Integrated Mid-Continent Stacked Carbon Storage Hub Project Phase II

Final Summary Report

DOE Agreement/Project # DE-FE0031623

Battelle Project # 100122657

Prepared by:

Technical POC:
Mr. Jared Walker
walkerjl@battelle.org
(614) 424-5702

Battelle
505 King Avenue
Columbus, Ohio 43201

Submitted to:

Project Manager:
Kyle Smith
U.S. Department of Energy
National Energy Technology Laboratory

December 18, 2020

Integrated Mid-Continent Stacked Carbon Storage Hub Phase II, Final Summary Report, DOE Agreement/Project # DE-FE0031623, Battelle Project # 100122657. December 2020

Acknowledgements

This material is based upon work supported by the Department of Energy under Award Number DE-FE0031623. The Project Team is led by Battelle and includes (in alphabetical order): Advanced Resources International Inc., Archer Daniels Midland Company, Berexco LLC, the Conservation and Survey Division at the University of Nebraska in Lincoln, the Energy and Environmental Research Center at the University of North Dakota, Great Plains Energy Inc., Great Plains Institute, Improved Hydrocarbon Recovery LLC, the Kansas Geological Survey at the University of Kansas in Lawrence, Los Alamos National Laboratory, Loudon Technical Services LLC, Pacific Northwest National Laboratory, and Schlumberger.

Battelle was responsible for the overall project execution, including project management, technical analysis, and coordination between team members with Mr. Jared Walker serving as the Project Leader/Manager. Additional project leadership and management support was provided by Mr. Jared Hawkins, Mr. Michael Heinrichs, and Ms. Mackenzie Scharenberg. This project also benefited from the leadership of Dr. Andrew Duguid and Dr. Neeraj Gupta, the project's Technical Advisor.

Technical contributors include (in alphabetical order): Esmail Ansari, Delphine Appriou, Diana Bacon, Tandis Bidgoli, Tiraz Birdie, Dan Blankenau, Katelyn Bocklund, Nicholas W. Bosshart, Jeff Burghardt, Matthew E. Burton-Kelly, Amber Conner, Shawna Cyphers, Chantsalmaa Dalkhaa, Dana Divine, Aldjia Boualam Djezzar, Andrew Duguid, Isis Fukai, William Garnes, Ben Grove, Hannah Haas, Jared Hawkins, Franciszek (Franek) Hasiuk, Jennifer Hollenbach, Eugene Holubnyak, Brendan Hoover, Nicolas Huerta, Todd Jiang, R.M. Joeckel, Brendan Jordan, Laura Keister, Jim Kirksey, George Koperna, Si-Yong Lee, Joel Main, Scott McDonald, Jingyao (Jenny) Meng, Richard Middleton, Farid Reza Mohamed, Matthew Place, Sean Polun, Priya Ravi Ganesh, Dave Riestenberg, Wayne Rowe, Arelys Y. Salazar, Mackenzie Scharenberg, Valerie Smith, James A. Sorensen, John Swanson, Manoj Kumar Valluri, Jared Walker, Neil Wildgust, Dana Wreath, and Z. Fred Zhang.

Table of Contents

List of Tables

List of Figures

Executive Summary

The Phase II Integrated Midcontinent Stacked Carbon Storage Hub (IMSCS-HUB) is part of the Carbon Storage Assurance Facility Enterprise (CarbonSAFE) established by the United States Department of Energy (DOE) National Energy Technology Laboratory (NETL). CarbonSAFE is phased to support the development of commercial-scale (50 million metric tonnes [Mt] over a 30-year period) carbon capture, utilization, and storage (CCUS) in the United States. The IMSCS-HUB study area comprises carbon dioxide (CO_2) sources in Iowa, Kansas, and Nebraska (the source corridor), and CO_2 sinks in Kansas and Nebraska (the storage corridor), representing the first large-scale project for the Midcontinent region (Figure ES-1). The stacked storage corridor is characterized by alternating sequences of deep saline formations, oil-bearing reservoirs, shale, and evaporite units that are conducive to vertically stacked CO_2 injection for geologic storage and enhanced oil recovery (EOR). Three sites within the IMSCS-HUB stacked storage corridor were evaluated in Phase II for commercial CCUS feasibility: one in southwest-central Nebraska, Sleepy Hollow Field (SHF), a second in southwestern Nebraska near Madrid (Madrid), and a third in southwestern Kansas, the Patterson Site (composed of the Patterson, Heinitz, Hartland, and Oslo fields).

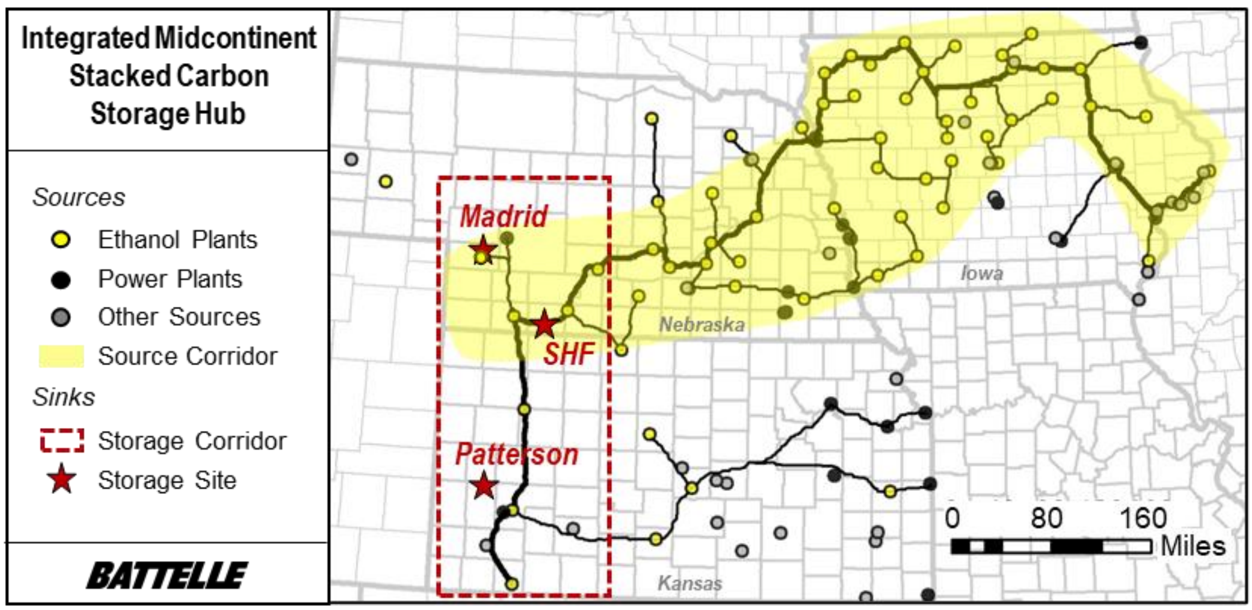


Figure ES-1. The IMSCS-HUB study region showing the CO_2 source and stacked storage corridors.

In Phase II, the team assessed the feasibility of storage complexes at the potential storage sites in Nebraska and Kansas to support a commercial-scale storage hub that integrates proven CO_2 capture technology and transport from nearby ethanol sources. Building on lessons learned from the DOE-NETL Regional Carbon Sequestration Partnerships (RCSPs), the Project Team has identified a clear strategy to meet DOE's 2025 objective of commercial carbon capture and storage (CCS) implementation by developing a CO_2 market and infrastructure that relies on multiple ethanol-based CO_2 sources in the short term and the incorporation of multiple coal-fired power plant CO_2 sources when commercial capture is economically viable. The team also leveraged the updated 45Q tax credit to develop capture and transport infrastructure.

Key Findings

The results of the IMSCS-HUB CarbonSAFE Phase II Storage Complex Feasibility study provide a foundation for implementing commercial-scale CCUS in the Midcontinent region. Key outcomes of the major project tasks are summarized as follows.

Feasibility and Data Collection Planning (Chapter 3):

- Existing geologic models were updated to include proprietary data held by the operators (where available) and used to conduct a data gap assessment for each study area.
- The gap assessment informed the Storage Complex Feasibility Data Collection Plan (Battelle, 2019a), which established the approach for data acquisition to facilitate the geologic feasibility assessment and meet the requirements for Class VI UIC permitting.

Storage Complex Feasibility Data Collection (Chapter 4):

- Prior to the data acquisition, the seismic surveys were designed, the appraisal well sites were selected, and the well designs were established.
- The Sleepy Hollow Reagan Unit (SHRU) 86A well was drilled, cored, and logged in May and June 2019 at the Sleepy Hollow Field .
- Two 3D surveys were acquired between May and July 2019 over the Patterson and Hartland fields at the Patterson Site.
- The Patterson KGS 5-25 well was drilled, cored, and logged in March and April 2020.
- The Hartland KGS 6-10 well was drilled and logged in May and June 2020.
- Well testing was conducted in the Patterson KGS 5-25 and Hartland KGS 6-10 wells in July and August 2020.
- Fifteen months (April 2019 – July 2020) of continuous passive seismic data was collected at the Patterson Site which indicates that the Patterson Site is located in a seismically stable area.

Storage Complex Analysis and Model Update (Chapter 5):

- The existing subsurface data from the three previous Phase I projects in the region (the IMSCS-HUB project in southwestern NE (Battelle), the Integrated Carbon Capture and Storage Pre-Feasibility Study in western NE (EERC), and the ICKan project (KGS) in southern KS) were integrated to develop a regional storage complex database for the Midcontinent study area for use in Phase II and during more detailed characterization efforts in future phases of work.
- All existing and newly acquired subsurface data (including core, log, and seismic) were integrated into existing site models and simulations from for each potential site.
- The refined models demonstrate that 51 Mt of CO_2 over an injection period of 30 years and more than 80 Mt of CO_2 over 25 years can be stored at the Madrid Site and Patterson Site, respectively.
- The Sleepy Hollow Field in Nebraska proves to be an attractive candidate for smaller-scale saline storage or stacked storage with CO_2-EOR.
- Geomechanical modeling at the Sleepy Hollow Field indicated that formation integrity was not compromised within the caprock and reservoir during CO_2 injection.
- Rock mechanics laboratory test results from the Patterson KGS 5-25 core demonstrate that the reservoir and seal interval have competent rock strength.

- Geomechanical analyses show that the target reservoir and seal intervals are under stable stress conditions at the Patterson Site.

Outreach (Chapter 6):

- Outreach in Nebraska included a three-part webinar series that facilitated stakeholder engagement with industry, trade groups, federal and state policymakers and regulators, research organizations, and legal entities and financial/tax firms (Battelle and GPI, 2020).
- In Kansas, outreach has been conducted through KGS and the Kansas CCUS working group.
- A stakeholder characterization was conducted to establish an IMSCS-HUB outreach team, demonstrate key messages for stakeholders in the study area, develop outreach strategies and materials, and foster public acceptance of CCUS projects and related infrastructure in the IMSCS-HUB study area.
- The project team coordinated with the RCSPs and other geologic carbon storage initiatives.
- An outreach plan for future phases of the project was developed to address issues that are of concern in the IMSCS-HUB project area (Battelle, 2020f).

Risk Assessment and Mitigation (Chapter 7):

- All components of a CCUS project were determined to be feasible in the IMSCS-HUB region.
- To mitigate the most impactful subsurface risks, the reservoir must be properly characterized, and operational constraints must always be followed.
- CO_2 pipeline operations are shown to be safe, especially compared to other types of pipelines (Battelle, 2019b).
- The component of pipeline development that has the highest amount of risk is construction. A strong safety plan and use of contractors that value worker safety will help to mitigate risks of injuries requiring hospitalization or worker fatalities.
- Non-technical risks are a result of the uncertainty that arises from a lack of defined regulations for many issues related to CCUS.
- The National Risk Assessment Partnership (NRAP) tools were used to estimate the risk of CO_2 and/or brine leakage through existing wells and subsequent impacts to USDWs as well as the risk of induced seismicity (Battelle and PNNL, 2020).
- A Risk Mitigation Plan was developed and includes strategies to deal with risks found during the evaluation of each project component (Battelle, 2020j).

Regulatory and Contractual Requirements Assessment (Chapter 8):

- A permitting and regulatory assessment was conducted to clearly define all permits needed for an integrated CCUS project in the IMSCS-HUB region.
- The federal, state, and local regulators with oversight of aspects of an integrated CCUS project were identified and regulatory gaps, roadblocks, and regulatory options were determined (Battelle 2020k).
- Requirements for capture, transport, and storage which included an assessment of the contractual agreements needed for an integrated CCUS project were evaluated (Battelle, 2020l).
- A roadmap was developed to obtain the required UIC permits for an integrated CCUS project (Battelle, 2020k).

CO_2 Management and Commercial Development Strategy (Chapter 9):

- A comprehensive CO_2 management and commercial development strategy for the IMSCS-HUB was developed.
- A regional storage resource characterization found that there is 577.4 Mt of stacked CO_2 storage capacity and the potential to produce 181.9 million barrels (MMbbls) of oil via EOR across 17 individual storage areas in the IMSCS-HUB storage corridor.
- Gross revenue for stacked storage (saline storage combined with CO_2-EOR) at the 17 fields is estimated to be $30.9 Billion.
- The pipeline assessment study found viable pipeline routes that connected 45Q-eligible ethanol plants, coal fired power plants, and other sources in the IMSCS-HUB corridor.
- The economic assessment study established the cost of capture from participating sources, storage projects at the Madrid, Nebraska Site and Patterson Site, and three integrated project scenarios.
- Results of subsurface characterization, modeling efforts, outreach assessment, and regulatory analysis from previous tasks were integrated to develop a Detailed Commercial Development Plan (Battelle, 2020n).

Commercial-scale CCUS is feasible at two candidate storage sites studied, the Madrid, Nebraska Site and the Patterson Site in Kearny County, Kansas. The Sleepy Hollow Field in Nebraska was found to be an attractive candidate for stacked storage with CO_2-EOR (Battelle 2020e). Outreach efforts facilitated engagement from industry, government, and research sectors (Battelle and GPI, 2020) and an outreach plan for future phases of the project was developed to address issues that are of concern in the IMSCS-HUB project area (Battelle, 2020f). All components of a CCUS project were determined to be feasible in the IMSCS-HUB region and Risk Mitigation Plan was developed and includes strategies to mitigate risks associated with each project component (Battelle, 2020j). A roadmap was developed to obtain the required UIC permits for an integrated CCUS project (Battelle, 2020k). The regional storage resource characterization demonstrated significant opportunity for commercial-scale projects in the IMSCS-HUB storage corridor with 577.4 Mt of stacked CO_2 storage capacity and the potential to produce 181.9 MMbbls of oil via EOR across 17 individual storage areas (Battelle and ARI, 2020). The pipeline assessment study found viable pipeline routes that connected 45Q-eligible ethanol plants, coal fired power plants, and other sources in the IMSCS-HUB corridor. The comprehensive results of subsurface characterization, modeling efforts, outreach assessment, and regulatory analysis from were integrated to develop a Detailed Commercial Development Plan for the IMSCS-HUB (Battelle, 2020n).

Next Steps

Commercialization efforts will involve obtaining Class VI UIC permits, establishing and finalizing the pipeline route, and evaluating capture projects at participating CO_2 sources. The next steps for the IMSCS-HUB are as follows.

- Detailed site characterization is needed for the Madrid, Nebraska site in order to select injection and monitoring well locations for the commercial-scale project. This includes acquisition of 3D seismic and the drilling and sampling of a characterization well.
- Outreach efforts must be continued and should include a stakeholder outreach plan and engagement of the public through educational forums and town halls. This is particularly important in the areas where the CO_2 will be stored and along the pipeline ROWs.

- The risks assessment established a robust method for investigating subsurface and pipeline risks. These analyses only need to be refined once project plans are finalized. Non-technical risks, such as pore space rights, liability, and contractual mechanisms, must be clearly defined for commercial-scale projects to be implemented.
- Once the project is clearly established, the permitting plan must be finalized. The permitting entities for CO_2 capture and storage will likely remain constant, but the permitting entities for construction projects can vary by county or locality. Therefore, the pipeline route must be decided before these permitting entities can be clearly identified.

Phases I and II of the IMSCS-HUB CarbonSAFE provide a strong foundation for safely, efficiently, and cost-effectively characterizing and permitting commercial-scale project sites in the region. The plan for implementation of commercial-scale CCUS projects in the IMSCS-HUB is aligned with the objectives of CarbonSAFE Phase III: Site Characterization and CO_2 Capture Assessment.

1 Introduction

1.1 Project Overview

The Phase II Integrated Midcontinent Stacked Carbon Storage Hub (IMSCS-HUB) is part of the Carbon Storage Assurance Facility Enterprise (CarbonSAFE) established by the United States Department of Energy (DOE) National Energy Technology Laboratory (NETL). CarbonSAFE is phased to support the development of commercial-scale (50 million metric tonnes [Mt] over a 30-year period) carbon capture, utilization, and storage (CCUS) in the United States. The IMSCS-HUB study area comprises carbon dioxide (CO_2) sources in Iowa, Kansas, and Nebraska (the source corridor), and CO_2 sinks in Kansas and Nebraska (the storage corridor), representing the first large-scale project for the Midcontinent region (Figure 1-1). The stacked storage corridor is characterized by alternating sequences of deep saline formations, oil-bearing reservoirs, shale, and evaporite units that are conducive to vertically stacked CO_2 injection for geologic storage and enhanced oil recovery (EOR). Three sites within the IMSCS-HUB stacked storage corridor were evaluated in Phase II for commercial CCUS feasibility: one in southwest-central Nebraska, Sleepy Hollow Field (SHF), a second in southwestern Nebraska near Madrid (Madrid), and a third in southwestern Kansas, the Patterson Site (composed of the Patterson, Heinitz, Hartland, and Oslo fields).

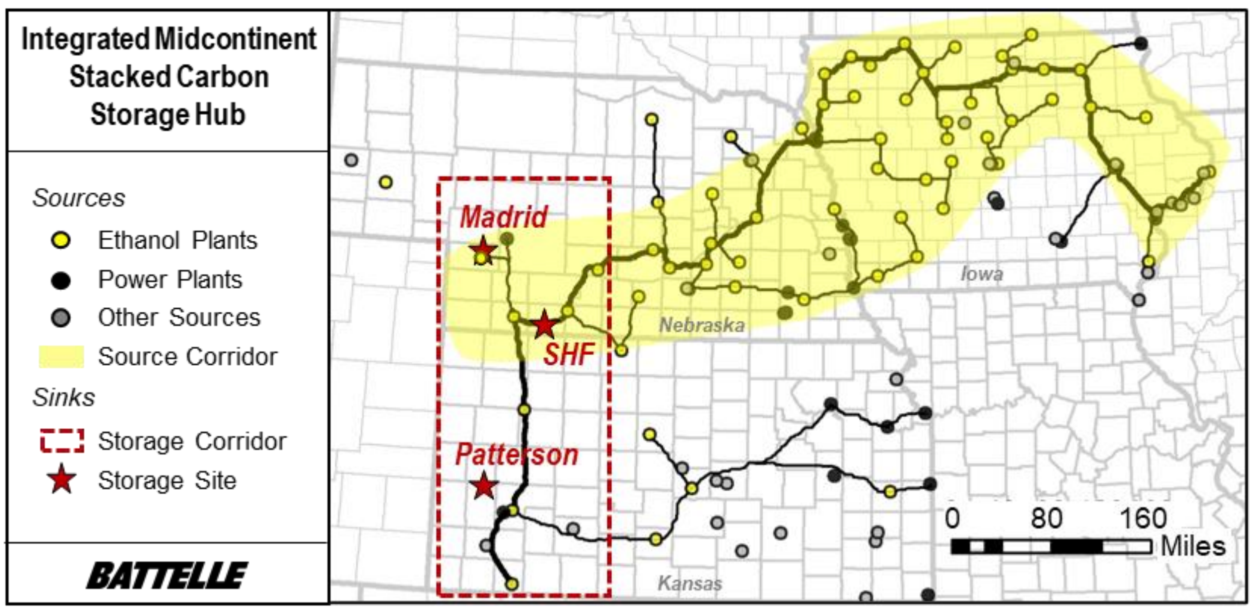


Figure 1-1. The IMSCS-HUB study region showing the CO_2 source and stacked storage corridors.

In Phase II, the team assessed the feasibility of storage complexes at the potential storage sites in Nebraska and Kansas to support a commercial-scale storage hub that integrates proven CO_2 capture technology and transport from nearby ethanol sources (Figure 1-1). Building on lessons learned from the DOE-NETL Regional Carbon Sequestration Partnerships (RCSPs), the Project Team has identified a clear strategy to meet DOE's 2025 objective of commercial carbon capture and storage (CCS) implementation by developing a CO_2 market and infrastructure that relies on multiple ethanol-based CO_2 sources in the short term and the incorporation of multiple coal-fired power plant CO_2 sources when commercial capture is economically viable. The team also leveraged the updated 45Q tax credit to develop capture and transport infrastructure.

1.2 Project Organization

The project team was led by Battelle and includes, the Kansas Geological Survey (KGS), the Energy and Environmental Research Center (EERC) at the University of North Dakota, Archer Daniels Midland Company (ADM), Great Plains Institute (GPI), Schlumberger, the University of Nebraska-Lincoln Conservation and Survey Division (UNL-CSD), Pacific Northwest National Laboratory (PNNL) and others.

The Phase II project consisted of nine tasks to assess the feasibility of the geologic storage complexes at the three potential sites to facilitate safe, permanent, and economical storage of 50 million (M) tonnes (t) or more of CO_2: Project Management and Planning (Task 1), Site Access and Permitting (Task 2), Feasibility Data Collection Planning (Task 3), Storage Complex Feasibility Data Collection (Task 4), Storage Complex Analysis and Model Update (Task 5), Outreach (Task 6), Risk Assessment and Mitigation (Task 7), Regulatory and Contractual Requirements Assessment (Task 8), and CO_2 Management and Commercial Development Strategy (Task 9). Figure 1-2 shows the project's high-level organization, the tasks, and the task leaders. Specific task approach and accomplishments are provided in the following sections.

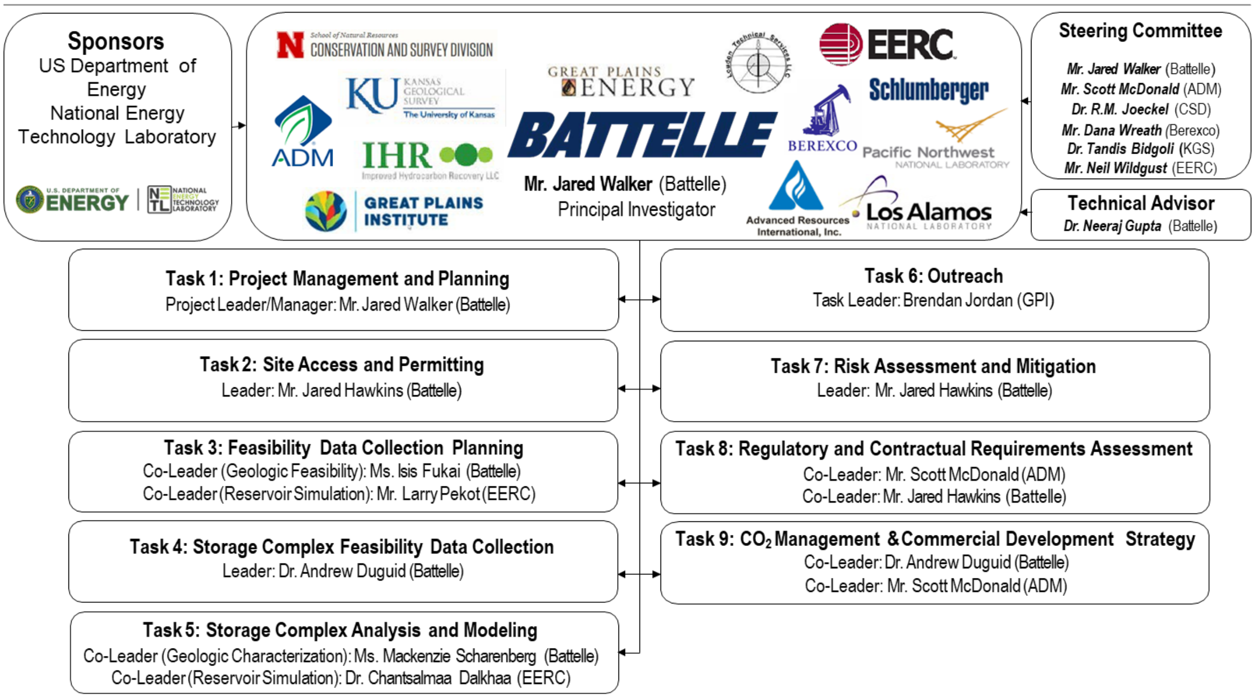


Figure 1-2. Project organization chart.

1.3 Geologic Background

The IMSCS-HUB stacked-storage corridor runs from southwest Nebraska to southwest Kansas (Figure 1-1). Porous and permeable Paleozoic deep saline formations have been identified as potential geologic storage complexes at potential storage sites in southwest-central Nebraska and western Kansas. Paleozoic sedimentary rocks in the sub-region are characterized by thick stratigraphic successions of marine and non-marine sedimentary rocks, (i.e. cyclothems). These stratigraphic successions provide alternating sequences of deep saline formations, oil-bearing reservoirs, shale, and evaporite units that are conducive to vertically-stacked CO_2 injection for geologic storage and enhanced oil recovery (EOR) (Figure 1-3; Figure 1-4; Figure 1-5).

Porous and permeable Paleozoic and Mesozoic epicontinental platform carbonates and sandstones occur within depositional compartments that are vertically isolated from interbedded and overlying oil-bearing zones by laterally extensive shale and impermeable limestones. Evaporites and shales of the Sumner and Nippewalla groups extend across the IMSCS-HUB study region, forming a regionally extensive caprock at each potential site. The proportion of shales and evaporites increases upward through the Paleozoic interval, forming regionally extensive caprock units for the underlying storage zones. Overlying the Paleozoic storage complexes are regionally extensive Cretaceous limestones, shales, and chalk that have potential to serve as secondary confining units between the primary caprocks and the overlying Cenozoic rocks hosting the High Plains Aquifer. Effective containment is also demonstrated at each site via trapping of commercial hydrocarbon accumulations within the storage complexes. Existing hydrocarbon resources, and the potential for a hybrid of CO_2-EOR and geologic storage may provide technical advantages, infrastructure, and economic incentives needed to successfully commercialize CCS in the region.

Sleepy Hollow Field, Nebraska

In southwest Nebraska, a potential site has been identified within an area of approximately 28 mi^2 in the Sleepy Hollow field (Red Willow County), the most productive oil field in Nebraska (e.g. Kincaid, 1961; Rogers, 1977; Carlson, 1989). The potential storage zones at the Sleepy Hollow site consist of six vertically stacked intervals of deep saline limestones and sandstones in the Wabaunsee, Shawnee-Douglas (Topeka, Deer Creek-Oread), Lansing Kansas City (A, D-F) and Pleasanton-Marmaton groups (Figure 1-3; Battelle, 2018). These deep saline storage zones occur at average depths ranging from 2,862 ft to 3,390 ft and exhibit both structural and stratigraphic trapping mechanisms, with reservoir facies pinching out toward the Cambridge Arch in the northeast and thickening toward the Denver-Julesburg Basin in the west (EERC, 2018). Upper Pennsylvanian and Lower Permian shale, evaporite, and carbonate formations are the primary caprocks for the underlying storage complex at the Sleepy Hollow site. In ascending order, these lithostratigraphic units include: Admire, Council Grove, Sumner, and lower Nippewalla groups (Figure 1-3). These units exhibit log responses consistent with tight (i.e., low porosity) non-reservoir lithologies, such as gamma ray (GR) log values greater than 70 American Petroleum Institute GR units (gAPI) for shale and/or effective log porosities less than 5%. Directly overlying the Wabaunsee Group, the shale and siltstone formations of the Admire Group represent the base of the primary caprock sequence. A shale unit in the lower portion of the Nippewalla Group represents the top of the Pennsylvanian-Permian caprock complex at the Sleepy Hollow site and is separated from the overlying High Plains Aquifer system by more than 1,000 ft of Cenozoic and Mesozoic rock, including the regionally extensive Carlile and Graneros shales identified as secondary confining units.

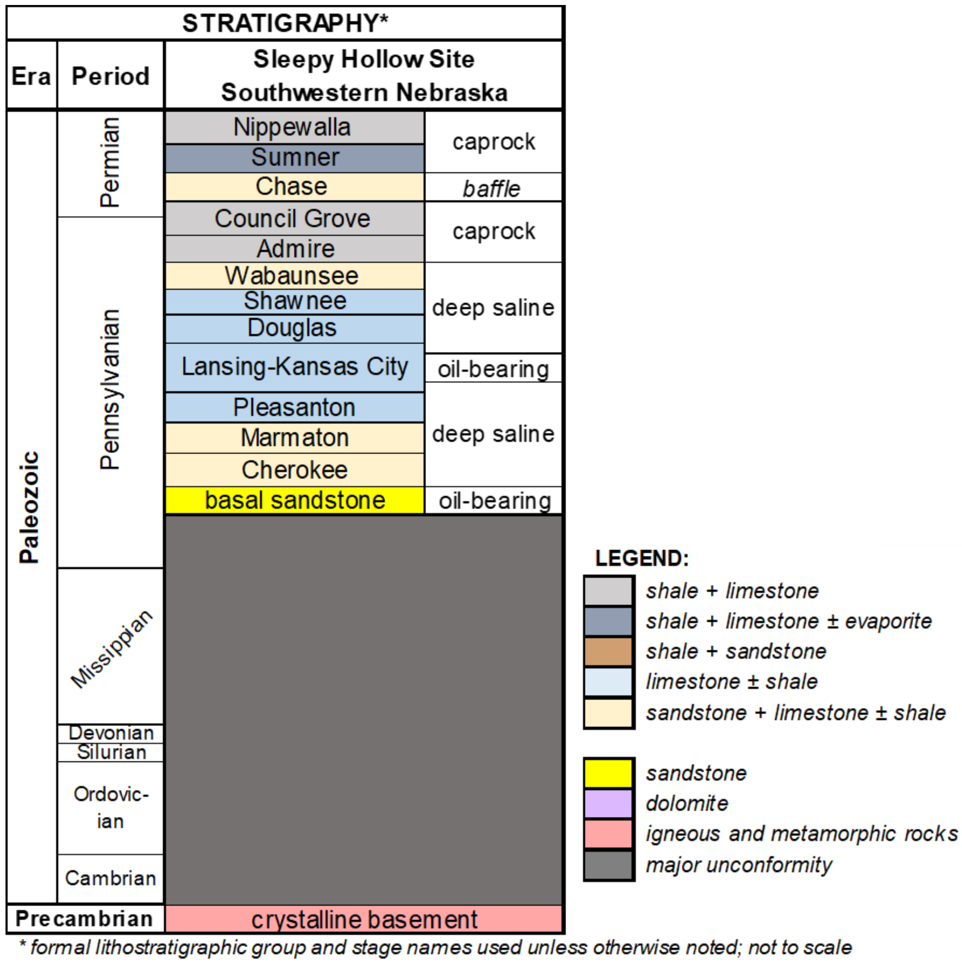


Figure 1-3. Stratigraphic column for Sleepy Hollow Field study area.

Madrid, Nebraska Site

An additional site in southwest Nebraska has been identified in Perkins County near Madrid. The deep saline storage reservoirs at the Madrid storage site are composed of Paleozoic and Mesozoic sandstones and carbonates (Figure 1-4). The Cretaceous-aged sandstone units of the Dakota Group are incised valley deposits. The Cedar Hills Formation is an interbedded eolian and evaporite deposit (Wildgust et al., 2018). The Pennsylvanian Cherokee Group is made up of interbedded lacustrine and nearshore marine shales, sandstones, and carbonates (Wildgust et al., 2018). The cyclothems of the Lansing-Kansas City Group has been defined as zone at this site as well. A connected volume analysis shows that stack-storage in all of the reservoir intervals is viable at this site. The uppermost sealing units at the Madrid site are the Cretaceous-aged Carlile, Greenhorn, and Graneros shales which overlie the Dakota Group sandstones. The shales of the Permian Nippewalla Group are seals for the Cedar Hills Sandstone reservoir and the Admire acts as the seal for the Lansing-Kansas City Group and the Cherokee Group and separate the storage zones from the overlying High Plains Aquifer, which occurs at approximately 300 ft at the Madrid, NE site.

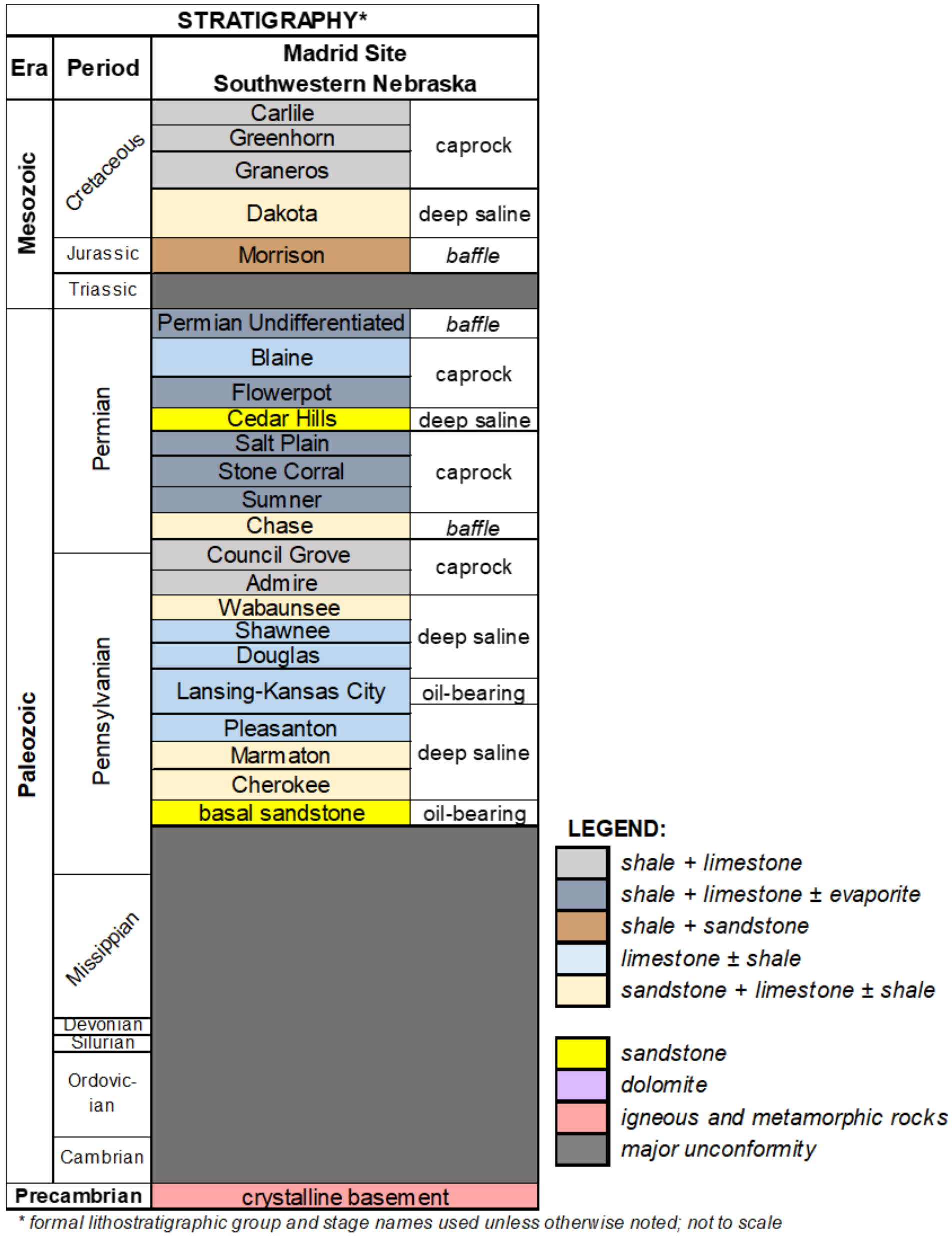
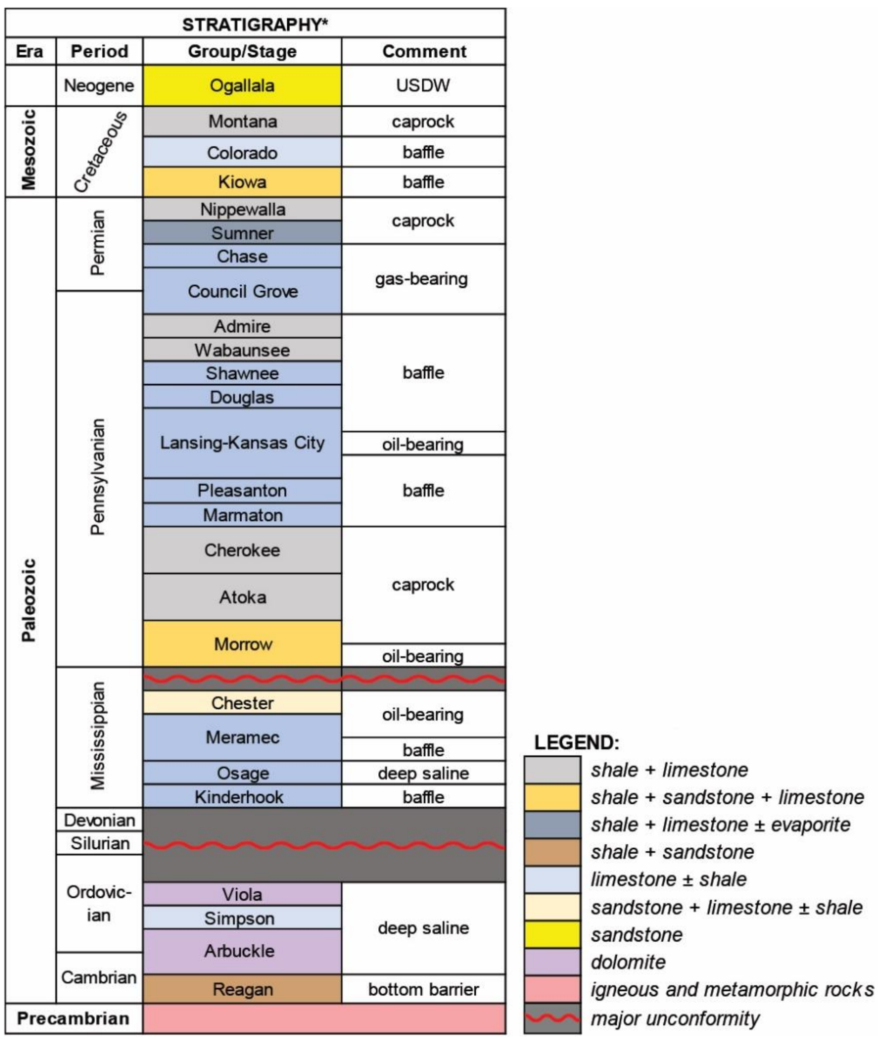


Figure 1-4. Stratigraphic column for the Madrid, Nebraska study area.

Patterson Site, Kansas

The Patterson storage site in southwestern Kansas' Kearney County is comprised of four fields, the Patterson, Heinitz, Hartland, and Oslo situated on a common structure covering 36 mi^2. At this site, Cambrian-Ordovician (Arbuckle), Ordovician (Viola), and Mississippian (Osage) dolomite and cherty dolomite are potential deep saline storage zones with high potential for commercial-scale storage (Figure 1-5). These zones are present at average depths of 5,310 ft to 5,800 ft and occur as thick, laterally extensive storage reservoirs underlying a northwest-trending, broad structural closure ideal for CO_2 storage. The Patterson geologic site is one of six closed geologic structures in the North Hugoton Storage Complex (NHSC), a 60-mile (mi) long

NW-SE structural trend in the north part of the Giant Hugoton gas field. Each of the large structures identified in the NHSC is underlain by the three storage reservoirs, and all six structures also contain shallower (5,000 feet [ft]) extensive oil production that have been demonstrated to have CO_2-EOR potential (Dubois et al., 2015). Deep saline storage zones at the Patterson site are well-confined by thick, tight carbonate and thin shale intervals isolating Osage, Viola, and Arbuckle injection zones. More than 400 ft of tight limestone separate the Osage from the regional unconformity at the top of the Meramec. Multiple regionally continuous shale layers in the Morrow, Atoka and Cherokee form the primary caprock sequence (Figure 1-2). More than 400 ft of tight limestone separate the Osage from the regional unconformity at the top of the Meramec. Between the top of the primary caprock complex (Cherokee top) and the High Plains Aquifer in southwest Kansas, there is an additional 4,300 ft of Upper Pennsylvanian, Permian, and Cretaceous rocks, including the regionally extensive shale and evaporite of the Permian Sumner and Nippewalla groups. Permian evaporites form the top seal to the giant Hugoton-Panoma and Panhandle fields covering southwest Kansas and the Oklahoma and Texas Panhandles that produce from the directly underlying Chase and Council Grove Groups.



*formal lithostratigraphic group and stage names used unless otherwise noted; not to scale

Figure 1-5. Generalized stratigraphic chart for Patterson Site in southwest Kansas. The comment column shows oil and gas producing intervals in the area as well as regional barriers, caprocks and baffles to vertical fluid flow. USDW = underground source of drinking water (Holubnyak et al., 2018; 2020).

2 Site Access and Permitting

Battelle worked with Berexco, the Patterson site operator, and Central Operating, the Sleepy Hollow site operator, to ensure access to all sites and ensure all proper permits were received prior to data collection. In Subtask 2.1, access was negotiated for each site to ensure the team had access to operations and subsequent data required to meet the project objectives. Permits were obtained, as required, for seismic data acquisition and well drilling (Subtask 2.2). Site access agreements and permits for the 3D seismic collection and characterization well drilling were submitted to DOE in the IMSCS-HUB Phase II Drilling and Data Collection Report (Battelle, 2020a).

3 Feasibility Data Collection Planning

Task 3 included updating existing geologic models to include proprietary data held by the operators (where available) and creating a data gap assessment for each study area. The gap assessment was used to develop the Storage Complex Feasibility Data Collection Plan, which identified necessary data to assess feasibility for commercial-scale CO_2 storage and Class VI UIC permitting.

In Subtask 3.1, existing core and log data newly available to the project in Phase II were compiled and incorporated into the existing site models and simulations for both potential sites. The updated models were used to facilitate the sensitivity analysis and data gap assessment for Subtask 3.2 to identify missing data that could provide the team with a better understanding of saline storage units and caprocks. An assessment of Underground Injection Control (UIC) Class VI permit requirements is also provided as part of Subtask 3.2 to identify associated data gaps that can potentially be addressed by the new data collection effort in this phase of the project. Results from the updated geologic models and the data gap assessment have been used in Subtask 3.3 to define new data acquisition and analysis needs at each potential site, including: new characterization well locations and design, whole core intervals, well tests and fluid sampling intervals, rock and fluid laboratory analyses, wireline log suites and intervals, and seismic survey locations (Patterson site only).

This Storage Complex Data Collection Plan was used to guide Task 4 field activities for acquisition of new data for initial characterization of the storage complexes at potential sites in southwest Nebraska and Kansas. This included data to support storage complex subsurface characterization and modeling (Task 5), outreach activities (Task 6), risk assessment (Task 7), UIC permit planning (Task 8), and commercial development strategies (Task 9) to establish a 50-Mt-scale carbon capture and stacked-storage project in the Midcontinent region by 2025.

The Storage Complex Data Collection Plan (Battelle, 2019a) includes initial site model updates (subtask 3.1), a data gap assessment (subtask 3.2), and the plans to collect data at the Sleepy Hollow Site in Nebraska and the Patterson Site in Kansas (subtask 3.3).

3.1 Geologic and Reservoir Model Update

Proprietary geological, geomechanical, and hydrogeological data held by the study area operators was compiled and incorporated into the existing site models and simulations. The new data and updated models were used to determine current subsurface conditions in the study areas, inform geologic models, refine estimates of storage resource, and aid in characterization and reduction of storage risks.

Data collection focused primarily on the acquisition of data from the deep saline and caprock units comprising the storage complexes at both potential sites. This included collection of petrophysical, geochemical, geomechanical, and hydrogeological data to facilitate initial characterization of the storage complex subsurface as well as model development, calibration, and testing. Uncertainty and data gaps in the storage complex models were evaluated at each site to inform and prioritize data collection efforts.

During Phase I of the IMSCS-HUB additional core measurements were acquired from existing core in the Sleepy Hollow study area. Routine core analysis was conducted on 18 samples from 5 wells including porosity, permeability, grain density, and oil and water saturations. X-ray diffraction (XRD) and X-ray fluorescence (XRF) measurements were performed on 25 samples from 5 wells. Tight rock analysis (TRA) was conducted on 5 caprock/baffle samples from 3 wells. The Pennsylvanian group combines all data in the Pennsylvanian period (the Shawnee-Douglas group through the basal Pennsylvanian sandstone). The additional core-measured porosity and permeability values were integrated with well log data in order to inform the Static Earth Model (SEM) updates.

The SEM for the Sleepy Hollow site was updated to facilitate regional continuity in modeling efforts and incorporate the new effective porosity and permeability well data. For better compatibility and alignment with broader project goals in Nebraska and Kansas, the Sleepy Hollow SEM was converted from the North American Datum (NAD) of 1983, Universal Transverse Mercator (UTM) Zone 14N (meters) to NAD 1983, Bureau of Land Management (BLM) Zone 14N (ft).

In the first SEM update in Phase II, the only modification to the Phase I version of the Patterson SEM was the addition of 10 wells with petrophysical data from well logs, a 50% increase in coverage. There were no changes to the workflow, including petrophysical transforms (porosity to permeability), nor were there significant changes in the dynamic simulation modeling workflow and the results.

3.2 Data Gap Assessment

A data gap assessment was conducted for each study area considering the updated models from Subtask 3.1 to identify missing data that could provide the team with a better understanding of saline storage units and caprocks.

The updated petrophysical dataset and static and dynamic reservoir models were used to conduct data gap assessments and sensitivity analyses for each potential site. Results were used to target and prioritize new data collection efforts needed to reduce model uncertainty, support initial characterization and commercial development planning, and address regulatory requirements for this and future phases of the project.

The U.S. Environmental Protection Agency (EPA) establishes criteria and standards for the UIC program to regulate wells used to inject fluids into the subsurface that could compromise underground sources of drinking water (U.S. EPA., 2017a). Wells used for the injection of CO_2 for geologic sequestration are classified as Class VI wells by the U.S. EPA UIC program (U.S. EPA, 2010; U.S. EPA, 2017b). To ensure the necessary data is acquired for the project to meet UIC Class VI regulatory requirements, a summary of the EPA UIC Class VI permit requirements is presented here as part of the data gap analysis at both potential sites.

Sleepy Hollow Field

The geologic and reservoir model updates were used to identify subsurface data gaps at the Sleepy Hollow site. The main knowledge/information gaps identified are related to lithologic, geophysical/model, geomechanical, and geochemical data needed for initial characterization of the Pennsylvanian-Permian storage complex at the potential site.

The sensitivity analysis in the Sleepy Hollow site reveals that the CO_2 storage is most sensitive to perforation of the Pleasanton-Marmaton interval, bottom hole pressure (BHP) constraints, initial reservoir pressure, and CO_2-brine relative permeability. Perforation of Wabaunsee, Oread, LKC E, LKC F, and Topeka, permeability of Wabaunsee, effects of vertical permeability anisotropy, and permeability of Pleasanton-Marmaton are less sensitive, but non-negligible. Sensitivity to salinity, permeability of other saline formations, thermal gradient, and porosity change appear to be insignificant.

Patterson Site

The main knowledge/information gaps identified at the Patterson site are related to geologic structures (3D seismic data), spatial data gaps, geophysical and model data, geomechanical data, and geochemical data needed for initial characterization of the storage complex at the potential site.

The sensitivity analysis conducted for storage complex at the Patterson site suggests that permeability of the Osage storage zone is the most sensitive parameter in the 10-year cumulative CO_2 storage simulation. Perforation of the Osage interval is the next most sensitive parameter evaluated. Thus, well tests and new data acquisition from the Patterson site should focus on characterization of the Osage formation. Cumulative CO_2 storage at the Patterson site is also sensitive to the BHP constraint, initial reservoir pressure, rock compressibility, permeability of the Arbuckle, CO_2-brine relative permeability, and the permeability of the Viola. The vertical permeability to horizontal permeability ratio, porosity of Osage, reservoir temperature, and salinity appear to be less sensitive but non-negligible. The sensitivity of porosities in the Viola and the Arbuckle was found to be minimal.

Madrid, Nebraska Site

A characterization well and 3-D seismic survey have not been completed at the Madrid, Nebraska site. The knowledge gaps identified at the Madrid, Nebraska site include lithologic, geomechanical, hydrogeological, geochemical, and geophysical/petrophysical data which are needed to characterize the storage complex. To conduct detailed site characterization at the site, 3-D seismic data must be acquired and a characterization well must be drilled, cored, and tested. The site-specific data generated from these activities will be used to refine static and dynamic models, test model scenarios and reservoir boundary conditions, and validate model results to ensure consistency and reliability of results as well as meet regulatory requirements.

3.3 Storage Complex Data Collection Plan

The information and knowledge gaps identified in the subsurface/petrophysical dataset, geologic and reservoir models, and regulatory data at each potential site were used to develop a data collection plan to support Phase II objectives and prepare for future tasks and phases of the project. The team used the gap assessment to select seismic survey locations, appraisal well locations, logging technologies, core intervals, and test intervals for data collection. The team considered the UIC Class VI requirements to ensure that any data gaps for permitting are identified and filled. The Storage Complex Data Collection Plan (Battelle, 2019a) details the plans for the seismic survey and the three new wells at the Sleepy Hollow and Patterson sites.

4 Storage Complex Feasibility Data Collection

This task included acquisition of two 3D seismic volumes, the designing and drilling of three appraisal/characterization wells, and baseline seismic monitoring. The new data collected as part of Phase II (Task 4) field activities were used for detailed feasibility analysis and initial characterization of the storage complexes at each potential site to prove feasibility, reduce project uncertainties, and help develop a commercial development plan for the IMSCS-HUB region.

The Drilling and Data Collection Report (Battelle, 2020a) is a combined technical memorandum for Task 2 and Task 4 and includes the site agreements for the characterization wells and seismic data acquisition (Subtask 2.1), the characterization well drilling permits (Subtask 2.1) which include wellsite surveys, (Subtask 4.2), well designs (Subtask 4.3), and drilling and data collection reports for all three characterization wells (Subtask 4.4).

4.1 Seismic Design and Acquisition

Prior to the Phase II data collection, subsurface analyses at the Patterson Site (the Patterson-Heinitz-Hartland-Oslo fields) were based on limited subsurface well, core, and injectivity data. The 3D seismic surveys inform the overall geometry of the geologic structure at the Patterson Site and assist in the selection of the appraisal well locations for subsurface characterization.

Two 3D surveys were acquired between May and July of 2019 over Patterson and Hartland fields in Kearny County, Kansas. Processed 3D volumes were delivered in early August of 2019. The 3D seismic data interpretation was used to determine the locations of the characterization wells drilled at the Patterson Site. The new seismic data were also used to update the geologic models in order to provide storage capacity estimates, minimization strategies for Areas of Review (AORs), stacked-storage monitoring strategies, reservoir seal mechanical properties and induced seismicity risks. These results will inform the UIC permit planning and commercial development (Phases III and IV and commercial operations).

4.2 Well Site Selection

Two appraisal wells were drilled at the Patterson site, and one appraisal well was drilled at the Sleepy Hollow site. Final site selection was based on the models from Subtask 3.1, the Storage Complex Data Collection Plan (Subtask 3.3), surface access and topology, and the 3D seismic data collected under Subtask 4.1.

The new well location at the Sleepy Hollow site was identified as a prospective drilling target by the operators of the field that also exhibited high estimated porosity-thicknesses and permeabilities in the deep saline storage zones of interest. The two new characterization well locations at the Patterson site were finalized after the initial interpretation of the 3D seismic data.

4.3 Well Design

The team designed appraisal wells including the operations for construction, logging, coring, and testing to ensure that required data were collected. Loudon Technical Services reviewed the plans and a drill well on paper (DWOP) exercise was conducted for each well to verify the completeness of each well's plan. Additionally, the wells were constructed to meet all state and local requirements and to ensure that there is no conflict with UIC regulations.

4.4 Well Drilling and Data Collection

Two appraisal wells were drilled by Berexco at the Patterson site and one well was drilled at the Sleepy Hollow site. A suite of basic and advanced log data was acquired in each well, facilitating caprock and deep saline formation evaluation. Basic logs included triple-combo and pulsed neutron. Advanced logs included dipole sonic, magnetic resonance, and borehole image. Whole core, sidewall cores, drill stem test (DST) data, and reservoir injection test data were also collected from each of the wells. Data collection at the Patterson site focused on Mississippian and Ordovician deep saline storage zones within the Osage, Viola, and Arbuckle formations, and confining units such as the Meramec, Morrow and Sumner Group. Data collection at Sleepy Hollow focused on deep saline intervals in the Pennsylvanian Wabaunsee, Shawnee-Douglas, and Pleasanton-Marmaton groups and caprocks of the Council Grove and Sumner groups.

The new geologic data acquired under Task 4 includes:

- Two 3D surveys (26 mi^2) acquired between May and July 2019 over the Patterson and Hartland fields
- The Sleepy Hollow Reagan Unit (SHRU) 86A well drilled, cored, and logged in May and June 2019
- The Patterson KGS 5-25 well drilled, cored, and logged in March and April 2020
- The Hartland KGS 6-10 well drilled and logged in May 2020

The following data were acquired from the reservoir and caprock intervals in the new characterization well at the Sleepy Hollow site.

Sleepy Hollow Reagan Unit 86A

- 113 feet of whole core and 32 sidewall cores were collected
- Specialized and routine core analyses were performed on samples from reservoir and caprock intervals
- Approximately 2,000 ft of numerous advanced and basic well logs were acquired over the storage complex
- 4 drill stem tests were run in storage zones
- Water samples were collected and analyzed from a storage interval

The following data were acquired from the reservoir and caprock intervals in the new characterization wells at the Patterson site.

Patterson KGS 5-25

- 778 feet of whole core
- Specialized and routine laboratory analyses were performed on core samples from reservoir and caprock intervals
- ~4,800 ft of numerous basic and advanced well logs were acquired over the storage complex
- 2 successful drill stem tests were run in storage zones
- 7 step-rate, falloff, and interference tests

Hartland KGS 6-10

- >4,900 ft of numerous basic and advanced well logs were acquired over the storage complex
- 2 drill stem tests were run in storage zones
- 7 step-rate, falloff, and interference tests

4.5 Baseline Seismic Monitoring

Hazard mapping indicates a low seismic hazard in the region, with a 1% probability reported for the likelihood of a seismic event exceeding a Peak Modified Mercalli Intensity rating of IV (light shaking) in any given year (Petersen et al., 2016). However, microseismic events detected in the sub-region and slightly elevated peak ground acceleration near the Central Kansas Uplift have resulted in deployment of microseismic monitoring networks at the Patterson Site to establish local baseline seismicity and increased vigilance to reduce the risk of induced seismicity during injection operations.

A network of eight seismic stations were installed in and around the Patterson and Hartland field in Kearny County, KS at the end of April 2019 to monitor background seismicity in the area (magnitude >1). The array completed background monitoring and was dismantled at the end of July 2020.

The CarbonSAFE Phase II passive seismic monitoring task was completed successfully. Data were streamed real-time to KGS servers where workflows for data handling, reduction and analysis were established. Over the 15 months of continuous monitoring, no local (less than 50-mile distance) earthquakes were identified, indicating that the Patterson and Hartland fields are in a tectonically stable region. The network installation designed and executed by University of Kansas scientists proved to be effective and efficient, capable of providing years of reliable and cost-effective site monitoring during potential future CO_2 injection activities. In the detailed characterization and permitting stage, additional seismic monitoring using borehole geophones could be conducted to obtain data for lower-level seismic activity. More details are included in the Baseline Seismic Monitoring at Patterson and Hartland Fields Topical Report (Battelle, 2020c).

5 Storage Complex Analysis and Model Update

The objectives of Task 5 included integration of existing subsurface data from the regional storage corridor and analysis of new site-specific data at each potential storage site. To accomplish this, the task was divided into three subtasks:

- Data Analysis and Integration
- Storage Complex Model Update
- Caprock Characterization and Geomechanical Modeling

Porous and permeable Paleozoic deep saline formations have been identified as potential geologic storage complexes at the potential storage sites in southwest-central Nebraska and western Kansas. Paleozoic sedimentary rocks in the sub-region are characterized by thick stratigraphic successions of marine and non-marine sedimentary rocks, (i.e. cyclothems). These stratigraphic successions provide alternating sequences of deep saline formations, oil-bearing reservoirs, shale, and evaporite units that are conducive to vertically stacked CO_2 injection for geologic storage and enhanced oil recovery (EOR).

5.1 Data Analysis and Integration

Three previous Phase I CarbonSAFE projects in the region were integrated into the IMSCS-HUB project as part of the Phase II Storage Complex Feasibility Assessment: the IMSCS-HUB project in southwestern NE (Battelle), the Integrated Carbon Capture and Storage Pre-Feasibility Study in western NE (EERC), and the ICKan project (KGS) in southern KS. The existing subsurface data from the three Phase I projects were integrated to develop a regional storage complex database for the Midcontinent study area. The database was used to store, share, and analyze all new and existing subsurface data available for initial characterization in Phase II and will be used during more detailed characterization efforts in future phases of work. The new characterization well data from the SHRU 86A, Patterson KGS 5-25, and Hartland 6-10 are stored in the IMSCS-HUB Regional Database.

Key findings from the new feasibility data analysis and integration at the Sleepy Hollow Field and the Patterson Site are discussed here.

Sleepy Hollow Field

The data collected from the new characterization well, SHRU 86A, were integrated and analyzed to assess reservoir and seal quality of the storage complex at the SHF. The primary caprock, or sealing unit, is the Admire, and the four deep saline reservoirs units are the Pleasanton-Marmaton, the LKC, the Shawnee-Douglas, and the Wabaunsee groups.

Key findings from the SHRU 86A data are as follows.

- The occurrence of shale and mudstone intervals increases as depth decreases, with many thick shale/mudstone intervals in the Admire.
- The Wabaunsee shows more lithologic heterogeneity than the lower deep saline intervals, with alternating thin beds of mudstone/shale and carbonate.
- The alternating intervals or carbonates and mudrocks thicken in the Shawnee-Douglas, similar to the LKC.
- An increase in mudstone also occurs in the Pleasanton-Marmaton, which is largely comprised of thick sections of mudstone and muddy carbonate with some thinner intervals of clean carbonate. The core data revealed that this interval is heterogenous and contains permeabilities ranging from less than 0.1 mD up to 10 mD.
- The red-brown siliciclastic mudstones and black-dark gray shales exhibit GR responses greater than 70. Total porosities were often greater than 10% due to clay-bound water with permeability values were at or near 0.001 mD.
- The limestone intervals generally exhibit GR responses less than 70 and effective porosities less than 10%.
- The highest porosities and permeabilities occurred in the thin Wabaunsee sandstone interval, throughout the LKC, and in the basal sandstone.
- The LKC intervals with the best outlook for injection are the oil-bearing B and C zones with the highest core and log permeabilities, which were around 10 mD.
- Although laboratory core analyses were not undertaken in oil-bearing basal sand, log data and previously acquired core data in SHF indicates that the formation has a positive outlook for injection with porosities over 10% and permeabilities in the hundreds of mD.

Patterson Site

The data collected from the new characterization wells, Patterson KGS 5-25 and Hartland KGS 6-1, and the new seismic volumes from the Patterson and Hartland fields were integrated and analyzed to assess reservoir and seal quality of the storage complex at the Patterson Site. The caprocks are the low permeability intervals of the Morrow, the Atoka, and the Cherokee Group and the three deep saline reservoirs units are the Osage, Viola, and Arbuckle.

- The new seismic volumes allow for more accurate definition of the structural model (i.e., traps and seals) for at the Patterson Site.
- A new element of the stratigraphic model, a meandering valley system incised into the Meramecian surface, was discovered through seismic attribute analysis
- Two major reverse faults were interpreted in the seismic at the Patterson Site. The faults offset the reservoir and seal intervals and constitute an uplifted block in the Patterson Area.
- Fault displacements are maximum at the Precambrian basement and decrease upward.
- Fault propagation folding on the hanging wall forms structural closures striking parallel to the NW-SE trending fault.
- Identified three- and four-way structural closures at the Patterson Site can assist trapping CO_2 in the Arbuckle-Osage reservoirs.
- The Atoka is composed of black shale with variable calcite cementation, low porosity, and low permeability which can act as a high-quality sealing interval
- The Morrow Sand, a medium-grained sandstone, shows excellent reservoir quality (core porosity 19.9 to 21%, core permeability 921 to 1410 mD). It is the only oil-producing horizon at the Patterson site, so it presents potential for CO_2-EOR development.
- The Meramec is fine-grained skeletal lime grainstones with mostly low reservoir quality (core porosity 0.6 to 1%, core permeability <0.001 to 0.002), except for a distinct interval of higher quality rock (porosity 14.5%, permeability 7.5 mD) that is visible in the core and on well logs. This provides a secondary storage target in an otherwise sealing interval.
- The Osage reservoir is a fine-grained skeletal oolitic lime grainstones with good reservoir quality (core porosity 3.7 to 5.4%, core permeability 0.009 to 0.34 mD). Coring missed the highest porosity interval observed in well logs, which suggests that the interval has good reservoir quality with approximately 10% porosity.
- The Viola reservoir is composed of porous, highly vugular dolostones and dolostone breccias with good reservoir quality (core porosity 5.1 to 9.7%, core permeability 0.062 to 10.1 mD).
- The Arbuckle is a porous, highly vugular dolomite reservoir with core porosity up to 11% and core permeability up to 13 mD
- The Reagan Sandstone is composed of porous medium to conglomeratic feldspar quartz sandstones with core porosity 4.6 to 13.7%, core permeability 0.023 to 14.6 mD.
- The basement is composed of weathered and fresh fractured granite with core porosity 0 to 19.2% and core permeability 0.001 to 24.2 mD.

Results of the advanced data analysis and new insights from the geologic interpretations support the static and dynamic modeling efforts, caprock characterization and geomechanical analysis, risk assessment, and the economic evaluation of potential storage sites in the region. The detailed interpretation and analyses of the SHRU 86A, well logs and core data, and the Patterson and Hartland 3D seismic data can be found in the IMSCS-HUB Phase II, Task 5

Advanced Data Analysis Topical Report (Battelle, 2020d). The analysis of the Patterson KGS 5-25 and Hartland KGS 6-10 well data are attached to this report in Appendix A.

5.2 Storage Complex Model Update

In Subtask 5.2, all existing and newly acquired subsurface data (including core, log, and seismic) were integrated into existing site models and simulations from for each potential site. The refined models are used to assess commercial-scale (50+ Mt) injection into saline stacked-storage units, update storage capacity, develop AoR minimization strategies, and develop stacked-storage monitoring strategies.

Sleepy Hollow Field

The SHRU 86A well was drilled, cored, and logged in June of 2019. Central to SHF and drilled to basement, this well penetrates the Pennsylvanian cyclothems, which represent the key CO_2 storage intervals being evaluated at this site for the IMSCS-HUB. In this model update, the SEM incorporates the latest subsurface interpretations derived from the SHRU 86A well data. A gamma ray (GR) facies model was used as the basis for partitioning the Pennsylvanian section. However, the facies definition is lithology-based rather than "energy-based" as used in earlier work (Battelle, 2018 and 2019a). Porosity and permeability were adjusted, so that reservoir quality was in alignment with the cyclic facies concept describing Pennsylvanian rock in this area (Dubois, 1985; Watney, 1980; Young, 2011). These adjustments ensure that mudstones and shales are correctly represented and have low effective porosity and low permeability.

Following the update on the static model, an update on dynamic simulation work was conducted to determine the feasibility of injecting and storing 50 Mt of CO_2 into the stacked saline formations at the SHF. The newly acquired data from core analyses and field tests performed at SHRU-86A, including the formation pressure and temperature gradients, salinity, and capillary pressure data, were integrated into the simulation model. A number of scenarios were run to investigate the feasibility of storing the target amount of 50 Mt of CO_2 using a varying number of injection wells with horizontal and vertical orientations, different lengths for horizontal wells, different stacked combinations of formations, and varying surface locations for injection. The results of the update indicated that the original 50-Mt target injection amount was not viable in the SHF, so two stacked scenarios were assessed: one with half the target injection amount (25 Mt) needed and the other maximizing the injection amount using ten wells. The simulation results indicated that 25 Mt can be stored using four wells. This suggested that two fields similar to the SHF would meet the target amount of 50 Mt of CO_2. The SHF can have a maximum of 30 Mt stored; however, this would require ten injection wells. The results also indicated that the simulated AoR size would be dictated by the pressure plume extent in the modeled area for this project because the pressure plume was greater than the CO_2 plume. The predicted AoR would be 155 mi^2 (12.6 mi × 12.3 mi) and 200 mi^2 (13.9 mi × 14.3 mi), respectively, for the investigated scenarios of four wells and ten wells.

Madrid, Nebraska Site

The Madrid site characterization included the construction of an SEM and dynamic modeling using existing site-specific data. A connected volume analysis indicates that stacked storage in all of the deep saline reservoir intervals is viable. Reservoir simulation results conclude that 51 Mt of CO_2 can be stored at the Madrid site over an injection period of 30 years. The resulting maximum plume diameter was around 2.7 mi (around 6 mi^2 at each well). The pressure buildup in the overlying layers and non-reservoir zones ranges between 0 and 2 psi which is low enough not to induce any hydraulic communication with the overlying Underground Safe Drinking Water (USDW) zones.

Patterson Site

The two new 3D seismic surveys acquired in July 2019 over the Patterson and Hartland oil fields were integrated with the two legacy datasets over the Heinitz and Oslo oil fields to characterize the regional structural framework of the Patterson Site. In March–June 2020, two new deep wells (Patterson KGS 5-25 and Hartland KGS 6-10) were drilled into Precambrian crystalline basement to acquire petrophysical, geomechanical, geochemical, and engineering data from core, wireline logs, and well tests. The results of the advanced data analysis of the new feasibility data were used to update the existing Patterson Site SEM (Figure 5-1).

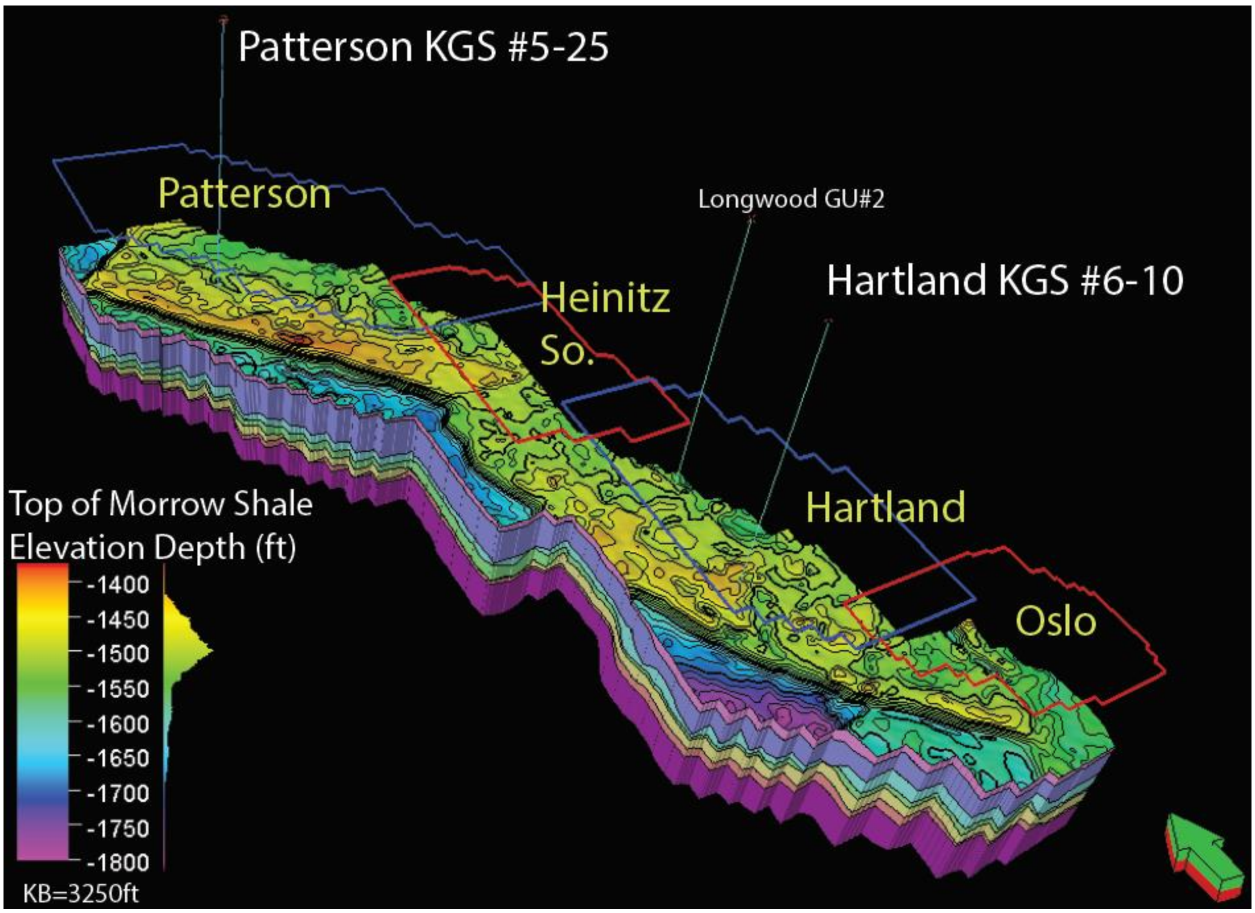


Figure 5-1. Structural model in the Patterson-Oslo area with the legacy deep well (Longwood Gas Unit #2) and two new deep wells (Patterson KGS 5-25 and Hartland KGS 6-10) noted. The top of the model is a depth structure map of the top of the Morrow Shale. On the left side of the legend is a histogram of elevation depths for the Morrow Shale top.

Storage resource estimates calculated using the US-DOE CO2-SCREEN methodology (Goodman et al., 2016) were refined for the three potential reservoirs at the Patterson Site. Site-specific efficiency were calculated and inputs were updated based porosity and permeability values derived from the new well-logs, well testing, and core data from the Patterson KGS 5-25 and Hartland KGS 6-10 wells. The resulting P_{50} CO_2 storage resource estimates for the Osage, Viola, and Arbuckle formations are 34, 28, and 105 Mt, respectively.

Dynamic modeling simulations were performed using three wells, located along the structural high of the Patterson Field, with a full equation of state compositional reservoir model in the CMG GEM simulator. The modeling was performed under constant bottomhole rate and constant bottomhole pressure scenarios, and the model input parameters were based on field-generated data.

With the constant bottomhole injection rate scenario, 50 Mt of CO_2 was injected into the three formations with 80% of the total mass being injected into the peripheral wells and 20% injected in the center well to minimize pressure interference and buildup. Wireline log-based permeability data from existing wells was determined to be significantly lower than the actual permeability, and the log-based data were increased by a factor of 30 during these modeling simulations. The models indicated that 50 Mt of CO_2 could be injected into the three formations (with the majority of the CO_2 stored in the Arbuckle Formation) over a 30-year period with an average reservoir pressure increase of less than 150 psi. The modeling also showed that the CO_2 plume would remain within the AoR with CO_2 saturation levels reaching approximately 60%.

Under the constant pressure scenario, multiple permeability and bottomhole pressure values were used in the modeling to determine the effects of these parameters on CO_2 storage capacity in the formations. The base scenario (with the underestimated log-based permeability data), indicated the feasibility of storing 20 Mt of CO_2 over a 25-year period. The higher permeability and bottomhole pressure model scenarios showed increased storage of CO_2. When permeability was factored by 20 and the maximum bottomhole pressure increase was set at 500 psi, the model indicated the ability to store approximately 270 Mt of CO_2 over a 25-year period. Intermediate pressure scenarios (5 times the base permeability and a 500 psi pressure increase; 10 times the base permeability and a 300 psi pressure increase) both indicated the ability to store more than 80 Mt of CO_2 in 25 years – exceeding CarbonSAFE objective of storing 50 Mt within 25 years. The models also showed that increasing the permeability values would reduce the pressure increase across the AoR; reducing the potential for formation fracturing and induced seismicity.

The geologic model updates for the Sleepy Hollow Field and the Madrid Site are detailed further in the IMSCS-HUB Phase II, Task 5 Storage Complex Geologic and Reservoir Modeling Topical Report (Battelle, 2020e) and the Patterson Site details can be found in Appendix A.

5.3 Geomechanical Modeling of the Storage Complex

In Subtask 5.3, numerical modeling was performed to examine the geomechanical effect of stacked carbon storage in the IMSCS-HUB storage complex at the Sleepy Hollow Field. Geomechanical core testing and analyses were conducted at the Patterson Site. Additional geomechanical modeling will be conducted in future phases of the IMSCS-HUB after characterization data is collected at the Madrid Site.

Sleepy Hollow Field

The potential saline reservoirs and caprock of the sub-basinal area encompassing the SHF in southwest-central Nebraska were evaluated with the coupled geomechanical simulation using ECLISPE-VISAGE, Schlumberger's dynamic and geomechanical modeling simulator. This study focused on the geomechanical risk of formation failure both in the reservoir and caprock due to CO_2 injection. In addition, a sensitivity analysis was conducted to investigate the effect of elastic (Young's modulus, Poisson's ratio, and Biot's coefficient) and mechanical strength (unconfined compressive strength, tensile strength, and friction angle) properties.

The Mechanical Earth Model (MEM) is a numerical representation of the state of stress and rock mechanical properties for a specific stratigraphic section. For this study, the MEM is based on the processing of advanced acoustic and density logs acquired from the SHRU 86A well. The MEM is 10 mi x 10 mi in size, based on the static earth and dynamic models. Modeling efforts included 4- and 10-well injection configurations and a sensitivity analysis.

Geomechanics simulation results indicated that formation integrity was not compromised within the caprock and reservoir in the 4-well injection or the 10-well injection configurations. The main risk for the reservoir is tensile failure. CO_2 injection increases the horizontal stresses creating a stress path towards tensile failure but does not exceed it. Expansion of the reservoir induces stress relaxation in the caprock. This increases the deviatoric stress state and increasing the likelihood of shear failure. Indeed, this creates a stress path towards the shear failure envelope, but the stress path is significantly under the shear failure limit.

Additionally, the near wellbore stress and formation integrity were analyzed by calculating the breakdown gradient (stress required to initiate a fracture). The calculated breakdown gradient for all injection wells is greater than 1 psi/ft – well above the planned injection pressure gradient of 0.665 psi/ft.

Sensitivity analysis was performed on several model parameters by varying the values by 20% either side of the base values. Of the elastic properties, Poisson's ratio showed the greatest impact on the stress path. Of the mechanical strength properties, the unconfined compressive strength (UCS) showed greatest impact to the failure envelope, while in the reservoir friction angle induced the largest change in the failure envelope. In all cases, neither the stress path nor the failure envelope changed sufficiently to cause formation integrity failure.

It is noted that the stress modeling is solely based on an uncalibrated geomechanical model of the SHRU 86A well. Though the uncertainties have been addressed with the sensitivity analysis cases, future data acquisition such as geomechanics core testing and injection fall-off tests are highly recommended to improve the robustness of the model, particularly if the model is to be used to assist and validate field monitoring studies.

Patterson Site

The geomechanical analysis conducted at the Patterson site included laboratory testing on the cored caprock and reservoir intervals from the Patterson KGS 5-25 well. Premier Oilfield Group (POFG) performed numerous triaxial tests on rock material from the Atoka, Morrow, Meramec, Osage-Kinderhook, Viola, Upper Arbuckle, Lower Arbuckle, Granite Wash/Reagan, and Precambrian intervals. Samples from the shale caprock of the Morrowan were unable to be used for geomechanical testing due to the highly fissile nature. However, those Morrowan shale intervals are overlain by competent Atokan Limestone. A table of the key rock mechanical properties for the tested intervals is provided in Appendix A. The UCS of the reservoir rocks from the Arbuckle, Viola, and Osagian intervals ranged from 12,923 psi to 49,985 psi. The UCS of the seal intervals (Meramecian, Morrowan, and Atokan) ranged from 9,519 psi to 26,837 psi. The Precambrian basement had a UCS of 28,544 psi. The Morrow Sandstone and the Granite Wash/Reagan Sandstone have lower UCS values (4,511 psi and 6,932 psi, respectfully). However, the Granite Wash/Reagan Sandstone are overlain by the most competent Arbuckle dolostone and underlain by the Precambrian basement. Overall, the geomechanical laboratory test results demonstrate that the reservoir and seal interval have competent rock strength.

In summary, geomechanical analyses show that the target reservoir and seal intervals are under stable stress conditions. Tensile hydraulic fracturing can be prevented by limiting the injection pressure below the minimum effective horizontal stress. Therefore, it is unlikely that shear fracturing will occur during injection as long as the injection pressure is kept below the minimum effective horizontal stress. According to the structural analysis, the average total vertical (TVD) depth of the Arbuckle, Viola, and Osage reservoirs are 5,878 ft, 5,652 ft, 5,384 ft, respectively (Battelle, 2020d*).* The estimated maximum injection pressures are therefore calculated as 1,587 psi for the Arbuckle potential reservoir, 1,526 psi for the Viola potential reservoir, and 1,454 psi for the Osagian potential reservoir.

