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Promotion of CO_2 fracturing for CCUS—the technical gap between theory and practice

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CO_2, used as an environmentally friendly fracturing fluid, has encountered a bottleneck in development in recent years. Despite great efforts in research work, limited progress has been made in field applications. In this study, an extensive literature review of research work and field cases was performed to summarize the technical issues and challenges of CO_2 fracturing. The key issues of CO_2 fracturing were analyzed to reveal the gap between fundamental research and field operations. The effects of CO_2 properties on fracture creation and proppant transport were synthetically analyzed to extract new common research orientations, with the aim of improving the efficiency of CO_2 injection. The hydraulic parameters of CO_2 fracturing were compared with those of water-based fracturing fluids, which revealed a theory-practice gap. By studying the developing trends and successful experiences of conventional fluids, new strategies for CO_2 fracturing were proposed. We identified that the major theory-practice gap in CO_2 fracturing exists in pump rate and operation scale. Consequently, the friction reducer, effects of flow loss (due to leak-off) and distribution (within fracture networks), and shear viscosity of thickened CO_2 are key factors in improving both fracture propagation and proppant transport. By increasing the scale of injected CO_2, the CO_2 fracturing technique can be enhanced, making it an essential option for carbon capture, utilization, and storage (CCUS) to reduce carbon emissions and mitigate climate change.

KEYWORDS

CCUS, CO_2 fracturing, case study, fracture propagation, proppant transport

1 Introduction

Carbon capture, utilization, and storage (CCUS) is an essential technique for achieving the goals set forth in the Paris Agreement, particularly the target of limiting global warming to 1.5°C (Zheng et al., 2022a; Shen et al., 2022; Zhao et al., 2022; Zhu et al., 2022). It plays a crucial role in mitigating greenhouse gas emissions and reducing the concentration of carbon dioxide (CO_2) in the atmosphere (Lab, 2022; Hou et al., 2024a). CCUS enables the capture of CO_2 emissions from various industrial processes, such as power generation, cement production, and steel manufacturing, and then stores the CO_2 underground or utilizes it in other applications (Sharifzadeh et al., 2019; Zhang et al., 2020). This allows for the continued utilization of these traditional assets while simultaneously reducing their carbon footprint. Among all the approaches to carbon sinks, geological storage of CO_2 can permanently remove the largest amount of carbon in a short time compared to other methods such as afforestation, agricultural practices, and chemical applications, among others (Busch et al., 2008; Tao and Clarens, 2013; Godec et al., 2014; Levine et al., 2016).

TABLE 1 Representative CCUS projects worldwide.

Project	Location	Resource	Utilization/Storage	Scale (million tons/year)	Notes
CNOOC CCUS Project	China	—	Oil reservoir	3.0~10.0	Planning
Shengli Oil Field	China	Power plant	Oil reservoir	2.0	Upgrading
Sinopec Qilu Petrochemical	China	Coal-to-gas	Oil reservoir	1.0	In process
Snohvit and Sleipner	Norway	Reservoirs	Saline/reservoir	1.7	Since 1992
Longship (Northern Lights)	Norway	Power plant	Saline	5.0	In process
Weyburn (Boundary Dam)	CA and United States	Power plant	Oil reservoir	1.0	Since 1998

The ideal underground reservoirs for CO_2 storage primarily include oil and gas reservoirs, saline formations, and salt caverns (Rutqvist et al., 2008; Gilfillan et al., 2009; Jia et al., 2019). In this study, we specifically focus on oil and gas reservoirs due to their well-known geological conditions and well-constructed infrastructures. These factors significantly improve the efficiency, economy, and safety of CO_2 injection and storage (Tayari et al., 2015). The utilization of CO_2 in oil fields has a long history, particularly in the context of enhanced oil recovery (EOR) techniques since the 1950s (Crawford et al., 1963; Lillies and King, 1982). The injection of CO_2 drives and displaces *in situ* oil and gas, especially the heavier components, by reducing their viscosity and increasing their mobility. This process enhances the ultimate recovery of oil and gas. The remarkable performance of CO_2 injection in both the oil and gas industry and as a carbon sink has drawn worldwide attention. Currently, approximately 80% of the CCUS projects worldwide inject CO_2 into oil and gas formations for EOR, as illustrated in Table 1 (Institute, 2021).

