacts, and risks associated with the geological storage or disposal of fluids, policymakers, industry, and regulatory agencies should review and understand the potential interactions of large-scale injection operations in the subsurface. In particular, as the CO_2 storage industry grows, operators and regulators will likely need to reframe their strategies in terms of pressure space to minimize the chance of such conflicts and maximize the use of the pore space resource.

Figure 12 shows the various categories/industries that have an eye on pore space in the deep subsurface. SWD and oil/gas production are inextricably linked and represent the largest (and geographically broadest) focus on the subsurface. The storage of various fluids (e.g., CO_2, H_2, natural gas) in the deep subsurface is a relatively new industry in North Dakota compared to SWD. Class I wells used to dispose of industrial waste target the same injection horizons as SWD wells but, to date, have generally been located away from the prime oil/gas production areas. Although not yet relevant, geothermal energy production is expected to become a reality in North Dakota and initiate another industry that uses pore space.

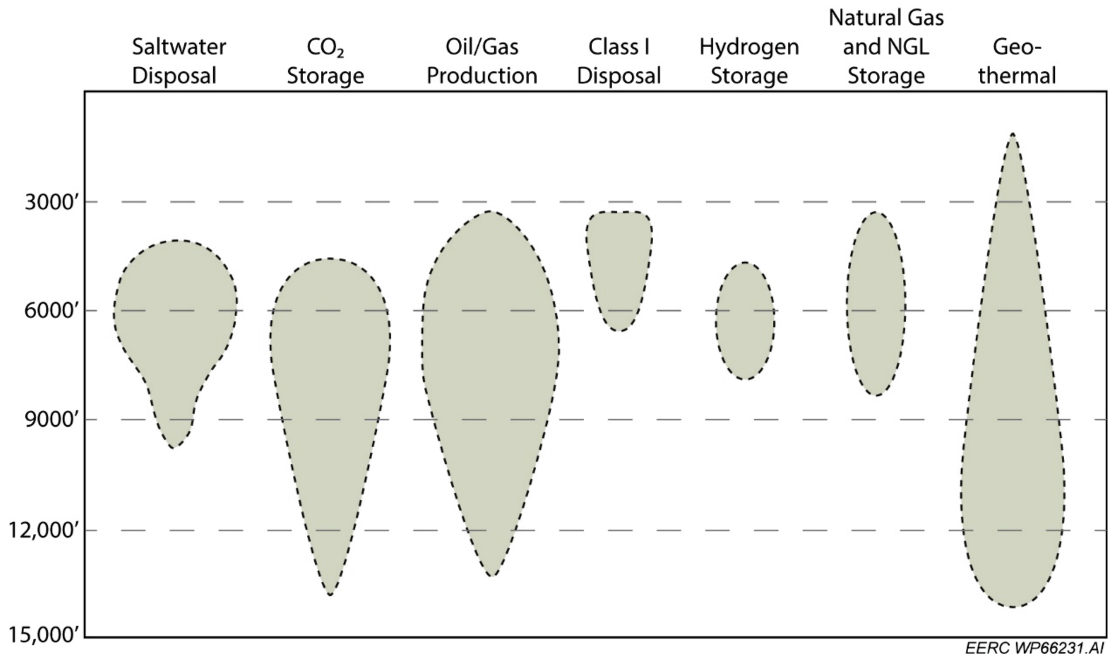

Figure 12. Schematic diagram of the typical depth ranges over which subsurface activities occur (or may occur) in the North Dakota portion of the Williston Basin. Variations in the widths of the shapes are in proportion to the most common depths for the activity (modified from Field and others, 2013).

Figure 13 depicts the potential for competition among various industries for pore space in North Dakota. The likelihood of competition varies depending on location within the state, with the highest potential for competition in western North Dakota where oil activity is greatest.

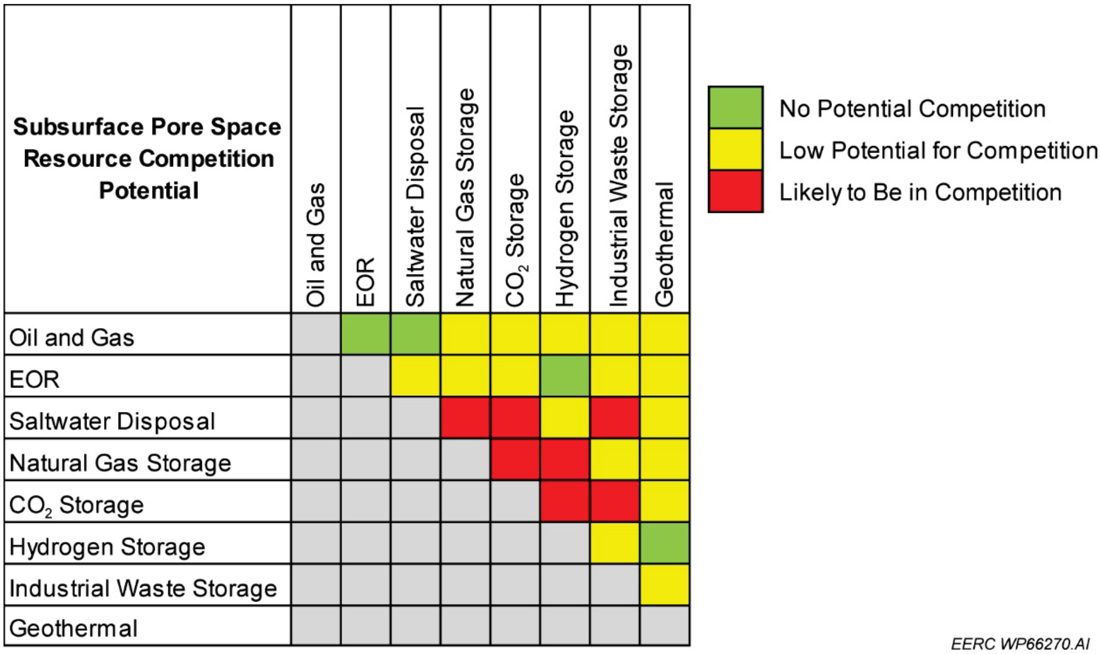

Figure 13. Potential for pore space resource competition in North Dakota.

Federal Government Engagement

A project task lead initiated contact with federal regulators at BLM—at both the state office level and Washington, D.C., headquarters—to demystify the regulatory permitting process associated with CCUS projects. BLM is a federal agency within the U.S. Department of the Interior that manages a large portion of America's public lands. CCUS projects that involve public land—surface, subsurface, and minerals—will likely need to navigate an extra layer of regulatory oversight from BLM. In Wyoming, CCUS projects involving public lands were particularly active during this investigation, and the Wyoming BLM staff had experience with both dedicated CO_2 storage and associated CO_2 storage. Different BLM processes were established for these types of projects.

In June 2022, BLM issued an instruction memorandum, IM 2022-041, titled National Policy for the Right-of-Way Authorizations Necessary for Site Characterization, Capture, Transportation, Injection, and Permanent Geologic Sequestration of Carbon Dioxide in Connection with Carbon Sequestration Projects (U.S. Department of the Interior, 2022). This memorandum conveyed the policy and direction for ROWs to use public lands in connection with dedicated CO_2 storage projects, including authorization for the use of federal pore space managed by BLM. ROW authorizations for carbon sequestration projects on public lands are issued under Title V of the Federal Land Policy and Management Act of 1976, as amended. The memorandum was effective through September 30, 2025. Once a nonpermanent BLM instruction memorandum expires, BLM may continue to follow its guidance unless it is specially withdrawn, superseded, or replaced. BLM is currently working on developing new or possibly supplemental guidance to address BLM's authorization of CCUS projects on public lands.

One area that remains under development is a framework for how best to collect an appraised fair market value for pore space ROWs. BLM may bill and collect rent in a manner and frequency that best suits the BLM's and public needs, such as a by area (e.g., dollars per acre), by mass injected (e.g., dollars per tonne), using other variables or factors, or a combination of these.

Some CCUS projects may solely involve a subsurface pore space ROW from BLM (i.e., the injection well and appurtenant surface facilities are entirely located on nonfederal lands), some projects may require only surface facility ROWs, and some may involve both surface and subsurface facility ROWs. In general, different types of facilities or uses are individually permitted through separate ROW grants, meaning the applicant may need to obtain multiple ROW grants (each with its own assessed rent) from BLM.

In Wyoming, three companies applied for pore space ROWs for future injection and permanent storage of CO_2—none with any related surface infrastructure on public land. All three of the projects progressed through the National Environmental Protection Act process and all three require a notice to proceed to authorize injection for use of BLM pore space, contingent upon receipt of a Class VI well authorization to inject from the Wyoming Department of Environmental Quality. As of September 30, 2025, no pore space ROW grants were finalized because the rent structure/appraisal process remains under development.

Once the rent structure/appraisal process is developed, and because several projects are on the cusp of receiving pore space ROWs, future CCUS projects developed on public land will benefit from this authorization process under development, removing the previous uncertainty experienced by project developers in Wyoming.

CO_2 Storage on Public Land Fact Sheet

A fact sheet titled *CO_2 Storage on Public Land* evolved from the engagement with BLM concerning its authorization processes for both dedicated storage (Class VI) and associated storage (Class II) projects. The fact sheet is broken into four key parts: 1) a general definition section, 2) the authorization process for dedicated storage projects involving subsurface pore space ROWs (Figure 14), 3) the authorization process for associated storage projects, and 4) a comparison of the different BLM processes for dedicated and associated storage projects.

The fact sheet provides a high-level overview of the authorization processes to help CCUS project developers plan their projects and understand the time and resources needed for projects involving public land.

The knowledge gained from the engagement with BLM will be transferred to state government and industry stakeholders through posting the fact sheet on the PCOR Partnership program website as well as dissemination at various CCUS-related meetings and events. A copy of the fact sheet is included in Appendix B.

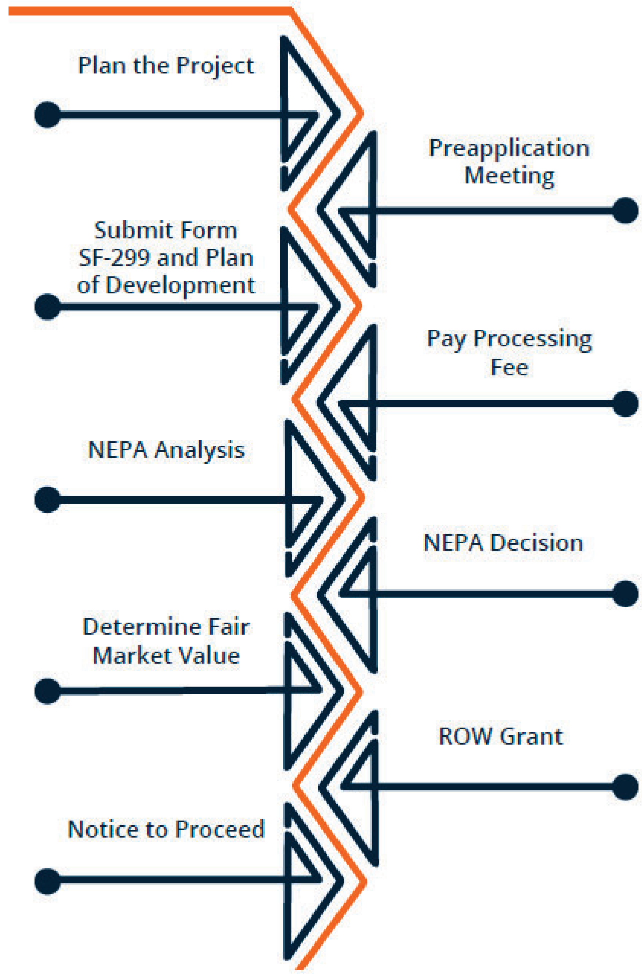

Figure 14. High-level process for BLM right-of-way authorization for dedicated CO_2 storage.

COMMUNITY OUTREACH

The objective of this project is build public confidence to benefit and accelerate commercial CCUS deployment. The following sections detail outreach activities and key learnings from stakeholder engagement in western North Dakota in and around the CMH project area. To ensure accuracy of stakeholder engagement learnings, including the results of the public opinion survey, the project team used the terms "CCS" for dedicated storage and "CO_2 EOR" or "EOR" for associated storage to make a clear distinction between these geologic storage activities.

Outreach activities consisted of community events and a county-wide public opinion survey. Both activities provided insight into stakeholders' thoughts, viewpoints, opinions, etc. on CCS and related topics (e.g., pipelines, CO_2 EOR, energy). These insights help inform the level of public confidence in CCS project development in the region. In turn, the project developers can use the learnings from this project to address public concerns with targeted outreach and engagement strategies.

Public Events

The EERC's project team attended public events as part of stakeholder engagement. Public events allow for direct interaction between the project team and landowners/residents in the area. One of the benefits is that the project team can better understand the public's concerns and questions related to potential CCS projects, which can enhance project planning and engagement should a project advance toward future phases of development. The stakeholder engagement included booths and presentations at community events. Most interactions with the public at these events were positive, and people generally were not familiar with CCS but wanted more information. The public events and project team observations are described below.

Gladstone, North Dakota, Informational Meetings

Six EERC staff members participated in two landowner informational meetings (open houses) hosted by Prairie Horizon Energy Solutions in Gladstone, North Dakota. These meetings were held to introduce a planned CCS project that was going to transport CO_2 from Marathon Petroleum Company's renewable diesel facility in Dickinson to a rural site near Gladstone for dedicated storage. The informational meetings were held on April 24, 2024, for potential pore space owners and April 25, 2024, for landowners along a potential pipeline ROW. The meeting included general information on CCS and the proposed project to help landowners understand what to expect with a potential CCS project in their area. The meeting also provided a forum for landowners to interact with the project team, ask questions, voice concerns, and offer input for project planning (e.g., environmental conditions that might impact infrastructure placement).

Landowner feedback from the event reflected a generally positive attitude toward the proposed project, especially its potential for economic growth in North Dakota and development of ammonia and hydrogen production. Many attendees were curious and supportive, with several asking whether the facility would produce urea. Concerns centered on the CCS component, skepticism about climate change, the need for CO_2 storage, and safety—particularly regarding groundwater protection and long-term containment, pipeline proximity to homes, and potential leaks. Additional issues included unease about seismic survey activities, increased rail traffic, and compensation for land access and pore space usage. Some landowners were frustrated by unclear or inconsistent messaging around payments and expressed a desire for compensation structures similar to oil and gas royalties.

North Dakota Petroleum Foundation's Annual Bakken Rocks CookFest

Held on July 18, 2024, in Tioga, North Dakota, this annual outdoor event invites public across western North Dakota to learn more about the oil and gas industry. EERC staff hosted a booth, gave a presentation introducing CCS to the public, and answered audience questions.

North Dakota Lignite Energy Council Annual Meeting

Held on October 2, 2024, in Bismarck, North Dakota, the audience included coal-related industries, public officials, and the public. EERC staff hosted a booth to share information on CCS development, engage attendees, and address CCS questions and concerns.

Online Public Opinion Survey

The project team implemented a web-based public opinion survey distributed to western North Dakota residents in January 2025. The purpose of the survey was to investigate public knowledge and opinions of CCS, the energy industry, CO_2, and CO_2 pipelines. Target counties included Stark, McKenzie, Dunn, and Mountrail.[1] The population of the surveyed region is over 65,000, with one multi-zip-code city center—Dickinson, population about 25,000—in this otherwise mostly rural area. Results of the survey are intended to help assess social acceptability of CCS while aiding in future project phase engagement planning and risk assessment.

The online survey and corresponding invitation to participate were approved by the University of North Dakota's Institutional Review Board, ensuring proper research ethics for human subjects. The survey response is a convenience sample, which is a non-probability sampling method in which participants are selected because they are willing to participate rather than via a random or systematic selection. Based on the convenience nature of the sample, this survey may not represent the opinions of the full underlying population. Instead, individuals with strong opinions (either in support or opposition) are more motivated to share their views (Groves and others, 2009). Thus, convenience sampling/voluntary response may better capture views among those who are critical or less trusting. Given the survey goal, this convenience sampling technique is a useful way to hear from those with strong opinions in western North Dakota. Similarly, if a project developer were to investigate CCS in the region, the types of individuals that responded to this survey likely represent those who would vocalize either support or opposition. Therefore, engagement and/or outreach should strongly consider addressing the questions and concerns raised by the respondents.

