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Experimental investigation of gaseous solvent huff-n-puff in the Middle Bakken Formation

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ABSTRACT

The efficacy of gaseous solvents in enhancing oil recovery (EOR) in unconventional reservoirs and the influence of operational and design parameters are still debated among the oil recovery research community. This work investigated the recovery-enhancing capabilities of two potent gaseous solvents, CO₂ and ethane, in tight core samples. Laboratory huff-n-puff (H-n-P) experiments were conducted under three miscibility conditions to investigate the influence of the key operating parameters and the dependency of their impact on the miscibility conditions and gas composition. The results show that oil recovery increased with increasing pressure from below (BM) to above (AM) miscibility pressure in a non-linear trend, irrespective of the gas composition. Furthermore, the influence of the soak period was noticeably dependent on the miscibility condition, specifically more remarkable under AM conditions and less apparent under BM conditions. Likewise, the effect of the production period was more pronounced at AM conditions for both gases. Finally, the impact of rock surface area-to-volume (SA/V) was only observed at BM, where both gases recovered more oil in the core samples with high SA/V. In general, ethane showed a higher efficacy for oil recovery than CO₂; CO₂ recovered 21%–70% of oil in small core samples, while ethane could recover 32%–88%. The highest recovery was achieved with ethane injected under AM conditions, with a prolonged soak time, a short production period and into a core sample with a high SA/V. We believe the findings from this work will help better understand and design H-n-P EOR projects.

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1. Introduction

Unconventional resources have recently gained tremendous attention in the energy industry and have significantly contributed to the worldwide energy supply (Soeder, 2018). Until recently, these reservoirs were challenging to produce due to their relatively low permeabilities. The emergence of tight oil production has been catalyzed by drilling and hydraulic fracturing (Wang and Krupnick, 2013). Horizontal wells increase the reservoir contact area, while hydraulic fracturing provides high conductivity flow pathways through which fluids flow easily to the well bore. These two technologies work in tandem to enhance production from the tight formations. Despite these advances, significant challenges still arise. These wells typically decline in production within the first

two years of production (Burrows et al., 2020), leaving substantial quantities (>90%) of residual oil trapped in the formations. In the Bakken Formation, for example, the amount of this residual oil is enormous; thus, a modest improvement in production translates to significant revenue inflow (Bohrer et al., 2008). This economic value has incentivized several investigations into techniques to enhance oil recovery from these tight formations.

Conventional enhanced oil recovery methods, such as water flooding, have been investigated to test their efficacy in tight formations. Experimental studies on tight samples from the Wolfcamp Formation revealed that water could recover between 2% and 8% of oil volume (Alvarez et al., 2017a, 2017b). For small core samples, this recovery is insignificant. These studies, and many others, have relied on spontaneous imbibition experiments that depend on the natural permeation of water into the formation matrix, which is a relatively slow process (Morrow and Mason, 2001). Furthermore, a field waterflood test conducted in the Upper Bakken Formation in

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1994 did not increase oil production (Todd and Evans, 2016). Due to their low permeability, injectivity issues arise and concerns over clay reactivity and swelling, which can further reduce the permeability, are also legitimate (Chakraborty et al., 2017).

Gas injection holds the promise of improving oil recovery in tight formations. In a simulation study, Sheng and Chen (2014) noted that gas injection enhanced recovery better than water-flooding. It is, thus, not surprising that several studies have focused on gas injection in shales to study and optimize oil recovery in unconventional reservoirs (Jia and Sheng, 2018; Jin et al., 2017; Ma et al., 2015). Owing to the low densities and viscosities of gases, they can easily flow through the tiny pore throats in tight formations. However, the high mobility of gases also presents a challenge in the field. In continuous injection mode, gas may bypass trapped oil and breakthrough prematurely in production wells, especially in the presence of natural fracture (Xu and Hoffman, 2013). Cyclic gas injection, also known as huff-n-puff (H-n-P), mitigates this problem. The technique involves the cyclic injection followed by soak and production through a single well. Experimental studies by Meng et al. (2019) showed that the H-n-P mode recovered 4% more oil than continuous injection in Eagle Ford shales. Sheng (2015) also reported a better recovery by H-n-P in a well-scale simulation study compared to flooding.

Following the seminal study by Gamadi et al. (2014), several attempts have been made to study influencing factors and understand the underlying recovery mechanism during H-n-P. Optimizing recovery by adjusting operation parameters, such as injection pressure and soak time, has also been a major research priority. Many investigations agree that increasing injection pressure positively impacts oil recovery (Hawthorne et al., 2017; Li et al., 2017, 2018; Sennaoui et al., 2022a, 2022b, 2022d). However, the same cannot be said about the soak period, and results have been mixed. Studies by Yu and Sheng (2015), Tovar et al. (2014) and Sennaoui et al. (2022d) all support the observation that a long soak period improved recovery. On the other hand, Shilov et al. (2019), Sanchez-Rivera et al. (2015) and Afari et al. (2022) have noted that shorter soak time is more beneficial to oil recovery by CO₂ than more prolonged periods. Although we acknowledge that discrepancies between these results could be due to different rock samples and length scales, it exposes the lack of understanding of the underlying by which H-n-P enhances recovery. In addition, other influencing factors, such as depletion rate and production period, have not received the needed attention compared to the soak period and injection pressure. It is, therefore, unsurprising that the use of H-n-P has not been extensively adopted by unconventional oil producers. Moreover, the few field pilot projects conducted have not yielded encouraging results (Hoffman and Evan, 2016).