However, CCUS in oil fields is facing several technical and environmental challenges. One of the most significant issues is the efficiency of CO_2 storage through the EOR process, which has been reported as low as 20% in previous studies (Zhang R.-H. et al., 2021). In other words, approximately 80% of the injected CO_2 is reproduced along with the extracted oil and gas, necessitating the separation and reinjection of CO_2. Additionally, the migration of CO_2 over geological timescales is currently difficult to predict. Extensive monitoring devices are installed from the surface to track the movement of injected CO_2 in representative CCUS sites, such as the Weyburn project. The continuous movement of CO_2 is monitored over time and injections. This is primarily due to the interconnected pore system in the rock matrix, which provides a pathway through which the mature oil and gas migrate from the source rock into the geological structure, reflecting the nature of a conventional oil and gas reservoir (Goodman et al., 2020).

The CO_2 fracturing technique is an alternative approach to CO_2 storage, distinct from EOR, and is typically employed in unconventional formations characterized by extremely low permeability and water sensitivity (Hou et al., 2024b). As a relatively new technique, CO_2 has demonstrated its efficiency as a working fluid in reducing the breakdown pressure of the formation and increasing the stimulated volume following hydraulic injection (Hou et al., 2021). Extensive laboratory research has been conducted to elucidate the rock-mechanical and flow-dynamical characteristics of CO_2 fracturing (Xiangzeng et al., 2014; Wang H. et al., 2019). Corresponding chemical additives have also been developed to enhance the performance of CO_2. Field trials have indicated that the flowback rate of CO_2 after hydraulic injection is significantly lower compared to that after EOR (Yiyu et al., 2021; Honglei et al., 2022). However, the CO_2 fracturing technique is still in the field-trial stage compared to CO_2 EOR. It injects CO_2 at much higher pressures and rates than in EOR injections, resulting in increased investment and challenges (Jing et al., 2022). Furthermore, there exists a gap between previous laboratory-scale efforts and practical field applications at a larger scale.

This study focuses on identifying the disparity and deficiencies between the theory and practice of CO_2 fracturing, with the aim of bridging this gap. Firstly, CO_2 fracturing is redefined and limited to supercritical CO_2 (SC-CO_2) fracturing, which presents a more environmentally friendly solution for CCUS in the oil and gas industry. Secondly, an extensive literature review is carried out to summarize the performances of fracture creation and proppant transport by CO_2—the major tasks of a hydraulic fracturing fluid. By conducting a systematic analysis of research findings and field trials related to CO_2 fracturing, we propose several promising research directions that can advance the field and enhance the efficiency of CO_2 fracturing in practical applications. Through these efforts, we anticipate the CO_2 fracturing technique to become an essential supplement and approach for CCUS in oil and gas reservoirs.

2 History and restricted definition of CO_2 fracturing

The history of CO_2 fracturing can be traced back to the 1970s when it was first experimented with as a method for enhancing oil recovery. Initial trials focused on using CO_2 as a miscible fluid to displace oil from reservoirs, with CO_2 being injected as a liquid from the wellhead. In order to enhance the performance of CO_2 fracturing and flooding, CO_2 was combined with foam-based fracturing techniques, leading to the development of CO_2 foam fracturing in the early 2000s (Martin and Taber, 1992; Yost et al., 1993). The use of foam in CO_2 fracturing offers several advantages over traditional hydraulic fracturing methods. Firstly, the foam acts as a carrier for the CO_2, reducing the amount of CO_2 required to achieve the desired fracturing effect. Secondly, the viscosity of CO_2 foam is significantly improved, enhancing the transport capacity of proppants (Lv et al., 2017). However, the behavior and stability of CO_2 foam under formation conditions present challenges due to the

TABLE 2 Comparisons between the fractures created by SC-CO_2 and water-based fluids (Zhang et al., 2017a; Li et al., 2019; Zhang et al., 2021; Feng and Firoozabadi, 2023).