The geomechanical modeling of the Sleepy Hollow Field is detailed further in the IMSCS-HUB Phase II, Task 5 Storage Complex Geomechanical Modeling Topical Report (Battelle and Schlumberger, 2020). The details of the geomechanical assessment conducted at the Patterson Site can be found in Appendix A.

6 Outreach

In Phase I of the IMSCS-HUB project, outreach was focused on building a project team capable of implementing a commercial scale CCS project. Phase II objectives were three-fold: (1) conduct stakeholder characterization, (2) conduct preliminary outreach sessions with interested stakeholders, and (3) outline outreach efforts to be implemented in Phases III and IV. Outreach for the IMSCS-HUB include efforts under Phase II of this project and other projects executed by project partners include the following: (1) Stakeholder outreach sessions (Battelle and GPI, 2020), (2) Interactions between KGS and the Kansas CCUS working group, and (3) Stakeholder characterization of the study areas by Battelle (2020f).

6.1 Government, Industry, and NGO Outreach

Outreach in Nebraska was largely accomplished by a webinar series. Three stakeholder outreach sessions with industry, trade groups, federal and state policymakers and regulators, research organizations, legal entities and financial/tax firms have been conducted. These outreach sessions were conducted as webinars due to the travel restrictions resulting from the COVID-19 outbreak. The three seminars provided an overview of CCUS in the Midcontinent, infrastructure buildout and capture requirements, and geology of the Midcontinent. The first webinar covered the basics of CCUS had 117 attendees from industry (including ethanol plants, coal fired power plants, and industry trade groups), government (including federal and state regulators), and research institutions (including KGS, Nebraska Conservation and Survey Division [CSD], Great Plains Institute [GPI], and Battelle).

Outreach in Kansas was accomplished by efforts from project partner KGS. KGS has conducted preliminary, informal stakeholder outreach with oil and gas and other industries. KGS indicates that they have received a positive to neutral response from most of the entities they have spoken with about CCS [Y. Holubnyak, personal communication]. Thus far, these entities have largely been ethanol and power facilities, industry trade groups, and oil and gas representatives. KGS indicated during the Phase II of this project that induced seismicity will be an issue of concern to the Kansas Department of Health and Environment (KDHE) and the public in Kansas. Messaging that emphasizes the difference in location (i.e., the proposed project is in western Kansas as opposed to the more seismically active central Kansas) and operations of the proposed project (i.e., injecting into three formations) will help allay these concerns [Battelle, 2020g, 2020h]. KGS also has an active CCS working group in conjunction with the KDHE, the Kansas Corporation Commission (KCC – the oil and gas industry regulatory body in Kansas), and the U.S. EPA, Region 7.

Phase II of the project includes a final stakeholder characterization report for the study areas (Battelle, 2020f). The report presents the efforts to establish an IMSCS-HUB outreach team, demonstrate key messages for stakeholders in the study area, develop outreach strategies and materials, and foster public acceptance of CCUS projects and related infrastructure in the IMSCS-HUB study area. The report also includes additional community characterization and outreach efforts that must be completed for Phase III outreach efforts. Key messaging developed in the report focuses on tailoring messages to be specific to the IMSCS-HUB project area, where possible. This includes relating the economic and environmental benefits to the tri-state study area; ensuring the concerns for environmentally, culturally, and socially sensitive areas are considered; and addressing region-specific concerns about induced seismicity.

6.2 Outreach Plan

An outreach plan was developed to address issues that are of concern in the IMSCS-HUB project area (Battelle, 2020f). The document described the establishment of the public outreach team, the social characteristics of the CCUS sites and associated infrastructure, the key messages developed for outreach efforts, the regional stakeholders that may have an interest in the project, and strategies to foster public acceptance of the project.

The Phase II project outreach team was led by Battelle and included GPI, the Nebraska CSD, and KGS. Work under IMSCS-HUB has helped establish a consortium of stakeholders interested in developing CCUS in the Midcontinent. This includes sources (ADM, MABE, Valero, NPPD, and OPPD), state governmental research agencies (Kansas Geological Survey [KGS] and the Nebraska Conservation and Survey Division [CSD]), non-profit research agencies (GPI and Energy and Environmental Resource Center [EERC]), and other industrial partners (Great Plains Energy [GPE] and Schlumberger).

Social characteristics of the site were investigated using data from the United States Census Bureau. In addition, local stakeholder concerns for pipeline projects and induced seismicity were investigated using proxies. This information will be used to guide future outreach efforts.

Key messages must be developed to communicate project benefits, risk and safety mechanisms, and environmental considerations to different stakeholders. The IMSCS-HUB developed four areas with key, region-specific messages to communicate to stakeholders in the Midcontinent: (1) Localizing the benefits of CCUS, (2) communicating the safety of CCUS, (3) accounting for environmentally and culturally sensitive areas, and (4) addressing induced seismicity. Outreach materials can be tailored to address the interests of specific stakeholders. Localized benefits included short-term (construction jobs, materials manufacture, etc.), medium-term (operations and maintenance jobs, revenue from CO_2-EOR, etc.), and long-term (addressing climate change, which has local risks such as flooding of fields from increased rainfall). Strategies for speaking about the safety of CCUS projects include communicating the relative safety of CO_2 pipeline operations and the safety measures that are in place at CCUS sites. The IMSCS-HUB project has also completed significant work to account for the environmentally and culturally sensitive areas along pipeline routes and at injection sites. Induced seismicity concerns could be allayed by communicating project controls on induced seismicity (e.g., monitoring strategies and maximum injection pressures).

Regional stakeholders with an interest in the project were established in Phases I and II through attendance at events related to CarbonSAFE. This included in-person events in Kansas and Nebraska in Phase I and a series of webinars covering CCUS in Nebraska. Stakeholders in Kansas were engaged in Phase I of the ICKan Project through two meetings, one in Wichita, Kansas on September 21, 2017 and one in Lawrence, Kansas on July 27, 2018. Attendees to the meetings included federal and state government officials and people from industry and NGOs (Table 6-1). The meetings were hosted to recruit additional industry partners for future phases of the ICKan Project. The presentations communicated the goals of the Phase II efforts and how CCUS would be promoted with near-term activities.

During Phase I of the IMSCS-HUB project, Battelle engaged stakeholders from agricultural groups (the Farmers Union, Farm Bureau, Corn growers), oil and gas (Great Plains Energy [GPE] and Central Operating), ethanol plants (ADM, Trenton Agri Products, and Valero), industry advocates (Nebraska Corn Board, Nebraska Petroleum Producers Association, Kansas Independent Oil and Gas Association, Renew Kansas), NGOs (Clean Air Task Force), state government (Nebraska Ethanol Board, Kansas and Nebraska Governors' offices, etc.), legislature (state and federal), and electric utilities (Nebraska Public Power District [NPPD], Westar Energy, etc.), academia (Kansas Geological Survey, University of Nebraska Conservation and Survey Division, etc.) (Battelle, 2018). These stakeholders were engaged to identify parties interested in participating in or promoting the IMSCS-HUB project as well as to determine organizations that would be effective partners for outreach efforts. Several of the entities agreed to become project partners, including GPE, ADM, KGS, Nebraska CSD, and NPPD.

Table 6-1. List of attendees at the CCUS for Kansas Meetings.

First Name	Last Name	Title	Organization	Wichita	Lawrence
Keith	Brock	Attorney	Anderson & Byrd, LLP		X
Scott	McDonald	Dir. of Biofuels Development	Archer Daniels Midland		X
Andrew	Duguid	Principal Engineer	Battelle	X	X
Dana	Wreath	VP	Berexco	X	
Scott	Ball	VP	BOE Midstream	X	
Fatima	Ahmad	Solutions Fellow	Center for Climate and Energy Solutions	X	
Rick	Johnson	Process Eng. & Dev. Manager	CHS McPherson Refinery	X	
Deepika	Nagabhushan	Energy Policy Associate	Clean Air Task Force	X	
Roger	Erickson	Field Representative	Congressman Estes Ks 4th District	X	
Keith	Tracy	President	Cornerpost CO_2 LLC	X	X
Joe	Schremmer	Attorney	Depew Gillen Rathbun & McInteer LC	X	X
Charles	Steincamp	Managing Partner	Depew Gillen Rathbun & McInteer LC	X	X
Michael	Barger	EHS Manager	East Kansas Agri-Energy		X
Todd	Barnes	Environmental Specialist	East Kansas Agri-Energy		X
Bill	Pracht	CEO	East Kansas Agri-Energy		X
Doug	Sommer	Vice President of Operations	East Kansas Agri-Energy		X
Eric	Mork	Business Development	EBR Development, LLC		X
Jason	Friedberg	General Manager	ELEMENT, LLC		X
Neil	Wildgust	Principal CCS Scientist	Energy & Environmental Research Center		X
Kevin	Gray	Director, Innovation	Flint Hills Resources	X	
Gary	Gensch	Consultant	Gary F. Gensch Consulting	X	
Dan	Blankenau	President	Great Plains Energy Inc.	X	X
Dane	McFarlane	Senior Research Analyst	Great Plains Institute	X	
Doug	Scott	Vice President	Great Plains Institute	X	
Brad	Crabtree	Vice President	Great Plains Institute		X
Jess	Jellings	Event Planner	Great Plains Institute		X
Brendan	Jordan	Vice President	Great Plains Institute		X
Chuck	Brewer	President	GSI Engineering	X	
Martin	Dubois	Owner	Improved Hydrocarbon Recovery, LLC	X	X
Ingrid	Setzler	Dir. Environmental Services	Kansas City Board of Public Utilities		X
Greg	Krissek	CEO	Kansas Corn	X	
Sue	Schulte	Director of Communications	Kansas Corn		X
Justin	Grady	Chief of Accounting and Financial Analysis	Kansas Corporation Commission	X	
Jeff	McClanahan	Director, Utilities Division	Kansas Corporation Commission	X	
Dwight	Keen	Commissioner	Kansas Corporation Commission		X

First Name	Last Name	Title	Organization	Wichita	Lawrence
Mike	Cochran	Chief, Geology & Well Tech Sec	Kansas Department of Health & Environment (KDHE)	X	X
Brandy	DeArmond	PG, Chief, UIC	KDHE	X	
Jessica	Crossman	Professional Geologist	KDHE	X	X
Michael	Chisam	President/CEO	Kansas Ethanol, LLC		X
Dave	Heinemann	Member	Kansas Geological Survey Advisory Council		X
Mark	Schreiber	Representative	Kansas House of Representatives		X
Edward	Cross	President	Kansas Independent Oil & Gas Association	X	
Mark	Ballard	Petroleum Engineer	Kansas Uni., Tertiary Oil Recovery Program		X
Jyun Syung	Tsau	Dir. CO_2 Flooding & Seq.	Kansas Uni., Tertiary Oil Recovery Program		X
Donna	Funk	Principal	KCoe Isom, LLP		X
Makini	Byron	Innovation Project Manager	Linde LLC	X	
Krish R.	Krishnamurthy	Head of Group R&D	Linde LLC	X	X
Kevin	Watts	EOR Bus. Development Dir.	Linde LLC		X
Steve	Melzer	Owner	Melzer Consulting	X	
Sarah	Bennett	MidCon Exploitation Manager	Merit Energy Company	X	X
Ryan	Huddleston	Engineer	Merit Energy Company	X	
Martin	Lange	Engineer	Merit Energy Company	X	X
Frank	Farmer	General Counsel	Mississippi Public Service Commission	X	
Leon	Rodak	VP Production	Murfin Drilling Company	X	
Al	Collins	Sr. Director Regulatory Affairs	Occidental Petroleum Corporation	X	X
Charlene	Russell	VP Low Carbon Ventures	Occidental Petroleum Corporation		X
Peter	Barstad	Policy Analyst	Office of Kansas Governor Jeff Colyer		X
Andrew	Wiens	Chief Policy Officer	Office of Kansas Governor Jeff Colyer		X
Christian	McIlvain	VP, Denaturant and CO_2	POET Ethanol Products	X	
Marcus	Lara	Marketing Manager	POET Ethanol Products		X
Jeffrey	Brown	Research Fellow	Stanford Business School	X	
Tom	Sloan	State Representative	State of Kansas		X
Tiraz	Birdie	President	TBirdie Consulting, Inc.		X
Anthony	Leiding	Dir. of Operations	Trenton Agri Products		X
Sarah	Forbes	Scientist	United States Department of Energy	X	X
Kurt	Hildebrandt	Geologist	U.S. Environmental Protection Agency		X
Be	Meissner	Physical Scientist	U.S. Environmental Protection Agency		X
Reza	Barati	Associate Professor	University of Kansas		X
Steve	Randtke	Professor	University of Kansas		X
Dana	Divine	Hydrogeologist	Nebraska Conservation & Survey Div.		X
Paul	Ramondetta	Manager of Exp. & Exploitation	Vess Oil Corp.	X	X
Scott	Wehner	Owner	Wehner CO_2nsulting, LLC	X	
Dan	Wilkus	Director, Air Programs	Westar Energy, Inc.	X	X
Kim	Do	Finance Manager	White Energy	X	
Greg	Thompson	Chief Executive Officer	White Energy		X
Matt	Fry	Policy Advisor	Wyoming Governor's Office	X	

Phase II efforts included a series of webinars, described by Battelle (2020i), that sought to communicate IMSCS-HUB project accomplishments and strategies for interested stakeholders to stay involved in CCUS projects in the Midcontinent. The webinars covered the basics of CCUS, case studies, and geologic investigations. Attendees included individuals from state and federal government, industry (including ethanol, energy, and power plants), advocacy groups (agricultural groups and NGOs), and other entities (including financial, legal, research, and international organizations, members of the media and unaffiliated attendees) (Table 6-2).

Table 6-2. Attendees of the three webinars hosted by Battelle and GPI communicating IMSCS-HUB project accomplishments to Nebraska stakeholders. From Battelle (2020i).

Entity Type	The Basics	Case Studies	Geology
Government	**38**	**29**	**23**
Federal Agency	13	12	11
Federal Policymaker	1	2	2
State Agency	22	15	9
State Policymaker	2	-	1
Industry	**78**	**61**	**31**
Ethanol/Biofuels	19	13	4
Energy/Oil & Gas	17	20	7
Power Plant	6	4	2
Other	36	24	18
Advocacy Group	**18**	**7**	**6**
Agriculture	12	6	6
NGO	6	1	-
Other	**19**	**22**	**20**
Financial	4	5	4
Legal	1	3	2
Research Organization	10	13	14
International	3	-	-
Media	1	-	-
Unaffiliated	-	1	-
Total	**153**	**119**	**80**

6.3 Coordination with DOE-NETL Carbon Storage Programs

To facilitate synchronization of CarbonSAFE and other DOE-NETL initiatives aimed at developing large-scale CCUS, the IMSCS-HUB project team includes members of several the Regional Carbon Sequestration Partnerships (RCSPs) including the Big Sky Carbon Sequestration Partnership (BSCSP), the Plains CO_2 Reduction (PCOR) Partnership, the Southeast Regional Carbon Sequestration Partnership (SECARB), the Midwest Geological Sequestration Consortium (MGSC), the Southwest Regional Partnership on Carbon Sequestration (SWP), and the Midwest Regional Carbon Sequestration Partnership (MRCSP).

Coordination efforts included PNNL, a member of BSCSP and DOE's National Risk Assessment Partnership (NRAP), implementing NRAP tools to assess the subsurface storage risks and the risk of induced seismicity in the IMSCS-HUB region. The EERC, the lead organization of PCOR Partnership Initiative, has been involved with the geologic characterization efforts and conducted the dynamic modeling at the SHF. Further engagement with the RCSPs was accomplished through the project's Technical Advisor, Dr. Neeraj Gupta, is the Principal Investigator of the Battelle-led Midwest Regional Carbon Sequestration Partnership (MRCSP) and the Midwest Regional Carbon Initiative (MRCI).

Additional collaboration efforts include submittal of the data collected under the IMSCS-HUB Phase II to DOE-NETL's Energy Data eXchange (EDX) and the shipment of the core materials to DOE-NETL for inclusion in future studies.

7 Risk Assessment and Mitigation

Phase II efforts focused on subsurface risks (Task 7.1) (Battelle, 2020g), pipeline risks (7.2) (Battelle, 2019b), and non-technical risks (Task 7.4) (Battelle, 2020h). In addition, the National

Risk Assessment Partnership (NRAP) (Task 7.3) tools were used to estimate the risk of CO_2 and/or brine leakage through existing wells and subsequent impacts to USDWs as well as the risk of induced seismicity [Battelle and PNNL, 2020]. The risk assessment culminated in a risk mitigation plan which outlines strategies to deal with risks found during the evaluation of each project component (Battelle, 2020j).

7.1 Storage Risk Assessment

The subsurface risk assessment focused on risks of CO_2 leakage through natural faults and fractures and artificial penetrations (e.g., wells) as well as other geologic risks such as induced seismicity (Battelle, 2020g). The subsurface risk assessment included three main parts: (1) an analysis of features, events, and processes (FEPs), (2) an assessment of the leakage potential of the network of wells in each of the proposed project AoRs, and (3) an analysis of geologically relevant risks in the study area (i.e., faulting and induced seismicity).

Entries from the Quintessa [2013] database were analyzed to determine whether they were applicable to the proposed Madrid, Nebraska and Patterson projects and other potential projects in the IMSCS-HUB storage corridor for the FEPs analysis. The analysis was intended as a screening level assessment of possible subsurface risks associated with projects in the area. FEPs identified are related to external factors (e.g., external receptors, external events affecting storage, etc.), CO_2 storage (e.g., scheduling, operational constraints, storage verification, etc.), CO_2 properties (e.g., CO_2 behavior, CO_2 interactions in the subsurface and CO_2 transport, etc.), geosphere considerations (e.g., reservoir properties, fractures/faults, mechanical properties, etc.), legacy well considerations (e.g., construction and materials, seals and abandonment, and orphan wells), near-surface environments (e.g., terrestrial environments. human behavior, etc.), and impacts (e.g., impacts on groundwater, impacts on soil and sediments, etc.).

The leakage potential from existing boreholes was found using leakage proxies, features of the well that were used to determine the relative likelihood of a leakage event (see Battelle, 2020g for more information on the process). This semi-quantitative method combined methods originally developed by Hnottevange-Telleen et al. (2009) and Tucker et al. (2013) in a similar approach as that used by Battelle (2018). Figure 7-1 shows a conceptual diagram that includes the likelihood factors, their relation to applicable FEPs, and potential consequence categories resulting from leakage. Ten factors were used as leakage proxies:

- **Well location:** Whether the well was in the footprint of the CO_2 plume or AoR
- **Spud date:** The decade the well was drilled as a proxy for the amount of time the well has degraded and the protectiveness of the materials and the drilling practices employed.
- **Well type:** The function/type (i.e., injection, monitoring, oil/gas production) of the well as a proxy for the stresses placed on the well.
- **Well status:** The status of the well (i.e., active, temporarily abandoned, plugged/abandoned) as a proxy for the potential (or lack of) active monitoring to detect problems.
- **Plugging and abandonment (P&A) date:** The decade the well was plugged as a proxy for the amount of time the plug has degraded, the protectiveness of the materials, and the plugging practices employed.
- **Surface casing cement:** The amount of cement in the annulus between the surface casing and the surface borehole as a function of the sealing potential of the cement to prevent contamination of groundwater and/or movement of fluids to the surface.

- **Production casing cement:** The amount of cement in the annulus between the production casing and the production borehole as a function of the sealing potential of the cement to prevent movement of fluids to the groundwater and/or surface. Two measures of production cement integrity were used: (1) whether the production cement reached the surface casing and (2) the percent of the well column covered by production cement.
- **Plug cement:** The amount of cement used to plug the well. Two measures of plug cement integrity were used: (1) the percentage of the well column filled with cement and (2) the space between the bottom of the lowest well plug and the bottom of the wellbore.
- **Treatment:** The treatment type as a function of the negative effects of wellbore treatment and treatment interval (e.g., acidification, hydraulic fracturing, etc.) as a function of whether the treatment directly affected the storage complex.
- **Total depth:** The total depth of the well indicates what part of the storage complex is affected by the artificial penetration. For the purposes of the IMSCS-HUB project, this could be the secondary caprock only, the primary and secondary caprocks, or the storage reservoir and primary and secondary caprocks. The analysis also indicated whether the baffle between these units was affected.

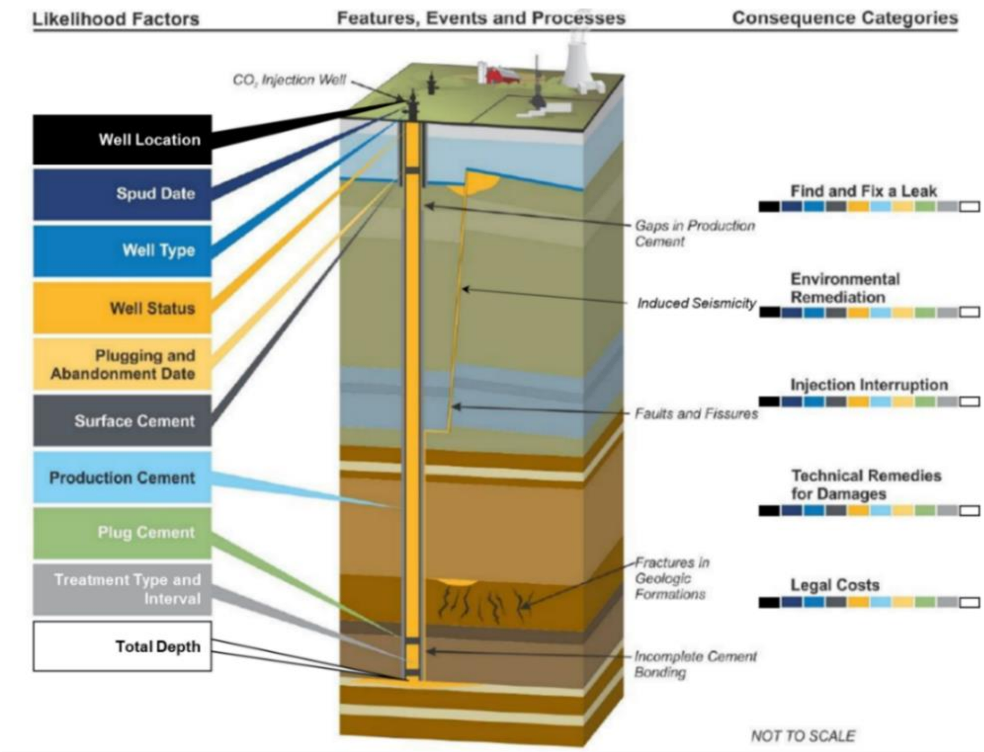


Figure 7-1. Conceptual diagram of the likelihood criteria, FEPs, and consequence categories of projects in the IMSCS-HUB project. Modified from Battelle (2018).

The subsurface risk assessment found a relatively small likelihood of leakage at the Madrid, Nebraska site. Eleven wells within the Madrid, Nebraska site AoR are drilled to the storage complex. All wells are within the AoR but do not intersect the modeled CO_2 plumes (Figure 7-2). As such, they are only a risk for the conveyance of brine. The normalized average likelihood parameters, found by summing the likelihood values of all likelihood proxy criteria (outlined above) and dividing by the maximum possible likelihood value, was 0.60 to 0.80 for most wells – the equivalent of 3 to 4. However, the normalized likelihood of leakage, found by using the normalized leakage likelihood with an “apparent date” (calculated with fitting parameters that are determined by the equation of the regression line of normalized likelihood versus spud date) was less than 0.20 for all but two wells.

The Patterson site had more wells than the Madrid, Nebraska site and a much different risk profile (Figure 7-3). The normalized average likelihood is generally lower than the wells at the Madrid, Nebraska site. However, due to differences in the fitting parameters, the leakage likelihood for these wells is generally higher than the Madrid, Nebraska site.

The risk of wells at the Patterson site may be overstated because of the inclusion of the Sumner Group as a secondary caprock in the analysis. Thousands of feet of baffle separate the Sumner Group from the primary caprock system, the Cherokee-Atoka and Morrowan formations. Wells drilled to produce gas from the Council Grove Group or Chase Group, directly underlying the Sumner Group, or oil and gas from the deeper Lansing-Kansas City formation are drilled through the Sumner Group. Wells that only affect the Sumner Group account for more than two-thirds of all the wells in the analysis (258 of 386 wells).

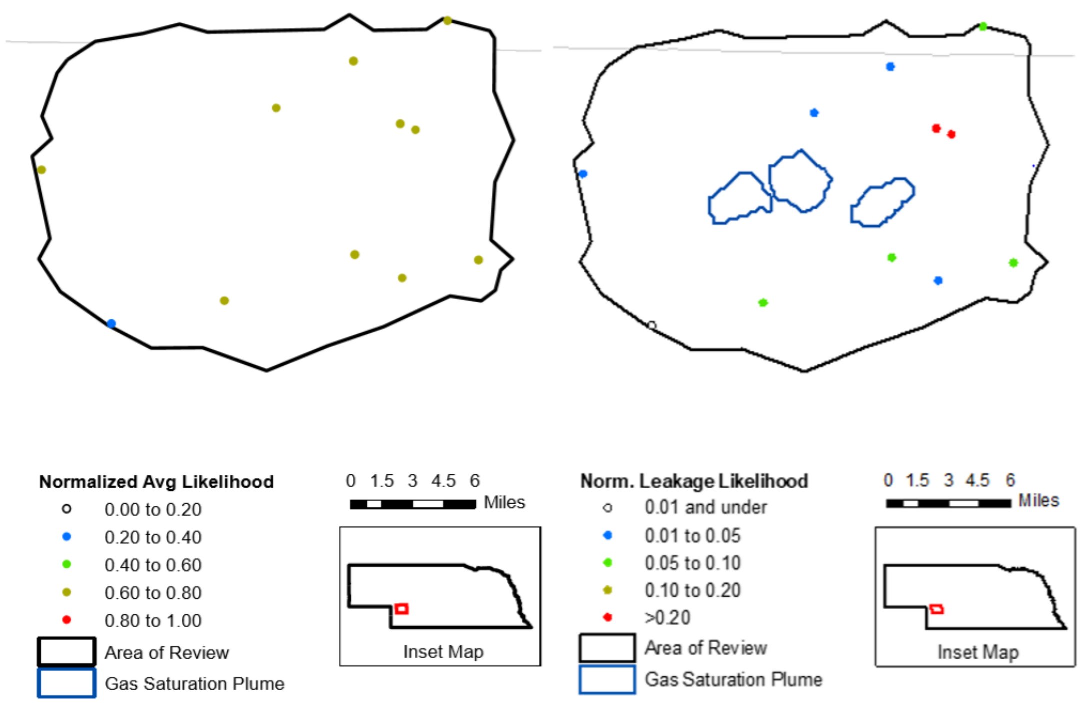


Figure 7-2. Normalized average likelihood (left) and leakage likelihood (right) for Surface Scenario in the Madrid, Nebraska site. From Battelle (2020g).

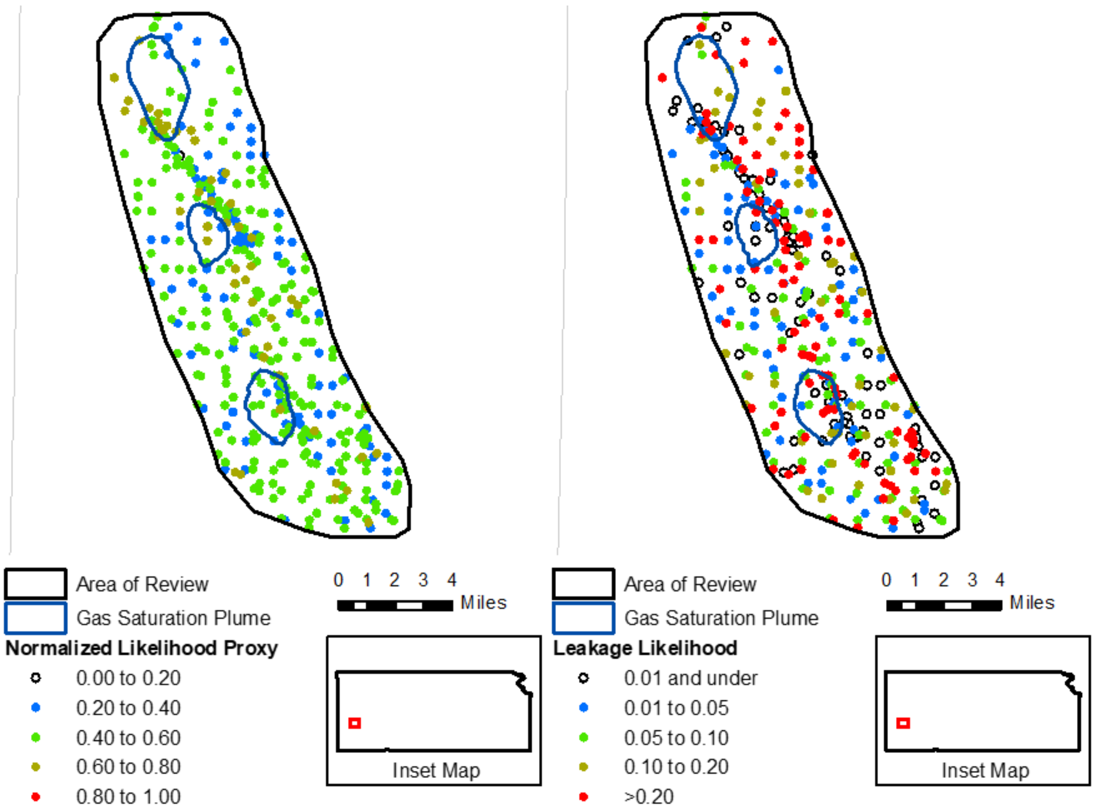


Figure 7-3. Normalized average likelihood (left) and leakage likelihood (right) for Surface Scenario in the Patterson site. From Battelle (2020g).

Including the shallower wells in the analysis changes the apparent risk of leakage in the Patterson field in two ways. First, including the shallow wells adds to the overall risk through the addition of 258 additional points where leakage could potentially occur. Secondly, the inclusion of the shallower wells increases the apparent risk from the deeper wells by affecting the scenario-specific fitting parameters used to generate apparent dates. When the Sumner Group was included in the analysis, the deep wells had an average normalized leakage likelihood of 0.3411, including 36 of 128 wells (28% of deep wells) with a normalized leakage likelihood of 1.0 (Table 7-1). Only half of the deep wells had a normalized leakage likelihood of less than 0.05. The shallower wells in the scenario considering the Sumner Group had an average normalized leakage likelihood of 0.1884, including 20 wells (around 8% of shallow wells) with a normalized leakage likelihood of 1.0. Only 38% of wells had a normalized leakage likelihood of less than 0.05. When considering the Sumner Group, the average normalized leakage likelihood for all wells is 0.2279.

When considering only the deeper wells, the average normalized leakage likelihood is 0.1717 (Table 7-1), nearly half of the average normalized leakage likelihood for deep wells when the Sumner Group is included in the analysis. The number of deep wells with a normalized leakage likelihood of 1.0 drops nearly three times to 13. In addition, the proportion of wells that with normalized leakage likelihood values less than 0.05 increases to 60% (77 of 128 deep wells).

Figure 7-4 shows the distribution of the wells with analysis of the normalized leakage likelihood calculated without the Sumner Group and with the Sumner Group. When the Sumner Group is excluded, most of the wells within the gas saturation plume boundaries do not exceed a leakage likelihood value of 0.10. Only three wells with leakage likelihood values of 1.0 are within a gas saturation plume (one in the northern plume and two in the southern plume) while an additional five wells are within one mile of the boundary of a plume (one near the northern plume, three near the central plume, and one near the southern plume). In contrast, six wells with leakage likelihood values of 1.0 are within the modeled gas saturation plumes when the Sumner Group is considered (three in the northern plume and three in the southern plume. An additional 11 wells are within one mile of the modeled plumes (two near the northern plume, six near the central plume, and three near the southern plume). In addition to demonstrating the effect of the Sumner Group on the analysis, this map could target future well remediation efforts.

Table 7-1. Average normalized leakage likelihood and distribution of normalized leakage likelihood values for the surface scenario found considering all wells and the scenarios considering only deep wells, defined as wells terminating in the primary caprock system or deeper.

Wells considered - well type	Avg. norm. leakage likelihood	No. Wells	No. wells with normalized leakage likelihood			
			= 1.0	*0.5-0.99*	*0.05-0.5*	*< 0.05*
Sumner Group considered - all wells	0.2279	386	56	10	158	161
- shallow wells	*0.1884*	*258*	*20*	*5*	*136*	*97*
- deep wells	*0.3411*	*128*	*36*	*5*	*22*	*64*
Only deep wells considered – all wells	0.1717	128	13	9	29	77

The risk of leakage from wells penetrating the subsurface, found by multiplying the leakage likelihood by the severity of the potential leaks and the number of wells in the AoR, is between \$104,000 to \$385,000 for the Madrid, Nebraska site and between \$11.4 million to \$40.0 million for all wells at the Patterson site and \$3.1 million to \$10.9 million if only wells affecting the primary caprock and reservoir are considered (Battelle, 2020g).

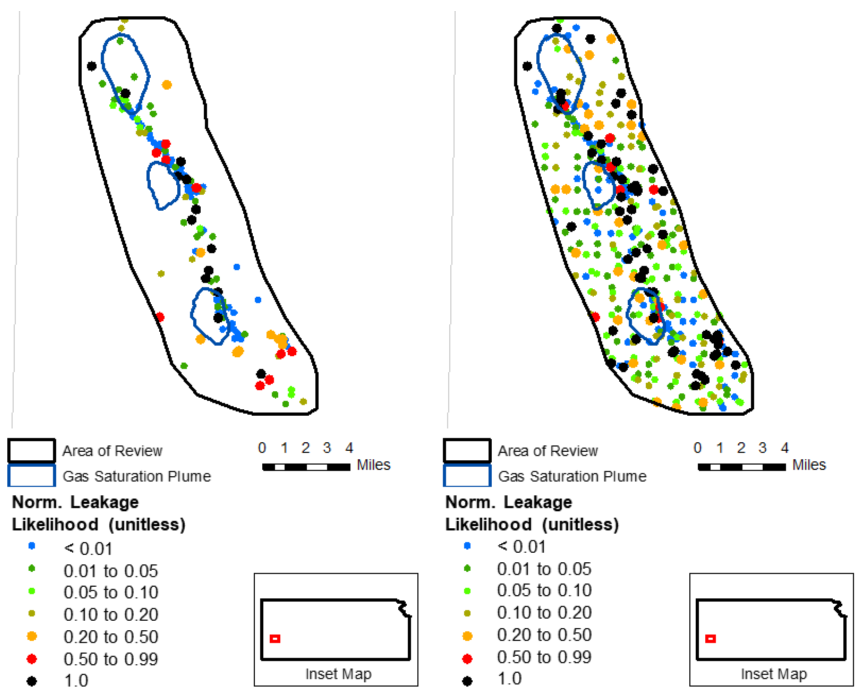


Figure 7-4. Normalized leakage likelihood for all wells in the analysis not considering the Sumner Group (left) and the analysis considering the Sumner Group (right), surface scenario at the Patterson site.

7.2 Pipeline Risk Assessment

The pipeline risk assessment focused on the risks of planning, constructing, and operating a CO_2 pipeline. The pipeline risk assessment included three components: (1) an FEPs analysis to outline the potential risks of pipeline siting (i.e., public opposition to pipeline projects, disruption of sensitive areas, routing and sizing issues, etc.), (2) quantitative assessment the risk of worker injuries or fatalities during pipeline construction, and (3) a quantitative assessment of the risk of leakage. The FEPs analysis detailed project risks related to pipeline planning, pipeline construction, pipeline operations, and public opposition (Figures 7-1 to 7-4).

A quantitative assessment of pipeline construction and operational risks was conducted using data from the Bureau of Labor Statistics (BLS) (BLS, 2018; 2017) and Pipeline and Hazardous Materials Safety Administration (PHMSA) databases [(PHSMA, 2019a, b), respectively. The BLS database was used to calculate the number of injuries requiring hospitalization and the number of fatalities per 10,000 full-time workers equivalent (FTWe) working in oil and gas pipeline construction (NAICS: 237120). The likelihood of an injury requiring hospitalization or fatality was calculated by dividing the number of injuries or fatalities by the number of FTWe required to construct a pipeline. This was then related to the miles of pipeline constructed using the ratio between the miles of pipeline constructed per year (estimated from the difference of the total mileage of pipeline operating, year over year, between 2010 and 2018 [PHMSA, 2019b]) and the number of FTWe working in the oil and gas pipeline construction industry (U.S. Census Bureau, 2018). The number of FTWe needed to construct each pipeline was then multiplied by the average occurrence of each injury to estimate risk. The severity of the accidents requiring hospitalization, determined based on the cost of hospitalization, lost wages, and potential litigation, was estimated between $186,538 to $226,538 per injury. The severity of fatalities was estimated to be $9.5 million in 2019 dollars, based on the U.S. EPA valuation for a human life ($7.4 million in 2006 $ - U.S. EPA [nd]).

Risk of Planning Events

- Pipeline undersizing
- Pipeline oversizing
- Incorrect booster station placement
- Poor material selection
- Incorrect gas composition requirements
- Inaccurate pipeline mapping
- Inaccurate land use characterization
- Pipeline rights-of-way
- Pipeline planning in high-risk or sensitive area
- Surface barriers and obstacles

Risk of Planning Consequences

- Insufficient delivery of CO_2 or need to construct additional pipeline to transport CO_2 to the same location
- Stranded/unused pipeline assets
- Critical pressure loss if boosters are placed too far apart and wasted capital if boosters are placed too close together
- Pipeline corrosion, material failure, or equipment failure due to accelerated pipeline wear
- Issues with accelerated corrosion or temperature/pressure conditions for transport due to CO_2 stream impurities
- Construction in sensitive or high-risk areas or potential damage to the environment
- Public opposition
- Schedule delays due to rerouting
- Difficulty negotiating leases
- Increased costs due to complex pipeline network

Figure 7-1. FEPs related to pipeline planning. From Battelle (2019b).

Risk of Construction (Worker Injury)
Events

- Slips, trips, falls, strain/injury, foot and ankle cuts, puncture wounds, or impacts
- Eye and skin irritation
- Pinch points, compression, entanglement from objects or equipment
- Electrocution
- Explosions
- Roadway incidents, land vehicle accidents, other transportation incidents
- Wildlife and domestic animal interaction
- Poisonous plants and insects
- Negligence, not wearing PPE

Risk of Construction (Worker Injury)
Consequences

- Single fatality
- Multiple fatalities
- Single disability or amputation
- Multiple disabilities or amputation
- Single severe injury
- Multiple severe injury
- Single minor injury

Risk of Construction (Environmental Factors)
Events

- Drought
- Deluge
- Blizzards
- Inclement Weather/ Storms

Risk of Construction (Environmental Factors)
Consequences

- Equipment/machinery inaccessible
- Site inaccessible
- Fires
- Project delay
- Employee sickness/injury

Figure 7-2. FEPs related to pipeline construction. From Battelle (2019b).

Risk of Operations (Leaks)
Events

- Small Unintentional Release (<100 barrels) or larger
- Medium Unintentional Release (100 – 3,300 barrels) or larger
- Large Unintentional Release (>3,300 barrels)[1]

Risk of Operations (Leaks)
Consequences

- Loss of gas
- Pipeline shutdown > 7 days < 30 days
- Pipeline shutdown > 30 days
- Pipeline shutdown > 365 days
- Gas accumulates / asphyxiant
- Sedimentation/erosion
- Property damage
- Human health impacts
- Fatality
- Multiple fatalities
- Ecological damage
- Financial Cost <$10,000 or more
- Financial Cost of $10,000 to $1 million or more
- Financial Cost $1 million to $10 million or more
- Financial Cost >$10 million

Figure 7-3. FEPs related to operation phase. From Battelle (2019b).

Risk of Public Opposition
Events

- Local resident opposition (limited)
- Local resident opposition (substantial)
- NGO Opposition (limited)
- NGO Opposition (substantial)
- Negative media coverage (limited)
- Negative media coverage (substantial)

Risk of Public Opposition
Consequences

- Project delayed
- Project canceled
- Technology delayed
- Technology killed

Figure 7-4. FEPs related to public opposition. From Battelle (2019b).

The likelihood of the pipeline incidents was determined quantitatively using past occurrence as in PHMSA (2019a, b). The severity of the risk was determined by determining the overall monetary value of the damage done by accidents, which is also available in these databases. reported costs of previous accidents, reported in PHMSA [2019a]. Risk was then determined by multiplying the likelihood of occurrence by the severity of impact.

The risk of worker injury requiring hospitalization during construction and the risk of worker fatality during construction for each of the Phase I pipeline configurations is shown in Table 7-2. Depending on the scenario, the risk of injury requiring hospitalization was between $376,586 to $14,442,219. The risk of worker fatality was about 50% (between $560,500 and $21,422,500).

While the risk of construction is not dependent on the pipeline type, the operational risks are. Operational risks for CO_2 pipelines were found to be orders of magnitude lower than for natural gas distribution or transmission pipelines or other non-CO_2 hazardous liquid pipelines. Table 7-3 shows the pipeline operational risks for a 30-year project for the four Phase I pipeline configurations operating as a CO_2, gas distribution, gas transmission/gathering, and non-CO_2 hazardous liquid pipeline. Average CO_2 pipeline risks were much lower than other pipeline types. Depending on the configuration, the average CO_2 pipeline operational risk for a 30-year project ranged from less than $100,000 to around $1.9 million. In contract, the average risk for gas distribution pipelines ranged from $132,404 to around $2.6 million (35% higher); the average risk for gas transmission/gathering pipelines ranged from around $1.4 million to around $28.2 million (around 14 times higher); and the average risk for non-CO_2 hazardous liquid pipelines ranged from around $5.2 million to over $100 million (more than 50 times higher).

Table 7-2. Risk of injury requiring hospitalization (top) and fatality (bottom) for pipeline construction of the four Phase I configurations. From Battelle (2020j).

Configuration	Miles	Likelihood of injury requiring Hospitalization				Risk of Injury Requiring Hospitalization		
		per 10,000 FTWe	For Configuration					
			Min.	Avg.	Max	Min.	Avg.	Max
Risk of injury requiring hospitalization								
a	344	**36.643**	8.603	11.953	16.864	$1,639,281	$2,277,824	$3,213,739
b	295		7.377	10.25	14.462	$1,405,759	$1,953,283	$2,755,848
c	79		1.976	2.745	3.873	$376,586	$523,087	$737,889
d	1546		38.662	53.717	75.792	$7,366,938	$10,235,923	$14,442,219
Risk of fatality								
a	344	**1.100**	0.258	0.359	0.506	$2,451,000	$3,410,500	$4,807,000
b	295		0.221	0.308	0.434	$2,099,500	$2,926,000	$4,123,000
c	79		0.059	0.082	0.116	$560,500	$779,000	$1,102,000
d	1546		1.150	1.598	2.255	$10,925,000	$15,181,000	$21,422,500

Table 7-3. Total pipeline risk for 30 years of operation for four Phase I pipeline configurations (with 3% annual inflation), by pipeline type.

Configuration	Mileage	CO_2		Gas Distribution		Gas Transmission/Gathering		Non-CO_2 Haz. Liquid	
		Average	Median	Average	Median	Average	Median	Average	Median
Risk per mile	-	$26.19	$6.97	$35.24	$4.06	$383.96	$45.97	$1,376.35	$46.33
30-year project	-	$1,246	$331	$1,676	$193	$18,266	$2,187	$65,478	$2,204
a	344	$428,624	$113,864	$576,544	$66,392	$6,283,504	$752,328	$22,524,432	$758,176
b	295	$367,570	$97,645	$494,420	$56,935	$5,388,470	$645,165	$19,316,010	$650,180
c	79	$98,434	$26,149	$132,404	$15,247	$1,443,014	$172,773	$5,172,762	$174,116
d	1546	$1,926,316	$511,726	$2,591,096	$298,378	$28,239,236	$3,381,102	$101,228,988	$3,407,384

7.3 National Risk Assessment Program Tools

The National Risk Assessment Partnership (NRAP) tools were used to quantify subsurface storage risks and the risk of induced seismicity. The NRAP – Integrated Assessment Model – Carbon Storage (NRAP-IAM-CS) provides a modeling-based approach to assess potential leakage from artificial penetrations and the subsequent impact to USDWs. The Short-Term Seismic Forecasting (STSF) Ground Motion Predictions for Induced Seismicity (GMPIS) model was used to model the risk of possible induced seismicity when injecting CO_2 into the Patterson or Sleepy Hollow Reservoirs. NRAP-IAM-CS analysis found limited risks for both the Patterson and Sleepy Hollow sites. The leakage rate found by the model was “significantly below the 1% CO_2 leakage metric commonly stated as an acceptable threshold” for both reservoirs (Battelle and PNNL, 2020). The authors note that additional information about the wellbores will help refine the results.

The analysis using the STSF and GMPIS tools is highly uncertain due to the lack of available information. In addition, the analysis assumes an initial state near critical pressure. The analysis found a significant risk of unintentional hydraulic fracturing in the Sleepy Hollow Oilfield. The field is currently undergoing waterflooding without issue, suggesting the findings are due to the uncertainty of the data. The authors note that a stress measurement would reduce the uncertainty in the data and that, with this measurement, the calculated risk will likely be lower.

7.4 Non-Technical Risk Assessment

Non-technical risks focused on those related to long-term liability, pore space ownership, public opposition, regulation, contractual obligations, and environmental justice. The analysis was completed using lessons learned from analogous pipeline and UIC injection projects. In addition, risks from other IMSCS-HUB studies were also considered. The resulting FEPs for the non-technical risks are shown in Figures 7-5 through 7-9. The most significant of these risks (those with risk values of 8 or higher) included the following:

- Loss of containment resulting in mitigation and remediation efforts, lost 45Q or LCFS credits, or impacts to the image of CCUS in the region or the country.
- Landowners' disputes of the modeled CO_2 plume after injection has begun resulting in other landowners filing similar suits and/or a reevaluation of the models that changes project dynamics.
- Public opposition from NGOs resulting in project cancellation or CCUS not being adopted and negative media coverage resulting in project cancelation.
- The failure of an entity to meet the conditions of an offtake agreement for extended period or permanently resulting in loss of revenue or tax credits.

The applicability of non-technical risk to integrated CCUS project components is in Table 7-4. The non-technical risk assessment found that induced seismicity may be an issue that complicates public acceptance, particularly in Kansas. Injection wells in south-central Kansas have caused induced seismicity issues (Figure 7-10). This is not likely to be as much of an issue in western Kansas where the Patterson Field is located; however, induced seismicity concerns must be addressed through effective public outreach (Battelle, 2020g, 2020h).

Risk of Pore Space Ownership Events

- Pore space regulated differently in middle of project
- Landowner holdouts from entering into contractual pore space agreement
- Landowner dispute of modeled CO2 plume

Risk of Pore Space Ownership Consequences

- Compensation dynamics change
- Compensation rates increase
- Project delayed
- Project canceled
- Technology delayed
- Technology not adopted
- Protracted legal battle delays injection
- Success of landowner dispute leads to others, model reevaluation and changes project dynamics

Figure 7-5. Risk of pore space ownership issues.

Risk of Long-Term Liability Events

- Loss of containment
- Site closure achieved 1-5 years after the min. period
- Site Closure achieved 5-15 years after the min. period
- Site Closure achieved >15 years after the min. period

Risk of Long-Term Liability Consequences

- Lost 45Q and/or LCFS credits
- Litigation by affected landowners
- Mitigation efforts required
- CCUS public image affected in area
- CCUS public image affect in US
- Financial responsibility mechanism needed for additional period, affecting project economics

Figure 7-6. FEPs of long-term liability issues.

Risk of Public Opposition Events

- Local resident opposition (limited or substantial)
- NGO Opposition (limited or substantial)
- Negative media coverage (limited or substantial)

Risk of Public Opposition Consequences

- Project delayed
- Project canceled
- Technology delayed
- Technology not adopted

Figure 7-7. FEPs of public opposition issues.

Risk of Regulations Events

- Overburdened regulators
- Permit denials
- Additional regulations for induced seismicity
- Change in permitting authority for injection

Risk of Regulations Consequences

- Slight delays in obtaining permits
- Substantial delays in obtaining permits
- Project cancellation due to no viable alternatives
- Changes in operational requirements
- Project cancellation due to no viable alternatives

Figure 7-8. FEPs of regulatory issues.

Risk of Contracts Events

- Offtake or supplier agreements are not met by an entity for a brief period, for an extended period, or permanently

Risk of Contracts Consequences

- Loss of revenue/tax credits
- Contract breach and cancellation

Figure 7-9. FEPs of contractual issues.

Table 7-4. Non-Technical Risk Issues for each component of an integrated CCUS project.

Non-Technical Risk Issue	Capture	Transport	Storage
Long-term liability (beyond operations)			•
Pore space ownership			•
Public opposition		•	•
Regulation	•	•	•
Contractual Obligations	•	•	•
Environmental Justice		•	•

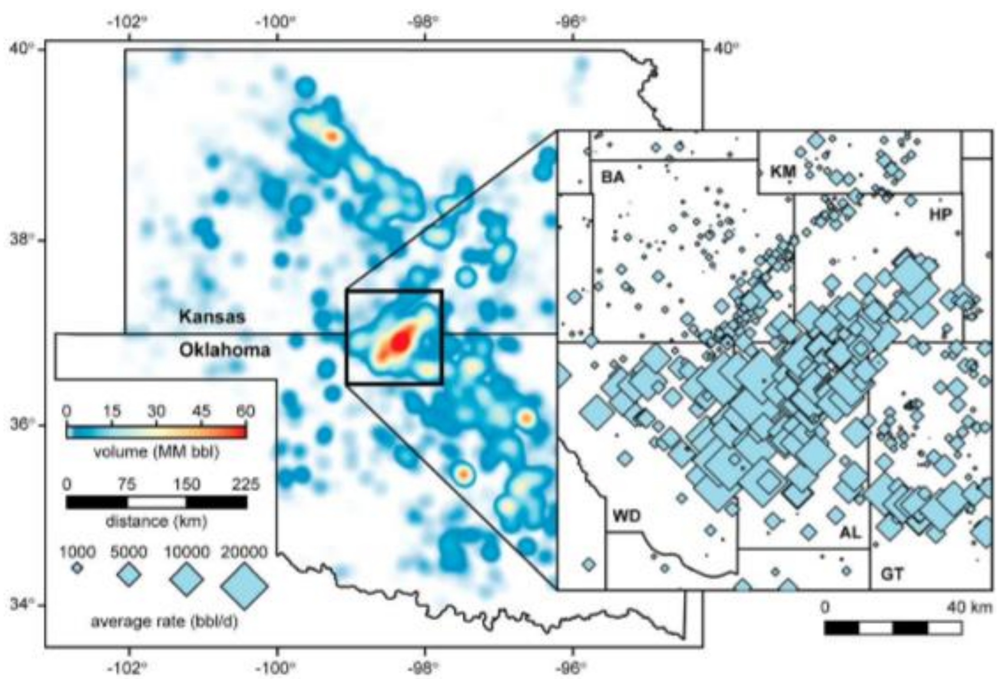


Figure 7-10. Map of UIC wells and injection volumes in Kansas and Oklahoma. From Peterie et al. [2018].

7.5 Risk Mitigation Plan

Based on the results of the Phase II risk assessment, a plan to mitigate risks for commercial CCUS sites was developed by Battelle (2020j). Risk mitigation strategies were developed to address subsurface, pipeline, and non-technical risks for the IMSCS-HUB area. Risk mitigation strategies for each project component area summarized below.

Subsurface Risks. A clearer representation of the wells that will pose the greatest risk to a CCUS project must be achieved. Risks from legacy wells at the Patterson site were likely overstated because of the definition of the Sumner Group as a secondary caprock in the analysis (See Section 4.1.1 of the Risk Mitigation Plan). Defining the primary caprock and the reservoirs as the storage complex and ignoring the Sumner Group was found to decrease the project risk by over 70% because 268 wells are eliminated from consideration and the inclusion of shallower wells altered the fitting equations used to calculate leakage likelihood (Battelle, 2020j). Even without defining the Sumner Group as a secondary caprock, the competence of the approximately 300 ft of primary caprock and the presence of thousands of feet of baffle between the primary caprock and the lowest USDW means the storage complex will be protective. Additional well construction, completion, and plugging records for wells that penetrate the caprock and/or storage reservoirs would also help to provide a more accurate analysis of subsurface risks. Additional records may be available in a non-digital format from KGS or in a digital format from the Kansas Geological Society.

Even without the additional well records, a more accurate depiction of well risks is possible by eliminating the wells that only penetrate the Sumner Group. Figure 7-4 shows the leakage likelihood for deeper wells in the Patterson Site, and Figure 7-2 shows the leakage likelihood for all wells at the Madrid, Nebraska site. These maps will help guide efforts to re-enter wells for remediation and/or the implementation of additional protective measures (e.g., sampling and monitoring). This can be done on a schedule as the CO_2 and/or pressure plume reach the wells in questions or all at once.

Induced seismicity and faulting are potential project risks that must be considered for the IMSCS-HUB storage corridor. While induced seismicity is an issue in Kansas, the worst instances of induced seismicity are in south-central Kansas, far from the Patterson site. Two faults penetrating the storage complex at the Patterson site were found by Battelle (2020d, 2020e). These faults do not penetrate the lowest USDW. For both induced seismicity and faulting, the additional characterization required by Class VI permitting will determine the operational constraints needed to induced seismicity is not as prominent of an issue in Nebraska but has been found on a limited scale by Filina et al. (2018). The closest known areas where induced seismicity has been observed is about 60 miles from the Madrid, Nebraska site.

Pipeline Risks. Pipeline risks are related to three phases of pipeline development: planning, construction, and operations. Pipeline planning/routing issues may lead to increased operational risks (i.e., more sensitive receptors) and/or may lead public opposition to pipeline projects. Routing efforts must consider receptors along the pipeline, including populated areas and occupied structures (urban areas, schools, hospitals, etc.), environmentally sensitive areas (wetlands, endangered species critical habitats, Protected Areas Database of the United States [PAD-US], etc.), and culturally sensitive areas (Native American Lands, historic landmarks). Through recent efforts, including Phase II of the IMSCS-HUB project, culturally and environmentally sensitive areas have been added to the SimCCS software described by Middleton and Bielicki (2009).

Impacts to some sensitive areas were mitigated with one of three strategies. The most sensitive areas most likely to elicit public backlash to a planned project (e.g., schools and hospitals) are avoided with a 1-km buffer. Other sensitive areas were avoided at the point (for buildings, dams, etc.) or within the boundary of the area (for ecological areas, mines, etc.) of the identified sensitive area. The impact on less consequential sensitive areas was limited but not avoided entirely. These areas, such as urban areas, existing mineral extraction, and commercially navigable waters, may be impediments to pipeline routes and operations, but pipelines can be safely routed and used with additional operational considerations. Finally, other areas (e.g., first responders, environmental justice, etc.) are included for informational purposes. Section 6.1.2 of the Risk Mitigation Plan provides a description of how these areas are handled. This tool will be used to develop feasible pipeline routes that avoid these sensitive areas, where possible (Battelle, 2020j). In addition, the SimCCS tool can be used as a public outreach tool to give interested stakeholders ownership and transparency in the routing process.

Pipeline construction is the component of pipeline development that has the highest amount of risk (Battelle, 2020j). Mitigation of pipeline construction risks include using contractors with a proven safety record. In addition, worker safety plans must be prepared and followed. These plans should cover the following issues: trenching, heavy equipment, highways, noise, dangerous wildlife, extreme heat, extreme cold, and sun exposure. Workers should also be trained to deal with safety issues outlined above and use fire extinguishers. Daily safety meetings should be held at the beginning of each workday to remind all workers of the hazards and ways to mitigate them. Finally, all workers should be given stop work authority in the event of any hazard. Delays are also a risk during pipeline construction. Delays can be mitigated by establishing a reasonable project schedule, scheduling work during appropriate seasons, and storing equipment and machinery properly to ensure accessibility.

CO_2 pipeline operations were found to be safer than other pipeline types (natural gas gathering, natural gas transmission, and non-CO_2 hazardous liquid pipelines) (Battelle, 2019b; 2020j) Despite the relatively low risk, Battelle (2020j) provided three strategies to mitigate the risks: (1) routing to avoid high-consequence areas, (2) monitoring strategies to detect leaks early, and (3) adhering to all operational requirements of PHMSA.

Non-technical risks: The following areas need to be focused on to mitigate these risks:

Long-term liability can be mitigated through the assumption of liability by a governmental entity (e.g., the state) after a period of time or the demonstration through site characterization and modeling that plume stabilization can be achieved in a period of time shorter than 50 years, the current required amount of time for post-injection site care (PISC).

Pore space ownership and compensation are currently not well defined by statute or precedent. While the current understanding suggests that pore space rights in the IMSCS-HUB storage corridor are tied to surface land ownership, no current regulation stipulates this. In addition, fair compensation to pore space owners must be determined with limited precedent. This could be accomplished through negotiations with individual landowners for a flat rate, percentage of profits, etc. The addition of CO_2-EOR in some stacked storage projects could require an additional amount of negotiation and compensation.

Regulations of an integrated CCUS project are most defined; however, some issues must be worked out for the implementation of the hub concept. First, there is no federal pipeline siting agency. Thus, siting CO_2 pipelines will require working with several state and local entities. Once the pipeline routes are finalized, a permitting plan for the IMSCS-HUB concept must be developed to ensure all permitting requirements are met in an efficient and timely manner.

Public outreach must be completed using an effective, project specific plan (see Section 3 of the Risk Mitigation Plan). The plan must outline specific outreach efforts and strategies, include stakeholder characterization, and be responsive to issues of interest to stakeholders and the public.

Contractual agreements are needed for an integrated CCUS project must be clearly defined for all projects. Standardized contractual arrangements must be developed to scale CCUS projects.

Environmental Justice and demographics must continue to be developed to ensure fairness in routing and to build an understanding of the community dynamics to facilitate public outreach efforts.

8 Regulatory and Contractual Requirements Assessment

The Phase II contractual assessment focused on identifying specific regulators and required permits and outlining necessary contractual terms for the IMSCS-HUB. The task was largely accomplished by researching relevant regulatory statutes, soliciting input from project partners, seeking guidance from regulatory agencies, and reviewing online permit forms and available completed applications.

The contractual assessment researched the following topics:

- Identified the federal, state, and local regulators with oversight of aspects of an integrated CCUS project (Battelle 2020k).
- Determined regulatory gaps and roadblocks for CCUS and suggested regulatory options (Battelle, 2019c).
- Evaluated requirements for capture, transport, and storage which included an assessment of the contractual agreements needed for an integrated CCUS project (Battelle, 2020l).
- Incorporated the results of Tasks 5 and 8.1 to develop a roadmap to obtain the required UIC permits for an integrated CCUS project at the two selected sites (Battelle, 2020k).

The conceptual model for the project is to transport CO_2 via pipeline from ethanol plant and electric utility sources along a source corridor spanning eastern Nebraska, central Kansas, and Iowa to sinks in a storage corridor southwestern Nebraska and western Kansas (see Figure 1-1). A detailed review of permitting entities and requirements of pipeline routing and operations, well drilling, oil and gas production, and CO_2 injection operations, compiled in Battelle (2019c), was used to develop the permitting plan for the project. Battelle (2020l) investigated four business model scenarios applicable for an integrated CCUS project in the study region and the required contractual agreements for each scenario.

Federal and state regulations that affect the IMSCS-HUB project, including pipeline routing and operations, well drilling and oil and gas operations, and CO_2 injection well construction and saline injection operation requirements (U.S. EPA UIC requirements) have been identified. Section 8.3 of this report highlights the permitting plan actions and appropriate regulatory authorities for these project components. Several permits must be received for each component of an integrated CCUS project including: permits to construct a capture system; site, construct, and operate a pipeline; and operate a storage project. Most of the permits that are needed for construction are routine permits that require little time for preparation and a relatively small application fee. The Class VI UIC permitting requires the longest lead times while siting of pipelines could possibly prove to be a time-consuming permitting process if formal objections are made via public comments or public opposition to project plans.

There is a need for standard business models and contractual agreements for integrated CCUS projects, which are currently evolving. The purpose of the contractual terms and conditions would be to identify and mitigate risks for all entities involved in a commercial CCUS project. Battelle (2020l) investigated capital investment model, business model and required contractual agreements for each of the four generalized entities for realistic integrated CCUS project scenarios for the IMSCS-HUB project area: (1) commercial CO_2 emitter, (2) public power district

CO_2 emitter, (3) pipeline operator/CO_2 transport entity, and (4) injection well operator. Possible risks and mitigation for CCUS projects were also examined with project participants including the risk of sole ownership. The two main contractual obligations for a CCUS project are supplier and offtake agreements. Because public power districts cannot take advantage of disposal tax credits offered for CCUS, NPPD would likely be interested in selling the scrubbed flue gas and having another entity to take care of capture, compression, transport, and disposal (referred to as third-party operator). For a third-party entity to operate a capture system for the CO_2 emitter, contract terms in the operating agreement between the two would need to clarify issues such as the minimum amount of CO_2 that the public power district must provide to the third-party operator to run the capture system and the liability of failing to maintain their delivery of CO_2.

8.1 Regulatory Assessment

UIC Class VI permit applications must be prepared for both sites and submitted to U.S. Environmental Protection Agency (EPA) Region 7. UIC Class VI requirements (40 CFR §146) have been defined in Table 8-1. Additional required permit information includes maps of pertinent features in the project area such as wells, cleanup sites, water bodies, existing infrastructure and mining operations, political and tribal boundaries, and known or suspected faults. Information about the site geology and hydrogeology, a tabulation of wells in the study area, maps and cross-sections showing the vertical and lateral limits of USDWs, baseline geochemical data of all reservoir formations and USDWs must also be included in the permit application. Operational data required for the permit application for each site includes the maximum daily injection rate, pressure, and source and characteristics of the CO_2 stream. All five required permit-required plans must be developed and submitted with the permit applications: (1) testing and monitoring plan, (2) post-injection site care (PISC) and closure plan, (3) corrective action plan (CAP), (4) emergency and remedial response plan, and (5) well plugging plan. The permit application must also cover the pre-operation formation testing program, stimulation program, procedure to conduct injection operations, schematics of well(s), AoR and financial responsibility.

Table 8-1. Requirements for UIC Class VI Permits.

Permit Information	UIC Class VI Permitting Actions
Required information with application	Develop all permit information, including maps and cross-sections, geologic conditions, and tabulated data for the Class VI permit.
Minimum siting criteria	Demonstrate the injection zones are of sufficient capacity and the confining zones are free of transmissive faults or fractures and are of sufficient extent and integrity to impede movement of CO_2 from injection zones.
AoR and Corrective Action Plan	Determine the area where USDWs may be impacted by project activities (AoR) and develop a plan for plugging wells that might affect the integrity of the seal (CAP).
Injection well construction	Design injection wells to prevent the movement of fluids into USDWs; use materials and equipment that are compatible with the CO_2 stream; and permit the use of testing, monitoring, and workover tools.
Logging, sampling, and testing prior to operation	Conduct logging sampling to verify conditions of injection and confining zones, establish baseline data, and determine operational constraints.
Injection well operations	Design operations that prevent confining zone fractures or fluid movement as well as obtain approval for the stimulation program (if required).
Testing and Monitoring Plan	Develop the testing and monitoring plan to verify operations adhere to permit requirements and do not endanger USDWs.
Mechanical integrity testing	Design and conduct testing to show mechanical integrity of project wells.
Well Plugging Plan	Develop the well plugging plan to plug the project wells as needed throughout the project from construction through PISC.
Post-Injection Site Care and Site Closure (PISC/SC) Plan	Develop a PISC/SC plan that demonstrates that USDWs are not endangered after active injection operations cease.

Permit Information	UIC Class VI Permitting Actions
Emergency and remedial response plan	Develop the emergency and remedial response plan to address any instances where injected fluids may endanger USDWs during construction, operations, or PISC.
Demonstration of volume containment	Demonstrate that each site meets the conditions required for a successful project, based on local geology, to ensure storage permanence of injected CO_2 and initiate site closure after PISC.
Demonstration of financial responsibility	Provide a strategy for permit holders (MABE and OLCV) to show financial responsibility satisfactory for the EPA Director to approve the Class VI permit.
Public participation	Execute a public outreach to ensure public concerns can be aired and addressed.
CO_2 source and chemical makeup of CO_2 stream	Define the CO_2 sources and chemical composition of the CO_2 stream to ensure reliability and compatibility of the well and facility materials.
Other requirements	Meet all other requirements including reporting requirements in 40 CFR 146.91

Several other permits must be obtained to implement an integrated CCS project (Table 8-2). National Environmental Policy Act (NEPA) permitting is required for all projects receiving federal dollars that have the potential to affect the environment. NEPA permitting requirements include the preparation and submission of an Environmental Information Volume (EIV) and NEPA documentation for all project-related activities to the DOE Council on Environmental Quality (CEQ). Capture permitting is the simplest permitting aspect of an integrated CCS project, requiring only construction-related permits from the county zoning administrator. Construction impacts are also controlled by National Pollution Discharge Elimination System (NPDES), permitted by state agencies. For the capture system, a General #2 permit must be obtained, and a stormwater management plan must be developed. If oversized equipment must be transported, permits must be obtained from the state agencies. For sources in Iowa and Kansas, an air quality permit must also be obtained from state agencies. Pipeline construction requires the same types of permits as capture system construction. If the proposed pipeline affects wetlands, additional permits must be obtained from the U.S. Army Corps of Engineers (USACE) to alter the wetlands. If the proposed pipeline affects endangered species or critical habitats, additional permits must be obtained from the U.S. Fish and Wildlife Service (U.S. FWS). Impacts to these features can be minimized by using the SimCCS routing tool modified to consider sensitive areas to mitigate public opposition and limit additional permitting. The regional pipelines needed for the hub concept are routed through Iowa, Nebraska, and Kansas (see Figure 1-1). Because there is no federal pipeline siting agency, the most complicated permitting is related to CO_2 transport operations. Pipeline siting for this scenario requires permits from state entities: Iowa Utilities Board (IUB), Nebraska Public Services Commission (NPSC), and the Kansas Conservation Commission (KCC). In addition, easements will be negotiated with individual landowners.

All CO_2 pipeline operations are regulated by the Pipeline and Hazardous Materials Safety Administration (PHMSA) as hazardous liquid pipelines. Requirements for pipeline operations include operational constraints (pressure, temperature, volume, and flow rate limits), safety, monitoring, and reporting.

To effectively implement the IMSCS-HUB, Monitoring, Reporting, and Verification (MRV) plan(s) must be accepted by the U.S. EPA Region 7. Monitoring well permits must be obtained from state authorities (Nebraska Oil and Gas Conservation Commission [NOGCC] and Kansas Corporation Commission [KCC]). Class II permits are required for CO_2-EOR operations, a major component of the CCUS business case.

Table 8-2. Non-Class VI permitting requirements for an integrated CCUS project in the IMSCS-HUB region. From Battelle (2020k).

Activity	Permitting Need	Permitting Authority
Federal Funding	NEPA is required for projects with federal funds that could affect the environment	**Federal entity**: DOE CEQ
Capture System and Pipeline Construction	Zoning permit	**Local entities**: County Zoning Administrator
	Water quality certification & NPDES General #2 Permit & stormwater management plan	**State entities**: Iowa Department of Natural Resources (IDNR), Nebraska Department of Environmental Quality (NDEQ), Kansas Department of Health and Environment (KDHE)
	Oversize equipment transport	**State entities**: Nebraska Department of Transportation (NDOT), Kansas Truck Routing and Intelligent Permitting System (K-TRIPS), Iowa Department of Transportation (IDOT)
	Air quality permit (not required in Nebraska)	**State entities**: IDNR, KDHE
Pipeline construction	Impact to (1) wetlands, (2) endangered species/critical habitats, (3) migratory birds	**Federal entities**: (1) USACE, (2) and (3) U.S. FWS
Pipeline siting	Approval for pipeline siting	**State entities**: IUB, NPSC, KCC
	Pipeline siting easements	**Landowners**: Negotiated with landowners
	Road cuts and rights-of-way	**Local entity**: County engineer
Pipeline operations	Pipeline operations (hazardous. liquid pipelines)	**Federal entity**: PHMSA
Storage	Class VI Permit for CCS projects	**Federal entity**: U.S. EPA, Region 7
	MRV plan	**Federal entity**: U.S. EPA, Region 7
	Monitoring wells & Class II permits for CO_2-EOR	**State entities**: Nebraska Oil & Gas Conservation Commission (NOGCC), KCC
	LCFS	**Other entity:** CARB
	Site and pore space access for CCS project	**Landowners**: Negotiated with landowners

To monetize the proposed CCS scenarios, permit applications must also be submitted for the LCFS program by participating ethanol plants. The LCFS program requires a two-part permit application to California Air Resources Board (CARB): The Sequestration Site Certification, which must provide evidence to ensure safe and effective CO_2 storage, and the CCS Project Certification, which requires an account of well construction, remediation of legacy wells, and any updates to previous plans. These application sections are similar to a UIC Class VI permit and are referred to as the Permanence Certification. In addition, the operator must provide an integrated assessment of the amount of CO_2 that will be offset by the project. These estimates must account for CO_2 emitted during project operations to assign a carbon index (CI) score, which determines the overall value of LCFS credits.

8.2 Contractual Assessment

The contractual assessment focused on four business model types were explored for the four business models. The summary of the required agreements for each of these business models are showing Table 8-3. The agreements cover the following issues:

- Operating agreements cover the issues necessary for a third-party entity to operate a capture system for a CO_2 emitter.
- Offtake agreements cover the timing and amount of CO_2 that must be delivered to or taken from each entity involved in the integrated CCUS project.
- Revenue and tax credit sharing agreements cover the equitable distribution of tax credits and revenue sources amongst parties participating in the integrated CCUS project.

- Construction agreements provide the necessary quality and safety conditions needed for a third-party contractor to construct infrastructure on the property of an entity involved in the integrated CCUS project. This includes site access agreements for construction.
- Surface access and/or mineral rights agreements are required for storage projects that will require the access of land, pore space, or mineral rights owned by a party not involved in the integrated CCUS project.

Table 8-3. Summary of the required agreements for each of the business models explored in this study.

Business Model	Required Agreements				
	Operating	Offtake	Revenue/ Credit Sharing	Construction	Surface Access and/or Mineral Rights
Entity: Commercial CO_2 Emitter					
Limited Involvement	X			X	
Single Component – Capture only		X	X	X	
Multiple Component – Capture and Transport		X	X	X	
Multiple Component – Capture and Storage		X	X	X	
Self-build and operate				X	X
Entity: Public Power District CO_2 Emitter					
Limited involvement	X			X	
Entity: Transport Operator					
Single Component – Transport only		X	X	X	
Multiple Component – Capture and Transport		X	X	X	
Multiple Component – Transport and Storage		X	X	X	
Self-build and operate				X	X
Entity: Storage Operator					
Single Component – Storage only		X	X	X	X
Multiple Component – Capture and Storage		X	X	X	X
Multiple Component – Transport and Storage		X	X	X	X
Self-build and operate				X	X

There are no standard business models for integrated CCUS projects, and contractual terms and conditions are constantly evolving. Standardization of contractual agreements will be required for scaleup of CCUS projects; however, it does not yet exist. The purpose of the contractual agreements would be to identify and mitigate risks for all entities involved in a commercial CCUS project. Possible risks for CCUS projects were also researched and discussed with project participants and included the following:

<u>Risk of Sole Ownership:</u> While Scenario #4 (Self-build and operate) would not require Operating Agreements, Off-Take Agreements, or Revenue/Tax Credit Sharing Agreements, there are additional project risks from being a sole-operator of an integrated CCUS project. For the self-build and operate scenario, the costs of capture, transport, and injection would need to be recovered using the 45Q tax credit, LCFS credits, or other state or federal credits. If these credits are insufficient to cover project costs, CO_2 may be sold to an oil and gas operator for use in CO_2-EOR, ideally for a price that is higher than the available credits minus O&M costs for transport and storage. While there is good indication that interest in CO_2-EOR is increasing, the CO_2 would need to be transported to the oilfields where it is needed, further complicating the contractual arrangements and project economics.

<u>Addressing Possible Risks/Risk Aversion:</u> The risks of CCUS must be mitigated for investors to be interested. The following could help address these risks:

- CO_2-EOR could act as a bridge to spur infrastructure development and general interest in CCUS. Oilfields are better understood than most saline sinks, the revenue sources are tangible, guaranteed, and longer-term than the current 45Q tax credits, and the appetite for CO_2 will grow as oil reservoirs are depleted. The Permian Basin will provide a good test case for infrastructure development in the context of CO_2-EOR.

- The safety of CO_2 pipelines will be demonstrated as more pipelines come online and are in operation in the future. Again, the Permian Basin, as well as the Gulf Coast and Wyoming, will provide good test cases for CO_2 pipeline safety.
- Saline reservoirs could be certified by oil and gas companies and other geological exploration entities that have the expertise to provide certainty of saline storage sites.
- Step-in rights for capital investors to run components of CCUS projects could be granted in the event the responsible entity is unable to fulfil their obligations.
- Termination payments should be included in contracts with capital investors to guarantee a return of their money, with an additional return, in the event the responsible entity or entities are unable to fulfil their obligations. A backstop to these terminations will need to be developed as well.

8.3 Permit Planning

Battelle has identified regulatory requirements for activities related to commercial development and identified model contracts for various plausible scenarios to facilitate a smooth transition from a DOE sponsored project to stand-alone commercial operation in the study region by 2025. It is crucial to proactively apply for permits to ensure long-term viability of the project. Permitting approvals are also crucial to implement the CCUS project. Several permits must be received for an integrated CCUS project. Apart from the UIC Class VI permit requirements defined in Table 8-1, other non-UIC permits are required for an integrated CCUS project for the following activities: (1) Use of federal funding, (2) capture system construction, (3) pipeline construction, (4) pipeline siting, (5) pipeline operations, and (6) non-class VI storage components.

Table 8-4 (Battelle, 2020k) shows the required permits, regulators, fee, and approval lead time for portions of an integrated CCUS project. These include permits to construct a capture system; site, construct, and operate a transport pipeline; and operate a storage project. Most of the permits that are needed for construction are routine permits that require little time for preparation and a relatively small fee. They are also generally approved within a few weeks or months. Approvals for the Class VI UIC (storage) and pipeline siting (transport) have the longest approval period (at least two years and up to a year, respectively). Planning to accommodate lead-times for these applications will ensure the project is completed on schedule. The lead-time for a capture system is up to 180 days based the capture system permit with the longest lead-time (Water Quality Permit). The required lead-time for pipeline construction permit for pipeline operations and for the two-part CARB LCFS permit are uncertain.

Potential issues that could lead to permit or eventually project delays would come from formal objections via public comments or public opposition to project plans during the permitting process. based on associated risks identified in the Phase II project, it is important to start these permit applications early to mitigate any potential project delays. Permitting fees for some permits are also uncertain (e.g., air quality permits and pipeline siting permits) The project team estimated that this review would be approximately $50,000, a fraction of the cost of an integrated CCUS project.

Table 8-4. Permitting Timeline for non-Class VI UIC permits needed for an integrated CCUS project in the IMSCS-HUB region. Table is from Battelle (2020k).