A comprehensive review of the available literature on cyclic gas injection in unconventional formations indicates that the majority of studies have primarily focused on CO₂ as the injection gas (Burrows et al., 2020). The gas has been favored due to environmental concerns as a greenhouse gas coupled with other favorable properties such as its solubility in oil and its oil swelling properties. However, alternative gaseous solvents such as ethane (C₂H₆) have shown promise as a recovery agent. Burrows et al. (2020) noted that C₂H₆ possesses superior miscibility properties compared to CO₂. Favorable diffusion coefficients and swelling factors have also been reported (Yang and Gu, 2006). Despite these properties, only a handful of studies have been done to thoroughly assess the efficacy of C₂H₆ (Jin et al., 2017; Sennaoui et al., 2022c).

In several studies, with CO₂ as the model gas for H-n-P in tight formations, its performance has been correlated to the injection pressure relative to its minimum miscibility pressure (MMP), and injection above the MMP leads to higher recovery. The question then arises; can one inject any other gas and expect a similar

performance to CO₂ so long as the injection pressure is above the MMP? What is the role of composition-dependent interactions in H-n-P EOR? Are the effects of operating parameters dependent on miscibility conditions and gas composition? These are pertinent questions that need to be addressed for H-n-P EOR to gain widespread adoption.

To this end, in this paper, we aim to study the viability of CO₂ and C₂H₆ as H-n-P gaseous solvents for enhancing recovery in the Middle Bakken Formation. We compare the recovery enhancing performance of the two gases in tight formations in the same set of cores. To the best of our knowledge, a comprehensive comparison of the two solvents in the same set of cores in the Middle Bakken is sparse in the literature. Based on laboratory H-n-P experiments, we investigate the influence of injection pressure (miscibility condition), soak period, surface area to volume ratio and production period on oil recovery. It is worth mentioning that experimental studies on the effect of the production period in tight formation are lacking, especially for the Middle Bakken Formation. The influence of the above-mentioned design parameters is done, taking into consideration the miscibility conditions of the gases. By so doing, the dependency of the effects of the design parameters on miscibility conditions, the gas composition, and the role of gas composition-dependent mechanisms are better assessed. Again, we know of no extant work in literature that has studied such relationships, and we believe such an approach helps elucidate the recovery mechanism in gaseous solvent H-n-P in unconventional reservoirs.

2. Materials and methodology

2.1. Study area and experimental materials

The Bakken Formation is a prolific oil-bearing unconventional formation in the Williston Basin. Its area straddles the states of North Dakota and Montana (in the USA), and the province of Saskatchewan (Canada), and has been a significant economic resource for these regions. The formation has three principal members: The upper and lower members, which are organic-rich black shales, have extremely low permeabilities (LeFever et al., 1991), and the middle member. The middle member has a lower total organic content and relatively higher permeability, thus the primary target formation for field developments in the Williston Basin.

All core samples used in this study are from the Middle Bakken Formation. Four core plugs were drilled from larger slabs obtained from the Titan F-WP 32-14-H well in the Mondak Field. Core plugs were selected to ensure minimal fractures and fissures that could have been artificially induced. The properties of the cores used in this work are summarized in Table 1.

A dead oil sample from the Bakken Formation was used in this study. The dead oil sample has a density of 0.86 g/cm³, API gravity of 46.7, and a viscosity of 2.4 cP at 72 °F and 14.7 psi.

The CO₂ used in the huff-n-puff experiments is industrial grade with a purity of 99.99% and at a tank pressure of 1000 psi, while C₂H₆ was obtained at 99.99% purity and a tank pressure of 750 psi. Both gases used were procured from Red River Welder Supply.

Table 1
Identity and petrophysical properties of core samples used in this work.

Core ID	Depth, ft	Diameter, cm	Length, cm	Porosity, %	Permeability, mD
MB1	10731	2.5	6.3	7.58	0.261
MB2	11617	2.5	6.7	5.70	0.356
MB3	10716	2.5	6.5	4.00	0.114
MB4	10930	3.81	4.1	3.60	0.457

2.2. Experimental procedure

2.2.1. Core cleaning

After obtaining the core plugs, they were cleaned in a Dean-Stark apparatus. The procedure involves immersing the cores in toluene vapor for approximately 5 days to strip off any residual oil and other oil-soluble impurities from the core plugs. Next, the cores were immersed in a vapor of isopropanol to rinse off any toluene. The cores were then dried in an air bath at a temperature of 150 °F for 24 h, after which the core samples' dry weights (W_{dry}) were recorded.

2.2.2. Vacuum saturation

The vacuum saturation setup is illustrated in the schematic in Fig. 1. The system consists of a high-pressure sample chamber connected to a vacuum pump and an accumulator. The accumulator is connected to a syringe pump which discharges distilled water under a piston in the accumulator. The accumulator is filled with the dead oil sample above the piston.

As illustrated, the cleaned core samples are placed in the saturation chamber and sealed tightly. The chamber is then vacuumed for 6 h to evacuate air from the sample chamber and the core samples' pores. Next, the dead oil is transferred to the evacuated chamber with the aid of the syringe pump until the cores are fully immersed. The pressure in the chamber is increased gradually to 6000 psi and held constant while we monitor the flow rate. The samples are kept under saturation pressure until the flow rate is stabilized, at which point the cores are assumed to be thoroughly saturated. At a pressure of 6000 psi, it takes 2–5 days for the crude oil to adequately saturate the core samples. After the core samples are thoroughly saturated, the saturated weights (W_{sat}) are measured and recorded. The total volume of oil imbibed into the core samples is calculated by taking the difference between the dry weight (W_{dry}) and the saturated weight (W_{sat}) of the core plugs and dividing it by the oil's density.

