URTeC: 2902813

FIELD TEST OF CO_2 INJECTION IN A VERTICAL MIDDLE BAKKEN WELL TO EVALUATE THE POTENTIAL FOR ENHANCED OIL RECOVERY AND CO_2 STORAGE

James A. Sorensen*1, Lawrence J. Pekot, José A. Torres, Lu Jin, Steven B. Hawthorne, Steven A. Smith, Lonny L. Jacobson, Thomas E. Doll; University of North Dakota Energy & Environmental Research Center

This paper was prepared for presentation at the Unconventional Resources Technology Conference held in Houston, Texas, USA, 23-25 July 2018.

Abstract

A research program was conducted by the Energy & Environmental Research Center (EERC) to examine the potential for CO_2 injection into tight oil-bearing formations to both store carbon dioxide (CO_2) and improve oil productivity. Previous laboratory- and modeling-based studies had suggested that CO_2 can permeate Bakken matrix, largely through diffusion, and mobilize oil. Those studies indicated that CO_2 will preferentially mobilize lower-molecular-weight hydrocarbons. In 2017, an injection test was conducted in a vertical well completed in the Middle Member of the Bakken Formation. The objectives of the field test were to quantitatively determine the injectivity of an unstimulated Bakken reservoir and the ability of injected CO_2 to mobilize oil.

The test was conducted in a virgin reservoir. The well completion program did not include the use of hydraulic fracturing and proppant. Upon perforation, the well did not flow to surface, but oil samples were collected before injection. Approximately 99 tons of CO_2 was injected over 4 days. Analysis of bottomhole pressure and temperature data indicates the injection resulted in a CO_2 saturation plume radius of between 50 and 70 ft. The CO_2 was allowed to soak for 15 days. Reservoir pressure and temperature were monitored throughout all stages of the test using downhole gauges. During the flowback period, gas composition was also monitored and fluid samples collected. Preinjection and postinjection oil samples were analyzed for oil composition, with an emphasis on determining the molecular weight distribution of the hydrocarbons. Pulsed-neutron logs were also run before and after injection to evaluate the vertical distribution of the CO_2 in the near-wellbore environment.

Injectivity of the unstimulated Middle Bakken matrix was found to be low, with stable CO_2 injection rates between 6 and 12 gallons per minute and bottomhole pressure during continuous injection ranging from 9400 to 9470 psi, 800 to 870 psi above initial pore pressure. During flowback, a mix of CO_2 and hydrocarbon gas was produced for 10.5 hours. The well then flowed oil to surface briefly during which time fluid and gas samples were collected. Analyses of the preinjection and postinjection oil samples indicate that the composition of the postinjection oil samples had greater amounts of lower-molecular-weight hydrocarbons than the pretest oils. Interpretation of the results from the field test suggests that although matrix injectivity is low, injected CO_2 can penetrate the Middle Bakken and mobilize oil from the matrix.

Past pilot-scale CO_2 injection tests in the Bakken have all been conducted in horizontal wells. Those tests demonstrated that injectivity into a stimulated Bakken well is not a problem, but incremental oil was not produced and there is no evidence in the publicly available data to suggest that a scientific approach was taken to evaluate the mechanisms controlling the ability of CO_2 to mobilize oil stranded in the matrix. The use of a vertical well in a virgin reservoir for this test eliminated uncertainties associated with long horizontal wells, such as the inherent unknown heterogeneity of rock properties and the nature and distribution of hydraulically induced fractures along

the wellbore. The data generated by this test support the findings of past lab studies which indicate that diffusion may play a significant role in the use of CO_2 for enhanced oil recovery (EOR) in the Bakken.

Introduction and Background

The Bakken Formation in the Williston Basin is a world-class unconventional tight oil play with oil-in-place estimates in the hundreds of billions of barrels. Matrix permeability in the Bakken is typically on the order of micro- to nanodarcies, and hydraulically induced fractures are necessary to produce oil from the reservoir. Despite the enormous resource, recovery factors are typically low, ranging from 4% to 10%. The Williston Basin also holds world-class lignite coal reserves. Several large lignite coal-fired power plants in North Dakota and Saskatchewan operate within 100 km, or less, of the most oil-productive areas of the Bakken Formation. The juxtaposition of a need to improve the productivity of a world-class oil resource with a desire to manage CO_2 emissions from nearby power plants has led to an interest in the potential to use CO_2 for enhanced oil recovery (EOR) and associated storage in the Bakken Formation.

From 2012 to 2018, the Energy & Environmental Research Center (EERC) has conducted the Bakken CO_2 Storage and Enhanced Recovery Program. The U.S. Department of Energy (DOE)- and industry consortium-funded program was carried out over two phases. Phase I, which ran from 2012 to 2013, used new and existing reservoir characterization and laboratory analytical data coupled with state-of-the-art modeling to examine the viability of injecting CO_2 into the unconventional tight Bakken Formation for simultaneous carbon storage and EOR. The Phase I results suggested that a better understanding of the fundamental mechanisms controlling the interactions between CO_2 and Bakken rock, oil, and other reservoir fluids in these unique, tight formations is necessary to develop accurate assessments of CO_2 storage and EOR potential. To address those knowledge gaps, a series of laboratory-, modeling-, and field-based activities were conducted from 2014 to 2018 under Phase II of the program. This paper describes and discusses the approach and results of a field injection test that was conducted in a Bakken well in 2017.

Goal of the 2017 Bakken CO_2 Injection Test

In 2016, XTO Energy entered into an agreement with the EERC to provide a well and undertake all field-based operations necessary to conduct a pilot-scale CO_2 injection test into a Bakken reservoir. The overarching, ultimate goal of the 2017 field-based Bakken investigations was to develop fundamental data to provide a technical foundation for the design and operation of future gas-driven EOR. Previous laboratory investigations and modeling work conducted as part of the research program (Hawthorne and others, 2013; Jin and others, 2016a–c) indicate that diffusion, solubility, and sorption may be primary mechanisms controlling CO_2 permeation and oil mobility in Bakken rocks. The results of minimum miscibility pressure (MMP) studies on Bakken oil samples collected in the vicinity of the test well show miscibility achieved at pressures greater than 2540 psi at 110°C. The MMP results indicate the injected CO_2 will almost certainly be miscible in the test well, which has a virgin Middle Bakken reservoir pressure of 8600 psi and a temperature of 120°C. The experiences and results gained from the 2017 field test provide new insight regarding the role that those mechanisms may play in the ability of CO_2 to permeate and mobilize oil from within the matrix of the Bakken.

Hypothesis

A series of laboratory experiments have demonstrated that CO_2 can permeate the rocks of the Middle Member and Shale Members of the Bakken Formation and cause an increase in oil mobility (Hawthorne and others, 2013, 2017). However, past pilot-scale CO_2 injection tests into horizontal Bakken wells have shown little to no effect on oil mobilization (Sorensen and Hamling, 2016). This is most likely due to natural and induced fractures in the reservoir system serving as fast flow pathways that disperse the CO_2, minimizing the contact time between the injected CO_2 and the matrix in which stranded oil resides. With respect to the potential for CO_2 storage and EOR in the Bakken, there is clearly a gap in what laboratory-scale experiments suggest may be possible and what the application of conventional approaches to CO_2-based EOR in the field has shown to be possible. In an effort to close this knowledge gap, the EERC and XTO Energy conducted a set of field-based experimental activities to test a two-pronged hypothesis: 1) that CO_2 can be injected into an unstimulated Bakken reservoir and 2) the injected CO_2 can interact with the in-place fluids, resulting in subsequent mobilization of hydrocarbons and storage of CO_2.

A field test to evaluate the injectivity of the unstimulated Bakken reservoir is an important step to determine if the observations in the lab can truly be applied to the field. One of the problems with the laboratory CO_2 permeation/hydrocarbon extraction experiments reported in Hawthorne and others (2013, 2017) and Jin and others (2017) is that the act of core collection inherently changes a couple of key sample characteristics, namely, the composition of the hydrocarbon content and the pore pressure of the rock. Bakken core in North Dakota is collected from depths between 9000 and 11,000 feet, and the process can take several hours to bring the core to surface. During that time, unless unusual (and expensive) precautions are taken to maintain pressure on the sample, the core will undergo significant depressurization, going from an in situ pressure of anywhere from 7000 to 9000 psi to atmospheric. A result of the uncontrolled depressurization of the core is that new fractures will be induced by the release of pressure. The depressurization also causes lighter hydrocarbons—which are in the liquid state in the high-pressure, high-temperature conditions of the reservoir—to volatilize and escape from the core. There are also questions about whether or not the pore structures seen in core samples are truly representative of the pore structures that exist in the reservoir, with the notion being that the loss of pore pressure that occurs during core collection will cause a relaxation of the rock fabric that allows preexisting pore throats and microfractures to open further than they are when in the reservoir. All of these phenomena imply that the results of the laboratory-scale tests represent the most optimistic case with respect to CO_2 permeation and oil mobility. The field injection test provides the opportunity to, in effect, scale up the laboratory CO_2 permeation/hydrocarbon extraction tests. Conducting the tests in a virgin Bakken reservoir (i.e., a reservoir that has not been stimulated by hydraulic fracturing and proppant placement and which has not undergone pressure depletion due to prolonged production) would arguably represent the most pessimistic case for CO_2 permeation and oil mobility. Results from such a pessimistic case provide a valuable end member data set that brackets the range of possibility when considering the potential to inject CO_2 for EOR and associated storage in tight unconventional oil reservoirs such as the Bakken.