Permit	Regulator	Fee[(4)]	Approval Lead-time[(4)]	Application Name (Requirement Citation)	Application Process and Information Required
Water Quality Permit	IDNR	$175 to $700, depending on timeframe (max. 5 yrs.)	Up to 180 days, although generally within 30 days based on reviewed permits	Section 401 Water Quality Certification (WQC), NPDES General Permit #2 Stormwater Discharge Associated with Construction Activities (Iowa Administrative Code [I.A.C] Title 567, Chapter 64)	-Notice of intent submitted and approved prior to full application -3-page application and submitted electronically to the IDNR. -General facility/location information -Pollution prevention plan -Outfall information, including pollutants and outflow waterbodies -Description of the project activities covered by the permit
	NDEQ	No Fee	Up to 180 days, although generally within 30 days based on reviewed permits	Section 401 WQC, NPDES General Permit #2, NPDES Dewatering Permit (Nebraska Administrative Code [N.A.C], Title 119)	-Notice of intent to be submitted and approved. -Application is six pages and submitted electronically to the NDEQ. -General facility/location information -Erosion control plan -Project Site Map -Description of the project activities covered by the permit
	KDHE	$60 annual fee	Up to 180 days, although generally within 45-50 days based on reviewed permits	Section 401 WQC, NPDES General Permit #2 (Kansas Administration Regulations [K.A.R.], Agency 28, Article 16)	-Notice of intent to be submitted and approved. -Application is three pages and submitted electronically to the KDHE. -General facility/location information -Erosion control plan -Project Site Map -Description of the project activities covered by the permit
Oversize Equipment Transport Permit	IDOT	$400 fee	Within 24 hours	IDOT Iowa online Permitting System (IAPS) (I.A.C, Title 321)	-3-page application submitted electronically to the IDOT -General info on the size, weight, and dimensions of the load. -General info on the transport vehicle.
	NDOT	$15-$25 depending on the size, weight, and dimensions of the load	Within 24 hours	Nebraska Automated Truck Permit System (N.A.C., Title 114)	-Submit permit application electronically through the online NDOT permit system. -General info on the size, weight, and dimensions of the load. -General info on the transport vehicle.
	KDOT	$40 fee	Within 24 hours	Kansas Truck Routing and Intelligent Permitting System (K-TRIPS) (K.A.R., Agency 8)	-Submit permit application electronically with the online portal -General info on the size, weight, and dimensions of the load. -General info on the transport vehicle.
Air Quality Permit[(1)]	IDNR	Variable. Costs to cover investigation (est. $50,000)	Up to 120 days	Air Quality Construction Permit (I.A.C. 567, Chapter 22)	-Application is 10-page document that is submitted electronically -General information on emission units and control equipment. -Recordkeeping, monitoring, and reporting plans
	KDHE	$750 fee	Up to 90 days	Notification of Construction Modification (K.A.R 29, Chapter 19)	-Submit permit application electronically through the online KEIMS permit system. -General facility/location information -Description of the source requiring permitting
Water withdrawal	KDA	$400 fee	30 days	Permit to Appropriate Water for Beneficial Use (Kansas Statutes Annotated [82a], Section 732)	-5-page application (+1-page supplement) -Water source, quantity/rate, intended use, method to withdraw, locations of withdraw point, and dates of withdraw -Industrial supplement requires type of industry, past and future water requirements, location for water use

Permit	Regulator	Fee(4)	Approval Lead-time(4)	Application Name (Requirement Citation)	Application Process and Information Required
Water discharge	NDEQ	None	10 days	NPDES Dewatering permit (N.A.C., Title 119)	
	KDA	$200 fee	10 days	Temporary Dewatering Permit (K.A.R, Article 5-9)	-2-page application -Required for discharge of water mixed with water from construction activities (up to 4 million gallons).
Approval for Pipeline Siting	IUB	Variable. Assessed to cover costs for investigation. (est. $50,000)	Within 1 month without comments; up to 12 months for projects with objections	Petition for Hazardous Liquid Pipeline Permit (I.A.C. Title 479)	-6-page document with nine attachments -General pipeline/location information -Includes nine additional attachment detailing the pipeline and its potential effects on local communities
	NPSC	Variable. Assessed to cover costs for investigation. (est. $50,000)	7 to 12 months	Major Oil and Gas Pipeline Act(3), (Public Services Commission, Article 14, Sections 57-1401 to 57-1413)	-A description of the proposed route and alternative routes considered -Reasons for selecting proposed route -List of counties and municipalities affected -Description of the commodity transported -Owner and operator of pipeline -Plan to comply with act -Methods to minimize or mitigate impacts
	KCC	*Laws governing CO_2 pipeline regulations have recently been introduced in Kansas State Legislature [Y. Holubnyak, personal communication). As these laws and regulations are developed, the permitting process will become clearer. Project managers will stay apprised as to these changes. Assumed 12 months lead time and $50,000 fee.*			
Water structures permit	KDA	$100 (pipeline cable crossing) to $1,000 (other impacts)	30 days	Stream Obstruction – General Permit (K.S.A, 82a, Article 3)	-2-page Application plus location map, plan view, and cross-section at roadway, to be completed by licensed engineer
Impacts to Federal Endangered Species	U.S. Fish and Wildlife Service	$100 fee	Within 30-90 days, unless formal public objection is made	Federal Endangered Species Permit (Endangered Species Act – Federally Threatened and Endangered Species Consultation [Section 7 Consultation])	-15-page application detailing, General information on company requesting permit and multi-page questionnaire on the effects that project may have on wildlife -Habitat Conservation plan that describes how the effects that the project may on environment will be minimized or mitigated.
Impacts to Migratory Birds	U.S. FWS	None	30 to 45 days	Migratory Bird Consultation/ Permit (Migratory Bird Treaty Act, Bald and Golden Eagle Protection Act)	Required if operations could affect migratory birds. Habitat assessment and avian nest surveys, if required
State Endangered Species Consult	IDNR	None	60 to 90 days	State Threatened and Endangered Species Consultation (I.A.C. 481B)	-Consultation with IDNR needed if state endangered or threatened species is affected, includes: +Habitat and biological assessment +Species-specific survey, if required
	KDWPT	None	Minimum of 90 days	State Threatened and Endangered Species Consultation (K.A.R. 115-15)	-Consultation with KDWPT needed if state endangered or threatened species is affected, includes: +Habitat and biological assessment +Species-specific survey, if required
Historical and Cultural Resources	ISHS	None	30 days	Historic and Cultural Resources Consultation (Sec. 106 of National Historic Preservation Act)	-Consultation to determine the potential impact of project activities on historical and cultural resources. Requires background research, cultural survey and visual impact assessment.
	NSHS	None	30 days	Historic and Cultural Resources Consultation (Sec. 106 of National Historic Preservation Act)	-Consultation to determine the potential impact of project activities on historical and cultural resources. Requires background research, cultural survey and visual impact assessment.

Permit	Regulator	Fee(4)	Approval Lead-time(4)	Application Name (Requirement Citation)	Application Process and Information Required
	KSHPO	None	30 days	Historic and Cultural Resources Consultation (Sec. 106 of National Historic Preservation Act)	-Consultation to determine the potential impact of project activities on historical and cultural resources. Requires background research, cultural survey and visual impact assessment.
Impacts to Wetlands	U.S. Army Core of Engineers	$100 fee	Within 60-120 days, unless formal public objection is made	Wetlands Individual Permit (Clean Water Act Section 404, and Rivers and Harbors Appropriation Act, Section 10)	-3-page applications of general pipeline/location information and summary of the potential effects of the project on local bodies of water
UIC Class VI	U.S. EPA, Region 7	Variable	At least two years	UIC Class VI Permit (40 CFR 146.91)	See Section 2.1.
UIC Class II Injection Permit	NOGCC	$250 fee	Within 10 days, unless formal public objection is made	Report of Injection Project – NOGCC Form 11 EOR (N.A.C, Title 122, Chapter 7)	-7-page application of general injection well/location information and questionnaire asking project related questions -Multiple attachments detailing injection project
	KCC	$200 fee	Within 30 days, unless formal public objection made	KCC Class II UIC Permit Application (K.A.R., Title 82, Article 3)	-7-page application of general injection well/location information and questionnaire asking project related questions -Multiple attachments detailing injection project
MRV	U.S. EPA, Region 7	Variable	Variable	Monitoring, Reporting and Verification (MRV) Plan (40 CFR 98.448)	-Used to develop lifecycle analysis (LCA) to account for stored CO_2
Pipeline Operations	PHMSA	Uncertain(2)	Uncertain(2)	PHMSA Pipeline (49 CFR 195)	
California LCFS	CARB	Uncertain(2)	Uncertain(2)	Sequestration Site Certification and CCS Project Certification (Title 17, California Code of Regulations (CCR), sections 95480-95503)	-Storage credits for CCUS at ethanol-based sources -Requires storage site certification and LCA
Zoning Permits	County	Variable	Variable	Application to county zoning officer(4)	-Typically, general information about the property and proposed structure, including sketch
Road cuts/ rights-of-way	County	Variable	5 to 10 days	Application to county planning and development office(4)	-Required for work within county rights-of-way or when road cuts are needed
Floodplains	County	Variable	60 to 90 days	Application to county engineer, planning and development office(4)	-Typically, site development plans
Conditional use	County	Variable	90 to 180 days	-Application to county planning and development office(4)	-Typically, meeting needed to assess conditional use prior to submitting application
Soil conservation	Local	None	Not applicable	-Consult with local soil conservation board(4)	Not applicable

Notes: 1. Not required in Nebraska; 2. Information not found; 3. There are no specific regulations for CO2 pipelines, so the Major Oil and Gas Pipeline regulations was used; 4. Based on estimates or assumptions made by project team.

9 CO_2 Management and Commercial Development Strategy

A comprehensive CO_2 management and commercial development strategy for the proposed storage hub has been created. This includes updating site-scale storage resource estimates, pipeline planning, evaluation of industrial CO_2 source(s) and reliability, and economic analysis based on various injection and operational scenarios at each potential site. Results of subsurface characterization, modeling efforts, outreach assessment, and regulatory analysis from previous tasks were be integrated to develop a detailed commercial development plan. Phase II commercialization efforts include: characterization of the stacked storage potential in the IMSCS-HUB storage corridor (Subtask 9.1), developing plans for a regional-scale pipeline (Subtask 9.2), assessing the economics of commercial-scale projects (Subtask 9.3), and planning commercial-scale projects (Subtask 9.4).

9.1 Regional Storage Resource Characterization

Regional storage resource characterization evaluated the stacked storage potential for the IMSCS-HUB study area. The Advanced Resources International's (ARI) Big Oilfield Database was screened for commercially viable CO_2-EOR opportunities in the Nebraska/Kansas storage corridor (Battelle and ARI, 2020). The analysis found 17 technically and economically feasible oilfields, including the Sleepy Hollow Field and Patterson Site (Figure 9-1). The CO_2-EOR potential and CO_2 demand for the oilfield and underlying saline target was then determined (Table 9-1).

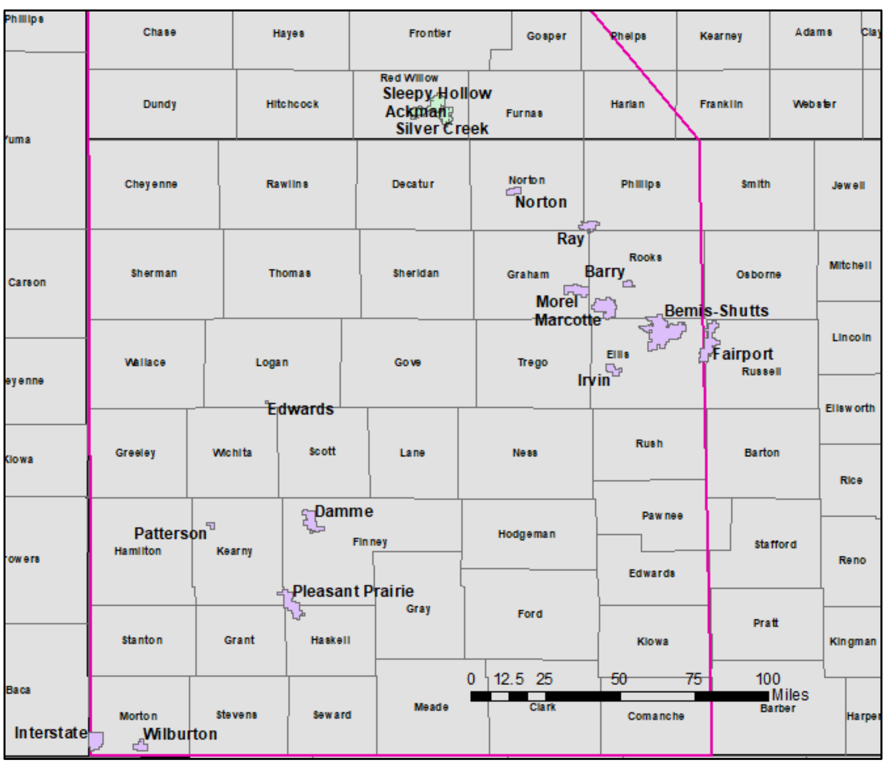


Figure 9-1. Seventeen CO_2-EOR targets evaluated for stacked storage potential. From Battelle and ARI (2020).

Table 9-1. Stacked storage areas with parameters determined by Battelle and ARI (2020). Table is from Battelle (2020m).

Oilfield	County (State)	EOR Production Potential (MMbbls)	CO_2 Purchased[a] for CO_2-EOR (Mt)	CO_2 Usage Rate – Oil produced per CO_2 purchased. (bbl./tonne)	Saline Storage Capacity (Mt)	Resource per unit area (Mt/mi^2)
Sleepy Hollow[b]	Red Willow (Nebraska)	13.8	6.3	2.2	94[d]	6.0
Ackman	Red Willow (Nebraska)	3.5	1.3	2.7	24	1.9
Silver City	Red Willow (Nebraska)	1.9	1.0	1.9	14	1.9
Norton	Norton (Kansas)	5.9	1.9	3.1	17	3.4
Ray	Phillips (Kansas)	10.3	4.1	2.5	20	2.0
Morel	Graham (Kansas)	16.8	7.0	2.4	41	2.4
Barry	Rooks (Kansas)	7.1	2.2	3.2	9	2.6
Marcotte	Rooks (Kansas)	12.3	6.8	1.8	154	5.4
Bemis-Shutts	Ellis (Kansas)	72.3	33.1	2.2	199	3.1
Irvin	Ellis (Kansas)	3.9	1.8	2.2	28	3.3
Fairport	Russell (Kansas)	16.4	6.0	2.7	105	3.5
Edwards	Logan (Kansas)	4.4	1.7	2.6	4	12.1
Patterson[c]	Kearny (Kansas)	4.3	2.0	2.2	101[d]	34.6
Damme	Finney (Kansas)	10.1	4.1	2.5	307	14.6
Pleasant Prairie	Finney (Kansas)	7.8	3.1	2.5	425	16.3
Interstate	Morton (Kansas)	14.9	3.6	4.1	278	13.2
Wilburton	Morton (Kansas)	3.9	1.4	2.8	131	13.2

Notes: (a) CO_2 storage during CO_2-EOR operations. (b) Included as part of Scenarios 2 and 3 (see section 4.2), so saline storage capacity is not considered here; (c) Field included as part of Scenario 3 (see section 4.2). (b) Original analysis by Battelle and ARI [2020] did not include the Heinitz and Hartland fields. CO_2-EOR potential only reflects the Patterson field, not Heinitz or Hartland. (d) Saline storage capacity reflects the P50 storage capacity found by (Battelle, 2018).

Fourteen oilfields in Kansas were identified for an initial assessment of their viability for EOR as a part of the IMSCS-HUB project. This initial assessment was completed to better identify which oilfields are most promising for CO_2-EOR and worthy of further research. Four criteria were used to conduct this assessment, including: 1) general data availability, 2) field production curves, 3) data quality, and 4) owner operator information.

Assessment results found that each of the 14 oilfields have well log, production, and owner operator data readily available. Each field was also found to have recent production within the year 2020, and that most wells across all the 14 fields were drilled to depths that allow for the supercritical storage of CO_2. The most significant variations between the fields occurred in the number of and age of wells, and the number of owner operators in each field. The most attractive fields had 1) over 100 wells with available data, 2) an average of over 100,000 bbls of annual production over the last ten years, 3) at least half of the selected wells in this assessment being less than 30 years old, and 4) an owner operator with at least 1,000 (Table 9-2). Although only the Damme field met each of these criteria, multiple other fields met two (Pleasant Prairie, Marcotte, Morel, and Ray) or three (Fairport and Bemis-Shutts) criteria. Additional research is needed to build on this assessment. Analysis of field level reservoir data and LAS and raster log data is necessary to further determine which fields are most attractive for potential CO_2-EOR projects.

Table 9-2. Table displaying desired criteria by field.

Field	> 100 wells with available data	Average >100,000 bbls annual production from 2010-2020	50% of selected wells less than 30 yrs old	Owner Operator with > 1000 wells
Wilburton	**Yes**	No	No	No
Interstate	**Yes**	No	No	No
Pleasant Prairie	**Yes**	**Yes**	No	No
Damme	**Yes**	**Yes**	**Yes**	**Yes**
Patterson	No	**Yes**	No	No
Edwards	No	No	No	No
Fairport	**Yes**	**Yes**	No	**Yes**
Irvin	**Yes**	No	No	No
Bemis Shutts	**Yes**	**Yes**	No	**Yes**
Marcotte	**Yes**	**Yes**	No	No
Barry	**Yes**	No	No	No
Morel	**Yes**	**Yes**	No	No
Ray	**Yes**	No	No	**Yes**
Norton	**Yes**	No	No	No

9.2 Pipeline Planning and CO_2 Management

Pipeline planning and CO_2 management focused on developing feasible pipeline routes connecting sources along the source corridor to sinks in the storage corridor (Battelle, 2019d). The analysis used the Scalable Infrastructure Model for Carbon Capture Storage (SimCCS) model described by Middleton and Bielicki (2009) to generate pipeline routes for 12 distinct scenarios comprised of four different 45Q-eligible source configurations (ethanol plants only, coal-fired power plants only, ethanol plants and coal-fired power plants, and all sources) and three different storage configurations (saline only, CO_2-EOR only, and saline and CO_2-EOR). The resulting pipelines were networks of trunk-lines and branches connecting the sources to six sink areas in western Kansas and southwestern Nebraska (Figure 9-2).

The analysis also focused on accounting for environmentally and culturally sensitive areas. The susceptible features considered in this study and potential consequences for pipeline construction and/or operations on these features are shown in Table 9-3. In addition, potential mitigation through pipeline siting considerations is also shown in the table. Three designations were developed for each of these features to describe the importance of avoiding them with pipeline infrastructure:

- **Features avoided with 1-km buffer** or **features avoided** by pipelines describe features that cannot be developed with pipeline infrastructure, either through statute or through significant public interest. Examples of these areas include schools, hospitals, Gap Status #1 and #2 in the PAD-US, National Parks and National Wild and Scenic Rivers, Exceptional State Waters (Kansas), historical landmarks, areas used for water supply, endangered species critical habitats, dams, and airports. Some of these features, such as endangered species critical habitats, can be developed with additional permitting; however, due to the extreme public interest of these areas, they are designated as features to be avoided.
- **Features limited** to pipelines describe features that can only be developed with pipeline infrastructure after a permitting process that includes a public comment period, those that would require additional pipeline safeguards or construction expense, and/or features that are of public interest. Examples of these features include Native American lands, wetlands, waterways, population centers, PAD-US Gap Status #3 areas, existing mineral extraction operations, areas with restricted or special aquatic wildlife, and areas with public water use.

- **Features that are informational** are those that do not have specific regulations or an identifiable public interest but could provide additional information about the impacts of a pipeline. These areas include emergency services locations, military installations, and PAD-US Gap Status #4 areas. In addition, environmental justice is considered informational because while environmental justice will not be used to actively guide routing activities, it is being considered as a passive indicator to ensure fair routing and foster effective public outreach.

The pipeline networks were too complicated to effectively cost using the Office of Fossil Energy and the National Energy Technology Laboratory (FE/NETL) CO_2 Transport Cost Model (DOE/NETL, 2018). Instead, the pipeline networks were costed using a method developed by Middleton (2012). Two linear regression equations were developed by the author to relate cost of pipeline per kilometer to the CO_2 flow rate. The method was found to produce results with an absolute error of only 2.1 (average net error is 0.1%) when compared to costs calculated using the FE/NETL model (Middleton, 2012).

The resulting costs for the trunk-lines and networks for the 12 scenarios are shown in Table 9-4. Each scenario has one to three trunk-lines connecting three to 40 sources along the trunk-lines that are between 299 km and 1,214 km long. The trunk-lines connect between 4.1 and 30.4 Mt of CO_2 annually to the sink areas. The total cost of each trunk-line ranges from $385 to $2,070 million, equating to $0.94 to $6.39 per tonne of CO_2 for a 30-year project.

Branches connect more sources to the trunk-line in most of the scenarios. The effect of connecting branches to the trunk-lines on total cost of each scenario trunk-line and cost per km of pipeline is shown in Figures 9-3 and 9-4, respectively. While the branches add to the CO_2 transport costs, they provide more CO_2 for commercial-scale CO_2 projects and, in some cases, can offer costs savings for a tonne of CO_2. The networks with branches connect between four to 87 sources along trunk-lines that include 449 to 4,259 km long. The networks can transport up to 94.2 Mt CO_2 per year. The networks cost between $603 to $5,662 million, equating to $1.14 to $5.21 per tonne of CO_2 for a 30-year project.

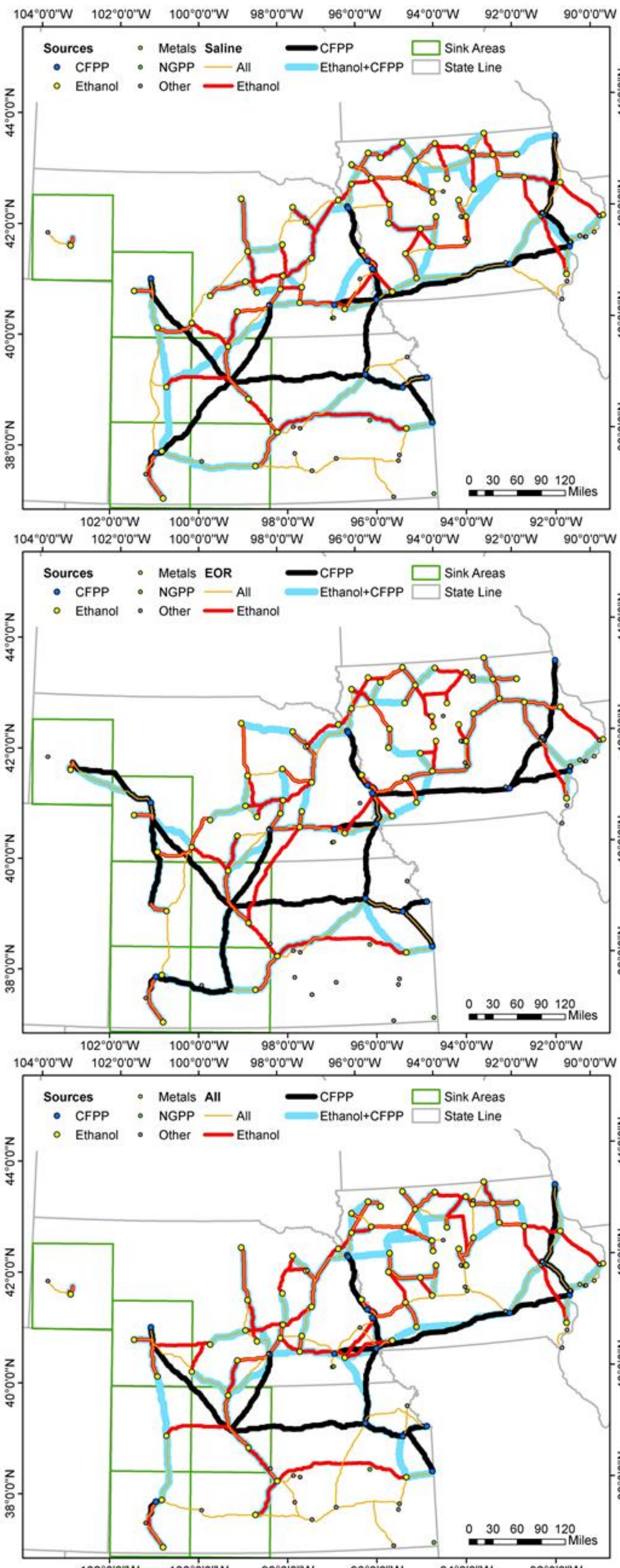


Figure 9-2. Pipelines routes, by sink, from all sources (orange), ethanol plants (red), CFPPs (black), and ethanol plants and CFPPs (blue) to saline sinks (top), CO_2-EOR sinks (middle), and all sinks (bottom). Figure is from Battelle (2019d).

Table 9-3. Features susceptible to CO_2 pipeline leaks, consequences of leaks, and mitigation opportunities to be used during routing processes. From Battelle (2019d).

Susceptible features	Consequence	Potential Mitigation Option
Critical Infrastructure/Water Supply		
Schools	-Pipeline leaks could cause a suffocation hazard to nearby students. -Pipeline construction near schools could lead to public opposition to project.	-Avoid known school locations
Hospitals	-Pipeline leaks could cause a suffocation hazard to nearby populace. -Pipeline construction near hospitals could lead to public opposition to project.	-Avoid known occupied structures
Urban areas	-Pipeline leaks could cause a suffocation hazard to nearby populace. -Urban areas contain significant obstacles that would prevent the siting of a pipeline. -Pipelines routed through urban areas could exacerbate public opposition to project. -High population areas and other populated areas are considered high consequence areas for hazardous liquid pipelines (§195.450).	-Avoid urbanized areas, preferring areas free of population centers and occupied structures. When passing through urbanized areas, follow Location Class standards for natural gas pipelines. -Construct pipeline so that operating pressures through urbanized areas is low for safe operations.
Dams	-Pipeline construction and operation could affect sensitive operations.	-Operations limited to the point itself. No buffer.
Airports	-Pipeline construction and operation could affect operations and an occupied structure. -Pipeline leaks could cause a suffocation hazard to those in airport structures.	-Operational buffer of 1-km recommended.
Nebraska wellhead protection areas and KDHE water use (all)	-Underground pipeline leak could acidify important groundwater resources. -Drinking water resources, represented by wellhead protection areas, source water protection areas (SWPA), and sole source aquifer recharge areas are considered high consequence areas for hazardous liquid pipelines (49CFR§195.6).	-Avoid areas where water is used for beneficial use, particularly for human consumption or food preparation.
National Hydrographic Dataset (NHD), water areas	-Substantial surface waters can be obstacles to pipeline construction -Commercially navigable waters are considered high consequence areas for hazardous liquid pipelines (49CFR§195.450).	-Avoid commercially navigable waters, where possible
Mineral extraction		
State and USGS mine locations	-Pipeline construction and operation could affect sensitive operations. -Underground pipeline leak could pose a suffocation hazard to mine workers.	-Operational buffer of footprint of underground mine recommended.
Environmentally sensitive areas		
Gap Status 1&2	- PAD-US Gap Status Areas #1 and #2 prevent the development of these environmentally sensitive areas. -Although the PAD-US is not mentioned specifically in 49CFR§195.6, they are likely considered high consequence areas due to their high ecological issues.	-Do not site pipelines where these areas are located
Gap Status 3	-PAD-US Gap Status Areas #3 allow for the development of these areas. -Although this is allowed, each Gap Status #3 area needs to be evaluated to determine potential environmental or public opposition issues.	-Avoid PAD-US Gap #3 areas, where possible
Gap Status 4	-PAD-US Gap Status Areas #4 contain no orders for protection. -Although this is allowed, each Gap Status #4 area needs to be evaluated to determine potential environmental or public opposition issues.	-Evaluate Gap #4 study areas to determine potential environmental or public opposition issues
Critical Habitat	-Critically imperiled species and ecological communities are considered high consequence areas for hazardous liquid pipelines (49CFR§195.6) -Building pipelines through critical habitats could lead to significant opposition from environmental NGOs.	-Do not site pipelines where these areas are located
KDHE, Outstanding or exceptional state waters/National Wild and Scenic Rivers	-Outstanding or exceptional state waters and National Wild and Scenic Rivers are environmentally sensitive areas that are important with many communities -Building through these areas could lead to significant opposition from environmental NGOs.	-Do not site pipelines where these areas are located
KDHE, aquatic wildlife	-Areas with aquatic wildlife are environmentally sensitive areas important to many people -Building through these areas could lead to significant opposition from environmental NGOs.	-Avoid expected aquatic wildlife is expected. -Do not site pipelines where these restricted or special aquatic wildlife is located.
National Parks	-National Parks are environmentally sensitive areas important to many people -Building through these areas could lead to significant opposition from environmental NGOs.	-Do not site pipelines where these areas are located
Culturally Sensitive Areas		
Native American Lands	-Native American communities are often vocal opponents of pipeline projects -Native American land can contain cultural, historical, and religious significance	-Do not site pipelines where these areas are located
National Registry of Historic Places (NRHP)	-The NRHP is a database of areas with cultural or historical significance. -Building through these areas can lead to public opposition.	-Do not site pipelines where these areas are located
Environmental Justice		
Education Ethnicity Annual Income	-Being conscious of environmental justice issues can lead to fairer pipeline routing	-Use Census data to determine the communities impacted by pipelines

Table 9-4. Results of design and cost factors for trunk-lines, by scenario, for sources along trunk-line and entire network of sources. The pipeline diameter and cost factors for the entire network of sources include the trunk-line only. From Battelle (2019d).

		Sources along trunk-line only							Networked trunk-line			Networked pipeline (including branches)						
Route	Trunk-line Length (km)	Trunk-line No. Sources	Range of Pipe Dia. (in.)	Cum. CO_2 (Mt)	Trunk-line Cost ($mil)	Avg. Cost per Mt CO_2 for 30-year Project[1] ($mil/Mt* 30 yr)	Trunk-line Avg. Cost per km ($mil/km)	Trunk-line Avg. Cost/CO_2 for 50 km-equiv. ([$mil/Mt]* 50-km)	Range of Pipe Dia. (in.)	Trunk-line Cost ($mil)	Trunk-line Avg. Cost per km ($mil/km)	Net-work Length (km)	Net-work No. Sources	Cum. CO_2 (Mt)	Net-work Cost ($mil)	Avg. Cost per Mt CO_2 for 30-year Project[1] ($mil/Mt* 30 yr)	Net-work Avg. Cost per km ($mil/km)	Network Avg. Cost/CO_2 for 50 km-equiv. ([$mil/Mt]* 50-km)
All-All-T1	1,033	22	12- 30	20	$1,705	$2.84	$1.65	$8.64	20-42	$3,523	$3.41	4,259	87	67.3	$5,662	$2.80	$1.33	$0.99
All-All-T2	699	9	16- 20	8	$762	$3.17	$1.09	$9.77	16-30	$1,483	$2.12	1,452	20	26.9	$2,187	$2.71	$1.51	$2.80
All-EOR-T1	1,054	18	12- 30	21.7	$1,577	$2.42	$1.50	$10.69	12-30	$1,930	$1.83	1,994	36	26.9	$2,391	$2.96	$1.20	$2.23
All-EOR-T2	568	5	16- 24	16.8	$973	$1.93	$1.71	$7.64	16-24	$984	$1.73	627	6	17	$1,010	$1.98	$1.61	$4.74
All-EOR-T3	1,038	17	6- 20	8.1	$1,081	$4.45	$1.04	$17.25	6-20	$1,247	$1.20	1,536	26	10.4	$1,476	$4.73	$0.96	$4.62
All-Saline-T1	989	16	12- 30	19.9	$1,647	$2.76	$1.67	$7.93	20-36	$2,713	$2.74	2,376	47	44.1	$3,638	$2.75	$1.53	$1.74
All-Saline-T2	762	10	8- 24	16.8	$1,264	$2.51	$1.66	$8.76	8-30	$1,470	$1.93	1,407	20	26.8	$2,140	$2.66	$1.52	$2.84
All-Saline-T3	855	12	16- 20	8.7	$1,095	$4.20	$1.28	$8.74	16-30	$1,828	$2.14	2,354	42	24.4	$2,822	$3.86	$1.20	$2.46
CFPPs-All-T1	901	5	16- 30	26.1	$1,700	$2.17	$1.89	$7.46	16-36	$2,513	$2.79	1,722	14	49.1	$3,218	$2.18	$1.87	$1.90
CFPP-EOR-T1	953	6	16- 30	33.4	$2,070	$2.07	$2.17	$7.14	16-36	$2,661	$2.79	1,745	14	49.1	$3,593	$2.44	$2.06	$2.10
CFPPs-Saline-T1	901	5	16- 30	26.1	$1,700	$2.17	$1.89	$7.46	16-36	$2,513	$2.79	1,722	14	49.1	$3,218	$2.18	$1.87	$1.90
Eth-All-T1	1,198	21	8- 20	6.9	$1,040	$5.02	$0.87	$15.28	8-24	$1,669	$1.39	3,385	56	18.2	$2,846	$5.21	$0.84	$2.31
Eth-EOR-T1	1,035	12	8- 16	4.1	$786	$6.39	$0.76	$15.02	8-24	$1,441	$1.39	2,229	28	18.4	$2,016	$3.65	$0.90	$2.46
Eth-EOR-T2	742	16	4- 16	4.6	$522	$3.78	$0.70	$20.32	4-20	$726	$0.98	1,569	31	9.0	$1,130	$4.19	$0.72	$4.00
Eth-Saline-T1	1198	21	8- 20	6.9	$1,040	$5.02	$0.87	$15.28	8-24	$1,709	$1.43	3,402	54	18.5	$2,844	$5.12	$0.84	$2.26
EC-All-T1	1071	17	8- 30	22.3	$1,836	$2.74	$1.71	$9.88	8-42	$3,243	$3.03	2,175	34	68.7	$3,866	$1.88	$1.78	$1.29
EC-All-T2	701	9	6- 20	7.0	$538	$2.56	$0.77	$21.84	8-24	$850	$1.21	1,708	34	14	$1,379	$3.28	$0.81	$2.88
EC-All-T3	299	3	8- 24	13.7	$385	$0.94	$1.29	$12.52	8-24	$471	$1.58	449	4	17.6	$603	$1.14	$1.34	$3.82
EC-EOR-T1	1,214	17	8- 24	15.1	$1,404	$3.10	$1.16	$13.94	8-36	$2,215	$1.82	2,376	40	37.7	$2,850	$2.52	$1.20	$1.59
EC-EOR-T2	576	11	6- 20	7.1	$483	$2.27	$0.84	$22.56	6-20	$534	$0.93	871	17	8.4	$670	$2.66	$0.77	$4.58
EC-EOR-T3	584	5	16- 24	14.6	$895	$2.04	$1.53	$8.29	No branches possible									
EC-Saline-T1	1,071	17	8- 30	22.3	$1,836	$2.74	$1.71	$9.88	8-36	$2,607	$2.43	1,812	26	51.0	$2,607	$1.70	$2.43	$9.21
EC-Saline-T2	818	15	6- 20	8.4	$698	$2.77	$0.85	$18.91	12-24	$1,090	$1.33	2,231	41	16.4	$1,090	$2.22	$1.33	$9.83
EC-Saline-T3	681	5	8- 24	14.0	$1,095	$2.61	$1.61	$9.25	8-24	$1,217	$1.79	934	7	17.9	$1,217	$2.27	$1.79	$8.89

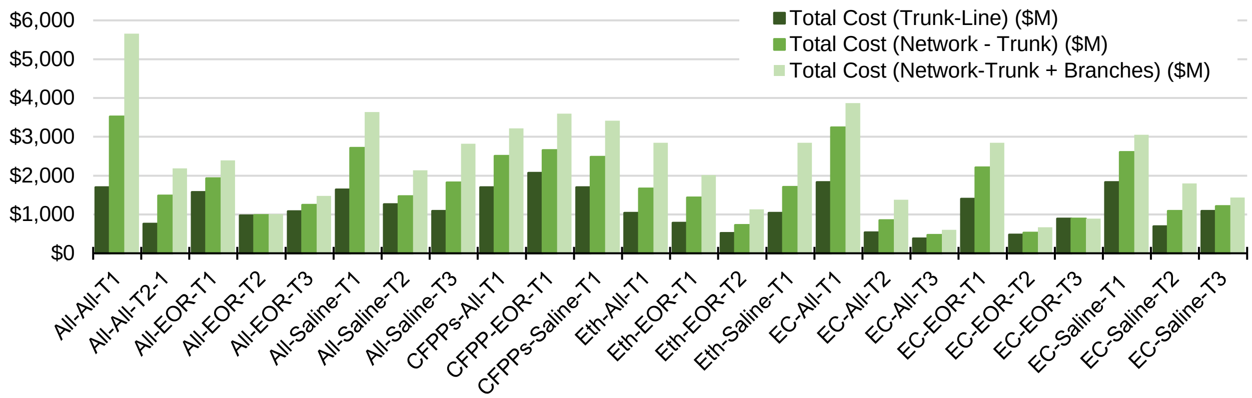


Figure 9-3. Total cost of trunk-line for scenarios connecting trunk-line sources only, trunk-lines for scenarios connecting all networked sources and the entire network (trunk-lines and branches) for the networked scenario. From Battelle (2019d).

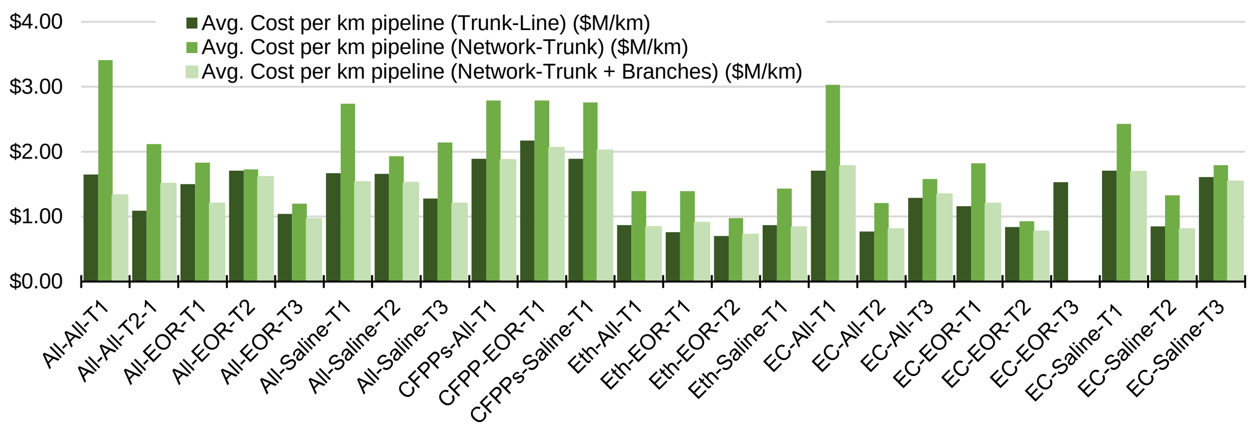


Figure 9-4. Average cost per km for scenarios connecting trunk-line sources only, trunk-lines for scenarios connecting all networked sources and the entire network (trunk-lines and branches) for the networked scenario. From Battelle (2019d).

Publicly available shapefiles and other geographic information for these features were found to include them in the SimCCS routing software (Table 9-5). Phase I routes were used as examples of the effect of including environmentally and culturally sensitive features in the routing process. Figure 9-5 shows the original results of Phase I pipeline routing plotted on the same map as the updated pipeline routes found using the environmentally and culturally sensitive areas as areas avoided or limited by project infrastructure. The exercise demonstrates that accounting for the environmentally and culturally sensitive areas can alter the modeled pipeline routes significantly. This is demonstrated by the changes in Configuration B and Configuration D.

Table 9-5. Risk Grid input files. From Battelle (2019d).

Category	Rationale	Description	Shape Type	Default Assessment	Shapefile Reference
Critical Infrastructure/ Water Supply	Protect Human Health/Public Safety	Schools	Point	Avoid/Buffer	USGS [2017a, b, c]
		Hospitals	Point	Avoid/Buffer	USGS [2017a, b, c]
		Airports	Point	Avoid	USGS [2017a, b, c]
		Dams	Point	Avoid	USGS [2017a, b, c]
		Military Installation	Polygon	Limit or Info	USGS [2017a, b, c]
		Emergency Services	Point	Information	USGS [2017a, b, c]
		Wellhead Protection Areas (Nebraska)	Polygon	Avoid or Limit	NDEQ [2011]
		KDHE, Domestic supply	Polygon or Line	Avoid or Limit	KDHE [2010]
		KDHE, Food procurement	Polygon or Line	Avoid or Limit	KDHE [2010]
		KDHE, Groundwater recharge	Polygon or Line	Avoid or Limit	KDHE [2010]
		KDHE, Public use – open	Polygon or Line	Avoid or Limit	KDHE [2010]
		KDHE, Public use – with permission	Polygon or Line	Limit or Info	KDHE [2010]
		KDHE, Other use[1]	Polygon or Line	Limit or Info	KDHE [2010]
		Population Density[2]	Polygon	Limit or Info	US Census Bureau [2019; 2016a, b]
Mineral Extraction	Avoid existing operations	State Mineral Extraction	Point or Polygon	Limit or Info	
		USGS Mineral Extraction	Point		USGS [2005a, b, c, d, e, f, g, h, i; 2001]
Sensitive Areas-Environmental	Avoid environ-mental areas	Gap Status 1&2	Polygon	Avoid	USGS [2016a]
		Gap Status 3	Polygon	Limit	USGS [2016a]
		Gap Status 4	Polygon	Information	USGS [2016a]
		Critical Habitat	Polygon and Line	Avoid	U.S. FWS [2017a]
		Wetlands[3]	Polygon	Limit	U.S. FWS [2017b]
		KDHE, Outstanding National Waters	Polygon or Line	Avoid	KDHE [2010]
		KDHE, Exceptional State Waters	Polygon or Line	Avoid	KDHE [2010]
		KDHE, Restricted aquatic life	Line	Avoid or Limit	KDHE [2010]
		KDHE, Special aquatic life	Polygon or Line	Avoid or Limit	KDHE [2010]
		KDHE, Expected aquatic Life	Polygon or Line	Limit or Info	KDHE [2010]
		National Wild and Scenic River	Line	Avoid	BLM/NPS/U.S. FWS/USFS [2017]
		National Parks	Polygon	Avoid	USGS [2016a]
Sensitive Areas-Cultural	Avoid cultural areas	Native American Lands	Polygon	Avoid or Limit	USGS [2016a]
		National Registry of Historic Places	Point or Polygon	Avoid	NPS [2017]
Water Features	Avoid obstacles	NHD, Areas	Polygon	Limit	USGS [2016b, c, d]
Environmental Justice	Ensure fair routing	Annual Income[2]	Polygon	Information	US Census Bureau [2019; 2016a, b]
		Education[2]	Polygon	Information	US Census Bureau [2019; 2016a, b]

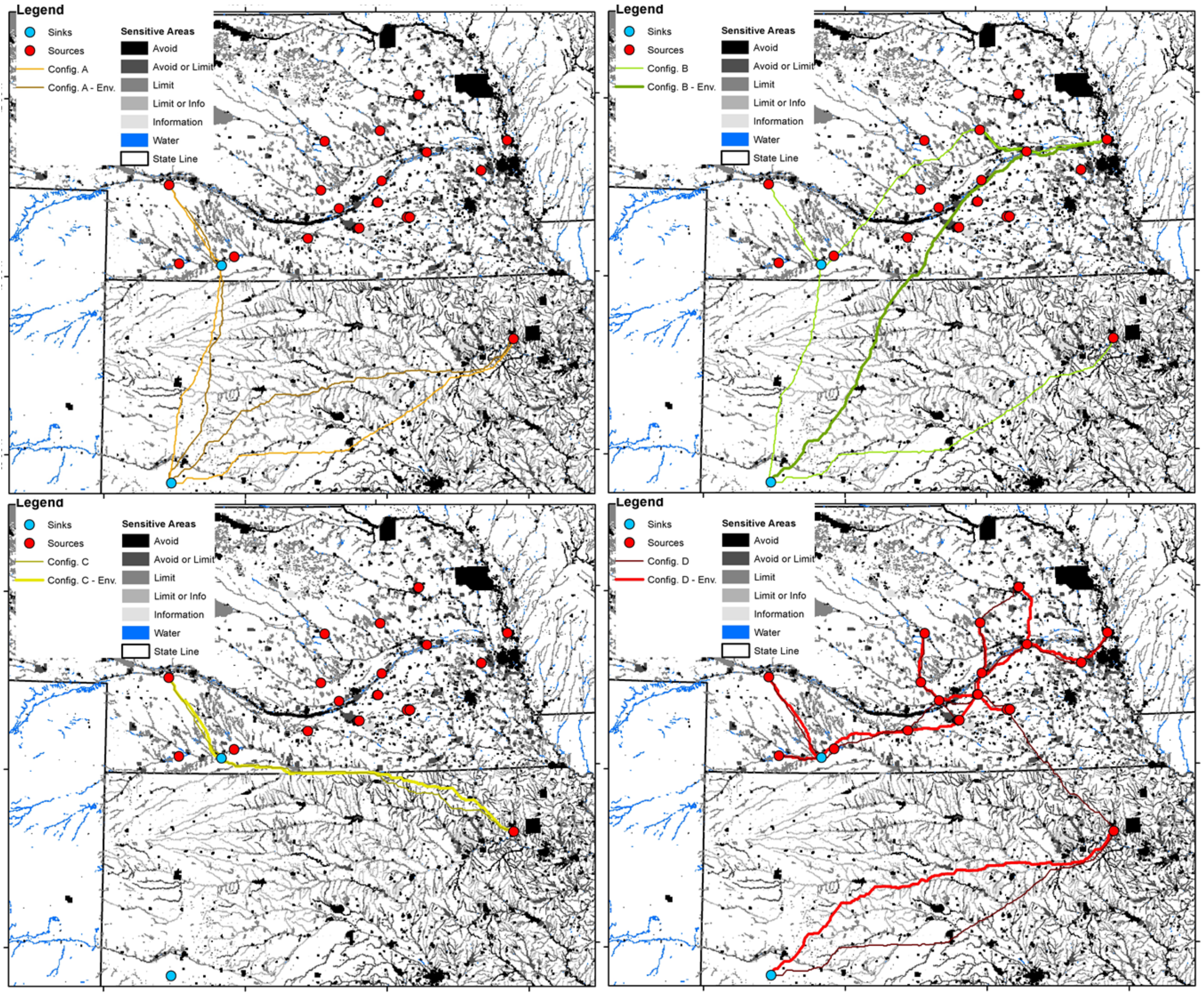


Figure 9-5. Map of initial and re-run Phase I pipelines (- env.) for Configuration A (top left), B (top right), C (bottom left), and D (bottom right).

One potential pitfall of constructing large, complex pipeline networks is the potential cost of pipeline oversizing [Middleton and Yaw, 2018]. Figure 9-6 demonstrates the increased costs of CO_2 from oversized trunk-lines for each scenario by plotting the total cost per tonne of CO_2 for a 30-year project for three different scenarios: (1) a trunk-line connecting sources along the trunk-line only (dark green), (2) a network pipeline connecting sources and branches (light green), and (3) a trunk-line oversized to accommodate additional branches that are not constructed (orange) on a logarithmic (base 2) scale. While the cost per tonne of CO_2 for a trunk-line connected sources along the trunk only and a trunk-line with branches that are constructed do not vary significantly, the cost of per tonne CO_2 is significantly affected by oversizing to accommodate CO_2 from branches that are not constructed. The cost of errantly oversizing pipelines increases the cost of CO_2 per tonne by more than three times in some cases. This is particularly significant for pipelines where the branches connect high quantities of CO_2 (i.e., the all sources, all sinks scenario trunk-lines) or where the quantities along the trunk-line are relatively smaller (i.e., the ethanol scenario trunk-trunk-lines). These results show that careful pipeline siting and routing with guarantees of CO_2 capture from participating sources is needed for these expensive infrastructure projects.

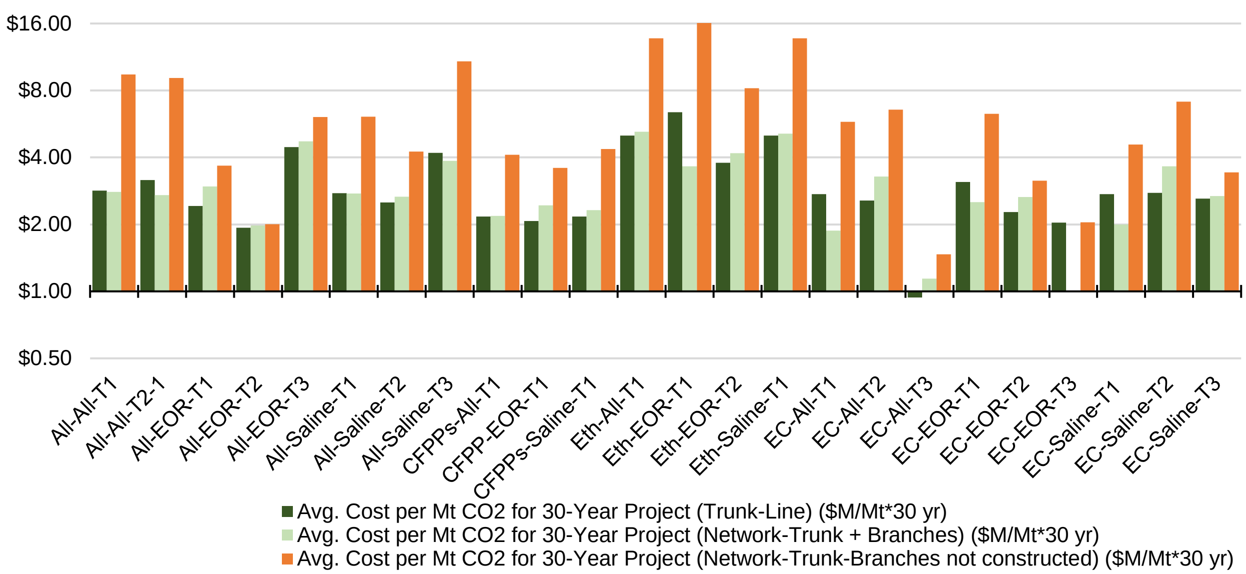


Figure 9-6. Average cost per Mt of CO_2 for 30-year projects for scenarios connecting trunk-line sources only, the entire network (trunk-lines and branches) for the networked scenario assuming all branches are constructed, and the entire network for the networked scenario assuming no branches are constructed. From Battelle (2019d).

9.3 Economic Analysis

The economic analysis task was conducted to (1) determine the costs of each component of an integrated CCUS project (capture, transport, and storage; (2) demonstrate the viability of three initial project scenarios involving the Madrid, Nebraska site, the Patterson site, and the Sleepy Hollow Field; and (3) model the potential revenue for additional stacked storage projects in the IMSCS-HUB storage corridor.

The individual project components (capture from participating sources and saline storage costs) were costed separately. Capture costs were developed for participating sources (Table 9-6). Storage costs were estimated using the FE/NETL CO_2 Saline Storage Cost Model [DOE/NETL, 2017] (Table 9-7). The costs of the CO_2 pipeline were developed for the scenarios and hub concept using the method in Section 9.2 above. The economic assessment investigated the revenue potential of extending the 45Q tax credits from 12 years to 22 years (Table 9-8).

Table 9-6. Anticipated capture costs for participating sources (2019 dollars/tonne of CO_2). From Battelle (2020m).

Source	Emissions	CAPEX	OPEX	Total
MABE	0.2	3.1	13.2	16.2
ADM wet mill	0.3	2.0	13.6	15.6
ADM dry mill	1.0	1.1	11.6	12.7
Valero Renewables	0.4	1.7	11.3	13
NPPD GGS #1	3.7	17.4	14.1	31.5
NPPD GGS #2	4.0	17.2	14.1	31.3
OPPD NC #2	3.9	18.6	14.1	32.7
OPPD Sheldon	0.78	NA	NA	$35-50[a]
OPPD Beatrice	0.13	NA	NA	$35-50[a]

Note: (a) Used a value of $42.50 per tonne for scenarios costs (See Section 4.2).

Table 9-7. CAPEX, OPEX, Total Costs and cost per tonne (all in 2019 dollars) for saline storage at the Madrid, Nebraska and Patterson sites.

Cost Type	Madrid, Nebraska	Patterson
CAPEX	$81,114,213	$37,524,623
OPEX	$105,014,053	$90,280,203
Total Cost	$186,128,266	$127,804,826
Cost per tonne	$3.72	$2.56

Table 9-8. CO_2 demand for saline storage at each stacked storage area for the extended project periods.

Oilfield	EOR Prod. Potential (MMbbls)	Total Oil Production, 2025-2036 (MMbbls)	Total CO_2 Stored, 2025-2036, Total (Mt)	CO_2 Demand through 2046 (Mt)			Remaining Saline Potential, after 2046 (Mt)	Value ($Mil.)	
				Saline (Mt)	CO_2-EOR	Total		Saline	Stacked Storage
Sleepy Hollow	13.8	13.8	26.7	37.4	6.3	43.7	56.6	$1,870	$2,406
Ackman	3.5	3.5	21.7	24.0	1.3	25.3	-	$1,200	$1,311
Silver City	1.9	1.9	15.0	14.0	1.0	15.0	-	$700	$785
Norton	5.9	5.9	18.9	17.0	1.9	18.9	-	$850	$1,012
Ray	10.3	10.3	24.1	20.0	4.1	24.1	-	$1,000	$1,349
Morel	16.8	16.8	27.4	37.4	7.0	44.4	3.6	$1,870	$2,465
Barry	7.1	7.1	11.2	9.0	2.2	11.2	-	$450	$637
Marcotte	12.3	12.3	27.2	37.4	6.8	44.2	116.6	$1,870	$2,448
Bemis-Shutts[a]	72.3	44.6	40.8	37.4	33.1	70.5	161.6	$1,870	$4,683
Irvin	3.9	3.9	22.2	28.0	1.8	29.8	-	$1,400	$1,553
Fairport	16.4	16.4	26.4	37.4	6.0	43.4	67.6	$1,870	$2,380
Edwards	4.4	4.4	5.7	4.0	1.7	5.7	-	$200	$345
Patterson	4.3	4.3	22.4	37.4	2.0	39.4	63.6	$1,870	$2,040
Damme	10.1	10.1	24.5	37.4	4.1	41.5	269.6	$1,870	$2,219
Pleasant Prairie	7.8	7.8	23.5	37.4	3.1	40.5	387.6	$1,870	$2,134
Interstate	14.9	14.9	24.0	37.4	3.6	41.0	240.6	$1,870	$2,176
Wilburton	3.9	3.9	21.8	37.4	1.4	38.8	93.6	$1,870	$1,989
Sum		**181.9**	**383.5**	**490.0**	**87.4**	**577.4**	**1,461.0**	**$24,500**	**$30,850**

Note: (a) The Bemis-Shutts Oilfield produces an additional 27.7 MMbbls if the tax credits are extended through 2046.

9.4 Detailed Commercial Development Plan

During future phases, commercialization plans must be completed and executed. First, the initial commercial-scale projects (Madrid, Nebraska and the Patterson sites) and CO_2-EOR projects (Patterson Site and SHF) must be permitted. Class VI UIC permits will initially be completed for two sites, one in Madrid, Nebraska and one at the Patterson Site in Kearny County, Kansas. This work is described in detail in Section 8.1 and 8.3 of this report. Capture technologies will also be evaluated for the participating sources (Figure 9-7 and Table 9-9). Non-technical risks, pipeline Right of Way (ROW)s, and other permitting requirements will also be evaluated using the methods outlined in this report.

Three scenarios were developed by Battelle (2020m) to show the potential for a single storage project (to show near-term commercial scale opportunities), a limited hub concept using participating sources and sinks in Nebraska, and an expanded regional hub concept using participating sources and sinks in Nebraska (Figure 9-7 and Table 9-9). The scenarios are as follows:

Scenario 1: Madrid, Nebraska. CO_2 is captured from the Mid America Bio Energy (MABE) ethanol plant and the Nebraska Public Power District (NPPD) Gerald Gentleman Station (GGS) coal-fired power plant. This CO_2 is transported by a 30-mile pipeline to a stacked saline storage site in Madrid, Nebraska.

Scenario 2: Nebraska Stacked Storage. The CO_2 is captured from MABE, GGS as well as the other sources that participated in Phase II (or had agreed to participate) in the IMSCS-HUB project: ADM Columbus, NPPD Beatrice, OPPD NC Station, NPPD Sheldon, and Valero Albion. CO_2 will be transported by a pipeline through central Nebraska to the Madrid, Nebraska site and the Sleepy Hollow Field in Red Willow County, Nebraska (Figure 9-7). CO_2 that is left over after storage at the Madrid site may be stored at additional saline storage sites further west in Nebraska or sold for CO_2-EOR.

Scenario 3: Nebraska-Kansas Stacked Storage. CO_2 is captured from the seven participating sources (see Scenario 2) to the Madrid, Nebraska and Patterson saline storage sites and the CO_2-EOR projects at Sleepy Hollow Field and Patterson Site by a regional pipeline from central Nebraska to western Kansas. The Madrid, Nebraska site will receive all of the CO_2 from MABE and around 1.5 Mt from GGS will be stored at the Madrid, Nebraska site. All other CO_2 will be routed to the Sleepy Hollow Field and through western Kansas for use at the Patterson stacked saline and CO_2-EOR sites. Additional CO_2 may be used at other storage sites in the IMSCS-HUB corridor or for CO_2-EOR in the Permian Basin.

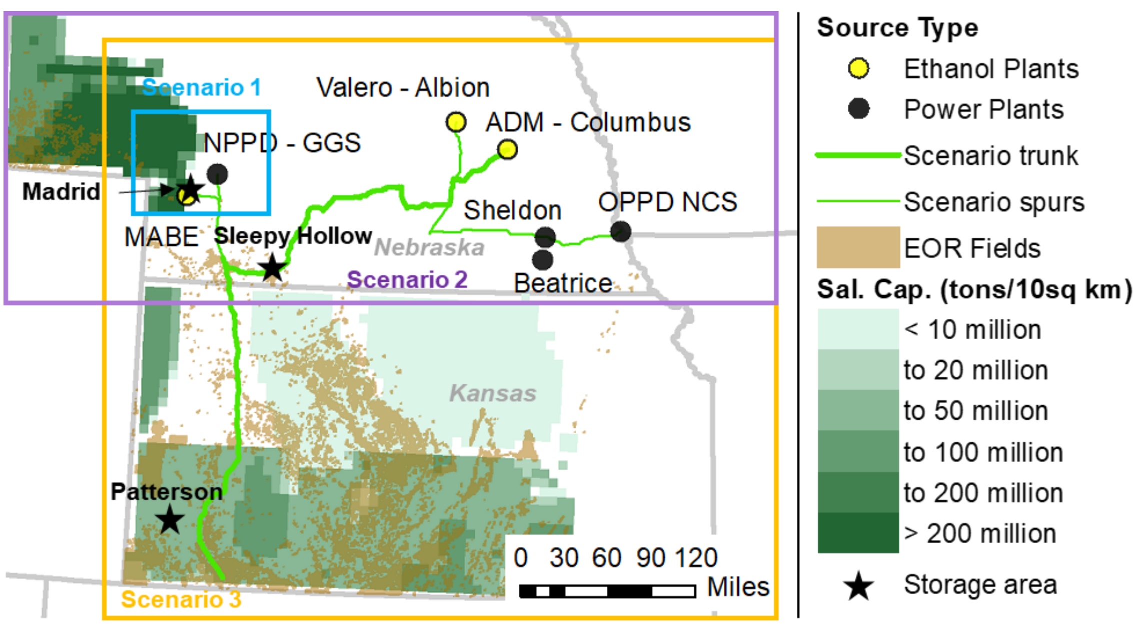


Figure 9-7. Scenarios evaluated to demonstrate project potential. Saline storage capacity is from DOE/NETL (2015). Map from Battelle (2020m).

Scenario costs are shown in Table 9-10. Capture costs were found using a weighted average based on captured emissions. Saline storage projects were assumed to have an annual CO_2 demand of 1.7 Mt for 30 years. CO_2-EOR targets was also assumed to have a CO_2 demand of 1.7 Mt per year until the CO_2 demand is satisfied. Storage projects within the IMSCS-HUB storage corridor received CO_2 first prior to transporting additional CO_2 to other projects. Thus, the CO_2 from ethanol sources (i.e., lowest cost of capture) was used for the three scenario projects. The remaining CO_2 in each scenario could be sold for additional revenue.

Table 9-9. Project scenario details. From Battelle (2020m).

Parameter	Madrid, Nebraska	Nebraska Stacked Storage	Nebraska-Kansas Stacked Storage
Sources	MABE, GGS	All participating sources	All participating sources
CO_2 Availability	7.9 Mt/yr.	14.9 Mt/yr.	14.9 Mt/yr.
Transport	Pipeline to storage	Regional pipeline	Regional pipeline
No. inj. Wells	3 (Madrid, Nebraska)	3 (Madrid, Nebraska)	3 (Madrid, Nebraska) + 3 (Patterson)
Storage Location(s)	Madrid, Nebraska	Madrid Nebraska + Sleepy Hollow (EOR)	Madrid, Nebraska + Sleepy Hollow (EOR), Patterson (saline + EOR)
Storage types	Stacked saline	Stacked saline + EOR	Stacked saline + EOR
Size AoR	317 mi^2 (Madrid, Nebraska)	317 mi^2 (Madrid, Nebraska)	317 mi^2 (Madrid, Nebraska)/104 mi^2 (Patterson)
Permit holder	MABE (Madrid, Nebraska)	MABE (Madrid, Nebraska), Central Operating (Sleepy Hollow)	MABE (Madrid, Nebraska), Central Operating (Sleepy Hollow), permit holder not yet determined (Patterson-saline), Berexco (Patterson-EOR)
Income sources	45Q, LCFS	45Q, LCFS, CO_2-EOR	45Q, LCFS, CO_2-EOR

Table 9-10. Anticipated costs, per tonne, for saline projects in all scenarios.

Cost Field	**Scenario 1** (Madrid, Nebraska)	**Scenario 2** (Nebraska Stacked Storage)	**Scenario 3** (Nebraska-Kansas Stacked Storage)
Costs per tonne CO_2 ($2019/tonne)			
Capture costs for CCUS project[(a)]	29.52	21.40	24.51
Transport (pipeline) cost	0.7	2.6	4.3
Saline storage costs	3.72	3.72	3.72 (Madrid, Nebraska)/2.62 (Patterson)
Total saline storage project costs	**33.94**	**27.72**	**32.53 (Madrid, Nebraska)/31.63 (Patterson)**
Other pertinent information about scenarios			
CO_2 Demand for storage projects (Mt)[(b)]	1.7	3.4	6.8
Proportion of CO_2 from ethanol sources	11.7%	55.9%	27.9%
Size CO_2 plume (mi^2)	41.3	41.3	41.3 (Madrid, Nebraska)/9.7 (Patterson)
No. landowners	125	125	125 (Madrid, Nebraska)/84 (Patterson)
CO_2 Remaining (Mt)[(b)]	6.2	11.01	7.61
Break-even price for remaining CO_2 ($2019/tonne)	*31.42*	*32.79*	*33.43*

Notes: (a) Sources with lowest capture costs used for storage projects in each scenario. (b) CO_2 demand includes CO_2-EOR targets for the Nebraska Stacked Storage and Kansas-Nebraska Stacked Storage Scenarios. (c) CO_2 remaining is the total CO_2 available minus CO_2 demand for storage projects.

Conclusions

The results of the IMSCS-HUB CarbonSAFE Phase II Storage Complex Feasibility study provide a foundation for implementing commercial-scale CCUS in the Midcontinent region.

To effectively implement a CCUS project, site- and region-specific information about the following is needed: (1) subsurface geology, (2) public outreach, (3) project and site risks, (4) contractual and regulatory obligations, and (5) plan for commercialization. Phase I and Phase II of the IMSCS-HUB project researched all aspects and found the following:

- Successful storage complex feasibility data collection planning and field implementation resulted in two new 3D seismic volumes and three newly drilled and sampled appraisal wells that were integrated to support the geologic characterization of the stacked storage corridor (Battelle, 2019a, 2020a-d).
- Commercial-scale CCUS sites are feasible at two of the modeled storage sites, one in Madrid, Nebraska and one at the Patterson Site in Kearny County, Kansas. The Sleepy Hollow Field in Nebraska was found to be an attractive candidate for stacked storage with CO_2-EOR (Battelle, 2020e).
- Outreach efforts facilitated engagement from stakeholders in the IMSCS-HUB region, including ethanol plants, power plants, and industry trade groups. In addition, state and federal regulatory entities also attended the webinars conducted by Battelle and GPI (2020) during Phase II of the project.
- Project risks for subsurface storage, pipeline construction and operations, and non-technical risks were established. All components of a CCUS project are feasible in the IMSCS-HUB region. To mitigate the most impactful subsurface risks, the reservoir must be properly characterized, and operational constraints must always be followed. Pipeline construction is the riskiest portion of a CO_2 pipeline project because operations are shown to be safe, especially compared to other pipelines (Battelle, 2019b). A strong safety plan and use of contractors that value worker safety will help to mitigate risks of injuries requiring hospitalization or worker fatalities. Non-technical risks came from the uncertainty resulting from a lack of defined regulations for many issues related to CCUS.
- A permitting and regulatory assessment was researched and established to clearly define all permits needed for an integrated CCUS project in the IMSCS-HUB region. The contractual assessment study established various types of contracting mechanisms that must be considered for the regional hub implementation.
- The regional storage resource characterization demonstrated significant opportunity for commercial-scale projects in the IMSCS-HUB storage corridor with 577.4 Mt of stacked CO_2 storage capacity and the potential to produce 181.9 MMbbls of oil via EOR across 17 individual storage areas (Battelle and ARI, 2020).
- The pipeline assessment study found viable pipeline routes that connected 45Q-eligible ethanol plants, coal fired power plants, and other sources in the IMSCS-HUB corridor. The economic assessment study established the cost of capture from participating sources, storage projects at the Madrid, Nebraska Site and Patterson Site, and three integrated project scenarios.
- The comprehensive results of subsurface characterization, modeling efforts, outreach assessment, and regulatory analysis from were integrated to develop a Detailed Commercial Development Plan for the IMSCS-HUB (Battelle, 2020n).

Path Forward

Commercialization efforts will involve obtaining Class VI UIC permits, establishing and finalizing the pipeline route, and evaluating capture projects at participating CO_2 sources. The next steps for the IMSCS-HUB are as follows.

- Detailed site characterization is needed for the Madrid, Nebraska site in order to select injection and monitoring well locations for the commercial-scale project. This includes acquisition of 3D seismic and the drilling and sampling of a characterization well.
- Outreach efforts must be continued and should include a stakeholder outreach plan and engagement of the public through educational forums and town halls. This is particularly important in the areas where the CO_2 will be stored and along the pipeline ROWs.
- The risks assessment established a robust method for investigating subsurface and pipeline risks. These analyses only need to be refined once project plans are finalized. Non-technical risks, such as pore space rights, liability, and contractual mechanisms, must be clearly defined for commercial-scale projects to be implemented.
- Once the project is clearly established, the permitting plan must be finalized. The permitting entities for CO_2 capture and storage will likely remain constant, but the permitting entities for construction projects can vary by county or locality. Therefore, the pipeline route must be decided before these permitting entities can be clearly identified.

Phases I and II of the IMSCS-HUB CarbonSAFE provide a strong foundation for safely, efficiently, and cost-effectively characterizing and permitting commercial-scale project sites in the region. The plan for implementation of commercial-scale CCUS projects in the IMSCS-HUB is aligned with the objectives of CarbonSAFE Phase III: Site Characterization and CO_2 Capture Assessment.

References

Battelle. (2020a). Integrated Mid-Continent Stacked Carbon Storage Hub Project Phase II, Drilling and Data Collection Report, Task 4. DOE Agreement/Project # DE-FE0031623. July 2020.

Battelle. (2020b). Integrated Mid-Continent Stacked Carbon Storage Hub Project Phase II, Seismic Acquisition and Processing Milestone Memo, Task 4. DOE Agreement/Project # DE-FE0031623. January 2020.

Battelle. (2020c). Integrated Mid-Continent Stacked Carbon Storage Hub Project Phase II, Topical Report: Baseline Seismic Monitoring at Patterson and Hartland Fields, Task 4. DOE Agreement/Project # DE-FE0031623. September 2020.

Battelle. (2020d). Integrated Mid-Continent Stacked Carbon Storage Hub Project Phase II, Topical Report: Advanced Data Analysis, Task 5 Storage Complex Analysis and Modeling. DOE Agreement/Project #DE-FE0031623. May 2020.

Battelle. (2020e). Integrated Mid-Continent Stacked Carbon Storage Hub Project Phase II, Topical Report: Storage Complex Geologic and Reservoir Modeling, Task 5 Storage Complex Analysis and Modeling. DOE Agreement/Project #DE-FE0031623. May 2020.

Battelle. (2020f). Integrated Mid-Continent Stacked Carbon Storage Hub Project Phase II Stakeholder Characterization Report, Task 6 Outreach. #DE-FE0031623. August 2020.

Battelle. (2020g). Integrated Mid-Continent Stacked Carbon Storage Hub Project Phase II Topical Report: Subsurface Risk Assessment, Task 7 Risk Assessment and Mitigation. DOE Agreement/Project # DE-FE0031623. June 2020.

Battelle. (2020h). Integrated Mid-Continent Stacked Carbon Storage Hub Project Phase II Topical Report: Non-Technical Risk Assessment, Task 7 Risk Assessment and Mitigation. #DE-FE0031623. February 2020.

Battelle. (2020i). Integrated Mid-Continent Stacked Carbon Storage Hub Project Phase II. Technical Memorandum: Capturing Carbon in Nebraska Webinar Series. Task 6 Outreach. DOE Agreement/Project #DE-FE0031623. September 2020.

Battelle (2020j). Integrated Mid-Continent Stacked Carbon Storage Hub Project Phase II Risk Mitigation Plan, Task 7 Risk Assessment and Mitigation. DOE Agreement/Project # DE-FE0031623. August 2020.

Battelle. (2020k). Integrated Mid-Continent Stacked Carbon Storage Hub Project Phase II Topical Report: Underground Injection Control Permitting Plan, Task 8 CO_2 Regulatory and Contractual Requirements Assessment. DOE Agreement/Project # DE-FE0031623. May 2020.

Battelle. (2020l). Integrated Mid-Continent Stacked Carbon Storage Hub Project Phase II Topical Report: Contractual Assessment, Task 8 CO_2 Regulatory and Contractual Requirements Assessment. DOE Agreement/Project # DE-FE0031623. February 2020.

Battelle. (2020m). Integrated Mid-Continent Stacked Carbon Storage Hub Phase II Topical Report: Economic Assessment, Task 9 CO_2 Management and Commercial Development. DOE Agreement/Project # DE-FE0031623. June 2020.

Battelle. (2020n). Integrated Mid-Continent Stacked Carbon Storage Hub: Phase II, Topical Report: Detailed Commercialization Plan, Task 9 Commercialization and CO2 Management, DOE Agreement/Project # DE-FE0031623, Battelle Project # 100122657. August 2020.

Battelle. (2019a). Integrated Mid-Continent Stacked Carbon Storage Hub Project Phase II, Storage Complex Data Collection Plan, Task 3. DOE Agreement/Project # DE-FE0031623. March 2019.

Battelle (2019b). Integrated Mid-Continent Stacked Carbon Storage Hub: Phase II Topical Report: Pipeline Risk Assessment, Task 7 Risk Assessment and Mitigation. DOE Agreement/Project # DE-FE0031623. November 2019.

Battelle. (2019c). Integrated Mid-Continent Stacked Carbon Storage Hub: Phase II Technical Memorandum Permitting, Task 9 CO_2 Management and Commercial Development. DOE Agreement/Project # DE-FE0031623. June 2020.

Battelle. (2019d). Integrated Mid-Continent Stacked Carbon Storage Hub Phase II Topical Report: Pipeline Routing, Task 9 CO_2 Management and Commercial Development. DOE Agreement/Project # DE-FE0031623. November 2019.

Battelle. (2018). Integrated Mid-Continent Stacked Carbon Storage Hub, Phase I Final Report. Contract DE-FE-0029264. October 2018.

Battelle and Advanced Resources International (ARI). (2020). Regional Storage Capacity Characterization, Task 9 CO_2 Management and Commercial Development. DOE Agreement/Project # DE-FE0031623. May 2020.

Battelle and Great Plains Institute (GPI). (2020). Integrated Mid-Continent Stacked Carbon Storage Hub Project Phase II Technical Memorandum: Capturing Carbon in Nebraska Webinar Series, Task 6 Outreach. DOE Agreement/Project # DE-FE0031623. May 2020.

Battelle and Pacific Northwest National Laboratory (PNNL). (2020). Evaluation of Containment and Geomechanical Risks at Integrated Mid-Content Stacked Carbon Storage Hub Sites National Risk Assessment Partnership Tool Application. Task 7, Risk Assessment. DOE Agreement/Project # DE-FE0031623. August 2020.

Battelle and Schlumberger. (2020) Integrated Mid-Continent Stacked Carbon Storage Hub Phase II Topical Report: Topical Report: Storage Complex Geomechanical Modeling, Task 5. DOE Agreement/Project # DE-FE0031623. July 2020.

Bureau of Labor and Statistics (BLS). (2018). Injuries, Illnesses, and Fatalities - Industry Injury and Illness Data. Retrieved June 2019. <bls.gov>

BLS. (2017). Census of Fatal Occupational Injuries (CFOI) - Current and Revised Data [HTML]. Retrieved June 2019. <bls.gov>

Department of Energy/National Energy Technology Laboratory (DOE/NETL). (2018). FE/NETL CO_2 Transport Cost Model. U.S. Department of Energy. Last Update: May 2018 (Version 2b).

DOE/NETL. (2017). FE/NETL CO_2 Saline Storage Cost Model. U.S. Department of Energy. Last Update: Sep 2017 (Version 3) <netl.doe.gov>

DOE/NETL. (2015). Carbon Storage Atlas, 5th ed. Pittsburgh, PA: DOE/NETL.

Dubois, M. K., Williams, E. T., Youle, J. C., and Hedke, D. E. (2015). Potential for CO_2 storage and enhanced oil recovery in four southwest Kansas oil fields, an extended abstract; in W. L.

Watney, PI, Final Report for DOE Award Number: DE-FE0002056, Modeling CO_2 Sequestration in Saline Aquifer and Depleted Oil Reservoir to Evaluate Regional CO_2 Sequestration Potential of Ozark Plateau Aquifer System, South-Central Kansas, p. IV1-IV19.

Energy and Environmental Research Center at University of North Dakota (EERC). (2018). Nebraska Integrated Carbon Capture and Storage Pre-Feasibility Study, Final Report. DOE Agreement/Project # DE-FE0029186.

Filina, I., K. Guthrie, M. Searls, and C.M. Burberry. (2018). Seismicity in Nebraska and adjacent states: The historical perspective and current trends. The Mountain Geologist, vol. 55, no. 4, p. 217-229.

Goodman, A., S. Sanguinito, J.S. Levine. (2016). Prospective CO_2 saline resource estimation methodology: Refinement of existing US-DOE-NETL methods based on data availability. International Journal of Greenhouse Gas Control, Volume 54, Part 1, 2016, Pages 242-249, ISSN 1750-5836, https://doi.org/10.1016/j.ijggc.2016.09.009.

Hnottavange-Telleen, K., I Krapac, and C Vivalda. (2009). Illinois Basin-Decatur Project: Initial risk assessment results and framework for evaluating site performance. Energy Procedia, vol. 1, no. 1, p. 2431-2438.

Middleton, R.S. (2012). A new optimization approach to energy network modeling: anthropogenic CO_2 capture coupled with enhanced oil recovery. International Journal of Energy Research, vol. 37, no. 14, p. 1794-1810.

Middleton, RS and JM Bielecki. (2009). A scalable infrastructure model for carbon capture and storage: SimCCS. Energy Policy, vol. 37, p. 1052-1060.

Middleton, RS and S Yaw. (2018). The cost of getting CCS wrong: Uncertainty, infrastructure design, and stranded CO_2. International Journal of Greenhouse Gas Control, vol. 70, p. 1-11.

Peterie, S.L., R.D. Miller, J.W. Intfen, and J.B. Gonzalez. (2018). Earthquakes in Kansas induced by extremely far-field pressure diffusion. Geophysical Research Letters, vol. 45, p. 1395-1401.

Pipeline and Hazardous Materials Safety Administration. (2019a). Distribution, Transmission & Gathering, LNG, and Hazardous Liquid Accident and Incident Data [ZIP files]. Retrieved from <dot.phmsa.gov>

PHMSA. (2019b). Annual Report Mileage. Retrieved March 2019. <dot.phmsa.gov>

Quintessa. (2013). The Generic CO_2 Geological Storage FEP Database, Version 2.0.0. <quintessa.org>

Tucker, O. M. Holley, R. Metcalfe, and S. Hurst. (2013). Containment risk management for CO_2 storage in the Goldeneye depleted gas field, UK North Sea. Energy Procedia, vol. 37, p. 4804-4817.

United States Census Bureau. (2019). TIGER/Line Shapefile, 2018, state, Iowa, Current Block Group State-based. Retrieved 28 March 2019. <census.gov>

United States Census Bureau. (2018). 2016 SUSB Annual Data Tables by Establishment Industry. Retrieved June 2019. <census.gov>

United States Census Bureau. (2016a). TIGER/Line Shapefile, 2016, state, Nebraska, Current Block Group State-based. Retrieved 20 December 2017. <census.gov>

United States Census Bureau. (2016b). TIGER/Line Shapefile, 2016, state, Kansas, Current Block Group State-based. Retrieved 20 December 2017. <census.gov> United States Environmental Protection Agency U.S. EPA [nd]. Valuation of Human Life.

United States Environmental Protection Agency (U.S. EPA). (nd). Mortality Risk Valuation. Retrieved 5 June 2019. <epa.gov>

U.S. FWS. (2017a). National Wetlands Inventory - Download Seamless Wetlands Data by State. <fws.gov>

U.S. FWS. (2017b). Threatened & Endangered Species Active Critical Habitat Report. <fws.gov>

United States Geological Survey (USGS). (2017a). National Structures Dataset 20170525 for Nebraska State or Territory File GDB 10.1. <usgs.gov>

USGS. (2017b). National Structures Dataset 20170525 for Kansas State or Territory File GDB 10.1. <usgs.gov>

USGS. (2017c). National Structures Dataset 20170525 for Iowa State or Territory File GDB 10.1. <usgs.gov>

USGS. (2016a). Protected Areas Database of the United States (PAD-US), version 1.4. <usgs.gov>

USGS. (2016b). National Hydrography Dataset Best Resolution 20170714 for Nebraska State or Territory File GDB 10.1 Model Version 2.2.1. <usgs.gov>

USGS. (2016c). National Hydrography Dataset Best Resolution 20170714 for Kansas State or Territory File GDB 10.1 Model Version 2.2.1. <usgs.gov>

USGS. (2016d). National Hydrography Dataset Best Resolution 20170714 for Iowa State or Territory File GDB 10.1 Model Version 2.2.1. <usgs.gov>

USGS. (2005a). Agricultural Minerals Operations. National Atlas of the United States. Reston, VA: USGS.Minop1x020. <nationalatlas.gov>

USGS. (2005b). Construction Minerals Operations. National Atlas of the United States. Reston, VA: USGS.Minop2x020. <nationalatlas.gov>

USGS. (2005c). Ferrous Metal Mines. National Atlas of the United States. Reston, VA: USGS.Minop3x020. <nationalatlas.gov>

USGS. (2005d). Ferrous Metal Processing Plants. National Atlas of the United States. Reston, VA: USGS.Minop4x020. <nationalatlas.gov>

USGS. (2005e). Industrial Minerals Operations. National Atlas of the United States. Reston, VA: USGS.Minop5x020. <nationalatlas.gov>

USGS. (2005f). Nonferrous Metal Mines. National Atlas of the United States. Reston, VA: USGS. Minop6x020. <nationalatlas.gov>

USGS. (2005g). Nonferrous Metal Processing Plants. National Atlas of the United States. Reston, VA: USGS. Minop7x020. <nationalatlas.gov>

USGS. (2005h). Refractory, Abrasive, and Other Industrial Minerals Operations. National Atlas of the United States. Reston, VA: USGS. Minop8x020. <nationalatlas.gov>

USGS. (2005i). Sand and Gravel Operations in the United States. National Atlas of the United States. Reston, VA: USGS. Sndgrvx020. <nationalatlas.gov>

USGS. (2001). Coal Fields of the United States. National Atlas of the United States. Reston, VA: USGS. Coalfdp050. <nationalatlas.gov>

Appendix A: Patterson Site Storage Complex Analysis and Model Update

Appendix A: Patterson Site Storage Complex Analysis and Model Update provides the details of the geologic characterization conducted at the Patterson Site in Kansas which was summarized in the body of this report.