The 184 participants' responses generated feedback on topics such as energy priorities, environmental concerns, and local interest in project developments. The responses gave the project team information about differences in opinion between those living in a city (i.e., Dickinson, subsequently referred to as urban residents) (50.5% of respondents) and those living in rural areas (49.5% of respondents).

Respondents strongly supported the oil and gas industry, with over 90% agreeing that the industry should continue in the state. The oil and gas industry was viewed as important to the area's economy, and respondents agreed that it provides affordable energy, good-paying jobs, and tax revenues that help state and local economies. Coal also received good support, with over 80% of respondents finding the coal industry important in the state. A higher percentage of rural residents strongly supported coal (68%) versus their urban counterparts (47%). Renewable energy

[1] This public opinion survey was cofunded through a second EERC-led, DOE-funded project, titled "Roughrider Carbon Storage Hub" DE-FE0032282. The combination of funding allowed for a larger survey area and population.

sources received moderate support, with wind leading the way with 63% support and solar receiving only about 30%.

About 90% of respondents were aware of CCS, and almost 70% claimed to know what CCS is (Figure 15). Of those who reported awareness, 98% provided written responses naming projects or locations they associated with CCS. Frequently named projects included the Richardton project (also referred to by respondents as the Red Trail Energy project, which was recently purchased by Gevo and renamed the Gevo Richardton CCS project), Summit Carbon Solutions, Dakota Gasification Company (Great Plains Synfuels Plant), and Blue Flint Ethanol. Respondents generally viewed CCS as clean, safe, and useful; however, neutral attitudes overall were significant (Figure 16), suggesting that effective outreach could shift a large share of opinions in a positive direction.

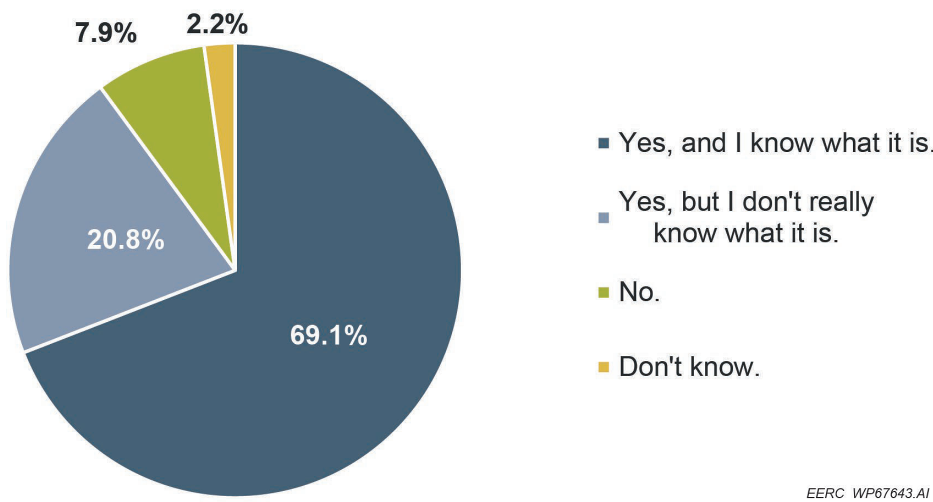

Figure 15. Share of responses to the question of awareness of CCS.

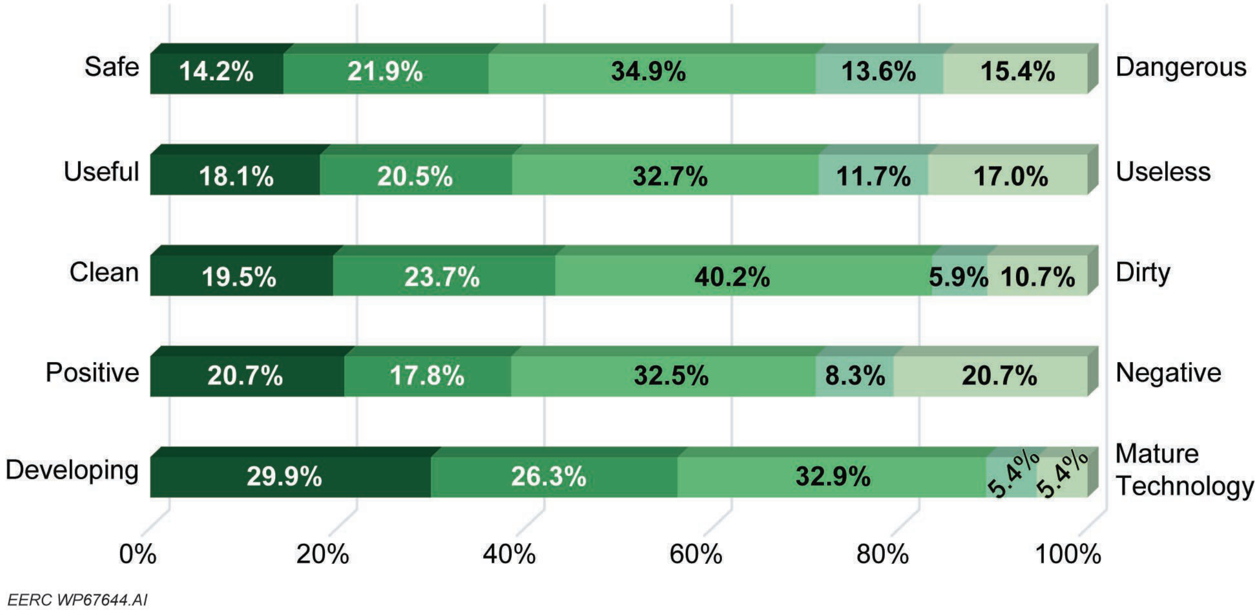

Figure 16. Respondent perceptions of CCS.

When the respondents were asked about potential CCS projects in North Dakota, support generally decreased with geographic proximity. In other words, projects in their county (Figure 17) were opposed more than projects in North Dakota or the United States. Further, rural respondents were more likely to oppose such projects than urban ones, regardless of location. In contrast, both rural and urban respondents expressed significantly greater support for EOR projects at over 80%.

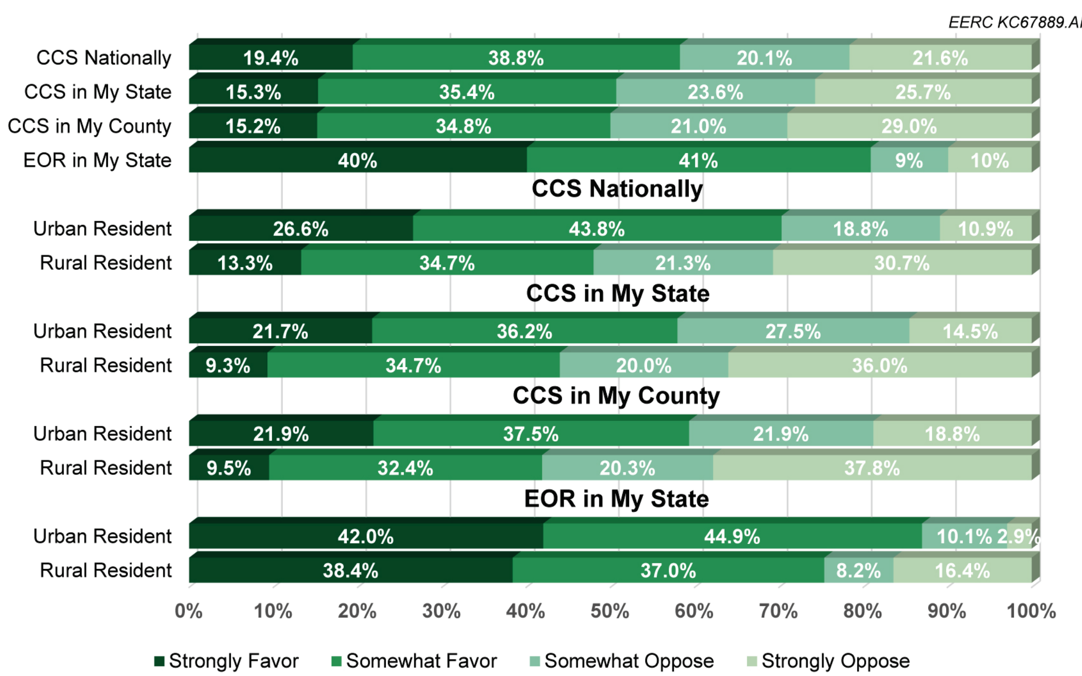

Figure 17. Respondent support of CCS projects based on proximity and residence.

Effect of Information Sharing

Survey participants were asked to evaluate a hypothetical CCS project scenario where they were given project information in two stages:

1. Researchers had investigated the project site ahead of time and determined the project site was suitable for safe, permanent storage.

2. Safety measures, environmental studies, and regulatory oversight were described.

The participants were asked to rate their support at each stage of project information. The level of opposition decreased noticeably—12% and 16% for rural and urban respondents, respectively—as additional information was given, which suggests that providing information about the project can shift public opinion toward greater support of the project.

Respondents were then asked to rate the importance of safety measures, environmental studies, and regulatory oversight and invited to share questions and concerns. While respondents were roughly split on environmental studies and regulatory oversight, nearly 80% found that safety measures are important to increasing support for CCS project development (Table 2). Survey question/concern topics centered around a few categories.

Table 2. Importance of Factors in Acceptance of CCS

Factor	Rural, %	Urban, %	Total, %
Safety Measures	79.5	76.6	78.1
Environmental Studies	51.3	56.0	53.6
Regulatory Oversight	53.2	56.6	54.9

Safety. Concerns included pipeline leaks, whether injected CO_2 would stay underground, and whether injected CO_2 could affect groundwater, cause earthquakes, or erupt from the ground. More pointed questions asked whether the project would be required to purchase a multimillion-dollar bond or why we were not storing CO_2 under our own homes.

Financial impact. Questions included overall cost, its accompanying bond costs, who pays for it, how much would be supported by the public; impact on property values and mineral rights; compensation for landowners and communities; and who was sponsoring the research.

Mistrust. A few questions conveyed a lack of trust in the research and people involved. These questions, which covered a variety of topics, included:

- How can we know your research is unbiased?
- Who is liable in case of a disaster?
- Will you respect the landowners?
- Is this a ploy to help oil companies save face?
- How are you going to convince the public that this is worthwhile?

Responses to the perceived trustworthiness of information sources put scientists/researchers ahead of project developers/energy companies; state or county representatives; and friends, neighbors, or family in the total sample. When trust was split between urban and rural residents, a plurality (42.7%) of rural residents rated scientists/researchers as "somewhat trustworthy." Although "very trustworthy" was the second-highest response (26.7%), the high share of negative responses (30.6%) suggests that it would be unwise to assume project personnel have already earned the full trust of residents near project areas; 10.7% of rural respondents rated scientists/researchers as "not trustworthy at all."

Why. Questions included why CCS is even necessary, whether the current amount of atmospheric CO_2 is actually a problem, what concentration of CO_2 in the atmosphere is too high, is CO_2 really affecting the climate, why remove something good for crops, and why bother when other countries' CO_2 emissions were increasing. Respondents questioned whether CCS was the best approach and advocated for EOR, nuclear power, shifting focus from fossil fuels to renewable energy systems, or planting more trees or cover crops.

Opinion Survey Conclusions

The survey results provide a snapshot of public attitudes toward CCS in western North Dakota, highlighting both opportunities and challenges for future project development. While support for the oil and gas industry remains strong, attitudes toward CCS are more nuanced, with urban respondents generally more favorable than rural ones. Nearly 90% of respondents indicated an awareness of CCS, and many respondents could name specific projects, yet negative opinions suggest room for education and outreach. Support for CCS increased when respondents were presented with detailed project scenarios that included safety measures, environmental studies, and regulatory oversight, underscoring the importance of transparent communication. Support for EOR was significant, with 80% of respondents in favor of CO_2 being used to produce additional oil in the state. Safety emerged as a critical factor influencing public acceptance, with nearly 80% rating it as "very important." These findings suggest that targeted outreach, trust-building with local communities, and clear communication about safety and oversight can meaningfully shift public opinion and enhance social feasibility for CCS initiatives in the region.

INVESTING IN JOB QUALITY AND A SKILLED WORKFORCE

DOE's workforce development strategy aims to build a technically diverse, skilled workforce capable of supporting the nation's energy industry, including CCS development. With this and the feasibility phase of the project in mind, the CMH project focused on promoting STEM (science, technology, engineering, and math) career development and introducing students to potential career pathways into CCS-related fields (e.g., energy development).

The CMH project participated in regional T4 (Tools, Trades, Torque, Tech) career exploration summits targeting middle and high school students by facilitating hands-on activities at T4 events in Parshall, North Dakota (October 9–10, 2024); Watford City, North Dakota (April 30 – May 1, 2025), and Grand Forks, North Dakota (November 6–7, 2025) to spark student interest in STEM careers related to energy and CCS. Team members engaged students with geology activities to explore porosity and permeability properties with shale and sandstone as well as chemistry experiments in polymerization and cation ionization. The hands-on activities and access to EERC professional staff aimed at sparking student interest in STEM careers, a critical component of DOE's goal of developing a skilled workforce.

Team members also presented on CCS to educators at the North Dakota Petroleum Foundation's Teacher Education Seminar held June 24–27, 2024, providing information on the geology of the Williston Basin, oil production, and opportunities for CCS.

OUTREACH TASK CONCLUSIONS

Outreach activities provided key insights into the social viability of CCS in western North Dakota. Through public events and a regional survey, the team engaged a broad mix of stakeholders—energy workers, landowners, educators, and officials—revealing moderate familiarity with CCS and strong interest in communicating through hands-on learning opportunities that convey relevant CCS/CCUS concepts (e.g., rock samples to illustrate properties of the subsurface). Survey results showed high support for traditional energy, less comfort with CCS, and a desire for projects that emphasize safety, transparency, and community benefit. Support grew when participants read detailed project scenarios, highlighting the value of proactive education.

Trust-building emerged as a critical factor, especially in rural areas where skepticism remains. Scientists were seen as relatively trustworthy, but ongoing engagement is needed to strengthen relationships. The project also advanced workforce development through STEM education and career events, aligning with DOE goals for a skilled CCS workforce.

Overall, these outreach activities established a strong foundation for future engagement, showing that CCS can be socially feasible when built on transparency, responsiveness, and meaningful dialogue.

CONCLUSIONS

In Stark County, the Inyan Kara and Broom Creek Formations present strong prospects for dedicated storage in deep saline formations. To date, the Gevo North Dakota ethanol plant near Richardton, North Dakota, has injected 577,485 tonnes of captured CO_2 into the Broom Creek Formation for dedicated storage. The DLM, a horseshoe-shaped series of oil fields in central Stark County, offer an intriguing opportunity for CO_2 EOR, with estimated incremental recovery of 21–34 million barrels of oil and associated storage of 6–15 MMt of CO_2. These positive factors for future CCUS and the active CO_2 storage project associated with the Gevo North Dakota ethanol plant in the county's northeast corner suggest ideal conditions favorable to advancing future additional CO_2 storage site development in Stark County. Project planners and developers can use the lessons from this project to inform early-stage decision-making and facilitate CCUS deployment in Stark County.

The key lessons learned and knowledge gaps addressed from the Prairie Horizon CMH are:

- Stark County is well-positioned for future CCUS deployment. All that remains are the commercial drivers and private sector investment to bring CO_2 to this region.
- Timelines for site selection, feasibility, and permit development can be improved by following established methodologies for CCUS evaluation.
- Stark County has infrastructure advantages with existing pipeline ROWs that may expediate the regulatory siting and permitting process, offering existing transportation corridors for CO_2 delivery to a future dedicated storage location or to the DLM.
- Dedicated CO_2 storage project planners should avoid geologic formations near active oil and gas development that may compete with subsurface pressure space, specifically SWD in the Inyan Kara Formation.
- The U.S. BLM has two distinct regulatory procedures for CO_2 storage on public lands, utilizing a ROW grant process for dedicated storage and a leasing process for associated storage. However, rent schedules for pore space use have not yet been defined, delaying the issuing of final ROW approvals.
- Public opinion survey participants in Stark County are generally divided in their opinion on CCS for dedicated storage. However, those same participants indicated strong (greater than 80%) support for CO_2 EOR.