The effect of CO_2 on a reservoir is primarily judged by changes in fluid production observed after injection as compared to preinjection production history (e.g., changes in parameters such as oil production rate, water cut, GOR [gas-to-oil ratio], etc.). Because a virgin well does not have prior production history to which test results can be compared, the effects of the injected CO_2 must be evaluated by different means. One of the key findings of the laboratory testing was that in both shale and nonshale Bakken rocks CO_2 was observed to preferentially mobilize lighter hydrocarbons. With that in mind, in the absence of historical production data, the primary means of addressing the second aspect of the hypothesis is to compare preinjection oil compositional data to postinjection data. According to the lab results, a shift in the molecular weight distribution toward the lighter end would be an indicator that the injected CO_2 was able to permeate the matrix and mobilize oil.

To test both aspects of the hypothesis, an existing horizontal well would not be ideal for the following reasons: 1) because of the heterogeneity of the various Bakken lithofacies (Figure 1), the petrophysical properties of a Bakken reservoir are not uniformly distributed and 2) the length of the wellbore (anywhere from 5000 to 15,000 feet) and existence of extensive hydraulically stimulated and propped fractures would require over 1000 tons of CO_2 to overcome the pore pressure of the reservoir. To reduce the uncertainty in petrophysical property distribution and conformance control that is associated with a long horizontal hydraulically fractured wellbore and reduce the amount of CO_2 that would be needed to pressure up the wellbore, a vertical well was considered to be a better choice for achieving the goals of the 2017 injection test.

Experimental Design

The field-based experimental activities included the following sequence of events in an existing vertical well that penetrates the Bakken but has not previously produced fluids from any units in those formations. The formal name of the well is Knutson–Werre 34-3WIW, North Dakota state well ID number 11413 (referred to in this paper as the Knutson–Werre well). The well was originally drilled and completed into the underlying Duperow Formation in 1985. The well is located in northern Dunn County, North Dakota, one of the most highly productive areas of the Bakken (Figure 2). This offered a unique opportunity to test the injectivity of CO_2 into the unstimulated matrix of the Bakken in a virgin reservoir in the heart of the Bakken play, thereby making the lessons learned from the test directly applicable to hundreds, if not thousands, of wells that could be candidates for future EOR efforts. The stratigraphy of the Bakken Formation in the Knutson–Werre well and a well completion diagram for the injection are shown in Figure 3.

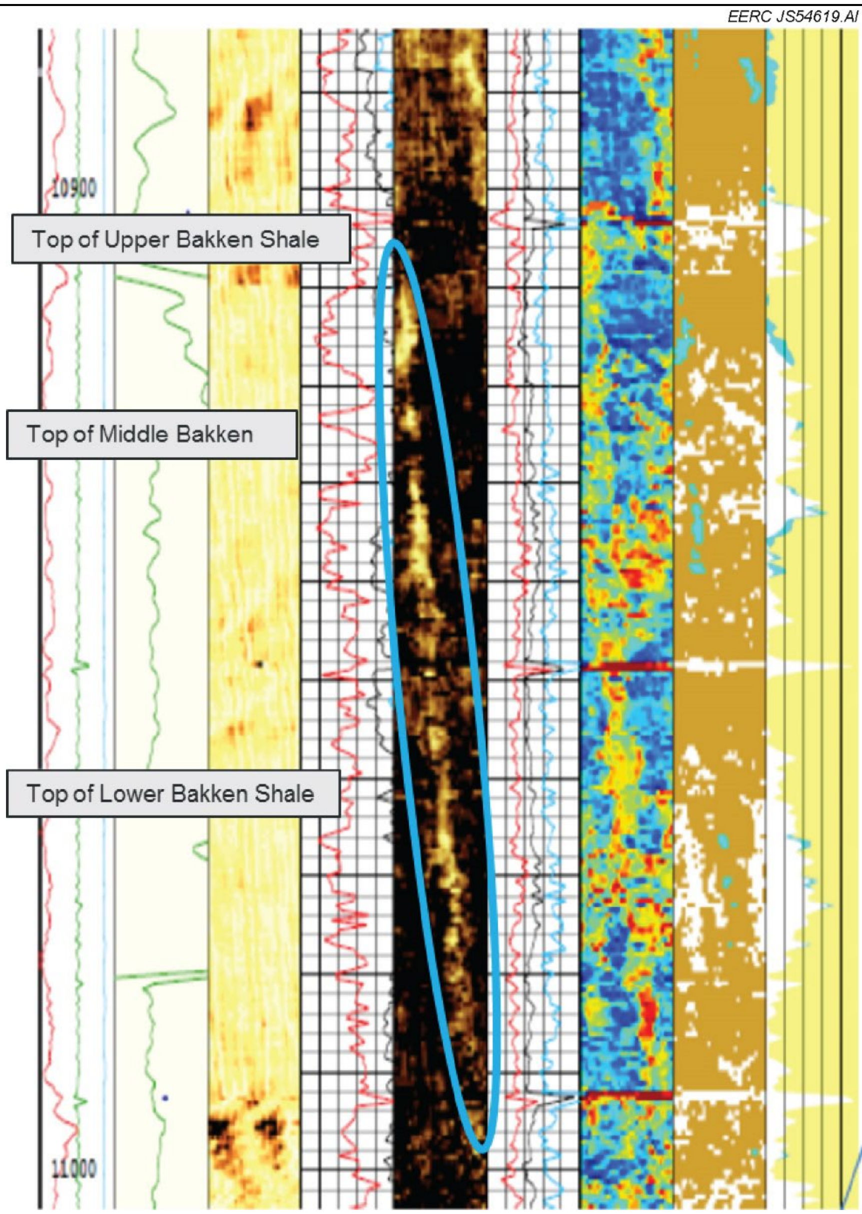

Figure 1: USI log showing evidence of a possible channel in the wellbore cement, circled in blue.

The well preparation and experimental design for the Knutson–Werre test included the elements listed below:

- Abandon and plug back from the original Duperow Formation completion.
- Perforation of the injection zone in the Middle Member of the Bakken Formation.
- Collection of preinjection reservoir fluids to establish baseline conditions.
- Collection of preinjection reservoir pressure and temperature data using downhole gauges.
- Well workover activities to prepare the well for high-pressure CO_2 injection.
- Small-scale CO_2 injectivity test, referred to as the "pretest," to help guide the final design specifications (e.g., amount of CO_2 to be purchased, size and type of injection equipment, etc.) and operational parameters of the "main" injection test.