2.2.3. Huff-n-puff experiments

The H-n-P experiment is designed to simulate matrix-fracture

interaction in tight formations (Table 2). A core sample is placed in the center of a pressure vessel (sample chamber), leaving some annular space around the core. Gas is injected into the annulus such that the core is fully immersed in the injected gas. The core sample simulates the matrix, while the annulus simulates the fractures.

Fig. 2 shows the laboratory apparatus used for the H-n-P experiments and its schematic diagram. It mainly consists of a high-pressure sample chamber, an accumulator, a syringe pump, a gas reservoir, and a temperature-controlled air bath. In addition, pressure gauges are placed at the inlet (top) of the sample chamber and the accumulator to monitor pressure during the experiments.

For one H-n-P cycle, the core sample is positioned in the center of the sample chamber, tightly sealed, and connected to the remainder of the system in the temperature-controlled oven. A sufficient volume of gas is then delivered from the gas tank to the accumulator using the syringe pump. The system temperature is set to 215 °F (the reservoir temperature) and allowed to equilibrate for approximately 1 h. Once the system is sufficiently equilibrated, additional gas is injected, and the pressure is increased to the design pressure. Next, the inlet valve is closed, and the pressure is held constant for the design soak period. After the design soak period elapses, the accumulator is steadily stepped down to atmospheric pressure over the design production period while the oven is cooled to room temperature. The core is then removed, and its weight is recorded as W_i .

2.2.4. Summary of workflow

The apparatus and methods described are used alternately to assess the H-n-P performance of CO₂ and C₂H₆. The workflow is summarized below.

- (1) The core is cleaned with solvents and then dried, and the dry weights (W_{dry}) is recorded.
- (2) The core is vacuum saturated with dead oil at 6000 psi for 2–5 days, after which the saturated weight (W_{sat}) is recorded.

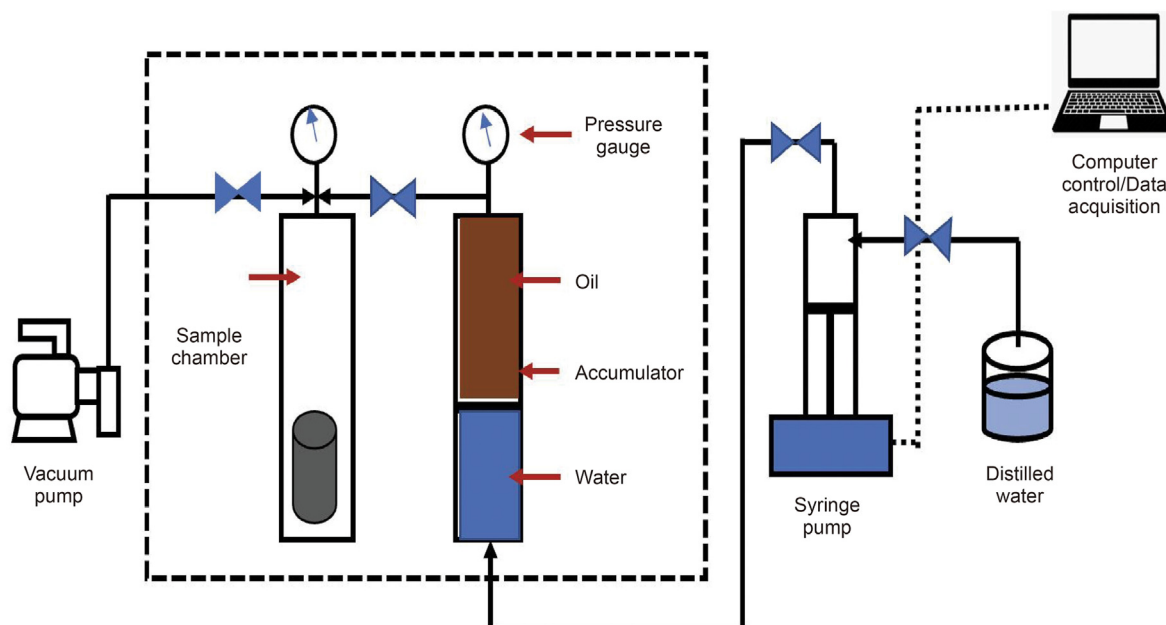


Fig. 1. Schematic of the vacuum saturation apparatus used in this work.

Table 2
Table of experimental design used in this work.

Experiment ID	Core sample	Solvent	Miscibility condition	Soak period, h	Production period, h
1	MB1	CO ₂	BM	6	6
2	MB2	CO ₂	NM	6	6
3	MB3	CO ₂	AM	6	6
4	MB1	C ₂ H ₆	BM	6	6
5	MB2	C ₂ H ₆	NM	6	6
6	MB3	C ₂ H ₆	AM	6	6
7	MB1	CO ₂	BM	12	6
8	MB2	CO ₂	NM	12	6
9	MB3	CO ₂	AM	12	6
10	MB1	C ₂ H ₆	BM	12	6
11	MB2	C ₂ H ₆	NM	12	6
12	MB3	C ₂ H ₆	AM	12	6
13	MB1	CO ₂	BM	6	12
14	MB2	CO ₂	NM	6	12
15	MB3	CO ₂	AM	6	12
16	MB1	C ₂ H ₆	BM	6	12
17	MB2	C ₂ H ₆	NM	6	12
18	MB3	C ₂ H ₆	AM	6	12
19	MB4	CO ₂	BM	6	6
20	MB4	CO ₂	NM	6	6
21	MB4	CO ₂	AM	6	6
22	MB4	C ₂ H ₆	BM	6	6
23	MB4	C ₂ H ₆	NM	6	6
24	MB4	C ₂ H ₆	AM	6	6