Prepared by:
Esmail Ansari
Tiraz Birdie
Jingyao Meng
Franciszek Hasiuk
Eugene Holubnyak

University of Kansas Center for Research
Kansas Geological Survey
1930 Constant Avenue
Lawrence, KS 66047

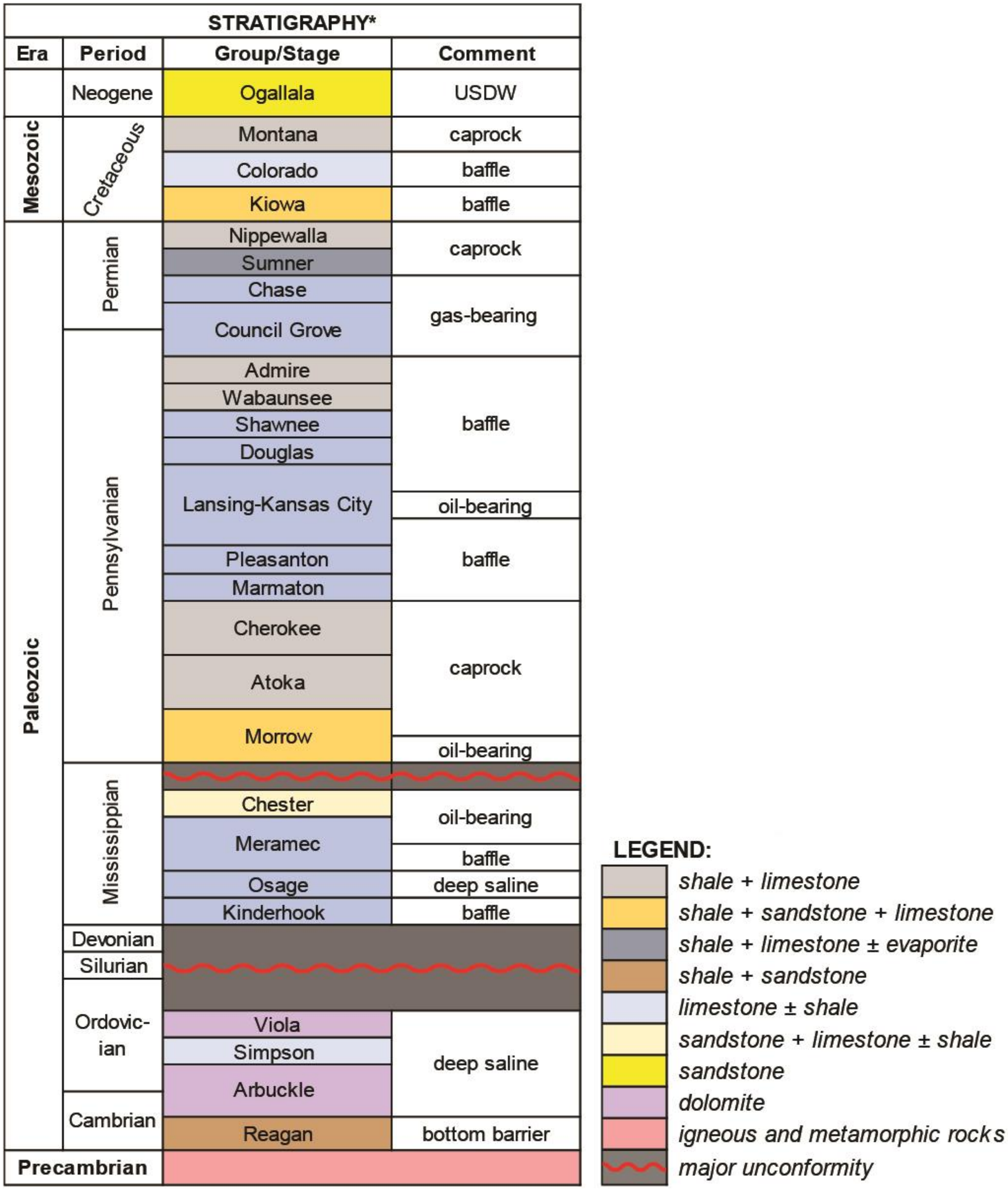
Technical POC:
Eugene Holubnyak
Eugene.h@ku.edu
785-864-2070

Introduction

Appendix A: Patterson Site Storage Complex Analysis and Model Update includes:

- An overview and analysis of the well testing conducted at the Patterson KGS 5-25 and Hartland KGs 6-10 wells
- An analysis of the Patterson KGS 5-25 core
- The caprock and geomechanical assessment
- Refined storage resource estimates
- Updated geologic models

The Patterson storage site in southwestern Kansas' Kearney County is comprised of four fields, the Patterson, Heinitz, Hartland, and Oslo situated on a common structure covering 36 mi^2. At this site, Cambrian-Ordovician (Arbuckle), Ordovician (Viola), and Mississippian (Osage) dolomite and cherty dolomite are potential deep saline storage zones with high potential for commercial-scale storage (Figure 1). These zones are present at average depths of 5,310 ft to 5,800 ft and occur as thick, laterally extensive storage reservoirs underlying a northwest-trending, broad structural closure ideal for CO_2 storage. The Patterson geologic site is one of six closed geologic structures in the North Hugoton Storage Complex (NHSC), a 60-mile (mi) long NW-SE structural trend in the north part of the Giant Hugoton gas field. Each of the large structures identified in the NHSC is underlain by the three storage reservoirs, and all six structures also contain shallower (5,000 feet [ft]) extensive oil production that have been demonstrated to have CO_2-EOR potential (Dubois et al., 2015). Deep saline storage zones at the Patterson site are well-confined by thick, tight carbonate and thin shale intervals isolating Osage, Viola, and Arbuckle injection zones. More than 400 ft of tight limestone separate the Osage from the regional unconformity at the top of the Meramec. Multiple regionally continuous shale layers in the Morrow, Atoka and Cherokee form the primary caprock sequence. More than 400 ft of tight limestone separate the Osage from the regional unconformity at the top of the Meramec. Between the top of the primary caprock complex (Cherokee top) and the High Plains Aquifer in southwest Kansas, there is an additional 4,300 ft of Upper Pennsylvanian, Permian, and Cretaceous rocks, including the regionally extensive shale and evaporite of the Permian Sumner and Nippewalla groups. Permian evaporites form the top seal to the giant Hugoton-Panoma and Panhandle fields covering southwest Kansas and the Oklahoma and Texas Panhandles that produce from the directly underlying Chase and Council Grove Groups.



*formal lithostratigraphic group and stage names used unless otherwise noted; not to scale

Figure 1. Generalized stratigraphic chart for Patterson Site in southwest Kansas. The comment column shows oil and gas producing intervals in the area as well as regional barriers, caprocks and baffles to vertical fluid flow. USDW = underground source of drinking water (Holubnyak et al., 2018; 2020).

Well Testing Overview

In order to determine the ability of the deeper formations (beneath the Pennsylvanian System) to accept injected fluids, Step Rate (SRT), falloff, and interference tests were conducted at multiple depths at the Hartland KGS 6-10 and Patterson KGS 5-25 wells in Kearny County, Kansas, between July 9 and August 7, 2020. As shown in Figure 2, the wells are approximately 10 miles apart, and the land surface elevation is 3,262 and 3,317 feet (above mean sea level) at the Hartland and Patterson well sites, respectively. The tests involved injecting increasing amounts of brine at regular intervals, a hard shut-in, and the observation and recording of the bottom hole pressure drop (falloff) in both wells. During injection in a particular formation at a well site (i.e., Hartland or Patterson), the pressure and temperature within the same formation in the other twin well was also monitored in order to determine the degree of hydraulic connection between two well sites and Precambrian basement and Lower Arbuckle intervals (interference test).

The tests were conducted in the Osage formation of Mississippian age, the Ordovician Viola formation, the upper, middle, and lower zones of the Arbuckle Group, and two intervals in the granitic basement. The injection intervals in each formation were selected after reviewing the Magnetic Resonance Imaging (MRI) based porosity logs. A similar geologic interval (at approximately the same depth) within each formation was perforated in both wells during the SRT. The injection rate in the wells was typically varied from 2.5 barrels per minute (bpm) to 15 bpm in ten-minute intervals. A summary of the test data in each of the tested formations is presented in Table 1 and briefly summarized below.

Well Testing Results

Osage

The Osagian Formation could easily accept the 15 bpm of brine (maximum rate) injected at both the Hartland and Patterson wells. The Osagian Formation at the Hartland KGS 6-10 well appeared to be slightly more permeable than at the Patterson KGS 5-25 well, as the Hartland KGS 6-10 well produced a lower (induced) bottom hole pressure response of 1,525 psi versus 1,774 psi (at the maximum injection rate) at the Patterson KGS 5-25 well. An estimated permeability for both sites is above 1 Darcy (D).

Viola

The Viola Formation also readily accepted the maximum injected amount of 15 bpm at both sites. In contrast to the Osagian Formation, the Viola Formation at the Patterson site appears to be more permeable than at Hartland KGS 6-10 well. The maximum induced bottom hole pressures were 2,469 psi and 1,444 psi (at the 15 bpm injection rate) in the Hartland and Patterson wells, respectively. An estimated permeability is above 2 D for the Patterson site and around 0.5 D for the Hartland KGS 6-10 well.

Upper Arbuckle

The Upper Arbuckle Zone could also accept 15 bpm of injected brine. The Upper Arbuckle Zone at the Hartland KGS 6-10 well is more permeable than at the Patterson KGS 5-25 well. The maximum induced pressures at the end of the 10-minute (15 bpm) period were 1,405 psi and 2,993 psi in the Hartland and Patterson wells, respectively. The final shut-in pressure in the Upper Arbuckle Zone at the Patterson KGS 5-25 well was at 4,519 psi (above the fracture pressure for this zone). The formation fractured at a pressure of approximately 4,150 psi, resulting in a calculated fracture gradient of approximately 0.7 psi/ft, which is in the range of values observed in the region for this parameter. An estimated permeability is above 0.3 D for Patterson and above 2 D for Hartland.

Middle Arbuckle

As noted for the other shallower formations, the Middle Arbuckle Zone could also accept 15 bpm of injected brine. The maximum induced pressures were lower than those observed in the Upper Arbuckle Zone, with pressures in the Middle Arbuckle Zone measured at 1,211 psi at the Hartland KGS 6-10 well and 1,909 psi at the Patterson site. An estimated permeability for both sites is above 2 D.

Lower Arbuckle

The Lower Arbuckle Zone could accept 15 bpm of injected brine at induced pressures of 1,967 psi and 1,594 psi at the Hartland and Patterson wells, respectively. This zone at the Hartland KGS 6-10 well appears to have fractured at a pressure of 3,725 psi resulting in a relatively low fracture gradient of 0.6 psi/ft. During the injection tests in the Lower Arbuckle Zone at both the Hartland and Patterson wells, pressures were also monitored in the Upper Granite. There was no pressure response noted in the Upper Granite as the Lower Arbuckle Zone was pressurized at either site. An estimated permeability for both sites is above 1 D.

Upper Granite

Attempts to inject brine in the Upper Granite at the Patterson KGS 5-25 well were not successful due to the tight nature of the formation. However, the Upper Granite at the Hartland KGS 6-10 well is more permeable and 6 bpm of brine was injected at the site resulting in an induced pressure response of 2,272 psi. An estimated permeability for the Upper Granite at the Hartland KGS 6-10 well is above 0.2 D.

Lower Granite

As noted for the Upper Granite, the Lower Granite at the Patterson KGS 5-25 well would not accept any fluids. The Lower Granite at the Hartland KGS 6-10 well, however, would accept 12 bpm of brine, which was the maximum amount attempted at the site. The resulting induced pressure response was 1,842 psi, indicating an estimated permeability of 1.5 D for the Lower Granite at the Hartland KGS 6-10 well.

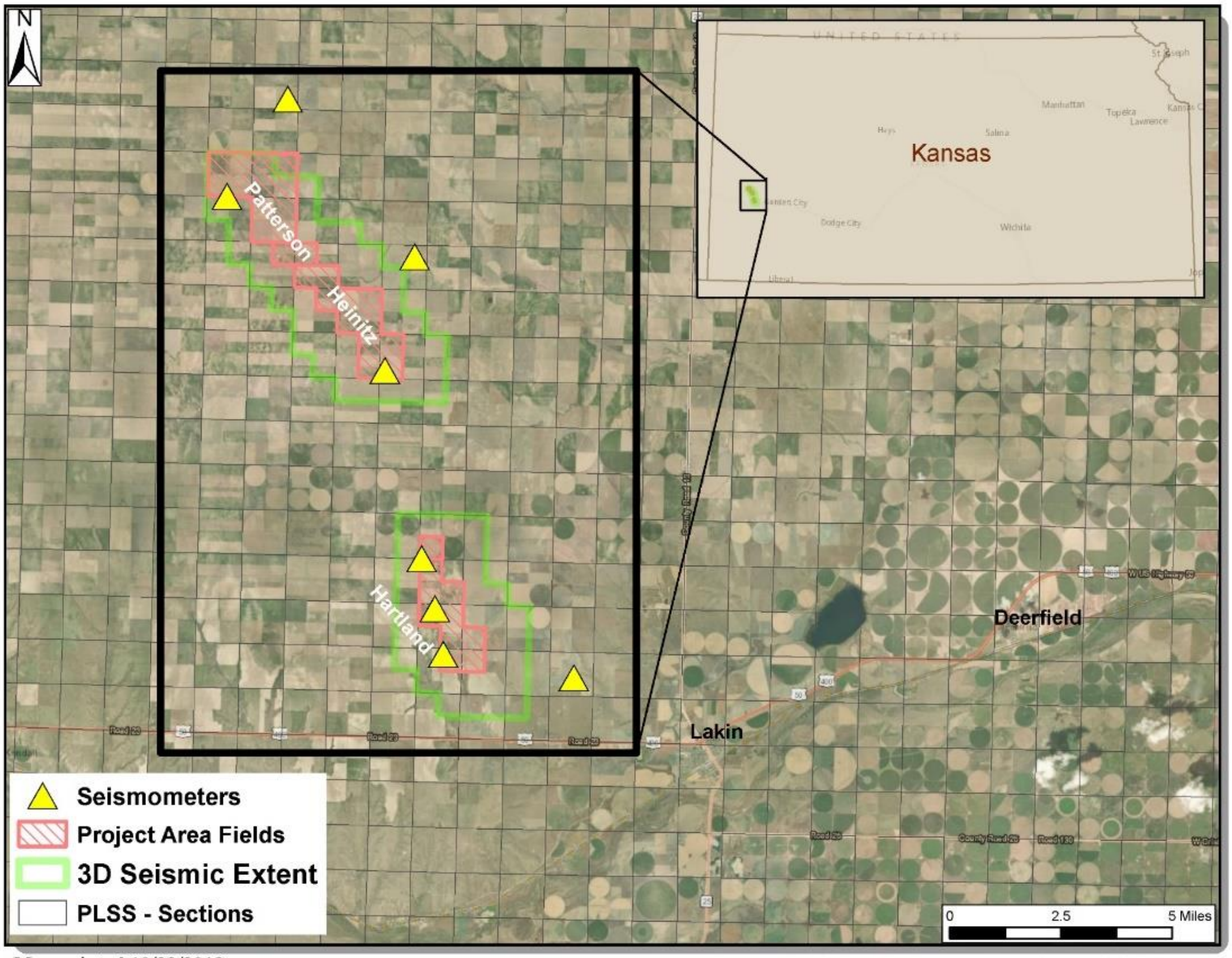


Figure 2. Location of the Hartland and Patterson test well sites.

Table 1. Step Rate Test summary at the Hartland and Patterson wells.

Formation	Parameter	Hartland KGS 6-10	Patterson KGS 5-25
Osage	*Injection Interval (ft)*	5,310-5,330	5,300-5,325
	Maximum Injection Rate (bbls/min)	15	15
	Maximum Induced Pressure (psi)	1,525	1,774
Viola	*Injection Interval (ft)*	5,640-5,660	5,600-5,620
	Maximum Injection Rate (bbls/min)	15	15
	Maximum Induced Pressure (psi)	2,469	1,444
Upper Arbuckle	*Injection Interval (ft)*	5,895-5,925	6,110-6,130
	Maximum Injection Rate (bbls/min)	15	15
	Maximum Induced Pressure (psi)	1,405	2,993
Middle Arbuckle	*Injection Interval (ft)*	6,284-6,300	6,040-6,060
	Maximum Injection Rate (bbls/min)	15	15
	Maximum Induced Pressure (psi)	1,211	1,909

Lower Arbuckle	*Injection Interval (ft)*	6,284-6,300	6,232-6,250
	Maximum Injection Rate (bbls/min)	15	15
	Maximum Induced Pressure (psi)	1,211	1,909
Upper Granite	*Injection Interval (ft)*	6,375-6,395	6,290-6,300
	Maximum Injection Rate (bbls/min)	15	N/A
	Maximum Induced Pressure (psi)	2,272	N/A
Lower Granite	*Injection Interval (ft)*	6,510-6,525	6,412-6,424
	Maximum Injection Rate (bbls/min)	15	N/A
	Maximum Induced Pressure (psi)	1,842	N/A

Osagian Stage

The Osagian Stage within the Mississippian System is a well-known liquid waste disposal zone in western Kansas. There are several medium to high porosity intervals within this formation at both sites as shown in Figure 3. The intervals from 5,310-5,330 feet at the Hartland KGS 6-10 well and 5,300-5,325 at the Patterson KGS 5-25 well were perforated for injection. Based on a review of the porosity logs, there is approximately 100 feet of sufficiently porous formation at the Hartland and Patterson wells, as can be inferred from Figure 3. The porosity in these "porous intervals" average approximately 6-7% at both the sites. Assuming a brine density gradient of 0.45 psi/ft, the water level in the wells was calculated at a depth of approximately 2,369 feet at the Hartland KGS 6-10 well and 2,426 feet at the Patterson KGS 5-25 well (Table 2). The SRTs at the sites are discussed below.

Table 2. Step rate test parameters at the Hartland and Patterson injection wells.

Well	Ground elevation (ft)	Gage Depth (ft)	Gage Pressure (psi)	Water Depth in Well (ft, bls)	Shut-in Pressure (psi)	Maximum Injection Rate (bpm)	Induced Pressure (psi)
Hartland KGS 6-10	3,262	5,340	1,336.7	2,369.5	2,861.7	15	1,525
Patterson KGS 5-25	3,317	5,335	1,308.8	2,426.5	3,081	15	1,774

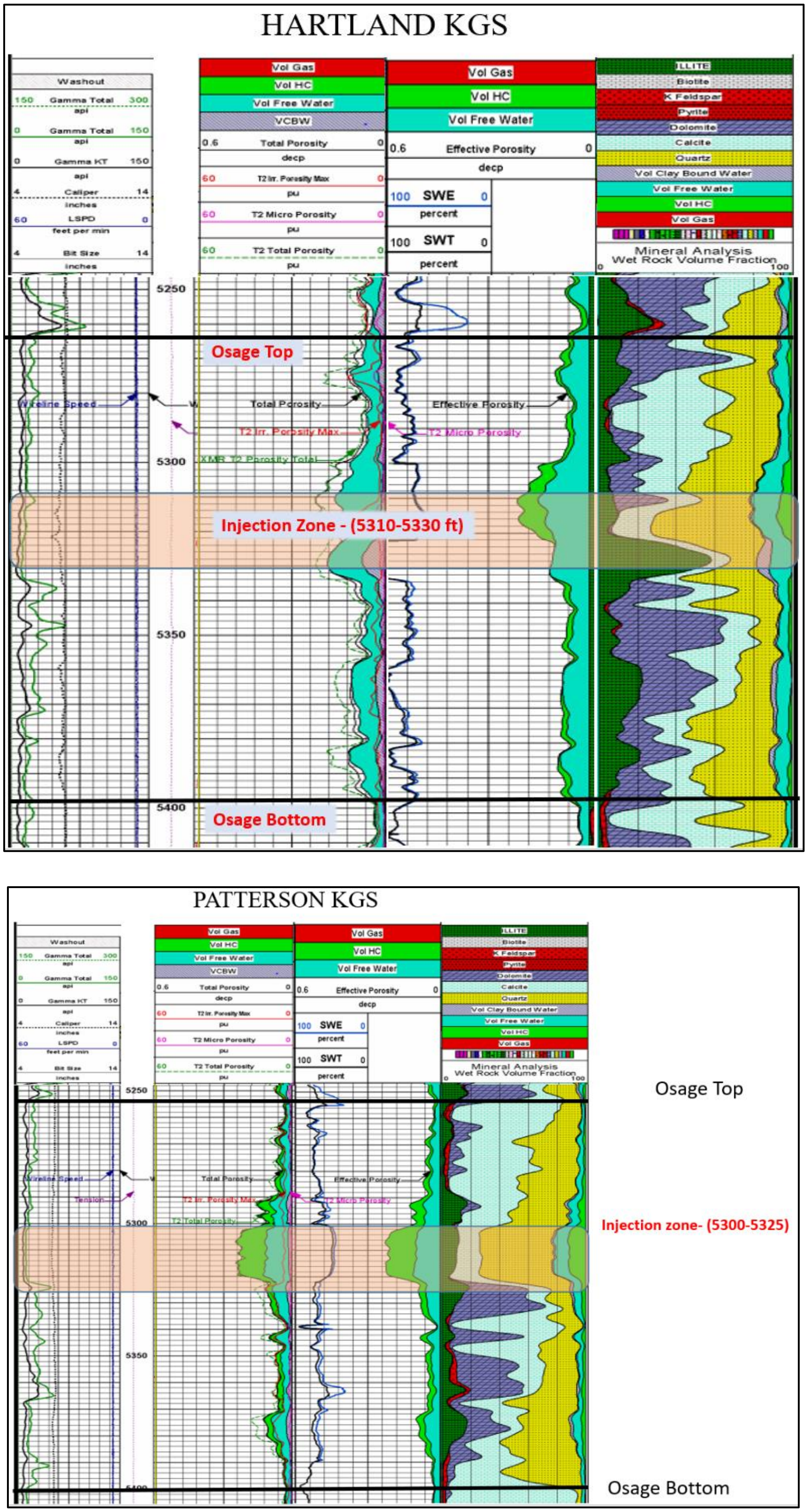


Figure 3. Porosity profile in the Osagian Formation at the Hartland KGS 6-10 and Patterson KGS 5-25 wells.

Hartland KGS 6-10 Well

As shown in Figures 4 and 5, the hydraulic testing was conducted on August 7, 2020. The pressure gage was inserted into the well at 10:45 am and was positioned at a depth of 5,340 feet. The baseline pressure measured at this depth was1336.7 psi. After placing the gage in the well, brine was injected gradually until the water level reached the top at which point the pressure in the gage measured approximately 2,500 psi.

Injection of 2.5 bpm commenced at 11:31 am. The formation appears to take the brine without any increase in bottom hole pressure suggesting that approximately 2.5 bpm is needed to maintain water levels. However, the bottom hole pressure increased from approximately 2,331 psi to approximately 2,535 psi as the injection rate increased from 2.5 bpm to 5.0 bpm. Each subsequent step in injection rate resulted in an increase in the bottom hole pressure. At 12:12 pm, the well was shut-in and water levels were allowed to recover. As can be noted from Figure 4, there was an immediate drop in pressure trending toward values recorded during the start of the SRT and corresponding to the approximately 2,350 psi observed with water levels at the top of the well during the well loading period. Also shown are the surface injection pressures and the downhole temperatures at the two sites.

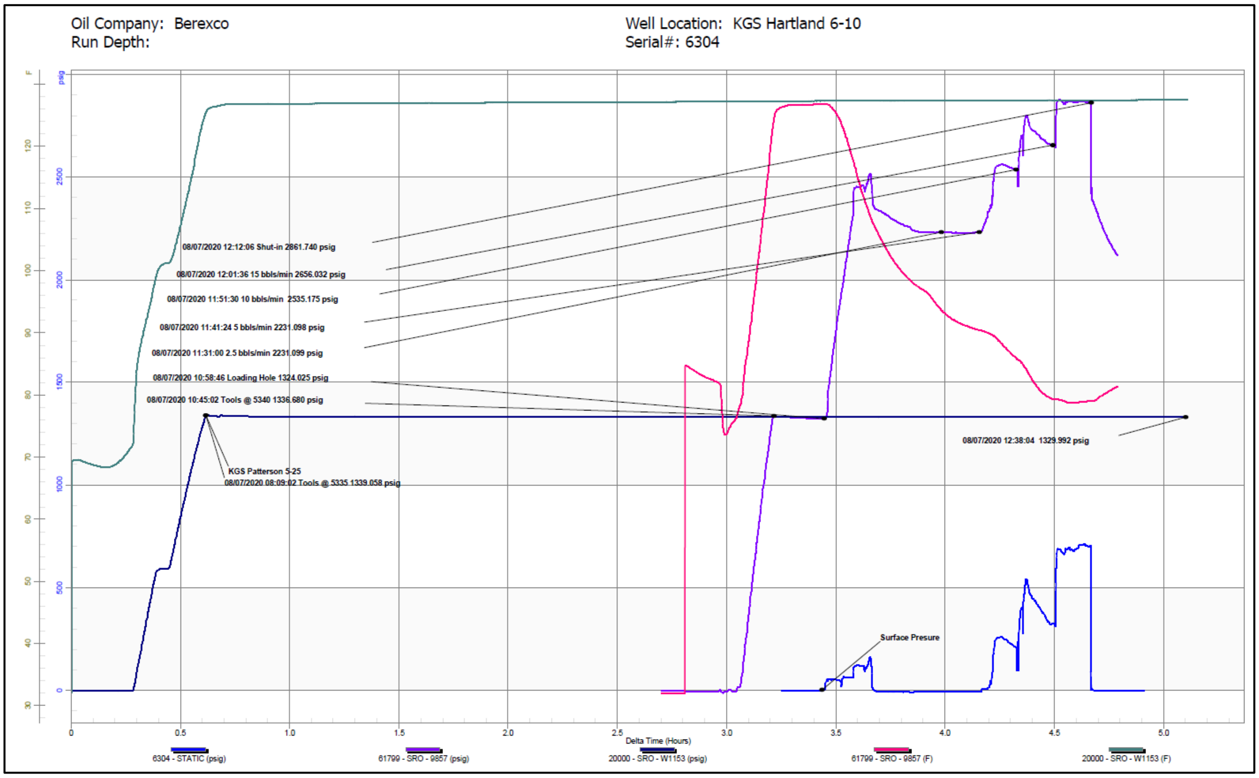


Figure 4. Gage pressures recorded during the Step Rate Test in the Osagian Formation at the Hartland KGS 6-10 well. Also shown are the surface injection pressures and the downhole temperatures at the two sites.

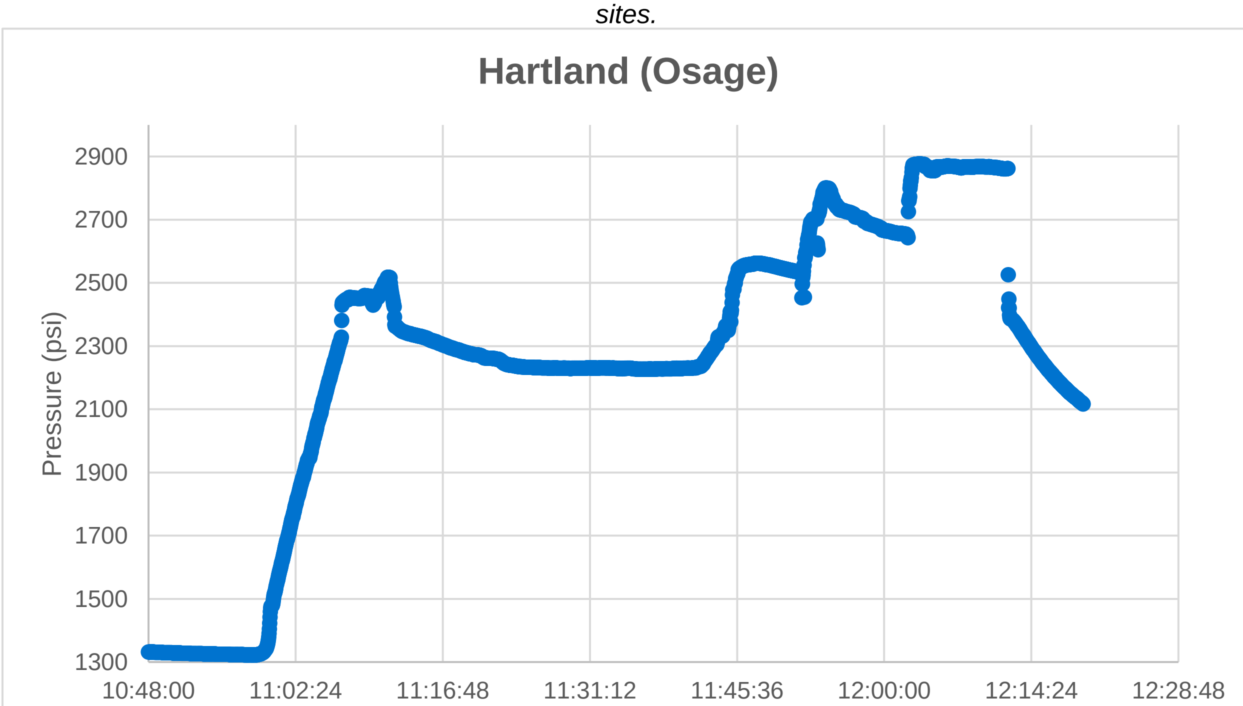


Figure 5. Recorded pressure in the Hartland well during the Osagian Step Rate Test.

Patterson KGS 5-25 Well

As shown in Figures 6 and 7, the step rate test was conducted at the Patterson KGS 5-25 well on August 6, 2020. The pressure gage was inserted in the well to a depth of 5,335 feet and measured a baseline pressure of 1,308 psi. Starting at 10:00 am, brine was gradually injected into the well until the water level reached the top of the well and was allowed to stabilize. Injection of brine at a rate of 2.5 bpm commenced at 9:37 am. The formation appears to take the brine without any increase in pressure suggesting that approximately 2.5 bpm is needed to maintain water levels at the top of the well. As the injection rate increased to 15 bpm, a fairly linear increase in pressure as a function of the injection rate was noted. At 10:18 am, the well was shut-in and water levels were allowed to recover. As can be noted from Figures 6 and 7, there was an immediate drop in pressure after shutting in the well, and thereafter two distinct recovery periods were observed.

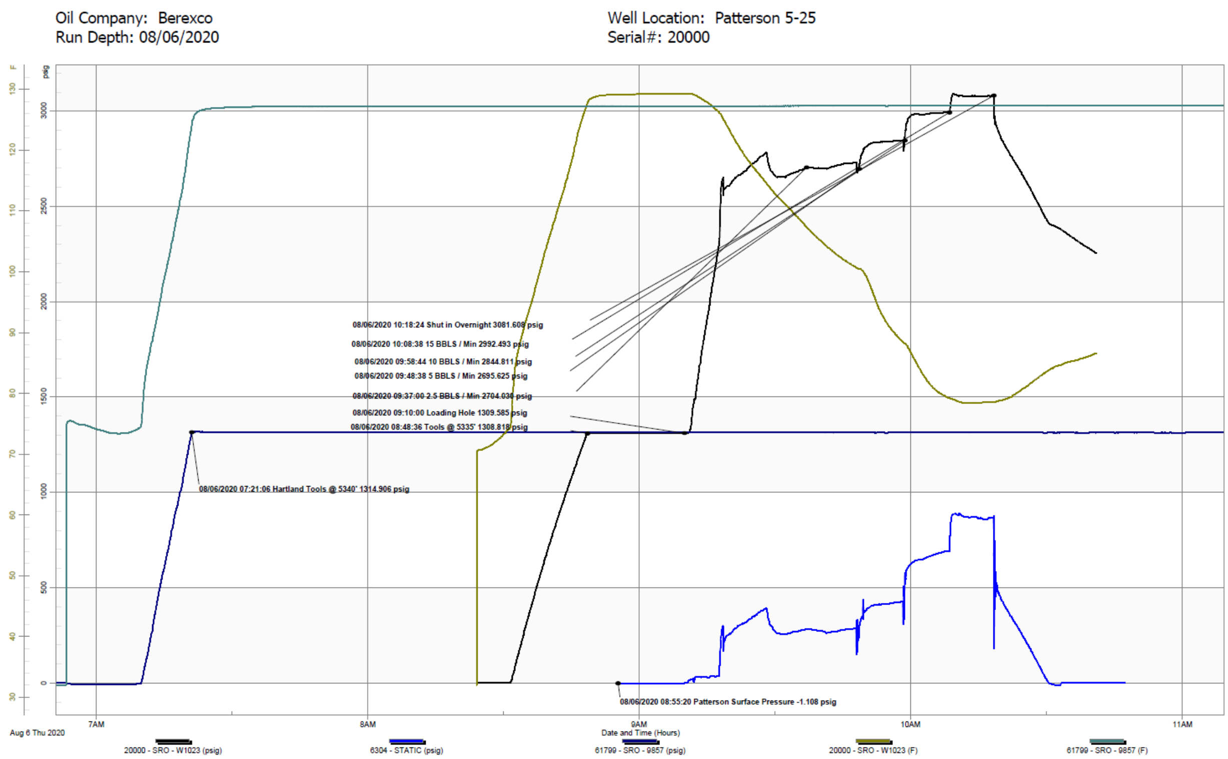


Figure 6. Gage pressures recorded at the Hartland and Patterson wells during the Step Rate Test in the Osagian Formation at the Patterson KGS 5-25 well. Also shown are the surface injection pressures and the downhole temperatures at the two sites.

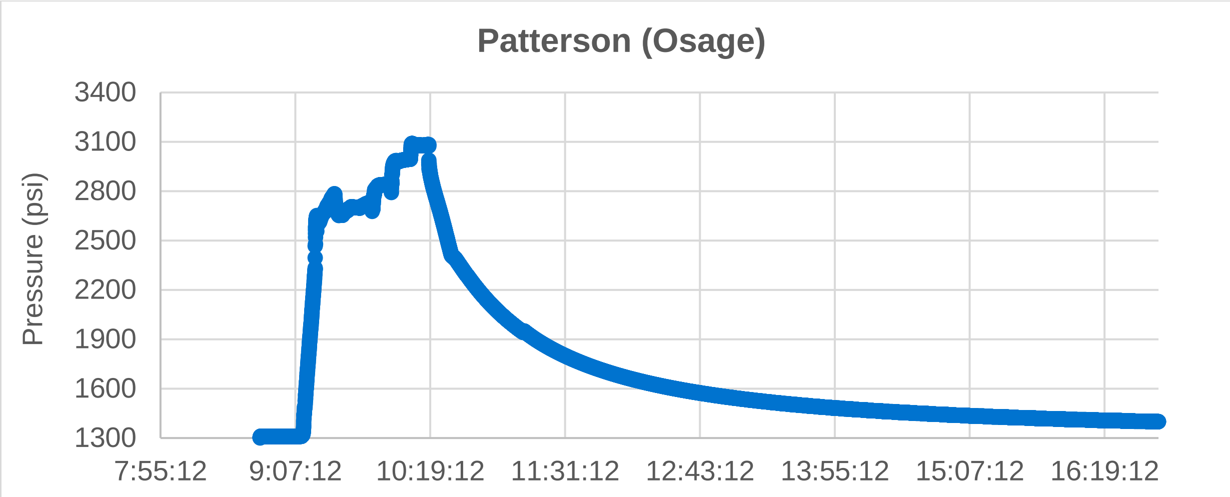


Figure 7. Recorded pressure in the Patterson well during the Osagian Step Rate Test.

Viola Formation

The Ordovician Viola Formation consists primarily of dolomite at the two sites and appears to be more porous at the Hartland KGS 6-10 well than at the Patterson KGS 5-25 well (Figure 8). However, the test data do not seem to validate this observation made from the electronic log data. The intervals from depths of 5,640-5,660 feet at the Hartland KGS 6-10 well and 5,600-5,620 at the Patterson KGS 5-25 well were perforated for injection. Assuming a brine density gradient of 0.45 psi/ft, the water levels in the wells are at depths of approximately 2,423 feet at the Hartland KGS 6-10 well and 2,438 feet at the Patterson KGS 5-25 well (Table 3).

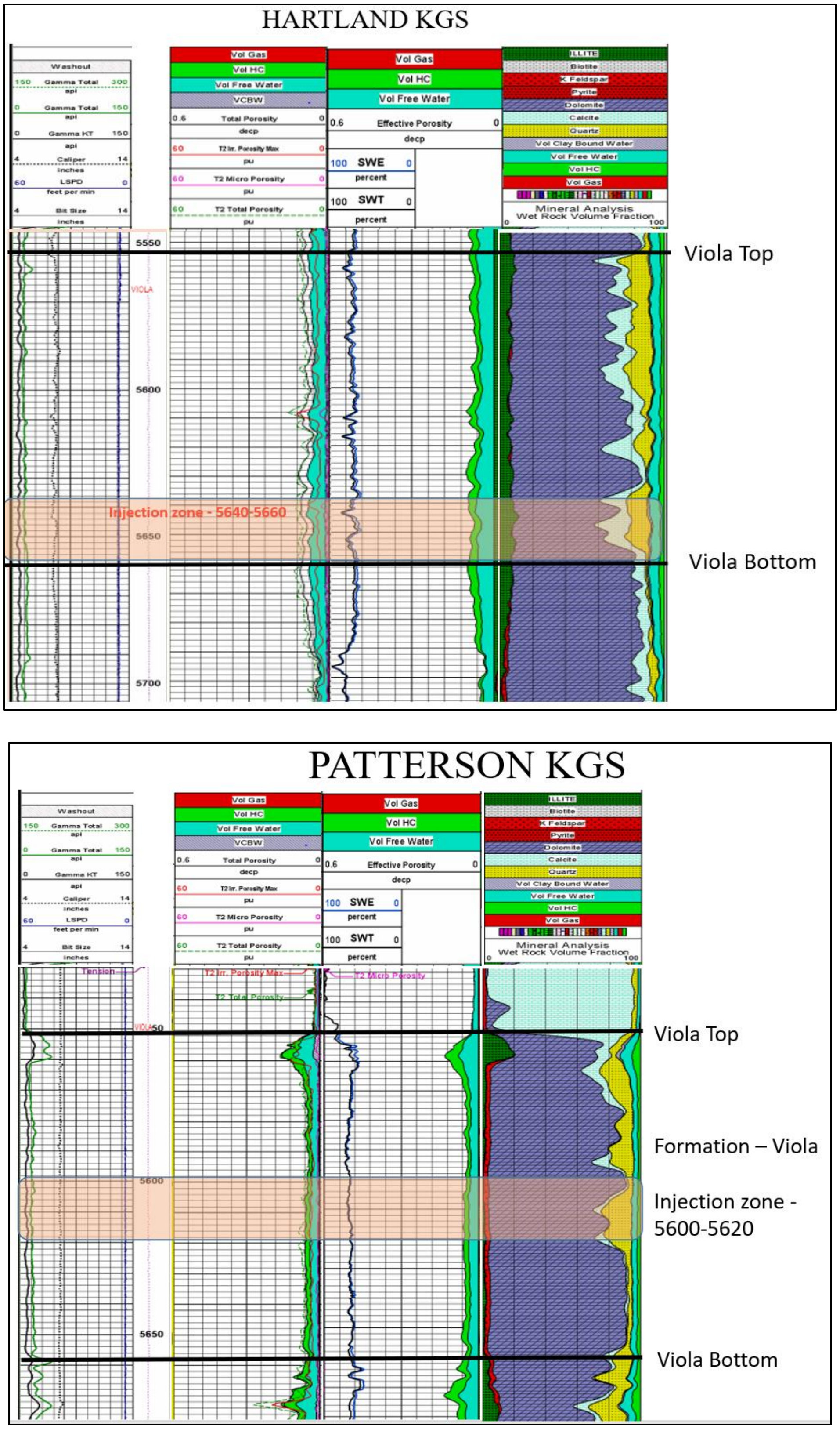


Figure 8. Porosity profile in the Viola Formation at the Hartland and Patterson wells.

Hartland KGS 6-10 Well

As shown in Figure 9, the step rate test was conducted in the Viola Formation at the Hartland well on August 4, 2020. The pressure gage was inserted to depth of 5,680 feet at 11:12 am and recorded a baseline pressure of 1,465 psi. Brine was gradually injected in the well until the water level reached the top of the well, at which point the downhole pressure in the well was approximately 2,550 psi (Figures 9 and 10).

After several minutes of stabilization with the well filled with brine, the testing commenced with the injection of brine at 2.5 bpm and then increasing rates of injection at 10-minute intervals as shown in Figure 9. As can be noted from the figure, there a momentary decreases in pressure between each step of the injection test. A linear increase in pressure was not noted as the injection rate increased. For example, as the rate increased to 5 bpm the pressure increase was larger than for the 2.5 bpm rate. The reason for this is not clear and it could be associated with loading of the brine. As the injection rate increased to 10 bpm, the formation appears to have fractured as can be noted from the pressure drop in Figures 9 and 10. Assuming a fracture gradient of0.65 psi/ft, a fracture would be expected at a bottom hole pressure of 3,692 psi., which is similar to the value observed during the test.

At 1:12 pm, injection was stopped and water levels were allowed to recover. Figure 9 displays an immediate drop in bottom hole pressure when injection is stopped and pressure values decrease to pre-injection levels (2,500 psi). Thereafter, the pressure recovery (under gravity) was slower and continued until reaching near-baseline levels.

Table 3. Step rate test parameters in the Viola Formation at the Hartland and Patterson injection wells.

Well	Ground Elevation (ft)	Gage Depth (ft)	Gage Pressure (psi)	Water Depth in well (ft, bls)	Maximum Injection Rate (bpm)	Shut-in Pressure (psi)	Maximum Induced Pressure (psi)
Hartland KGS 6-10	3,262	5,680	1,465.5	2,423	15	3,934	2,469
Patterson KGS 5-25	3,317	5,630	1,436.4	2,438	15	2,880	1,444

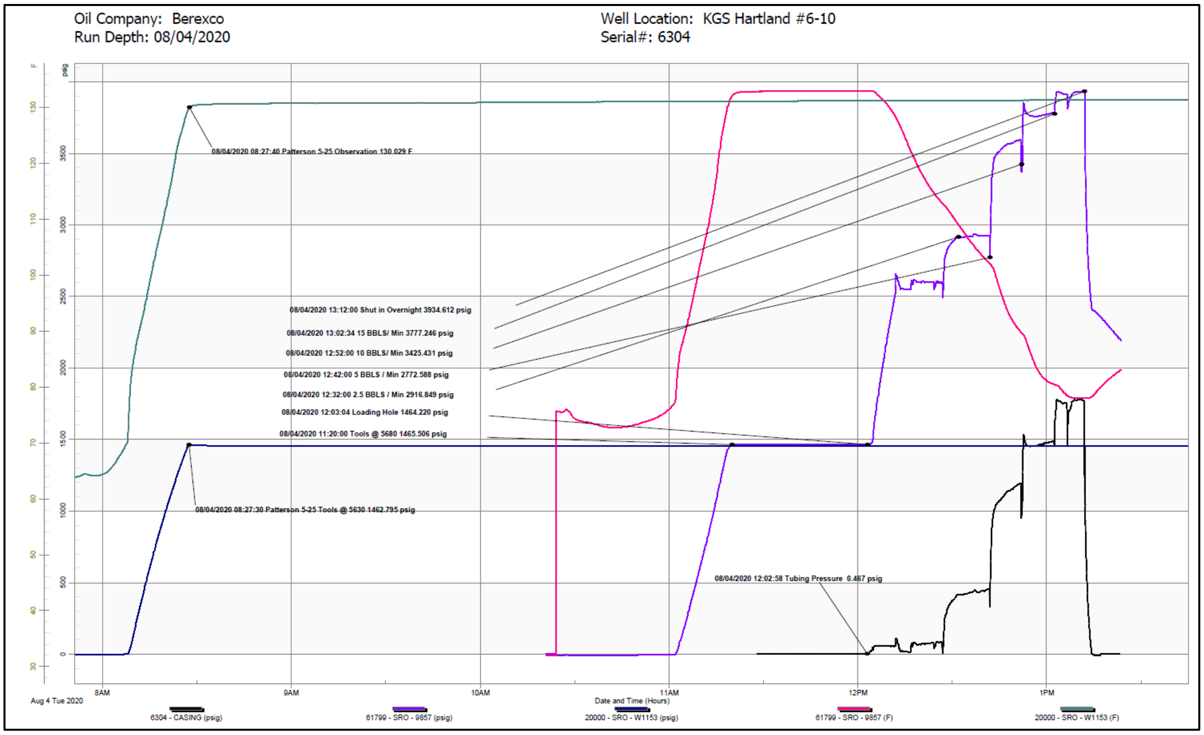


Figure 9. Gage pressures recorded at the Hartland and Patterson wells during the Step Rate Test in the Viola Formation at the Hartland KGS 6-10 well. Also shown are the surface injection pressures and the downhole temperatures at the two sites.

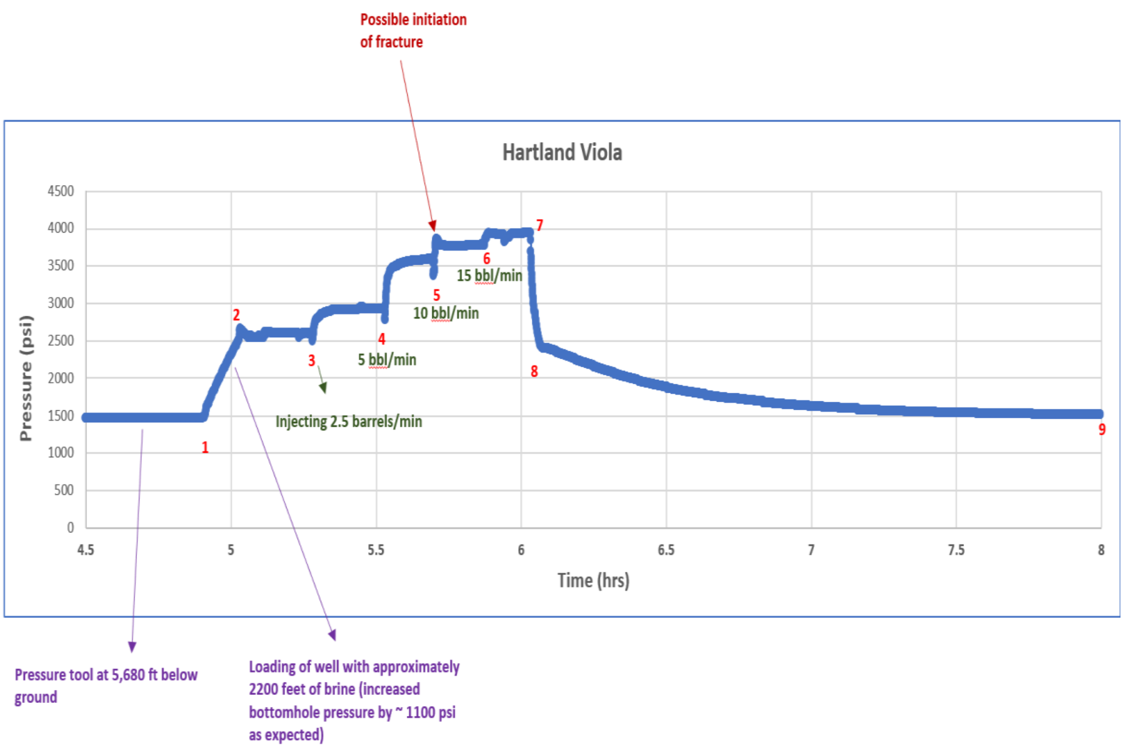


Figure 10. Gage pressure recorded as a function of the injection rate during the Hartland KGS 6-10 well Viola Formation Step Rate Test.

Patterson KGS 5-25 Well

As shown in Figure 11, the step rate test in the Viola Formation at the Patterson site was conducted on August 3, 2020. The pressure gage was set in the well at a depth of 5,630 ft at 9:31 am and recorded a baseline pressure of 1,436 psi. Brine was gradually injected into the well until the water level reached the top of well, at which point the pressure at the gage was approximately 2,550 psi.

After several minutes of stabilization, the test commenced with starting brine injection at 2.5 bpm and increasing the injection rates at 10-minute intervals as shown in Figure 11. A linear increase in pressure was not noted as the injection rate increased. The bottom hole pressure displayed a decrease during the 10-bpm loading stage, but this decrease was not attributed to fracturing on account of the low resulting fracture gradient.

At 11:21 am, injection stopped and the water levels in the well were allowed to recover. As shown in Figures 11 and 12, there was an immediate decrease in pressure. Thereafter, the pressure recovery (under gravity) was slower and continued until reaching pre-injection levels.

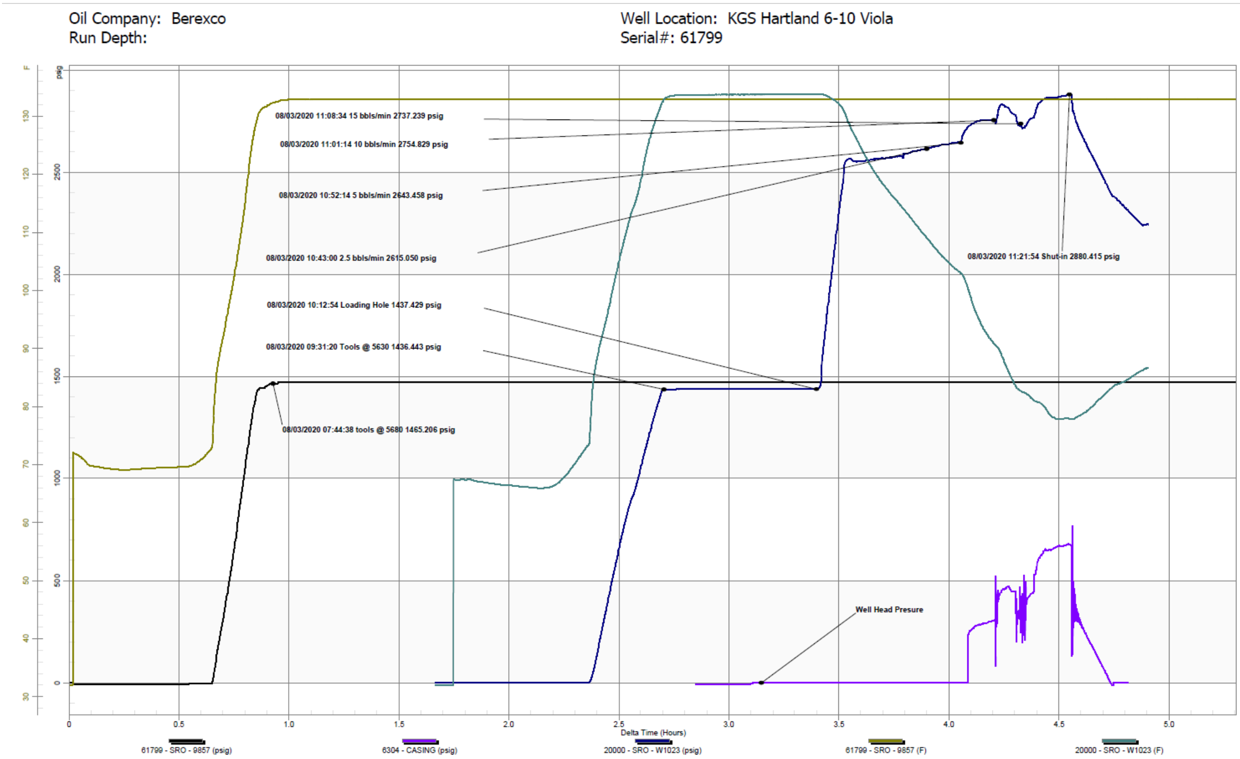


Figure 11. Downhole gage pressures recorded at the Hartland and Patterson wells during the Step Rate Test in the Viola Formation at the Patterson KGS 5-25 well. Also shown are the surface injection pressures and the downhole temperatures at the two sites.

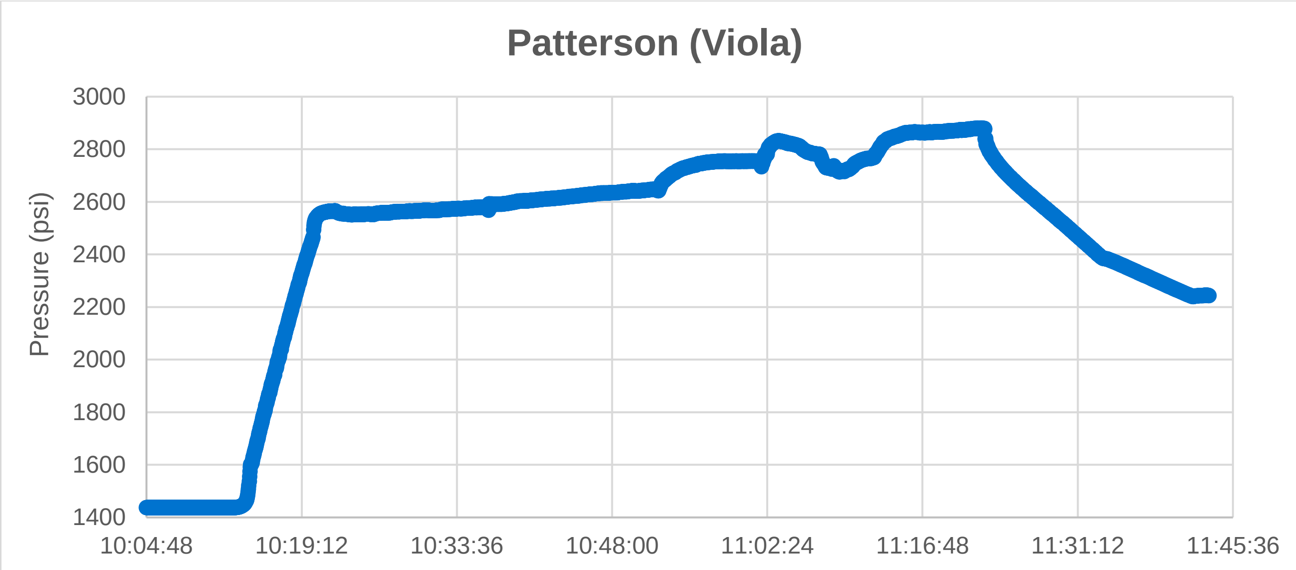


Figure 12. Gage pressure recorded as a function of the injection rate during the Patterson KGS 5-25 well Viola Formation Step Rate Test.

Upper Arbuckle

Rocks in the Arbuckle Group consist primarily of dolomite. It is a well-known liquid waste disposal zone in western Kansas and is used throughout the state for disposing industrial waste fluids without any surface pressurization during injection. There are several medium- to high-porosity intervals within this formation at both sites as shown in Figure 13. The intervals from 5,895-5,925 feet at the Hartland KGS 6-10 well and 5,810-5,830 at the Patterson KGS 5-25 well were perforated for injection in the upper zones of the Arbuckle Group. The porosity in "porous intervals" of the Upper Arbuckle at the Hartland and Patterson wells tends to be approximately 6-7%. Assuming a brine density gradient of approximately 0.45 psi/ft, the static water levels in the wells are estimated to be approximately 2,413 feet at the Hartland KGS 6-10 well and 2,541 feet at the Patterson KGS 5-25 well (Table 4).

Table 4. Upper Arbuckle step rate test parameters at the Hartland and Patterson injection wells

Well	Ground elevation (ft)	Gage Depth (ft)	Gage Pressure (psi)	Water Depth in well (ft, bls)	Maximum Injection Rate (bpm)	Shut-in Pressure (psi)	Maximum Induced Pressure (psi)
Hartland KGS 6-10	3,262	5,935	1,584.7	2,413.4	15	2,989	1,405
Patterson KGS 5-25	3,317	5,935	1,526.9	2,541.9	15	4,519	2,993

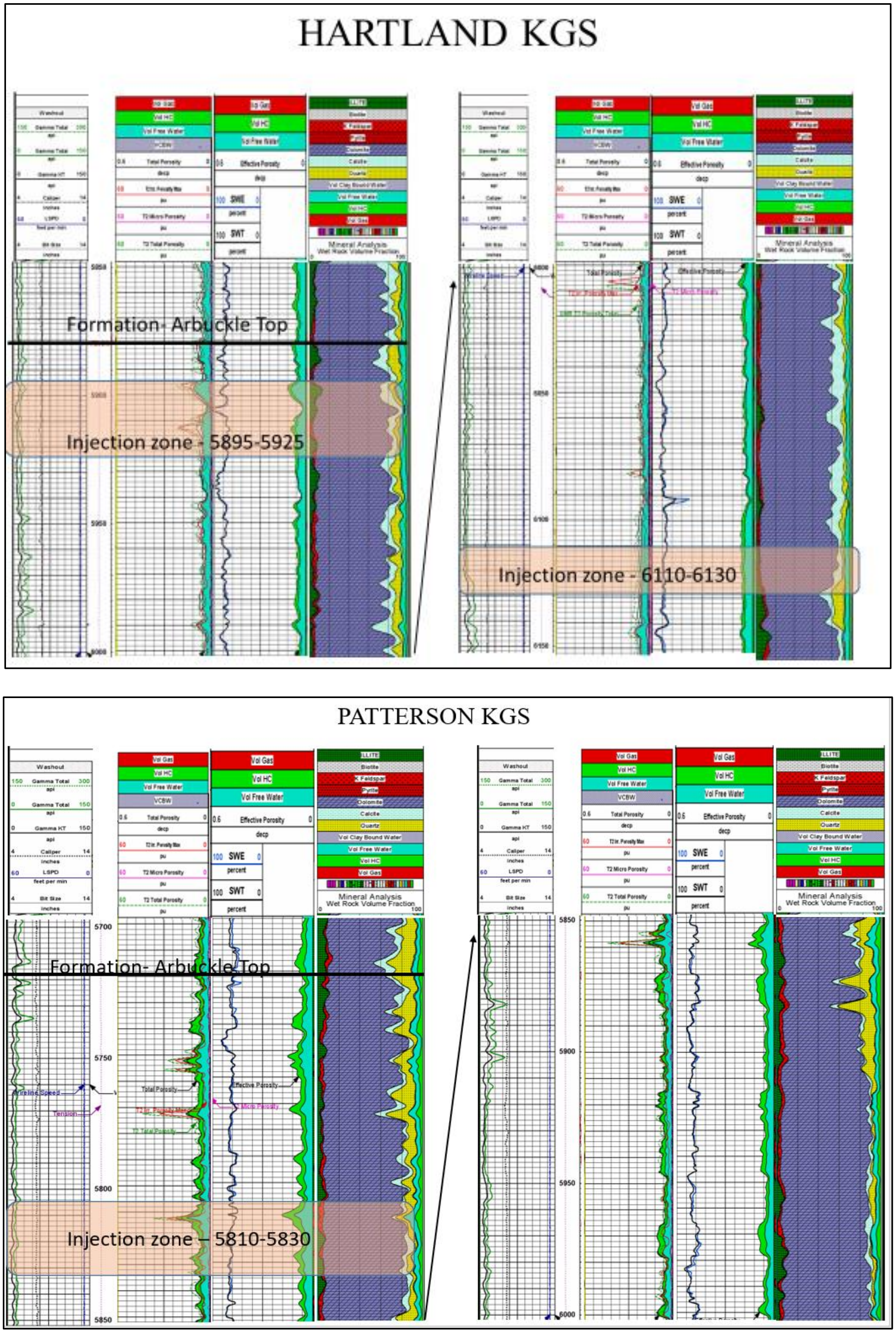


Figure 13. Porosity profile in the Upper Arbuckle at the Hartland KGS 6-10 and Patterson KGS 5-25 wells.

Hartland KGS 6-10 Well

As shown in Figure 14, the step rate test in the Upper Arbuckle at the Hartland KGS 6-10 well was conducted on July 29, 2020. The pressure gage was placed in the well at a depth of 5,935 feet and recorded a baseline pressure of 1,584.7 psi. Starting at 11:25 am, brine was gradually injected until the water levels reached the top of the well. With water levels at the top of the well, the bottomhole pressure decreased, which could be due to dislodging of formation material in the vicinity of the well.

The step rate test was initiated at 11:03 am with the injection of brine at a rate of 2.5 bpm. Brine injection rates were increased to 5.0, 10.0, and finally 15.0 bpm to complete the test. The bottom hole pressure decreased throughout the 2.5 bpm injection step, but began to increase when the injection rate increased to 5.0 bpm. The bottom hole pressures increased during the remaining injection steps. A pressure response was also observed in the Upper Arbuckle at pressure gage in the Patterson during the Upper Arbuckle step rate test at the Hartland KGS 6-10 well. As shown in Figure 14, there was no pressure variation noted in the Patterson well

At 12:10 pm, the well was shut-in and water levels allowed to recover. As can be noted from figures 14 and 15, there was an immediate drop in pressure to values recorded during the start of the SRT and corresponding to pressures observed with water levels at the top. Thereafter the recovery (under gravity) was slower and continued till pre-injection water levels and pressures were reached.

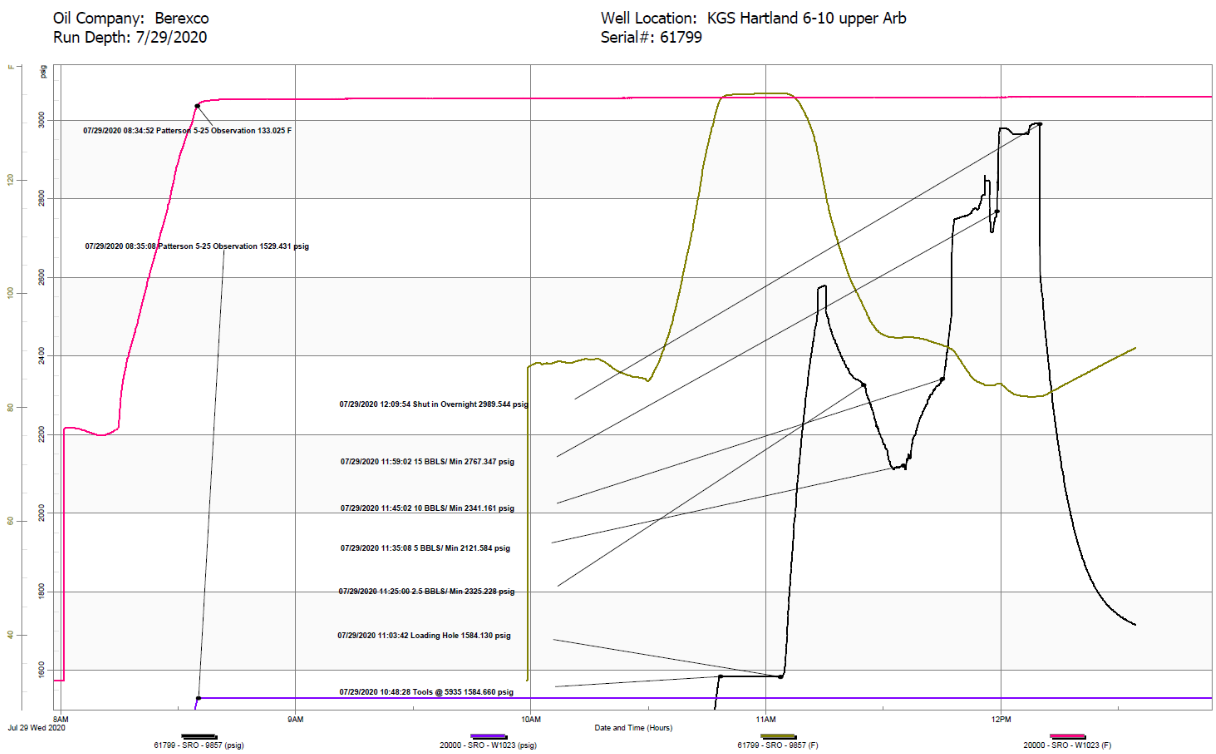


Figure 14. Downhole gage pressures recorded at the Hartland and Patterson wells during the Step Rate Test in the Upper Arbuckle at the Hartland KGS 6-10 well. Also shown are the surface injection pressures and the downhole temperatures at the two sites.

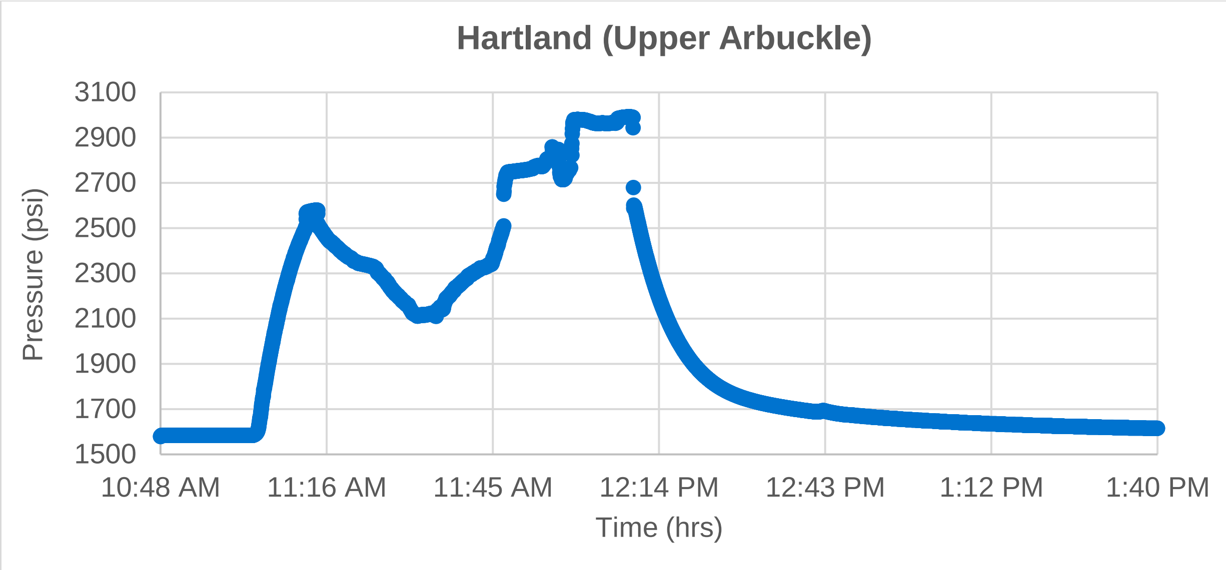


Figure 15. Gage pressure recorded as a function of the injection rate during the Hartland KGS 6-10 well Upper Arbuckle Step Rate Test.

Patterson KGS 5-25 Well

As shown in Figures 16 and 17, the step rate test in the Upper Arbuckle at the Patterson KGS 5-25 well was conducted on July 28, 2020. The pressure gage was inserted to a depth of 5,935 feet and recorded a baseline pressure of 1,526.9 psi. Starting at 9:50 am, brine was gradually injected into the well until the water level reached the top of the well and was allowed to stabilize. With water levels at the top of the well, the bottomhole pressure decreased, which could be due to dislodging of some formation materials in the vicinity of the well.

The step rate test was initiated at 10:43 am with the injection of brine at a rate of 2.5 bpm. The formation took the brine without any increase in pressure suggesting that approximately 2.5 bpm is needed to maintain water levels at the top of the well. Injection was increased thereafter to 5,10, and 15 bpm during which the formation appears to have fractured at approximately 4,490 psi. This corresponds to a fracture gradient of approximately 0.74 psi/ft which is in the high end of the range observed for this parameter at other sites in the area. During the step rate test in the Upper Arbuckle at the Hartland KGS 6-10 well, a pressure response was also observed in the in the Upper Arbuckle at the Patterson. As shown in Figure 16, there was no pressure variation noted in the Patterson well.

At 11:23 am, the well was shut-in and water levels were allowed to recover. As can be noted from Figures 16 and 17, there was an immediate decrease in pressure values to levels recorded at the start of the step rate test and corresponding to pressures observed with water levels at the top of the well. Thereafter, the pressure recovery (under gravity) was slower and continued until pre-injection water levels and pressures were reached.

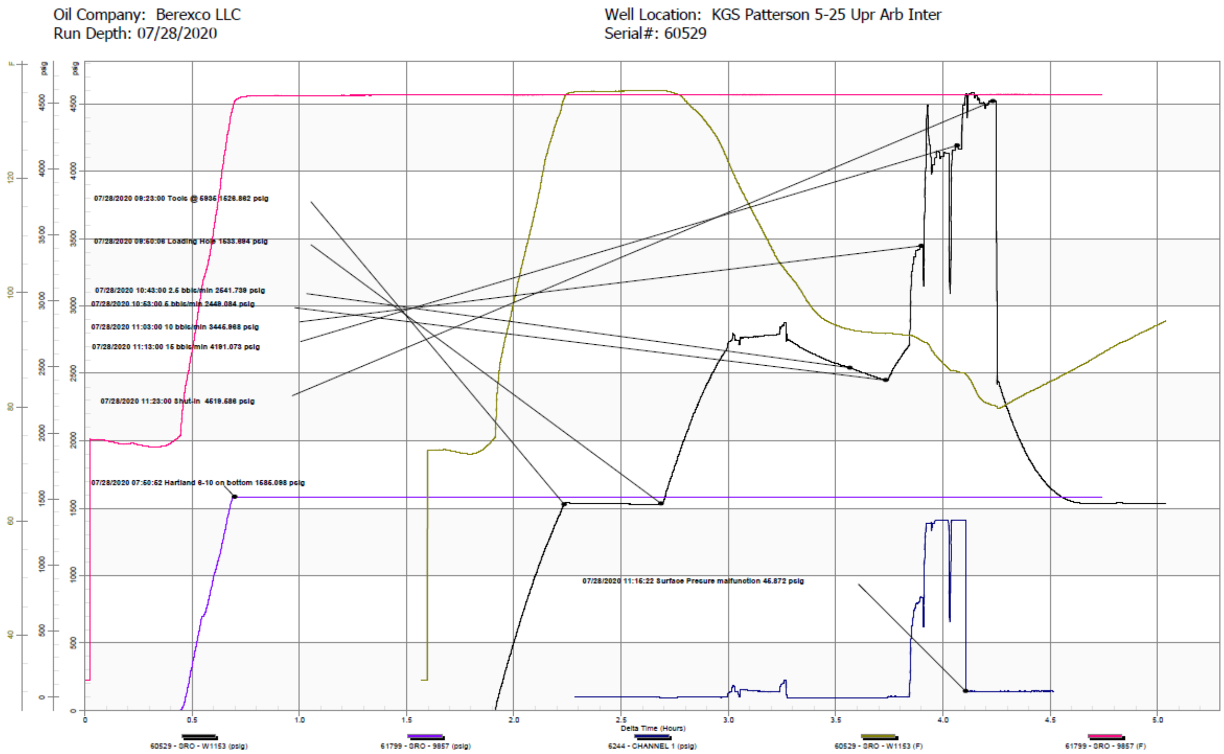


Figure 16. Downhole gage pressures recorded at the Hartland and Patterson wells during the Step Rate Test in the Upper Arbuckle at the Patterson KGS 5-25 well. Also shown are the surface injection pressures and the downhole temperatures at the two sites.

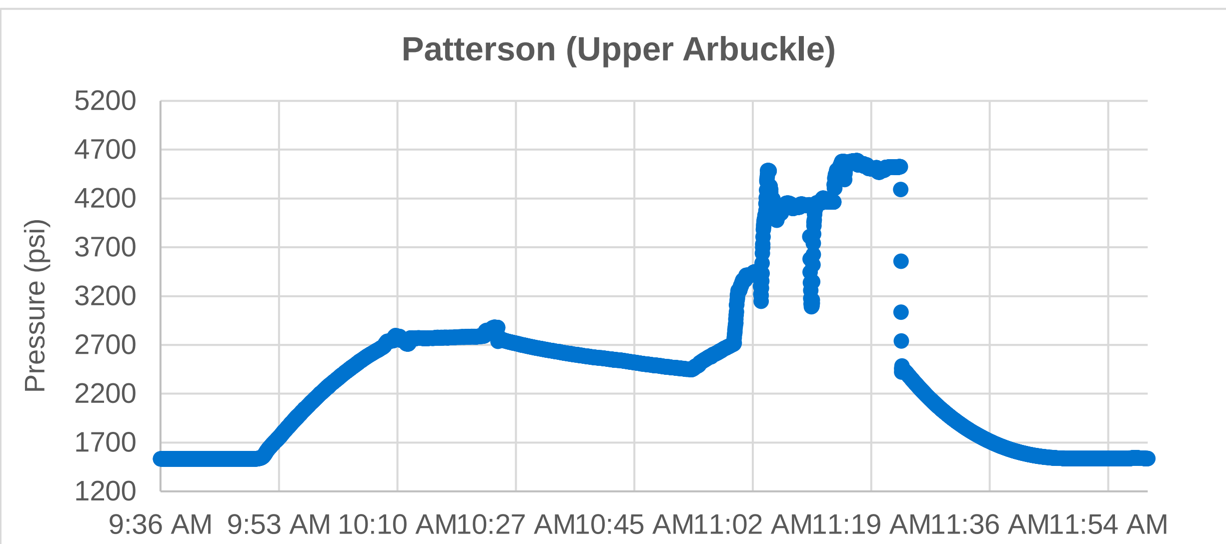


Figure 17. Gage pressure recorded as a function of the injection rate during the Step Rate Test in the Upper Arbuckle at the Patterson KGS 5-25 well.

Middle Arbuckle

There are several medium to high porosity intervals in the Middle Arbuckle at both sites as can be inferred from Figure 18. The intervals from 6,110-6,130 feet at the Hartland KGS 6-10 well and 6,040-6,060 feet at the Patterson KGS 5-25 well were perforated for injection in the Middle Arbuckle. Based on a review of the porosity logs, there is sufficient amount of porous formation at the Hartland and Patterson wells to accept fluids. Assuming a brine density gradient of approximately 0.45 psi/ft, the water level in the wells is approximately 2,488 feet at the Hartland KGS 6-10 well and 2,314 feet at the Patterson KGS 5-25 well (Table 5). The large difference in depth to water in the two wells (with perforation in the Middle Arbuckle) is counter to what was observed for other formations in which the water levels in both wells were fairly similar.