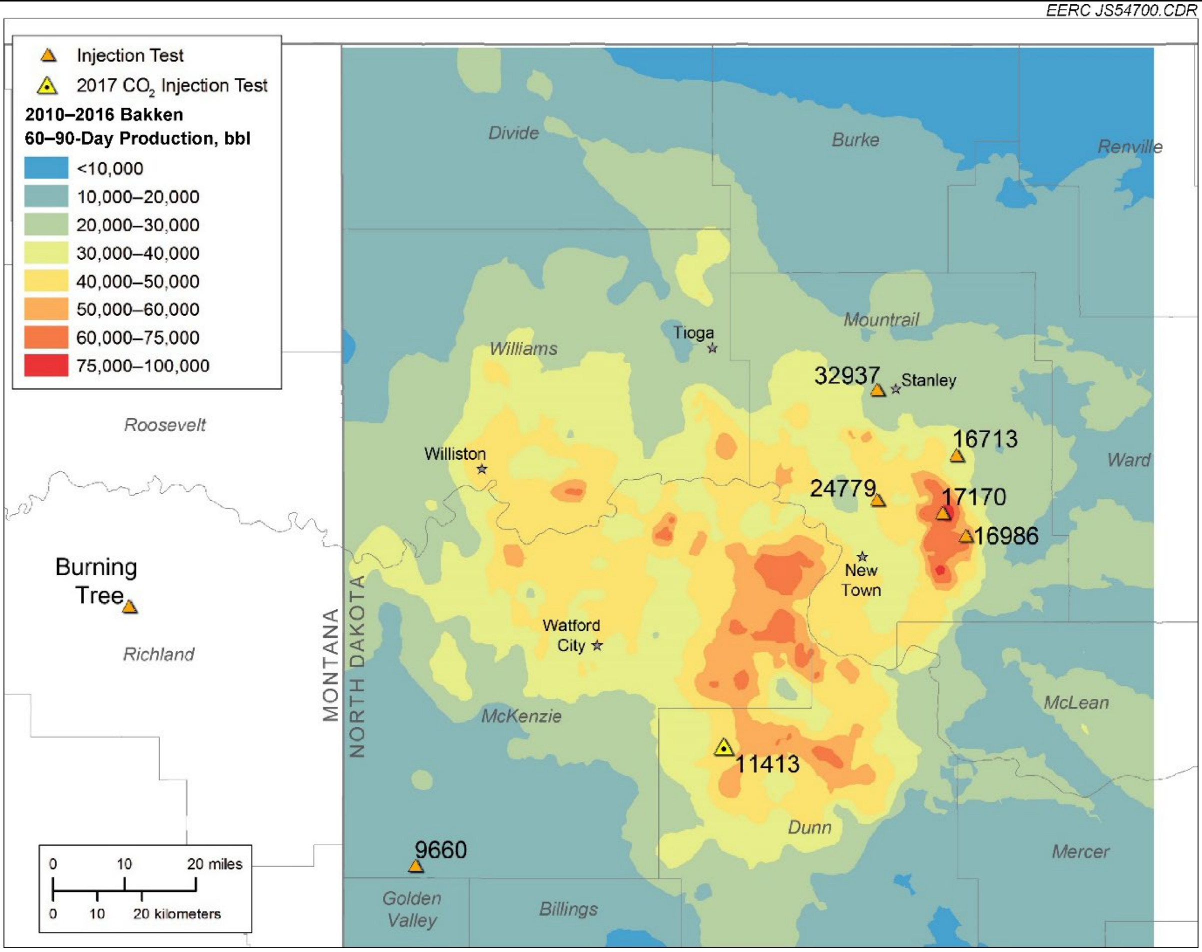

Figure 2: Map showing location of the Knutson–Werre injection test well relative to Bakken production and other Bakken injection test locations.

- Main CO_2 injection test.
- Soak period.
- Flowback period during which postinjection reservoir fluids (gas, oil, water) are collected.
- Preinjection well logging to determine wellbore integrity and reservoir properties, including fluid distribution in the formation.
- Postinjection well logging to determine any changes that may have occurred in the near wellbore environment, including potential evidence of vertical CO_2 migration out of the injection zone.
- Compositional analysis of fluids collected prior to pretest and after the main test, particularly to determine any changes in the hydrocarbon composition.

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

Extensive well workover activities were required to convert the test well from a legacy vertical production well in a conventional oil-bearing formation into a CO_2 injection well in an unconventional tight oil formation. This included the removal of the production wellhead and installation of a CO_2-rated high-pressure injection wellhead. All well preparation work was planned and conducted by XTO Energy.

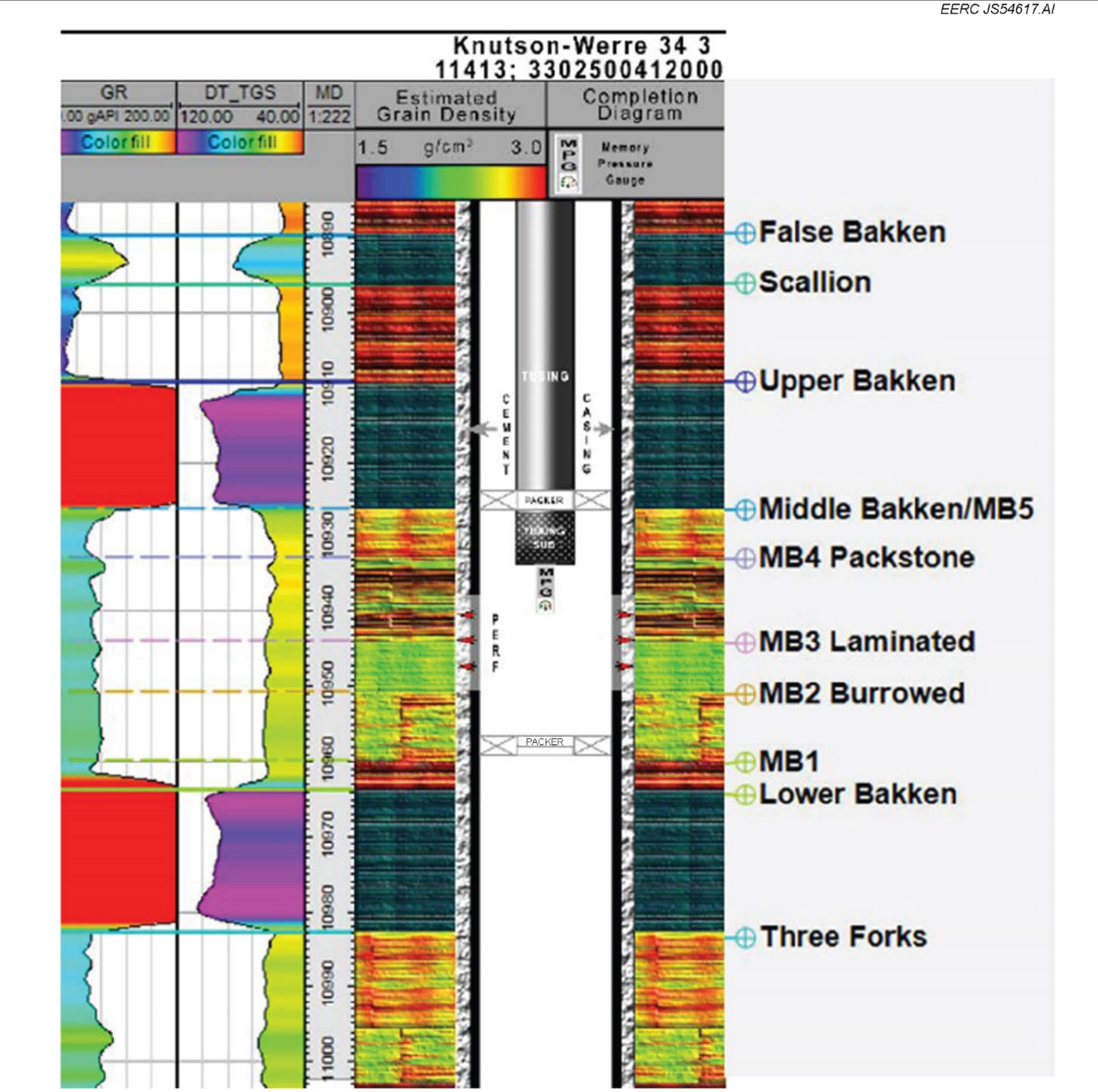

Figure 3: Stratigraphy of the Bakken Formation in the Knutson–Werre well based on gamma ray (GR) and density (DT-TGS) logs. A well completion diagram showing the perforated (perf) zone at a depth of 10,940 to 10,950 ft, and the location of packers to isolate the injection zone is also provided.

Maintaining wellbore integrity is necessary to ensure that injected fluids go into the target formation and that the wellbore does not serve as a conduit for injected fluids to move out of the intended zone. Determination of wellbore cement and casing conditions prior to injection is, therefore, critical to the success of an injection test. The Schlumberger ultrasonic imager (USI) log was run to determine the condition of the casing and cement bond and provide guidance in the selection of perforation points and the final design of the perforations. The USI logging indicated the presence of a channel in the cement that appeared to cut across the injection zone in the Middle Bakken (Figure 1). This channel could possibly serve as a leakage pathway, so the decision was made to deploy a "zero degree" perforation configuration. A zero degree configuration means that all of the perforation charges are oriented in a straight line on one side of the perforation tool. The goal of this perforation configuration is to create a straight line of perforations on one side of the well, ideally opposite of the side with the channel. The results of another USI logging run made after perforation were inconclusive as to whether or not the perforations missed the channel. No fluids flowed to surface, and swabbing operations were used to collect baseline reservoir fluids. Bottomhole gauges were installed to monitor pressure and temperature in real time during all major stages of the test (pretest baseline, injection, soak, and flowback).

A pulsed-neutron log (PNL) was run to determine baseline preinjection fluid (oil, gas, and water) saturations in the zones of interest. The PNL also yielded lithology and estimates of reservoir porosity through integration of the logging data with Schlumberger's ELAN petrophysical analysis software (Figure 4).

Injection testing was conducted in two distinct phases: the first being a small-scale injectivity test, referred to as the "pretest," and the second being a larger-scale "main test." Because the Bakken in this well was a virgin reservoir, there were many uncertainties about the local reservoir conditions (e.g., injectivity of the nonstimulated matrix, reservoir pressure, temperature). The uncertainty surrounding those conditions made injection scheme design difficult. The purpose of the pretest was to use the results from this short-duration, low-volume injectivity test to cost-effectively inform the design of the larger-scale main test. For both tests, the injection zone in the well was isolated by two packers, as shown in Figure 3.