- (3) One H-n-P cycle is conducted at the design injection pressure, soak period, production period, surface-to-volume ratio, and solvent composition (Table 2).
- (4) At the end of the cycle, the weight of the core sample is recorded as W_i . The cumulative oil recovery factor (CRF) after each cycle is calculated as follows:

$$CRF = \frac{W_{sat} - W_i}{W_{sat} - W_{dry}} \quad (1)$$

- (5) Steps 4–6 are repeated for all 4 cycles for each set of design parameters.
- (6) Steps 1 and 2 are repeated for another set of experiments after all 4 cores have been used.

3. Results and discussion

3.1. Recovery factor as a function of miscibility condition and gas composition

Six H-n-P experiments were done to investigate the effects of the miscibility condition and its interaction with gas composition. The operating pressures were chosen to represent the conditions 'Below miscibility' (BM), 'Near miscibility' (NM), and 'Above miscibility' (AB), as shown in Table 2. The injection pressures will therefore depend on the gas compositions. We obtained the MMPs of CO₂ and C₂H₆ from Hawthorne et al. (2017), which are presented in Table 3. It is worth noting that we set these parameters based on the first contact miscibility of the gases. The multiple contact miscibility for these gases with Bakken oil has been measured to be lower than the chosen pressures (Green and Wilhite, 2018). The soak and production times are constant at 6 h each, and the cycle number for all experiments is fixed at 4 cycles.

Fig. 3 shows an example of core sample before and after gas (CO₂) H-n-P. Fig. 4 shows the results of the measured recovery factors for the H-n-P experiments. The results show several vital observations. Firstly, as expected, the recovery factor generally increases with an increase in pressure for both CO₂ and C₂H₆. The

recovery factor increases with the pressure gradient as it passes from BM to NM to AM, irrespective of the gas composition. This observed trend corroborates with results reported by several other authors (Gamadi et al., 2014; Li et al., 2017; Meng et al., 2019). This pattern may be associated with the capillary pressure phenomenon. Under BM conditions, the interfacial tension between gas and oil is relatively high, and in combination with the restricted pore throats in tight formations, this leads to an increased capillary pressure that hinders the displacement of oil by the injected gas. As pressure increases, while below the MMP, the injected gas can invade smaller pores with high entry capillary pressure thresholds. Increased pressure to and above the MMP results in a significant drop in IFT to zero and complete gas dispersion in oil. This mixing also results in several secondary mechanisms taking effect, which include oil swelling (Yang and Gu, 2006), viscosity reduction (Li et al., 2013) and lighter component extraction (Hawthorne et al., 2013).

As seen more clearly in Fig. 5, our results also show that, for both gases, an increase in pressure from BM to NM led to a larger increment in recovery factor than from NM to AM. When CO₂ is injected, an increase in the pressure from BM to NM results in $\approx 18\%$ improvement in the recovery factor, whereas an increase in pressure from NM to AM results in $\approx 13\%$ increase in the recovery factor.

For C₂H₆, going from BM to NM resulted in a $\approx 40\%$ increase in recovery factor, but only a modest $\approx 5\%$ improvement in recovery factor was realized when pressure was increased from NM to AM. The increase in recovery factor per psi pressure has been a subject of interest in H-n-P studies. In their H-n-P studies in Wolfcamp core samples, Li et al. (2018) observed an improvement in recovery factor with increased pressure for pressure ranges below the MMP. Beyond the MMP, the oil recovery leveled off or improved modestly depending on the permeability of the cores. In other studies, Hawthorne et al. (2017) and Tovar et al. (2018) reported a continuous recovery increase as the pressure increases beyond the MMP. The former attributed this observation to the low permeability of the core sample, which causes a substantial pressure drop on the surface of the core. Our findings support this theory. Thus, even at or beyond the MMP, miscibility is not achieved uniformly

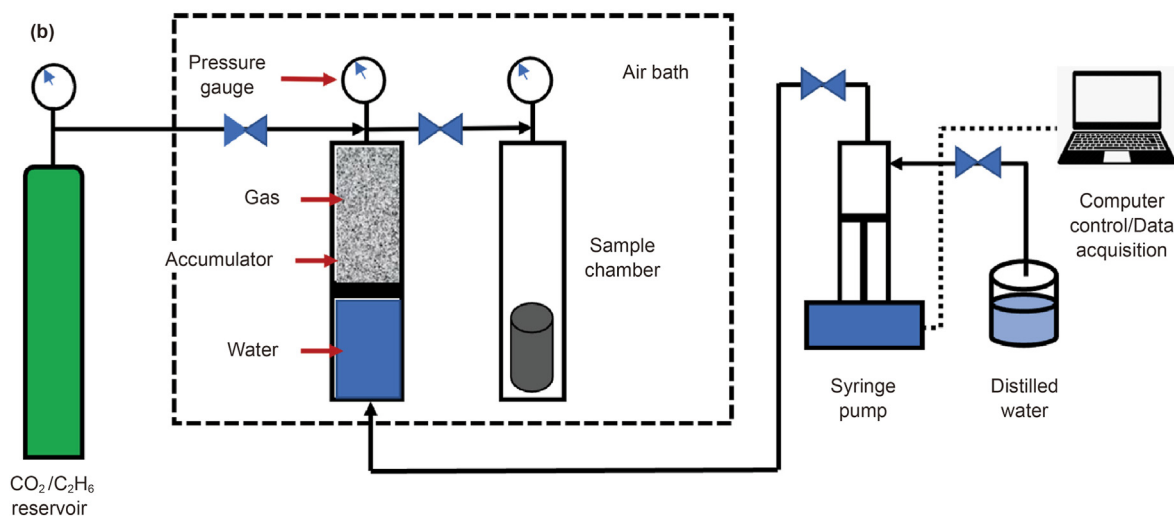


Fig. 2. (a) Laboratory setup and (b) schematic for the solvent huff-n-puff experiments.