Table 5. Middle Arbuckle step rate test parameters at the Hartland and Patterson injection wells

Well	Ground elevation (ft)	Gage Depth (ft)	Gage Pressure (psi)	Water Depth in well (ft, bls)	Maximum Injection Rate (bpm)	Maximum Recorded Pressure (psi)	Maximum Induced Pressure (psi)
Hartland KGG 6-10	3,262	6,131	1,639.1	2,488	15	2,850	1,211
Patterson KGS 5-25	3,317	6,070	1,690.6	2,314	15	3,600	1,909

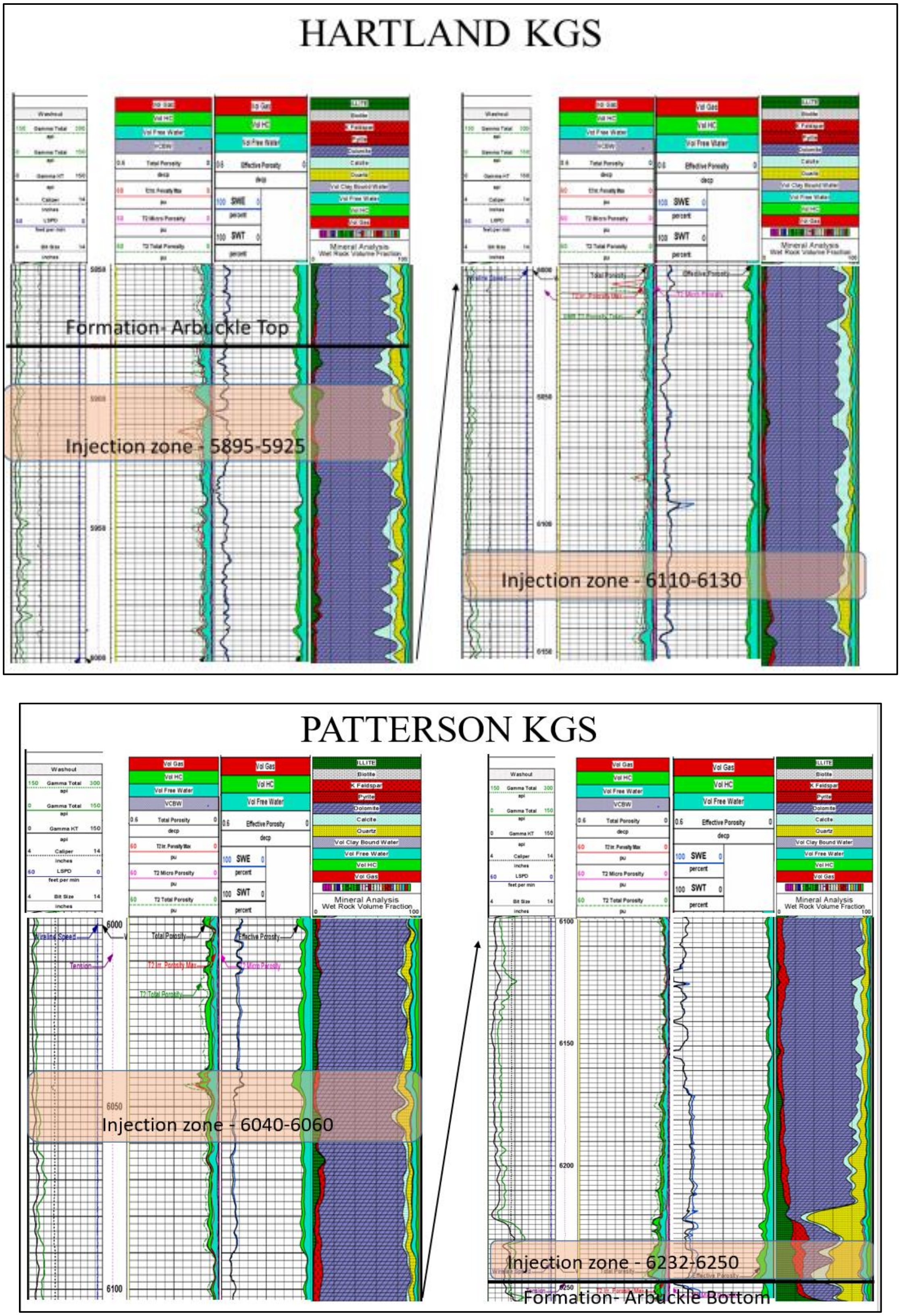


Figure 18. Porosity profile in the Middle Arbuckle at the Hartland and Patterson wells.

Hartland KGS 6-10 well

As shown in Figure 19, the step rate test was conducted in the Middle Arbuckle at the Hartland KGS 6-10 well on July 23, 2020. The pressure gage was set to a depth of 6,131 feet and recorded a baseline pressure of 1,639.1 psi. Starting at 09:26 am, brine was gradually injected into the well to allow water levels to rise to the top of the well. As was observed during the step rate test in the Upper Arbuckle at the Patterson KGS 5-25 well, the bottomhole pressure decreased during loading of the well which could be due to dislodging of some formation in the vicinity of the well.

Injection of brine at a rate of 2.5 bpm commenced at 10:28 am but the pressure continued to decrease until the injection rate was increased to 5 bpm. Injection was increased thereafter to 10 and 15 bpm. During the step rate test in the Middle Arbuckle at the Hartland KGS 6-10 well, a pressure response was observed in the Middle Arbuckle at the Patterson well. As shown in Figure 19, there was no pressure variation noted in the Patterson well.

At 11:13 am, the well was shut-in and water levels were allowed to recover. As can be noted from Figures 19 and 20, there was an immediate decrease in pressure levels to values recorded at the start of the step rate test when the water level was at the top of the well. Thereafter, the pressure recovery (under gravity) was slower and continued until pre-injection (baseline) water levels and pressures were reached.

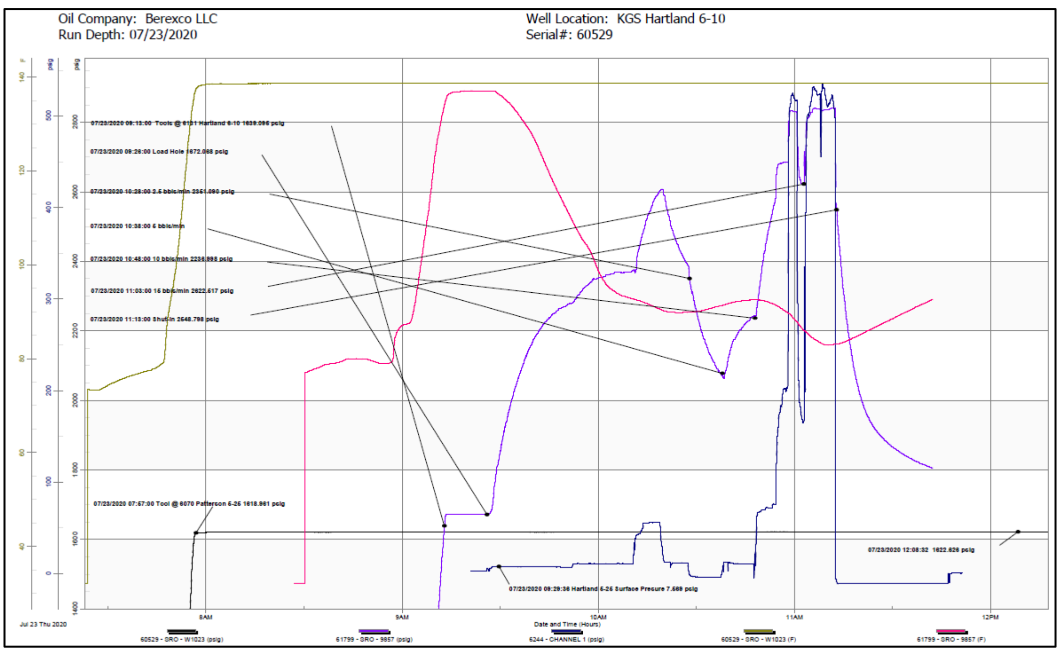


Figure 19. Downhole gage pressures recorded at the Hartland and Patterson wells during the Step Rate Test in the Middle Arbuckle at the Hartland KGS 6-10 well. Also shown are the surface injection pressures and the downhole temperatures at the two sites.

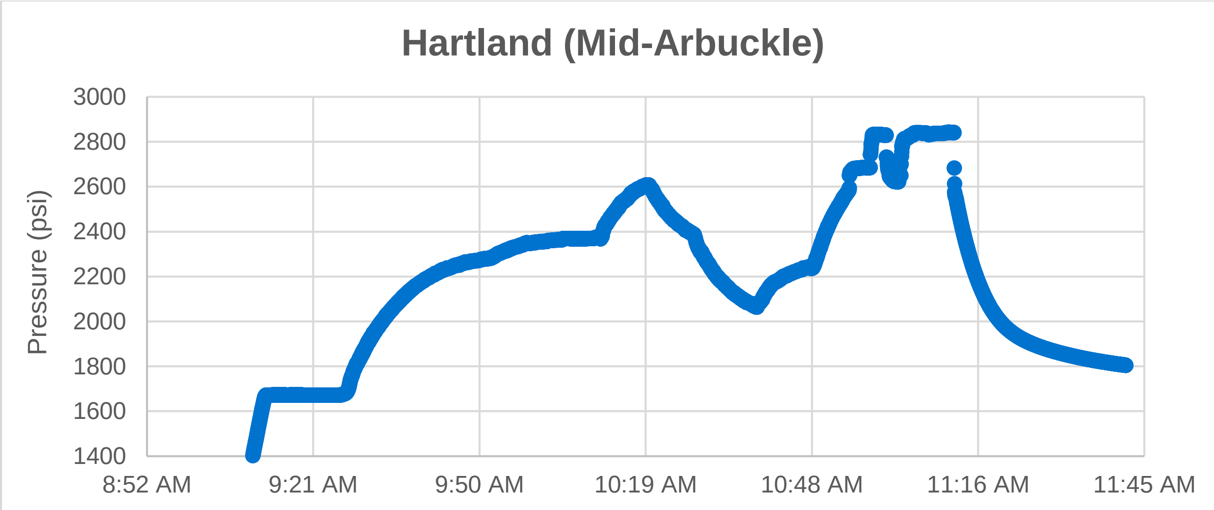


Figure 20. Gage pressure recorded as a function of the injection rate during the Step Rate Test in the Middle Arbuckle at the Hartland KGS 6-10 well.

Patterson KGS 5-25 Well

As shown in Figure 21, the step rate test was conducted in Middle Arbuckle at the Patterson KGS 5-25 well on July 24, 2020. The pressure gage was inserted in the well to a depth of 6,070 feet and recorded a baseline pressure of 1,690 psi. Starting at 12:54 pm, brine was gradually injected into the well to allow water levels to rise to the top of the well. Injection of 2.5 bpm commenced at 1:32 pm and thereafter the injection rates increased in a stepwise manner at 10-minute intervals to 15 bpm. During the step rate test in the Middle Arbuckle at the Patterson KGS 5-25 well, a pressure response was observed in the Middle Arbuckle in the Hartland well. As shown in Figure 21, there was no pressure variation noted in the Hartland well.

After completing the injection phase of the testing, the well was shut in and the water levels allowed to recover. As can be noted from Figures 21 and 22, there was an immediate decrease in pressure. Following the immediate decrease in pressure, the recovery (under gravity) was slower and continued until pre-injection water levels and baseline pressures were reached.

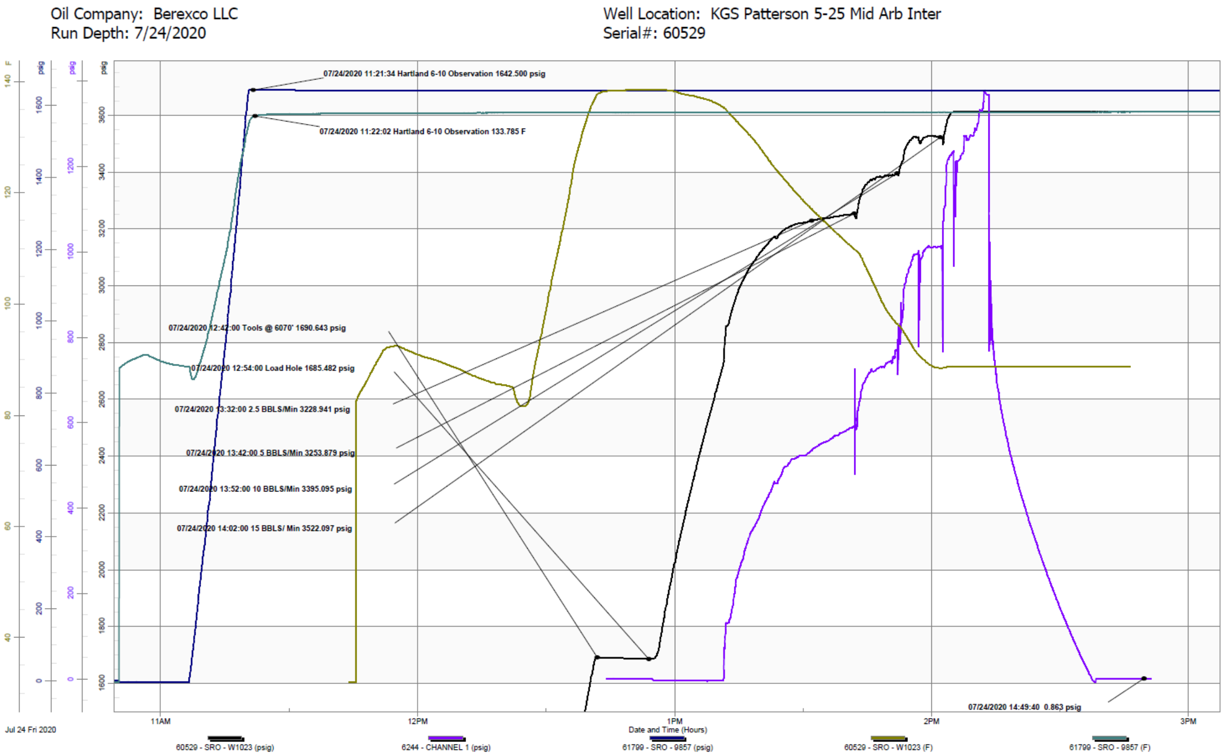


Figure 21. Downhole gage pressures recorded at the Hartland and Patterson wells during the Step Rate Test in the Middle Arbuckle at the Patterson KGS 5-25 well. Also shown are the surface injection pressures and the downhole temperatures at the two sites.

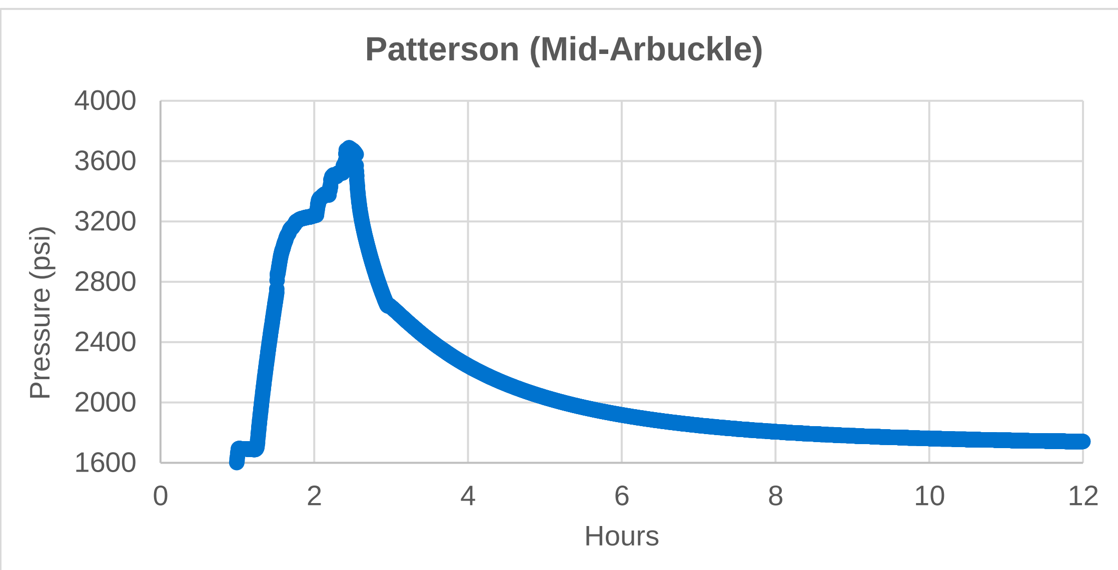


Figure 22. Gage pressure recorded as a function of the injection rate during the Patterson middle Arbuckle Step Rate Test.

Lower Arbuckle

There are medium porosity intervals in the Lower Arbuckle at both sites as can be inferred from the electronic log data in Figure 23. The intervals from 6,284-6,300 feet at the Hartland KGS 6-10 well and 6,232-6,250 feet at the Patterson KGS 5-25 well were perforated for injection in the Lower Arbuckle. Based on a review of the porosity logs, there is a sufficient amount of porous formation at the Hartland and Patterson wells to accept injected fluids. Assuming a brine density gradient of approximately 0.45 psi/ft, the water levels in the wells are approximately 2,413 feet at the Hartland KGS 6-10 well and 2,480 feet at the Patterson KGS 5-25 well (Table 6).

Table 6. Lower Arbuckle SRT data in the Hartland and Patterson injection wells

Well	Ground elevation (ft)	Gage Depth (ft)	Gage Pressure (psi)	Water Depth in well (ft, bls)	Maximum Injection Rate (bpm)	Maximum Recorded Pressure (psi)	Maximum Induced Pressure (psi)
Hartland KGS 6-10	3,262	6,320	1,758	2,413	15	3,725	1,967
Patterson KGS 5-25	3,317	6,260	1,701	2,480	15	3,295	1,594

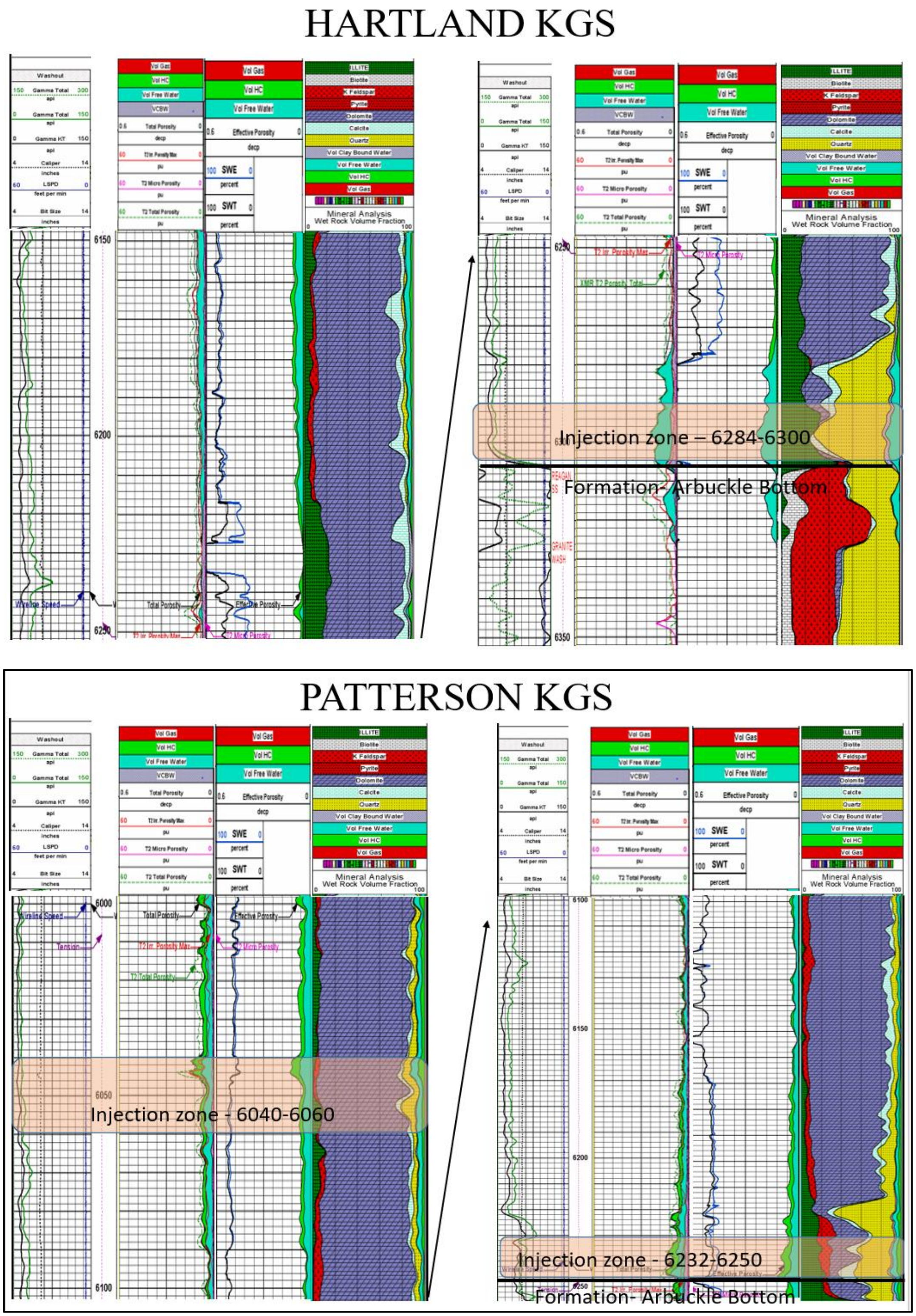


Figure 23. Porosity profile in the Lower Arbuckle at the Hartland and Patterson wells.

Hartland KGS 6-10 well

As shown in Figure 24, the step rate test in the Lower Arbuckle at the Hartland KGS 6-10 well was conducted on July 18, 2020. The pressure gage was placed in the well at a depth of 6,320 feet and a baseline pressure of 1,758 psi was recorded (Table 6). Starting at 10:38 am, brine was gradually injected into the well to bring the water level to the top of the well. The step rate test was initiated at 11:16 am with the injection of brine at a rate of 2.5 bpm. The injection rate was increased in a stepwise manner every 10 minutes to 5, 10, and finally 15 bpm. During the step rate test in the Lower Arbuckle at the Hartland KGS 6-10 well, a pressure response was measured in the in the Lower Arbuckle at the Patterson well. As shown in Figure 24, there was no pressure variation noted in the Patterson well over the duration of the step rate test.

At 11:58 am, the well was shut-in and water levels were allowed to recover. As can be noted from Figures 24 and 25, there was an immediate reduction in pressure values to levels recorded at the start of the step rate test. After the water levels achieved pre-test conditions, the pressure recovery (under gravity) was slower and until baseline water levels and pressures were reached.

In order to determine the hydraulic connectivity between the Arbuckle Group and the Upper Granitic Basement, tests were conducted in the Hartland well on July 14 and 15, 2020 in which brine was injected in the Lower Arbuckle and pressures were measured in the Upper Granite. During both tests, there was no hydraulic communication observed between these two formations.

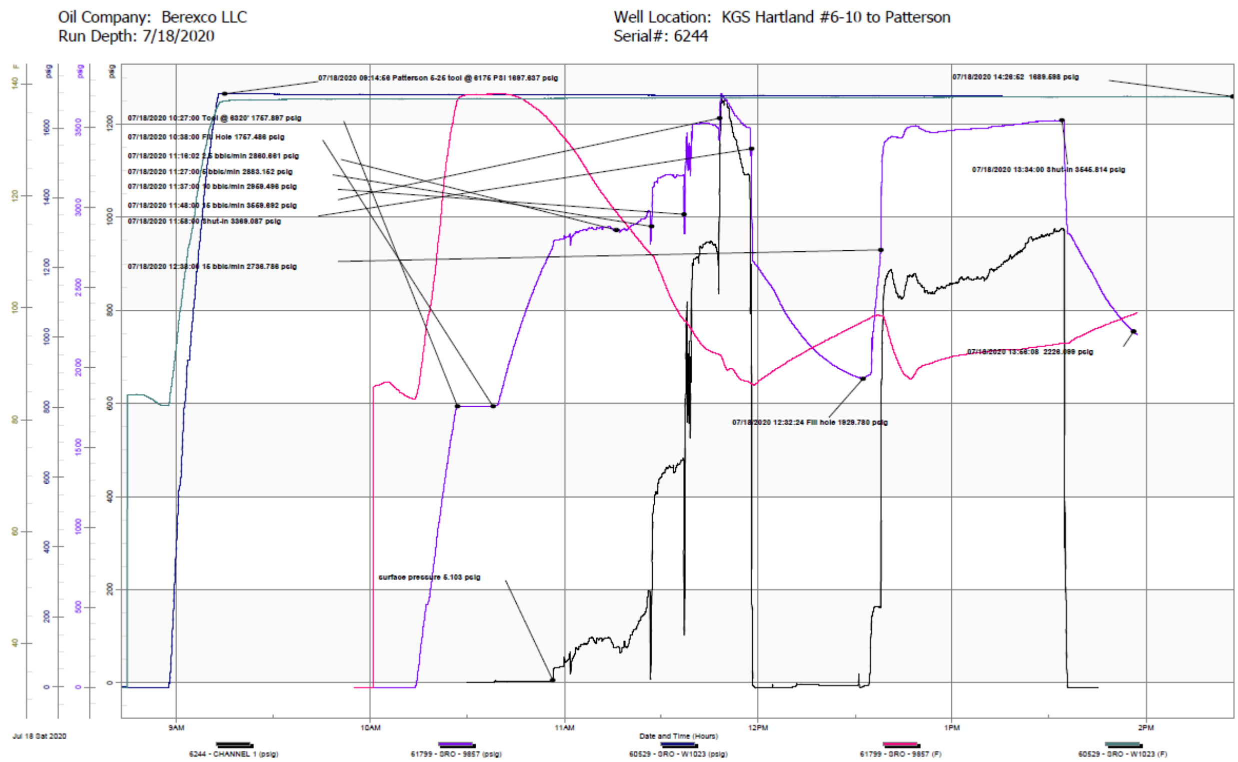


Figure 24. Downhole gage pressures recorded at the Hartland and Patterson wells during the Step Rate Test in the Lower Arbuckle at the Hartland KGS 6-10 well. Also shown are the surface injection pressures and the downhole temperatures at the two sites.

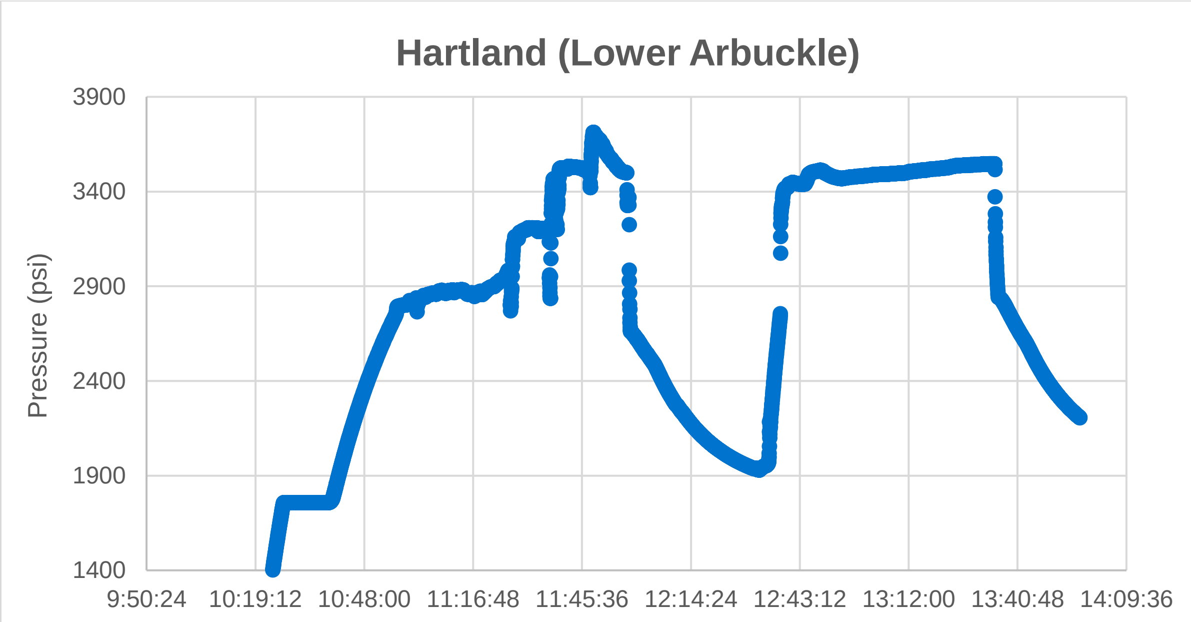


Figure 25. Gage pressure recorded as a function of the injection rate during the step rate test in the Lower Arbuckle at the Hartland KGS 6-10 well.

Patterson KGS 5-25 Well

As shown in Figure 26, the step rate test in the Lower Arbuckle at the Patterson KGS 5-25 well was conducted on July 17, 2020. A pressure gage was set in the well at a depth of 6,260 feet and measured a baseline pressure of 1,701 psi (see Table 6). Starting at 9:11 am, brine was injected gradually into the well to allow water levels to rise to the top the well. Injection of 2.5 bpm of commenced at 9:51 am to start the step rate test, and was increased to 5, 10 and 15 bpm in 10-minute intervals. , A pressure response in the Lower Arbuckle in the Patterson well was also observed during the step rate test in the Lower Arbuckle at the Hartland KGS 6-10 well.. As shown in Figure 26, there was no pressure variation noted in the Patterson well throughout the step rate test at the Hartland KGS 6-10 well.

At 10:31 am, the well was shut-in and water levels were allowed to recover. As can be noted from Figures 26 and 27, that an immediate decrease in pressure was measured following the shut in of the well. Under gravity flow, the pressure recovery was slower and continued until baseline water levels and pressures were achieved.

In order to determine the hydraulic connectivity between the Arbuckle Group and the Upper Granitic Basement, tests were conducted on July 15, 2020 in which brine was injected into the Lower Arbuckle while pressures were monitored in the Upper Granite. There was no hydraulic communication observed between these two formations during the test.

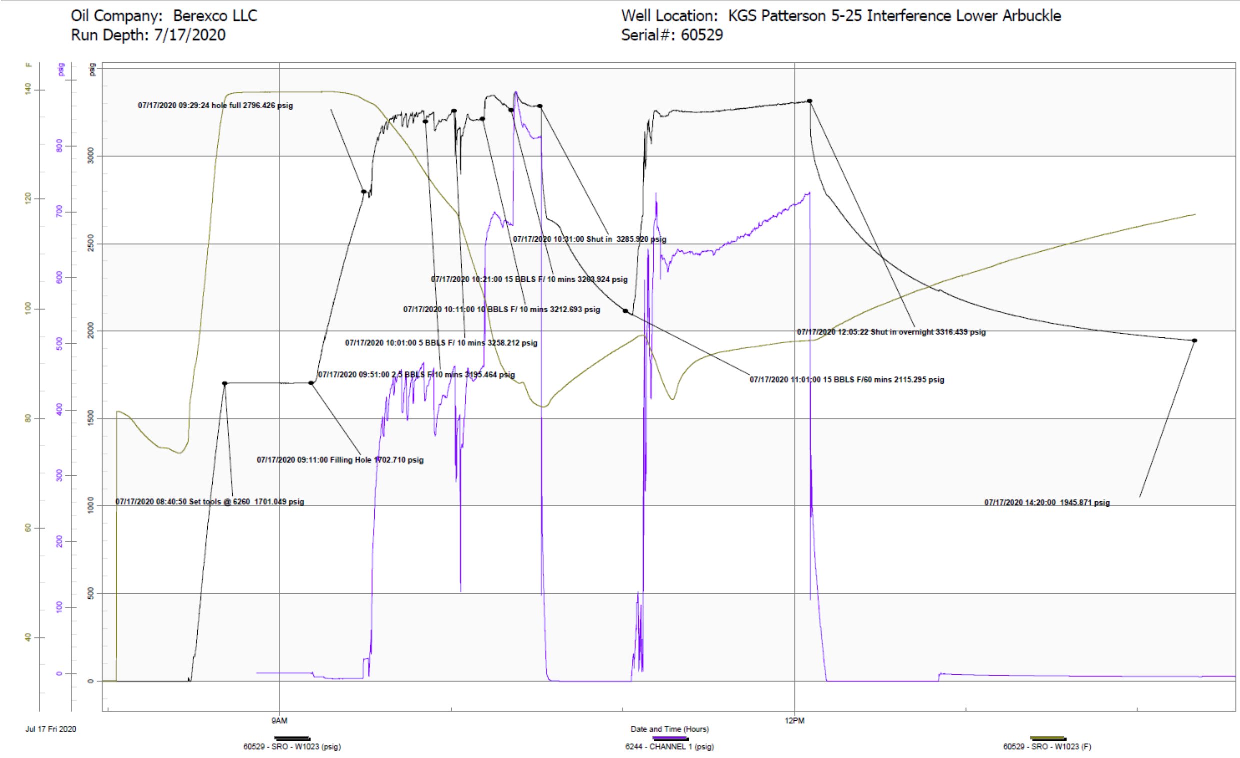


Figure 26. Downhole gage pressures recorded at the Hartland and Patterson wells during the Step Rate Test in the Lower Arbuckle at the Patterson KGS 5-25 well. Also shown are the surface injection pressures and the downhole temperatures at the two sites.

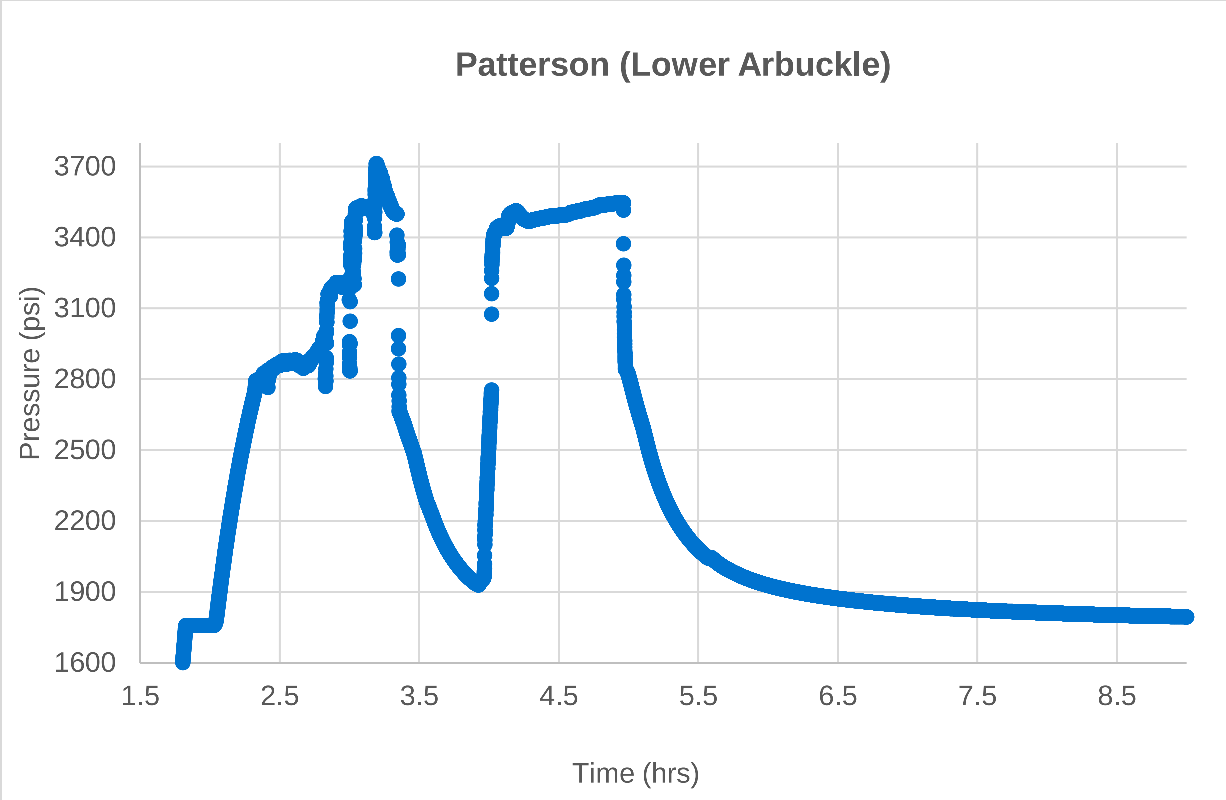


Figure 27. Gage pressure recorded as a function of the injection rate during the Hartland lower Arbuckle Step Rate Test.

Upper Granite

The porosity estimates derived from the MRI log are presented in Figures 28 for both the Hartland and Patterson wells. There is a marked difference in the formation texture at the two sites. The Upper Granite at the Hartland KGS 6-10 well appears to be quite porous while virtually no porosity is noted at the Patterson KGS 5-25 well. This observation is supported by the injection tests conducted at both sites in the intervals noted in Figure 28. Injection of brine into the Upper Granite was possible at the Hartland KGS 6-10 well, but was not possible at the Patterson KGS 5-25 well. Assuming a brine density gradient of approximately 0.45 psi/ft, the water level in the Upper Granite of the Hartland well was calculated to be at a depth of is approximately 3,604 feet below surface, resulting a pressure gradient of only 0.2 psi/ft (Table 7).

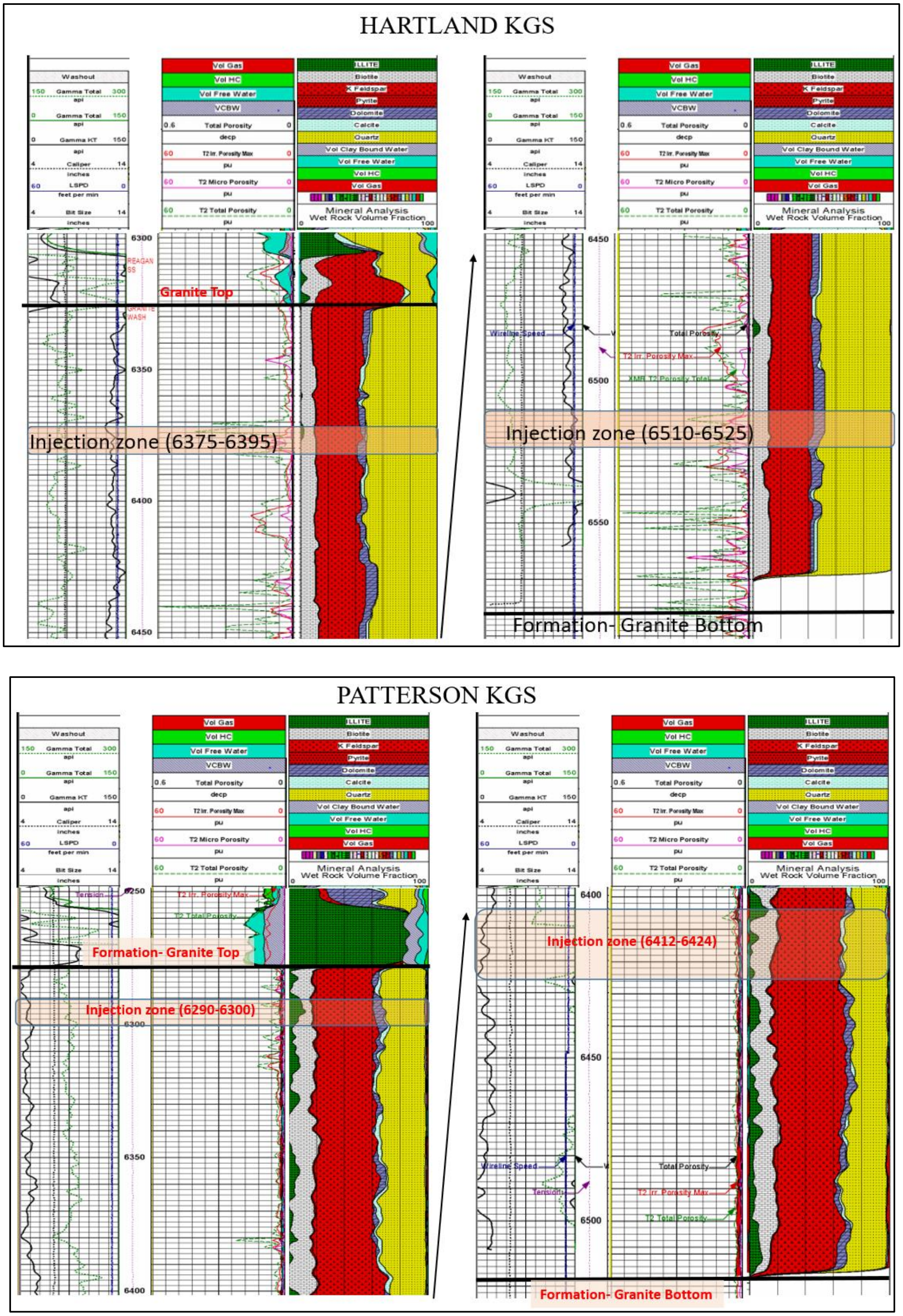


Figure 28. Geophysical logs from the granitic basement at the Hartland and Patterson wells showing the injection intervals.

Hartland KGS 6-10 Well

As shown in Figure 29, the step rate test in the Upper Granite of the Hartland well was conducted on July 14, 2020. The pressure gage was place in the well at a depth of 6,400 feet and recorded baseline a pressure of 1,258.3 psi. This results in an extremely low pressure gradient of 0.2 psi/ft. Brine was injected gradually into the well until the water level reached the top of the well. The step rate test in the Upper Granite was completed with an initial brine injection rate of 1 bpm and increasing the rate in 1 bpm increments every 10 mins. The maximum brine-injection rate achieved in the Upper Granite was 6 bpm. At end of the 6 bpm loading rate period, the well was shut-in and fluid levels were allowed to recover as noted in Figures 29 and 30.

Table 7 Upper Granite SRT data at the Hartland KGS 6-10 well.

Well	Ground elevation (ft)	Gage Depth (ft)	Gage Pressure (psi)	Water Depth in well (ft, bls)	Maximum Injection Rate (bpm)	Maximum Recorded Pressure (psi)	Maximum Induced Pressure (psi)
Hartland KGS 6-10	3,262	6,400	1,258	3,604	6 bpm	3,530	2,272

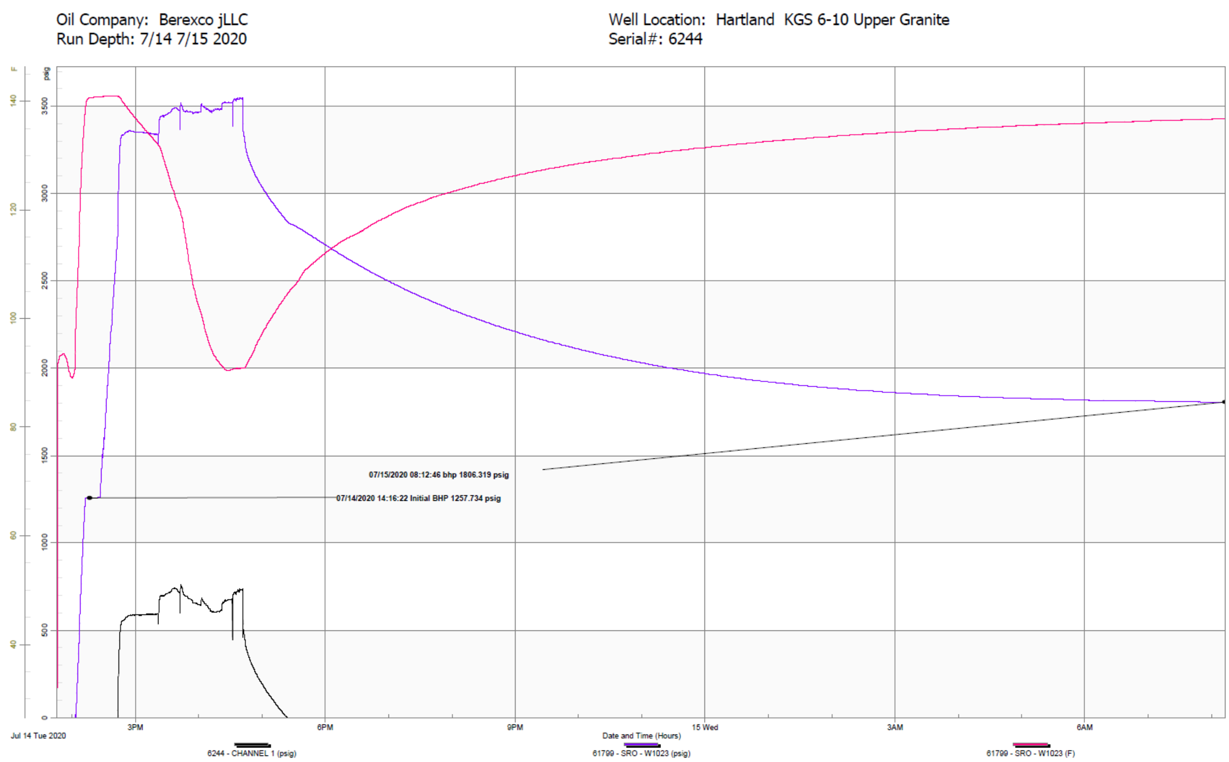


Figure 29. Downhole gage pressures recorded at the Hartland and Patterson wells during the Step Rate Test in the Upper Granite at the Hartland KGS 6-10 well. Also shown are the surface injection pressures and the downhole temperatures at the two sites.

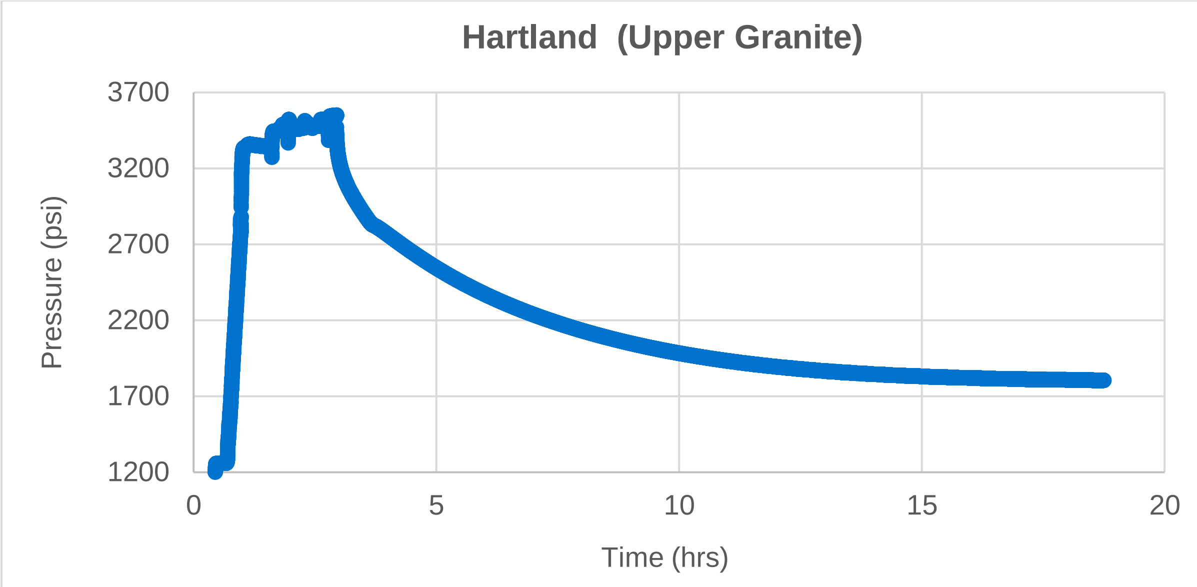


Figure 30. Gage pressure recorded as a function of the injection rate during Step Rate Test in the Upper Granite at the Hartland well.

Patterson KGS 5-25 Well

The Patterson KGS 5-25 well was perforated at depths between 6,290-6,300 feet in the Upper Granite to inject brine into the formation. The formation was virtually impermeable and all attempts to inject the fluid failed. This was expected as a review of the electronic log data indicated that porosity is minimal to absent throughout the penetrated depth of the granite at the Patterson KGS 5-25 well (Figure 28).

Lower Granite

The porosity data derived from the MRI log are presented in Figure 28 for both the Hartland and Patterson wells. As noted above, there is a marked difference in the formation texture at the two sites. The granite at the Hartland stie appears to be quite porous while virtually no porosity is noted at the Patterson KGS 5-25 well. No fluid could be injected at the Patterson KGS 5-25 well. Assuming a brine density gradient of approximately 0.45 psi/ft, the water level in the Hartland well is approximately 2,303 feet below surface (Table 8) in the Lower Granite, with a pressure gradient of only 0.29 psi/ft.

Table 8. Lower Granite SRT data at the Hartland Injection site.

Well	Ground elevation (ft)	Gage Depth (ft)	Gage Pressure (psi)	Water level Depth in well (ft, bls)	Maximum Injection Rate (bpm)	Maximum Recorded Pressure (psi)	Maximum Induced Pressure (psi)
Hartland KGS 6-10	3,262	6,526	1,900	2,303	12	3,742	1,842

Hartland KGS 6-10

As shown in Figure 31, the step rate test was conducted in the Lower Granite of the Hartland KGS 6-10 well on July 9, 2020. A pressure gage was inserted in the well to a depth of 6,526 feet and recorded a baseline pressure of 1,900.3 psi. The well was then gradually filled to the top with brine. Injection of brine at a rate of 2.5 bpm commenced at 12:10 pm. The injection rate was increased to 5, 10, and 15 bpm at 10-minute intervals to complete the test (Figure 27). A fairly linear increase in pressure as a function of the injection rate was noted. There was no inferred fracturing of the formation during the test. At 1:51 pm, the well was shut-in and water levels allowed to recover (Figures 31 and 32).

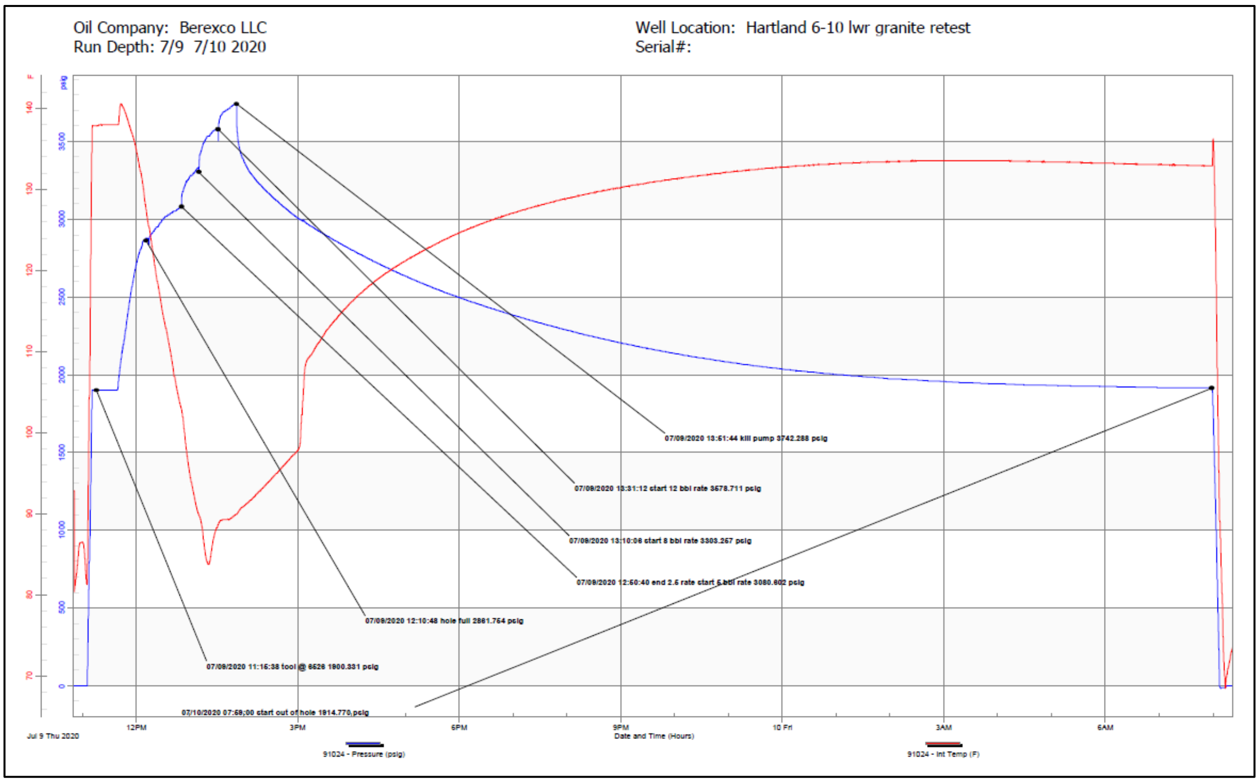


Figure 31. Downhole gage pressures recorded at the Hartland and Patterson wells during the Step Rate Test in the lower granite at the Patterson KGS 5-25 well. Also shown are the surface injection pressures and the downhole temperatures at the two sites.

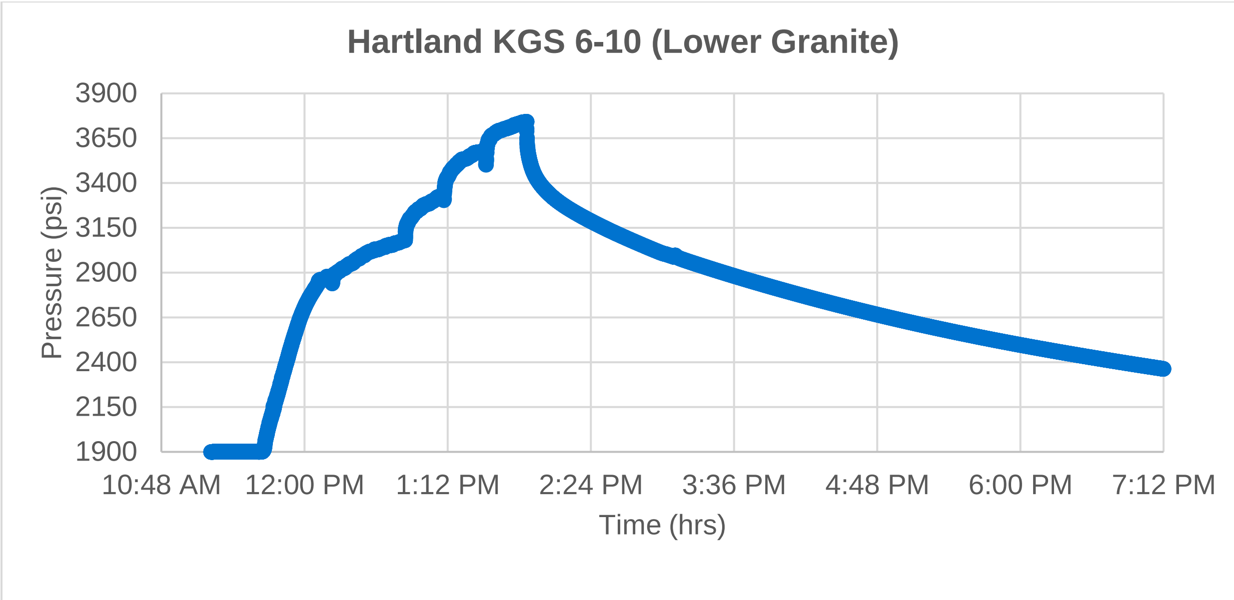


Figure 32. Gage pressure recorded as a function of the injection rate during the Step Rate Test in the Lower Granite at Patterson well.

Patterson KGS 5-25 Well

The Patterson KGS 5-25 well was perforated between 6,412-6,424 feet in the Lower Granite in order to inject brine into the formation. As expected, the formation was virtually impermeable and all attempts to inject the fluid failed. The MRI log data indicated that porosity in the Lower Granite of the Patterson well was extremely low (see Figure 28).

Patterson KGS 5-25 Core Analysis

Core Data Collected

A total of 840 feet of core was planned to be cut from the caprock and reservoir intervals of the storage complex with 17 coring runs of varying length between 15 and 61 feet each. Sample intervals include the Atoka (caprock), Morrow (caprock and reservoir), Meramecian (reservoir and baffle), Osage (reservoir), Kinderhook (baffle), Viola (reservoir), Simpson (reservoir), Arbuckle (reservoir), Reagan/Granite Wash (bottom barrier), and the Precambrian (bottom barrier). Implementation resulted in the collection of 778 feet of 4-inch-diameter whole core. Whole cores were cut into 3-ft sections, packaged, and transported to the Premier Oilfield Group Laboratories for core analyses. Table 9 summarizes the whole core acquired from Patterson KGS #5-25.

Table 9. Summary of whole core sections from Patterson KGS #5-25 well.

Core Number	Formation or Group	Acquisition Depth* (ft)	Core Length Acquired (ft)
1	Atoka	4,615–4,676	61
2	Atoka, Morrow	4,676–4,736	60
3	Morrow	4,736–4,796	60
4	Morrow, Meramecian	4,880–4,897	17
5	Meramecian	4,897–4,957	60
6	Osage, Kinderhook	5,380–5,439	59
7	Viola	5,640–5,670	30
8	Simpson, Arbuckle	5,670–5,719	49
9	Arbuckle	5,780–5,811	31
10	Arbuckle	5,811–5,826	15
11	Arbuckle	5,959– 6,019	60
12	Arbuckle	6,019–6,042	23
13	Arbuckle	6,042–6,102	60
14	Arbuckle	6,102–6,162	60
15	Arbuckle, Reagan/Granite Wash	6,162–6,222	60
16	Reagan/Granite Wash	6,222–6,273	51
17	Precambrian	6,278–6,300	22
		Total footage acquired:	**778**

Core Depth Correction

Core-depth correlation was performed by Premier Oilfield Group (Houston, TX) to correlate the core depth to the depth measured during the wireline logging. A spectral gamma ray log was measured on the core to correlate the core depth to the wellbore gamma ray log. Cores were then re-marked with corrected depths before sampling, slabbing, photographing, or analyzing the core.

Core Data Analysis

Qualitative descriptions of the Patterson KGS 5-25 core were generated and integrated with well logs, mineralogical data, petrographic images, and quantitative core analysis data. Routine core data statistics for each zone are shown in Table 10. Correlations between core and well log data in the Patterson KGS #5-25 well were extrapolated to the Hartland KGS #6-10 well where core data was not collected.

Table 10: Statistics for routine core analysis data (measured at reservoir confining pressures) for each lithological zone identified in the Patterson KGS #5-25 core.

Zone	No. of Samples	Grain Density (g/cm^3)			Helium Porosity (%BV)			Air Permeability (mD)		
		Min.	Max.	Mean	Min.	Max.	Mean	Min.	Max.	Mean
Atoka	10	2.64	2.84	2.72	0.8	11.4	3.9	0.001	1.19	0.13
Morrow Sand	4	2.63	2.64	2.64	19.9	21.0	20.2	921	1410	1165
Meramec	7	2.69	2.7	2.7	0.6	14.5	3.8	0.001	7.55	1.58
Osage	5	2.68	2.69	2.69	3.7	5.4	4.5	0.009	0.338	0.108
Viola 1	2	2.83	2.83	2.83	5.1	9.7	7.4	0.062	10.1	5.06
Viola 2	5	2.81	2.83	2.82	2.5	12.1	8.4	0.001	0.093	0.0288
Upper Arbuckle	6	2.77	2.83	2.81	1.9	10.0	6.0	0.001	13.0	4.68
Lower Arbuckle 1	4	2.82	2.83	2.82	1.8	4.1	2.8	0.001	0.695	0.177
Lower Arbuckle 2	5	2.82	2.83	2.83	7.6	11.3	9.2	0.04	3.83	1.62
Lower Arbuckle 3	12	2.81	2.85	2.82	1.0	9.4	5.3	0.001	0.98	0.186
Lower Arbuckle 4	6	2.72	2.82	2.79	2.8	8.7	5.8	0.013	0.683	0.194
Lower Arbuckle 5	1	2.73	2.73	2.73	3.9	3.9	3.9	0.065	0.065	0.065
Granite Wash	5	2.67	2.73	2.71	4.6	13.7	9.6	0.023	14.6	4.59
Granite	8	2.57	2.74	2.64	0.0	19.2	8.5	0.001	24.2	7.52

Atoka Shale

Cores 1 and 2-3 collected 136 ft of continuous core from the Early Carboniferous (Pennsylvanian System) strata of the Atoka from 4615-4751 ft.

The Atoka interval was characterized by black shale with variable calcite cementation and skeletal debris (Figure 33). The background sedimentology is a black shale. A modification of this facies includes open framework skeletal material (e.g., crinoids, brachiopods, fusilinids), often these skeletal intervals have uniform or at least very low diversity. At 4657 ft, a 15-cm stromatoporoid head dominates the core. Another modification of this facies includes variable calcite cementation, probably from sub-seafloor diagenetic processes. Syneresis cracks filled with calcite cement are present in some cemented intervals. In some intervals, this cement occurs as nodules, while in others it occurs as complete cementation of the core. A third modification of the basic black shale facies is at what appears to be where significant surfaces (e.g., subaerial exposure breccias or hardgrounds) occur in core. This facies was where fractures were most abundant (common).

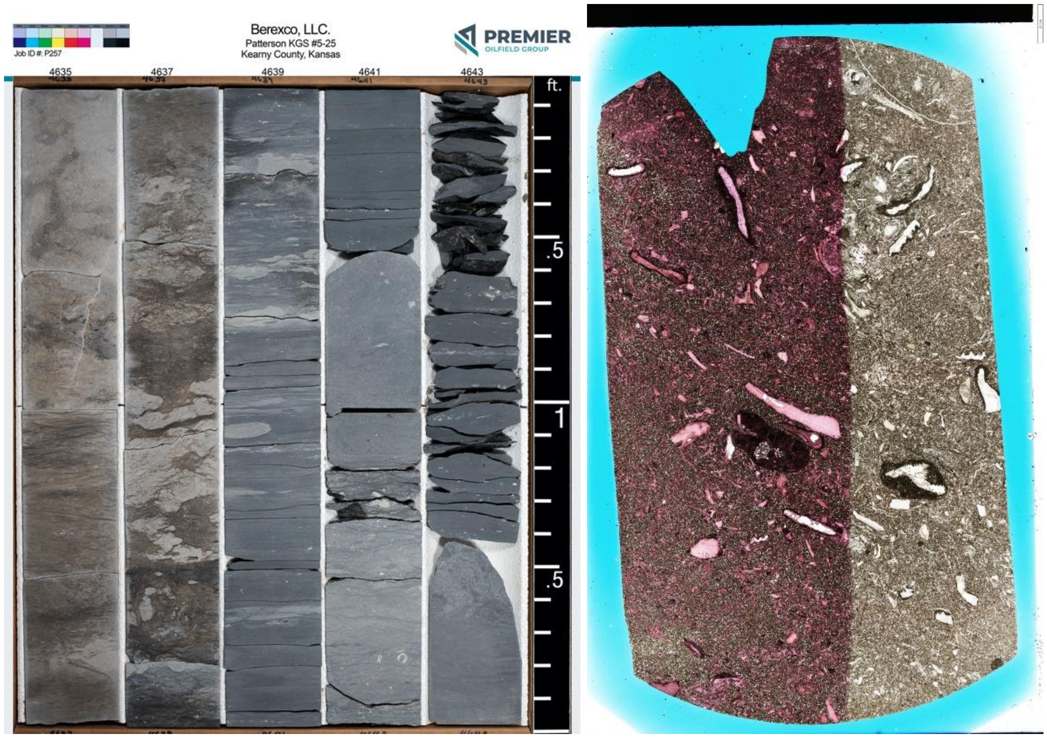


Figure 33: Representative core from the Atoka Interval showing black shale facies (4643-4644.5ft), calcite-cemented black shale facies (4641-5-4643 ft) and exposure surface-modified black shale (4635-4639 ft). Representative thin section image of fossiliferous black shale from 4700.10 ft. Half of the slide has been dyed pink with Alizarin Red-S to show presence of calcite.

Porosity ranged from 0.8-11.4%, permeability ranged from 0.001 to 1.2 mD (Table 11), and the median pore throat radius was 3.73 nm measured on a sample collected from a depth of 4700.10 ft (Figure 34), suggesting high seal quality. Grain density ranged from 2.64 g/cm^3 in the pure black shale to 2.71-2.75 g/cm^3 in the highly calcite-cemented intervals. Mineralogical analysis (Table 12) showed high dolomite content suggesting that some grain densities that appear to reflect calcite (~2.7 g/cm^3) may be mixes of clay/quartz (~2.6 g/cm^3) and dolomite (~2.8 g/cm^3).

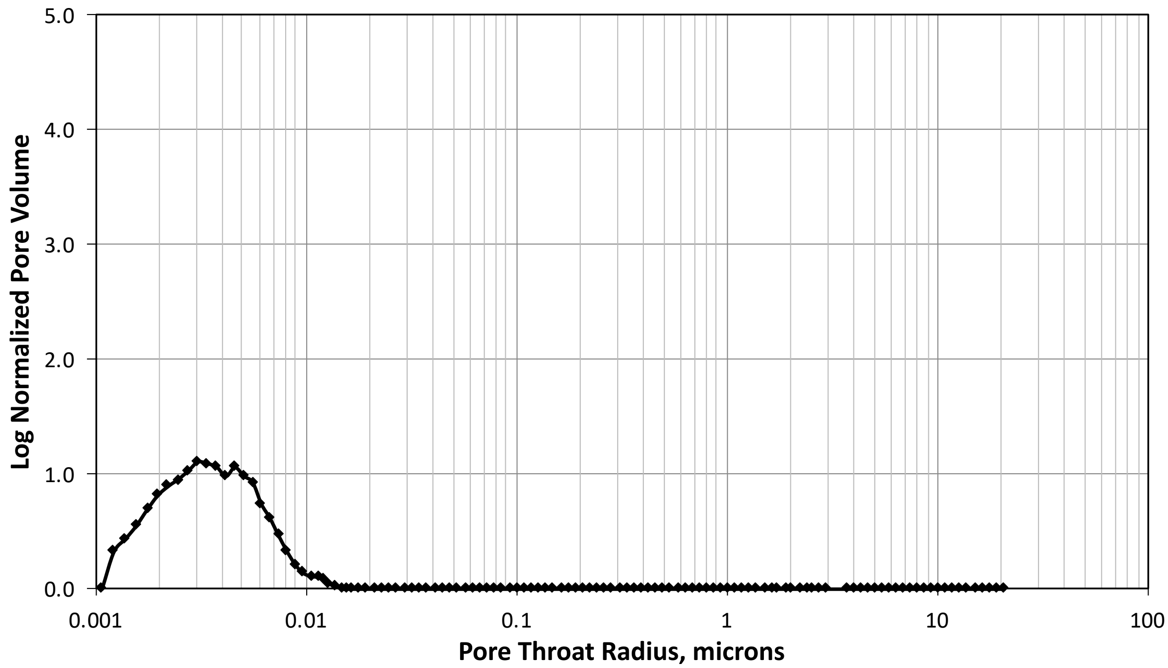


Figure 34: Pore throat size distribution from mercury intrusion capillary pressure measurements on end trim from core plug taken at 4700.10 ft. Median pore throat radius was 3.73 nm.

Table 11. Atoka routine core analysis data for core plug samples.

Sample Depth (ft)	Lithology	Porosity (%)	Permeability (mD)	Grain Density (g/cm^3)	Water Sat. (%)	Oil Saturation (%)
4624.65	Limestone	0.8	0.001	2.71	91.4	0
4634.15	Shaley Limestone	3.6	0.001	2.75	78.2	0
4649.85	Limey Shale	1.8	0.068	2.69	93.9	0
4671.75	Limey Shale	8.7	0.002	2.69	94.5	0
4679.10	Shaley Dolostone	11.4	1.191	2.84	84.1	0
4689.85	Shaley Limestone	1.3	0.002	2.70	81.8	0
4701.20	Shaley Limestone	4.0	0.001	2.71	97.3	0
4712.30	Shaley Limestone	1.3	0.001	2.72	98.1	0
4728.30	Shale	4.3	0.032	2.64	86.5	0
4740.15	Shaley Limestone	1.9	0.001	2.71	83.8	0

Table 12. Relative abundances of minerals in Atoka from XRD.

Sample Depth (ft)	Lithology	Quartz (wt%)	Feldspars (wt%)	Calcite (wt%)	Dolomite (wt%)	Clay Group (wt%)
4634.15	Shaley Limestone	19.2	2.5	40.6	35.5	1.6
4701.20	Shaley Limestone	17.4	3.0	60.1	11.7	7.0

Morrow Sand

Core 3 recovered approximately 26 feet of nearly continuous core from the Early Carboniferous (Pennsylvanian System) Morrow-age sandstone from 4751-4777 ft (Figure 35). Analysis of the Morrow Sandstone indicated that the formation is porous, medium-grained quartz sandstone with interbeds of cm-thick black shale with pyrite. Some intervals were cross-bedded and some horizontally bedded. The interval was pervasively oil-stained. The basal 4 ft of the Morrow sand was coarse-grained.

Porosity ranged from 19.9 to 21.0%, permeability ranged from 921 to 1410 mD (Table 13) , and the median pore throat radius measured in a sample from a depth of 4761.15 ft was 15.9 µm (Figure 36), suggesting excellent reservoir quality. Grain density ranged from 2.63 to 2.64 g/cm^3 indicating a dominantly quartz mineralogy, which was confirmed with the mineralogical analysis (Table 14).

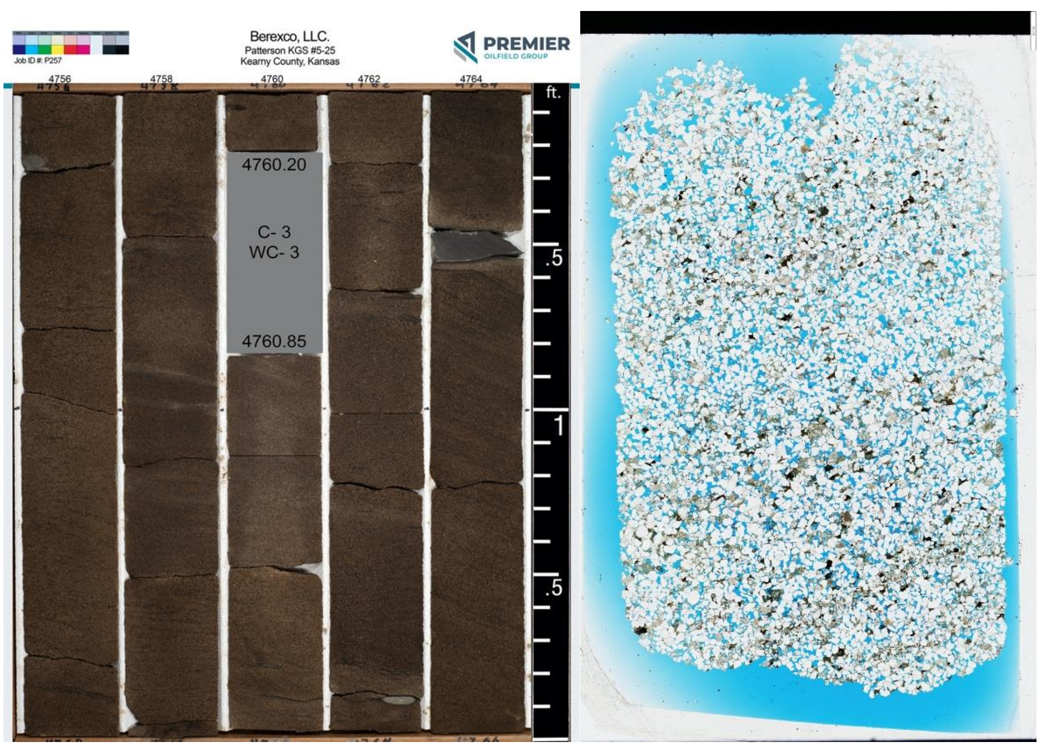


Figure 35: A) Representative core from the Morrow Sand interval showing oil-stained, cross-bedded sandstone. B) Representative thin section image of Morrow Sand from 4760.95 ft.

Table 13. Morrow Sand routine core analysis data for core plug samples.

Sample Depth (ft)	Lithology	Porosity (%)	Permeability (mD)	Grain Density (g/cm^3)	Water Sat. (%)	Oil Saturation (%)
4755.95	Sandstone	20.0	1017	2.63	58.0	18.2
4760.95	Sandstone	21.0	921	2.63	67.9	16.1
4766.95	Sandstone	20.0	1410	2.64	50.8	26.5
4771.4	Sandstone	19.9	1309	2.64	50.4	23.7

Table 14. Relative abundances of minerals in Morrow Sand from XRD.

Sample Depth (ft)	Lithology	Quartz (wt%)	Feldspars (wt%)	Calcite (wt%)	Dolomite (wt%)	Clay Group (wt%)
4761.0	Sandstone	81.8	14.0	0.0	0.0	3.1

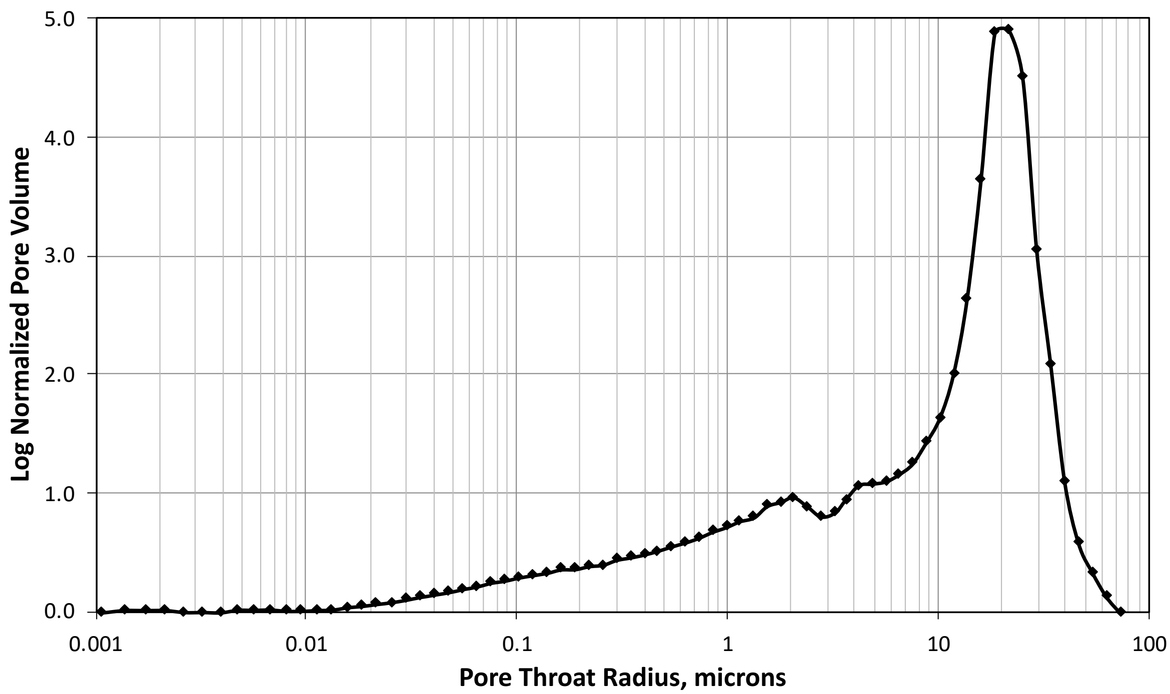


Figure 36: Morrow Sand pore throat size distribution from mercury intrusion capillary pressure measurements on end trim from core plug taken at 4761.15 ft. Median pore throat radius was 15.9 µm.

Morrow Shale

Core 3 recovered approximately 21 ft of continuous core consisting of interbedded shale and shaley limestone from the Morrow Stage (Figure 37). The lime packstones were interbedded with green/black shales with rare fractures. No petrographic or core analysis data were collected in this interval, but the lithologies and their interbedded nature suggests high seal quality.

Figure 37: Representative core from the Morrow Shale interval showing black shale with calcite-cemented interval from 4787-4789.5 ft.

Meramec

Cores 4-5 recovered ~77 ft of continuous core from the Meramec Stage of the Mississippian (early Carboniferous) System from 4880-4957 ft (Figure 38). The Meramec section is characterized mostly by fine grained skeletal lime grainstones. Some intervals were cross-bedded. The basal portion (below 4933 ft) is unfractured, but stylolites are present. Above 4933 ft, wispy stylolites and open fractures are present. Rare coarse quartz sand was visible in thin sections around 4890 ft. The only visible pores were common interparticle pores occurring between 4940 and 4950 ft. A thin black shale was present at about 4884 ft. Thin conglomeratic/brecciated intervals occurred at 4955 ft, 4915 ft, 4895 ft, and 4886 ft. Green silty mudrock filled touching vugs from 4907 to 4923 ft.

Porosity ranged from 0.6 to 1% and permeability from <0.001 to 0.002 mD in the upper part of the core, while in the interval with visible interparticle pores, porosity ranged from 2.5 to 14.5%, permeability from 0.002 to 7.5 mD (

Table 15), and the median pore throat radius measured in a sample from a depth of 4890.00 ft was 0.021 µm (Figure 39), indicating good seal quality. Grain densities ranged from 2.69 and 2.71 g/cm^3 indicating a dominantly calcite mineralogy with some dilution by quartz, which was borne out by mineralogical analysis (Table 16).

Figure 38: A) Representative core from the Meramec interval showing crossbedded skeletal grainstone. B) Representative thin section image of Meramec from 4890.00 ft.

Table 15. Meramec routine core analysis data for core plug samples.

Sample Depth (ft)	Lithology	Porosity (%)	Permeability (mD)	Grain Density (g/cm^3)	Water Sat. (%)	Oil Saturation (%)
4889.95	Limestone	0.6	0.001	2.69	85.9	0
4890.85	Limestone	0.6	0.002	2.70	93.0	0
4898.85	Limestone	0.9	0.001	2.70	63.3	0
4905.90	Limestone	1.0	0.001	2.70	77.7	0
4940.00	Limestone	6.6	3.533	2.69	32.9	0
4946.75	Limestone	14.5	7.551	2.70	51.5	0
4951.85	Limestone	2.5	0.002	2.69	65.8	0

Table 16. Relative abundances of minerals in Meramec from XRD.

Sample Depth (ft)	Lithology	Quartz (wt%)	Feldspars (wt%)	Calcite (wt%)	Dolomite (wt%)	Clay Group (wt%)
4890.0	Limestone	6.7	1.6	90.8	0.0	0.7
4905.9	Limestone	7.5	1.8	89.4	0.2	1.0

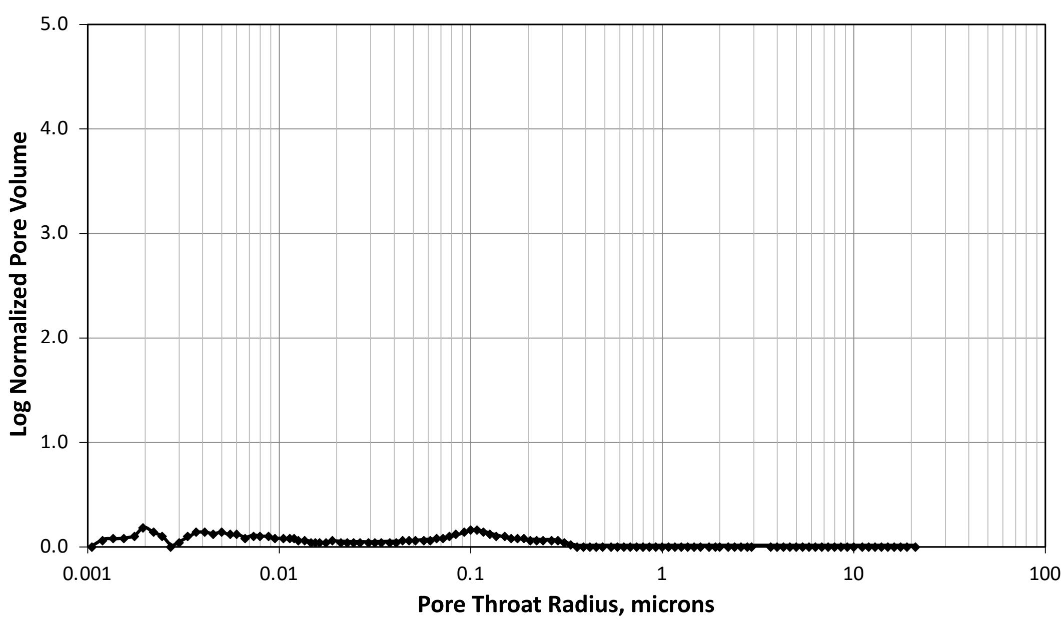


Figure 39: Meramec pore throat size distribution from mercury intrusion capillary pressure measurements on end trim from core plug taken at 4890.00 ft. Median pore throat radius was 21 nm.