The pretest was conducted on April 13, 2017. Figure 5 is a photo of the pumping unit and wellhead during the pretest. While plans called for 60 tons of CO_2 to be injected, the amount of CO_2 injected in the well during the pretest was limited to approximately 16 tons, which is enough to fill the tubing and build pressure on the perforations. However, it is thought that very little of that CO_2 went into the formation because the upper packer that isolated the injection zone experienced mechanical failure shortly after the injection reached the BHP (bottomhole pressure) needed to overcome the native reservoir pressure. Despite the inability to inject substantial CO_2 into the formation during the pretest, valuable downhole data were obtained that enabled the technical team to redesign the packer configuration and design the main test in a way that reduced the risk of packer failure. The data generated by the pretest included evidence that CO_2 was not bleeding off through the channel in the cement that had been observed in the USI data. The pretest also provided a definitive determination of reservoir conditions prior to the primary test. Key lessons learned from the pretest included the following:

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

Prior to the main test, the well was swabbed, during which approximately 62 barrels of fluid was recovered and sampled for later analysis. The initial BHP after swabbing and before the start of the main injection test was approximately 7500 psi. At approximately 7:00 p.m. MDT (Mountain Daylight Time) on June 24, 2017, the main injection test was initiated into the Middle Member of the Bakken. The main test injection was concluded at approximately 5:00 a.m. MDT on June 28. Figure 6 is a Gantt chart showing the timing and duration of each activity conducted during the main CO_2 injection test. The main test injection period included periods of cyclic injection and continuous injection as well as a brief shut-in period (ca. 5 hours) on June 27 to conduct a pressure falloff test, which was then followed by a period of continuous injection until the test conclusion. BHP and temperature data were collected continuously. Those data were crucial components of the efforts to interpret the results of the test. A total of 98.9 tons of CO_2 was injected during the main injection test. The well was then shut in to allow a period of several days during which the injected CO_2 would soak into the reservoir. The plans called for the well to be opened at the end of the first week of July or early in the second week of July, depending on the BHP behavior observed

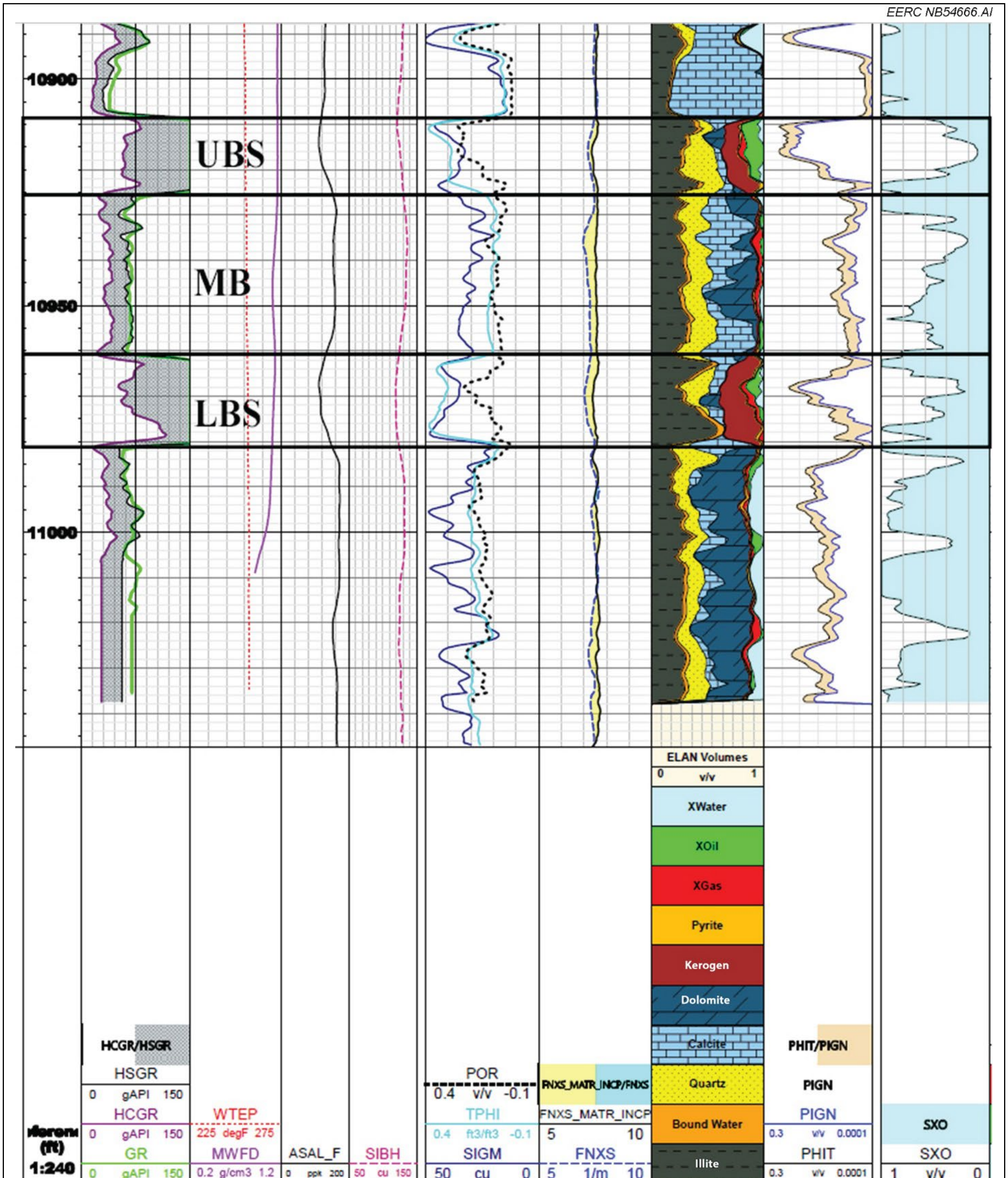

Figure 4: Interpreted PNL display with annotations for Bakken Members. The well logs included in this display, from left to right, are gamma ray(GR), wellbore temperature (WTEP) and manometer fluid density (MWFD), salinity (ASAL_F_, borehole sigma (SIBH), porosity (POR/TPHI) and formation sigma (SIGM), fast-neutron cross section (FNXS_MATR_INCP/FNXS), volumes for various minerals and fluids, total and effective porosity (PHIT and PIGN, respectively), and invaded zone water saturation (SXO).

Figure 5: CO_2 pumping unit setup for the pretest. The injection wellhead is visible on the far left of the photo.

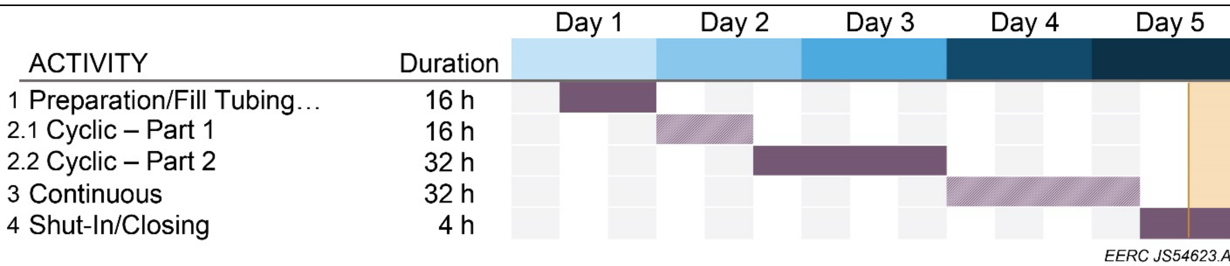

Figure 6: Gantt chart showing timing and duration of each activity for the main test.

during the shut-in period. Table 1 presents statistics for the main injection test. Key operational parameters of the main injection test include the following:

- Initial BHP was approximately 7500 psi. This pressure is lower than the estimated virgin reservoir pressure of approximately 8670 psi because of the sporadic removal of fluids by swabbing (approximately 60 bbl) and degassing that occurred during the well preparation activities.
- Stable injection rates were between 6 and 12 gpm.
- Maximum BHP was approximately 9480 psi.
- BHP during continuous injection ranged from approximately 9400 psi to approximately 9470 psi.
- BHT ranged from 251° to 257°F (Figure 7c).

Table 1: Main Test Injection Statistics

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

Analysis of the injection Test BHP and HBT Data

Because of the low matrix permeability, the injection rate and pressure during the test were controlled carefully to prevent fracturing around the wellbore. Figure 7a–c shows the injection rate, BHP, and BHT response during and after the final injection cycle of the test. CO_2 injection rates (6–12 gpm) caused an increase of the BHP to 9468 psi and decreased the BHT to about 250°F in just under 16 hours.

Analysis of BHP response during the test played a vital part in understanding the reservoir. The pressure response resulting from fluid flow in the matrix can be interpreted using well-testing principles, including continuity of flow (mass balance), fluid flow resistance, and rock/fluid compressibility, providing insights into the physical mechanisms involved in the process (Smith and Montgomery, 2015). Figure 7b shows the BHP during and after CO_2 injection. The continuous increase of pressure indicates that the pressure needed to initiate fractures was not exceeded; however, the opening of a preexisting fracture(s) was interpreted.