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APPENDIX A

PRELIMINARY CO_2 EOR INVESTIGATION FOR THE ELAND FIELD

PRELIMINARY INVESTIGATION OF CO_2 ENHANCED OIL RECOVERY (EOR) PERFORMANCE FOR THE ELAND FIELD

Final Report

(for the period of July 16, 2025, through November 26, 2025)

Prepared for:

DOE Final Report Appendix

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EXECUTIVE SUMMARY

Partnering with Scout Energy Partners, the Energy & Environmental Research Center (EERC) investigated the feasibility and potential effectiveness of enhanced oil recovery (EOR) using CO_2 injection in the Eland Field of the Dickinson Lodgepole Mounds (DLM). Through investigation, a sectional simulation was created based on publicly available data with a proposed new well location considered. The simulation model was calibrated to match the historical injection and production performance trend. The tuned model was then used to forecast the production performance and evaluate the scenarios involving CO_2 EOR performance screen with different operation strategies.

The simulation result indicates that CO_2 flooding could approximately yield 3.9 million barrels (MMbbl) of incremental oil recovery using 20 billion standard cubic feet (approximately 1 million tonnes) of CO_2 over a 30-year project period in the modeled area that covers approximately 2560 acres. The net CO_2 utilization factor is approximately 0.26 tonnes/bbl. Six operational scenarios evaluating variations in CO_2 injection rate, bottomhole pressure control, and well completion strategies demonstrate that EOR performance is strongly influenced by reservoir management. Across the cases, incremental oil recovery ranges from 2.9 to 6.7 MMbbl, with net CO_2 utilization factor ranges from 0.23 to 0.36 tonnes/bbl. The estimated final oil recovery factors for CO_2 EOR are 57%–69%, representing approximately 6–18 percentage points higher than the business-as-usual recovery factor estimate. While the results confirm CO_2 EOR is a promising EOR option for Eland Field, uncertainty exists in the current screening simulation model and could be reduced with the availability of detailed data, such as fracture distribution and properties, oil saturation distribution across the reservoir, pressure history, and relative permeability curves. Building a detailed full-field geologic simulation model, performing dynamic simulations with history matching individual wells, and conducting a thorough sensitivity study of CO_2 EOR design parameters would provide a better understanding of reservoir uncertainties and help derisk the field development plan.

In reviewing the Knudsen and others (2009) predictions of the DLM, this work shows comparable oil recovery and CO_2 utilization factors for the Eland Field. Based on the results of the present work and reviews and comparisons with previous studies, it can be confirmed that the Eland Field is a strong candidate for CO_2 EOR.

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PRELIMINARY CO_2 ENHANCED OIL RECOVERY (EOR) INVESTIGATION FOR THE ELAND FIELD

1.0 INTRODUCTION AND OBJECTIVES

1.1 Eland Field Introduction

Discovered in the early 1990s, the Dickinson Lodgepole Mounds (DLM) represent one of the most significant oil plays within the Lower Mississippian Lodgepole Formation of the Williston Basin. These Waulsortian-age carbonate mounds are geologically distinctive, consisting of marine-cemented microbial boundstones and skeletal grainstones with local stromatactis structures that create excellent, although localized, reservoir conditions. Among the various fields developed in this play, the Eland Field stands out as the most productive, yielding tens of millions of barrels of oil since its discovery. Production at the Eland Field went through primary depletion and, later on, an extensive waterflooding program, which maintained reservoir pressure and supported recovery. In mid-2010s, 29.6 million barrels (MMbbl) of oil were produced through 16 wells, doubling the early estimation, and production continued with a relatively low oil cut at approximately 5.5% (Longman and Cumella, 2016). The low oil cut reflects the maturity of the field after decades of sustained production. Previous studies have identified the DLM as having high potential for gas enhanced oil recovery (EOR) and storage (Gorecki and others, 2008; Knudsen and others, 2009; Zhao and others, 2020). Given the long production history and current waterflood maturity, the Eland Field can be considered a good candidate for EOR investigation.

The Eland Field spans about 7 miles in an east–west direction and 5 miles in a north–south direction. For this work, a 2560-acre area containing 10 production and injection wells with historical production and injection data, along with the proposed new well, was selected for investigation while considering computational efficiency (Figure 1-1). Public data (North Dakota Industrial Commission, 1996; Longman and Cumella, 2016) were reviewed to support development of the preliminary simulation model. These data include a structural cross section of the Eland Field (Figure 1-2), an overview of the Eland Field and other DLM in the region, and a reconstructed cross section of well logs (Figure 1-3). This information was used to define model depth, grid cell thickness, and initial fluid saturation distribution, including the oil–water contact (OWC).

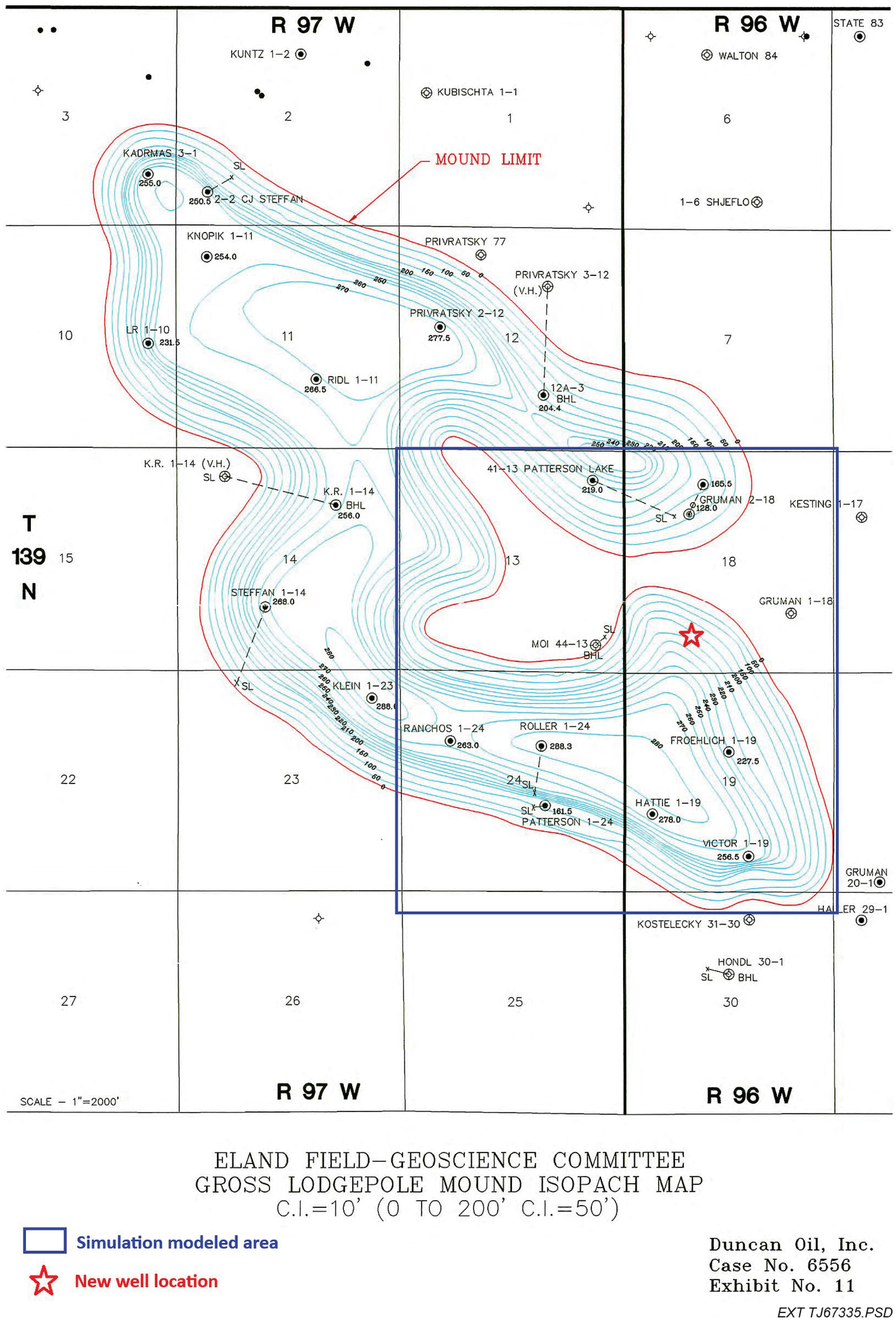

Figure 1-1. Eland Field gross thickness map.

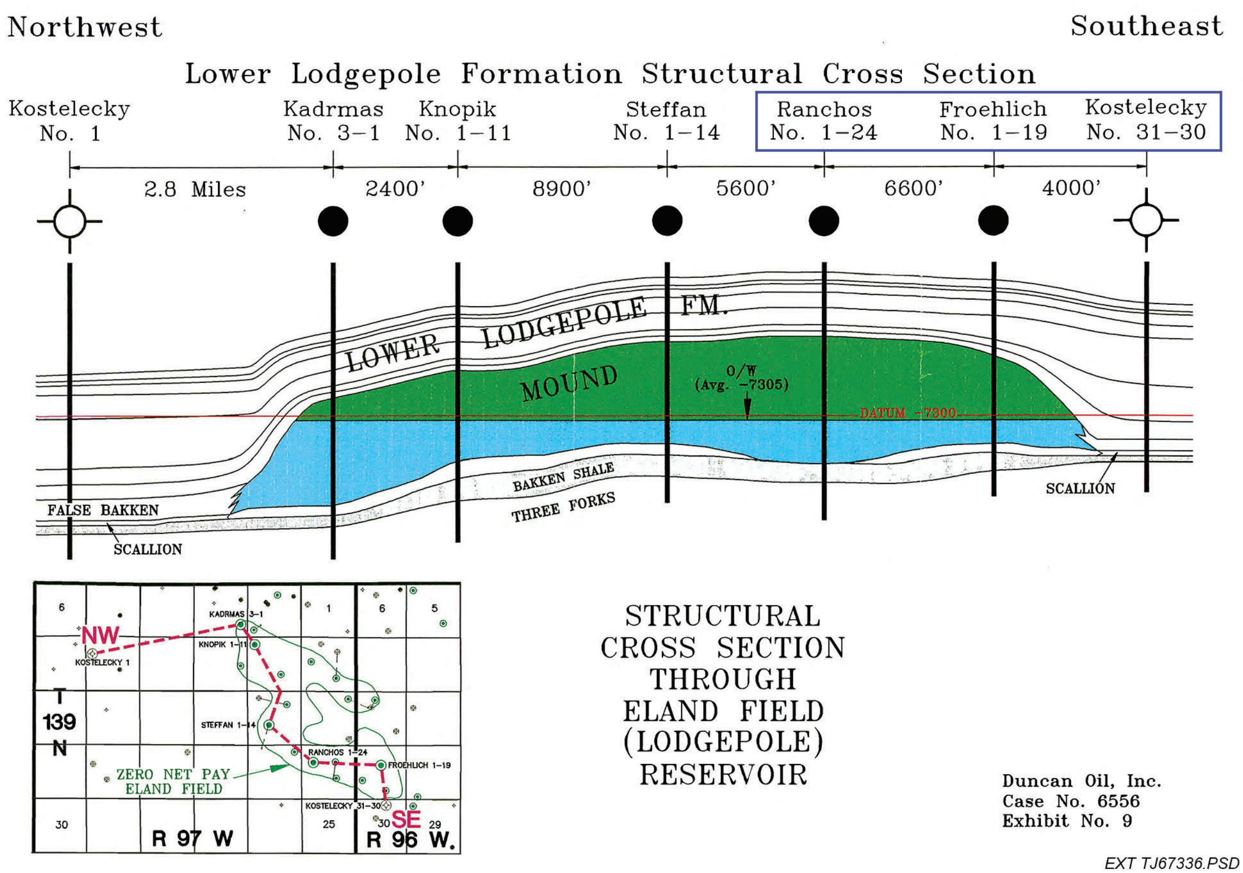

Figure 1-2. Structural cross section of the Eland Field, taken from North Dakota Industrial Commission (NDIC) Case File No. 6556. Simulation modeled area and wells are shown in the blue box.

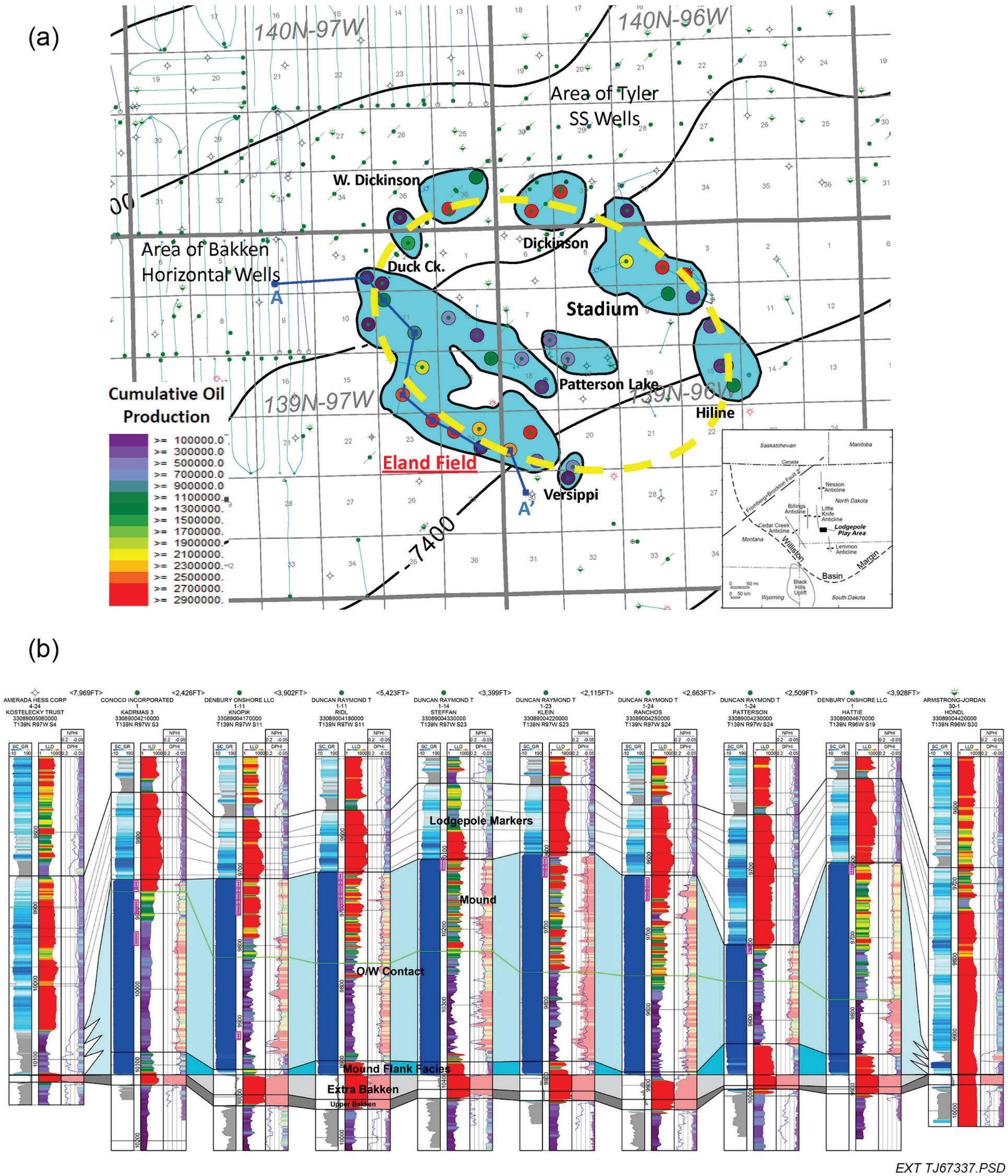

Figure 1-3. (a) Overview of the Eland Field and other DLM reservoirs and (b) re-created logs using the same well cross A-A' line in (a) (Longman and Cumella, 2016).