Fluid type	Rock type	Research condition		Fracturing behaviors		Method	References
		Confining Pressure/MPa	Fluid Temperature/°C	Breakdown Pressure/MPa	Fracture geometry		
SC-CO_2	Granite	40	40	53.4	Main fracture and branches	Experiment	Feng and Firoozabadi (2023)
			60	52.3			
			80	50.1			
	Sandstone	15/15/7 (Triaxial stress)	80	8.8			Li et al. (2019)
	Shale	12/10/8 (Triaxial stress)	60	15.16	Irregular multiple fractures of different lengths and widths		Zhang et al. (2017a)
	Hot Dry Rock	10/7.5/5 (Triaxial stress)	32	~20.3			Zhang et al. (2021a)
Water	Granite	40	20	61.1	Single main fracture	Simulation	Feng and Firoozabadi (2023)
			20	59.0			
Slickwater	Sandstone	15/15/7 (Triaxial stress)	20	12.8		Experiment	Li et al. (2019)
Water	Shale	12/10/8 (Triaxial stress)	60	31.79			Zhang et al. (2017b)
Water	Hot Dry Rock	10/7.5/5 (Triaxial stress)	32	~37.5		Simulation	Zhang et al. (2021b)

phase change of CO_2 from a gaseous to a supercritical phase. The quality of the foam plays a crucial role in fracture generation, propagation, and production enhancement. Moreover, the use of water in CO_2 foam is inevitable, which can lead to permeability and conductivity losses in water-sensitive formations.

With the revolution of unconventional oil and gas, a more specific definition of CO_2 fracturing has emerged - supercritical CO_2 (SC-CO_2) fracturing, also known as water-free fracturing (Middleton et al., 2015; Sanguinito et al., 2018; Wang et al., 2019). This technique utilizes 100% CO_2 as the primary fracturing fluid to prevent damage caused by water in unconventional formations. In reservoirs buried approximately 800 m deeper, the injected CO_2 undergoes a transition into a supercritical phase state, characterized by temperatures and pressures above the critical point (7.3 MPa, 31°C). The phase state transition of CO_2 (from supercritical state to liquid state) has been observed and illustrated in Figure 1. In the process of supercritical CO_2 fracturing, CO_2 is initially pressurized and heated to reach its supercritical state at the surface. This supercritical CO_2 is then mixed with proppant and injected into the wellbore to fracture the targeted reservoir zone. Supercritical CO_2 exhibits high density, low viscosity, low surface tension, high diffusion coefficient, and excellent heat and mass transfer properties (Hou et al., 2021). As a fracturing fluid, it does not harm the reservoir, effectively avoiding near-wellbore formation damage, protecting the oil and gas reservoir, improving reservoir permeability, and facilitating easy flowback, compared with the traditional water-based fracturing fluids. Moreover, supercritical CO_2 fracturing fluid can dehydrate tight clay formations, open up sandstone pore channels, and reduce the skin factor of the wellbore.

In this study, we adopt a specific definition of CO_2 fracturing, specifically referring to supercritical CO_2 (SC-CO_2) fracturing, which is distinct from other forms of CO_2 fracturing such as CO_2 foam. For one reason, the focus on supercritical CO_2 fracturing is justified by its similarity to the process of CO_2 storage, as it eliminates the use of water and demonstrates higher efficiency in CO_2 storage (Hou et al., 2020; Hou and Elsworth, 2021). The flowback rate of fracturing injected CO_2 is lower than other forms of CO_2 storage, for instance, CO_2-EOR (Hou et al., 2024b). This indicates a higher efficiency of permanent CO_2 storage. This approach presents a more environmentally friendly solution for CCUS in the oil and gas field. For the other reason, CO_2 fracturing represents one of the most promising approaches to large-scale carbon sinks. If water-based fracturing operations could be replaced by CO_2 fracturing, one single horizontal well may store more than ten thousand tons of CO_2. Considering that thousands of wells may be fractured in a single oil or gas field, the CO_2 storage capacity by CO_2 fracturing shows enormous potential. Therefore, the promotion of CO_2 fracturing for CCUS represents a critical approach to carbon sinks and carbon neutrality.