The pressure response in the shut-in period also provided important information for the reservoir. Various flow regimes (Figure 8) may be observed from a shut-in pressure decline period. Different analysis techniques have been proposed to analyze the pressure decline period, which is usually referred to as fracture diagnostics (Barree and others, 2009). Equation 1 shows the Bourdet derivative (also termed the "pressure derivative"), which is usually used in such analysis (Bourdet and others, 1983):

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

Where *BPD* is the Bourdet (or pressure) derivative (psi); *P* is the pressure (psi); *t* is the time (hour).

Together with pressure difference and BPD, the classic log–log plot used in well test analysis provides a powerful tool for fracture diagnostics in unconventional reservoir testing. Figure 9 shows the log–log plot for the shut-in pressure analysis. Immediately after the injection stops, there follows a period of wellbore storage, or "afterflow," as injectate continues flowing from the wellbore into fractures. At the end of the wellbore storage period, fluid loss from the opened natural fractures begins to control the pressure decline behavior. The flow regime in the fractures is linear when the fractures remain open. This flow regime is observed where the curve's slope = ½ of BPD in the diagnostic plot. During the test, natural fractures remained open for about 4 hours. With the energy of the injected fluid decreasing, the fractures began gradually closing, shown where the curve's slope = $^3/_2$ of BPD vs. Δt (Marongiu-Porcu and others, 2011). The plot indicates that fractures closed after 10 hours. Fluid flow in the matrix dominated the system when the fractures were closed. Because the permeability in the Middle Bakken matrix was very low, the −½ slope remained after 170 hours, meaning linear flow lasted through the well shut-in period.

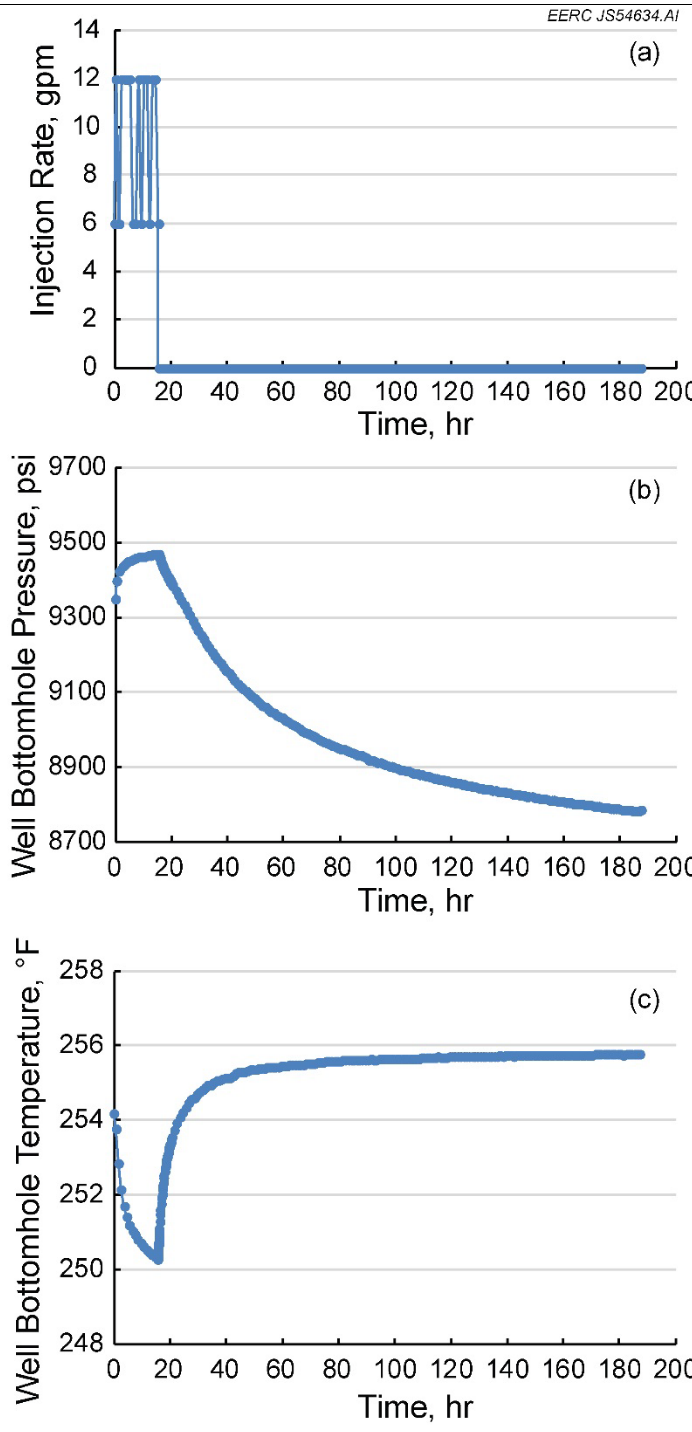

Figure 7a: Injection rate, b. BHP, and c. BHT response during the final injection cycle of the test, ending on June 28, and 170 hours after injection ended.

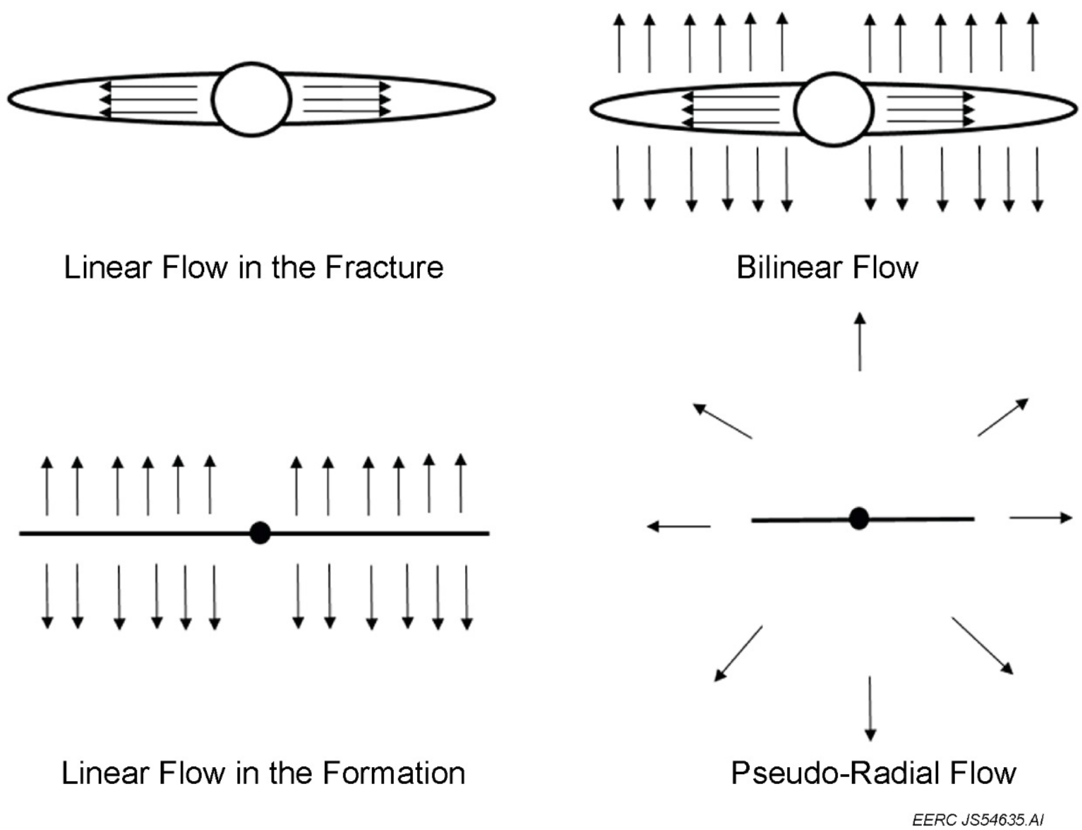

Figure 8: Typical flow regimes diagnosed from the pressure decline curve during the shut-in period (Smith and Montgomery, 2015).