Table 3

Minimum miscibility pressures and conditions defined for the gases used in this study and measured at 230 °F.

Solvent	MMP, psi	Below miscibility, psi	Near miscibility, psi	Above miscibility, psi
CO ₂	2521*	1000	2500	3500
C ₂ H ₆	1358*	500	1500	2500

Note: * Obtained from Hawthorne et al. (2017).

throughout the core sample. As a result, the residual oil at the center of the core becomes inaccessible despite any further increase in pressure.

Although C₂H₆ performs better under all miscibility conditions,

the performance difference varies with the miscibility condition. At BM conditions, C₂H₆ recovered only ≈ 7% more oil than CO₂. Contrarily, C₂H₆ recovered around 30% more oil than CO₂ under NM conditions and about 20% more oil than CO₂ under AM conditions.

This finding implies that, under BM conditions, the effect of gas composition is diminished. Under BM conditions, the injected gas displaces the oil immiscibly, and the principal forces at play during immiscible displacement are advective forces provided by the piston-like displacement from pore to pore. Irrespective of the gas composition, high interfacial tension limits molecular interactions between the displacing gas and the displaced oil (except at the interface). At NM conditions, the distinction between the gases becomes apparent as the effect of molecular interactions begins to become relevant. The mechanism of recovery by which CO₂ varies from that of C₂H₆. CO₂ may interact with oil by extracting lighter oil components from the pores facilitating oil recovery.

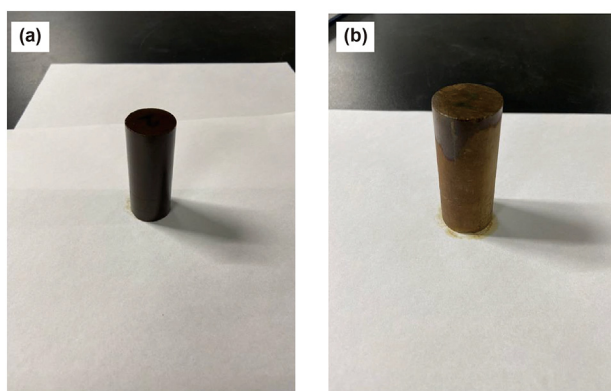


Fig. 3. Core sample #MB3 (a) before (fully saturated) and (b) after CO₂ H-n-P.

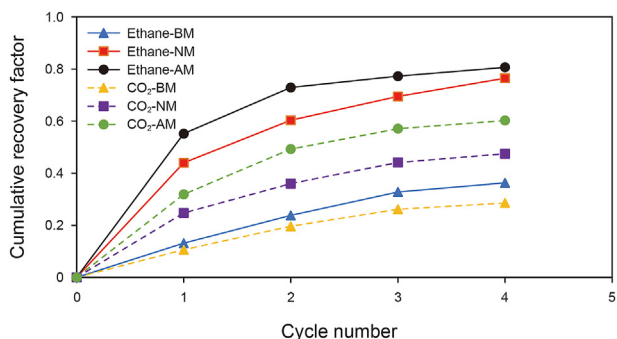


Fig. 4. Recovery performance of ethane and CO₂ as a function of miscibility condition. All experiments are conducted with 6-h soak period, 6-h production period and a temperature of 215 °F.

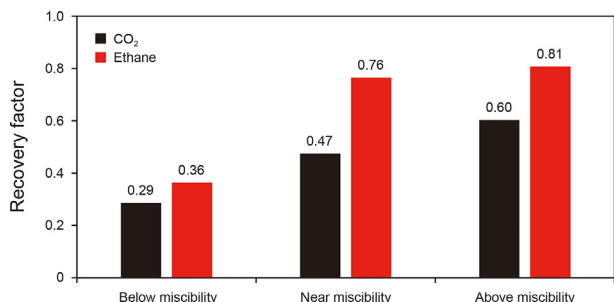


Fig. 5. Terminal recovery factors for CO₂ and C₂H₆ at various miscibility conditions over a 6-h soak and production period.

3.2. Influence of the number of cycles and its dependency on miscibility condition

The number of cycles is essential to optimizing the H-n-P injection scheme as it directly relates to the volume of gas utilized. Sensitivity analysis was not carried out specifically to study the effect of the number of cycles, as the number of cycles was fixed at 4 cycles for all experiments. However, specific key observations are worth mentioning.

Fig. 6 is presented to identify observable trends in the relation between the cycle number and recovery at different miscibility conditions. The cycle number is plotted against the normalized recovery (as bar graphs) and cumulative normalized recovery (as line graphs). Note that the normalized recovery here is defined as the volume of oil recovered during the cycle as a proportion of the total volume of oil recovered. These definitions are to be differentiated from the recovery factor, which is the volume of oil recovered as a proportion of the total pore volume.