Osage Stage

Core 6 recovered approximately 59 ft of continuous core from the Osage Stage of the Mississippian (early Carboniferous) System from 5380-5439 ft (Figure 40). The cored interval was topped by a tan cherty skeletal lime packstone with rare cement, fractures, and stylolites. At 5392 ft, lithology changed to coarse- to fine-grained skeletal lime grainstones with rare interparticle pores throughout. Stylolite character and abundance varied from common down to 5412 ft, abundant to 5422 ft, and wispy stylolites were common from that depth to the bottom of the cored Osage interval.

Porosity ranged from 3.7 to 5.4% and permeability from 0.009 to 0.34 mD (Table 17), and the median pore throat radius measured in a sample from a depth of 5430.10 ft was 0.26 µm (Figure 41) indicating good seal quality in the cored interval. Grain densities ranged from 2.56 and 2.60 g/cm^3. Mineralogical analysis suggests that calcite is the dominant component with minor admixtures of quartz and feldspar (Table 18). Chert was observed macroscopically in the upper part of the core (though no samples were taken for core analysis from this zone) and in thin section in lower parts of the core.

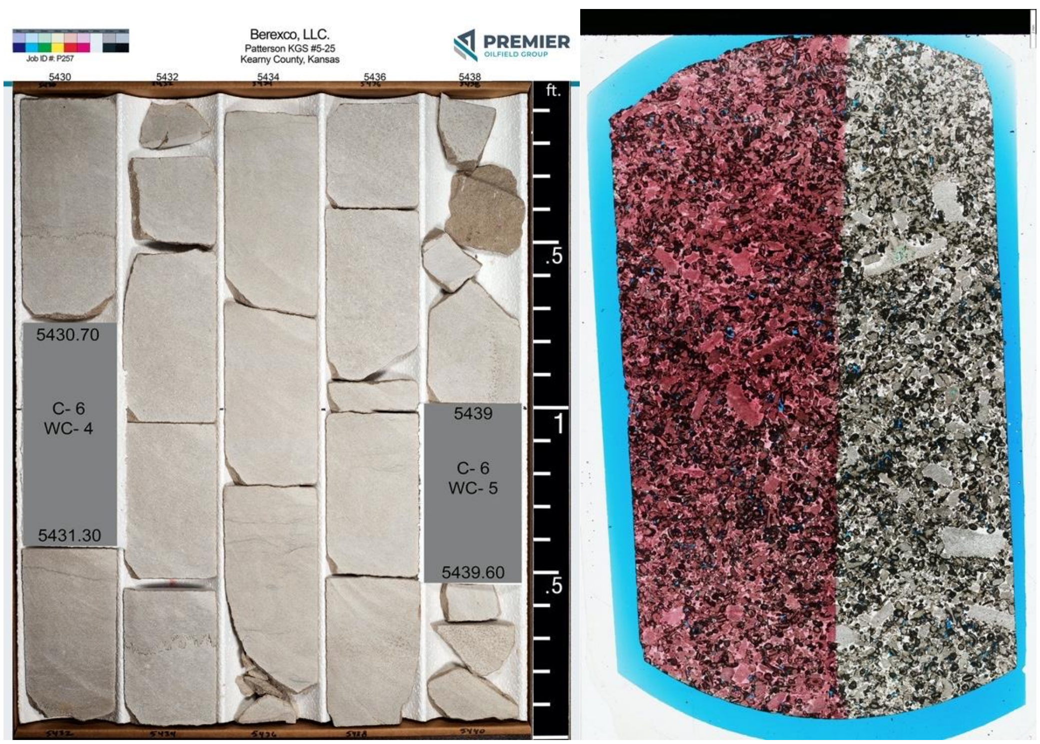


Figure 40: A) Representative core from the Osage interval showing crossbedded skeletal lime grainstone. B) Representative thin section image of Osage from 5430.50 ft.

Table 17. Osage routine core analysis data for core plug samples.

Sample Depth (ft)	Lithology	Porosity (%)	Permeability (mD)	Grain Density (g/cm^3)	Water Sat. (%)	Oil Saturation (%)
5398.90	Limestone	3.9	0.009	2.69	20.5	Tr
5408.55	Limestone	4.4	0.027	2.69	34.2	Tr
5426.00	Limestone	5.1	0.150	2.68	34.1	Tr
5430.50	Limestone	3.7	0.017	2.68	36.1	Tr
5438.80	Limestone	5.4	0.338	2.69	32.6	Tr

Table 18. Relative abundances of minerals in Osage from XRD.

Sample Depth (ft)	Lithology	Quartz (wt%)	Feldspars (wt%)	Calcite (wt%)	Dolomite (wt%)	Clay Group (wt%)
5430.5	Limestone	0.7	1.5	97.3	0.3	0.0

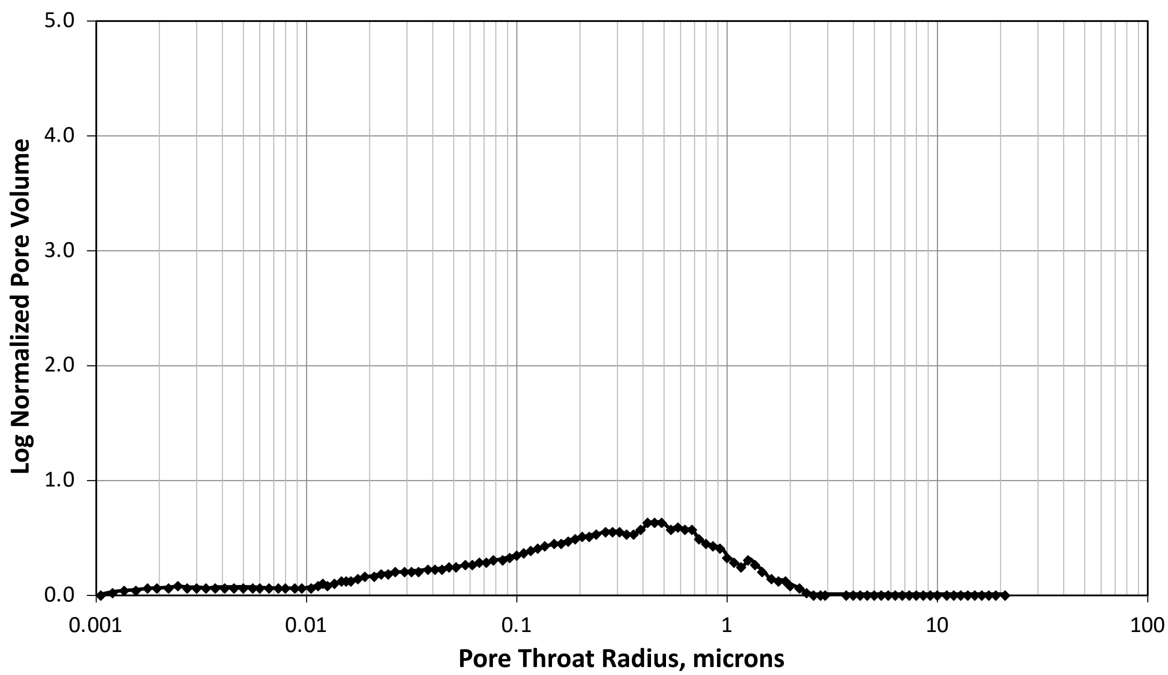


Figure 41: Osage pore throat size distribution from mercury intrusion capillary pressure measurements on end trim from core plug taken at 5430.10 ft. Median pore throat radius was 0.26 µm.

Viola Formation

Cores 7 and 8 recovered approximately 79 ft of continuous core from the Ordovician Viola Formation between 5640 and 5719 ft (Figure 42). At the top of Core 7 was a dolopackstone with large separate vug pores (up to 4 cm in diameter). Interparticle and separate vugs were common, however, touching vugs were rare. No fractures were observed and stylolites were common.

Figure 42: Representative core from the Upper Viola interval showing vuggy dolopackstone.

The base of Core 7 and into Core 8 consisted of a dolostone breccia, highly fractured with some fractures cemented with chert or calcite (Figure 43). Interparticle pores were rare but separate vug pores were common. Above this package was a dolomudstone interbedded with mudrock intervals 0.5-2 cm thick with rare touching vugs. Stylolites were rare.

In the upper section of the core (to a depth of 5651 ft), porosity ranged from 5.1 to 9.7%, permeability from 0.062 to 10.1 mD (Table 19), and the median pore throat radius measured in a sample from a depth of 5650.30 was 0.019 µm (Figure 44), suggesting good reservoir quality. Grain density ranged was 2.83 g/cm^3 for both samples from this interval indicating dolomite mineralogy, which was supported by mineralogical analysis (Table 20).

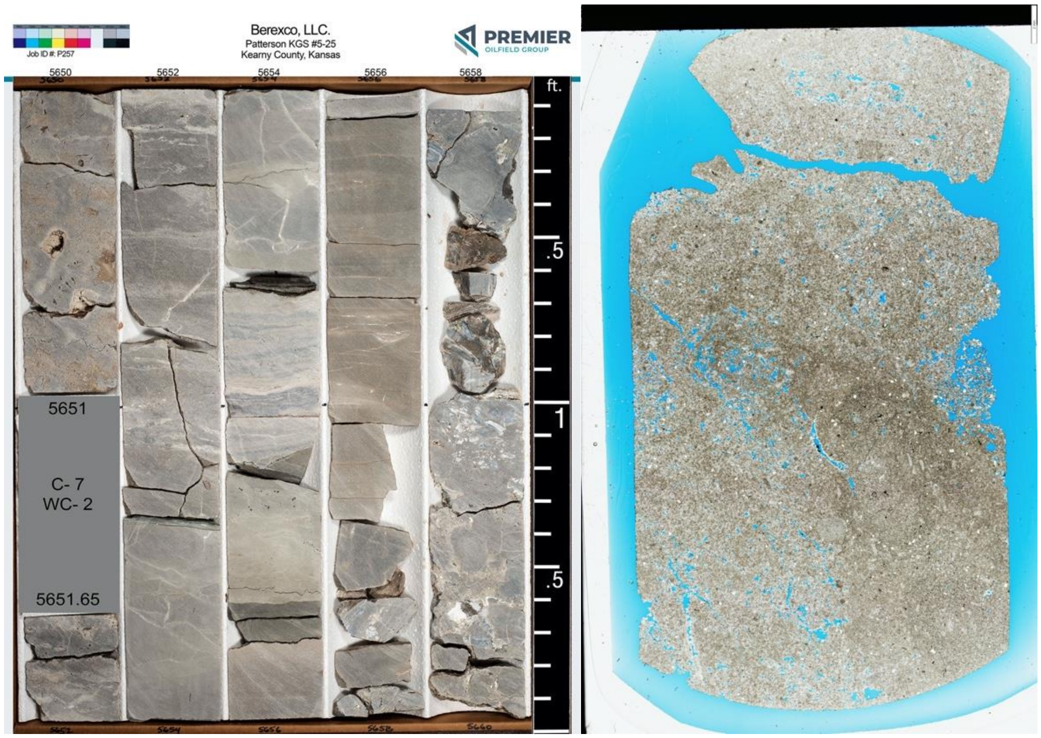


Figure 43: A) Representative core from the Upper Viola interval showing porous laminated dolostone. B) Representative thin section image of Upper Viola from 5650.90 ft.

Table 19. Viola routine core analysis data for core plug samples.

Sample Depth (ft)	Lithology	Porosity (%)	Permeability (mD)	Grain Density (g/cm^3)	Water Sat. (%)	Oil Saturation (%)
5649.00	Dolostone	5.1	0.062	2.83	63.7	0
5650.90	Dolostone	9.7	10.055	2.83	50.1	0
5666.80	Dolostone	2.5	0.001	2.82	93.4	0
5675.75	Dolostone	8.4	0.016	2.81	80.3	0
5683.70	Dolostone	11.6	0.093	2.83	84.7	0
5703.15	Dolostone	12.1	0.032	2.82	76.1	0
5717.20	Dolostone	7.5	0.002	2.81	81.1	0

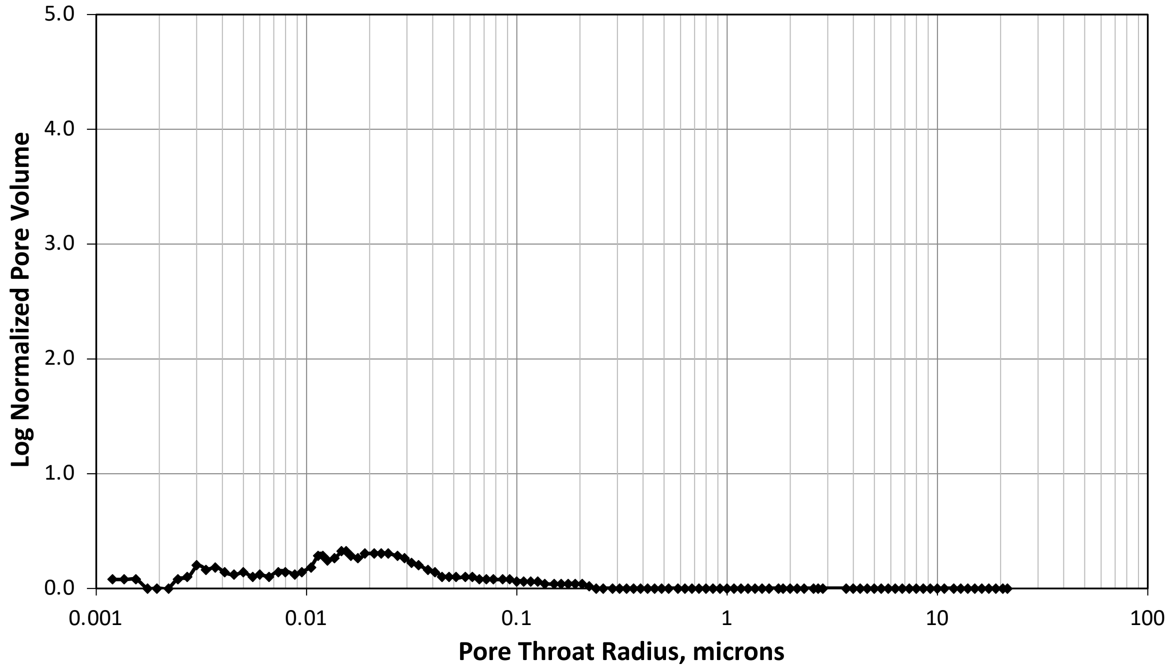


Figure 44: Upper Viola pore throat size distribution from mercury intrusion capillary pressure measurements on end trim from core plug taken at 5650.30 ft. Median pore throat radius was 0.019 µm.

Table 20. Relative abundances of minerals in Viola from XRD.

Sample Depth (ft)	Lithology	Quartz (wt%)	Feldspars (wt%)	Calcite (wt%)	Dolomite (wt%)	Clay Group (wt%)
5650.9	Dolostone	1.6	0.9	0.9	94.3	2.4
5683.7	Dolostone	4.1	1.2	0.6	88.2	5.9

The base of Core 8 consisted of interbedded dolograinstone and dolomudstone, both with chert as a minor constituent. Interparticle pores are common with rare separate vugs. Above this was about 40 ft of chert dolostone breccia with wispy clay laminations. Largest clasts were 10 cm in diameter, and the mudstone clasts were commonly fractured. Some clasts were oomoldic. Stylolites were rare throughout. A thin green laminated mudrock was observed at a depth of 5710 ft.

Porosity ranged from 2.5 to 12.1% and permeability from 0.001 to 0.093 mD (Table 19), and the median pore throat radius measured in a sample from a depth of 5683.20 ft was 0.09 µm (Figure 46), suggesting good reservoir quality. Grain density ranged was 2.81 to 2.83 g/cm^3 (Table 19) for this interval indicating dolomite mineralogy, which was also measured in the mineralogical analysis (Table 20).

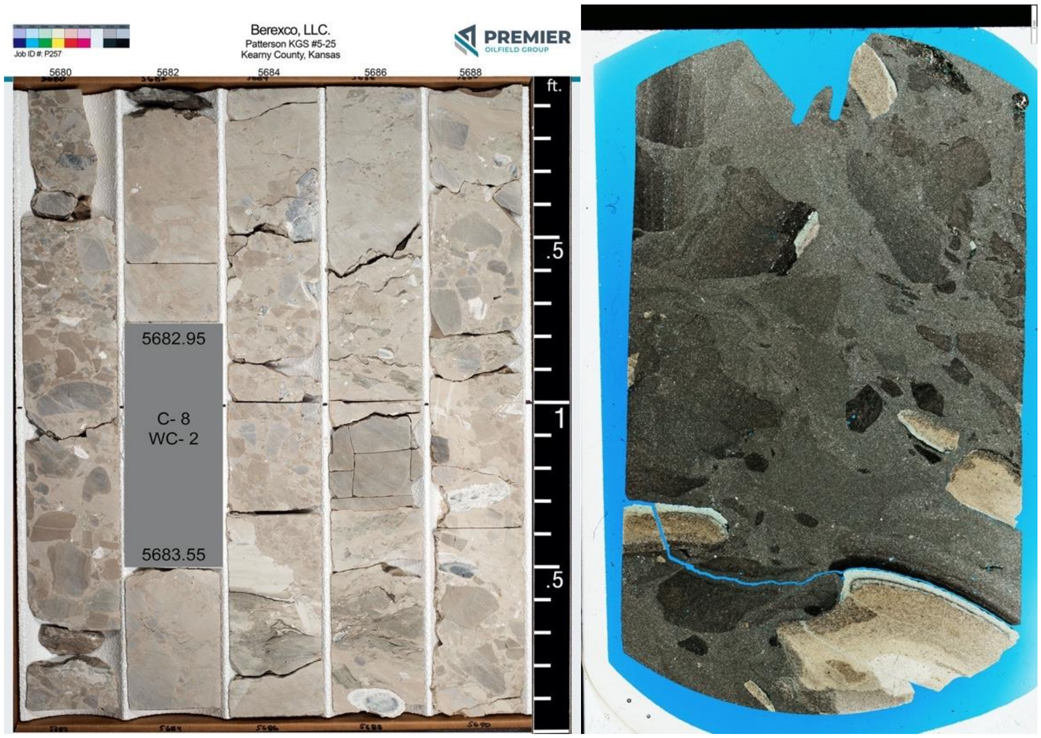


Figure 45: A) Representative core from the Lower Viola interval showing dolostone breccia. B) Representative thin section image of Lower Viola from 5675.75 ft.

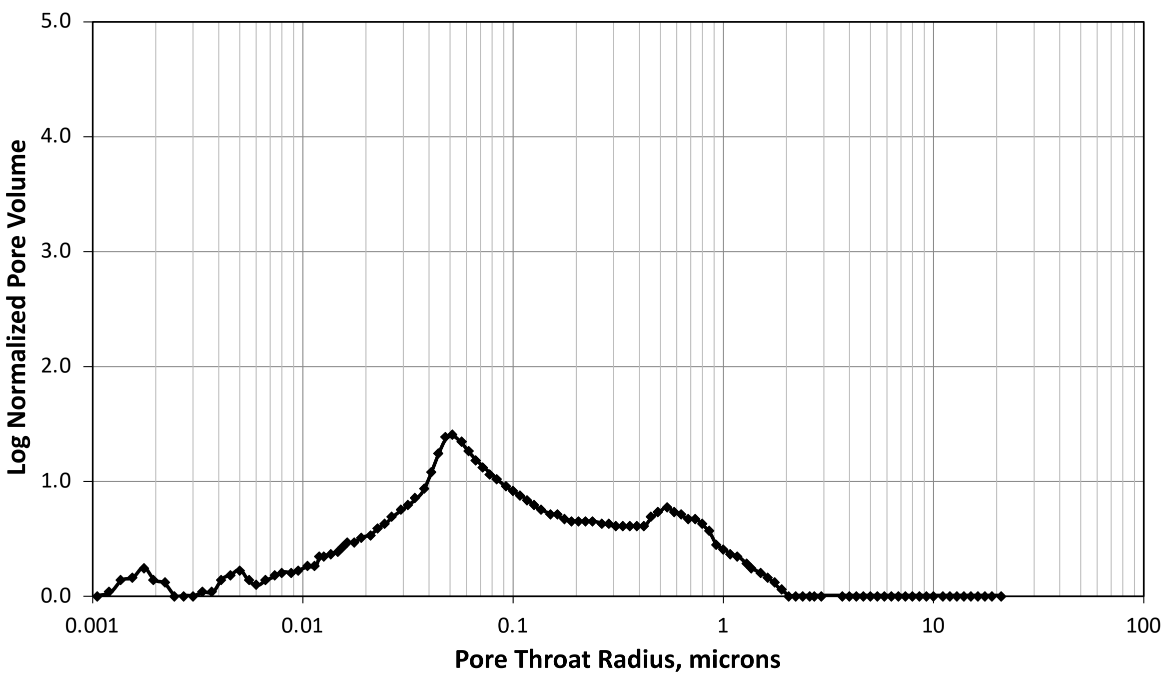


Figure 46: Lower Viola pore throat size distribution from mercury intrusion capillary pressure measurements on end trim from core plug taken at 5683.20 ft. Median pore throat radius was 0.09 µm.

Upper Arbuckle Group (Jefferson City-Cotter Formations)

Due to the difficulties in correlating the pervasively dolomitized strata of the Cambro-Ordovician strata in Kansas, it is common to refer to them at the group-level (Arbuckle), rather than the constituent formations (Jefferson City-Cotter City Dolomite, Roubidoux Dolomite, Bonneterre Dolomite). However, based on distinguishing lithological characters, it was possible to make preliminary assignments of core material to these specific geological formations. The presence of chert in the uppermost interval (5780-5826 ft) suggests that it likely represents the Jefferson City-Cotter Formations.

Cores 9-10 recovered approximately 46 ft of continuous core from the Ordovician Upper Arbuckle Group (Jefferson City-Cotter Formations) from a depth interval of 5780-5826 ft. Material in Core 9 included repeated packages of dolomudstone, overlain by dolograinstone, overlain by doloboundstone (Figure 47). The dolomudstone was laminated to mudcracked with chert nodules. Fractures in the dolomudstone showed mineralization with pyrite and/or other opaque minerals. The dolograinstone had open fractures. Grainstones tended to be the most porous with common separate vugs and rare touching vugs (fractures). Material in Core 10 consisted of interbedded dolograinstone-dolorudstone overlain by dolomudstone (Figure 48). Pore types included common interparticle pores, common to rare separate vugs and rare touching vugs (fractures). Fractures in the dolomudstone showed mineralization with pyrite and/or other opaque minerals. The lodestone was laminated, gray and contained chert nodules.

Porosity ranged from 1.9 to 10.0%, permeability from 0.001 to 13 mD (Table 21), and the median pore throat radii measured in samples collected from depths of 5788.00 and 5819.50 ft were 0.005-0.014 µm, respectively (Figure 49, Figure 50), suggesting good reservoir quality. Grain density ranged was 2.77 to 2.83 g/cm^3 for samples from this interval indicating dominantly dolomite mineralogy with some chert admixture, which was borne out by mineralogical analysis (Table 22).

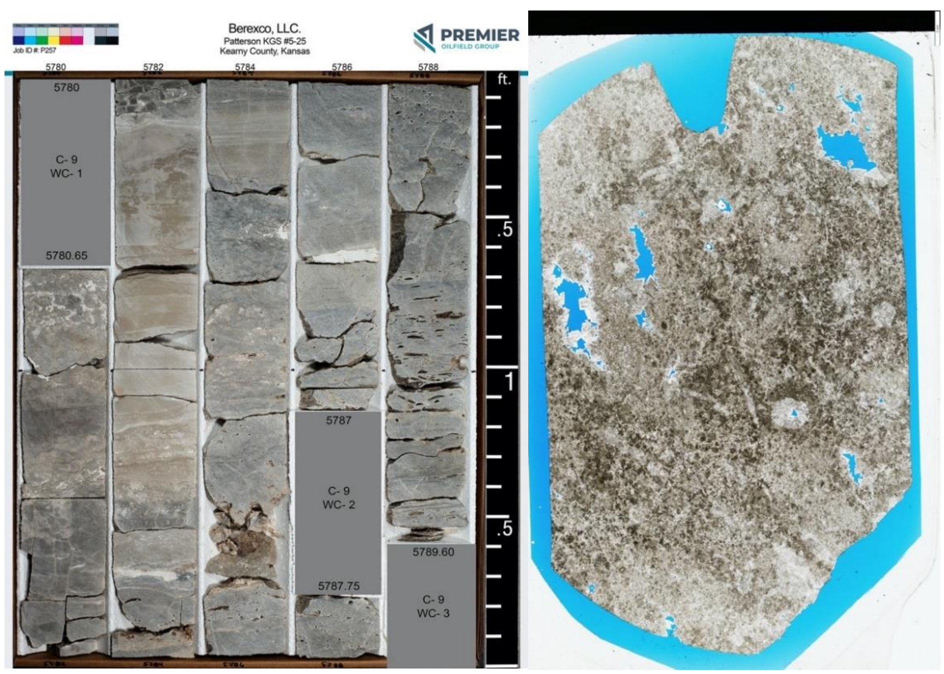


Figure 47: A) Representative core from the Upper Arbuckle (Jefferson City-Cotter) interval showing cherty dolostone. B) Representative thin section image of Upper Arbuckle (Jefferson City-Cotter) from 5787.95 ft.

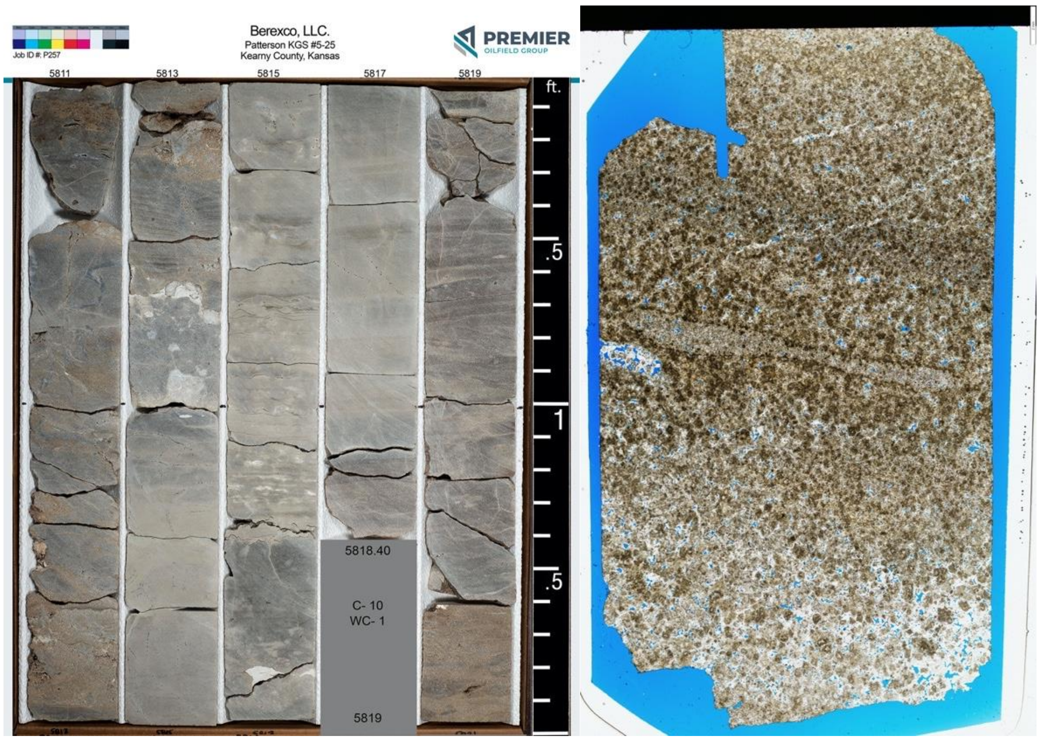


Figure 48: A) Representative core from the Upper Arbuckle (Jefferson City-Cotter) interval showing cherty dolostone. B) Representative thin section image of Upper Arbuckle (Jefferson City-Cotter) from 5818.30 ft.

Table 21. Upper Arbuckle (Jefferson City-Cotter) routine core analysis data for core plug samples.

Sample Depth (ft)	Lithology	Porosity (%)	Permeability (mD)	Grain Density (g/cm^3)	Water Sat. (%)	Oil Saturation (%)
5780.80	Dolostone	10	0.056	2.77	66	0
5787.95	Dolostone	3.2	1.261	2.82	58.4	0
5790.75	Dolostone	9.2	7.729	2.82	89.4	0
5804.00	Dolostone	6.4	12.953	2.83	87.4	0
5818.30	Dolostone	1.9	0.001	2.82	58.5	0
5821.00	Dolostone	5.1	6.098	2.82	44.3	0

Table 22. Relative abundances of minerals in Upper Arbuckle (Jefferson City-Cotter) from XRD.

Sample Depth (ft)	Lithology	Quartz (wt%)	Feldspars (wt%)	Calcite (wt%)	Dolomite (wt%)	Clay Group (wt%)
5788.0	Dolostone	0.5	1.3	0.9	95.7	1.6
5818.3	Dolostone	0.5	1.1	0.8	96.6	1.0

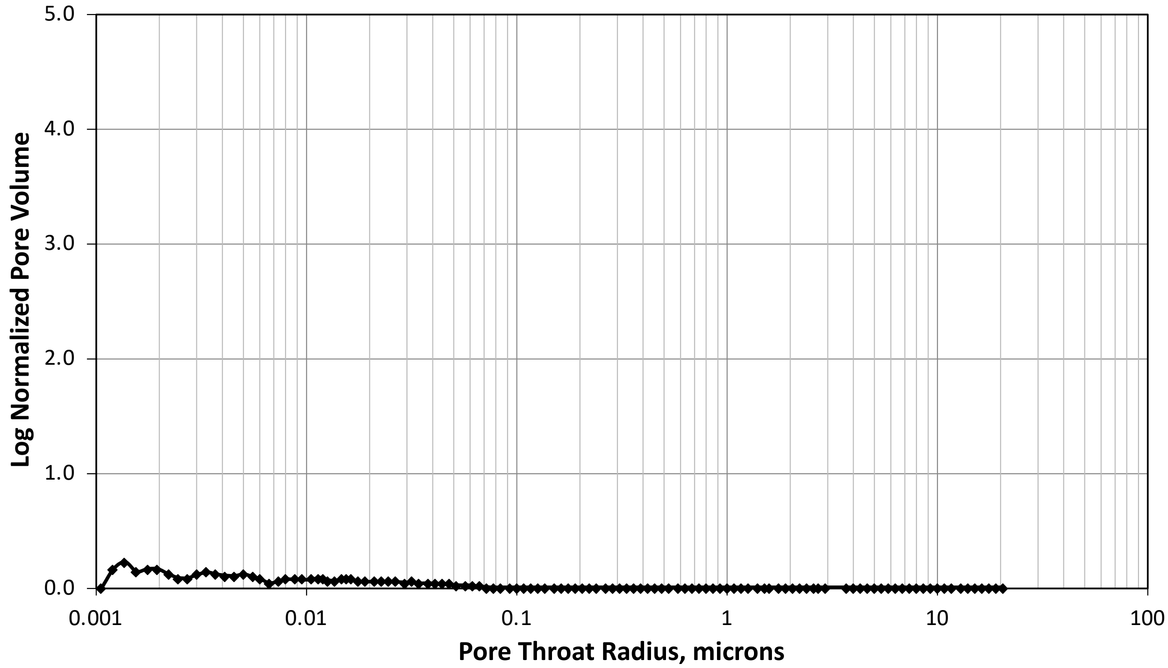


Figure 49: Upper Arbuckle (Jefferson City-Cotter) pore throat size distribution from mercury intrusion capillary pressure measurements on end trim from core plug taken at 5788.00 ft. Median pore throat radius was 0.005 µm.

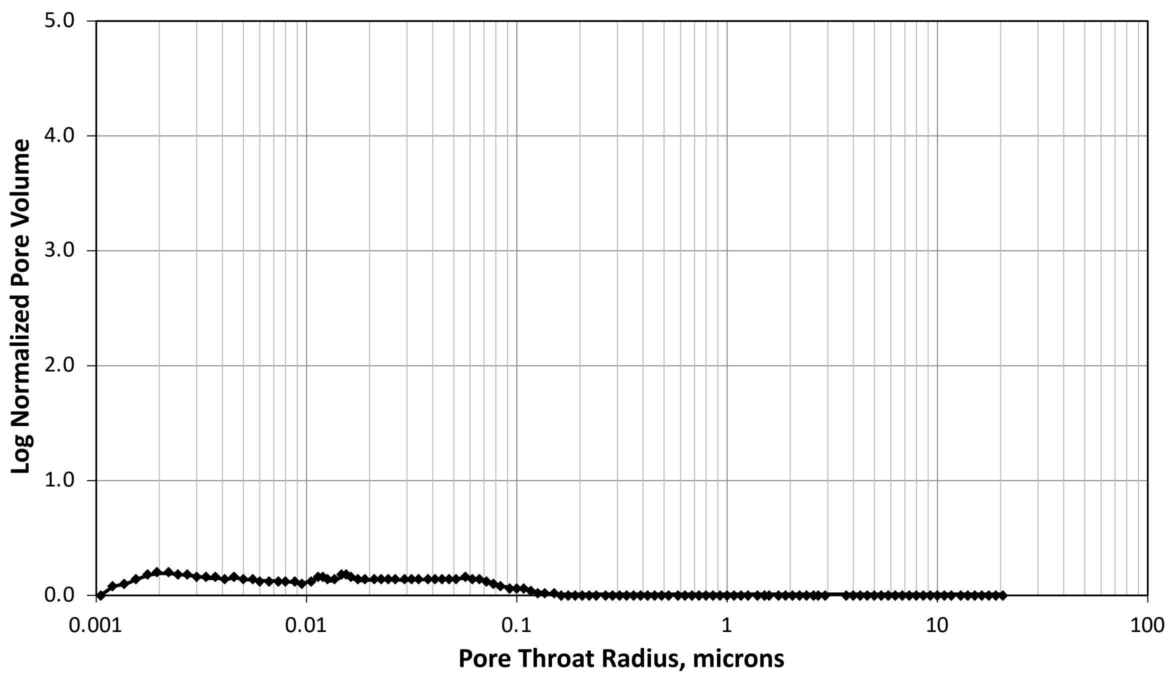


Figure 50: Upper Arbuckle (Jefferson City-Cotter) pore throat size distribution from mercury intrusion capillary pressure measurements on end trim from core plug taken at 5819.50 ft. Median pore throat radius was 0.014 µm.

Lower Arbuckle Group (Roubidoux Formation)

Cores 11-12 recovered approximately 83 ft of continuous core from the Ordovician Lower Arbuckle Group (Roubidoux Formation) from 5959-6042 ft. The correlation of these strata with as Roubidoux rests on the observation of sand-rich strata at the base of this interval.

Core collected between the depths of 5959 and 6000 ft displayed multiple cycles of laminated dolomudstone (in some cases brecciated or flat pebble conglomerate with filled fractures) overlain by clotted microbial boundstone, highly porous with cement in large vugs—up to 1 cm (Figure 51). Pore types included common to abundant separate vug pores, especially in the boundstone. The interval was fractured with most being uncemented. No stylolites were observed.

Porosity in this zone ranged from 1.8 to 4.1% and permeability was from 0.001 to 0.7 mD (Table 23), and the median pore throat radius was 0.005-0.019 µm (Figure 52), suggesting good reservoir quality. Grain density ranged was 2.82 to 2.83 g/cm^3 for samples from this interval indicating dolomite mineralogy, which was corroborated by mineralogical analysis (Table 24).

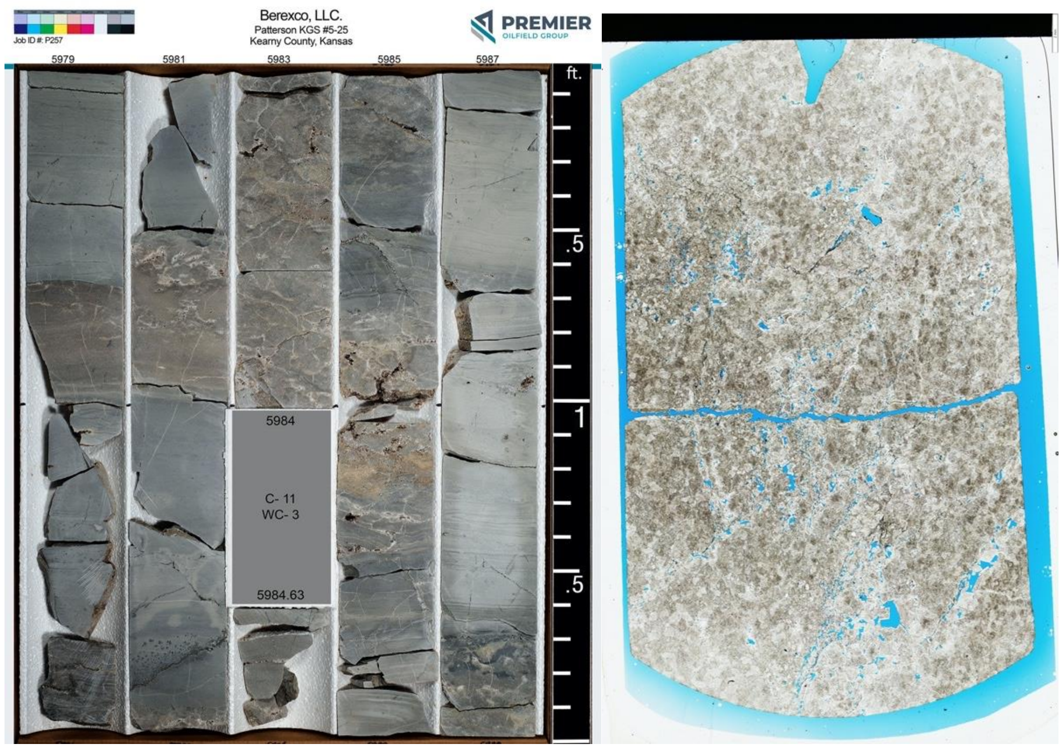


Figure 51: A) Representative core from the Lower Arbuckle (Roubidoux) interval showing laminated to clotted doloboundstone. B) Representative thin section image of Upper Arbuckle (Roubidoux) from 5983.85 ft.

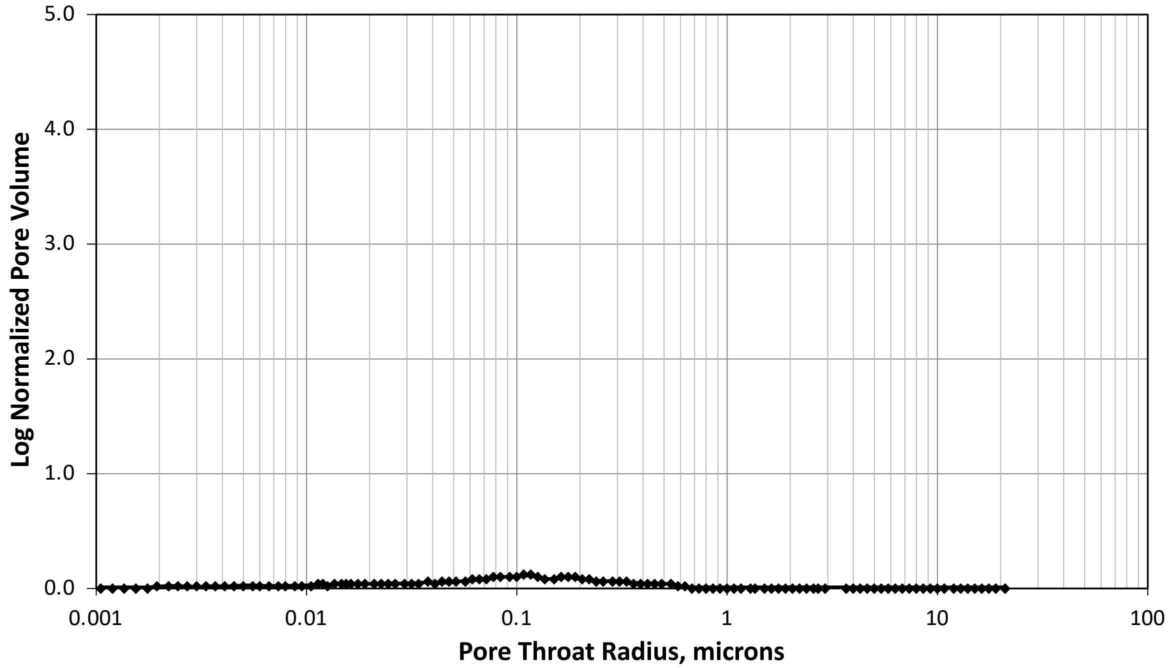


Figure 52: Lower Arbuckle (Roubidoux) pore throat size distribution from mercury intrusion capillary pressure measurements on end trim from core plug taken at 5983.25 ft. Median pore throat radius was 0.11 µm.

Table 23. Lower Arbuckle (Roubidoux) routine core analysis data for core plug samples.

Sample Depth (ft)	Lithology	Porosity (%)	Permeability (mD)	Grain Density (g/cm^3)	Water Sat. (%)	Oil Saturation (%)
5969.10	Dolostone	1.8	0.001	2.83	81.8	0
5977.15	Dolostone	4.1	0.009	2.82	51	0
5983.85	Dolostone	2.4	0.695	2.82	54.5	0
6001.65	Dolostone	7.6	0.617	2.82	61.2	0
6013.80	Dolostone	9.9	0.371	2.83	39.6	0
6018.55	Dolostone	11.3	3.832	2.83	74.9	0
6023.20	Dolostone	9.3	3.218	2.83	58.7	0
6032.00	Dolostone	8.0	0.04	2.82	72.4	0

Table 24. Relative abundances of minerals in Lower Arbuckle (Roubidoux) from XRD.

Sample Depth (ft)	Lithology	Quartz (wt%)	Feldspars (wt%)	Calcite (wt%)	Dolomite (wt%)	Clay Group (wt%)
5983.9	Dolostone	0.7	1.0	1.0	95.6	1.7
6023.2	Dolostone	2.9	1.0	0.7	93.2	2.1

The interval between 6000 and 6042 ft consisted of several beds of porous sandy to silty dolostone with some beds capped by digitate structures (Figure 53). Interparticle pores were common throughout with rare to common separate vugs. Rare to common touching vugs (fractures) were mostly uncemented. Rare stylolites were present. The zone between 6016 and6018 ft was possibly oil-stained. An angular unconformity was observed at 6012 ft.

Porosity ranged from 7.6 to 11.3%, permeability from 0.04 to 3.8 mD (see Table 23), and the median pore throat radius was 5.9 µm, measured in a sample from a depth of 6023.00 ft (Figure 54), suggesting good reservoir quality. Grain density ranged was 2.82 to 2.83 g/cm^3 for samples from this interval indicating dolomite mineralogy, which was born out by mineralogical analysis (see Table 24).

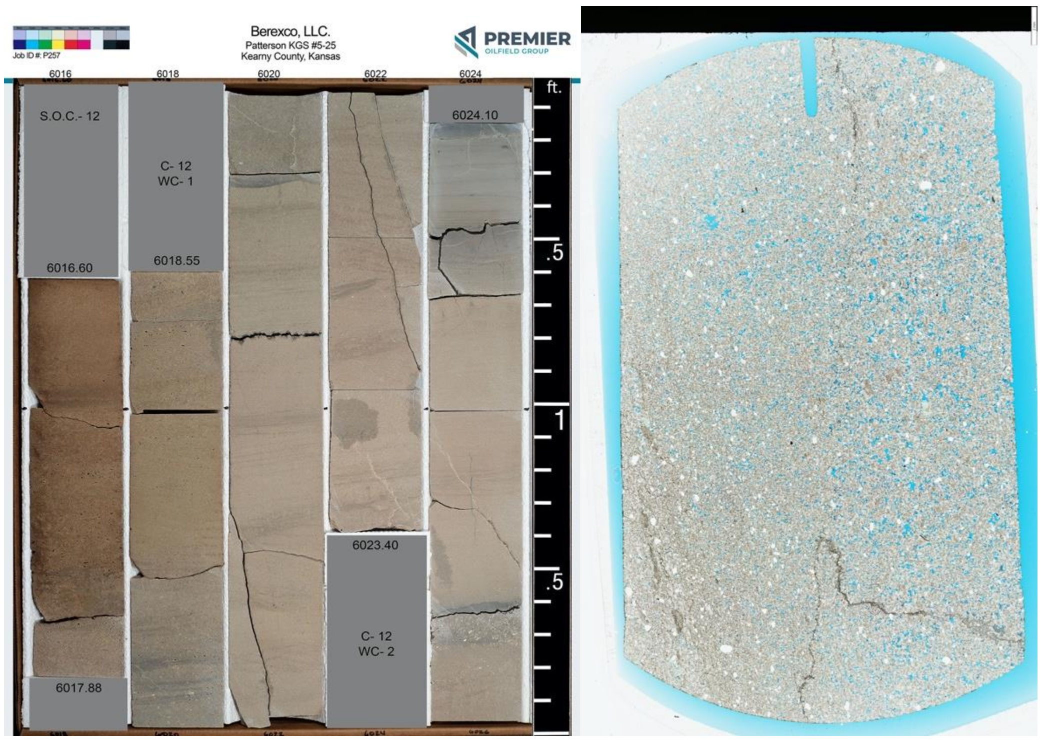


Figure 53: A) Representative core from the Lower Arbuckle (Roubidoux) interval showing laminated to clotted doloboundstone. B) Representative thin section image of Upper Arbuckle (Roubidoux) from 6023.20 ft.

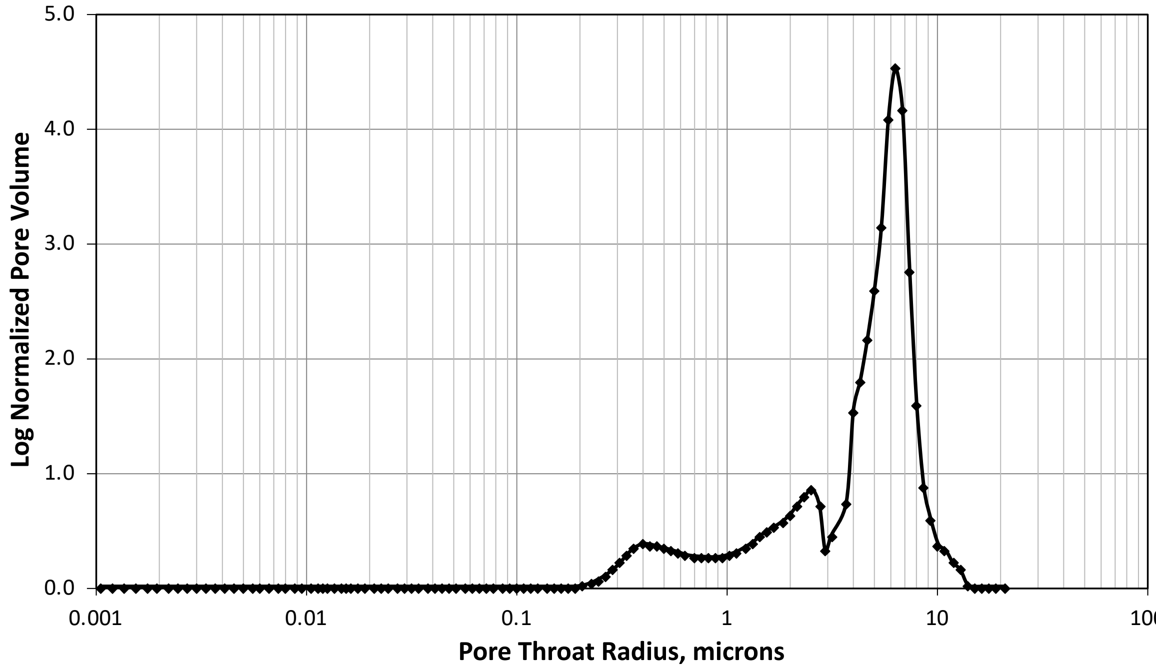


Figure 54: Pore throat size distribution from mercury intrusion capillary pressure measurements on end trim from core plug taken at 6023.00 ft. Median pore throat radius was 5.9 µm.

Lower Arbuckle Group (Bonneterre Formation)

Cores 13-15 recovered approximately 172 ft of continuous core from the Ordovician Lower Arbuckle Group (Bonneterre Formation) from 6042-6214 ft. The correlation of these strata with as Bonneterre rests on the observation of sand-rich strata at the base of this interval as well as presence of glauconite.

The interval between 6042 and 6170 ft is a lengthy interval characterized by clotted algal boundstone (light brown/dark brown) (Figure 55, Figure 56, Figure 57, Figure 58). Lighter brown areas were porous. Interparticle pore types were common to abundant. Separate vugs were rare to common. Brecciation with coarse fracture-fill calcite and baroque dolomite fills extended from 6086 to 6152 ft, with the most intense brecciation and cementation between depths of 6120 and 6138 ft. Clay seams were present as were black grains. Pyrite and chert were rare secondary pore-filling cements. Stylolites were only observed at the very base of the interval.

Porosity ranged from 1.0 to 9.4%, permeability from 0.001 to 0.98 mD (Table 25), and the median pore throat radius ranged from 0.019 to 0.22 µm (Figure 59, Figure 60, Figure 61), suggesting good reservoir quality. Grain density ranged was 2.81 to 2.85 g/cm^3 for samples from this interval indicating dolomite mineralogy (Table 25), which was supported by mineralogical analysis (Table 26).

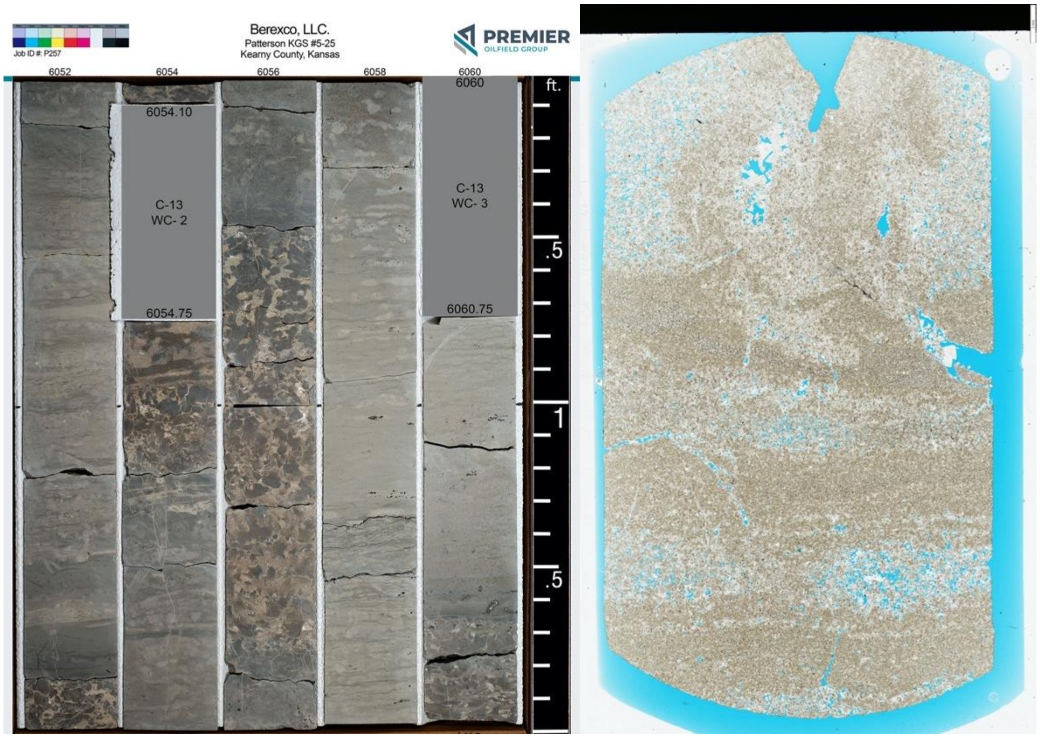


Figure 55: A) Representative core from the Lower Arbuckle (Bonneterre) interval showing clotted algal doloboundstone. B) Representative thin section image of Upper Arbuckle (Bonneterre) from 6054.85 ft.

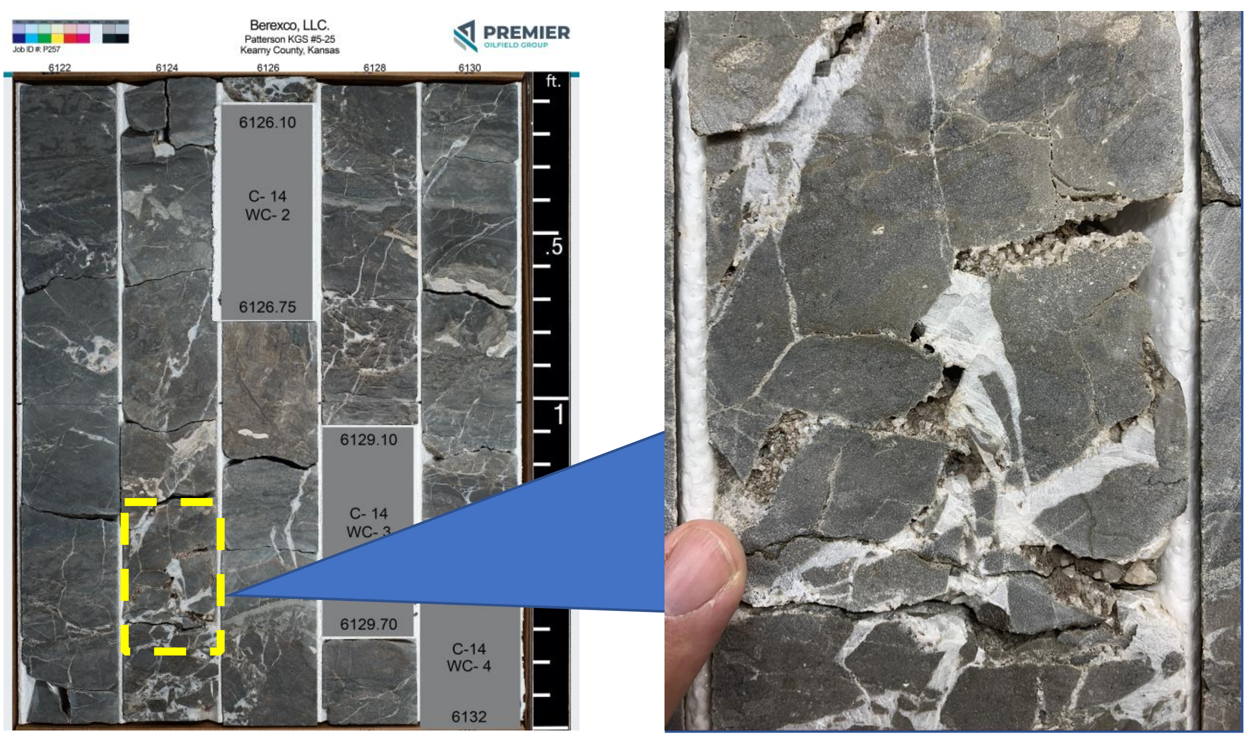


Figure 56: Photographs of intensely brecciated and cemented core at 6125.75 ft. Note blocky calcite cement occluding most pore space and baroque dolomite lining open pore space.

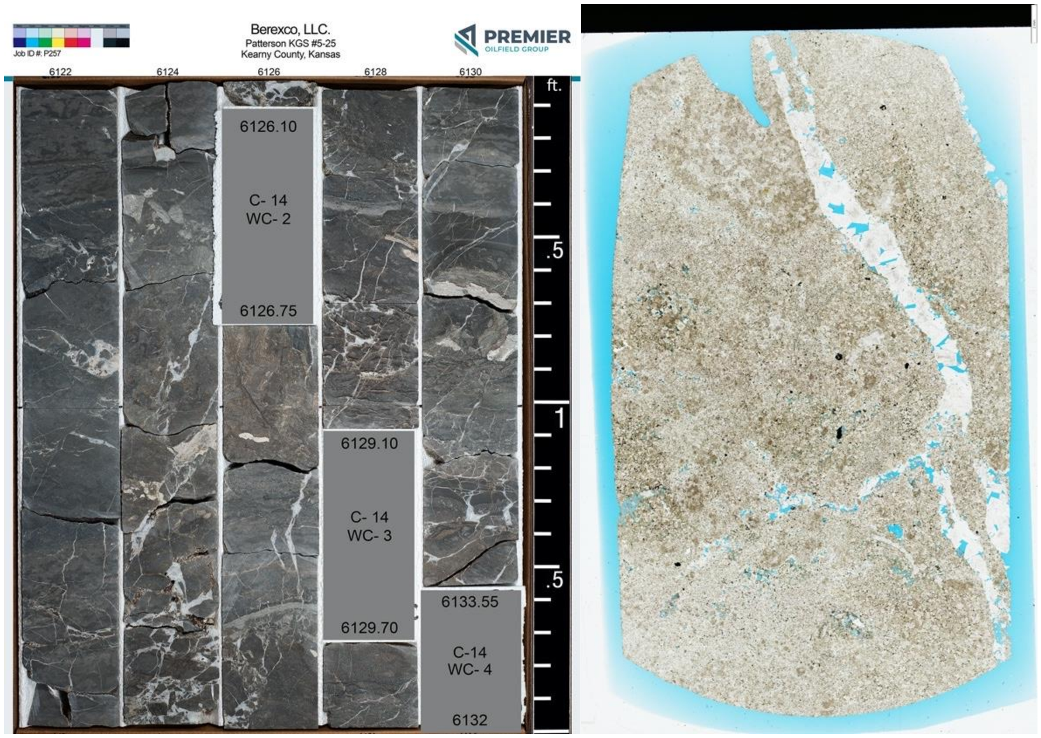


Figure 57: A) Representative core from the Lower Arbuckle (Bonneterre) interval showing fractured clotted algal doloboundstone. B) Representative thin section image of Upper Arbuckle (Bonneterre) from 6126.80 ft.

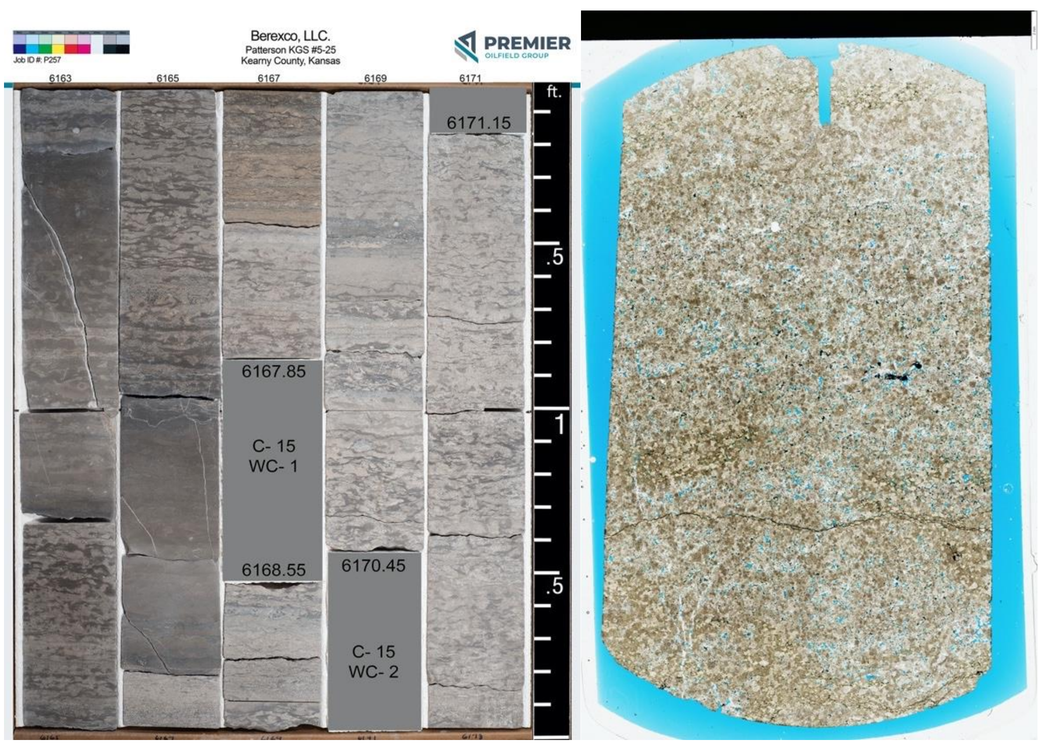


Figure 58: A) Representative core from the Lower Arbuckle (Bonneterre) interval showing clotted algal doloboundstone. B) Representative thin section image of Upper Arbuckle (Bonneterre) from 6167.70 ft.

Table 25. Lower Arbuckle (Bonneterre) routine core analysis data for core plug samples.

Sample Depth (ft)	Lithology	Porosity (%)	Permeability (mD)	Grain Density (g/cm^3)	Water Sat. (%)	Oil Saturation (%)
6043.80	Dolostone	6.1	0.029	2.83	29.4	0
6054.85	Dolostone	8.1	0.980	2.83	45.7	0
6060.90	Dolostone	9.4	0.001	2.82	82.4	0
6073.65	Dolostone	5.7	0.021	2.83	73.1	Tr
6077.85	Dolostone	8.9	0.317	2.82	58.6	0
6088.90	Dolostone	1.2	0.001	2.82	72.9	Tr
6106.75	Dolostone	1.1	0.001	2.82	82.2	0
6126.80	Dolostone	6.5	0.003	2.81	73.4	0
6129.85	Dolostone	1.1	0.095	2.84	61.3	Tr
6131.30	Dolostone	1.0	0.019	2.85	55.1	0
6140.10	Dolostone	7.8	0.739	2.81	48.4	0
6167.70	Dolostone	6.2	0.025	2.82	82.7	Tr
6171.30	Dolostone	8.7	0.088	2.81	81.7	0
6179.80	Dolostone	5.0	0.026	2.81	67.2	0
6182.25	Dolostone	2.8	0.017	2.82	76.0	Tr
6190.15	Dolostone	6.0	0.013	2.79	85.9	Tr
6194.10	Dolostone	4.4	0.337	2.72	90.6	0
6197.10	Dolostone	7.8	0.683	2.78	71.4	0
6218.00	Dolostone	3.9	0.065	2.73	44.9	0

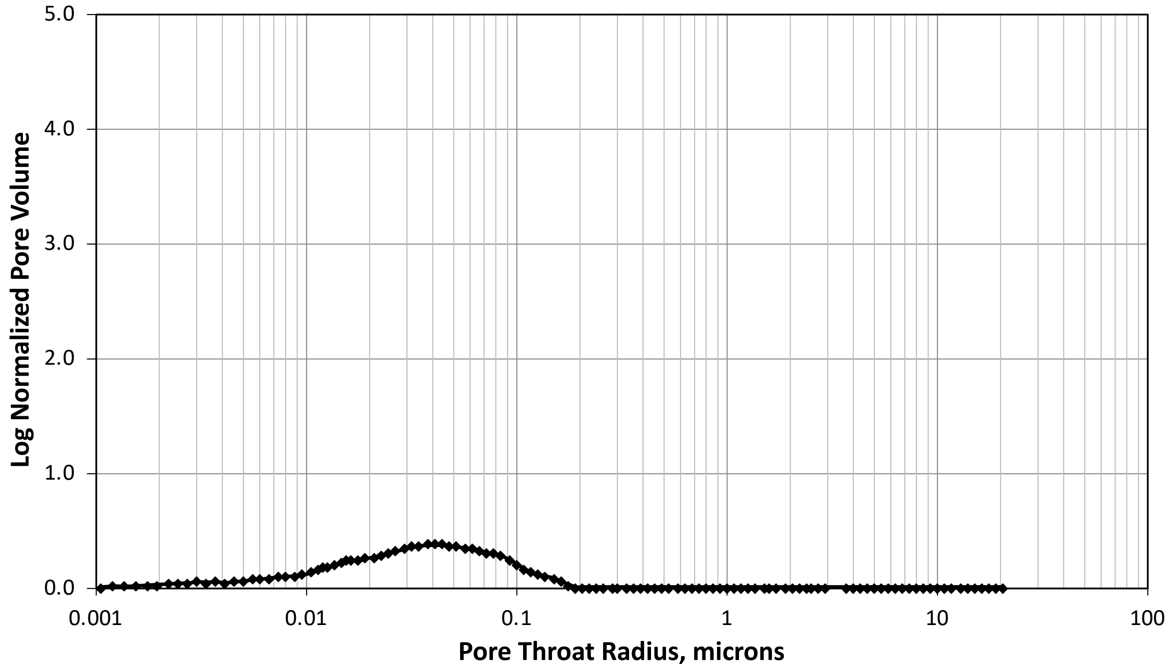


Figure 59: Pore throat size distribution from mercury intrusion capillary pressure measurements on end trim from core plug taken at 6054.85 ft. Median pore throat radius was 0.038 µm.

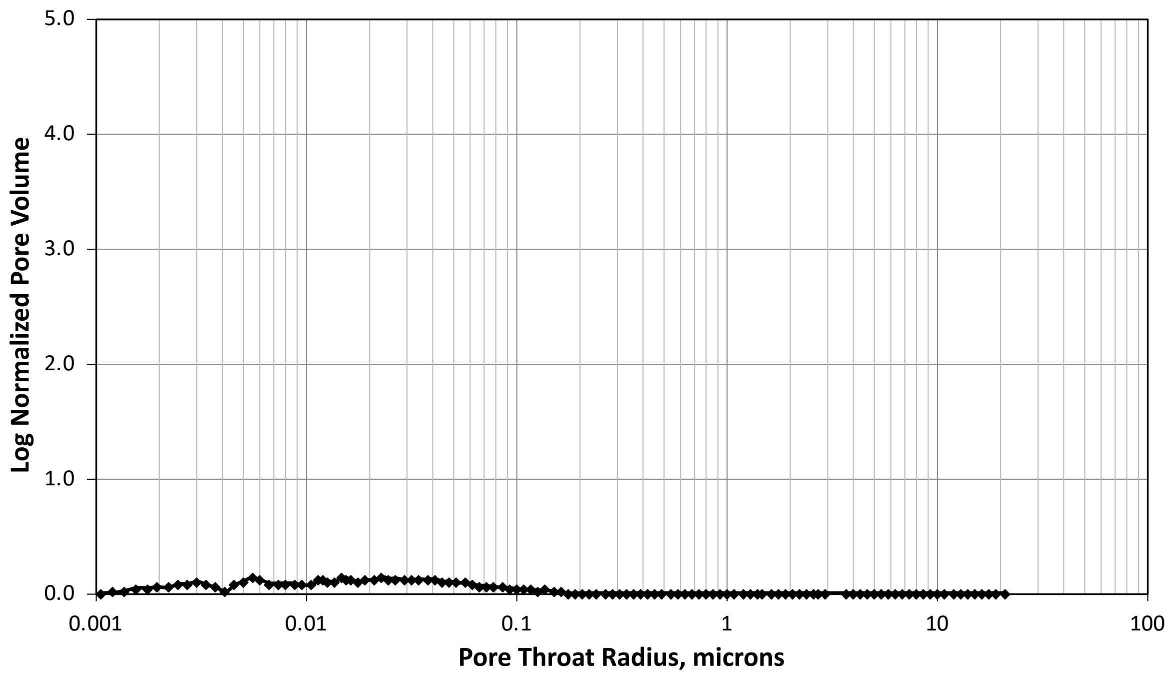


Figure 60: Pore throat size distribution from mercury intrusion capillary pressure measurements on end trim from core plug taken at 6127.20 ft. Median pore throat radius was 0.019 µm.

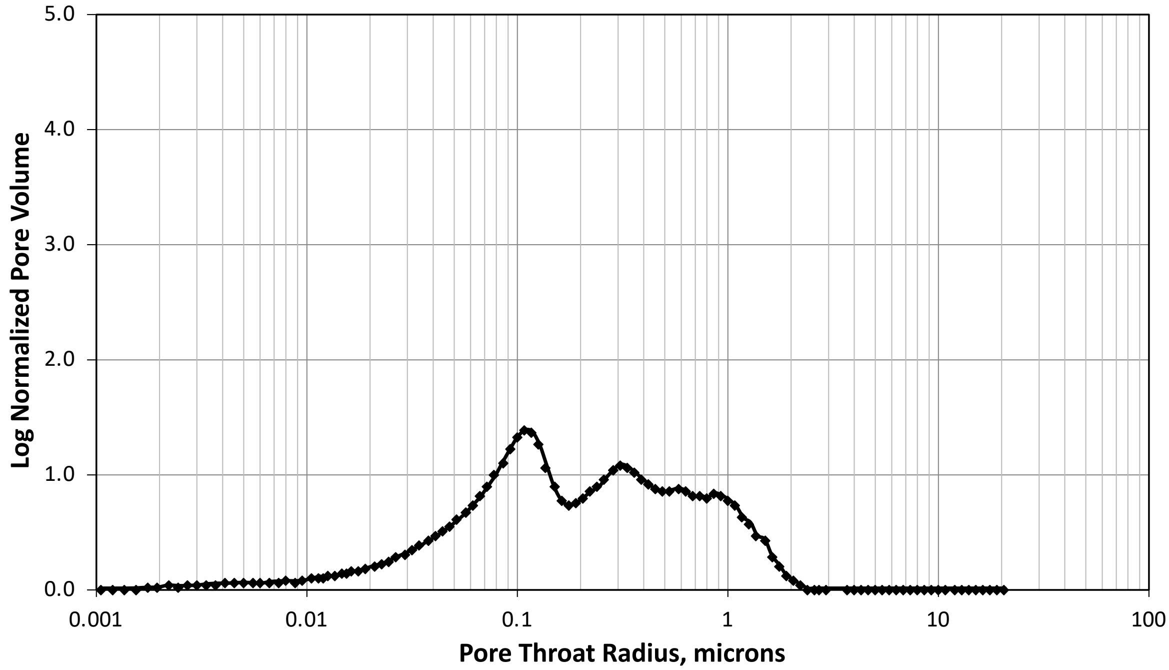


Figure 61: Pore throat size distribution from mercury intrusion capillary pressure measurements on end trim from core plug taken at 6161.20 ft. Median pore throat radius was 0.22 µm.

Table 26. Relative abundances of minerals in Lower Arbuckle (Bonneterre) from XRD.

Sample Depth (ft)	Lithology	Quartz (wt%)	Feldspars (wt%)	Calcite (wt%)	Dolomite (wt%)	Clay Group (wt%)
6054.9	Dolostone	1.4	0.9	2.4	93.2	1.5
6126.8	Dolostone	5.0	5.2	1.8	82.1	4.9
6171.3	Dolostone	3.5	2.2	2.1	89.4	2.5

Between the depths of 6170 and 6200 ft, mottled dolostone was present with abundant clay seams approximately 1 cm apart (Figure 62). Burrows are well cemented, but the rest of the rock is porous. Small lenses of chert were present. Bed boundaries were sharp with black grains below them grading down for 5 mm. Glauconite was present in some beds. Interparticle pores were abundant in this interval with no other pore types being observed. Rare chert or pyrite cement was observed in this interval. No fractures or stylolites were observed in this interval.

Porosity ranged from 2.8 to 8.7% and permeability from 0.013 to 0.683 mD, suggesting good reservoir quality (see Table 25). Grain density ranged was 2.72 to 2.82 g/cm^3 for samples from this interval indicating dolomite mineralogy, which was also observed in the mineralogical analysis (see Table 26).

Figure 62: Representative core from the interval of the Bonneterre from 6170-6200 ft showing clotted algal boundstone texture.

Between the depths of 6200 and 6214 ft, the formation consisted of sandy dolostone with clay seams (Figure 63). Glauconite was observed. Light colored mottles were more porous, though visible pore types were rare overall. No fractures and rare stylolites were observed in this interval.

Porosity and permeability from the single sample from this interval were 3.9% and 0.065 mD, respectively (see Table 25), suggesting fair reservoir quality. The one core plug sample from this interval had a grain density ranged of 2.73 g/cm^3 for samples from this interval indicating dolomite and quartz mineralogy, which was borne out by mineralogical analysis (see Table 26).

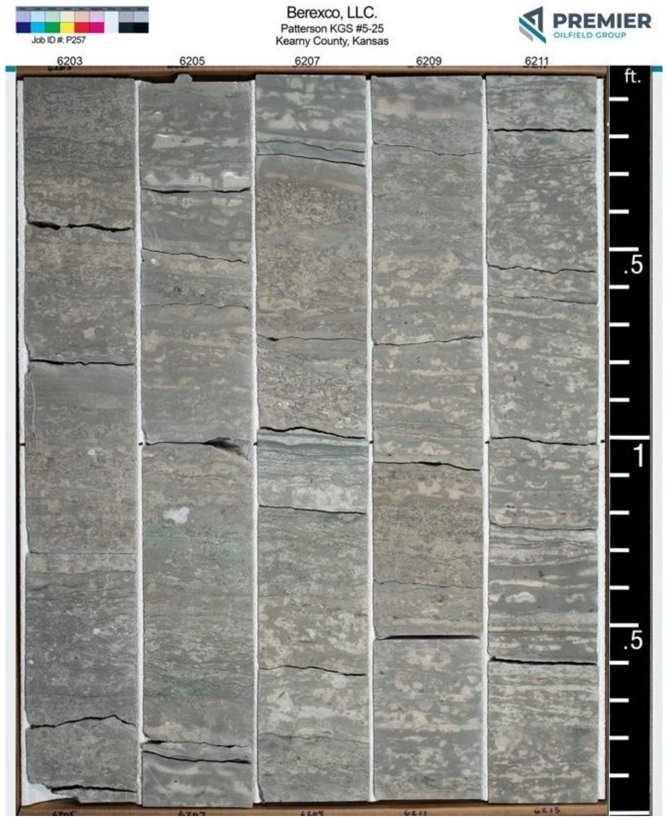


Figure 63: Representative core from the interval of the Bonneterre from 6200-6214 ft showing clotted algal boundstone texture, glauconite, and shale interbed.

Reagan Sandstone

Core 16 recovered approximately 55 ft of Reagan sandstone between the depths of 6214 and 6269 ft. This section was composed of two beds. The upper bed (6214-6259 ft, Figure 64) was composed of several packages of conglomeratic sandstone fining-upwards into siltstone. Quartz pebbles in the conglomerate were white. Siltstone was green and laminated. Interparticle and separate vugular pore types were rare. No fractures or stylolites were observed. The lower bed (6259-6269 ft, Figure 65) was composed of packages beginning at erosion surfaces with pebble conglomerate that fined upwards into medium sandstone. Quartz pebbles in the conglomerate were white. Interparticle pores were common as was quartz cement. Pyrite cement was rare, except at 6268 ft where it was abundant. No fractures or stylolites were observed.

Porosity ranged from 4.6 to 13.7%, permeability from 0.023 to 14.6 mD (Table 27

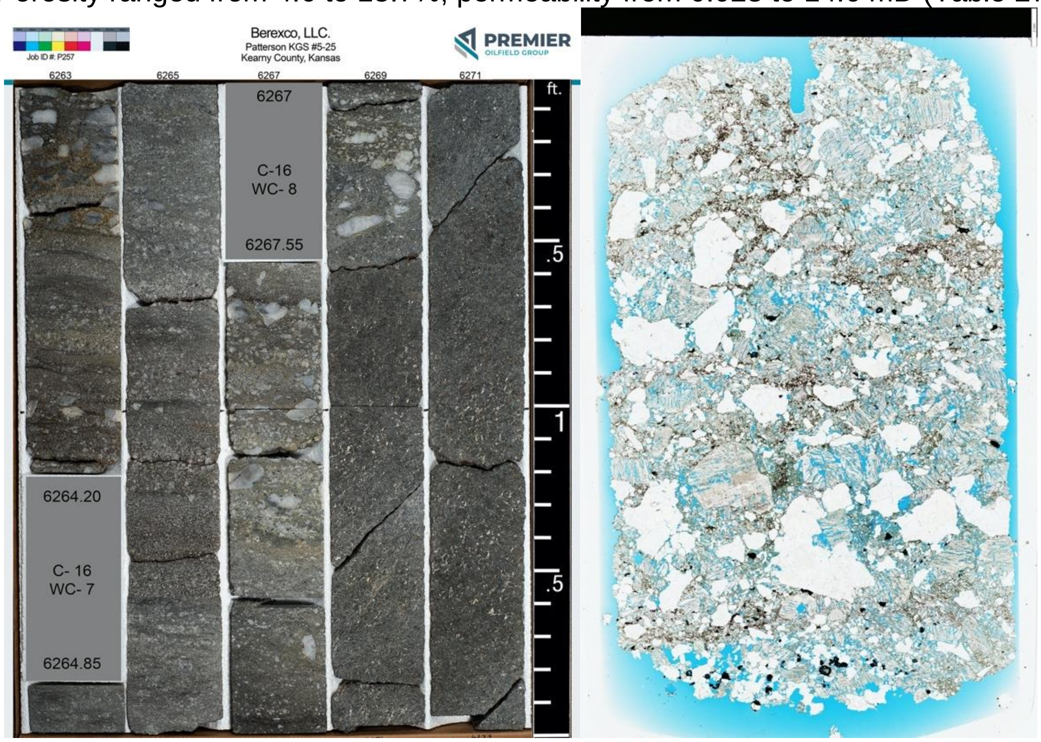


Figure 65: A) Representative core from the Reagan Sandstone interval showing contact between weathered basement granite and Reagan Sandstone at ~6269.5 ft. B) Representative thin section image of Reagan Sandstone from 6266.65 ft.