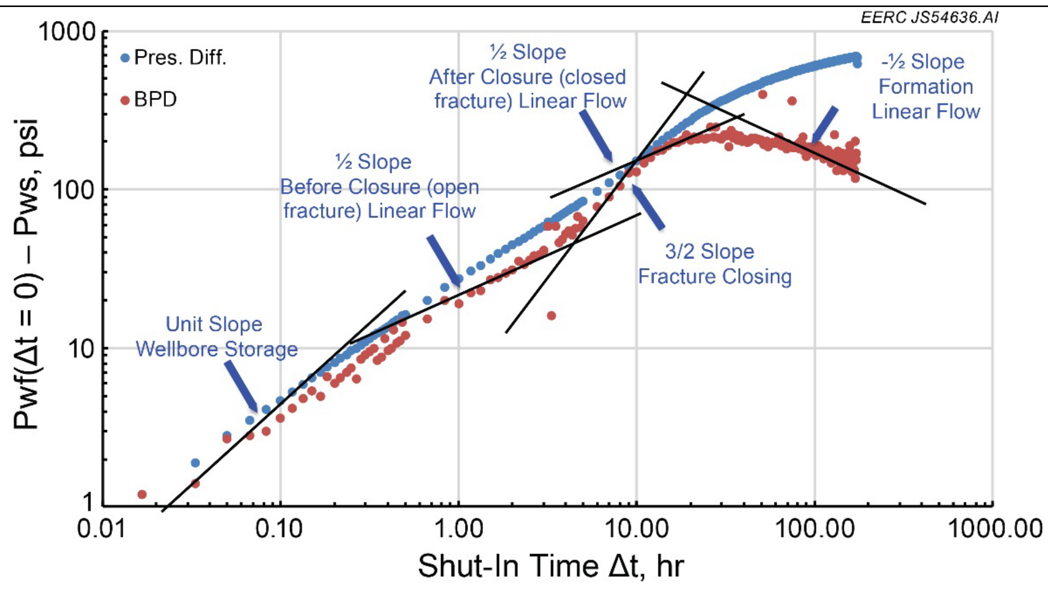

Figure 9: Log–log plot for shut-in pressure analysis.

Postinjection: Soak Period and Flowback Interpretation

The soak period for the injection test began when injection ceased on June 28 and extended into the first 2 weeks of July. Reservoir pressure and temperature were monitored using the downhole gauges. The test procedure called for opening the well after the soak period to conduct a flowback period, during which pressure, temperature, and gas composition would continue to be monitored while fluid samples were collected at the surface. The well was first opened on July 7, 9 days after injection ceased. The initial BHP on July 7 was at 8740 psi, which was back to very near the estimated pretest reservoir pressure. Gas flowed for 8.5 hours, after which time the BHP had dropped to 100 psi. The composition of the gas started out as essentially 100% CO_2 and, since this was the residual fluid in the tubing after injection, showed some traces of hydrocarbons in the last 2 hours of the first flowback period. The decision was made to shut in the well again and extend the soak period for another 6 days. The second flowback period began on July 13. The BHP at the start of the second flowback period was 3116 psi. After a mix of CO_2 and hydrocarbon gas was produced for 10.5 hours, the well started flowing oil to surface at a rate of approximately an eighth of a barrel/minute. The well flowed for a total of 45 minutes, producing a total of nine barrels of oil. Oil, gas, and water samples were collected. The BHP when the oil started flowing to the surface was approximately 1890 psi. An explanation for the delayed response and flow at low-BHP conditions is that the Middle Bakken reservoir is so tight that continuous flow from the matrix could not be sustained during the first flowback period. The very low BHP indicates that the high saturation of CO_2 in the near-wellbore area vaporized, further reducing liquid permeability. However, a considerable fraction of the injected CO_2 was voided from the reservoir during the first flowback period. The subsequent 6-day shut in and pressure buildup period allowed mobilized reservoir oil to return to the near-wellbore area. During the second flowback period, gas was again cleared from the wellbore, but some mobilized oil was able to enter the well and be produced under the more controlled, but still below saturation pressure, BHP condition of 1890 psi. At the same time, the small tubing size of the wellbore caused higher gas velocities which temporarily enhancing the transport of fluids from the bottomhole to the wellhead. This beneficial effect of increased production was short-lived, as the gas expansion does not propagate into the far-reservoir region, which is controlled by the tight matrix compressibility and virgin reservoir high pressure (Owusu and others, 2013). A PNL was run in the injection well after all other field activities were complete to determine any changes in oil, water, or gas saturation that may have occurred as a result of the injection tests. The results of the postinjection PNL run are provided in Figure 10, showing no evidence of CO_2 occurring out of the Middle Bakken injection zone. The well was then shut in, and the field-based portion of the main injection test was considered to be completed.

Changes in Hydrocarbon Composition as Evidence of CO_2 Effect on Oil Mobilization

The samples collected during the oil flowback period were sent to the EERC where the hydrocarbon composition (as defined by molecular weight distribution and hydrocarbon species) were determined. Figure 11 shows the results of the compositional analysis of oil samples collected before the pretest and after the main test soak period. The data shown in Figure 11 are plotted as a cumulative distribution function on a mass percent basis. The red dots represent “typical” Bakken crude composition, based on analysis of oil samples from a different Bakken well in northern Dunn County. The green and yellow dots represent the preinjection oil from the Knutson–Werre 34-3 well. The gold and purple dots represent the oil collected during the flowback period on July 13 (i.e., the postinjection/postsoak oil). The data points represent the mass percent of hydrocarbon molecules in the sample that have a carbon number smaller than or equal to the carbon number on the x-axis. For example, the purple dot at the intersection of x = C9 and y = 75% means that 75% of the hydrocarbons in that postinjection sample are in the C9 and lighter range. Compare that to the preinjection sample represented by the green dot at y = 75% where x = C13. These data indicate that there was an observable shift toward the lower-molecular-weight hydrocarbons as a result of CO_2 injection. These observations are consistent with observations from the laboratory rock extraction experiments, which showed that CO_2 preferentially mobilizes lower-molecular-weight hydrocarbons from the Middle Bakken matrix (Figure 12). The phenomenon of preferential mobilization of lighter-molecular-weight hydrocarbons by CO_2 is observed to be even more pronounced in the Bakken Shales, as shown in Figure 13. These pre- and posttest oil compositional data from the field test suggest that the CO_2 did, indeed, penetrate the matrix of the Middle Bakken, interacted with the oil therein, and mobilized lighter oil.