Initially, we observe that the first cycle recovered the most oil,

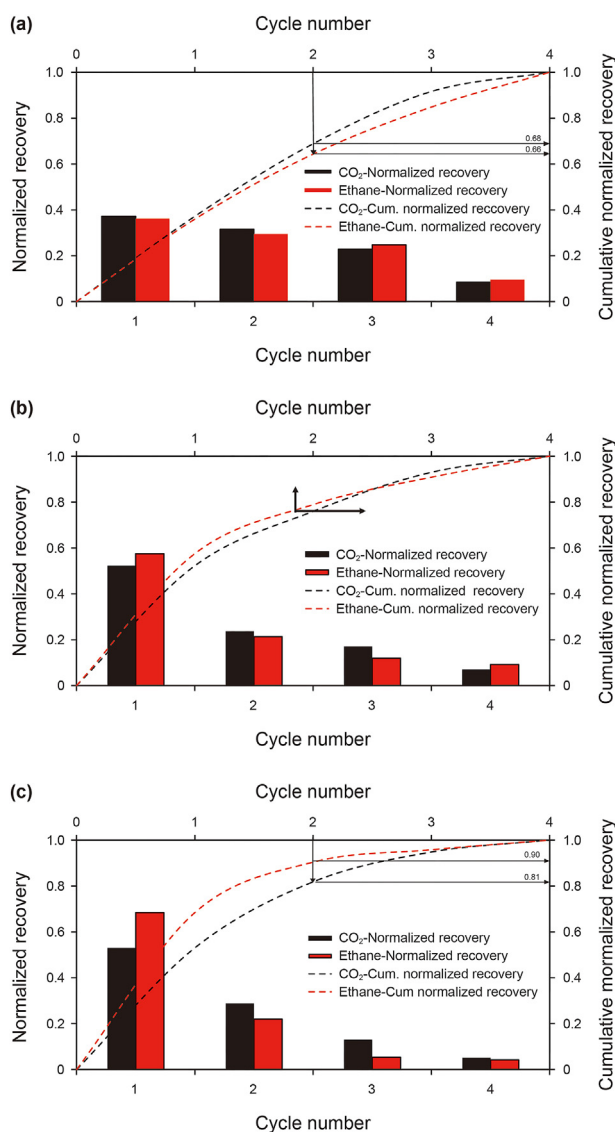


Fig. 6. Normalized and cumulative normalized recovery versus cycle number for different miscibility conditions: (a) Below, (b) near, and (c) above miscibility conditions.

while recovery continuously decreased with successive cycles. This trend was observed for both gases and under all miscibility conditions. The behavior has also been reported in existing literature (Gamadi et al., 2014; Li et al., 2019). Initially, the injected gas contacts and displaces oil in easily accessible pores, which consist of large to medium-sized pores. Since these pores contain a large volume fraction of the oil, the initial cycle interacts with and displaces the large volume. In subsequent cycles, the injected gas would have to access more difficult-to-reach pores containing a smaller fraction of the oil.

Fig. 6(a) reveals that the behavior described above under BM conditions is less apparent, and the oil recovery rate is gradual compared to NM and AM conditions for both. However, under NM and AM conditions, the initial cycles recover significantly more oil than subsequent cycles. For example, for CO₂ under BM condition, the first two cycles recovered ≈68% of recoverable oil but under AM conditions, the first two cycles recovered ≈81% of the total volume recovered. A similar observation was made for C₂H₆, as shown in Fig. 6. This observation indicates that the injected gas can only penetrate a limited pore volume per cycle under BM conditions. Because there is no mixing, the injected gas merely displaces the amount of oil it immediately contacts. On the other hand, under NM and AM conditions, owing to dispersion and molecular diffusion, the injected gas can contact a wider range of pore sizes, thus displacing a larger volume of oil in the first few cycles compared to BM conditions.

In addition, we note that CO₂ and C₂H₆ behaved similarly in terms of oil recovery per cycle under BM conditions. Under AM conditions, the distinction between the two gases is more pronounced. C₂H₆ recovered more oil (≈90% normalized recovery) during the first two cycles compared to CO₂ (≈81% normalized recovery). This observation suggests that C₂H₆ exhibits more favorable properties for enhancing recovery under miscibility conditions compared to CO₂. Yang and Gu (2006) noted that C₂H₆ has superior oil swelling and diffusion properties in oil than CO₂. These properties could partly explain C₂H₆ ability to recover more oil than CO₂.

3.3. Influence of soak period and its dependency on miscibility condition

The effect of the soak period on cyclic gas injection performance has been a subject of interest in several studies and results have been mixed. To investigate the impact of the soak period and its dependency on miscibility condition (and gas composition), 6 laboratory scale H-n-P experiments were carried out with soak periods set to 12 h, for CO₂ and C₂H₆, at BM, NM and AM conditions. The production periods were all fixed at 6 h. The data is then compared to previously described experiments conducted at 6-h

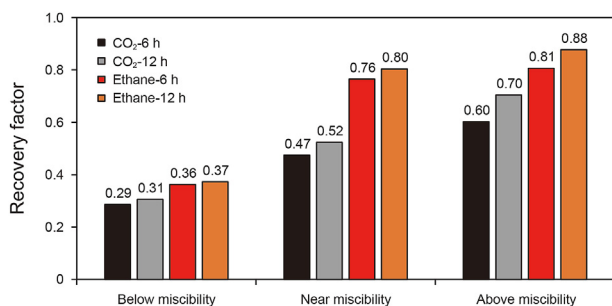


Fig. 7. Effect of soak period under different miscibility conditions and gas compositions.

soak periods.