1.2 Objectives

The primary objective of this work was to assess the feasibility and potential effectiveness of EOR using CO_2 injection in the Eland Field of the DLM. The investigation combined reservoir characterization analysis, historical production and waterflood performance analysis, and early-stage predictive simulation, with the focus placed on the selected sectional area where a potential infill well will be drilled. The incremental oil recovery, CO_2 utilization efficiency, and amount of CO_2 stored associated with EOR were estimated. The differences in oil recovery factor and CO_2 utilization factors under various operational conditions, such as different CO_2 injection rates, reservoir pressure control, and well completions, were assessed. The results provide an overview of how the field could respond to different CO_2 EOR operation strategies and establish a technical foundation and understanding for future work regarding long-term planning, field implementation, and optimization of EOR strategies.

1.3 Scope of Work

1) Collect publicly available reservoir characterization data, such as structural, stratigraphic, petrophysical, and fluid properties. Collect historical production and injection data, including rate and cumulative production.

2) Analyze historical production trends to identify reservoir driving mechanisms and performance anomalies. Identify data limitations that would affect the prediction results. Determine reservoir characteristics that may impact CO_2 EOR performance.

3) Construct a simplified sectional model for early-stage EOR screening. The size and extent of the model will be determined based on the area of interest (AOI) and potential new well locations.

4) Use historical production and injection data to understand reservoir performance and tune the model to match observed production trends.

5) Run preliminary simulation predictions with different CO_2 injection strategies to estimate incremental oil recovery, CO_2 utilization efficiency, and the amount of CO_2 stored associated with EOR in the reservoir.

6) Simulation prediction of different operation strategies:
   a. Various CO_2 injection rate investigations.
   b. Different operational pressure investigations.
   c. Well recompletion investigation.

2.0 RESERVOIR SIMULATION MODEL DEVELOPMENT AND HISTORY MATCHING

A reservoir simulation model (as shown in Figure 2-1) was developed for the selected section of the Eland Field that covers 2560 acres to evaluate CO_2 EOR and associated storage potential in the field. Fourteen wells were set in the model, including 10 wells with production and/or injection history, one proposed new well, and three pseudo-boundary wells to adjust the material balance during simulation from the unsimulated area. The model has 111, 111, and 24 cells in the X, Y, and Z directions, respectively. The dimensions of each cell are 100 ft × 100 ft in the X × Y directions and varied in the Z direction. The reservoir conditions feature a temperature of 233°F and an average reservoir pressure of 4540 psi based on the reservoir depth. A 10-component equation of state (EOS) was used in the Eland sectional model. The estimated original oil in place is 38.3 MMbbl in the sector model.

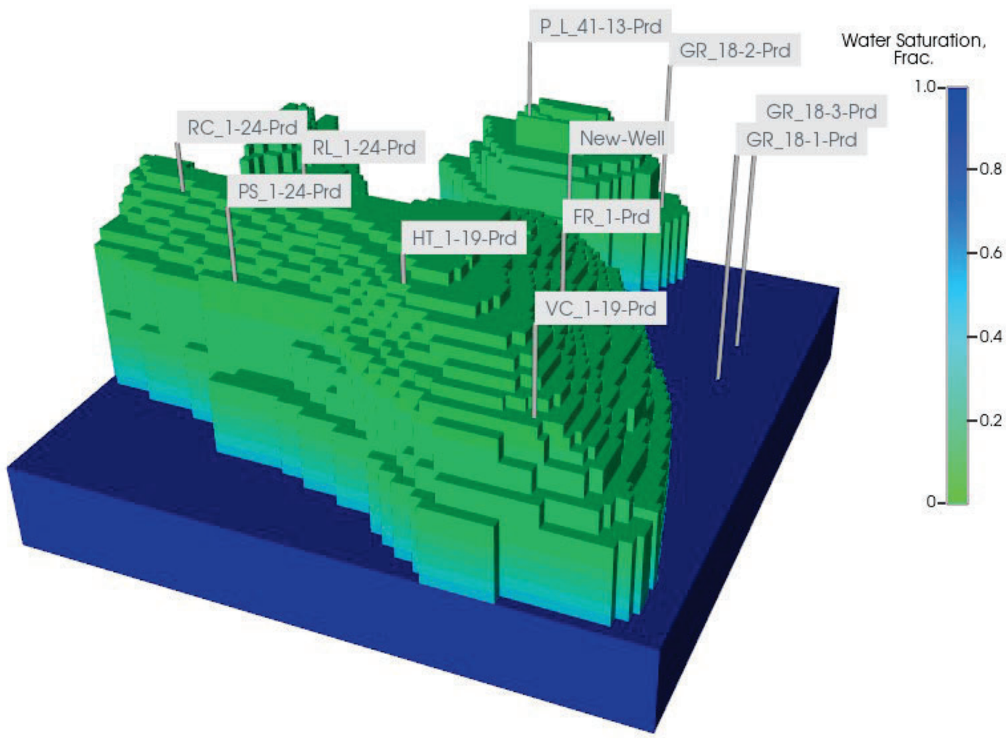

Figure 2-1. Simulation model for the selected section of the Eland Field. Vertical exaggeration is 20×.

Liquid production and water injection historical data were used as input constraints for the simulation model, as shown in Figure 2-2. The estimated well bottomhole pressure (BHP) was used as a secondary constraint to ensure that the model reflects the physical condition in the reservoir. To ensure the simulation model can mimic reservoir dynamics and predict CO_2 EOR performance, the model was tuned by matching the group production and injection history of the modeled area. Parameters including porosity, permeability, water saturation, and relative permeability curves were tuned to match the field's historical production trend. Since few fracture data are available for the Eland Field, an average effective permeability value was used for each layer.

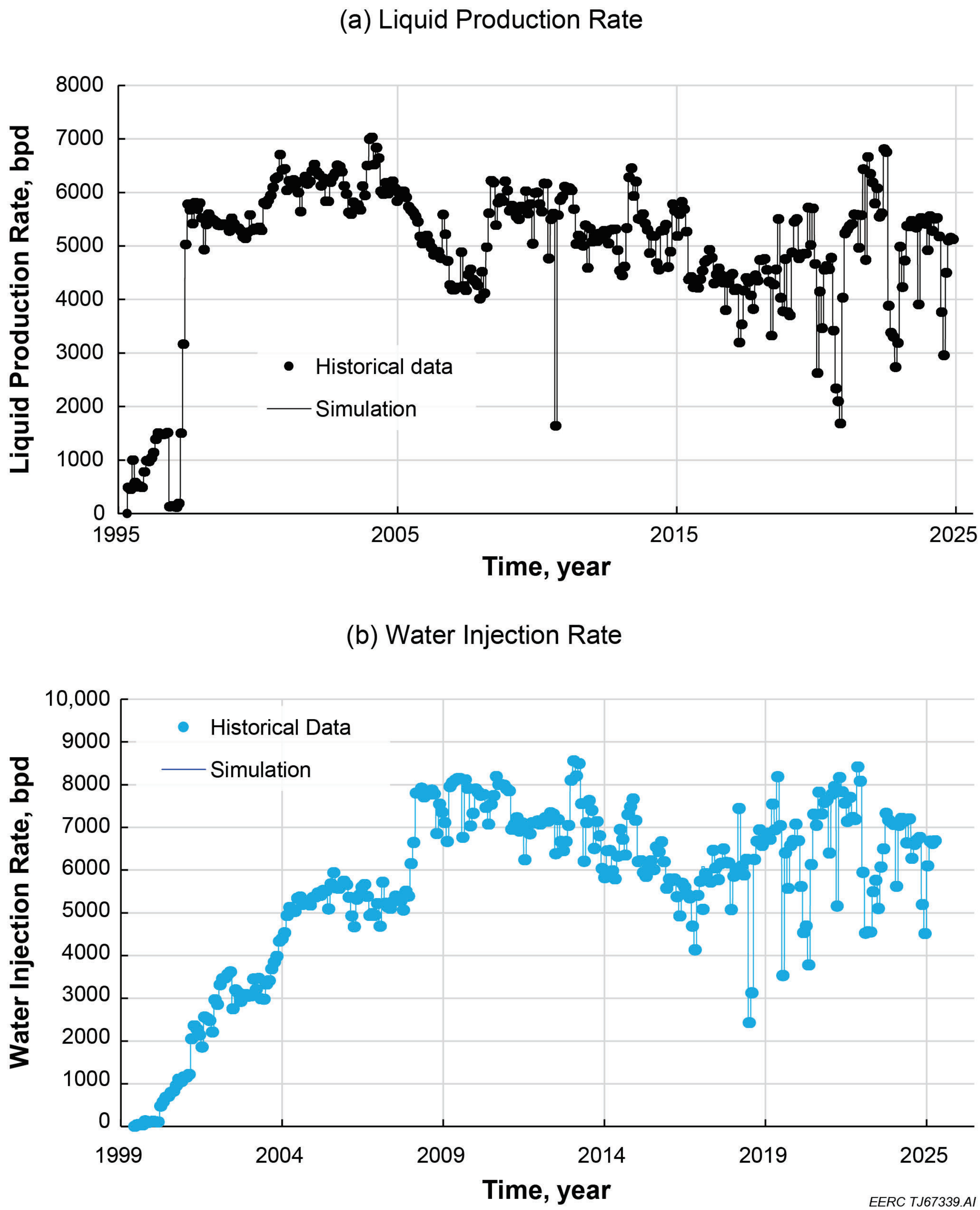

Figure 2-2. Input constraints for the simulation model: (a) liquid production rate and (b) water injection rate (bpd is barrels per day).

The model successfully replicated the overall reservoir behavior after a series of parameter tuning and production/injection analysis. Figure 2-3 shows the history match results for oil and water production rates, demonstrating that the model can capture the overall reservoir performance trends in the selected section of the Eland Field. This history-matched model was then used to predict future performance, including both regular production and CO_2 EOR-screening predictions.

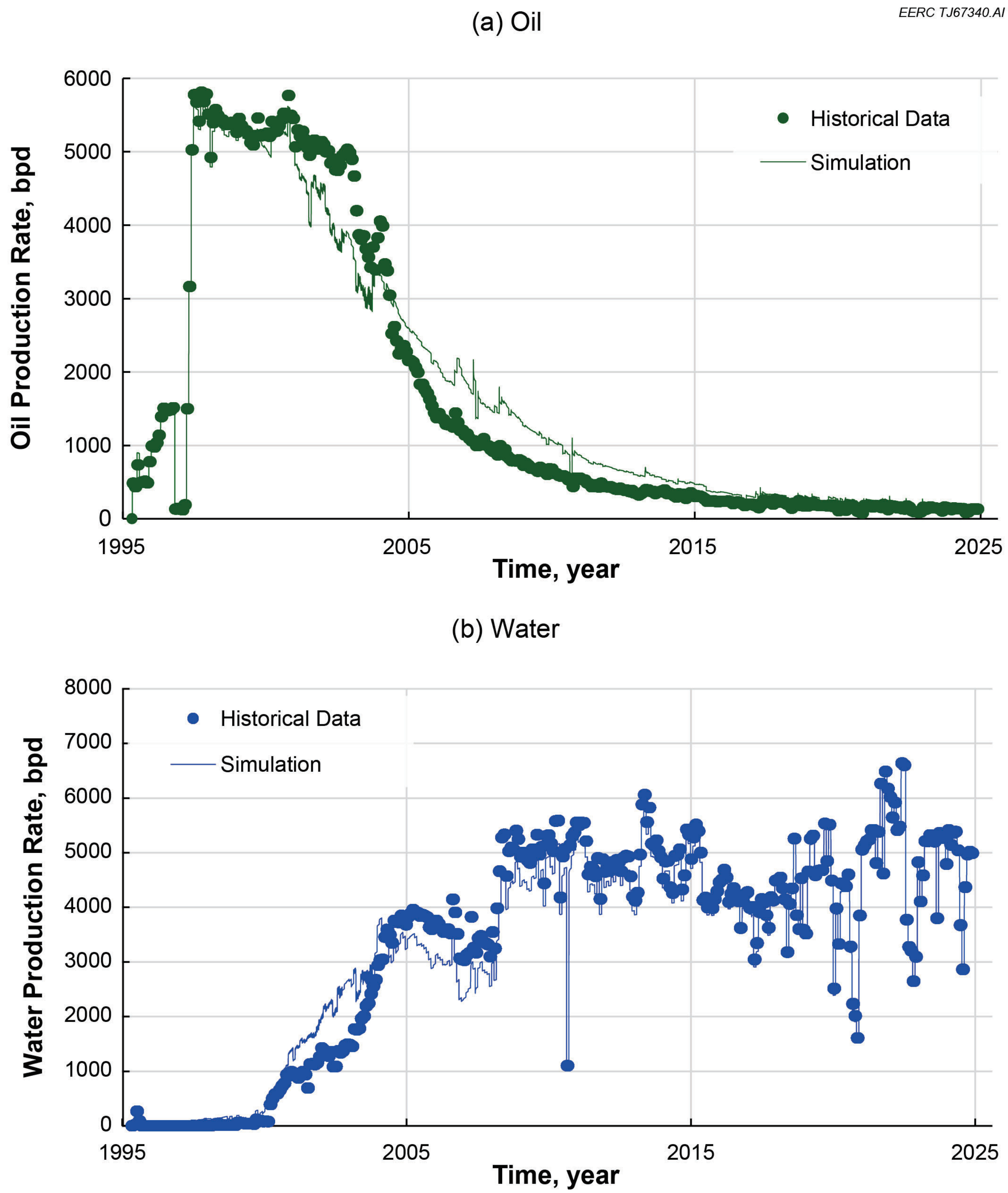

Figure 2-3. History match results for group production rates of the Eland Field section: (a) oil production rate and (b) water production rate.

3.0 PRELIMINARY CO_2 EOR PREDICTION

Two predictive simulation cases—one for regular production (business as usual) and the other for CO_2 flooding, were performed to assess if CO_2 could enhance oil recovery in the Eland Field. In the regular production case, six wells were open for production and two wells were open for water injection based on the latest field data. The group fluid production and water injection rates were set the same (6700 bpd) to keep the reservoir pressure stable. In the CO_2 EOR case, five wells were used for production, and two wells (Patterson Lake 41-13 [NDIC No. 13788] and Roller 1-24 [NDIC No. 13886]) were used for CO_2 injection. Bottomhole fluid rates were used to control production and injection during the CO_2 EOR process. Both group production and injection rates were set at 5000 bpd under reservoir conditions to maintain the reservoir pressure above the minimum miscibility pressure (~3000 psi).

Figure 3-1 illustrates that the average reservoir pressure could be maintained consistently during the predictive period (after 2025) for both cases. Figure 3-2 shows that CO_2 EOR could recover considerably more oil than regular production in the same period: the cumulative oil production volumes are 1.13 and 3.90 MMbbl for regular production and CO_2 EOR, respectively, over the next 30 years. The incremental oil recovery factors are 2.9% and 12.5% for these two cases, i.e., CO_2 EOR operation could recover approximately 10% of original oil in place (OOIP) more than regular production over 30 years based on the simulation settings.