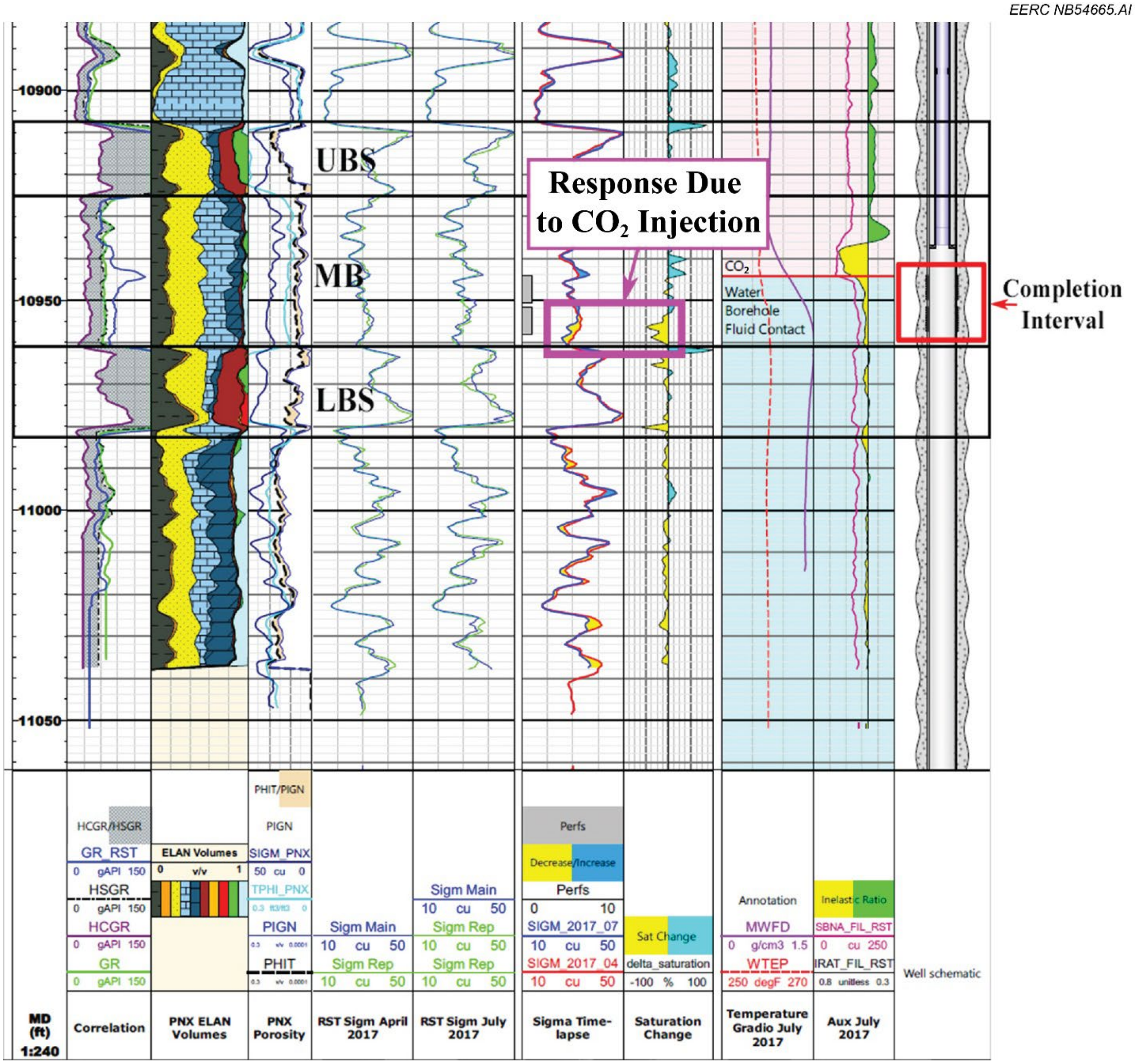

Figure 10: Postinjection PNL results. The well logs included in this display, from left to right, are gamma ray (GR_RST/HSGR/HCGR/GR), volumes for various minerals, formation sigma (SIGM_PNX) and porosity (TPHI_PNX/PIGN/PHIT), baseline sigma measurement (SIGM MAIN/SIGM REP), repeat sigma measurement (SIGM MAIN/SIGM REP) both baseline and repeat sigma and perforated interval (SIGM_2017_04, SIGM_2017_07, and PERFS, respectively), water saturation change (SAT CHANGE), manometer well fluid density (MWFD) and well temperature (WTEP), filtered near-borehole sigma (SBNA_FIL_RST) and filtered far/near inelastic count ratio (IRAT_FIL_RST), and a wellbore schematic at the far right.

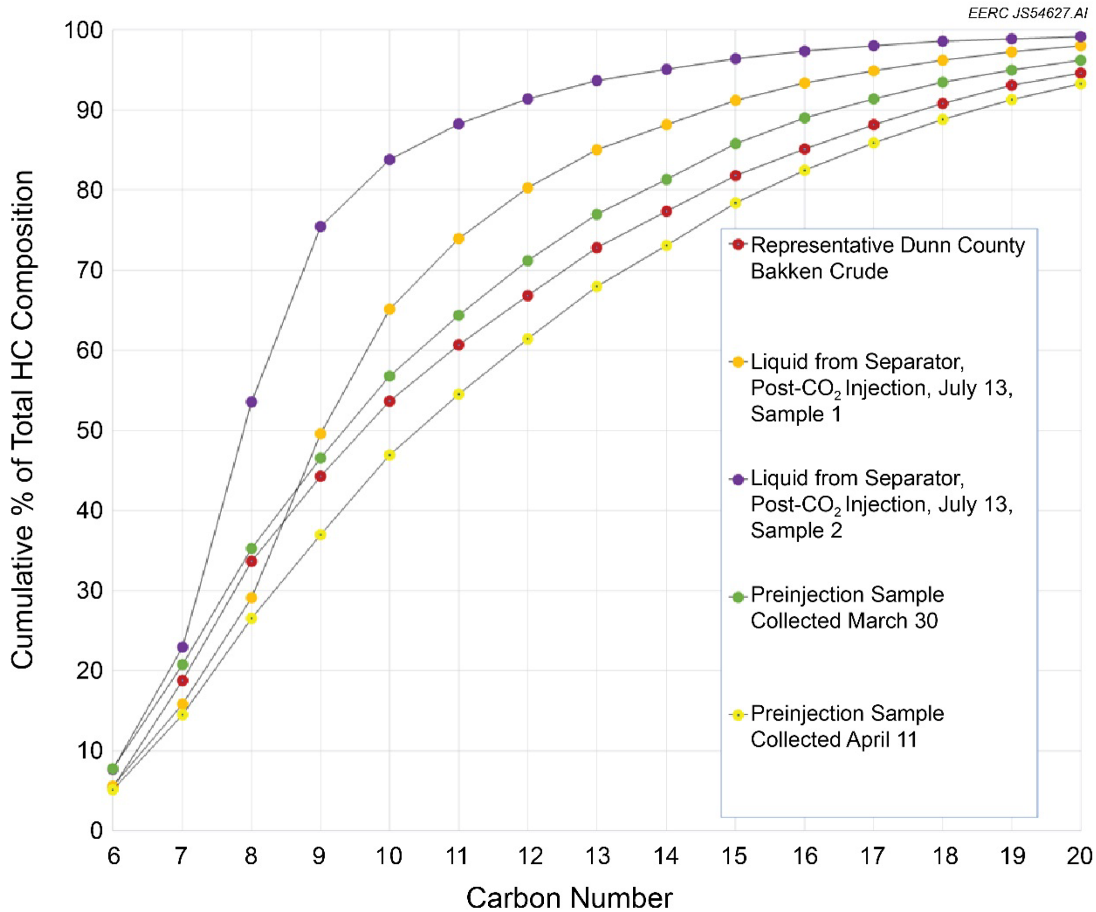

Figure 11: Comparison of preinjection oil composition and a representative Bakken oil sample from another Dunn County well to postinjection oil composition.

Conclusions

Key lessons learned from the Bakken CO_2 injection test in the Knutson–Werre well include the following:

- Although the injection rates were low, the test demonstrated that CO_2 can be injected into an unstimulated Middle Bakken reservoir rock (i.e., no use of hydraulic fracturing fluids or proppant to open and maintain complex induced fracture networks).
- Fluid compositional data before and after the test indicate that CO_2 penetrated into the matrix of the Middle Bakken and mobilized lighter-molecular-weight hydrocarbons.
- The data generated by the main test serve to verify and validate the previously generated laboratory experimental data from the CO_2-based permeation and hydrocarbon extraction studies conducted on MB core samples.

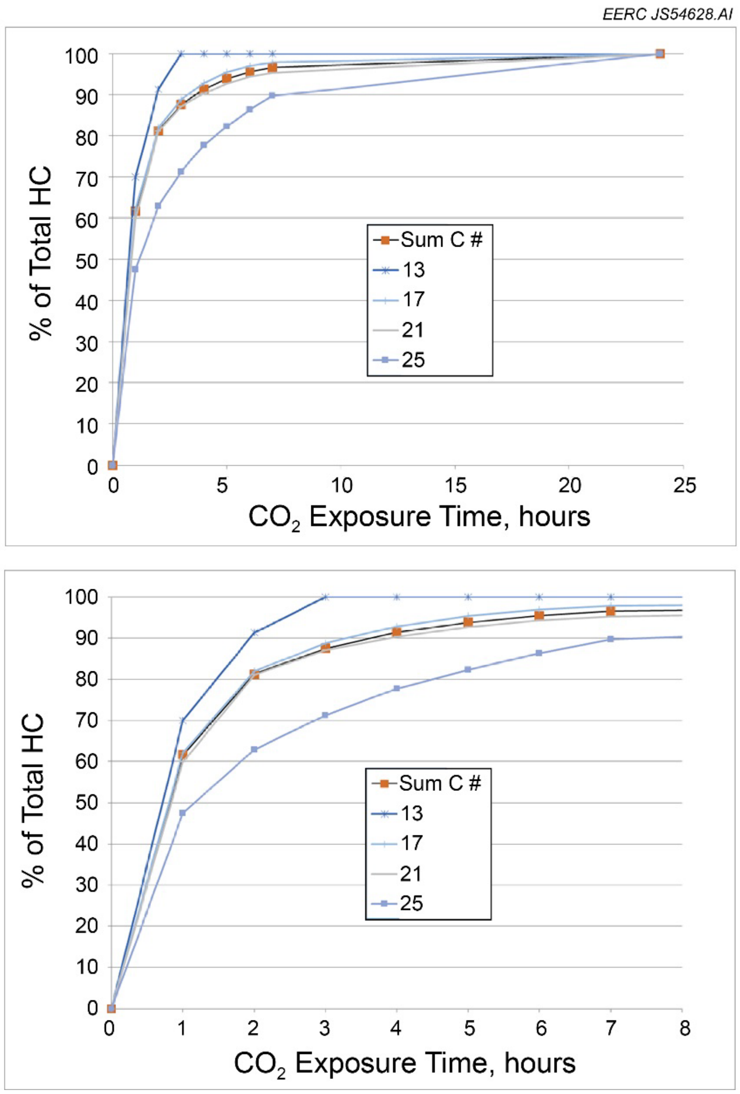

Figure 12: Results of CO_2 extraction tests using a method described in Hawthorne and others (2013) on two samples of Middle Bakken rock showing that lower-molecular-weight hydrocarbons were mobilized faster and more completely by CO_2.

Production responses to injection were observed, and while the nature of the test meant that those responses were not directly related to improved oil production, they suggest that fluid mobilization can be influenced by the injection of CO_2. If CO_2 or other gases that enhance oil mobility can be injected and fluid mobilization can be influenced, developing an effective means of EOR in unconventional formations is possible. That said, developing cost-effective EOR approaches will require more fieldwork. Another key lesson learned from the Bakken tests is that detailed pre- and posttest data on reservoir conditions and fluids production are essential for test and offset wells. Robust reservoir characterization provides information that is crucial to creating realistic geomodels and conducting valid dynamic simulations of potential EOR scenarios. This knowledge is essential to designing the operational parameters of injectivity tests and interpreting the results. Detailed data on the reservoir pressure and temperature conditions and composition of reservoir fluids prior to and after the injection test are essential to thoroughly and quantitatively evaluate the effects of injection.