The results are presented in Fig. 7. As seen from the figure, there is no remarkable difference in the recovery factor for short (6 h) and long (12 h) soak periods under BM conditions. This finding holds for both the CO₂ and C₂H₆ experiments. On the other hand, there is a significant difference in recovery factor at NM and AM conditions (compared to shorter soak periods for the same gas compositions). For CO₂, there was ≈5% improvement in recovery factor under NM conditions and ≈10% under AM conditions. For C₂H₆, there was an improvement of ≈4% under NM conditions and ≈7% under AM conditions.

The increase in recovery factor with prolonged soak periods has been attributed to diffusion (Gamadi et al., 2014; Jin et al., 2017). When gas molecules contact oil at the fracture–matrix interface (surface of the core sample), the molecules move from the region of higher concentration to a region of lower concentration until a dynamic equilibrium is established. The movement of molecules allows the gas to access deeper pores within the matrix, which will otherwise not be directly accessible. Diffusion is time-dependent; thus, the longer the contact time, the further the molecules can travel. This implies that a longer soak time allows molecules to diffuse deeper into oil-filled pore spaces and enhance the microscopic sweep. The results at BM conditions show that diffusion is negligible. For molecular diffusion (differentiated from self-diffusion) to be initiated, the gas and oil should be miscible, which doesn't happen under BM conditions. It is evident from the findings that a prolonged soak period results in a superior microscopic sweep under NM and AM conditions where oil and gas become miscible, and the influence of diffusion is noticeable.

Under NM and AM conditions where diffusion mechanism plays a significant role, C₂H₆ outperformed CO₂ at extended soak periods; C₂H₆ achieved ≈80% and ≈88% under NM and AM, versus ≈52% and ≈70% by CO₂ under NM and AM, respectively. In fact, injecting C₂H₆ at AM condition for 12 h achieved the highest recovery among all experiments. As indicated, the literature has already reported that C₂H₆ has a superior diffusion coefficient than CO₂. In our opinion, this may partly contribute to ethane's superior performance during prolonged soak times. However, given that CO₂ had a better recovery factor (over a shorter soak period for the same gas composition), a more extended soak period will be economically more beneficial for CO₂ than C₂H₆.

3.4. Influence of production period and its dependency on miscibility condition

Although the production (puff) period has been recognized in literature to influence H-n-P performance at the field scale, there is a paucity of experimental data on its influence at the core scale (Afari et al., 2022; Fragoso et al., 2018; Kong et al., 2016). Therefore,

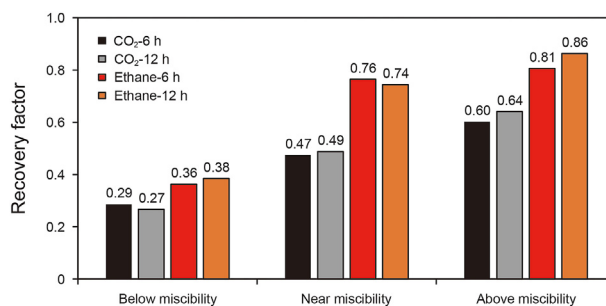


Fig. 8. Effect of production time on recovery at different miscibility conditions and gas compositions.

to study the effect of the production period in this work, 6 experiments were carried out at 12 h production period under BM, NM, and AM conditions and for CO₂ and C₂H₆. At the end of the design soak period, the pressure in the accumulator is stepped down at a rate of three equal pressure steps per time. This was done to replicate the pressure reduction at the field scale as closely as possible. The results are presented in Fig. 8.

The results show that, at the core scale, the recovery factor was not affected by the puff period under BM and NM conditions, irrespective of gas composition. Surprisingly, under AM conditions, the influence of the puff period was quite noticeable. Under AM conditions, CO₂ achieved ≈4% higher recovery factor at 12 h puff time compared to 6 h puff time, while C₂H₆ achieved ≈5% higher recovery factor.

Under miscible conditions, gas is dissolved in oil. As the pressure declines, the expansion of the gas drives oil to the surface. Under AM conditions, a larger volume of gas is dissolved in oil, requiring more time for complete exsolution from the bulk oil phase. Thus, the more time that is allowed, the more oil is recovered. In their work, Akita et al. (2018) also reported an increase in recovery factor when the depletion rate was reduced (i.e., increased puff period). They attributed this finding to the so-called "choke effect", which describes the loss of pore connectivity after a sudden pressure drop caused by physical closure and two-phase blockage. A gradual reduction in pressure may prevent the choke effect and enhance production. Sheng (2020) proposed a gas bubble nucleation mechanism to explain the direct relationship between depletion rate and recovery factor. Under miscible conditions, as pressure is depleted, exsolution of the gas is initiated, and small gas bubbles begin to nucleate in the bulk oil phase. These droplets then diffuse in the bulk oil phase until they coalesce with other droplets to form larger gas bubbles. The authors explain that this coalescence into large gas bubbles is detrimental to recovery as large gas bubbles are likely to bypass oil. This phenomenon could explain the lack of improvement in recovery with pressure decline from the NM pressure condition. At AM conditions, a similar mechanism may be playing a role. However, during pressure decline from a pressure value higher than the MMP, the fluid is still in a condition where IFT is still low. Sohrabi et al. (2008) reported that at low oil–gas IFT conditions, when large gas bubbles bypass oil-containing pores, oil could still be transferred to the gas and be produced to the surface. We believe this mechanism may also contribute to high recovery at AM; however, we recommend further studies to ascertain this mechanism in tight formations.