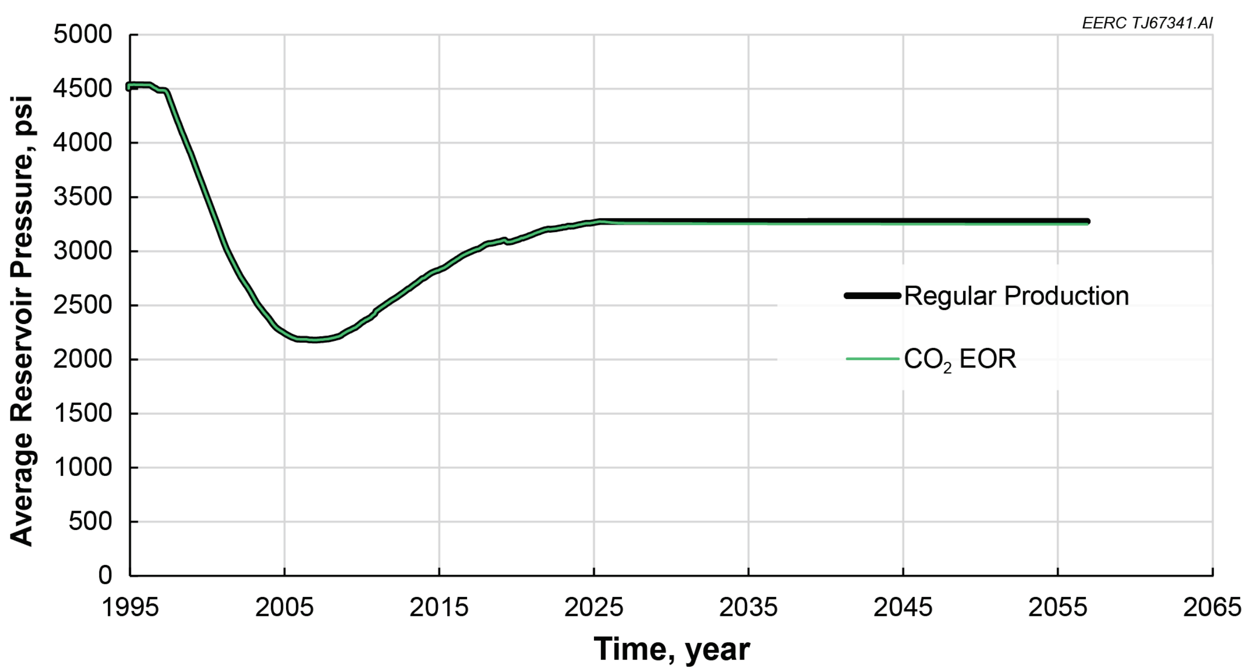

Figure 3-1. Prediction of average reservoir pressure for regular production and CO_2 EOR cases.

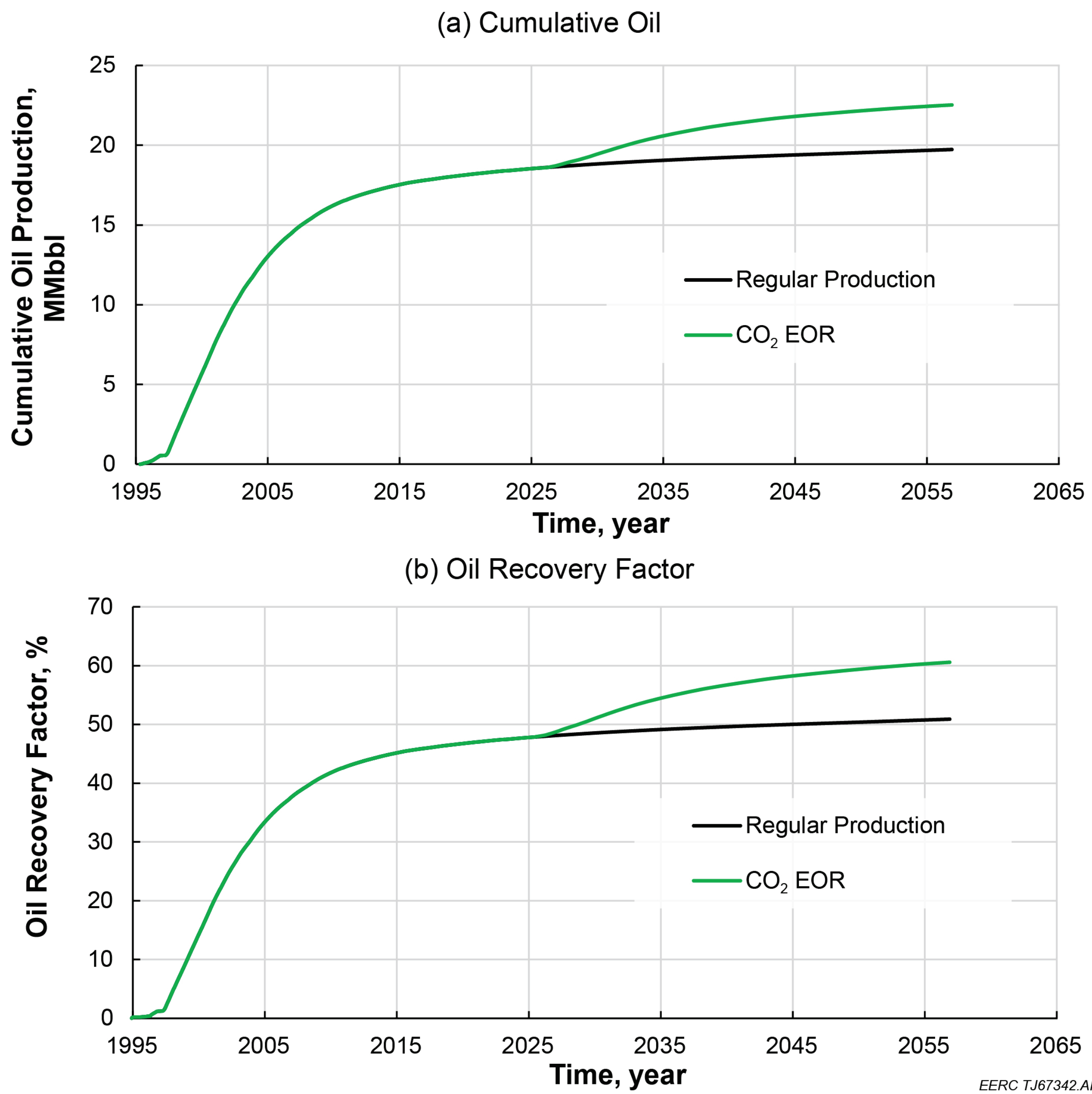

Figure 3-2. Prediction of oil production performance for regular production and CO_2 EOR: (a) cumulative oil production and (b) oil recovery factor.

The quantities of CO_2 injection, production, and storage in the simulated area are shown in Figure 3-3, which indicates that approximately 1 million tonnes of CO_2 would be permanently stored after 30 years of CO_2 flooding in the studied section of the field. CO_2 requirements are higher in the early years, with a peak utilization factor of 3 tonnes/bbl. The long-term (>10 years) CO_2 utilization factor could be 5–7 Mscf/bbl (or 0.26–0.36 tonnes/bbl), as shown in Figure 3-4. This indicates that CO_2 could improve oil production in the Eland Field.

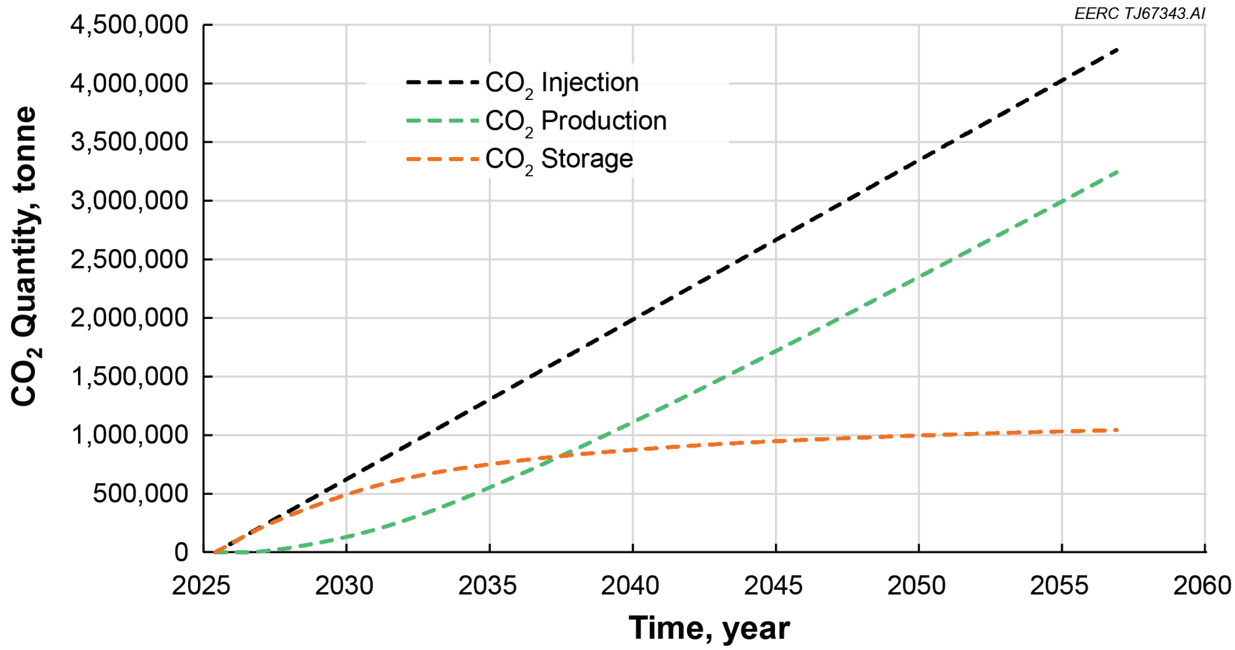

Figure 3-3. Predicted quantities of CO_2 injection, production, and storage in the simulated area.

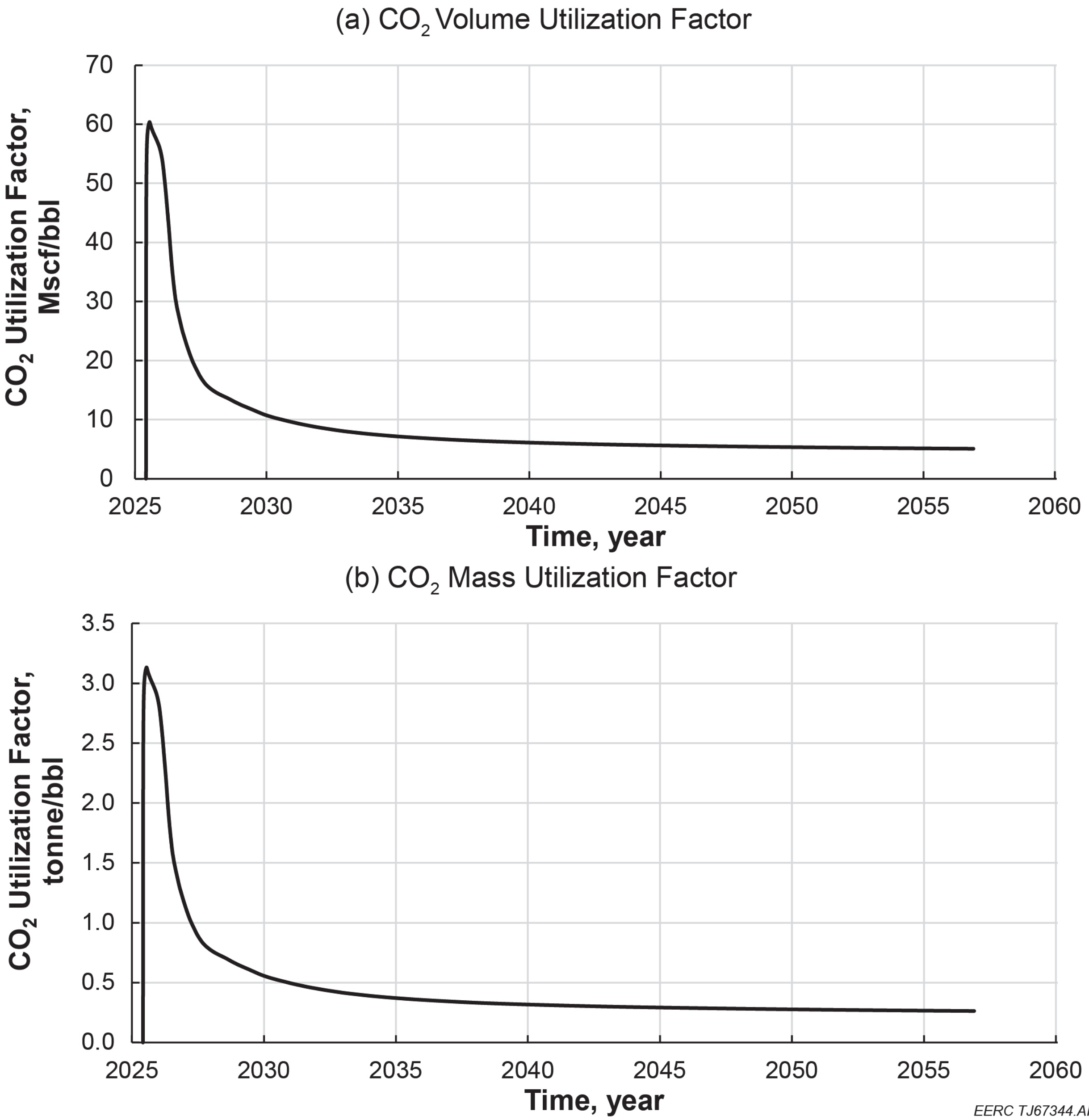

Figure 3-4. Prediction of CO_2 utilization efficiency in the simulated area: (a) CO_2 volume utilization factor and (b) CO_2 mass utilization factor.

4.0 CO_2 EOR PREDICTION UNDER VARIOUS OPERATION STRATEGIES

A series of six additional simulation cases, Cases 2–7, were designed to evaluate the sensitivity of CO_2 EOR performance to key operational and well completion strategies in the sector model of Eland Field. The cases were organized into four categories, as shown in Table 4-1: base EOR case represents the reference operating scenario for CO_2 EOR evaluation that was presented and discussed previously, CO_2 injection rate variation, operational pressure (reflected by average reservoir pressure) variation, and well completion configurations. These cases allowed a general assessment of the primary operational factors that influence incremental oil recovery, CO_2 utilization, and CO_2 storage performance in the studied area that the sector model covers.

Table 4-1. Summary of Operational Design Parameters for CO_2 EOR Simulation Cases

Category	Case No.	CO_2 Injection Rate, rb/d*	CO_2 Injection Rate, tonne/d	Average Reservoir Pressure, psi	Injection Well Completion	Production Well Completion
Base Case	1	5000	372	3250	Original**	Original
CO_2 Injection Rate	2	3000	224	3250	Original	Original
	3	7000	521	3250	Original	Original
Operational Pressure	4	5000	451	4040	Original	Original
	5	5000	276	2480	Original	Original
Well Completion	6	5000	372	3250	Top	Middle
	7	5000	372	3250	Top	Time-dependent

* rb/d: bbl/day under reservoir conditions.
** Original (all in the table): indicates a well has the same completion interval as it is reported in the well file.

Cases 2 and 3 were constructed by decreasing and increasing the CO_2 injection rate relative to the base case while keeping all other conditions consistent with it. Figures 4-1 and 4-2 illustrate cumulative oil production and oil recovery factor, respectively, over time for Cases 1–3 compared with the continuation of regular production without CO_2 injection. All CO_2 injection scenarios show incremental recovery attributable to CO_2 flooding. The result confirms that the Eland Field is responsive to miscible CO_2 flooding.