3 Results

3.1 Fracture creation by CO_2

Fractures formed through supercritical CO_2 fracturing exhibit distinct characteristics that are influenced by the properties of supercritical CO_2. One notable effect is the reduction in the breakdown pressure of the formation, allowing for easier penetration into the rock matrix due to its low viscosity, high diffusivity, and absence of surface tension. Supercritical CO_2 exhibits a lower viscosity (three magnitudes or even smaller) compared to alternative fracturing fluids

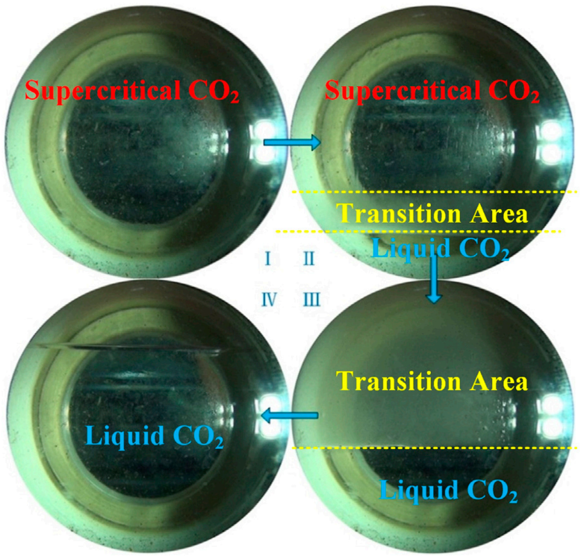

FIGURE 1
CO_2 phase transitions (from the supercritical state to CO_2 liquid) observed through a pressure-resistent window during a depressurization and cooling process, from 8.10 MPa to 42.5°C (I) to 5.80 MPa and 12.6°C (IV).

like water-based fluids (Kuang et al., 2023). This attribute allows for smoother flow through minuscule pores and fractures within the reservoir rock, enabling deeper penetration into the rock matrix and generating fractures with enhanced tortuosity. This characteristic allows the injected fluid to effectively access the pre-existing fracture, and as the induced fracture propagates along its path, there is a significant reduction (~50%) in breakdown pressure (Zhang et al., 2017a; Li et al., 2019; Zhang et al., 2021; Feng and Firoozabadi, 2023), as summarized in Table 2.

Laboratory tests have indicated that fractures created by CO_2 have higher tortuosity, as illustrated in Figure 2 (Song et al., 2019). Tortuosity pertains to the extent of deviation from a linear trajectory observed in fractures. The higher degree of fracture tortuosity indicates that CO_2 follow intricate routes within the reservoir rock, thereby augmenting their interaction surface. Additionally, CO_2 fracturing holds the potential to generate a more intricate network of interconnected fractures within the reservoir, surpassing the complexity of fractures induced by water-based fluids (Wang and Sharma, 2023). This characteristic enhances the fracture surface area and the volume of the reservoir that is stimulated. The increased fracture surface area provides more flowing pathways for *in situ* hydrocarbons during production operations, thus improving well productivity and enhanced recovery rates from unconventional formations.

However, a significant challenge associated with CO_2-created fractures is their underdeveloped width, primarily due to the high rate of CO_2 leak-off and the net stress loss within the fracture. This loss of driving force leads to narrower and shorter fractures (Zhou and Burbey, 2014; Wang et al., 2017; Ranjith et al., 2019). The average fracture aperture of water, N_2, L-CO_2 and SC-CO_2 shows relatively small variances falling in the range between 0.304 mm and 0.317 mm, as presented in Figure 3. However, the largest standard deviation (0.201) of the aperture formed by SC-CO_2 fracturing is obtained, followed by water fracturing (0.171), L-CO_2 fracturing (0.123), and N_2 fracturing (0.091). This suggests the maximum roughness of the fractures created by SC-CO_2 (Yang et al., 2021). Furthermore, given the higher complexity and tortuosity of CO_2-created fractures, the injection of proppants afterward becomes more challenging, resulting in elevated operation wellhead pressures. More careful planning and innovative solutions tailored specifically for CO_2 fracturing techniques are essential to overcome these challenges posed by narrow and short CO_2-created fractures with complex geometries.