Table 27). The median pore throat radii measured in the samples was 0.062 to 5.6 µm (Figure 66, Figure 67, Figure 68), suggesting good reservoir quality. Grain density ranged was 2.67 to 2.73 g/cm^3 mineralogical analysis showed that this represents a mixture of quartz, feldspar, and dolomite (Table 28).

The siliciclastic unit above the basement igneous/morphic rocks and below Arbuckle Group strata in Kansas is formally known as the Lamotte Sandstone (in correlation with beds that outcrop in the St Francois Mountains of Missouri), informally as the Reagan Sandstone, and variably as “granite wash”. “Granite Wash” is a lithological term, rather than stratigraphic, which refers to a siliciclastic unit composed of the immature proceeds from weathering granite. In the Patterson core, the section is more conglomeratic than typical Lamotte and much coarser and with a more immature mineralogy than what is often called Reagan, a white pure quartz sandstone. The core material is more mature than typical for a granite wash. Lamotte is the best term for this interval. However, in this project it was termed the "Reagan" based on custom.

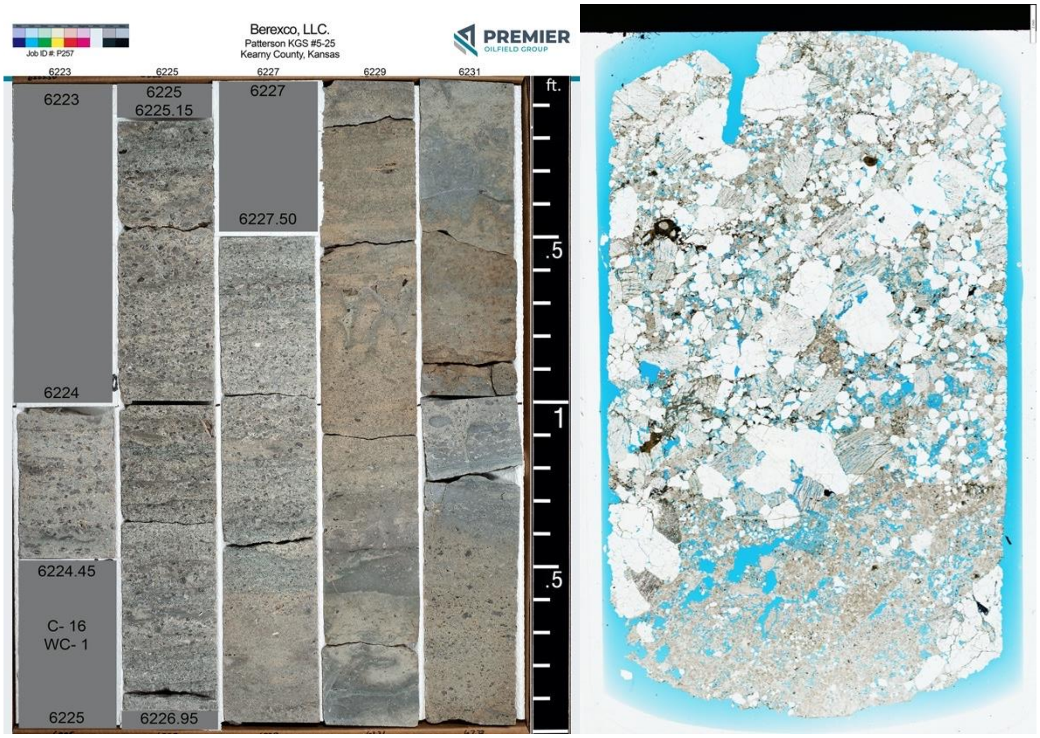


Figure 64: A) Representative core from the Reagan Sandstone interval showing coarse dolomitic quartz-feldspar sandstone. B) Representative thin section image of Reagan Sandstone from 6225.25 ft.

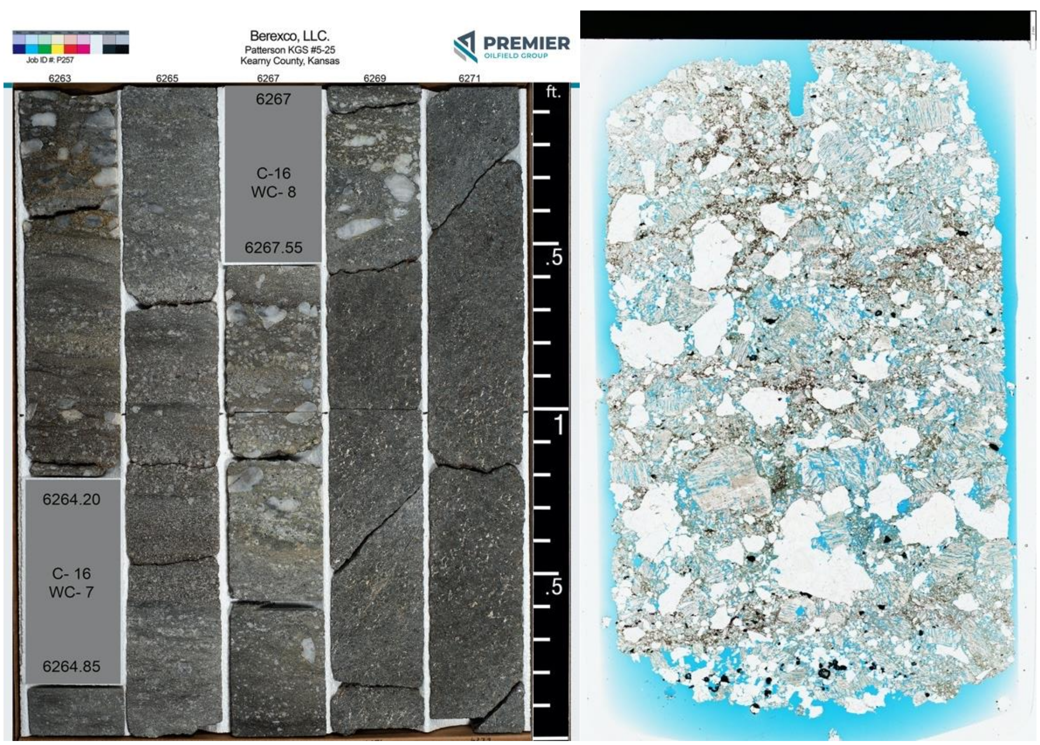


Figure 65: A) Representative core from the Reagan Sandstone interval showing contact between weathered basement granite and Reagan Sandstone at ~6269.5 ft. B) Representative thin section image of Reagan Sandstone from 6266.65 ft.

Table 27. Reagan routine core analysis data for core plug samples.

Sample Depth (ft)	Lithology	Porosity (%)	Permeability (mD)	Grain Density (g/cm^3)	Water Sat. (%)	Oil Saturation (%)
6224.15	Sandstone	11.7	7.060	2.70	76.8	0
6225.25	Sandstone	10.3	1.140	2.67	77.9	0
6227.60	Sandstone	7.9	0.124	2.72	82.1	0
6240.35	Sandstone	13.7	14.590	2.73	80.7	0
6247.55	Sandstone	4.6	0.023	2.73	60.3	0

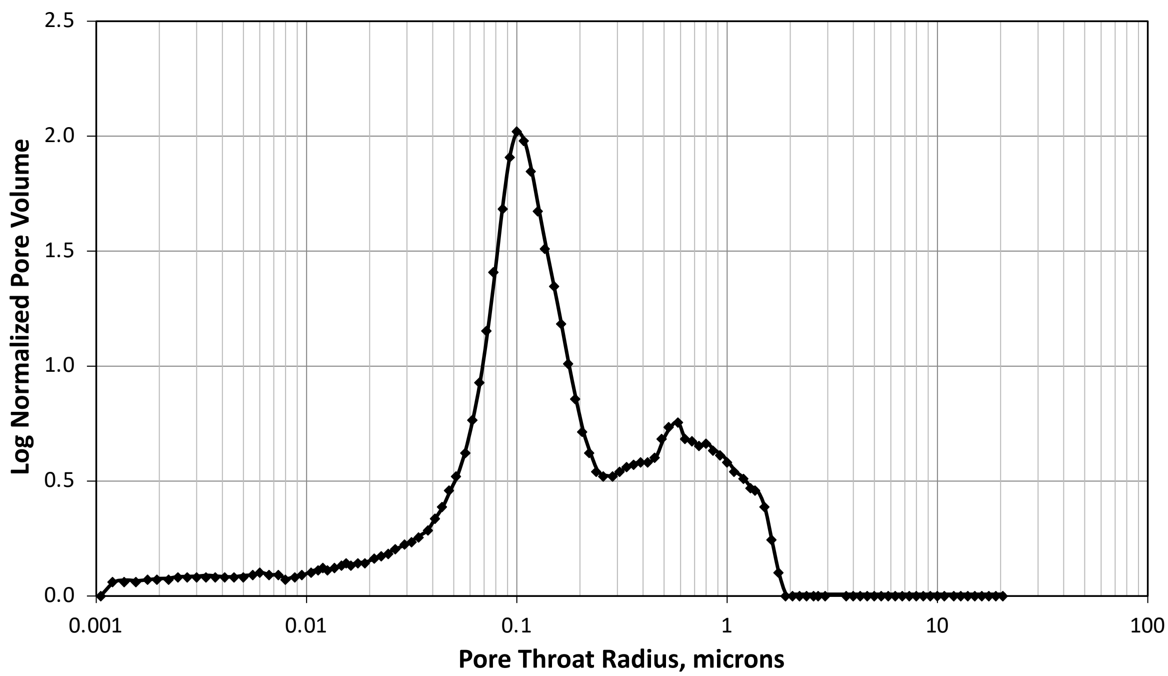


Figure 66: Pore throat size distribution from mercury intrusion capillary pressure measurements on end trim from core plug taken at 6225.50 ft. Median pore throat radius was 0.14 µm.

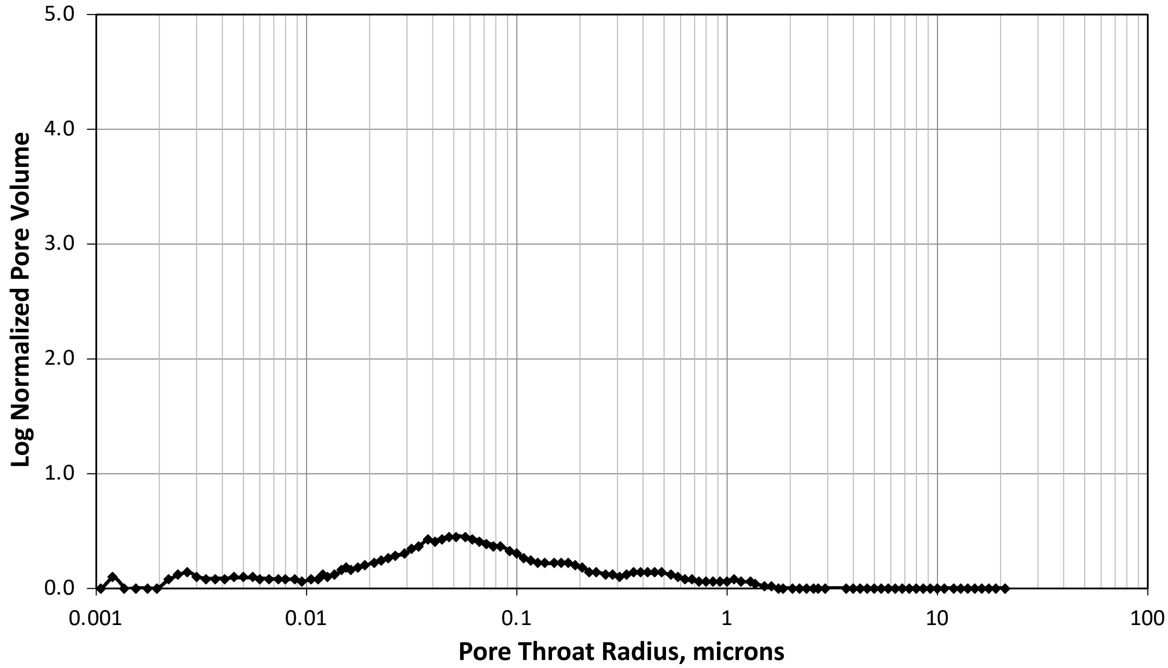


Figure 67: Pore throat size distribution from mercury intrusion capillary pressure measurements on end trim from core plug taken at 6252.50 ft. Median pore throat radius was 0.062 µm.

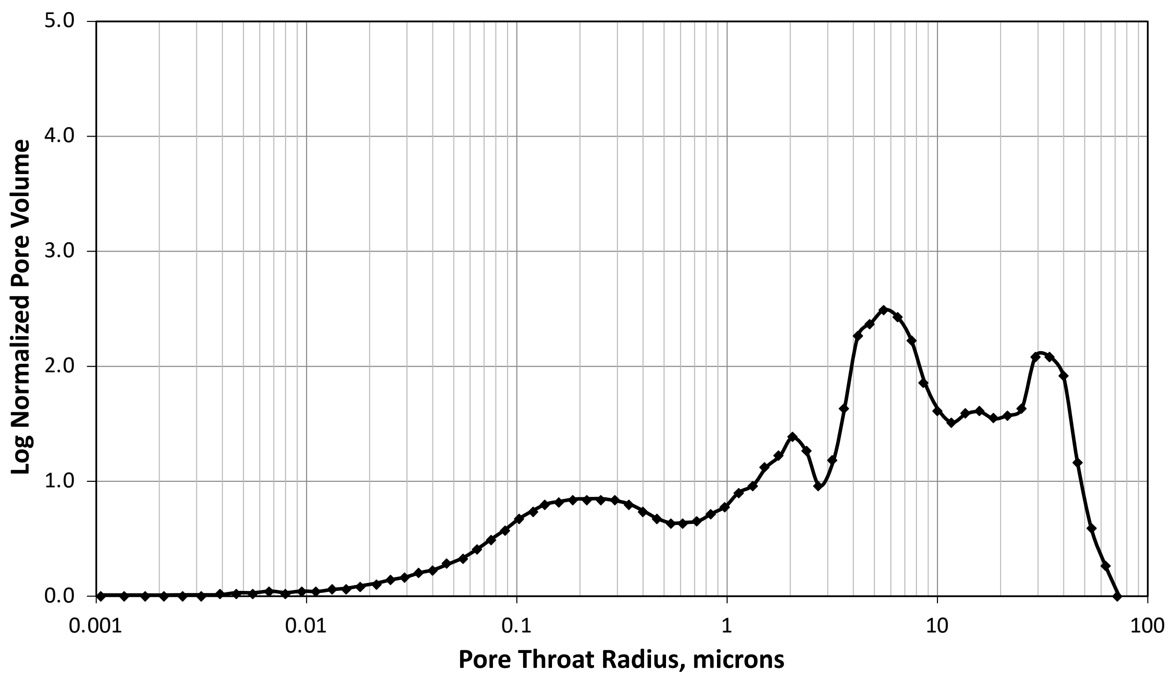


Figure 68: Pore throat size distribution from mercury intrusion capillary pressure measurements on end trim from core plug taken at 6266.15 ft. Median pore throat radius was 5.6 µm.

Table 28. Relative abundances of minerals in Reagan from XRD.

Sample Depth (ft)	Lithology	Quartz (wt%)	Feldspars (wt%)	Calcite (wt%)	Dolomite (wt%)	Clay Group (wt%)
6225.30	Sandstone	37.8	39.4	0.0	12.9	7.8
6252.50	Sandstone	29.1	14.5	0.6	53.6	1.7

Basement Granite

Cores 16-17 collected approximately 30 ft of continuous core from the Precambrian basement, including its weathered surface. The base of Core 16 included about 5 feet of highly weathered, black/gray granite. Pore types present included rare interparticle pores as abundant separate vugs. Iron oxide, pyrite, and perhaps kaolinite cement was observed in open separate vugs. Rare open fractures were present. No stylolites were observed. Core 17 recovered approximately 22 ft of unweathered, pink, coarse grained granite (Figure 69). Fractures were common in the interval from the base of the core up to 6280 ft but were rare at the top of the core (6278 ft). Fractures, the only pore type present, were mostly open with apertures less than 0.5 mm (Figure 70). The only interval of closed fractures was seen at 6299 ft, where the fractures were cemented with mafic material and pyrite.

Porosity ranged from 0 to 19.2% and permeability from 0.001 to 24.2 mD (Table 29). Grain density ranged was 2.57 to 2.74 g/cm^3 for samples from this interval indicating quartz and feldspars dominate the mineralogy of this interval, which was borne out by mineralogical analysis (Table 30).

Figure 69: A) Representative core from the basement granite interval showing pink feldspar-rich composition.

Figure 70: Core photos showing both horizontal and angled fractures that cross-cut the whole cores.

Table 29. Basement Granite routine core analysis data for core plug samples.

Sample Depth (ft)	Lithology	Porosity (%)	Permeability (mD)	Grain Density (g/cm^3)	Water Sat. (%)	Oil Saturation (%)
6252.50	Granite	1.6	0.001	2.74	74.0	0
6258.40	Granite	14.7	0.675	2.61	93.5	0
6263.90	Granite	18.1	23.051	2.71	83.9	0
6266.65	Granite	14.2	12.204	2.61	75.4	0
6272.65	Granite	19.2	24.242	2.57	81.8	0
6278.80	Granite	0.1	0.001	2.63	76.0	0
6280.20	Granite	0.0	0.001	2.63	71.5	0
6297.75	Granite	0.1	0.001	2.66	79.3	0

Table 30. Relative abundances of minerals in Basement Granite from XRD.

Sample Depth (ft)	Lithology	Quartz (wt%)	Feldspars (wt%)	Calcite (wt%)	Dolomite (wt%)	Clay Group (wt%)
6266.7	Granite	42.1	51.3	0.0	0.7	5.3
6278.8	Granite	11.9	81.8	0.9	0.4	5.0
6297.8	Granite	5.1	87.8	0.5	0.5	5.5

Core Analysis Summary and Conclusions

A total of 778 ft of core was collected from the Patterson KGS #5-25 and analyzed for physical and mineralogical properties to assess the potential of several stacked seals and reservoirs for CO_2 storage. These geologic units sampled with the core included: Pennsylvanian Atoka Shale (seal), Pennsylvanian Morrow Sand (reservoir), Pennsylvanian Morrow Shale (seal), Mississippian Meramec (seal), Mississippian Osage (reservoir), Ordovician Viola Formation (reservoir), Ordovician Arbuckle Group (reservoir), Reagan Sandstone (reservoir), Precambrian Granite (seal).

A summary of the core analyses are as follows:

- ***Atoka Shale—Seal—*** core material was composed of black shale with variable calcite cementation and would provide good seal quality (porosity 0.8-11.4%, permeability 0.001 to 1.2 mD) with good thickness.
- ***Morrow Sand—Reservoir—*** core material was composed of medium-grained sandstone with excellent reservoir quality (porosity 19.9 to 21%, permeability 921 to 1410 mD). It is the only oil-producing horizon at the Patterson site, so it presents potential for CO_2-EOR development.
- ***Meramec—Seal—*** core material was composed of fine-grained skeletal lime grainstones with mostly low reservoir quality (porosity 0.6 to 1%, permeability <0.001 to 0.002), except for a distinct interval of higher quality rock (porosity 14.5%, permeability 7.5 mD) that is also visible on well logs. This provides a secondary storage target in an otherwise sealing interval.
- ***Osage—Reservoir—*** core material was composed of fine-grained skeletal oolitic lime grainstones with good reservoir quality (porosity 3.7 to 5.4%, permeability 0.009 to 0.34 mD). Coring missed the highest porosity interval observed in well logs, which suggests that the interval has good reservoir quality (~10% porosity).
- ***Viola—Reservoir—*** core material was composed of porous vuggy dolostones and dolostone breccias with good reservoir quality (porosity 5.1 to 9.7%, permeability 0.062 to 10.1 mD).
- ***Upper Arbuckle (Jefferson City-Cotter)—Reservoir—*** core material was composed of porous vuggy dolostones with good reservoir quality (porosity 1.9 to 10.0%, permeability 0.001 to 13 mD).
- ***Lower Arbuckle (Roubidoux)—Reservoir—*** core material was composed of porous vuggy dolostones with good reservoir quality (porosity 1.8 to 11.3%, permeability 0.001 to 3.8 mD)
- ***Lower Arbuckle (Bonneterre)—Reservoir—*** core material was composed of porous clotted algal doloboundstone with good reservoir quality (porosity 1.0 to 9.4%, permeability 0.001 to 0.98 mD).
- ***Reagan Sandstone—*** core material was composed of porous medium to conglomeratic feldspar quartz sandstones with porosity 4.6 to 13.7%, permeability 0.023 to 14.6 mD.
- ***Basement Granite—*** core material was composed of weathered and fresh fractured granite with porosity 0 to 19.2% and permeability 0.001 to 24.2 mD.

Caprock Analysis

Data and Analysis

In CarbonSAFE Phase I, 305 wells deeper than 4,500 ft were used to generate the static geological model. Of these, 304 wells contain formation top data, including manually picked tops from depth-calibrated wireline log images at 164 wells. There are 211 wells with picked tops penetrating Mississippian strata (60 of these wells penetrated the Salem Limestone, 26 penetrated the Warsaw Limestone); 13 wells penetrated the Ordovician Viola Limestone; and 8 wells penetrated strata of the Cambro-Ordovician Arbuckle Group. In this study, seal distribution analysis and modeling were performed with the existing exploration and scientific wells in the area. During CarbonSAFE Phase II, two new 3-D reflection seismic surveys were acquired in July 2019 over the Patterson and Hartland oil fields and integrated with two legacy datasets over the Heinitz and Oslo oil fields to characterize the regional structural framework of the Patterson Site. Data from the new and legacy 3-D seismic surveys were integrated to identify major structural features, including dipping panels, folds, and faults as well as to evaluate the structural integrity of the site as a whole. In March–June 2020, two new deep wells, Patterson KGS 5-25 and Hartland KGS 6-10, were drilled to the Precambrian crystalline basement to acquire petrophysical, geomechanical, geochemical, and engineering data from core, wireline logs, and well tests. Overburden stress, horizontal stress, and formation pore pressure of the potential reservoir and seal intervals were obtained using a broad range of geophysical and well test data. Laboratory rock mechanical testing was performed using the core material from the from the two new wells.

Seal Analysis and Modeling

Detailed well log analysis was performed on wells to identify the lithology of the seal intervals. The static model section of this report summarizes the average porosity and permeability of the sealing intervals from the wireline logs, indicating low porosity and permeability of the primary seal intervals. Figure 71 shows a cross-section of the site representing a strike-oriented cut. Figure 72 shows the stratigraphic model demonstrating the distribution of the seal rock from Meramecian Stage to Cherokee Group of the Patterson site. Lithology in the cross section and model indicates that the Arbuckle-Osagian potential reservoirs are directly overlapped by non-porous limestone from the Meramecian Stage. Two laterally continuous shale units in the Morrowan Stage can serve as the primary seal for the stacked reservoirs and for the Morrowan sandstone production zone. The upper Morrowan shale is up to 100 ft thick. Overlapped by the middle Morrowan limestone, the lower Morrowan shale is up to 25 ft thick. The Atokan Stage-Cherokee Group above the Morrowan also contain thick layers (~250 ft) of interbedded shale and non-porous limestone, which can further seal the reservoirs and protect against CO_2 migration.

Structural Analysis of Seal Intervals

Seismic interpretation confirmed that all proposed reservoirs are below several laterally continuous sealing stratigraphic units. Seismic interpretation revealed that the Patterson Site contains multiple structural closures that lie on uplifted fault blocks, bounded by two reverse faults that strike nearly perpendicular to one another. These faults offset Precambrian through Pennsylvanian sections, including several primary reservoir and seal intervals. Detailed seismic and structural analyses are in Battelle, (2020d).

The non-porous carbonate of the Meramecian is thick (~462 ft) and regionally extensive. The Meramecian Stage immediately overlies the Osagian carbonate and is the uppermost seal above the three reservoirs. Morrowan shale and non-porous carbonate are also regionally extensive (as evidenced by strong reflections throughout the combined seismic data sets) and have an average thickness of 134 ft. The superjacent Atokan-Cherokee shale/non-porous carbonate section, which has been interpreted as uniformly thick (~223 ft) throughout the study area, further reduces the risk of leakage. Also, oil and gas production from the Morrowan sandstone across the Patterson-Hartland-Heinitz-Oslo fields suggests that the Patterson Site is effectively sealed against the upward flow of oil. In addition, the presence of the largest gas field in North America (Hugoton) above the oil-producing Morrowan intervals is testament to the sealing quality of the Upper Permian units at the Patterson Site to the upward flow of gaseous hydrocarbons. While the properties of supercritical CO_2 are different from either oil or gas, supercritical CO_2 is likely to be sealed by the same intervals that seal these economic deposits of oil and gas.

During the structural analysis, two major faults were identified in the seismic data that intersect the strata from the basement to the Pennsylvanian Pleasanton Group and offset the Mississippian saline reservoirs and their primary seal. Multiple fractures are observed in the basement surface, which may affect the integrity of the bottom seal. During injection, increasing pore pressure will increase the tendency of an existing fault and associated fractures in the caprock to slip or dilate, thereby forming a potential fluid migration pathway. A fault is potentially sealed when a reservoir unit is juxtaposed with shale, tight limestone, evaporite, or clay gouge. Although the Morrowan sandstone oil and gas reservoir is trapped by the fault, it is unknown whether the fault would act as a migration pathway or a fault seal for trapping the CO_2 for the Arbuckle, Viola, and Osagian reservoirs. Therefore, future studies should perform fault reactivation tendency analysis to understand the likelihood of dilation or slip along existing fractures. Detailed analyses of the basement fracture network, fault reactivation tendency, and fault seal are recommended in future research to provide an integrated seal evaluation to understand the fault sealing characteristics of those saline reservoirs.

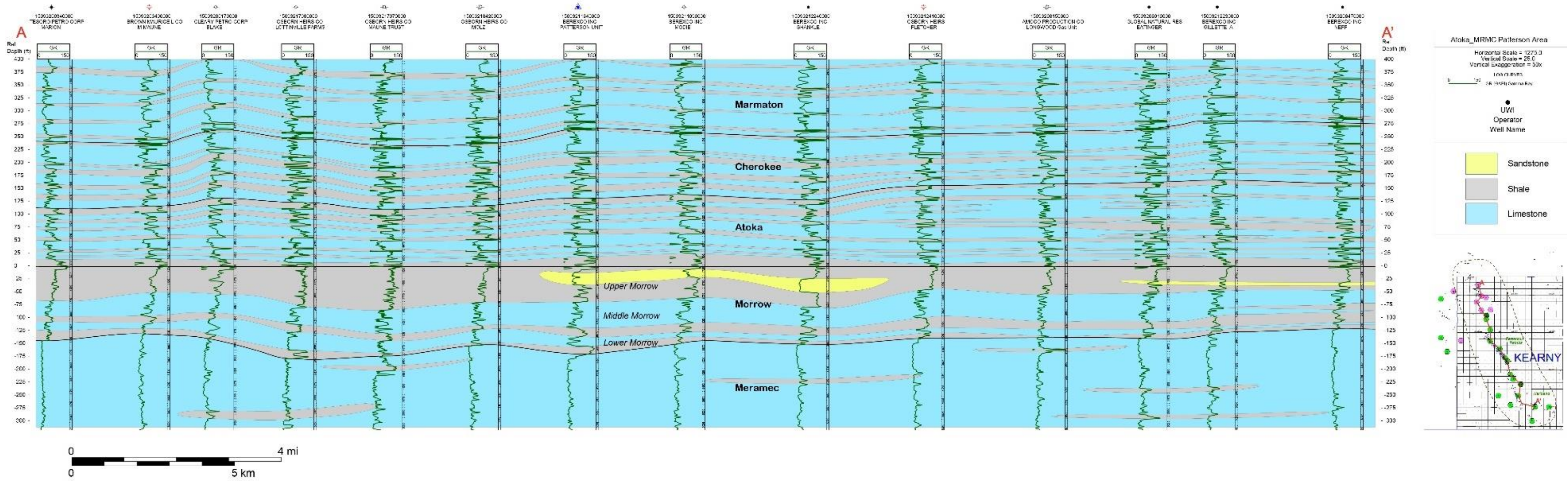


Figure 71. Cross-Section showing lithology interpretation of the seal intervals of the Patterson Field.

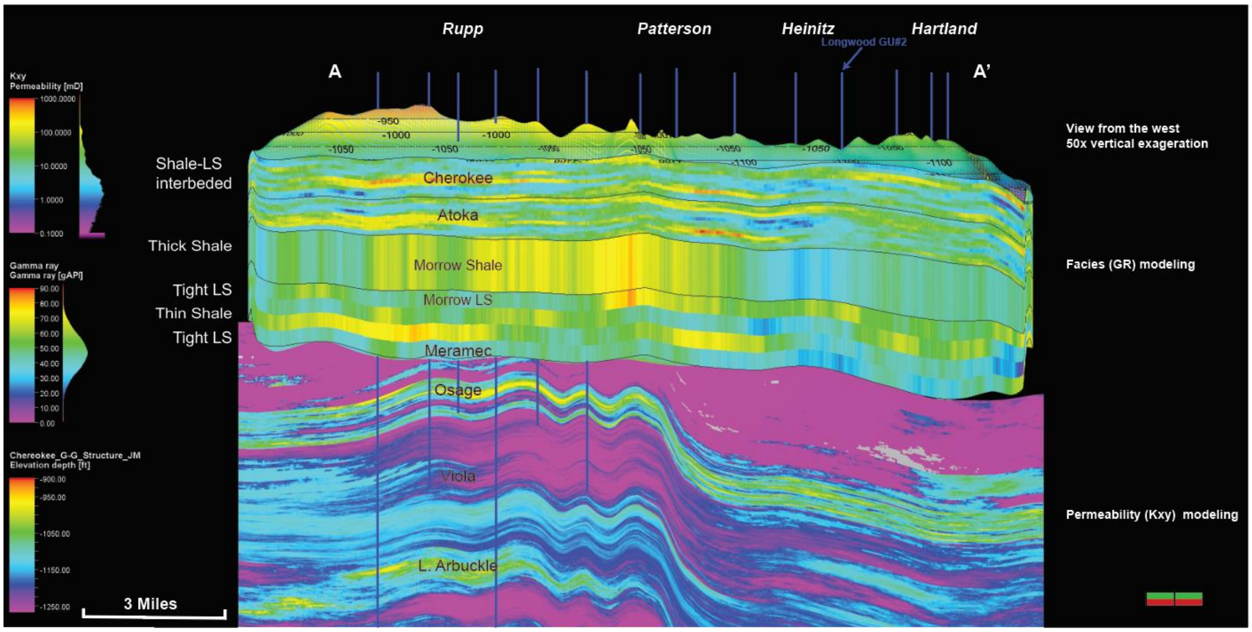


Figure 72. Property modeling of the Patterson Field. Upper section is the facies modeling of the seal intervals. Hotter colors represent increasing shale content. The Morrowan interval contains laterally continuous shales and tight limestone that should provide adequate primary seal integrity for the reservoir candidates. Atoka and Cherokee Groups contain shale-limestone interbedded layers provided secondary confining units further sealing the reservoir. Lower section is the permeability modeling of the reservoir intervals. See Figure 71 for lithology interpretation of cross-section A-A'.

Stress and Pressure Analysis

Methods

Stress Orientation

Maximum horizontal stress orientation was normally analyzed on the basis of fast shear wave azimuth, drilling induced fractures (DIFs) and borehole breakouts (Reinecker et al., 2003; Zoback et al., 2003; Reynolds, 2005; Sinha et al., 2010). The orientation of the fast shear azimuth and with the direction of *SHmax*. In the two new wells, the fast-shear azimuth is obtained through sonic crossed-dipole anisotropy analysis. Drilling included fractures and borehole breakouts can be interpreted using either imaging or caliper logs. DIFs form in the orientation of *SHmax* when the circumferential stress around the well bore is less than the tensile strength of the rock (Brudy and Zoback, 1999). DIFs in the image logs are representing as pairs of narrow, well defined conductive features separated by 180˚ (Aadnoy and Bell, 1998). No breakout zone was identified in the Patterson and Hartland wells.

Overburden Stress (Sv)

Subsea formations bear the weight of the overlying sea water and lithologic column. Therefore, the vertical lithostatic stress or overburden stress (*Sv*) for a given depth (*D*) is equivalent to the weight of the sea water and the overburden, with the stress derived from equation (1),

$$Sv = \int_0^D \rho(z) g d(z) \quad (1),$$

where D is depth; *ρ(z)* is the bulk density of the fluid-saturated rock; *g* is the standard gravitational acceleration (9.80665 m/s^2); and *d(z)* is depth increment. Figure 73 contains overburden stress from Patterson KGS#5-25 and Hartland KGS #6-10 well. The data are best fit with a linear curve. *Sv* increases with depth, and the average *Sv* gradient is (1.02-1.03 psi/ft).

Pore Pressure

The formation pore pressure can be determined by drill stem test (DST). During a DST, pressure is continuously recorded against time, two pressures measure the pore pressure of the formation being tested: the initial shut-in pressure (ISIP) and the final shut in pressure (FSIP). The higher is usually closest to true formation pore pressure. In many cases, it is the ISIP. In addition, initial formation pressure from step-rate tests (SRT) also provide pore pressure information. In CarbonSAFE Phase II, 5 DSTs and 14 SRTs we performed in Patterson KGS#5-25 well and Hartland KGS#6-10 well. Four of the 5 DSTs successfully obtained ISIP and FSIP data.

Horizontal Stress Magnitude

By plotting maximum stabilized pressure for each step, the fracture propagation pressure (FPP) is identified by the change in slope. After the well shut-in, the pressure will reach the critical point where it can no longer sustain the least principal stress to keep the hydraulic fracture open. At this stage, FCP can be calculated from the break in slope of the pressure-time curve and the pressure recorded should more or less reflect the *Shmin* in the reservoir (Quality A *Shmin*). However, FCP is not always showing after shut in. In this case, we use FPP or shut in pressure to obtain a closer pressure of FCP (Quality B *Shmin*). SRTs failed to provide *Shmin* information are listed as Quality C. A total of 14 step-rate pressure tests were performed in the Patterson and Hartland wells at potential storage and seal intervals. Four of the SRTs obtained Quality A *Shmin*. A summary of the *Shmin* from step-rate pressure tests are plotted in Figure 73.

Limited number of SRT was carried out in the Patterson Site. The magnitudes of the minimum can also be calculated by assuming linear elastic rock behavior, the minimum stress state is given as equation (2),

$$Shmin = \frac{\nu}{1-\nu}(Sv - P_p) + P_p \qquad (2),$$

Where *Shmin* is the minimum horizontal stress magnitude; ν is Poisson's ratio from wireline logs; *Sv* is the vertical stress magnitude; and *Pp* is the pore pressure. Figure 73 contains *Shmin*-depth plot of the Patterson KGS#5-25 and Hartland KGS #6-10 wells. The average *Shmin* gradient is approximately 0.56 psi/ft.

Measurement of the maximum horizontal stress (*SHmax*) is not directly possible (Zoback 2010). The Hugoton Embayment belong to a normal-slip (NS) to strike-slip (SS) stress regime (Levandowski et al., 2018), where Shmin<SHmax≈Sv. Therefore, *SHmax* is approximately equal to *Sv* (Zoback et al., 2010). Drilling induced fractures (DIFs) occur whenever there is a significant difference between the two horizontal stresses. Consider the state of stress in a strike-slip faulting environment, the upper bond of the magnitudes of the maximum horizontal stresses can be constrained by equation (3),

$$SHmax = 3Shmin - 2P_p - \Delta P - T_0 \qquad (3),$$

Where *SHmax* is the maximum horizontal stress, *Shmin* is the minimum horizontal stress magnitude; *Pp* is the pore pressure; ΔP is the difference between the wellbore pressure and the pore pressure; T_0 is tensile strength. ΔP and T_0 are negligible.

Stress and Pressure at Patterson Site

Maximum horizontal stress orientations were determined from fast shear wave azimuth and drilling induced fractures (DIFs) and are highly uniform and parallel with east to southeast strike (Figure 74), which is consistent with previous stress analyses in the Oklahoma-Texas Panhandle of the Hugoton Embayment (Holubnyak et al., 2018).

Overburden stress increases with depth according to overburden thickness and rock density, having an average gradient of 1.02-1.03 psi/ft. Pore pressure gradients were determined based on drill stem tests and step-rate tests. The average pore pressure gradient of the Mississippian through Precambrian sections was 0.27 psi/ft, indicating an underpressured condition relative to normal hydrostatic pressure at depth. This is consistent with the known underpressured reservoirs in the Hugoton Embayment of southwest Kansas, and indicating the reservoirs at the Patterson site are isolated from the adjacent fluid system by the barrier intervals and primary seal.

Minimum horizontal stress was determined using fracture closure pressure from the step-rate test, and using numerical methods that assume linear elastic behavior of the strata (Figure 73). The average gradient of the minimum horizontal pressure was found to be 0.56 psi/ft. The Hugoton Embayment lies within a normal-slip (NS) to strike-slip (SS) stress regime, where the maximum horizontal stress is approximately equal to the overburden stress. By assuming a strike-slip faulting environment, the upper bound of the magnitudes of the maximum horizontal stress gradient was estimated to be 1.13 psi/ft.

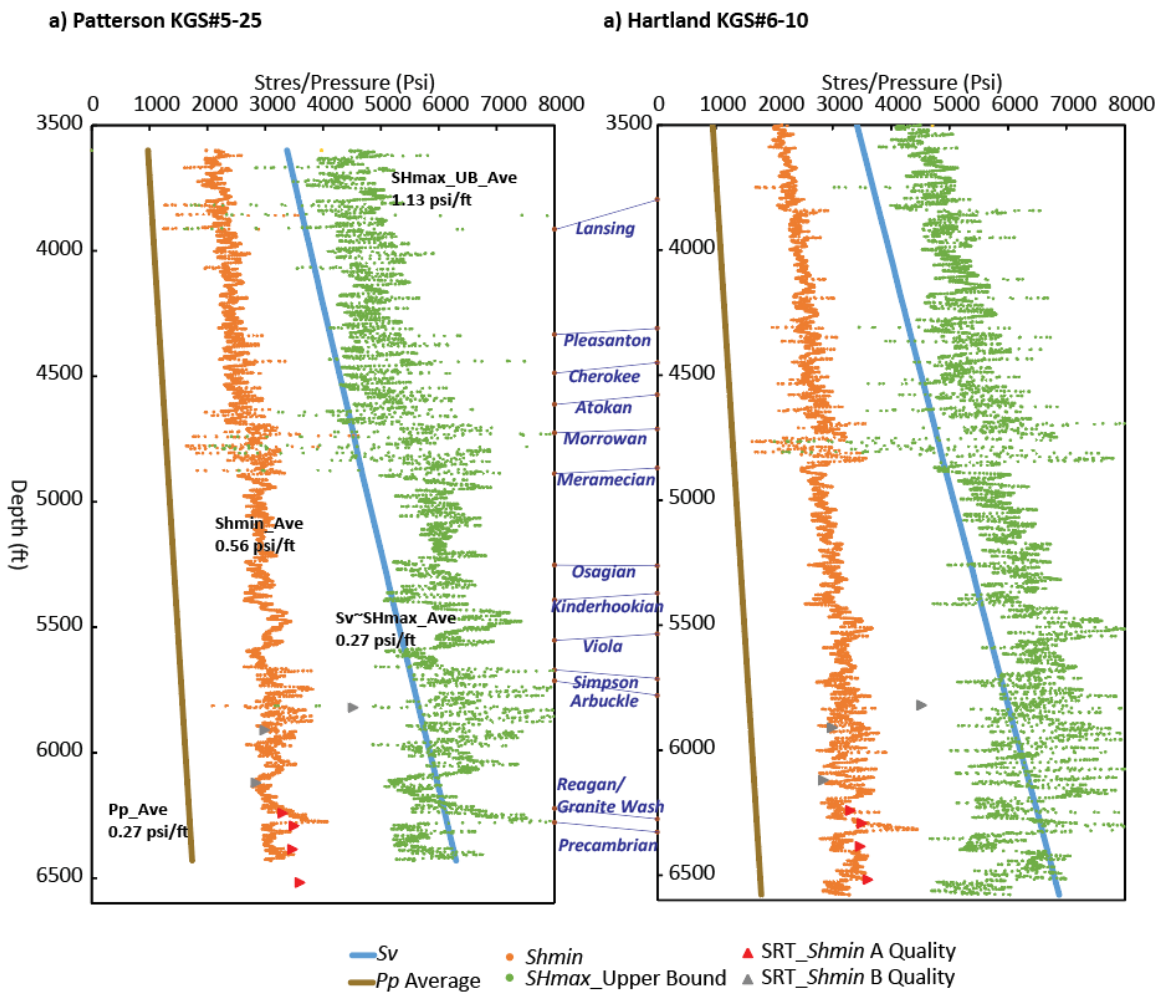


Figure 73. Depth profiles showing overburden stress (S_v), minimum horizontal stress (Sh_{min}), and maximum horizontal stress (SH_{max}) from Patterson KGS#5-25 (left) and Hartland KGS#6-10 (right) wells. Sh_{min} data (red and grey triangles) were obtained from step-rate test.

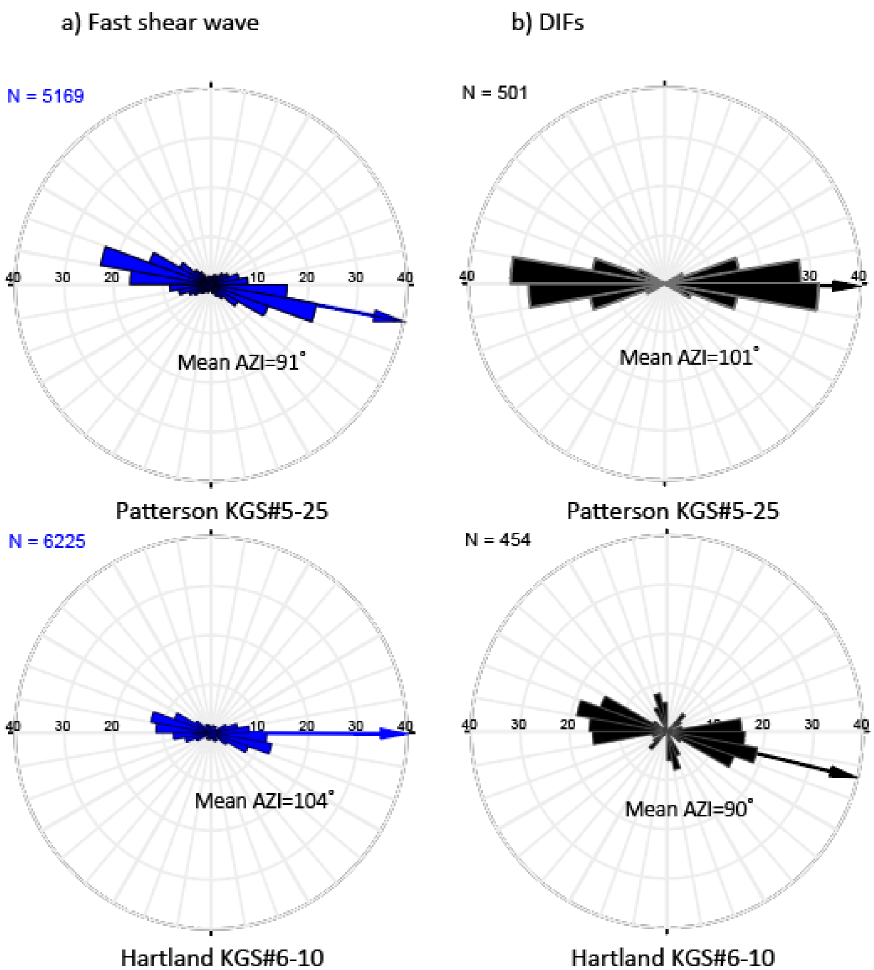


Figure 74. a) Rose diagrams and vector mean azimuth (blue) of the fast shear wave direction; b) Rose diagrams and vector mean azimuth (black) of the DIFs in the Patterson KGS#5-25 well, orientation of DIFs agree with the fast shear wave azimuth.

Rock Mechanics Analysis

Laboratory rock mechanical testing was performed to obtain mechanical properties at various effective stresses for numerous intervals of the Paterson KGS #5-25 well. Premier Oilfield Group (POFG) was tasked with conducting numerous triaxial (TXC) tests on rock material from the Atoka, Morrow, Meramec, Osage-Kinderhook, Viola, Upper Arbuckle, Lower Arbuckle, Granite Wash/Reagan, and Precambrian intervals. Table 31 summarizes the key rock mechanical properties for the tested intervals. Detailed procedures and results have been included in the Reservoir Characterization Core Services Report provided by POFG. Geomechanical analyses demonstrated that the reservoir and seal rock have an overall very competent rock strength. The unconfined compressive strength (UCS) of the reservoir rocks from the Arbuckle, Viola, and Osagian intervals ranged from 12,923 psi to 49,985 psi. The UCS of the seal intervals (Meramecian, Morrowan, and Atokan) ranged from 9,519 psi to 26,837 psi. The Precambrian basement had a UCS of 28,544 psi. Morrow sandstone and the granite wash/Reagan sandstone have lower UCS values (4,511 psi and 6,932 psi, respectfully).

Samples from the shale caprock of the Morrowan were unable to be used for geomechanical testing due to the highly fissile nature. However, those Morrowan shale intervals are overlain by competent Atokan Limestone. The granite wash/Reagan intervals are overlain by the most competent Arbuckle dolostone and underlain by the Precambrian basement. In summary, rock mechanical test results of both the reservoir and seal integrity analyses show that the stacked target reservoir/seal intervals are under stable stress conditions. Tensile hydraulic fracturing can be prevented by limiting the injection pressure below the minimum effective horizontal stress. Therefore, it is unlikely that shear fracturing will occur during injection as long as the injection pressure is kept below the minimum effective horizontal stress. According to the structural analysis, the average total vertical (TVD) depth of the Arbuckle, Viola, and Osage reservoirs are 5,878 ft, 5,652 ft, 5,384 ft, respectively (Battelle, 2020d). The estimated maximum injection pressures are therefore calculated as 1,587 psi for the Arbuckle potential reservoir, 1,526 psi for the Viola potential reservoir, and 1,454 psi for the Osagian potential reservoir.

Table 31. Summary key data of the rock mechanics analysis.

				Static Properties		MC Failure Envelope		
				Mechanical Properties				
Sample ID	Formation Type	Plug Depth (ft)	UCS (psi)	E (Mpsi)	PR (Dec)	Cohesion (psi)	Friction Angle (Deg)	COF (Dec)
GM13-1	Atoka Limestone	4627.00	24505	7.08	0.24	4681	45.90	0.72
GM12-1	Atoka Limestone	4682.50	26837	7.12	0.25	5368	45.30	0.71
GM10-1	Morrow Limestone	4741.00	9519	3.42	0.24	2055	47.10	0.73
GM11-1	Morrow Limestone	4743.25	18619	3.75	0.13	3837	46.90	0.73
GM9-1	Morrow Sandstone	4771.00	4511	1.90	0.31	1374	33.60	0.55
GM8-1	Meramec Limestone	4901.15	21512	5.60	0.30	4517	44.60	0.70
GM14-1	Meramec Limestone	4952.00	19870	4.45	0.29	4647	40.80	0.65
GM7-1	Osage / Kinderhook Dolostone	5418.00	12923	5.26	0.21	2511	50.30	0.77
GM5-1	Viola Dolostone	5715.25	24701	7.73	0.30	4440	49.20	0.76
GM4-1	U. Arbuckle Dolostone	5792.25	15320	5.20	0.31	3298	45.90	0.72
GM6-1	U. Arbuckle Dolostone	5817.00	19737	6.11	0.31	4000	47.00	0.73
GM15-1	L. Arbuckle Dolostone	5965.75	15553	4.85	0.44	3223	45.00	0.71
GM16-5	L. Arbuckle Dolostone	6022.70	20227	9.26	0.39	3738	44.30	0.70
GM17-1	L. Arbuckle Dolostone	6089.15	23553	5.64	0.18	4233	51.00	0.78
GM3-1	L. Arbuckle Dolostone	6148.20	49985	13.40	0.33	9521	48.50	0.75
GM2-1	Granite Wash/Reagan Sandstone	6251.20	6932	1.72	0.29	1699	41.80	0.67
GM1-4	PreCambrian Granite	6281.00	28544	9.74	0.26	6047	44.10	0.70

Static Earth Model Updates

Introduction

The Patterson Site is located in Kearny County, Kansas, approximately 6 miles (9.7 km) northwest of the City of Lakin, Townships 22-24 South, Range 37-38 West. The new 3D seismic survey was the basis for updating the three-dimensional (3D) static geological model using Schlumberger's Petrel software. The cells were populated with porosity and permeability values based on porosity-permeability transforms developed from wireline log data. This report provides a record of the data, methodology, and results pertaining to the development of this geological model.

Modeling Workflow

The modeling workflow consisted of data collection and analysis, structural mapping, 3D structural development of a cellular 3D model, upscaling of wireline logs, modeling of the upscaled petrophysical properties, and the vertical upscale of the model. Figure 75 presents a generalized diagram of this workflow.

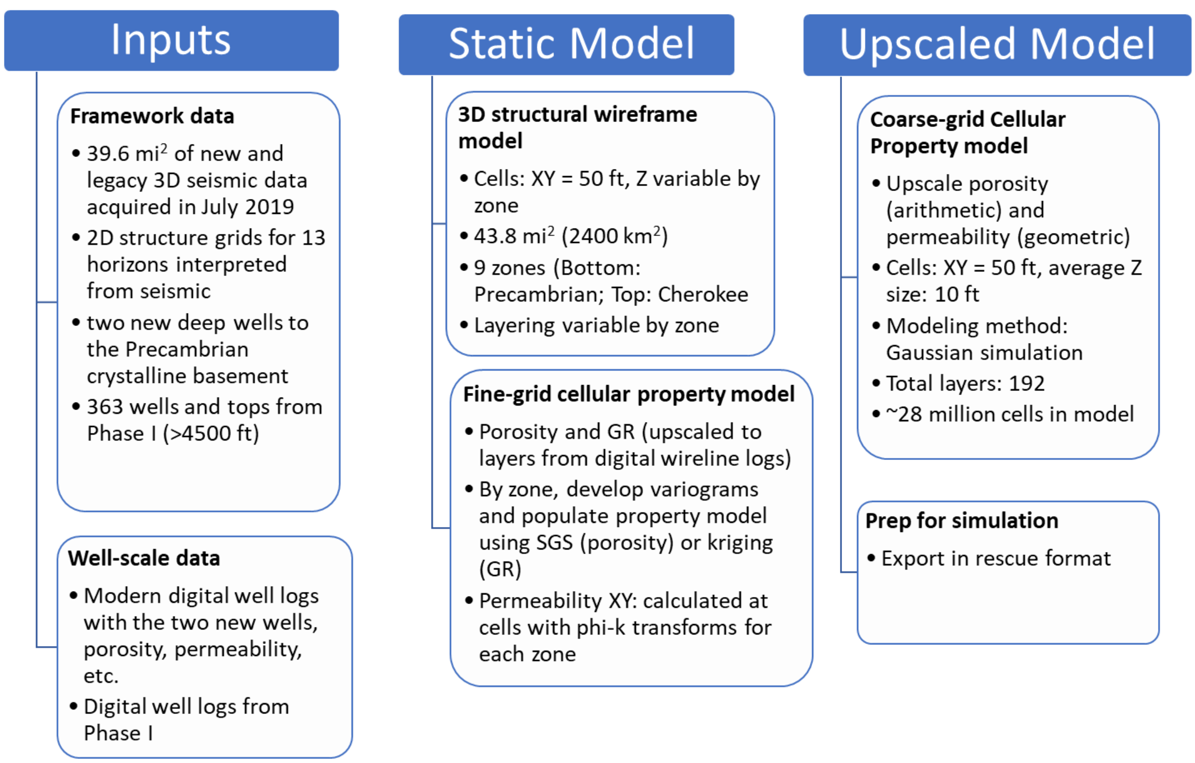


Figure 75. General workflow followed during the building of the Patterson site 3D geologic model.

Data

During CarbonSAFE Phase II, two new 3D seismic surveys were acquired in July 2019 over the Patterson and Hartland oil fields and integrated with two legacy datasets over the Heinitz and Oslo oil fields to characterize the regional structural framework of the Patterson Site. In March–

June 2020, two new deep wells were drilled into Precambrian crystalline basement to acquire petrophysical, geomechanical, geochemical, and engineering data from core, wireline logs, and well tests. In this study, data from the new and legacy 3D seismic reflection surveys were integrated in Petrel to define the 3D structural model. A 43.8 mi^2 (113.4 km^2) polygon area with the complete 3D seismic coverage was selected for model development comprising the Patterson, Heinitz South, Hartland, and Oslo areas (Figure 76).

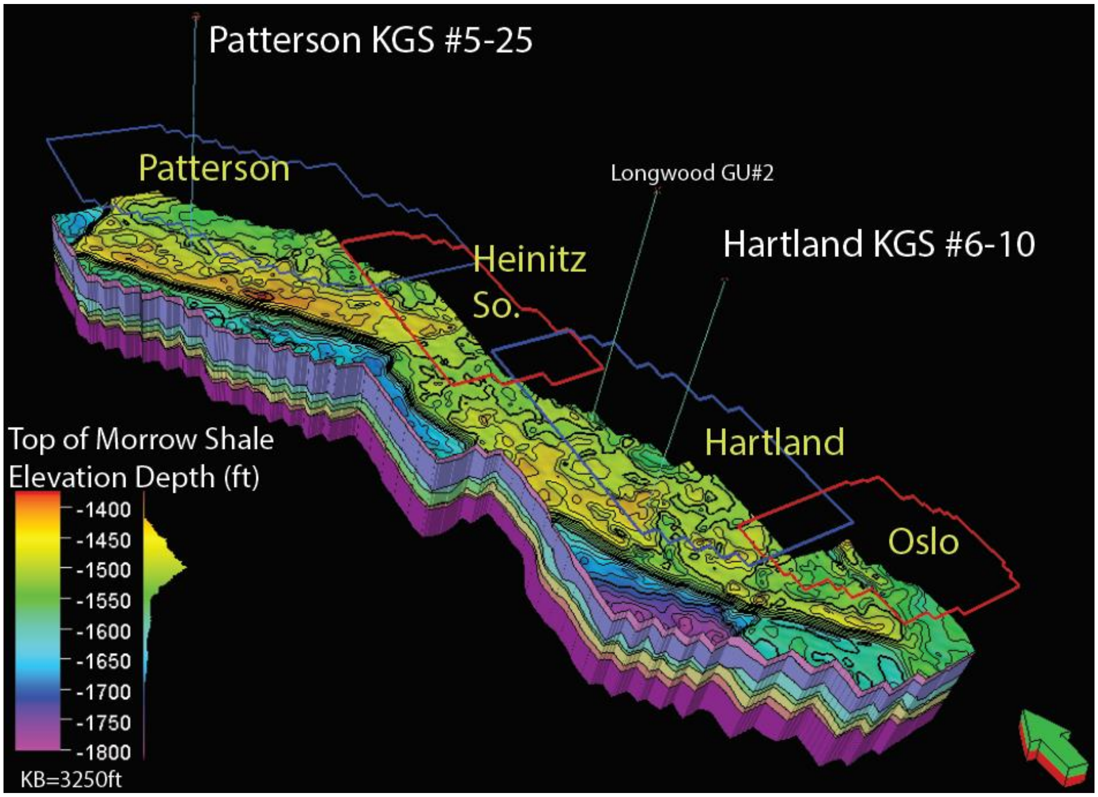


Figure 76. Structural model in the Patterson-Oslo area with the legacy deep well (Longwood Gas Unit #2) and two new deep wells (Patterson KGS 5-25 and Hartland KGS 6-10) noted. The top of the model is a depth structure map of the top of the Morrow Shale. On the left side of the legend is a histogram of elevation depths for the Morrow Shale top.

Analysis

An extensive set of data including: wireline logs (conventional and nuclear magnetic resonance (NMR) logs) and core data for estimating permeability was obtained from the two newly drilled deep wells, Patterson KGS 5-25 and Hartland KGS 6-10. In Phase I modeling, 305 wells deeper than 4,500 ft were incorporated into the model. Of these, 304 wells contain formation top data, including manually picked tops from the depth-calibrated wireline log images at 164 wells. There are 211 wells with picked tops penetrating Mississippian strata (60 of these wells penetrated the Salem Limestone, 26 penetrated the Warsaw Limestone); 13 wells penetrated the Ordovician Viola Limestone; 8 wells penetrated strata of the Cambro-Ordovician Arbuckle Group. Twenty wells from Phase I work had digitized porosity logs and were used to calculate permeability using porosity-permeability transform equations derived from available core analysis data. The 3D static geological model was generated using digital porosity and permeability by applying a Coates model to the NMR from wireline logs from the existing model and the two new characterization wells.

Porosity and Permeability

Table 32 summarizes the average porosity and permeability from the wireline logs acquired in the Patterson KGS 5-25 and Hartland KGS 6-10 wells. Average porosity was calculated from the neutron and density porosity log. A permeability log was generated by applying a Coates model to the NMR log data. Porosity and permeability logs from the two new wells further refine the Phase I estimates of reservoir quality of the three storage targets (i.e., Osage, Viola, and Arbuckle). Figures 77-79 display the wireline log intervals from Patterson KGS 5-25 showing porosity, permeability, and other relevant logs through the three target intervals. Figures 80-82 show the wireline log intervals from Hartland KGS 6-10. The Arbuckle reservoir is the thickest among the three target reservoirs, showing a ~500 ft (152 m) porous cherty dolomite in the Patterson KGS 5-25 and Hartland KGS 6-10 wells. It contains 8-10% porosity with the porosity reaching 30% locally (Figure 77). The Viola reservoir contains a 120-180 ft (37-55m) porous cherty dolomite with average porosity of 15%. The Osage reservoir contains a 110-140 ft (34-43m) cherty dolomite and limestone, with porosity reaching 30% locally. The T_2 Coates permeability log showed higher values in the Hartland KGS 6-10 well than the Patterson KGS 5-25 well. The average permeability in the Arbuckle reservoir was 0.04 mD in the Patterson well and 0.62 mD in the Hartland well. In the Viola reservoir, the average permeability was 0.01 mD in the Patterson well and 2.35mD in the Hartland well. The average permeability in the Osage was 5.08 mD in the Patterson well and up to 482.53 mD in the Hartland well. The Hartland well showed 339 mD permeability in the Precambrian basement. This may due to wireline log processing during drilling. Further study is needed to verify the permeability log, especially in the deeper sections.

Table 32. Summary of the average porosity, T_2 Coates permeability, and model zone information of each relevant interval in the static geological model.

Zone Name	Avg. Z size (ft)	No. of Layers	Patterson KGS 5-25			Hartland KGS 6-10		
			MD (ft)	Avg. Porosity (%)	Avg. Perm. (mD)	MD (ft)	Avg. Porosity (%)	Avg. Perm. (mD)
Cherokee Group	9.7	15	4487	9.14	0.01	4449	8.86	0.12
Atokan Stage	9.6	10	4612	10.56	0.04	4578	10.33	0.91
Morrowan Stage	10.9	15	4726	20.85	0.58	4715	20.07	9.66
Meramecian Stage	9.7	45	4888	3.96	0.01	4844	4.27	0.9
Osagian Stage	10.6	15	5252	10.96	5.08	5263	11.78	482.53
Kinderhookian Stage	10	14	5392	3.91	0.01	5372	5.60	0.61
Viola Limestone	10.6	16	5552	6.16	0.01	5535	9.37	2.35
Simpson Group	10.5	12	5670	9.56	0.03	5716	8.10	1.61
Arbuckle Group	10.3	50	5714	6.34	0.04	5781	6.51	0.62
Reagan/Pre-cambrian	N/A	N/A	6223	12.23	0.34	6275	10.35	49.07
Precambrian	N/A	N/A	6278	3.15	0.03	6327	2.06	339.45

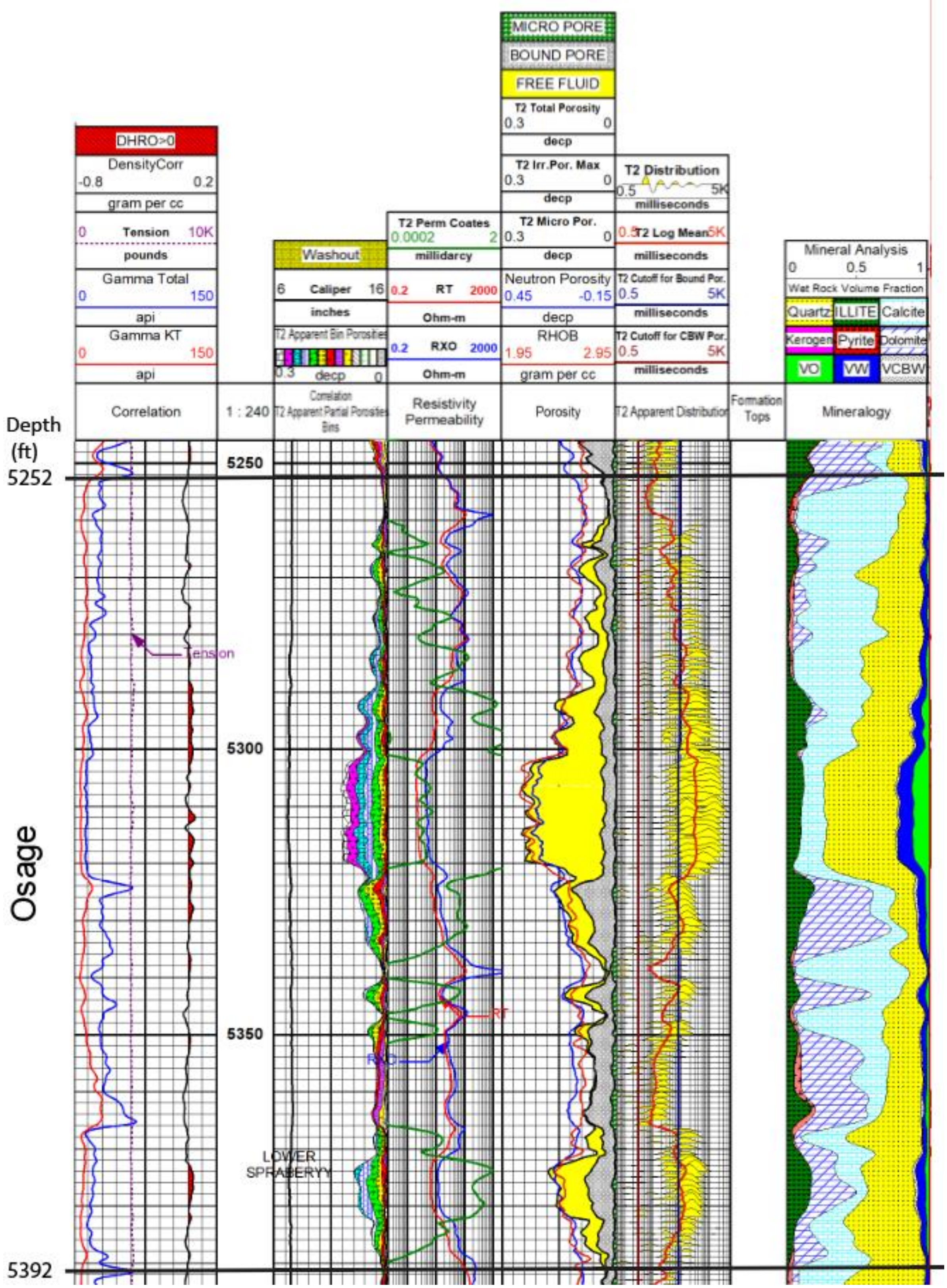


Figure 77. Wireline log of the Patterson KGS 5-25 well showing the porosity, permeability and other relative logs in Osage target reservoir intervals.

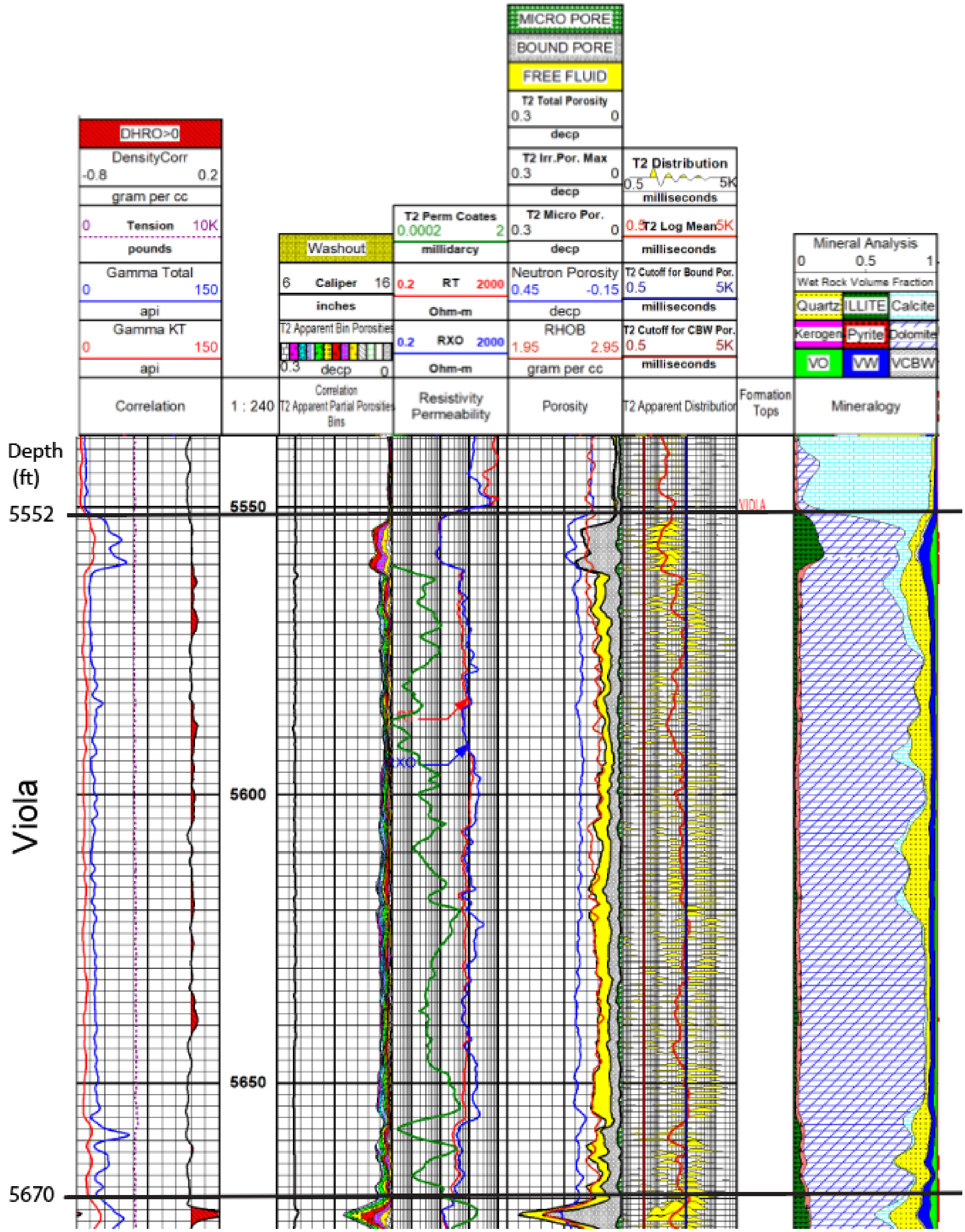


Figure 78. Wireline log of the Patterson KGS 5-25 well showing the porosity, permeability and other relative logs in the Viola reservoir intervals.

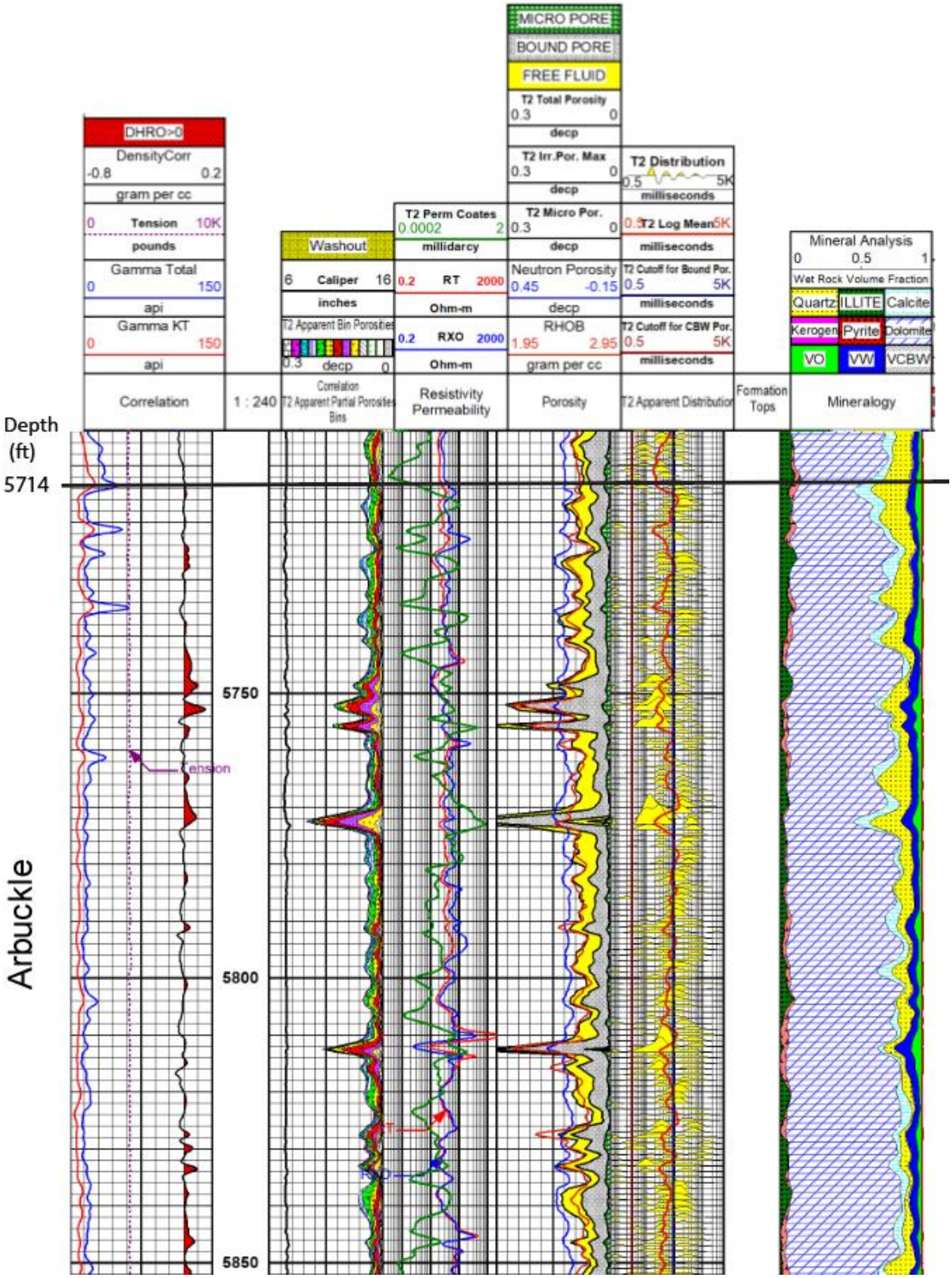


Figure 79. Wireline log of the Patterson KGS 5-25 well showing the porosity, permeability and other relative logs in the Arbuckle reservoir intervals. Figure 79 continues onto the next four pages.

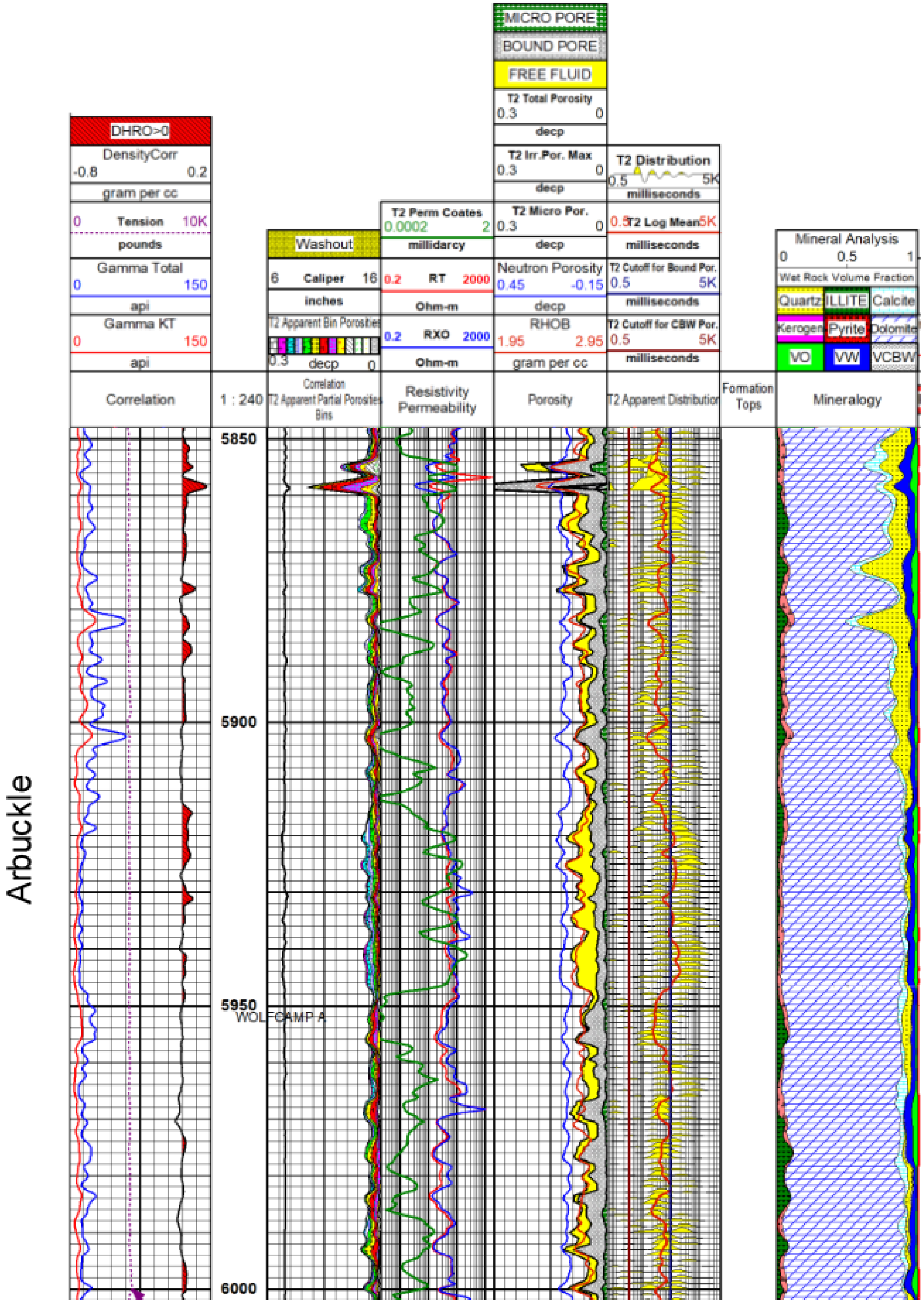


Figure 79 continued.