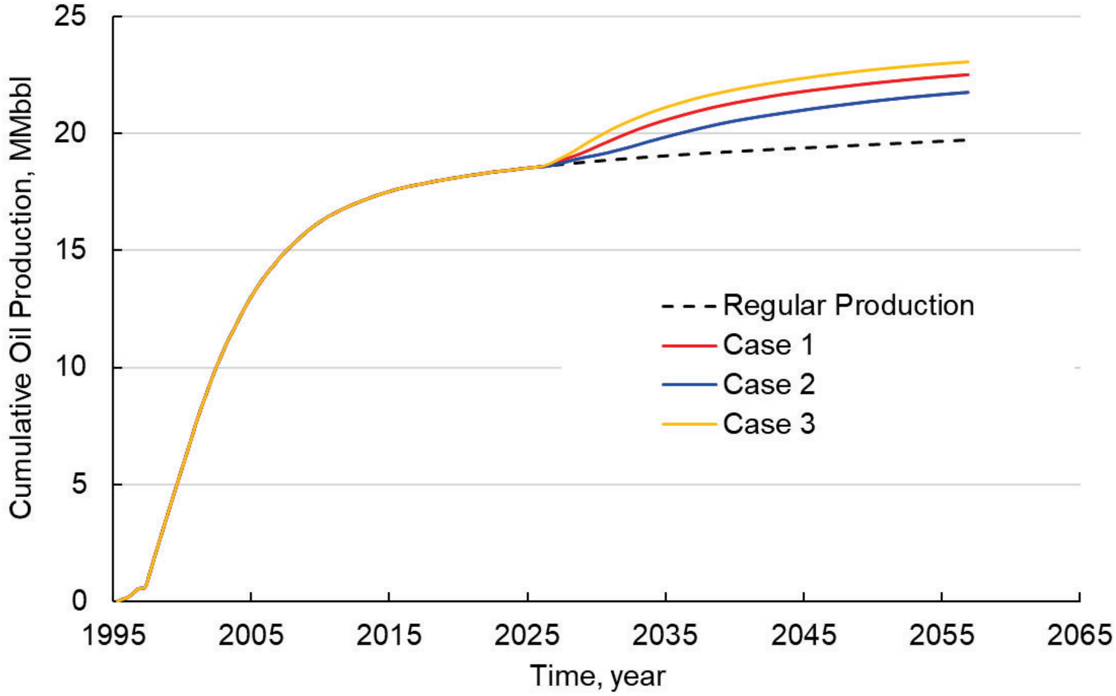

Figure 4-1. Effect of CO_2 injection rate on cumulative oil production.

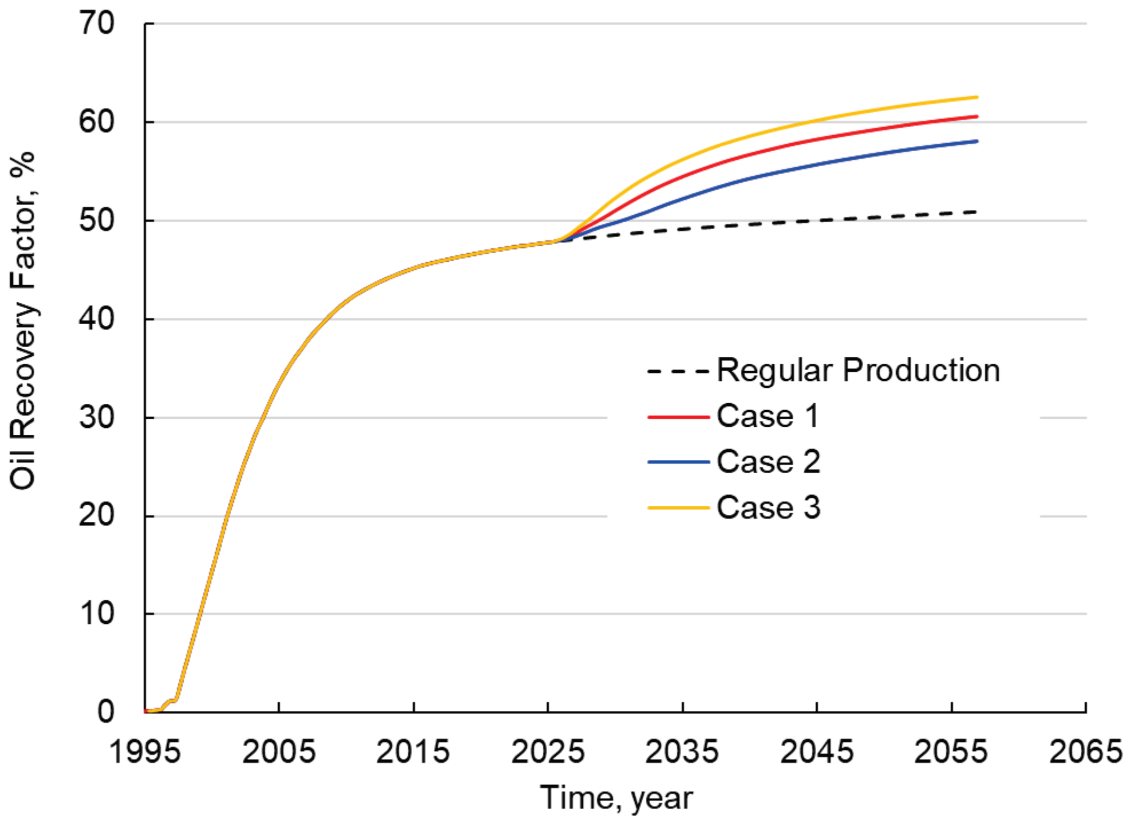

Figure 4-2. Effect of CO_2 injection rate on oil recovery.

Throughout the simulated production period, the base case shows noticeably higher cumulative production and recovery factor compared to regular production and stays between Cases 2 and 3. The curve shape suggests efficient sweeping and sustained incremental recovery over the predicted operation. Case 2 yields lower oil recovery improvement, with ultimate recovery around 58.1%. The lower injection rate slows down the oil-displacing process and reduces the volume of CO_2 contacting the remaining oil in the reservoir, resulting in a lower recovery curve. Although the response is still positive relative to regular production, the diminished slope reflects reduced sweep volume and delayed EOR effectiveness. The separation between Case 2 and the other two cases underscores that an insufficient CO_2 injection rate limits both the rate and magnitude of incremental oil recovery.

Case 3 consistently delivers higher cumulative oil production than Cases 1 and 2. The production curve rises more rapidly after the onset of CO_2 injection and maintains an advantage throughout the entire forecast. By the end of the simulation, the curve reaches the highest cumulative oil volume among the three scenarios, consistent with an incremental oil of ~4.52 MMbbl and an ultimate recovery of 62.6%. The steeper slope of Case 3 indicates faster reservoir sweep and more aggressive displacement. This suggests the reservoir can accommodate higher CO_2 injection rates for EOR optimization.

Figures 4-3–4-5 illustrate the CO_2 storage performance and utilization factors for Cases 1–3. All cases experience rapid CO_2 accumulation during the first 10 years followed by a slower increase as the reservoir has less available pore space to store CO_2. The base case stores just over 1 million tonnes of CO_2 by 2056. This leads to an average net CO_2 utilization factor of 0.26 tonnes/bbl (or 5.07 Mscf/bbl) at the end of the simulation period. Case 2, which uses the reduced injection rate of 3000 bbl/day under reservoir conditions, stores the least CO_2 at 0.88 million tonnes. The lower CO_2 injection rate not only leads to less CO_2 storage but also a slightly higher CO_2 utilization factor of 0.27 tonnes/bbl (or 5.29 Mscf/bbl). In contrast, Case 3 yields better CO_2 storage, 1.17 million tonnes. The net utilization factor remains comparable to Case 1, at 0.26 tonnes/bbl (or 5.00 Mscf/bbl)

These results show that the reservoir can accommodate a higher injection rate without an injectivity concern. A higher CO_2 injection rate will improve oil recovery and total CO_2 stored. The net CO_2 utilization factor remains comparable, though a higher CO_2 injection rate will slightly improve it.

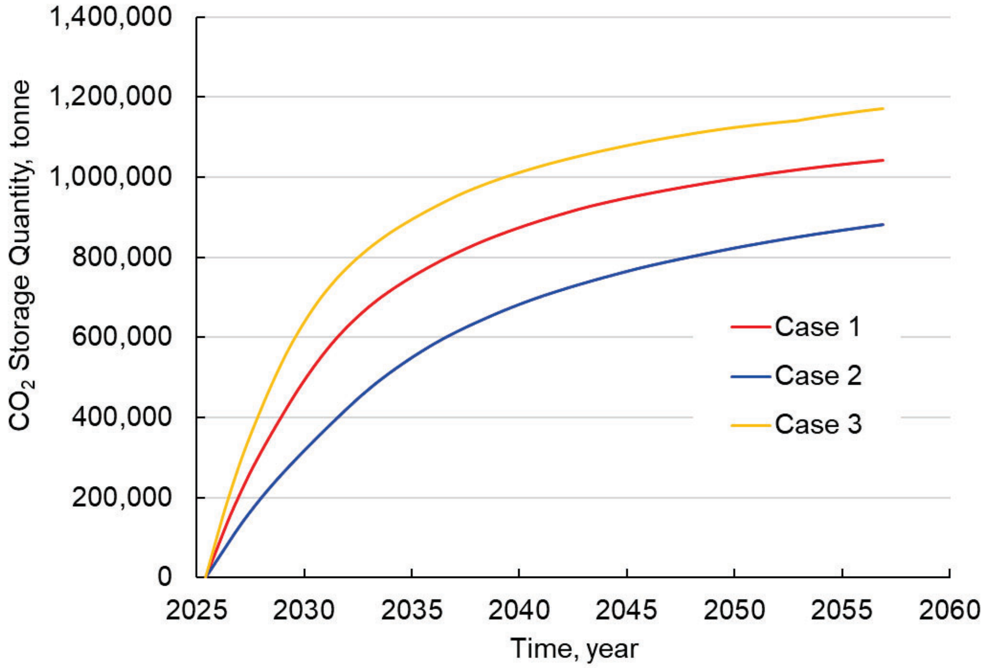

Figure 4-3. Comparison of Cases 1–3 shows the effect of CO_2 injection rates on CO_2 storage.

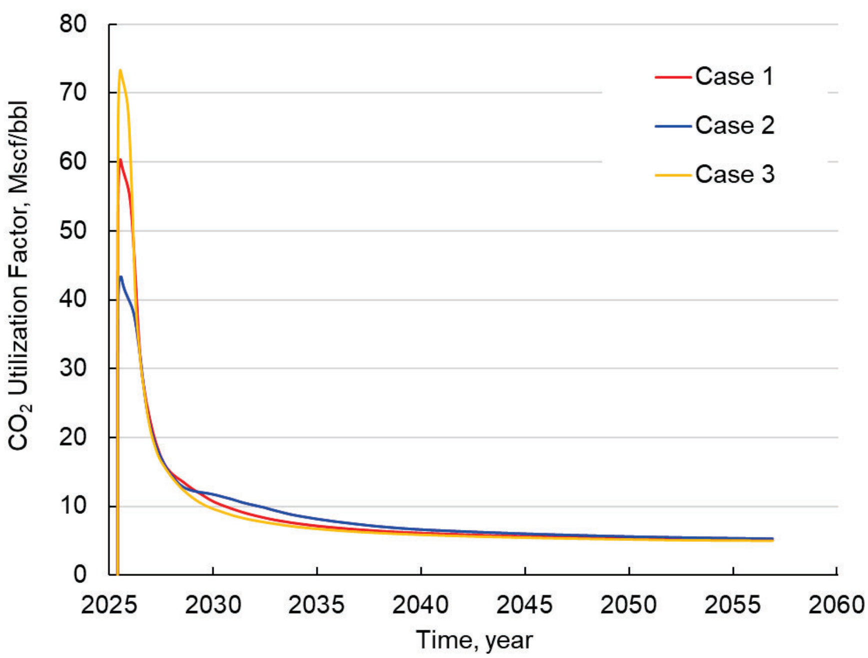

Figure 4-4. Comparison of Cases 1–3 shows the effect of CO_2 injection rates on CO_2 utilization factor, estimated in Mscf/bbl.

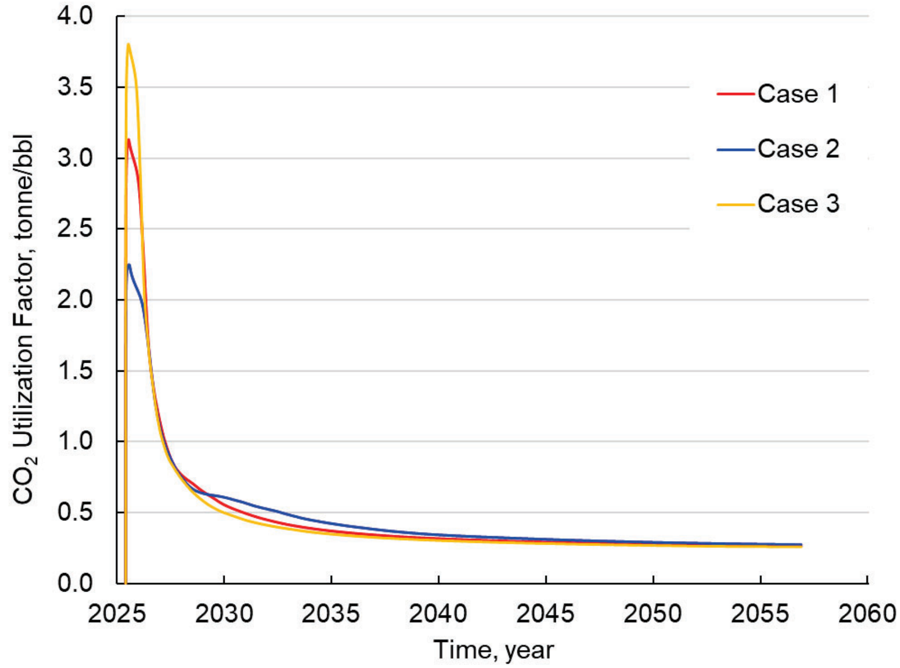

Figure 4-5. Comparison of Cases 1–3 shows the effect of CO_2 injection rates on CO_2 utilization factor, estimated in tonne/bbl.

Cases 4 and 5 evaluate the influence of average reservoir pressure on CO_2 EOR performance while keeping injection rate and completions unchanged. Case 4, which increases reservoir pressure to 4040 psi, shows a notable improvement in both oil recovery and CO_2 storage. Incremental oil production rises to 4.58 MMbbl, and ultimate recovery reaches 62.8%, slightly higher than Case 3. The higher reservoir pressure enhances miscibility, increases sweep efficiency, and reduces residual oil saturation. The higher pressure environment also raises CO_2 storage to 1.47 million tonnes. The long-term net CO_2 utilization factor therefore increased to 0.32 tonnes/bbl (or 6.17 Mscf/bbl), indicating deeper CO_2 penetration into the reservoir.

In contrast, Case 5 reduces reservoir pressure to 2480 psi, significantly deteriorating performance. Incremental oil falls to 2.90 MMbbl, and ultimate recovery drops to 57.3%. The lower pressure limits miscibility and reduces sweep efficiency. CO_2 storage also declines sharply to 0.66 million tonnes, less than half of Case 4. The low utilization factor (0.23 tonnes/bbl, or 4.35 Mscf/bbl) reflects poor sweep and storage efficiency. Together, Cases 4 and 5 demonstrate that reservoir pressure is one of the most influential parameters in the studied area, with high pressure providing substantial benefits while low pressure severely constraining both EOR and storage outcomes.

Cases 6 and 7 examine how modifying the injection and production well completions influence CO_2 sweep efficiency and overall EOR performance. Figures 4-6 and 4-7 illustrate well completion locations for an injection well and a production well, respectively. Case 6 shifts the production well completion from the original interval to the middle reservoir zone while keeping the injection well completed at the top (the completion interval length is tuned to ensure the CO_2 injectivity). This configuration increases incremental oil production to 4.82 MMbbl and the ultimate recovery to 63.1%, which slightly exceeds the high-pressure Case 4. CO_2 storage also improves to 1.10 million tonnes, and the utilization factor decreases to 0.23 tonnes/bbl (or 4.41 Mscf/bbl), suggesting more efficient CO_2 usage per barrel of oil recovered. The vertical separation between injection (top) and production (middle) enhances gravity-stable flow and delays breakthrough, contributing to better sweep.