3.2 Proppant transport by CO_2

In addition to the more challenging conditions for proppant transport, a significant hurdle in CO_2 fracturing is the low viscosity of supercritical CO_2, which is similar to gaseous CO_2. As a result, proppant particles settle rapidly, leading to the formation of accumulations known as dunes (Hou et al., 2015). These dunes vary in shape and size as continuous injections progress. Within fractures, the proppant is then transported in the form of these dunes, creating a dynamic and complex process, unlike water-based high-viscosity fluids that evenly suspend the proppant (Hou et al., 2022a; Hou et al., 2022b). When the mass flow remains constant, altering the injection temperature to a higher value or reducing the injection pressure will lead to a decrease in both viscosity and density of supercritical CO_2, resulting in evolutions of equilibrium height and distance for dune transport, as presented in Figure 4 (Zheng et al., 2022b).

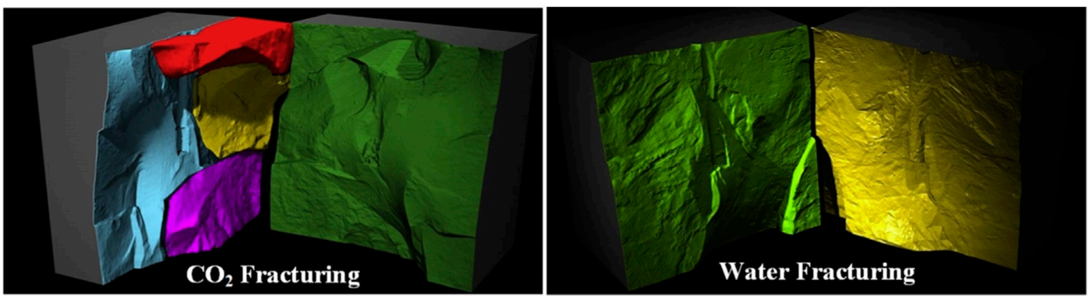

FIGURE 2
The fracture morphology created by CO_2 and fracturing fluids. Reproduced with permission from Ref. Song et al. (2019), copyright (2019) Elsevier.

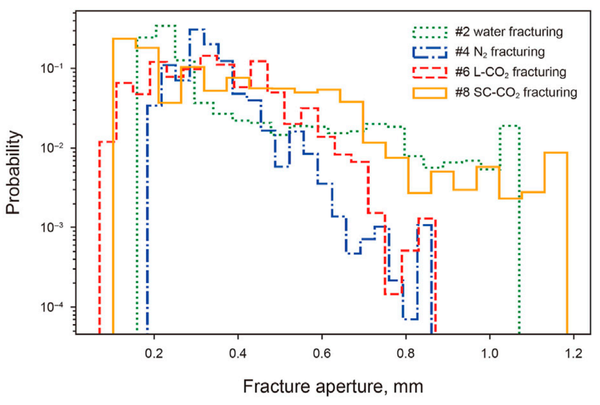

FIGURE 3
The distribution of fracture apertures induced by CO_2 and fracturing fluids. Reproduced with permission from Ref. Yang et al. (2021), copyright (2022) Elsevier.

Furthermore, the high leak-off of CO_2 and the distribution of the injected fluid in complex fracture networks exacerbate proppant accumulation and can even cause sand screen-out due to the loss of the carrying fluid. Previous studies have demonstrated the influence of supercritical CO_2 on the settling, restarting, and flowing behaviors of proppants (Hou et al., 2017a; Chen and Sun, 2023). It has been observed that the high density of CO_2, which is similar to liquid CO_2, contributes to an enhanced capacity for proppant transport in supercritical CO_2, as depicted in Figure 5. Each black point (P1, P2, P3, P4 and P5) represents a proppant particle captured by the high-speed camera. The dashed lines derived from the black points represent the moving trajectory of the proppant particles, which are plotted automatically by the image analysis software. The terminal settling velocity of proppants in CO_2 is slightly higher, within the same magnitude, compared to settling velocities in water (Hou et al., 2015). Additionally, the slippage between the particles and the carrying CO_2 can be eliminated by increasing the flow rate of the slurry (Hou et al., 2017b). Restarting the movement of particles in CO_2 is even easier than in water due to the absence of interfacial tension and the generation of additional Magnus force through high-speed spinning, facilitating the restarting process (Hou et al., 2019).