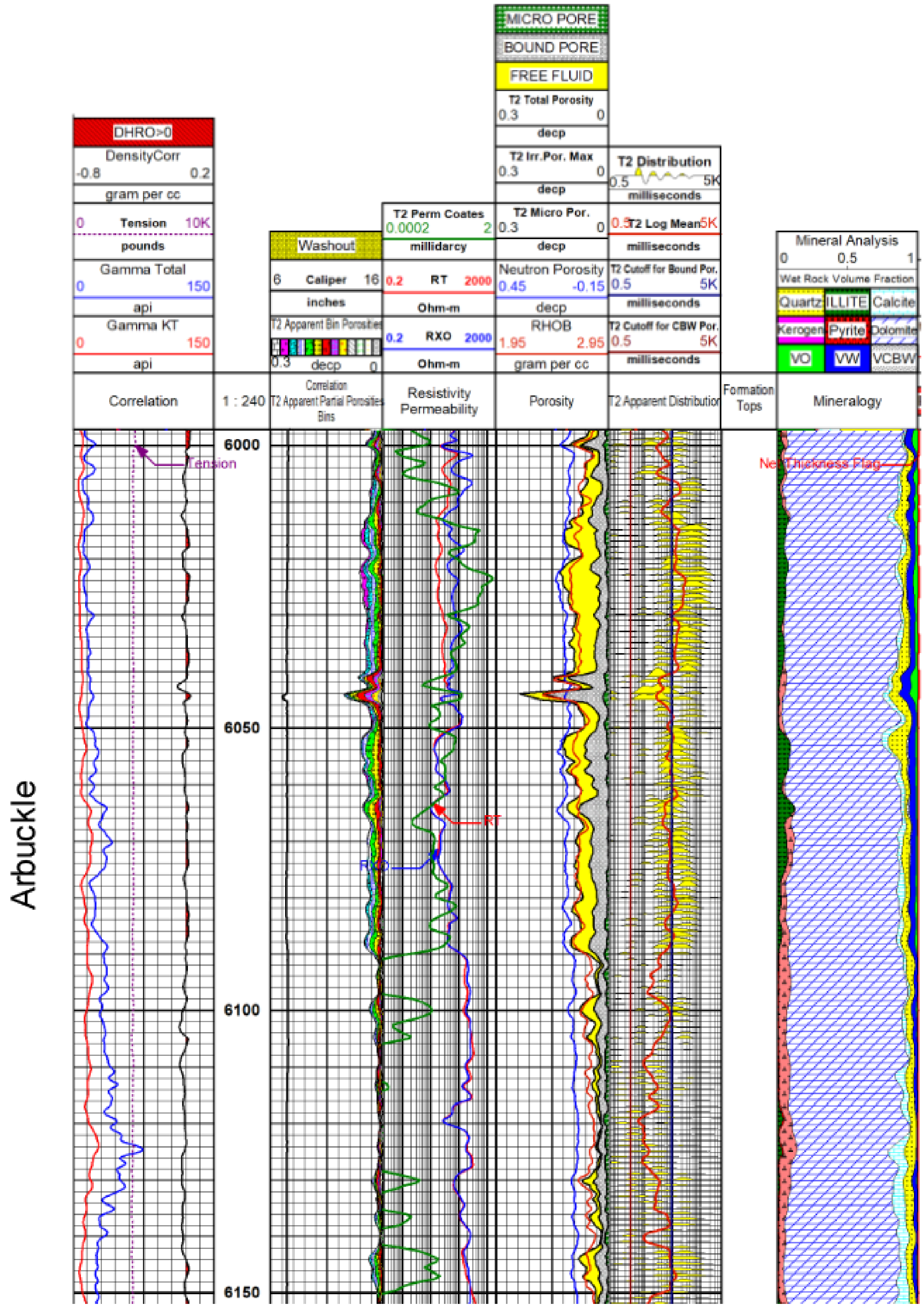


Figure 79 continued.

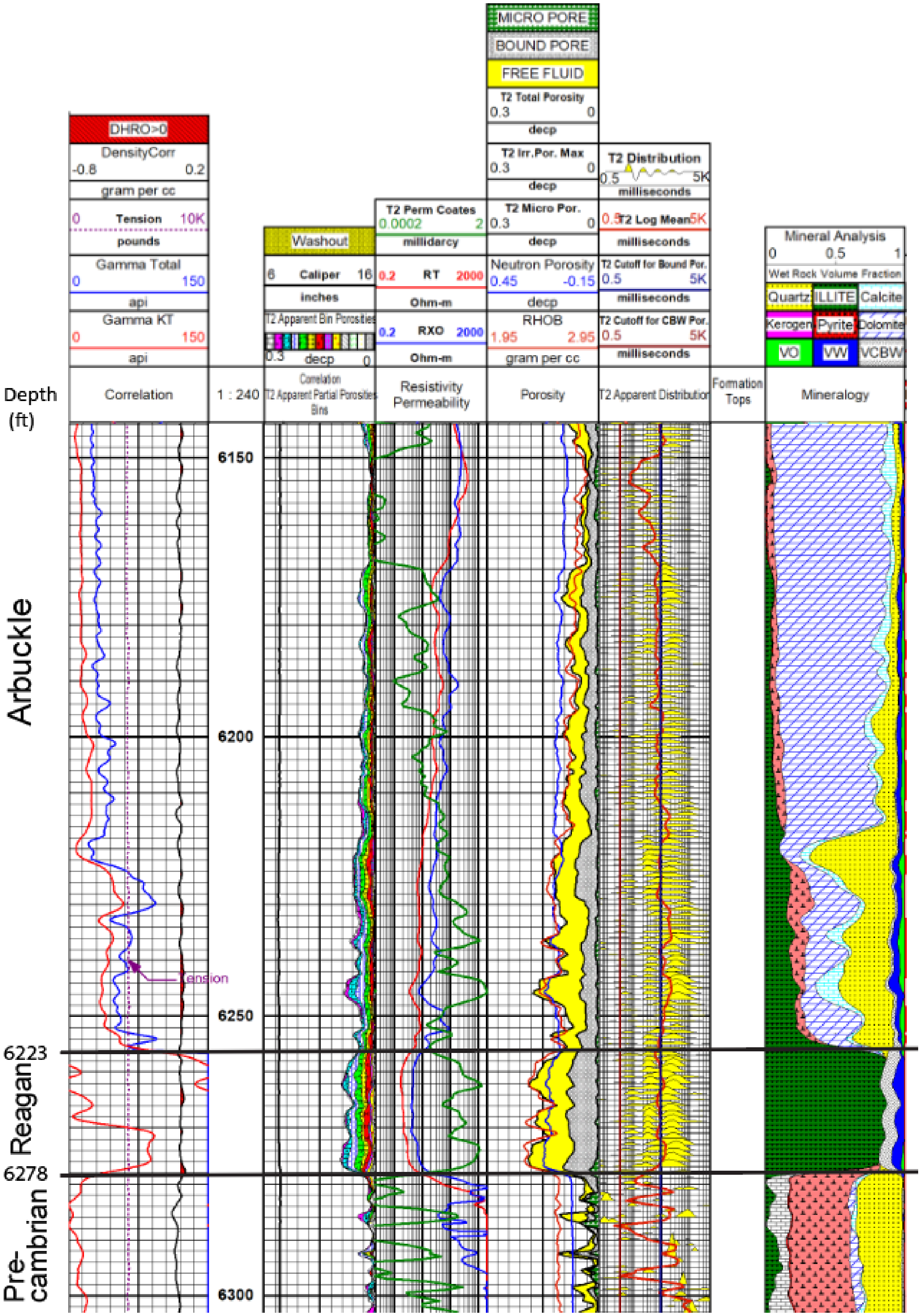


Figure 79 continued.

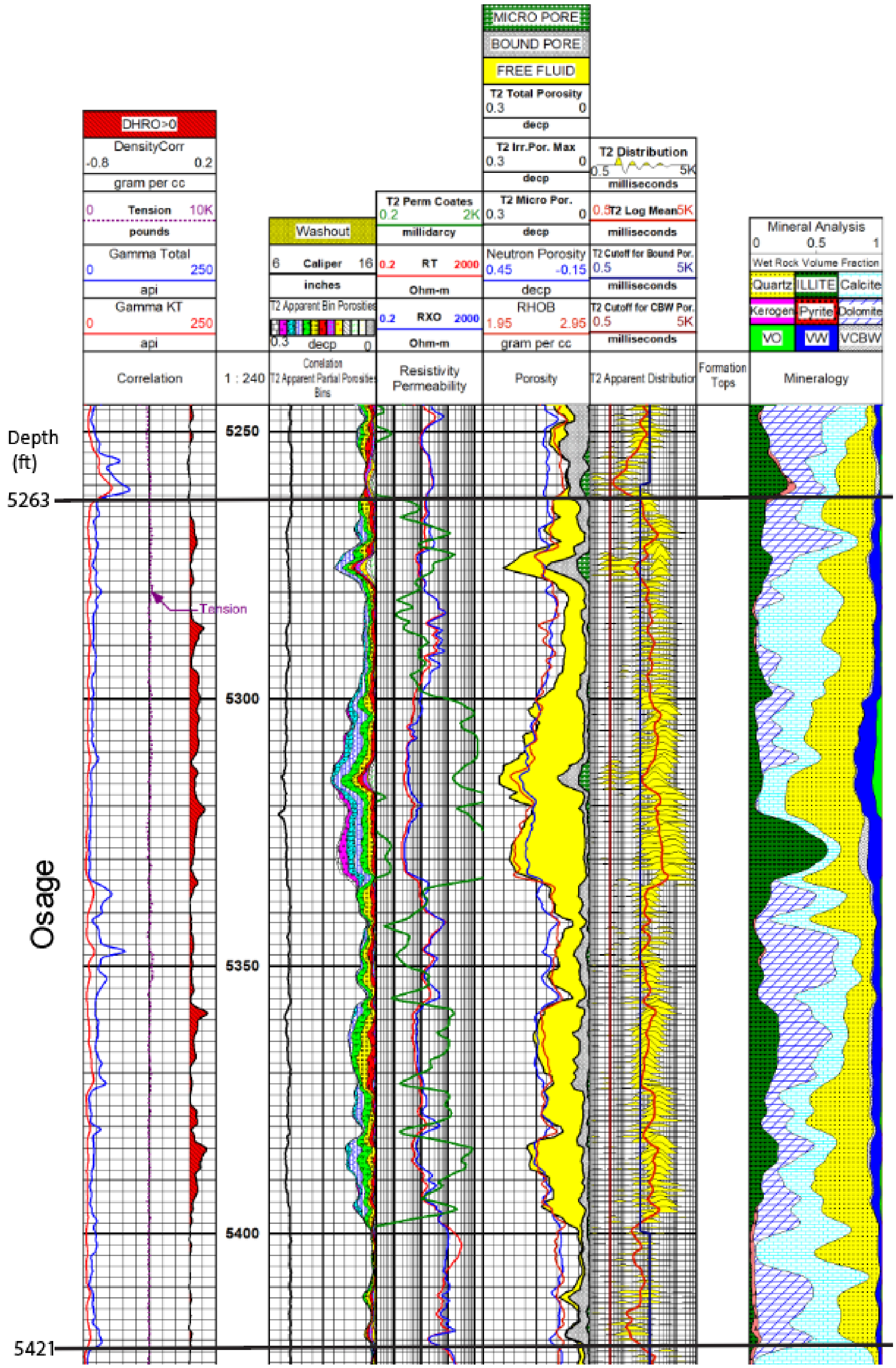


Figure 80. Wireline log of the Hartland KGS 6-10 well showing the porosity, permeability and other relative logs in Osage target reservoir intervals.

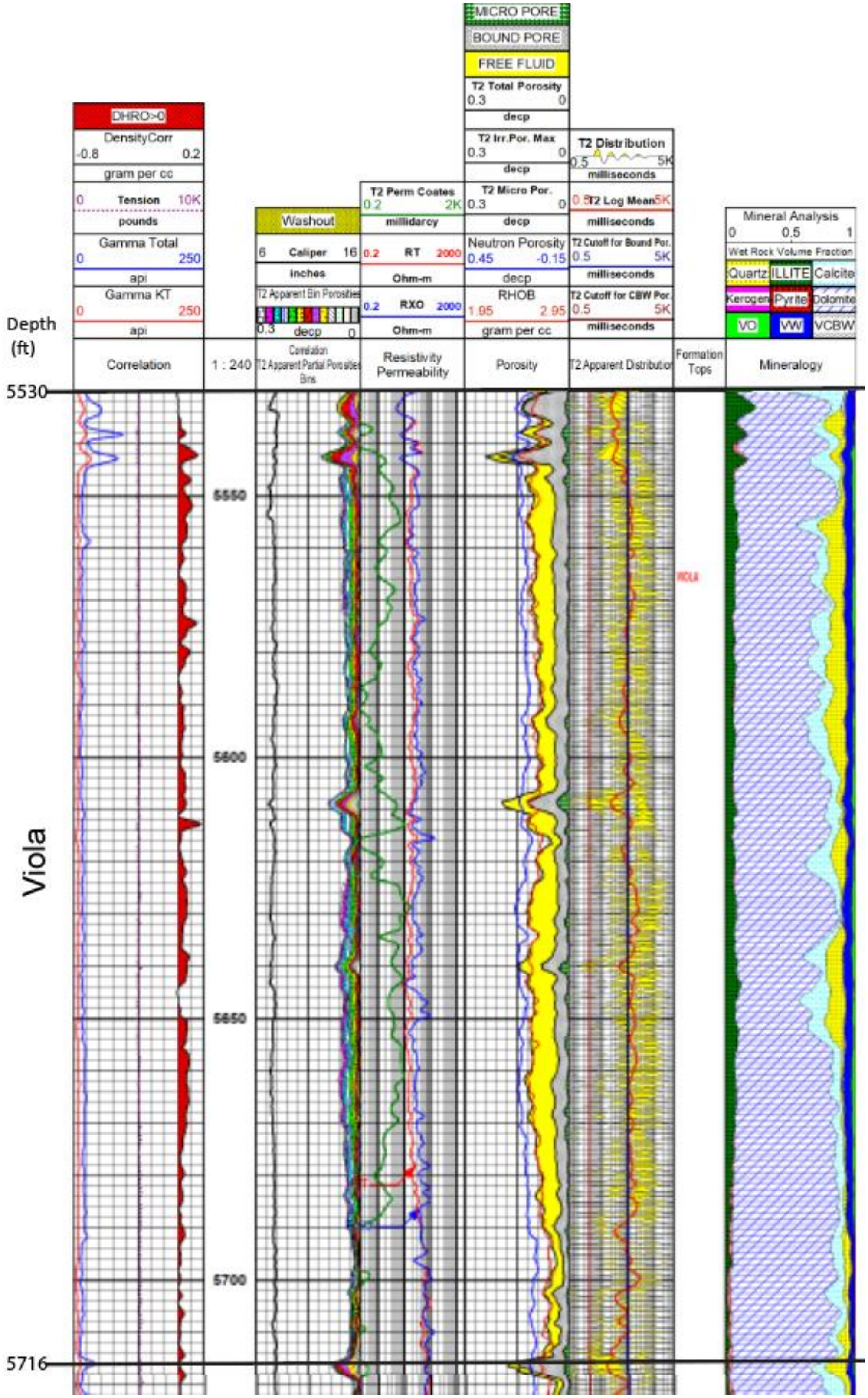


Figure 81. Wireline log of the Hartland KGS 6-10 well showing the porosity, permeability and other relative logs in Viola target reservoir intervals.

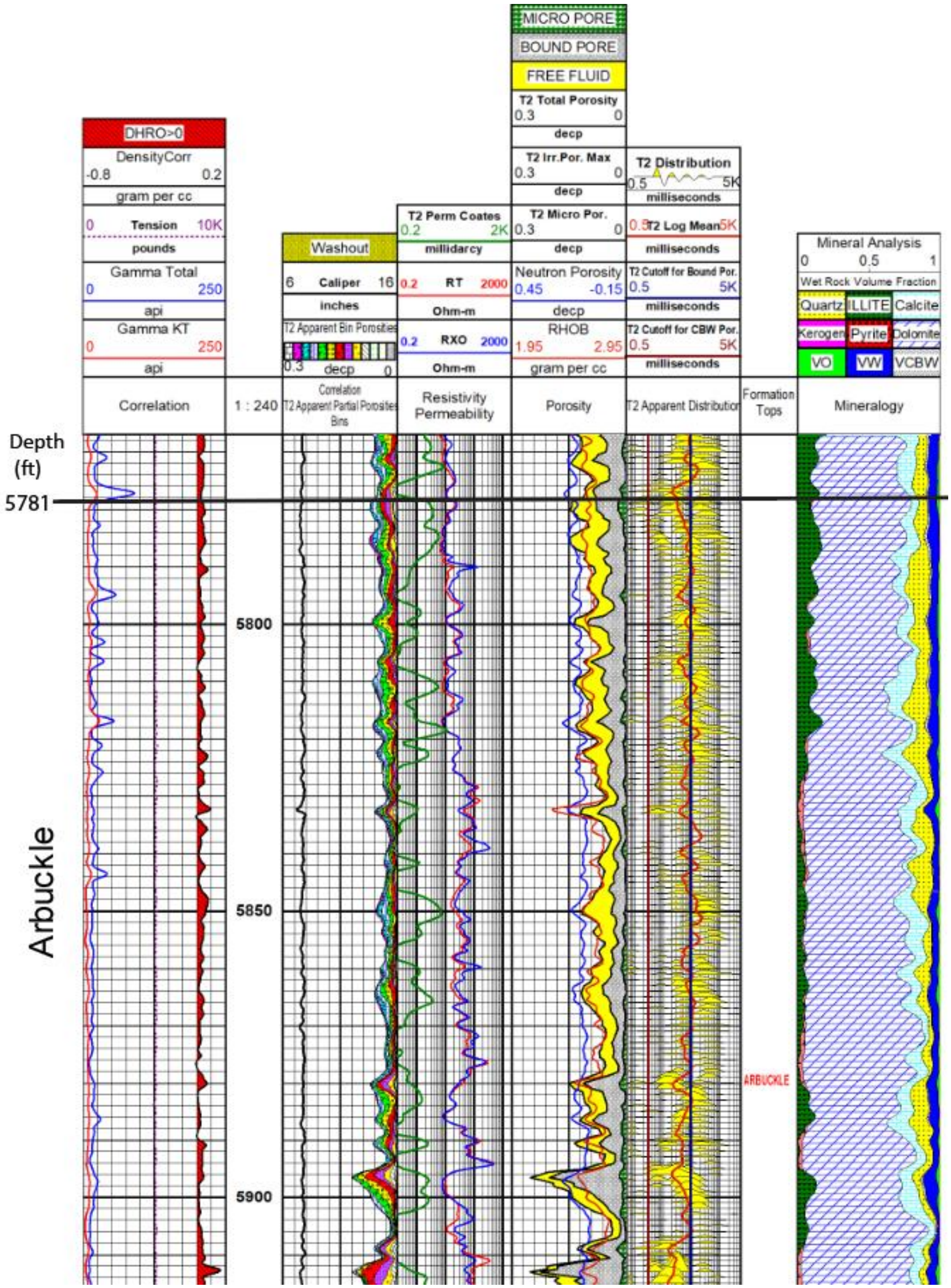


Figure 82. Wireline log of the Hartland KGS 6-10 well showing the porosity, permeability and other relative logs in the Arbuckle reservoir intervals. Figure 82 continues onto the next four pages.

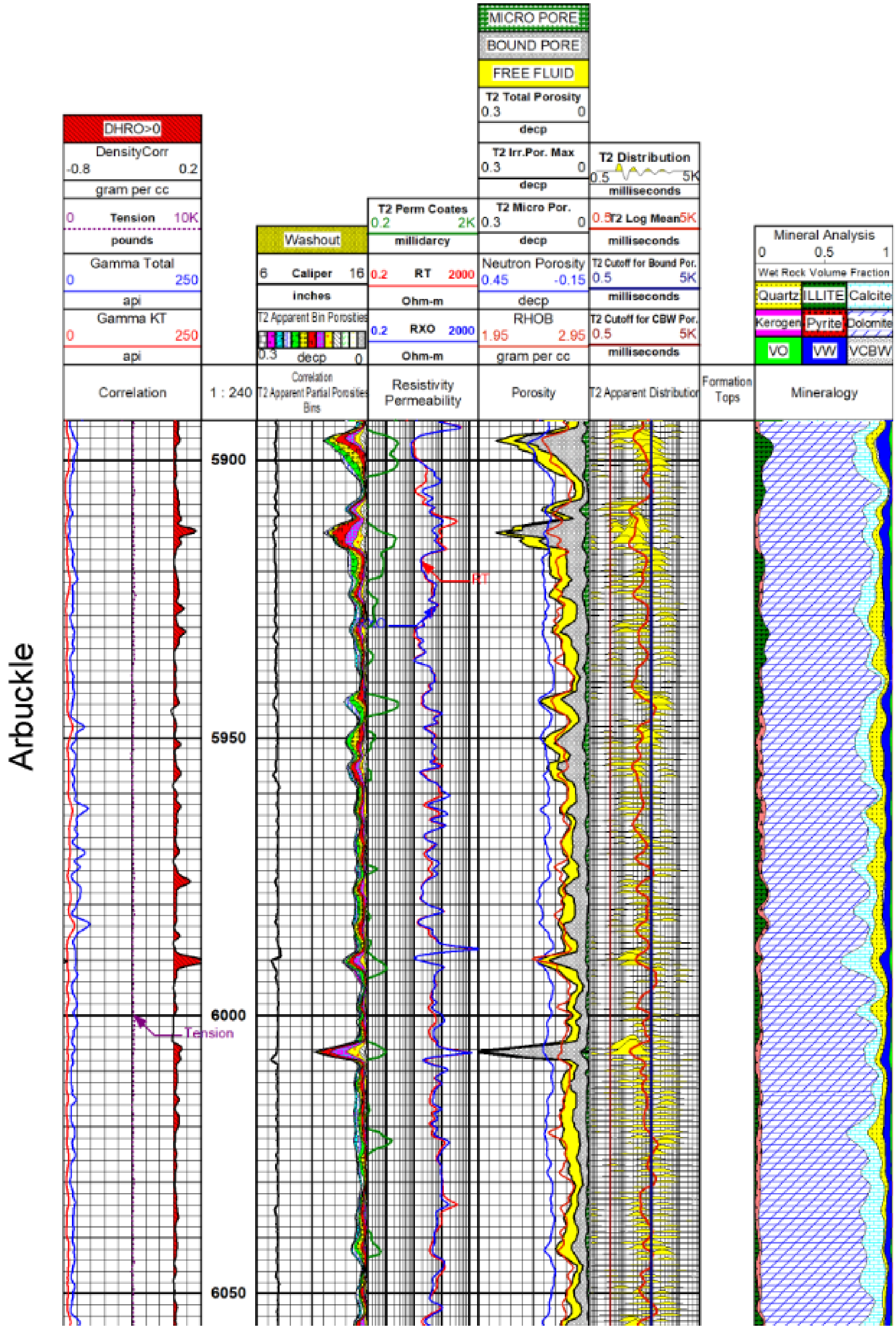


Figure 82 continued.

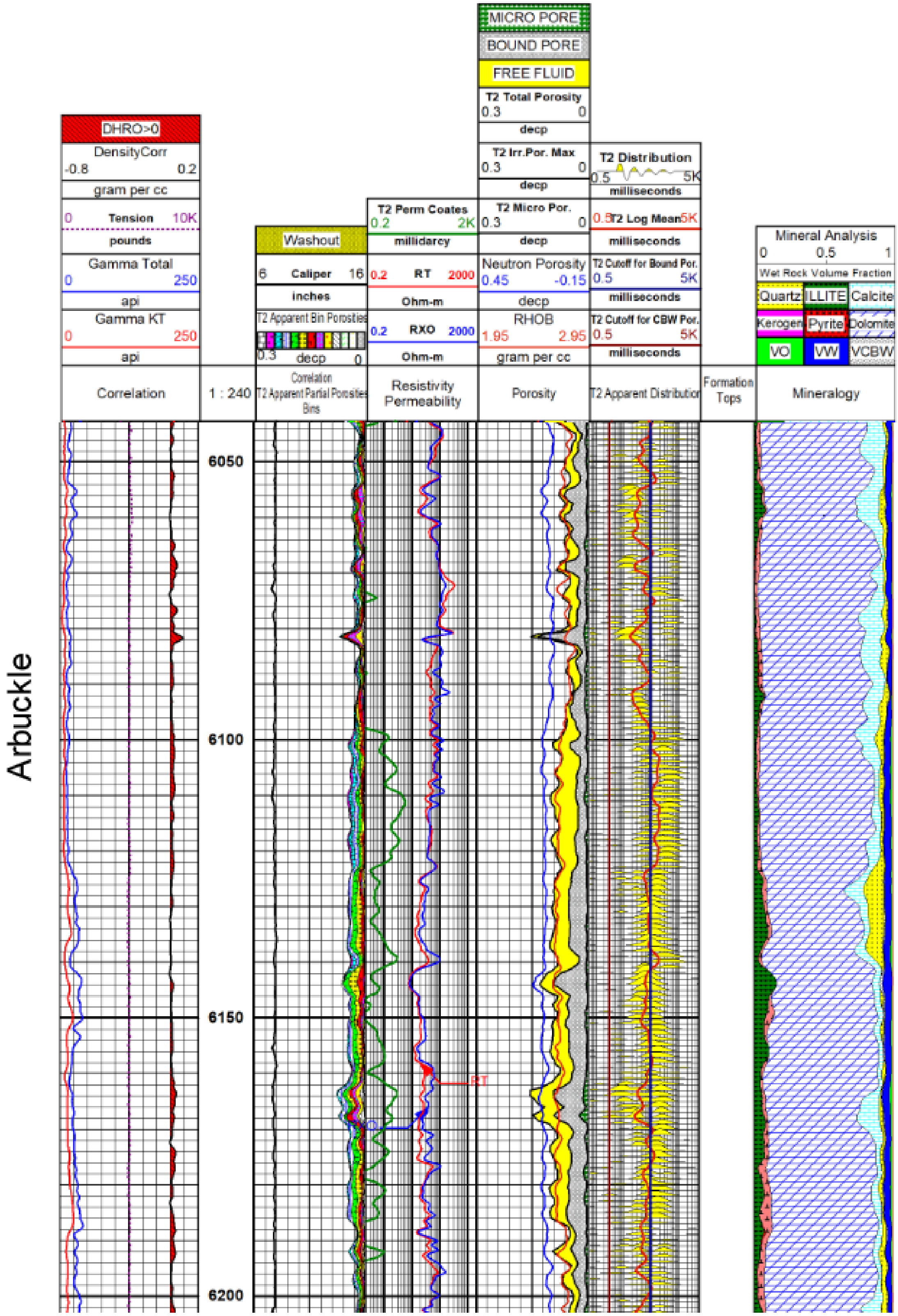


Figure 82 continued.

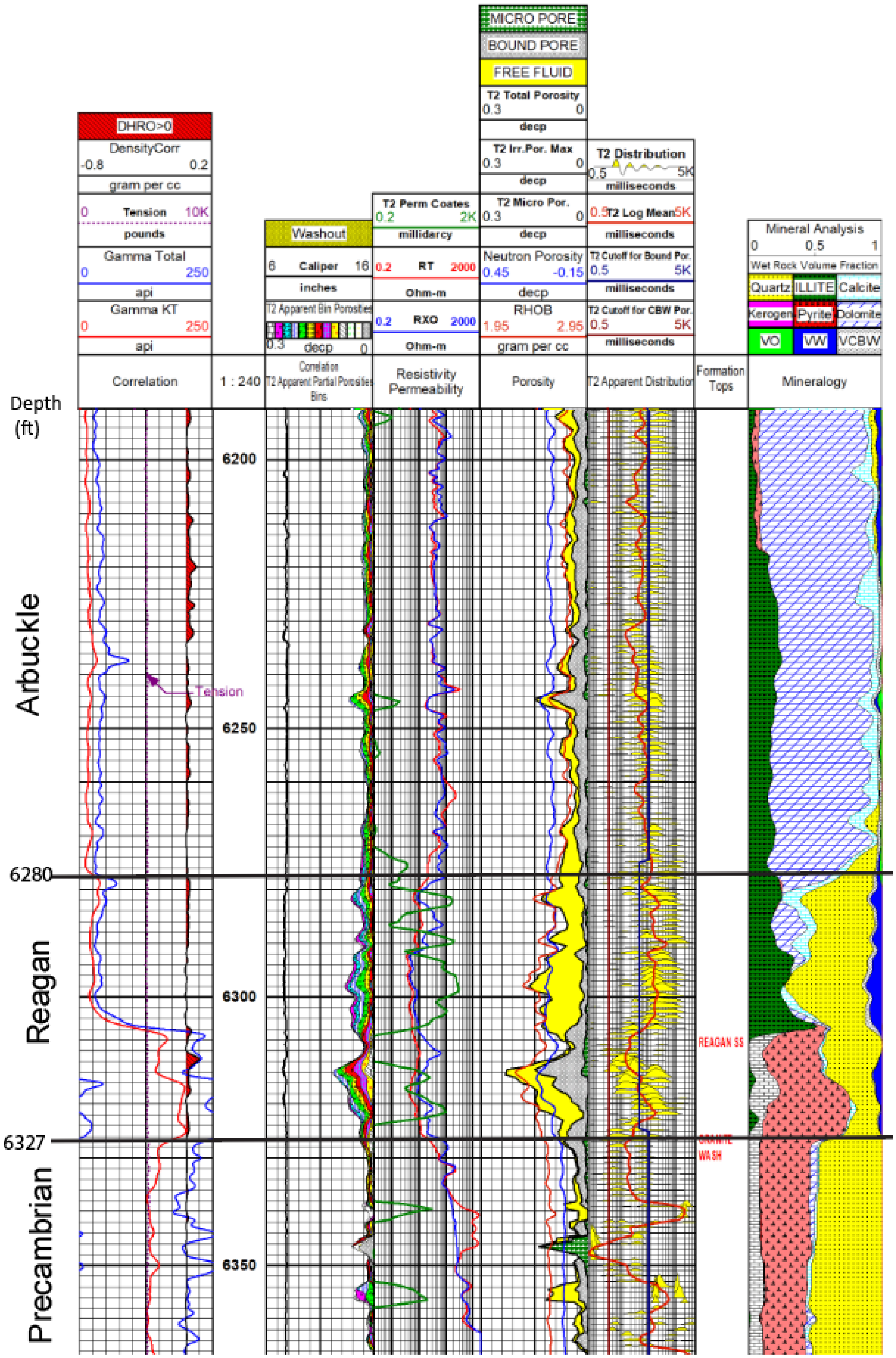


Figure 82 continued.

Petrophysical Analysis

Permeability was derived from the NMR log using the Coates method (Coates et al., 1999), and then subsequently plotted against neutron porosity to derive porosity transforms for each formation. Data points of T2 Coates permeability and neutron porosity from the KGS 5-25 and KGS 6-10 wells were combined for each reservoir and seal interval in both wells. The sampling rate for both logs is 0.5 ft. Each interval was determined from formation tops identification based on previously defined well log analysis. A single PHI-K relationship was derived for the Cherokee to Reagan intervals using the Techlog Software. Predicted permeability by a single relationship resulted in a reasonable prediction compared to Coates with small deviations. PHI-K relationships for the key intervals are showing in Figure 83. Regression equation and correlation coefficients for each interval are shown in Table 33.

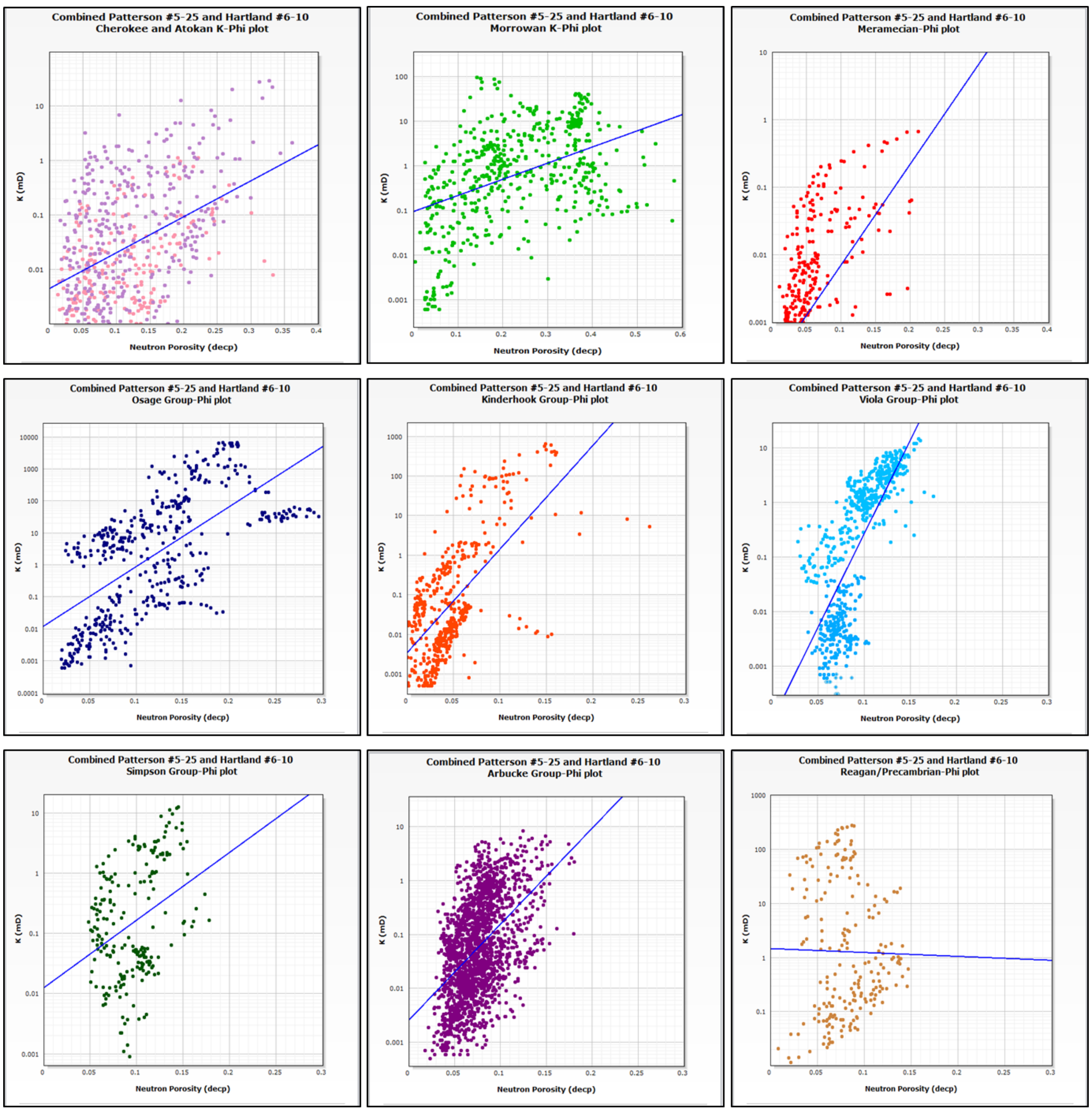


Figure 83. Coates Model correlation plots for neutron porosity-permeability for individual stratigraphic intervals in the Patterson #5-25 and Hartland #6-10 wells.

Table 33. Model equations and correlation numbers of the plots for combined Patterson #5-25 and Hartland #6-10 wells. PHI is porosity. y is permeability

Name	Equation	R^2 Value	No. of Samples
Cherokee/Atokan	log10(y) = + 6.611314 * PHI - 2.355634	0.20	590
Cherokee Group	log10(y) = + 4.596471 * PHI - 2.498495	0.14	215
Atokan Stage	log10(y) = + 7.249561 * PHI - 2.219232	0.23	375
Morrowan Stage	log10(y) = + 3.620624 * PHI - 1.025555	0.17	534
Meramecian Stage	log10(y) = + 11.88383 * PHI - 2.987294	0.40	280
St. Louis Formation C	log10(y) = + 16.65072 * PHI - 2.215913	0.52	417
Osagian Stage	log10(y) = + 18.76410 * PHI - 1.927222	0.42	443
Kinderhookian Stage	log10(y) = + 26.19423 * PHI - 2.465316	0.42	495
Viola Limestone	log10(y) = + 33.59321 * PHI - 3.878796	0.58	569
Simpson Group	log10(y) = + 11.25185 * PHI - 1.903642	0.12	214
Arbuckle Group	log10(y) = + 17.81419 * PHI - 2.590029	0.24	1862
Reagan Sandstone/Precambrian	log10(y) = - 0.723755 * PHI + 0.166147	0.0003	214

Static Earth Model

Two 3D cellular models, porosity model and permeability model, covering the Patterson geologic site were constructed using the workflow discussed in detail above (Figure 75). Table 32 summarizes the zone and layer information for each interval. Figure 84 presents views from the southwest of the fine-grid porosity and permeability models. The Patterson site contains multiple structural closures that lie on uplifted fault blocks, bounded by two reverse faults that strike nearly perpendicular to each other. The 3D model cross section in Figure 84 illustrates the continuous nature of the permeable intervals in the proposed injection zones: Osage, Viola, and Arbuckle. It also shows the low permeability in the Meramec intervals above the Osage.

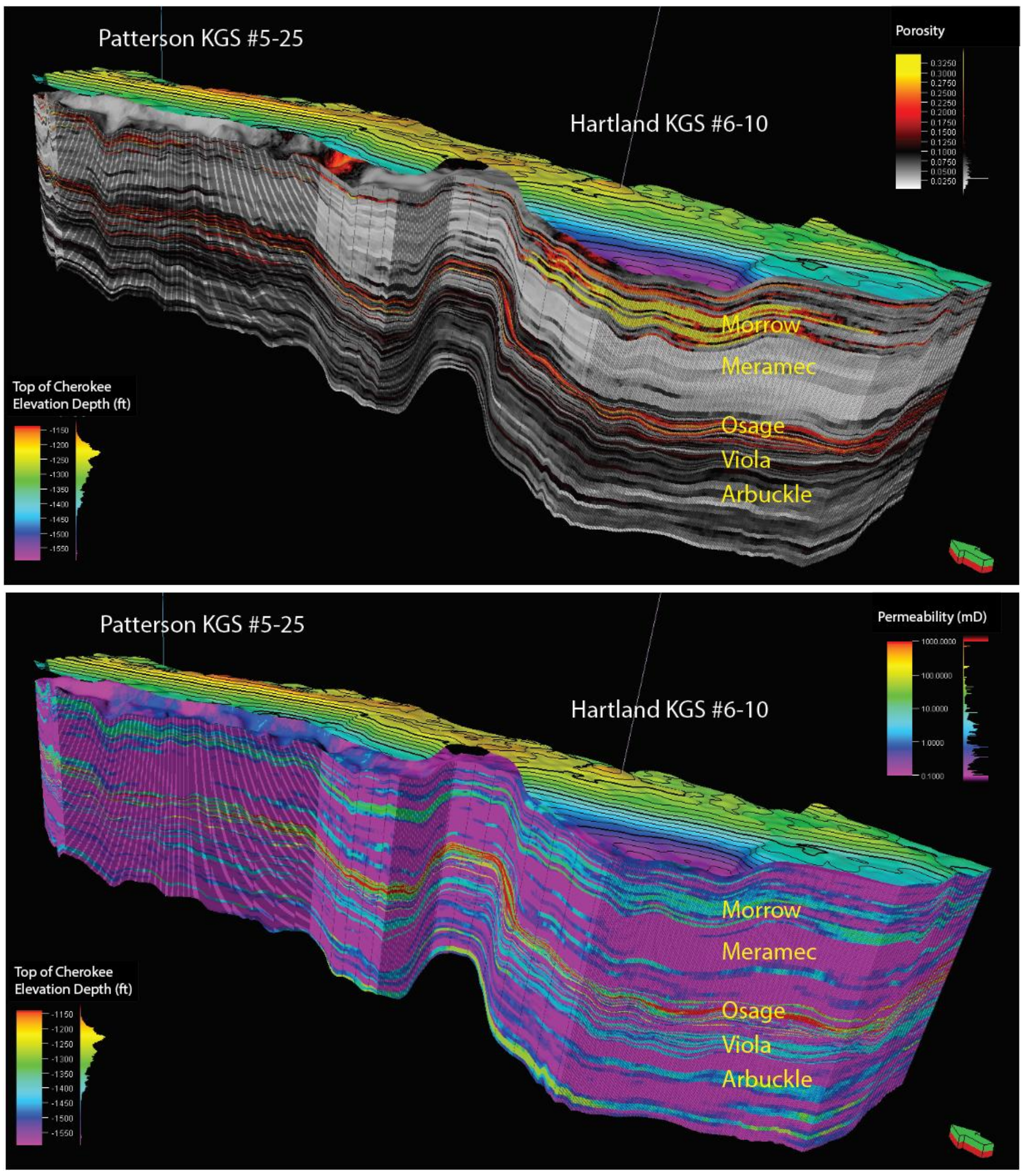


Figure 84. Upper figure: 3D volume of porosity from the top of the Atoka to basement. The map on top of the volume is the top of the Cherokee; its color does not reflect porosity. Lower figure: 3D volume of permeability from the top of the Atoka to basement. Well locations indicate the two new characterization wells drilled during Phase II.

CO_2 Storage Capacity Estimation: NETL CO_2 –SCREEN

The US-DOE methodology known as NETL CO_2-SCREEN (Goodman, Sanguinito, & Levine, 2016) is used for estimating CO_2 storage potential in the Patterson area. The methodology is general and could be applied globally; however, we refined the required data using the currently available information for the Patterson area. The Patterson area is an open system (no impermeable aerial boundary) with closures and caprocks to vertically seal and trap the injected CO_2 within the injected area. Thus, the percentage of pore space that can be filled with CO_2 primarily depends on storage efficiencies and is independent of bottom hole pressure. The Patterson field has an approximated area of 50 mile^2 (130 km^2) with three potential injection formations: Osage (limestone), Viola (dolomite), and Arbuckle (dolomite). Table 34 summarizes the geological properties of each formation as needed by CO_2-SCREEN.

Table 34: Properties of the Patterson area.

Grid #	Formation	Area (km^2)	Gross Thickness(m)		Total Porosity (%)		Pressure† (MPa)		Temperature (°C)	
		Mean	Mean	Std Dev	Mean	Std Dev	Mean	Std Dev	Mean	Std Dev
1	Osage	130	46	0	12	6.4	11.4	0	54	0
2	Viola	130	55	0	7	2.5	11.5	0	56	0
3	Arbuckle	130	174	0	7	3.7	11.7	0	58	0

The storage efficiency of the saline formations (G_{CO2}) is calculated by:

$$G_{CO2} = A_t h_{gross} \phi_{tot} \rho_{CO_2} E_{saline}$$

in which pore space ($A_t h_{gross} \phi_{tot}$) obtained using Table 36 parameters is multiplied by ρ_{CO_2} to convert to CO_2 mass in the reservoir and then multiplied by the storage efficiency factor for saline formations (E_{saline}), defined as:

$$E_{saline} = E_A E_h E_\phi E_v E_d$$

In which E_A is the net-to-total area, E_h is the fraction of total thickness that meets minimum permeability and porosity requirements, E_ϕ is the fraction of interconnected porosity, E_v is the volumetric displacement efficiency defining the volume that can be contacted by the CO_2 plume, and E_d is the microscopic displacement efficiency describing the fraction of water in water-filled pore volume that can be displaced by contacting CO_2. Efficiency values are based on Goodman et al., 2011. The E_A *and* E_h values are chosen higher than the global recommended values considering that the Osage, Viola, and Arbuckle formations in the Patterson area have good net-to-total area and net-to-gross thickness and high permeabilities.

Table 35 summarizes the injection capacity of each formation and the probability results for the calculated storage efficiency factors (i.e. $p(E_{saline})$) assuming one grid block for each formation. The injection capacity of the Arbuckle and Osage are high because the former has high thickness and the latter has higher porosity and is limestone. Results shown in Table 35 are presented graphically in Figures 85 and 86.

Table 35: Calculated storage efficiency factors for each formation.

Grid	Formation	Lithology	Saline Efficiency (%)			P_{10} (Mt)	P_{50} (Mt)	P_{90} (Mt)
			P_{10}	P_{50}	P_{90}			
1	Osage	Limestone	11	19.5	29	22	34	46
2	Viola	Dolomite	9.5	16	23	18	28	38
3	Arbuckle	Dolomite	8.5	14	21	56	105	142
					Total	**96**	**167**	**226**

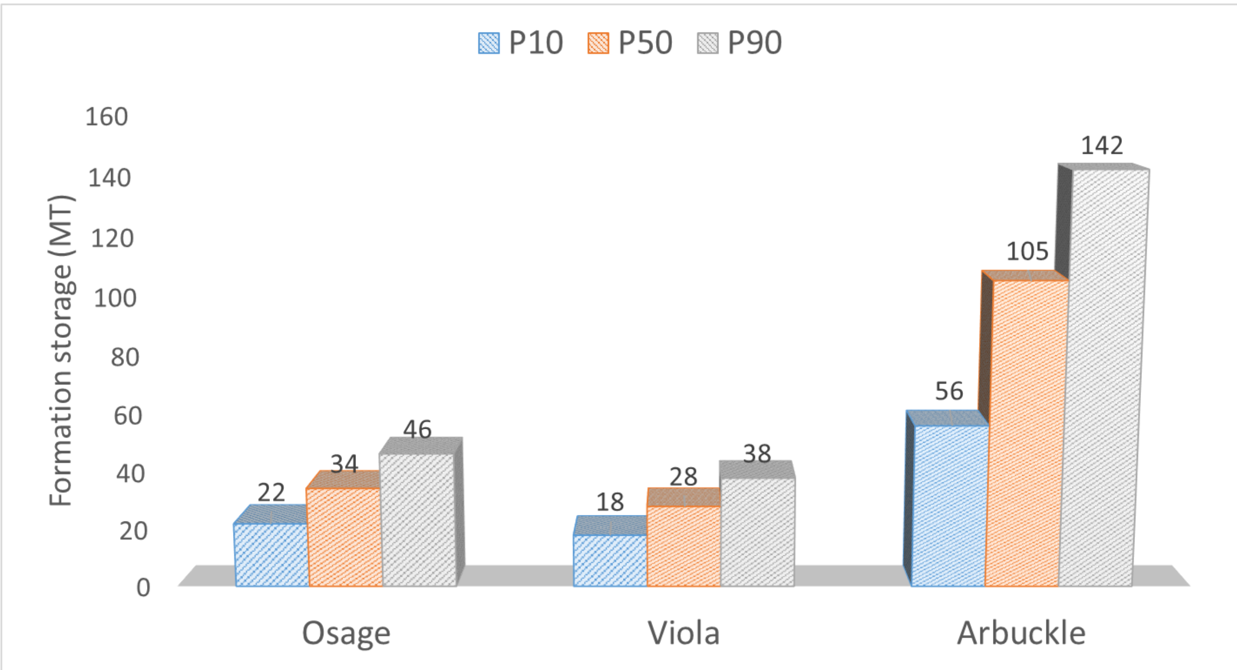


Figure 85: Formation storage capacity for the formations in the Patterson area.

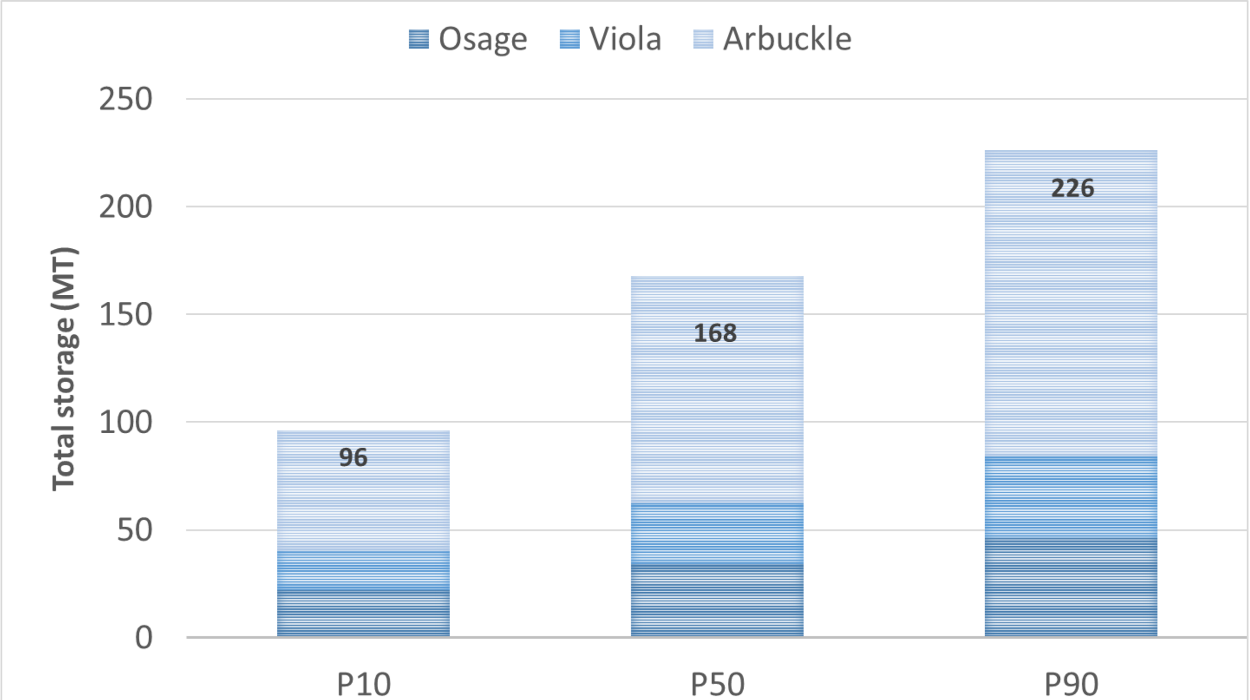


Figure 86: Maximum storage for the Patterson area.

Dynamic Modeling: Patterson Site, KS

The key objectives of the dynamic modeling were to determine the volume of CO_2 that could be stored, the resulting rise in pore pressure, and the extent of CO_2 plume migration in the Patterson field structure. Simulations were conducted using the Computer Modeling Group (CMG) GEM simulator, a full equation of state compositional reservoir simulator with advanced features for modeling the flow of three-phase, multi-component fluids that has been used to conduct numerous CO_2 studies (Chang et al., 2009; Bui et al., 2010).

Three wells, located at the structural highs of the Patterson site, were used to simulate the injection of 50 Mt of CO_2 into the subsurface to trap the CO_2 within the closures. The three wells are located equidistantly from one another to minimize the pressure interference and build-up. This study discusses two injection scenarios: injection under constant bottomhole rate and injection under constant bottomhole pressure. In practice, it is easier to maintain a constant wellhead and bottomhole pressure, and thus the pressure difference, between the reservoir and the bottomhole, determines the injection rate. For these simulations, the entire Static Earth Model (SEM) was up-scaled and run to capture the effect of cap- and base-rocks on reducing the overpressure, and thus increasing the total mass of CO_2 storage.

Initial reservoir conditions and simulation constraints

The initial conditions specified in the reservoir model are provided in Table 36. The simulations were conducted assuming isothermal conditions. Although isothermal conditions were assumed, a thermal gradient of 9.768°F/ft (0.008°C/ft) was considered for specifying petrophysical properties that vary with layer depth and temperature such as CO_2 relative permeability, CO_2 dissolution in formation water, etc. The initial static pressures (the model input) in the storage formations were derived from reported field test pressures and the Arbuckle pressure gradient of 0.27 psi/ft was assumed for specifying petrophysical properties. The perforated zone was set from the top to the bottom of all three injection intervals: Osage, Viola, and Arbuckle. The injection rate was assigned according to maximum bottomhole pressure calculated based on well tests and reservoir properties. Boundary conditions were selected as open Carter-Tracy aquifer with leakage allowed.

Table 36: Model input specification and CO_2 injection rates.

Parameter	Injection Interval		
	Osage	Viola	Arbuckle
Temperature	129 °F (54 °C)	133 °F (56 °C)	136 °F (58 °C)
Pressure	1,650 psi (11.38 MPa)	1,700 psi (11.5 MPa)	1,800 psi (11.72 MPa)
Max. BHP	2250 psi (15.5 MPa)	2300 psi (15.9 MPa)	2400 psi (16.5 MPa)
TDS	100 g/l	140 g/l	180 g/l
Formation Top	5,380 ft (1640 m)	5,640 ft (1719 m)	5,780 ft (1761 m)
Formation Base	5,440 ft (1658 m)	5,670 ft (1728 m)	6,220 ft (1896 m)
Perforated Zone	60 ft (18 m)	30 ft (9 m)	440 ft (134 m)
Injection Period	30 years	30 years	30 years
Number of wells	3	3	3

Simulation Results: Constant Injection Well Constraint

In this scenario, a total of 50 Mt of CO_2 is injected into the Osage, the Viola, and the Arbuckle Formations (note that constant pressure well constraint modeling indicated that the Osage, the Viola, and the Arbuckle are capable of accepting 30%, 20% and 50% of the total injected CO_2, respectively. To minimize the pressure interference and build-up, it is also assumed that the 80% of the total CO_2 is injected using boundary wells, while 20% of the total CO_2 is injected using the center well. The permeability values inferred from well logs, which do not consider fractures and vugs, systematically underestimate injectivity and storage capacity in the carbonate reservoirs. Therefore, data from the city of Lakin wastewater injection well (KS-05-093-002) were used along with extensively analyzed cased-hole well tests performed at the Patterson KGS 5-25 and Hartland KGS 6-10 wells during the course of this modeling effort. In this scenario, the permeability in each grid block, estimated from wireline log data, was multiplied by a factor of 30, assuming that the interpreted permeability for well log is proportionally correct. Figure 87 shows the total mass of CO_2 stored and the corresponding reservoir pressure increase over a 30-year injection period for the Patterson Field. The data indicate that there is a maximum average reservoir pressure increase of approximately 150 psi after 50 Mt of CO_2 is injected. Figure 88 shows the stacked capacity for the individual geologic formations.

The CO_2 plume migrates upwards due to lower density and viscosity. Figure 89a shows the pressure plume at the top of Osage formation after 30 years of injection, where pressure reaches its maximum because of upward CO_2 movement. Pressure can reach approximately 150 psi in the well located at the south Patterson Field. Figure 89b shows that CO_2 saturation can reach as high as 60%, but the plume remains within the area of review (AoR). Figure 89b also indicates that the plume will have the maximum extent in the Osage formation.

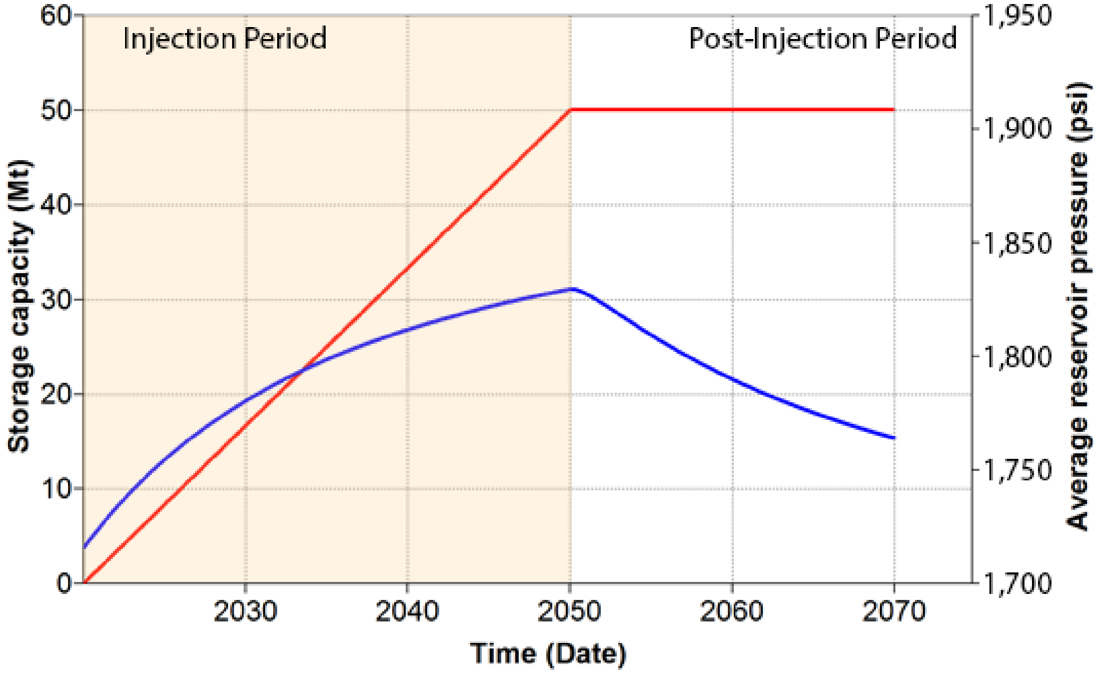


Figure 87. Plot of CO_2 storage capacity (red line) and average reservoir pressure (blue line). Note: permeability scaled by a factor of 30.

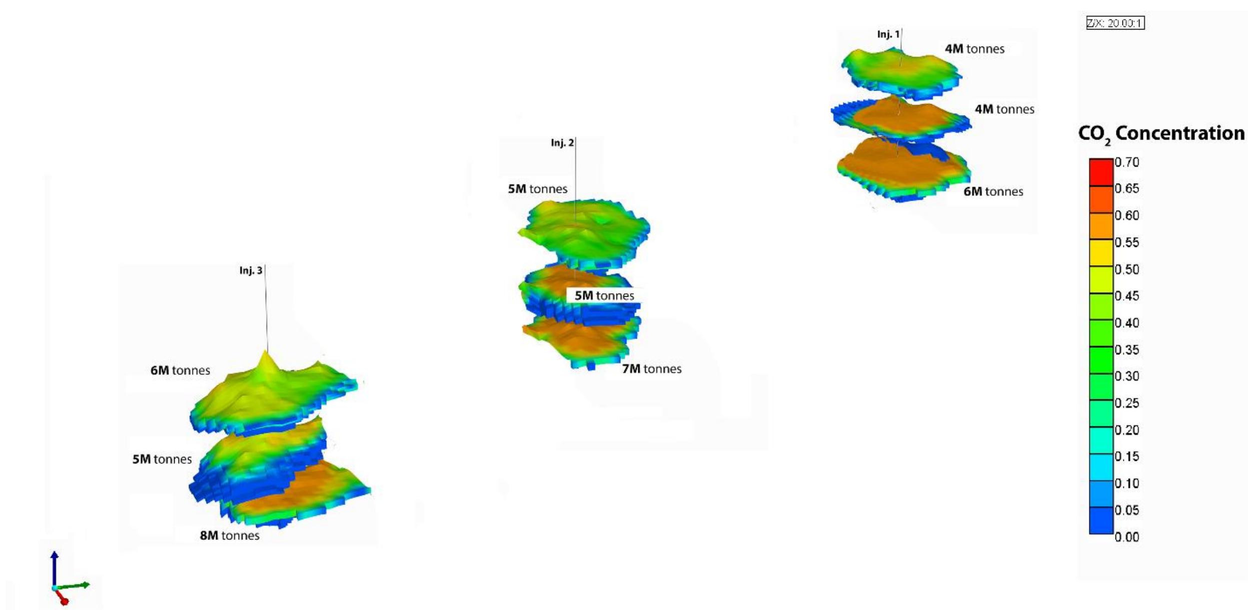


Figure 88. Stacked CO_2 plume and storage capacity (Mt) for the Osage, the Viola, and the Arbuckle Formations. The Arbuckle aquifer is thicker than the Osage and Viola and is expected to accept more CO_2.

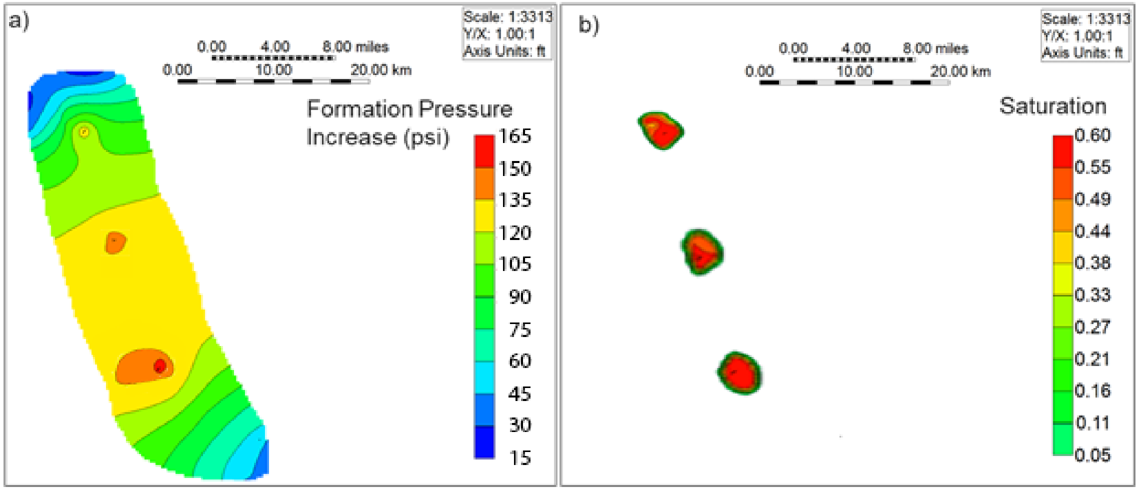


Figure 89. a) Pressure plume (top of Osage) after 30 years of injection. Maximum pressure may be approximately 150 psi . b) CO_2 plume saturation (top of Osage) after 30 years. The CO_2 plume remains within the area of review.

Constant Pressure Well Constraint

An additional CO_2 injection scenario was simulated under a different permeability multiplier and constant bottomhole pressure to study additional scenarios and quantify the injection uncertainties. Figure 90 summarizes several possible permeability and bottomhole pressure scenarios for CO_2 injection into the Patterson field. The base case, in which the permeability is underestimated, indicates 20 Mt of storage for the field. Figure 90 shows that if the actual permeability of the reservoir is five times greater than the log-interpreted permeability, and a reasonable formation pressure increase (ΔP) of 300 psi is used in the simulation, the CO_2 storage can reach almost 60 Mt in 25 years of injection. This scenario accounts for the high permeability of the Arbuckle inferred from hydraulic testing in the wells. Figures 91 and 92 display the reservoir pressure increase and CO_2 saturation ratio for two cases: Scenario 1) log-interpreted permeability with a multiplier of 5 and a pressure increase of 500 psi and Scenario 2) permeability with a multiplier of 10 and a pressure increase of 300 psi. When compared to the CarbonSAFE objective of storing 50Mt of CO_2 over 30 years, both of these cases offer more than adequate storage of greater than 80 Mt in 25 years, with the CO_2 confined within the AoR. A comparison between Scenario 1 (Figure 91) and Scenario 2 (Figure 92) demonstrates that using a higher reservoir permeability in the models results in the injected CO_2 moving more rapidly across the AoR and increases CO_2 saturation. The higher permeability scenario (Scenario 2) also results in lower pressure increase across the AoR, and thus helps in reducing the injection risks such as leakage and induced seismicity.

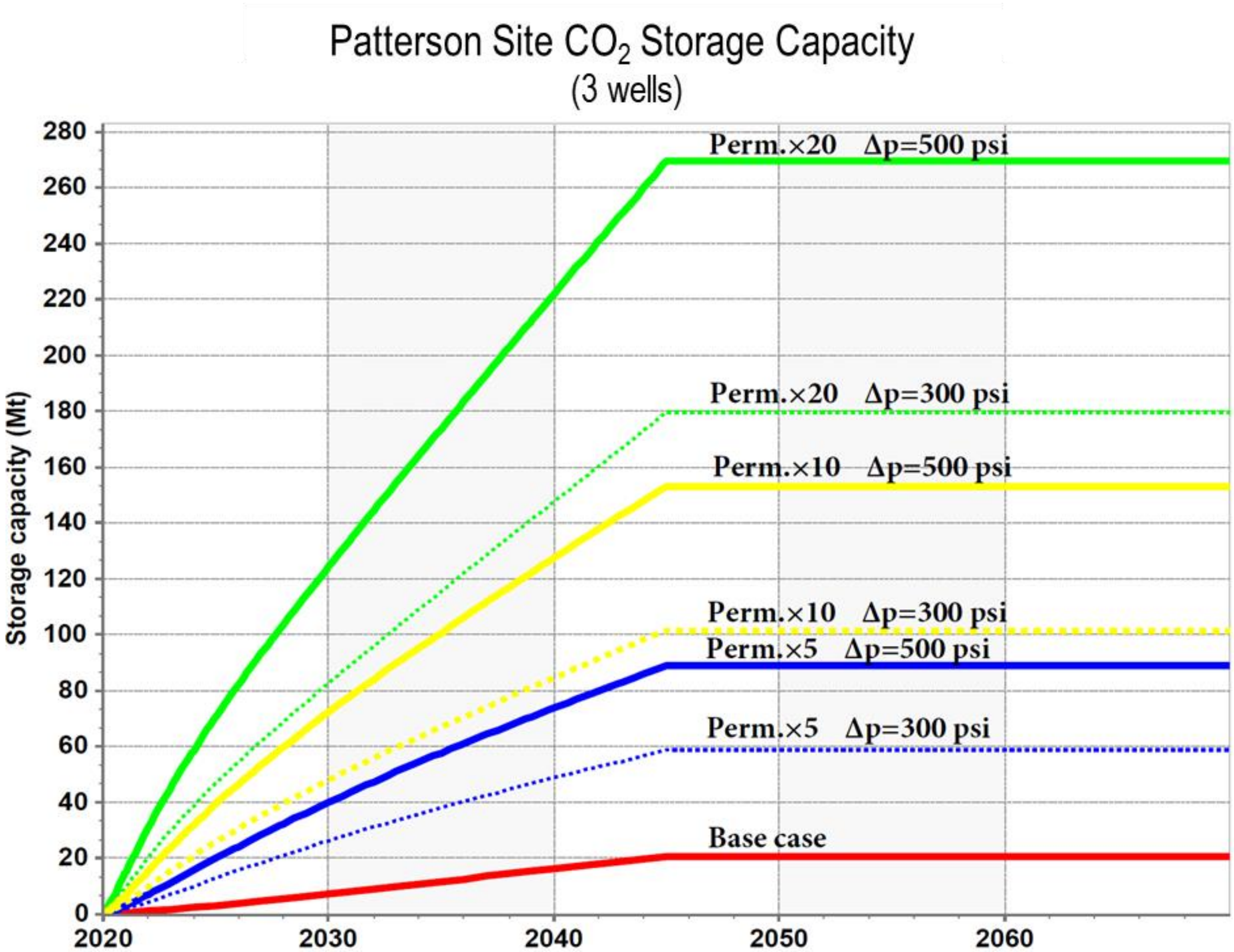


Figure 90. Storage capacity (Mt) for different permeability and bottomhole pressure scenarios.

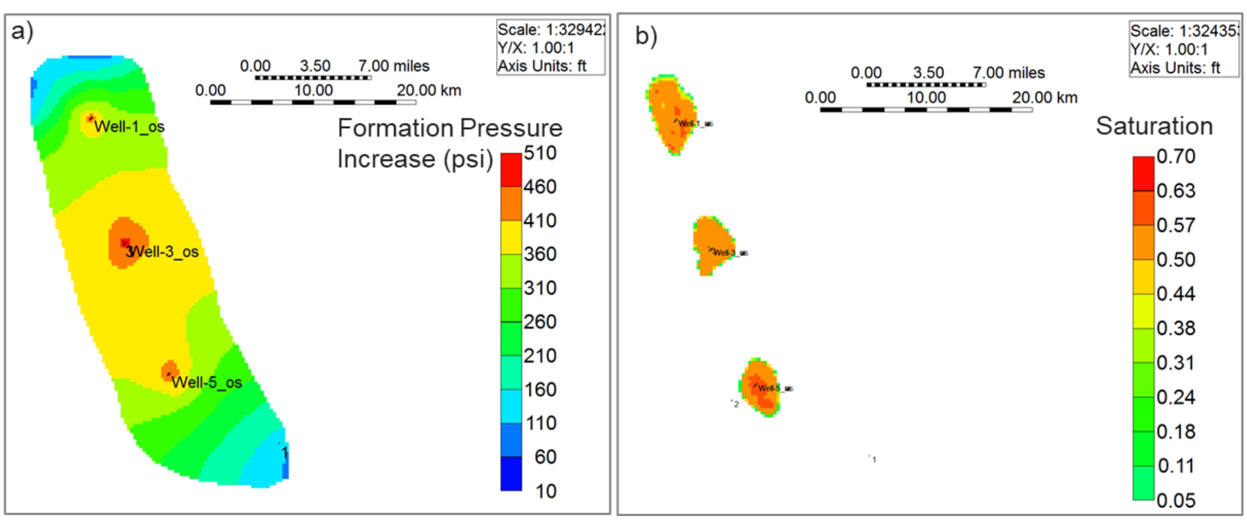


Figure 91. a) Pressure plume (top of Osage) after 25 years of injection for the case of permeability x5 and Δp=500 psi. b) Corresponding CO_2 plume (top of the Osage) after 25 years.

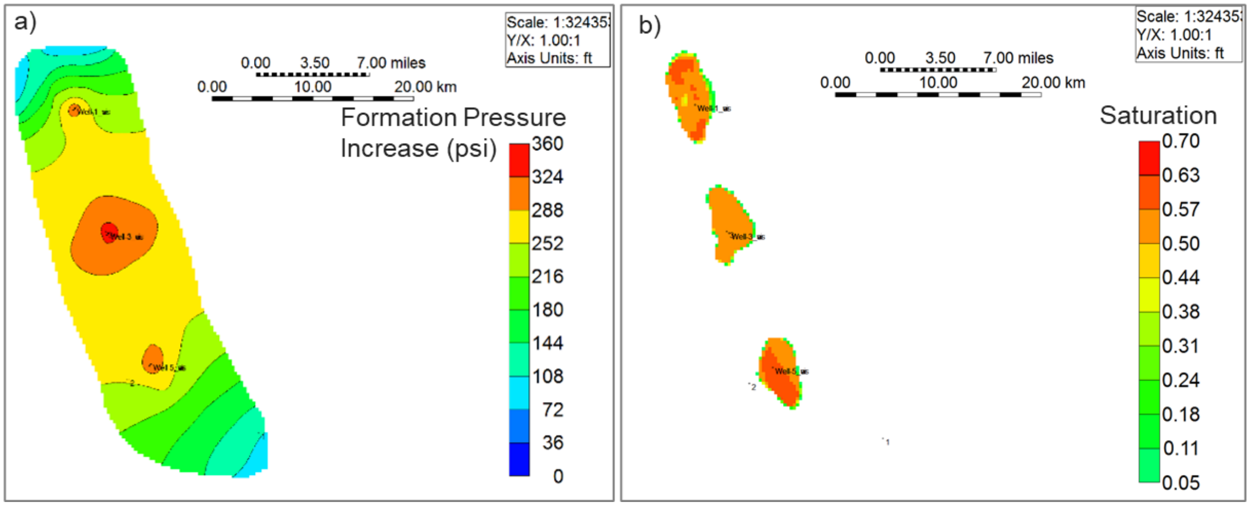


Figure 92. a) Pressure plume (top of Osage) after 25 years of injection for the case of permeability x10 and Δp=300 psi. b) Corresponding CO_2 plume (top of the Osage) after 25 years.

Summary/Discussion

Data generated during the characterization of the Patterson Field were used with the NETL CO_2-SCREEN method to estimate CO_2 storage for the field. Storage in the 50 mi^2 Patterson Field was focused on three potential storage formations: the Osage (a limestone), the Viola, and the Arbuckle (both dolomites). For each potential storage formation, a site-specific storage efficiency was calculated using the new feasibility data collection from the wells drilled at the Patterson Site during Phase II (Patterson KGS 5-25 and Hartland KGS 6-10).. The P_{50} CO_2 storage capacities estimated for the Osage, Viola, and Arbuckle formations are 34, 28, and 105 Mt, respectively.

Dynamic modeling simulations were performed using three wells, located along the structural high of the Patterson Field, with a full equation of state compositional reservoir model in the CMG GEM simulator. The modeling was performed under constant bottomhole rate and constant bottomhole pressure scenarios, and the model input parameters were based on field-generated data.

With the constant bottomhole injection rate scenario, 50 Mt of CO_2 was injected into the three formations with 80% of the total mass being injected into the peripheral wells and 20% injected in the center well to minimize pressure interference and buildup. Wireline log-based permeability data from existing wells was determined to be significantly lower than the actual permeability, and the log-based data were increased by a factor of 30 during these modeling simulations. The models indicated that 50 Mt of CO_2 could be injected into the three formations (with the majority of the CO_2 stored in the Arbuckle Formation) over a 30-year period with an average reservoir pressure increase of less than 150 psi. The modeling also showed that the CO_2 plume would remain within the AoR with CO_2 saturation levels reaching approximately 60%.

Under the constant pressure scenario, multiple permeability and bottomhole pressure values were used in the modeling to determine the effects of these parameters on CO_2 storage capacity in the formations. The base scenario (with the underestimated log-based permeability data), indicated the feasibility of storing 20 Mt of CO_2 over a 25-year period. The higher permeability and bottomhole pressure model scenarios showed increased storage of CO_2. When permeability was factored by 20 and the maximum bottomhole pressure increase was set at 500 psi, the model indicated the ability to store approximately 270 Mt of CO_2 over a 25-year period. Intermediate pressure scenarios (5 times the base permeability and a 500 psi pressure increase; 10 times the base permeability and a 300 psi pressure increase) both indicated the ability to store more than 80 Mt of CO_2 in 25 years – exceeding CarbonSAFE objective of storing 50 Mt within 25 years. The models also showed that increasing the permeability values would reduce the pressure increase across the AoR; reducing the potential for formation fracturing and induced seismicity.

References

Aadnoy, B.S. and Bell, J.S., 1998, Classification of drill-induce fractures and their relationship to in situ stress directions, Log Analyst, 39, 27-42.

Ansari, E., 2019. Estimates of Permeability and CO_2 Storage Capacity at the Patterson Field Using Analysis of City of Lakin Wastewater Injection Well Characteristics. Kansas Geological Survey Open-File Report 2019-22.

Bell, J., and Gough, D., 1979. Northeast-southwest compressive stress in Alberta evidence from oil wells. Earth and Planet. Sci. Lett. 45, 475-482.

Brudy, M. and Zoback, M.D., 1999, Drilling-induced tensile wall-fractures: implications for determination of in-situ stress orientation and magnitude, Int. J. Rock Mech. Min. Sci., 36, 191–215.

Bui, L. H., Tsau, J. S., and Willhite, G. P., 2010, Laboratory investigations of CO_2 near-miscible application in Arbuckle Reservoir: SPE Improved Oil Recovery Symposium held in Tulsa, Oklahoma, 24–28 April 2010, SPE Publication 129710.

Carter, R. D., and Tracy, G. W., 1960, An improved method for calculating water influx: Petroleum Transactions, AIME, vol. 219, p. 415–417.

Chang, K. W., Minkoff, S. E., and Bryant, S. L., 2009, Simplified model for CO2 leakage and its attenuation due to geological structures: Energy Procedia, v. 1, p. 3,453–3,460.

Coates, G.R., L.Z. Xiao, and M.G. Prammer (1999), NMR Logging – Principles and Applications, Gulf Publ. Co., Houston, 256 pp.

Dake, L. P., 1978, Fundamentals of Reservoir Engineering, Chapter 9, Elsevier Scientific Publishing Co., 1978.

Dubois, M. K., Williams, E. T., Youle, J. C., and Hedke, D. E. (2015). Potential for CO_2 storage and enhanced oil recovery in four southwest Kansas oil fields, an extended abstract; in W. L. Watney, PI, Final Report for DOE Award Number: DE-FE0002056, Modeling CO_2 Sequestration in Saline Aquifer and Depleted Oil Reservoir to Evaluate Regional CO_2 Sequestration Potential of Ozark Plateau Aquifer System, South-Central Kansas, p. IV1-IV19.

Goodman, A., Hakala, A., Bromhal, G., Deel, D., Rodosta, T., Frailey, S., et al.,2011,U.S. DOE methodology for the development of geologic storage potential for carbon dioxide at the national and regional scale:International Journal of Greenhouse Gas Control, v. 5, no. 4,p.952–965. https://doi.org/10.1016/j.ijggc.2011.03.010

Hawkes, C.D., Bachu, S., Haug, K., Thompson, A.W., 2005. Analysis of in-situ stress regime in the Alberta Basin, Canada, for performance assessment of CO_2 geological sequestration sites. Fourth Annual Conference on Carbon Capture and Sequestration Pittsburgh, DOE-NETL, p. 22.

Holubnyak, Y., Dubois, M., Bidgoli, T., Wreath, D., Watney, L., Stover, S., Newell, D., Fazelalavi, F., Hollenbach, A., Jennings, J., Steincamp, C., Schremmer, J., Jordan, B., Crabtree, B., Christensen, J., McFarlane, D., Doveton, J., Krishnamurthy, K., Byron, M., and Watts, K., 2018, Integrated CCS for Kansas (ICKan) Final Technical Report, doi:10.2172/1491482. https://www.osti.gov/servlets/purl/1491482.

Keast, R. T., 2018, Modeling the Proterozoic basement's effective stress field, assessing fault reactivation potential related to increased fluid pressures in south central Kansas and north central Oklahoma, and improving seismic imaging of basement faulting within Wellington and Anson-Bates Fields, Sumner County, Kansas (Master Thesis).

Reinecker, J., Tingay, M., and Müller, B., 2003, Borehole breakout analysis from four-arm caliper logs. World stress map project, 1-5.

Reynolds, S. D., Mildren, S. D., Hillis, R. R., Meyer, J. J., and Flottmann, T., 2005, Maximum horizontal stress orientations in the Cooper Basin, Australia: implications for plate-scale tectonics and local stress sources. Geophysical Journal International, 160(1), 331-343.

Scheffer, A., 2012, Geochemical and microbiological characterization of the Arbuckle saline aquifer, a potential CO2 storage reservoir; implications for hydraulic separation and caprock integrity (Master Thesis).

Sinha, B.K., Ouellet, A. and Bérard, T., 2010, June. Estimation of principal horizontal stresses using radial profiles of shear slownesses utilizing sonic data from a CO_2 storage site in a saline formation in Germany. In SPWLA 51st annual logging symposium. Society of Petrophysicists and Well-Log Analysts.

Sperner, B., Muller, B., Heidbach, O., Delvaux, D., Reinecker, J., Fuchs, K., 2003. Tectonic stress in the Earth's crust: advances in the World Stress Map project. Sp. Publ. Geol.Soc. Lond. 212, 101–116.

Zoback, M. D., 2010, Reservoir geomechanics, first ed. Cambridge University Press, Cambridge.

It can be done