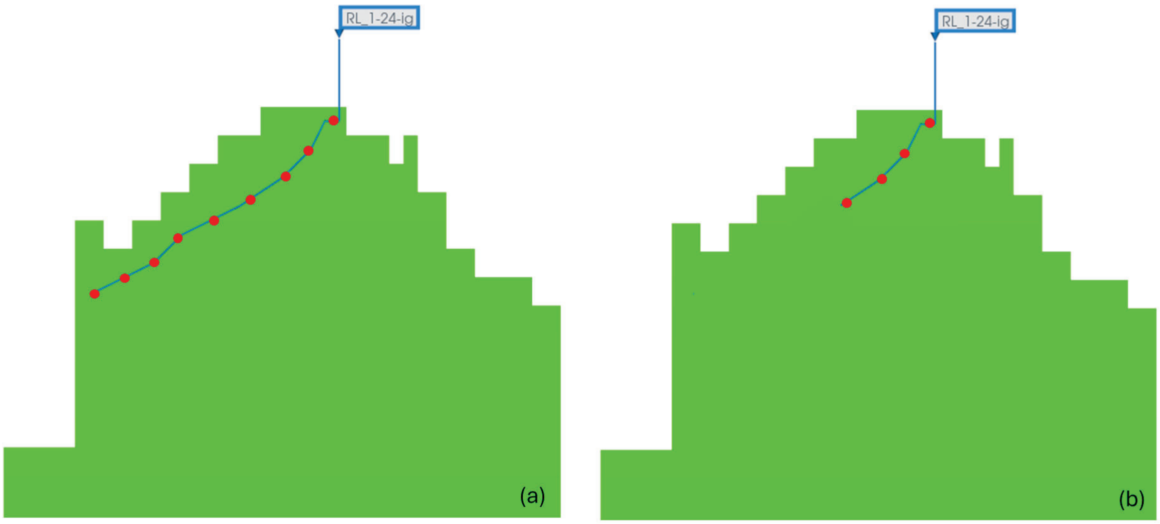

Figure 4-6. Schematic of different completion locations for an injection well: (a) original completion and (b) top completion.

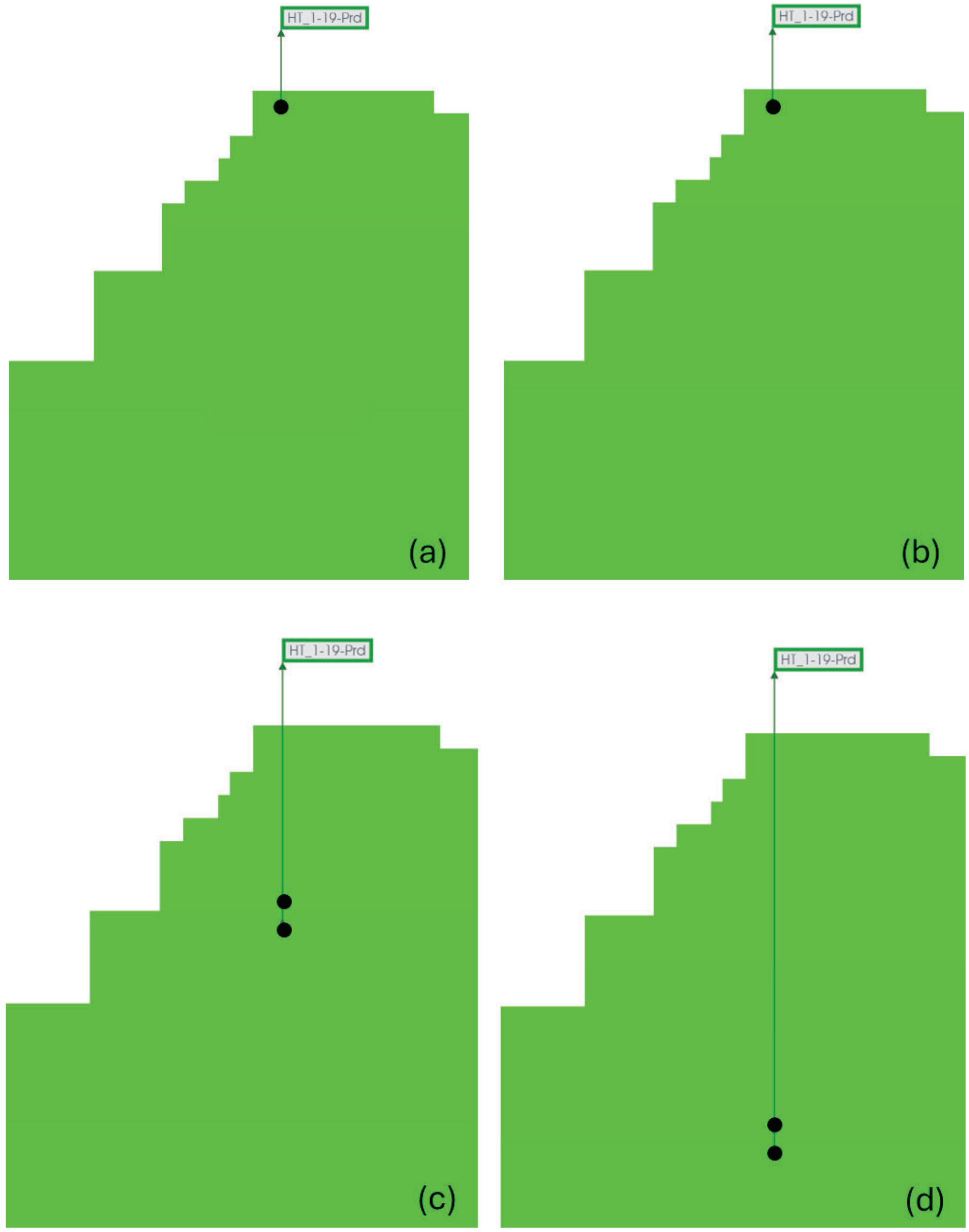

Figure 4-7. Schematic of different completion locations for a production well: (a) original completion, (b) top completion, (c) middle completion, and (d) bottom completion.

Case 7 introduces a time-dependent production well completion, which dynamically adjusts the producing interval over time to better capture mobilized oil and delay CO_2 arrival. Figure 4-8 compares gas saturation distribution in the reservoir at the end of CO_2 EOR prediction for Cases 1 and 7. The comparison clearly illustrates the improvement of CO_2 sweep efficiency by completing the production completion at the lower part of the reservoir. By sweeping CO_2 vertically through the reservoir, Case 7 becomes the highest-performing scenario in the study. Incremental oil production rises dramatically to 6.76 MMbbl, and ultimate oil recovery reaches 69.3%, which is 8.7% higher than the base case and substantially higher than any other scenario. CO_2 storage also reaches 2.43 million tonnes, which is more than any other case. The long-term CO_2 utilization factor of Case 7 is the highest among all scenarios, 0.36 tonne/bbl (or 6.93 Mscf/bbl).

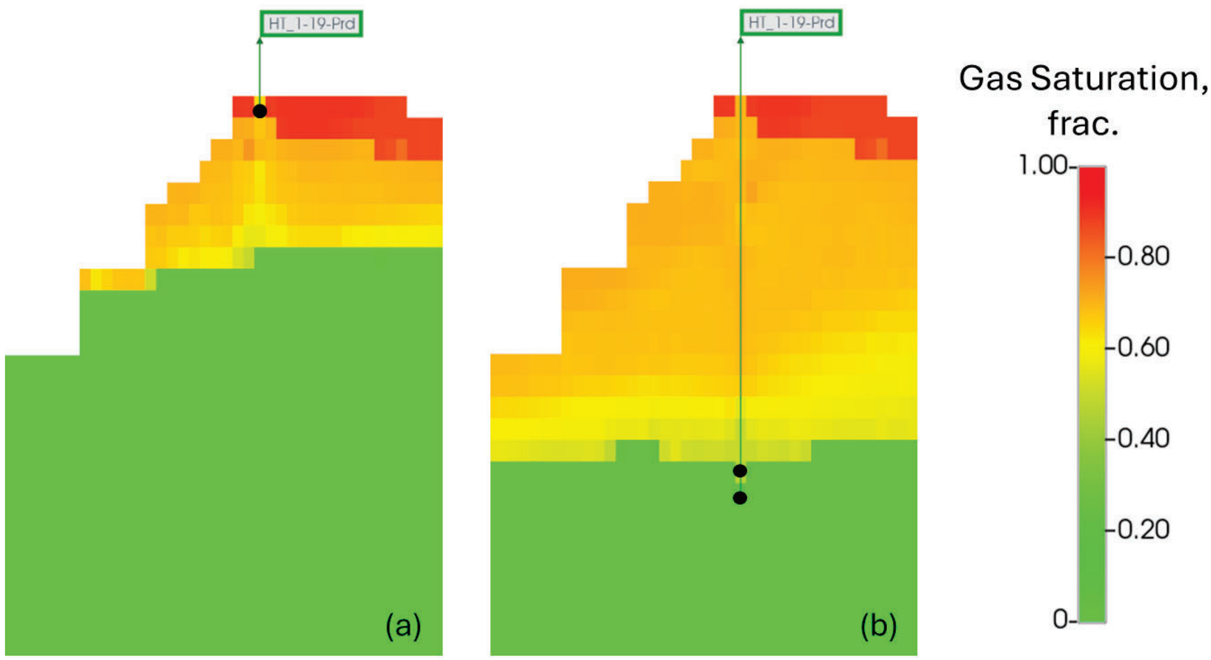

Figure 4-8. Comparison of gas saturation distribution in the reservoir at the end of CO_2 EOR prediction: (a) Case 1 and (b) Case 7.

Table 4-2 summarizes the key predictive CO_2 EOR and storage results for Cases 1–7. Changing the CO_2 injection rate shows meaningful differences, though the CO_2 utilization factor remains comparable. The high-rate case (Case 3) outperforms both the base case and low-rate Case 2, delivering higher incremental oil and greater CO_2 storage. The reduced injection rate limits contact between oil and CO_2 in the reservoir, therefore yielding lower oil recovery and CO_2 storage. These results suggest that the field CO_2 EOR will benefit from maintaining moderate to high injection rates as long as facility constraints allow.

Table 4-2. Summary of Predictive CO_2 EOR and Storage Results for Cases 1–7

Case No.	Incremental Oil Production, bbl	Ultimate Oil Recovery, %	CO_2 Storage, tonne	Long-Term Net CO_2 Utilization Factor, tonne/bbl (Mscf/bbl)
1	3,965,828	60.6	1,042,342	0.26 (5.07)
2	3,211,008	58.1	881,783	0.27 (5.29)
3	4,515,648	62.6	1,171,523	0.26 (5.00)
4	4,582,222	62.8	1,467,276	0.32 (6.17)
5	2,903,860	57.3	655,649	0.23 (4.35)
6	4,820,894	63.1	1,102,150	0.23 (4.41)
7	6,764,026	69.3	2,431,333	0.36 (6.93)

Reservoir pressure significantly influences both CO_2 EOR and storage performance. High-pressure operation in Case 4 improves miscibility and sweep, leading to higher recovery and CO_2 retention than the base case. In contrast, Case 5 shows the lowest oil recovery and storage across all scenarios as the average reservoir pressure is below the MMP (estimated at 3000 psi). This demonstrates that maintaining the reservoir pressure near or above MMP is essential for both effective EOR and long-term CO_2 storage.

Completion design offers some of the largest performance gains. Case 6 improves CO_2 sweep efficiency by adjusting the well completions vertically, improving oil recovery and CO_2 storage relative to the base case. Case 7, which uses time-dependent production completions, achieves the best overall performance. It produces the highest incremental oil, the highest recovery factor, and the greatest amount of CO_2 stored. This indicates that targeted completion strategies can be highly effective and may provide more benefits than changing the injection rate alone.

Overall, CO_2 EOR remains a promising EOR method for the Eland Field, with the poorest-performing CO_2 EOR case predicting 6% more recovery factor compared to the regular production (57.3% vs. 50.9%) and the most optimal prediction, Case 7, showing 18% more recovery factor compared to the regular production (69.3% vs. 50.9%). Cases 4, 6, and 7 are the best-performing scenarios among six additional simulated cases, demonstrating that combining miscible-pressure operation with optimized well completions will most effectively maximize both oil production and long-term CO_2 storage in the Eland Field.

5.0 DISCUSSION AND FUTURE WORK

Knudsen and others (2009) estimated that the oil recovery factor could be between 37% and 42% for the Eland Field at the time they conducted the work. In contrast, the simulation model in this work estimated a slightly higher recovery factor for the same production period, possibly because the section model contains a few of the most productive wells in the field. With that, it is reasonable to believe that a ±5% difference in recovery factor estimation is reasonable to believe. The preliminary CO_2 EOR simulation showed that an additional 12.5% of OOIP could be recovered through miscible CO_2 flooding over 30 years. It is anticipated that most of the CO_2

injected during the early years will remain in the reservoir, resulting in a higher CO_2 utilization factor. With CO_2 breakthrough and recycling, the additional CO_2 injection source requirement is expected to gradually decline over time, leading to a lower utilization factor. The long-term (>10 years) CO_2 utilization factor could be 5–7 Mscf/bbl (or 0.26–0.36 tonnes/bbl). Different injection rate, BHP control, and completion strategies were evaluated and confirmed the operation strategy and reservoir management will influence the oil recovery and net CO_2 utilization factors. The simulations indicated variability and uncertainty in the predicted oil recovery factors, which may be associated with the current stage's model limitations. Therefore, future investigations supported by additional data and detailed reservoir modeling to better understand the effectiveness of the different operational strategies are required.

It is worth noting that this investigation constitutes an initial CO_2 EOR-screening simulation and, at this stage, does not incorporate a fully resolved geologic model or the explicit representation of natural fracture networks. Although a fractured reservoir model using the Embedded Discrete Fracture Models method has been tested, the lack of an explicit natural fracture description and greater uncertainty in the fracture network assumptions, it has been found that the model may overestimate the oil recovery factor for CO_2 EOR. Subsequent phases of the study may encompass advanced geologic modeling and comprehensive history-matching workflows to support full-field development planning and implementation.

Based on the findings of this preliminary CO_2 EOR investigation in the Eland Field, several areas of future work are recommended to reduce uncertainty, optimize development design, and ensure successful implementation of a full-field EOR program:

1) Comprehensive geological and reservoir characterizations
   - Acquire new well logs and pressure buildup test to better define reservoir heterogeneity, fracture distribution, oil saturation distribution, and position of the OWC.
   - Conduct laboratory studies (relative permeability, capillary pressure, miscibility tests) to strengthen the reservoir simulation input dataset.

2) Full-field dynamic simulation and history matching
   - Develop a full-field geologic model incorporating natural fractures and heterogeneities beyond the sectional model.
   - Perform detailed history matching at the well level to constrain uncertainties.
   - Conduct sensitivity and optimization studies to evaluate injection/production strategies, well placement, and CO_2 utilization efficiency.

3) CO_2 supply, storage, and monitoring strategy
   - Evaluate CO_2 sourcing, transportation, and injection infrastructure requirements for full-field scale operations.
   - Design a monitoring, verification, and accounting program to track CO_2 storage security and long-term retention.
   - Quantify storage capacity and evaluate cobenefits of permanent CO_2 sequestration in conjunction with EOR.

4) Economic and risk assessment
   - Update economic analyses with refined reservoir forecasts, CO_2 supply costs, and oil price sensitivities.
   - Assess project risks, including injectivity, CO_2 breakthrough timing, and long-term operational requirements.
   - Develop decision gates for pilot expansion and phased field implementation.

5) Field pilot and optimization
   - Implement a phased pilot CO_2 injection program in the Eland Field to validate model predictions under controlled operating conditions.
   - Collect field data to improve understanding of CO_2 sweep efficiency, breakthrough behavior, and incremental recovery.
   - Use pilot learnings to optimize injection patterns, rates, and cycling strategies for full-field deployment.

The next phase of work should transition from preliminary screening to fully integrated reservoir characterization, detailed simulation, and field data acquisition. A structured pilot test, coupled with robust economic and risk analyses, will be critical to derisking full-field CO_2 EOR implementation while maximizing both oil recovery and CO_2 storage potential.