3.3 Improving the research work on CO_2 fracturing

The primary objectives of a fracturing fluid are to create fractures and transport proppants. However, CO_2 fracturing faces significant challenges in both areas, as outlined in Figure 6. In terms of fracture creation, there are several approaches that can be employed to improve performance. These include reducing the leakage of CO_2 into the rock matrix and natural fractures, establishing net stress within the fractures, and then enhancing the propagation of fracture networks. On the other hand, the capacity of CO_2 to carry proppants can be enhanced by addressing issues such as particle settling, eliminating slippage between the particles and CO_2, and improving proppant transport within complex fracture networks.

In order to address these challenges, various solutions have been analyzed and summarized in Figure 6. One common approach is the use of CO_2 thickeners, which increase the viscosity of the fluid. This serves to reduce both proppant settling and CO_2 leak-off (Enick et al., 2012; Al Hinai et al., 2018). Additionally, it has been observed through numerical and experimental simulations that fracture width and particle slippage are influenced by the CO_2 pump rate. Higher pump rates facilitate fracture growth and help eliminate slippage (Lei et al., 2016). CO_2 leak-off is another prevalent issue that hampers fracture propagation and proppant transport. Therefore, promising research directions for improving CO_2 as a fracturing fluid include the development of friction reducers, investigating the effects of flow loss (caused by leak-off) and distribution (within fracture networks), as well as studying the shear viscosity of thickened CO_2 (the performance of the thickener under high pump-rate condition).

4 Discussion

4.1 Case study of CO_2 fracturing

The CO_2 fracturing technique is mainly applied in unconventional formations that have extremely tight rock matrix and nano-Darcy permeability (decreasing the leak-off of CO_2). Three representative cases of CO_2 fracturing in tight oil, shale

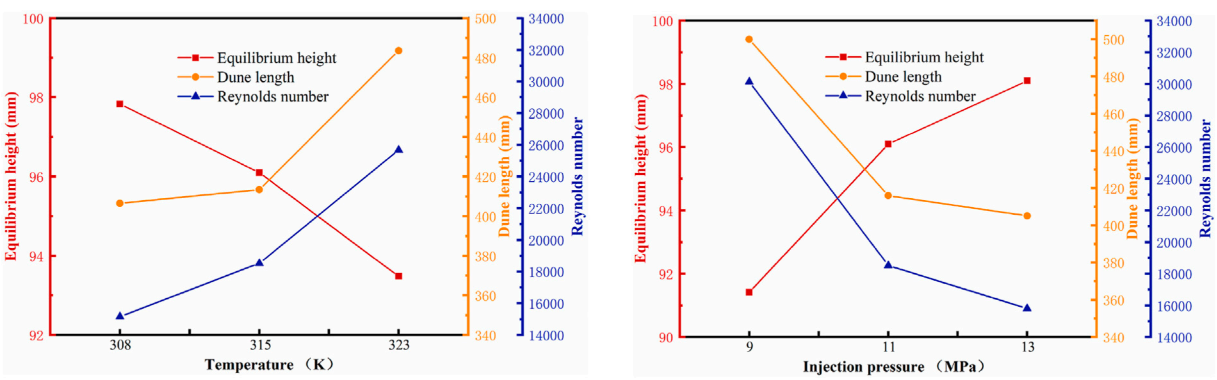

FIGURE 4
Effects of injection temperature and pressure on dune equilibrium height and length based on experiments. Reproduced with permission from Ref. Zheng et al. (2022b), copyright (2022) Elsevier.

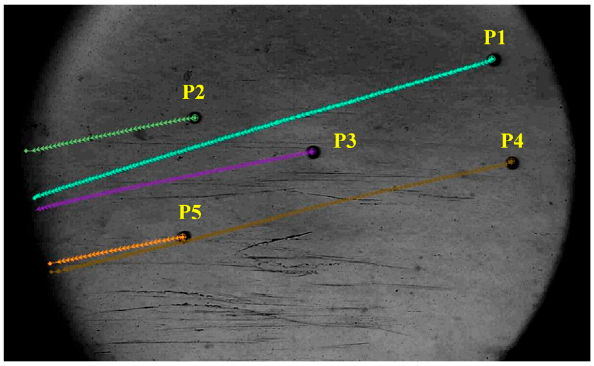

FIGURE 5
Proppant particle movements (trajectories in colorized dashes), from the right side to the left side, in supercritical CO_2 captured by the high-speed camera.