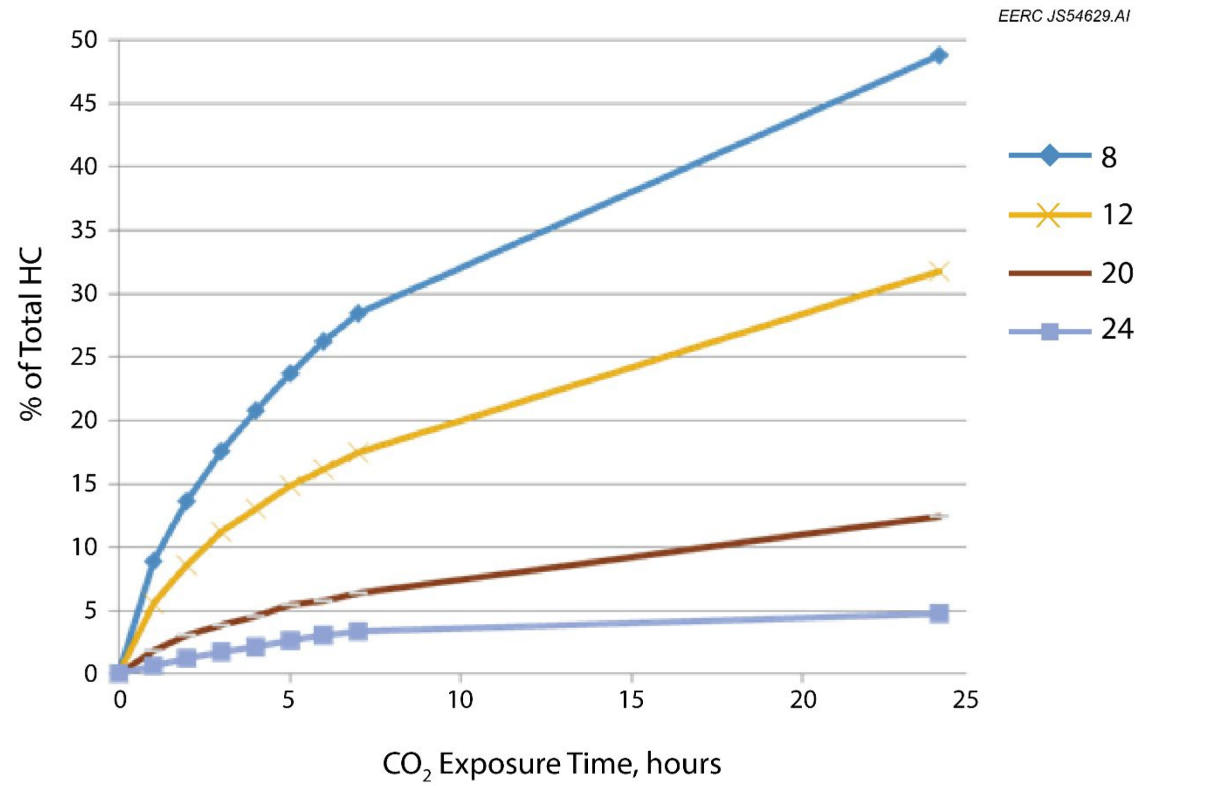

Figure 13: Results of CO_2 extraction tests using a method described in Hawthorne and others (2013) on a sample of Lower Bakken Shale showing that lower-molecular-weight hydrocarbons (represented here by Carbon Numbers C8 and C12) were preferentially mobilized by CO_2 over higher-molecular-weight hydrocarbons (represented here by Carbon Numbers C20 and C24).

Acknowledgments

This material is based upon work supported by the U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL) under Award Number DE-FC26-08NT43291. Funding for this program was also provided by the North Dakota Industrial Commission Oil and Gas Research Program, XTO Energy, Marathon Oil Company, Hess, and Continental Resources. In-kind contributions were provided by Schlumberger, Computer Modelling Group (CMG), and Baker Hughes. The authors want to particularly acknowledge the tremendous commitment made by XTO Energy with respect to providing a well for the test and conducting all of the field-based activities for this project. Special acknowledgment is also given to Mary Flynn, and Jugal Gupta of XTO Energy, Max Boone of Exxon Mobil, and Nathaniel Kurczewski, formerly of XTO Energy, for their personal commitment to ensuring the success of this project. The authors also thank Mary Sullivan and Traci Rodosta of DOE NETL for their invaluable guidance and support of this project.

References

Aguilera, R., 2014, Flow units—from conventional to tight–gas to shale–gas to tight–oil to shale–oil reservoirs: SPE Reservoir Evaluation & Engineering, v. 17, p. 190–208.

Barree, R.D., Barree, V.L., and Craig, D., 2009, Holistic fracture diagnostics—consistent interpretation of prefrac injection tests using multiple analysis methods: SPE Production & Operations, v. 24, no. 3, p. 396–406.

Bourdet, D., Whittle, T.M., Douglas, A.A., and Pirard, Y.M., 1983, A new set of type curves simplifies well test analysis: World Oil, v. 196, no. 6, p. 95–106.

Hawthorne, S.B., Gorecki, C.D., Sorensen, J.A., Steadman, E.N., Harju, J.A., and Melzer, S., 2013, Hydrocarbon mobilization mechanisms from Upper, Middle, and Lower Bakken reservoir rocks exposed to CO_2: Paper presented at the SPE Unconventional Resources Conference – Canada, Society of Petroleum Engineers, SPE 167200-MS.

Hawthorne, S.B., Jin, L., Kurz, B.A., Miller, D.J., Grabanski, C.B., Sorensen, J.A., Pekot, L.J., Bosshart, N.W., Smith, S.A., Burton–Kelly, M.E., and Heebink, L.V., 2017, Integrating petrographic and petrophysical analyses with CO_2 permeation and oil extraction and recovery in the Bakken Tight Oil Formation: SPE–185081, Presented in SPE Unconventional Resources Conference, Society of Petroleum Engineers, Calgary, AB, Canada, February 15–16.

Jin, L., Sorensen, J., Hawthorne, S., Smith, S., Pekot, L., Bosshart, N., Burton–Kelly, M., Miller, D., Grabanski, C., Gorecki, C., and Steadman, E., 2016c, Improving oil recovery by use of carbon dioxide in the Bakken unconventional system—a laboratory investigation: SPE Reservoir Evaluation & Engineering.

Jin, L., Hawthorne, S., Sorensen, J., Kurz, B., Pekot, L., Smith, S., Bosshart, N., Azenkeng, A., Gorecki, C., and Harju, J., 2016a, A systematic investigation of gas-based improved oil recovery technologies for the Bakken tight oil formation, *in* Proceedings of the Unconventional Resources Technology Conference: RTeC-2433692, San Antonio, Texas, August 1–3.

Jin, L., Hawthorne, S.B., Sorensen, J.A., Pekot, L.J., Kurz, B.A., Smith, S.A., Heebink, L., Herdegen, V., Bosshart, N.W., Torres, J., Dalkhaa, C., Peterson, K., Gorecki, C.D., Steadman, E.N., and Harju, J.A., 2017, Advancing CO_2 enhanced oil recovery and storage in unconventional oil play—experimental studies on Bakken shales: Applied Energy, v. 208,
no. 171–183, ISSN 0306-2619.

Jin, L., Sorensen, J.A., Hawthorne, S.B., Smith, S.A., Bosshart, N.W., Burton-Kelly, M.E., and Harju, J.A., 2016b, Improving oil transportability using CO_2 in the Bakken system—a laboratory investigation: Society of Petroleum Engineers, doi:10.2118/178948-MS.

Marongiu-Porcu, M., Ehlig-Economides, C.A., and Economides, M.J., 2011, Global model for fracture falloff analysis, *in* Proceedings of the North American Unconventional Gas Conference and Exhibition: Society of Petroleum Engineers.

Owusu, P.A., DeHua, L., Nyantakyi, E.K., Nagre, R.D., Borkloe, J.K., and Frimpong, I.K., 2013, Prognosticating the production performance of saturated gas drive reservoir—a theoretical perspective: International Journal of Mining Engineering and Mineral Processing, v. 2, n. 2, p. 24–33, DOI: 10.5923/j.mining.20130202.02.

Presley, J., 2018, Unraveling the Bakken's EOR complexity: E&P Magazine, Hart Energy, 4 p., March 19, 2018.

Smith, M.B., and Montgomery, C., 2015, Hydraulic fracturing: CRC Press.

Sorensen, J.A., and Hamling, J.A., 2016, Historical Bakken test data provide critical insights on EOR in tight oil plays: The American Oil & Gas Reporter, v. 59, no. 2, p. 55–61.