3.5. Influence of rock surface area-to-volume ratio and its dependency on miscibility condition

Production from tight formations primarily depends on the matrix volume exposed to hydraulic fractures. Therefore, to the extent possible, tremendous effort is dedicated to ensuring that a high fracture surface area is achieved in the hydraulic fracturing operation and design. Questions often arise about the effect of exposed rock surface area-to-volume ratio (SA/V) on EOR performance, which may also determine if refracturing is required for efficient recovery (Hejazi et al., 2017). In laboratory core-scale experiments, the SA/V is controlled by the core size (Chaisoontornyotin et al., 2019; Li and Sheng, 2017). We used two core sizes in this work, as presented in Table 1. Six experiments using core sample MB4 with a SA/V of 3.6 in²/in³ were conducted under BM, NM, and AM conditions with both CO₂ and C₂H₆ to better understand the impact of rock surface area-to-volume ratio on EOR performance.

As seen from the results in Fig. 9 the core samples with lower SA/V generally resulted in a decreased oil recovery factor. Under BM

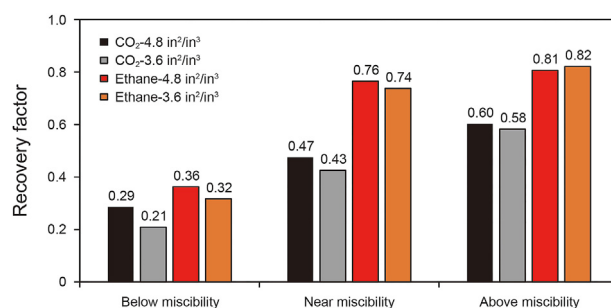


Fig. 9. Influence of surface area on recovery at different miscibility conditions and gas composition.

and NM conditions, there is a considerable difference in recovery factors. Under BM conditions, the recovery was reduced by ≈8% and ≈4% for CO₂ and C₂H₆, respectively, compared to recovery from 4.8 in²/in³. Likewise, under NM conditions, the recovery factors decreased by ≈4% and ≈2% for both CO₂ and C₂H₆, respectively. Under AM conditions, the effect of SA/V is less conspicuous; recovery by CO₂ was reduced by a meager ≈2% and by ≈1% with C₂H₆. These observations also indicate that the effect of SA/V seems to diminish with increased injection pressure. In addition, the impact of SA/V is much more significant for CO₂ than for C₂H₆.

According to Darcy's flow model, the flow rate is expected to increase as the flow area increases, thus the increased recovery at high SA/V. In radial flow geometry, as present in our core-scale experiment, a reduction in the radius (increase SA/V) results in an increased pressure gradient (dP/dr) which increases flow out of the core. Second, according to Fick's law, a decrease in surface area impacts the diffusive flux of gas molecules into the core. Under BM conditions, diffusion tends to play a minimal role in the recovery; thus, we can deduce that the reduction in recovery may be primarily due to the increased pressure gradient. However, although diffusion plays a role at NM and AM, gas dissolution in oil also occurs. Other mechanisms, such as oil swelling, lighter component extraction and viscosity reduction, may play significant roles. The surface area less influences these mechanisms and may explain the lack of significant difference in recovery under AM conditions since these mechanisms have a more considerable influence. Our results suggest that injecting gases at higher pressure may compensate for a reduced simulated reservoir volume (SRV) in the field. However, more studies at the field scale are recommended to ascertain this conclusion.

4. Conclusions

A laboratory-scale study has been conducted to investigate the efficacy of CO₂ and C₂H₆ as H-n-P gaseous solvents for improving recovery in the Middle Bakken Formation. First, we investigated the recovery improvement performance of the two gases in the same set of tight formation cores. In addition, we studied the effect of injection pressure, soak time, surface area to volume ratio, and production time on oil recovery.

The results of the study indicate that increasing the injection pressure increases the recovery factor, with the most significant improvement observed when transitioning from BM to NM conditions. Recovery tends to decrease with successive cycles, particularly noticeable in NM and AM conditions. Extended soak periods significantly enhances recovery, specifically under AM conditions. The influence of the production period is contingent upon miscibility, demonstrating a discernible impact in AM conditions. Lower surface area-to-volume ratios generally lead to reduced oil

recovery, particularly pronounced in BM and NM conditions. Overall, C₂H₆ exhibits superior performance compared to CO₂, even when accounting for miscibility conditions, underscoring the significance of gas composition in gas huff-n-puff recovery.

It is worth mentioning that there were some limitations to this work. First, although the core samples were selected in close vicinity of each other, heterogeneities are present, as shown by the variations in the porosity and permeability values in Table 1. These heterogeneities may influence the conclusions of this work. In addition, the re-use of core samples and the cyclic saturation and desaturation may alter core properties due to hysteresis and physical damage to the samples, which could affect the conclusion of this work (Badrouchi et al., 2022). Finally, we used a dead oil sample with a different composition than live oil at reservoir conditions; thus, we caution against extrapolating the results presented to the reservoir scale. These limitations notwithstanding, we believe the results can facilitate a better understanding and design of enhanced oil recovery strategies in unconventional reservoirs.

Declaration of competing interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests: Samuel Asante Afari reports financial support was provided by North Dakota Industrial Commission. Kegang Ling reports a relationship with North Dakota Industrial Commission that includes: funding grants.

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