gas, and shale oil formations are summarized in Table 3 (Meng et al., 2016; Yiyu et al., 2021; Jing et al., 2022). Case A uses pure CO_2 for cracking fractures and carrying proppant. Two types of additives are tested to increase the viscosity of CO_2 and its proppant-carrying capacity. Cases B and C only use CO_2 to crack the formation and create complex fracture networks. The high-viscosity gel is applied afterward to further develop the networks and carry the proppant. Generally, both the fracturing scale and pump rate are relatively small for CO_2 fracturing compared with those for water-based fracturing.

Approximately ~300 m^3 of CO_2 is injected in each well or stage, with approximately ~180 m^3 of CO_2 injected in each stage of the horizontal well in Case C. The pump rate may be restricted by the high friction encountered along the wellbore when using CO_2, resulting in a high wellhead pressure of approximately ~65 MPa, as indicated in Table 3. The sand ratio in Case A is around 5.6%, which is less than half of the sand ratio typically used in water-based fracturing. The efficiency of CO_2 fracturing in field trials is relatively low due to the limited scale of fracturing (both proppant and CO_2 volumes), low sand ratio, restricted pump rate, and comparatively high injection pressure. This could be one of the main reasons, as well as the high cost of CO_2 additives, why recent tests have opted for a hybrid approach that combines CO_2 injection with water-based fracturing, as illustrated in Cases B and C.

4.2 Potential of CO_2 fracturing for CCUS

Most of the current CO_2 fracturing field cases are reported along with the development of shale oil in China (Hou et al., 2024a). The field engineers injected CO_2 as a pre-fracturing process, aiming to create more complex fracture networks. The following injected conventional water-based fluids continuously develop the fracture dimensions and transport the proppant into fractures (Yang et al., 2022). Therefore, the usage of CO_2 (several hundred scales for each fracturing stage) is significantly smaller than the water-based fluids for the main fracturing operation, as listed in Table 3. However, the flowback rate of fracturing injected CO_2 is approximately one order of magnitude lower than other forms of CO_2 storage (as shown in Figure 7), indicating a higher efficiency of permanent CO_2 storage (Louk et al., 2017; Hou et al., 2024a). The usage of CO_2 may be improved by increasing its proportion in the total fracturing fluids. A possible approach is using CO_2 to share the proppant injection task, for instance, carrying the fine proppant (100 mesh) (Hou et al., 2017a; Hou et al., 2017b). Meanwhile, the developments of the carbon market and carbon capture techniques may reduce the cost of CO_2 sources. The policy incentives are also essential to encourage the operators to promote the usage of CO_2, for instance, the tax preference applied in the United States (Ren et al., 2022). The increasing proportion and decreasing cost may significantly promote the potential and contribution of CO_2 fracturing to CCUS, considering the huge consumption of fracturing fluids.

The other challenge of CO_2 fracturing for CCUS is the mismatch between CO_2 sources and fracturing sites (Munkejord et al., 2016), for instance, transporting the