6.0 CONCLUSIONS

This work represents a preliminary evaluation of CO_2 EOR potential in the Eland Field of the DLM. A sectional reservoir simulation model was developed using publicly available geologic, petrophysical, and production data and calibrated to match primary and secondary production performance. The calibrated model was used to forecast incremental oil recovery from miscible CO_2 flooding. Overall, the Eland Field shows potential for CO_2 EOR and associated storage. Key conclusions are summarized as follows:

1) Miscible CO_2 flooding could achieve significant incremental recovery, with approximately 3.9 MMbbl of oil (12.5% of OOIP) over a 30-year period in the modeled area. CO_2 requirements are higher in the early years, with a peak utilization factor of 3 tonnes/bbl. The long-term CO_2 utilization factors could be 0.26–0.36 tonnes/bbl. Roughly 1 million tonnes of CO_2 could be stored in the reservoir section over 30 years, demonstrating the potential for dual benefits of oil recovery and carbon storage.

2) Different operation strategies will influence CO_2 EOR performance. Higher injection rates provide some benefit, but the scenarios that maintain miscible pressure and apply targeted completion designs best improve oil recovery and long-term CO_2 storage. The incremental oil production ranges from 2.9 to 6.7 MMbbl. The estimated incremental oil recovery factors through CO_2 EOR are approximately 6%–18% compared to the regular production recovery factor estimate. Net CO_2 utilization factor ranges from 0.23 to 0.36 tonnes/bbl.

3) In alignment with previous studies on DLM (Knudsen and others, 2009; Zhao and others, 2020), results confirm that the Eland Field remains a strong candidate for CO_2 EOR, although optimization of development strategy is essential to maximize recovery efficiency.

4) Current results are subject to uncertainty because of reliance on limited public datasets and the absence of detailed fracture characterization, relative permeability data, and full-field geologic modeling.

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APPENDIX B

FACT SHEET: CO_2 STORAGE ON PUBLIC LANDS WORKING WITH BUREAU OF LAND MANAGEMENT FOR SAFE SEQUESTRATION

CO_2 Storage on Public Lands

WORKING WITH BUREAU OF LAND MANAGEMENT FOR SAFE SEQUESTRATION

Carbon capture, utilization, and storage (CCUS) is a technology used to support continued energy development. When CCUS occurs on public land, the Bureau of Land Management (BLM) plays a key role in authorizing and regulating projects. These projects can include surface infrastructure as well as underground pore space use for CO_2 storage. Understanding how BLM manages pore space and surface rights of way (ROWs) for these projects is essential to advancing safe, permanent CO_2 storage alongside responsible land and resource management.

WHO IS BLM?

BLM is a federal agency within the U.S. Department of the Interior. It manages a large portion of America's public lands—about 245 million acres of surface land—and oversees roughly 30% of the nation's mineral resources. BLM plays a key role in balancing conservation, energy development, recreation, and other land uses.

WHAT IS A BLM ROW?

A ROW legally authorizes the use of public land for specific purposes over a set period of time. ROWs are commonly used for infrastructure like roads, pipelines, power lines, and communication systems. ROWs can also be granted for underground pore spaces associated with long-term CO_2 storage projects.

WHAT IS PORE SPACE?

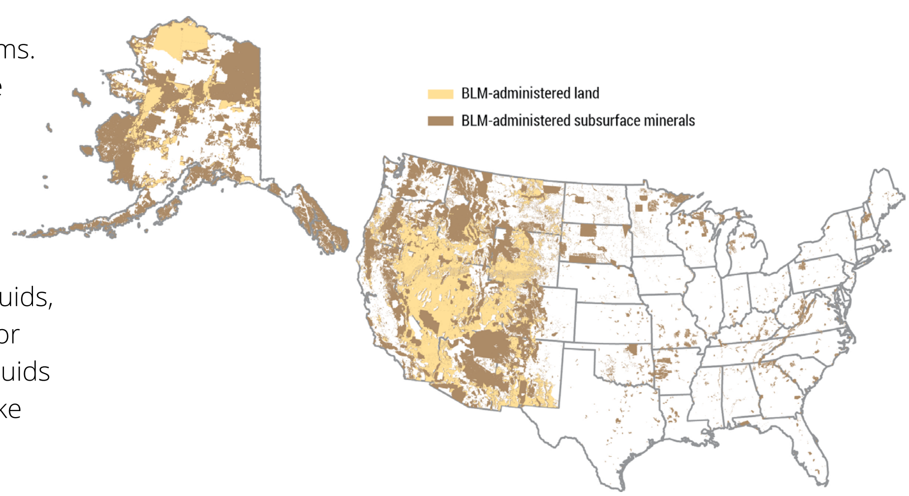
Pore space is the voids or gaps among grains in sedimentary rocks. These spaces are filled with fluids, like water or oil, or natural gas. When new fluids or gases are injected into these rocks, the existing fluids are displaced, creating room to store materials like carbon dioxide.

TWO METHODS OF CO_2 STORAGE

The two main ways to permanently store CO_2 deep underground are **dedicated storage** and **associated storage**.

- Dedicated storage involves injecting CO_2 into deep underground rock layers called saline formations using specially regulated wells known as underground injection control (UIC) Class VI wells. These wells are designed for long-term CO_2 storage.
- Associated storage happens as part of a process called enhanced oil recovery (EOR). In this method, CO_2 is injected into oil and gas reservoirs using UIC Class II wells to help push out more oil. After the oil is recovered, More than 97% of the CO_2 stays trapped in the underground rock.

Both methods can be used to store CO_2 permanently beneath public land, but they are governed by different rules and are managed under separate programs by BLM.



Source:https://publicland.org/about/blm-flpma/

DEDICATED CO_2 STORAGE USING PUBLIC LAND

For dedicated carbon storage projects on public lands, BLM issues ROWs under Title V of the Federal Land Policy and Management Act of 1976 (FLPMA). These ROWs allow for the use of public land to build and operate infrastructure like injection wells and pipelines. ROWs also authorize the use of underground pore space for CO_2 injection and storage. In some cases, the project may solely involve a subsurface pore space ROW because no surface infrastructure is needed on public land or BLM does not own the surface land.

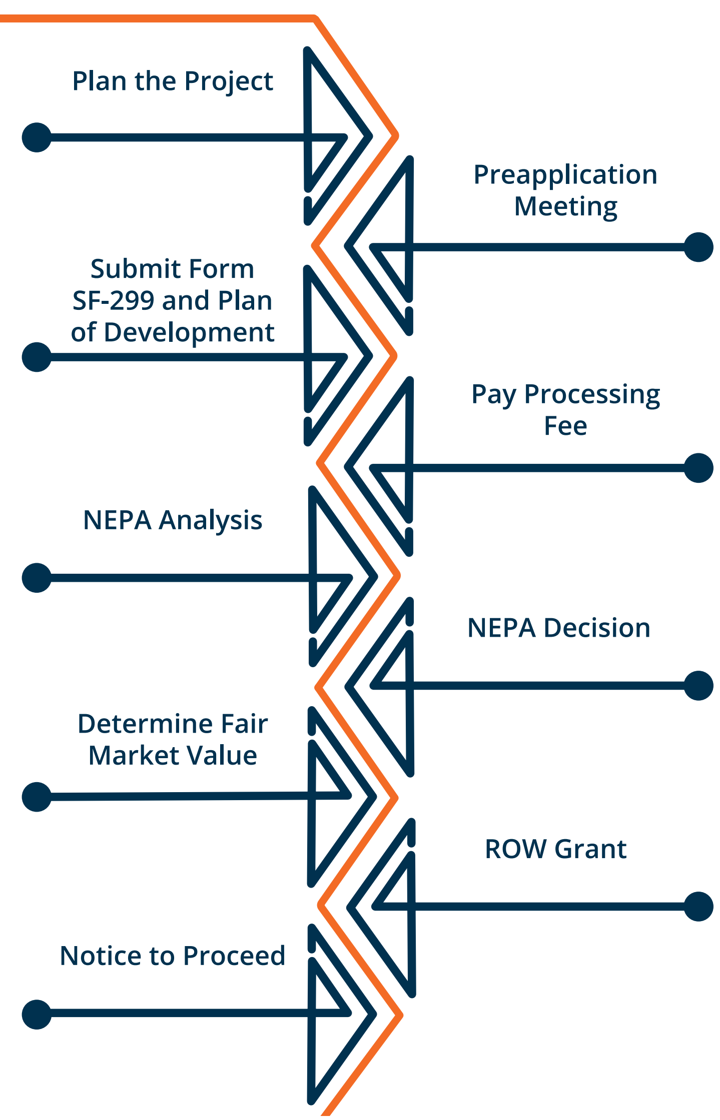
Something to note is that landownership can be split. For example, the federal government might own the surface but not the underground rights—or vice versa. In most cases, the pore space is owned by whomever owns the surface, but ownership can vary state to state and may require further investigation.

PROCESS FOR ISSUING A ROW FOR DEDICATED STORAGE

BLM has a process for applicants to follow when seeking a ROW for CO_2 storage (see flowchart). This process includes meeting with BLM early in the planning stages to determine pore space ownership, land availability, and potential conflicts. Next, the applicant submits a ROW application (Form SF-299) and a plan of development outlining the full project scope, along with required fees and a cost recovery agreement. Fair market value of the land and/or pore space use is also determined.

BLM next conducts a National Environmental Protection Act (NEPA) analysis that includes public input and mitigation planning to reduce environmental impacts, coordinating with other agencies as needed. If approved, BLM issues a ROW grant (typically for a 30-year renewable term) specifying surface and/or subsurface use, bonding requirements, monitoring and reporting conditions, and rent and fee structure. A notice to proceed is issued once the applicant obtains the required UIC Class VI permits from the U.S. Environmental Protection Agency (EPA) or the state with primacy.

All CCUS-related ROW authorizations stipulate the ROW holders comply with federal and state laws, prevent damage to potentially recoverable mineral resources, and avoid interference with any operations authorized under the Mineral Leasing Act of 1920 (MLA).



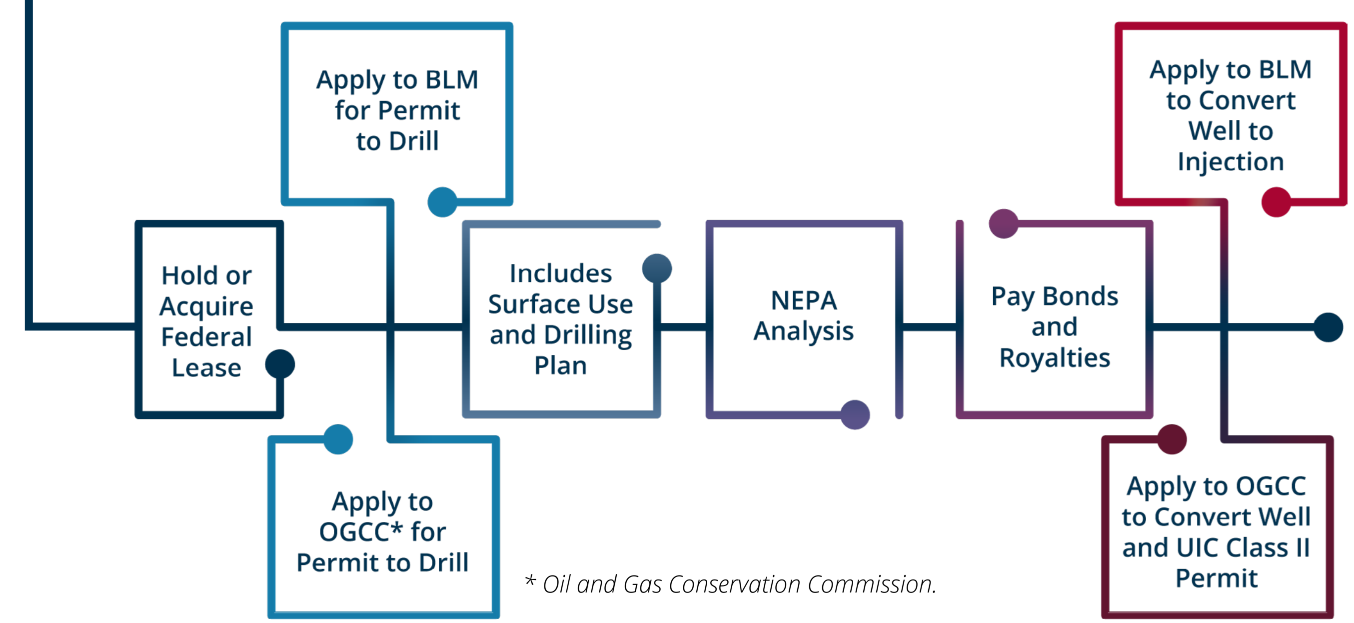
ASSOCIATED CO_2 STORAGE USING PUBLIC LAND

BLM has the authority to manage oil and gas resources on public lands in the lower 48 states because of two main laws: the MLA and the Mineral Leasing for Acquired Lands Act of 1947. When EOR projects involve federal leases, BLM oversees their approval and maintenance. The exception is Alaska, where BLM's authority is established under the Department of the Interior Appropriations Act.[1]

The process for gaining BLM approval for an EOR project on public land is different than storing CO_2 as part of a Class VI dedicated storage project. For an EOR project, the applicant must hold or acquire a federal oil and gas lease and obtain a permit to drill from BLM and the applicable state oil and gas regulatory agency. Usually, a well is drilled first for oil production and then is converted to an injection well for waterflood or CO_2 enhanced recovery. Below is a flowchart showing the general approach for obtaining BLM approval to pursue an EOR project on public lands. Both Class VI dedicated storage and CO_2 EOR projects require a UIC permit from EPA or the state with primacy as well as NEPA analyses. For CO_2 EOR, the required permit is a UIC Class II permit. Unlike dedicated storage projects, BLM does not require a subsurface ROW grant and valuation to inject CO_2 into the federal subsurface for EOR projects where oil is being produced.

WHAT IS A FEDERAL OIL AND GAS LEASE?

A federal oil and gas lease is a contract that grants a private company (the lessee) permission to search for and produce oil and gas from a specific area of public land for a set amount of time. In return, , the company must pay royalties for production and other fees to the federal government. BLM administers these onshore leases and awards them through a competitive process, as all public lands eligible for oil and gas leasing must be offered competitively.



* Oil and Gas Conservation Commission.

[1] www.blm.gov/programs/energy-and-minerals/oil-and-gas/about.

CLASS VI VS. CLASS II PROCEDURES

From policy to pore space authorization, BLM's process for geologic CO_2 storage differs between dedicated UIC Class VI and associated UIC Class II projects. Understanding the different requirements up front will help when working with BLM later.

	Dedicated Storage (UIC Class VI)	Associated Storage (CO_2 EOR) (UIC Class II)
Policy	FLPMA	MLA and Mineral Leasing for Acquired Lands Act
Purpose	Diverse purposes	Leasing federally owned minerals
Authorization	ROW	Lease
Rent	Schedule is under development	Established rent schedule
Use	Nonexclusive use of ROW	Exclusive right for specific mineral
Size	No size limitation	Limitations on size of area
Pore Space Authorization	Yes	No

EXAMPLES OF BLM PORE SPACE AUTHORIZATIONS

Wyoming is leading the way for pore space ROW authorizations on BLM-managed public land. Three companies—Moxa Carbon Storage, Tallgrass, and Pond Field (an affiliate of Frontier Carbon Solutions)—all applied for pore space ROWs for future injection and permanent storage of CO_2. As of August 2025, none has applied for any related surface infrastructure on public land. All three projects have progressed through the NEPA process and are awaiting ROW grants. In addition, all three require a notice to proceed to authorize injection for use of BLM pore space, contingent upon receipt of a Class VI well authorization from the Wyoming Department of Environmental Quality (DEQ).

Two of the three projects have received Class VI well permits to construct. Frontier Carbon Solutions received DEQ approval to construct three wells in the southwestern corner of Wyoming, and Tallgrass received permits to construct six wells in southeastern Wyoming. In addition, Tallgrass received DEQ Class VI authorization to inject CO_2 for one of the wells in June 2025.

ABOUT THE EERC

The EERC is a global leader in researching and developing technologies that make the energy we use and produce more efficient and environmentally friendly. We work in partnership with clients to develop, refine, demonstrate, and commercialize marketable products that provide practical solutions to real-world challenges. Utilizing decades of energy research, we are a driving force for innovation and new opportunities in the energy industry. The EERC is part of the University of North Dakota and is designated as North Dakota's State Energy Research Center.

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