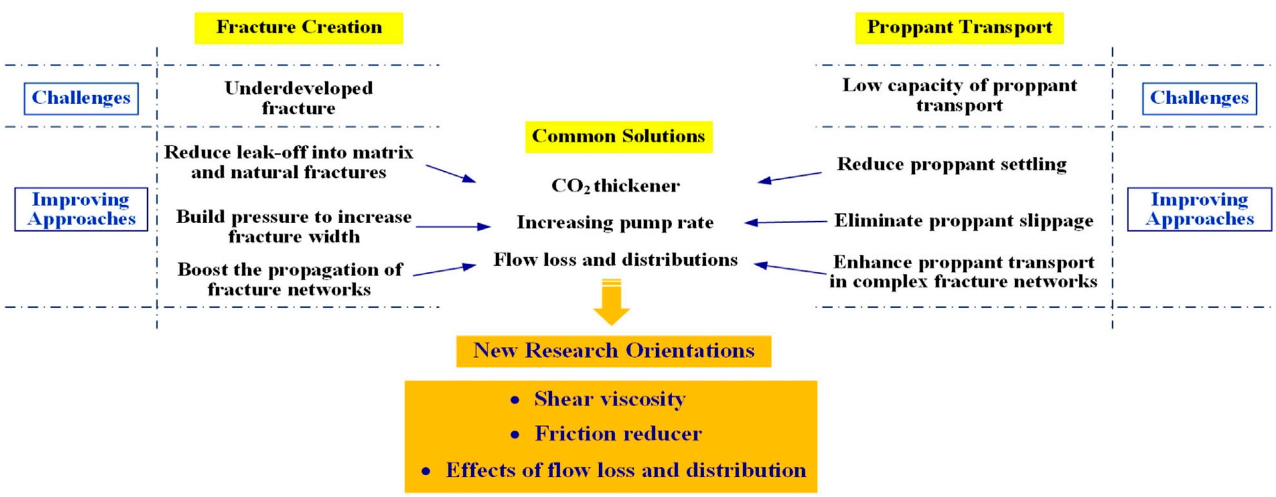

FIGURE 6
Synthetical analyses of fracture creation and proppant transport regarding CO_2 fracturing.

TABLE 3 Summary of CO_2 fracturing cases.

No.	Case A	Case B	Case C
Year	2016	2017	2019
Well No.	—	Yan-2011	Jiye-1
Location	Jilin Oilfield	Ordos Basin, Shaanxi	Jilin Oilfield
Formation	Tight oil	Yanchang Formation Shale	Qingshankou Formation Shale
Depth	~2,000 m	~2,940 m	2,420–2,500 m
In-situ Fluid	Oil	Gas	Oil
Well Completion	Vertical well	Vertical well	Horizontal/18 stages
CO_2 Injection Scale	290~601 m^3	386 m^3	3,265 m^3
Sand scale	8.4~11.2 m^3	—	—
Stimulation Type	Fracturing	Fracturing	Fracturing
Fluid Component	Pure CO_2	Pure CO_2 and gel	Pure CO_2 and gel
Injecting Rate	3.8 m^3/min	~2 m^3/min	~4 m^3/min
Wellhead Pressure	~65 MPa	~20 MPa	~52 MPa

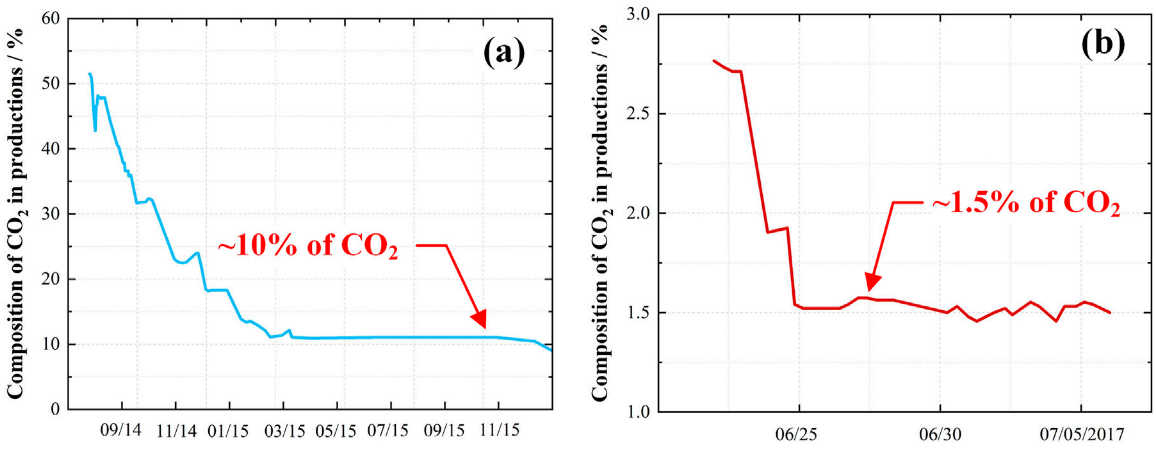

FIGURE 7
Recovery of CO_2 after injections in **(A)** CO_2 huff-and-puff case and **(B)** CO_2 fracturing case. Reproduced with permission from Ref. Hou et al. (2024a), copyright (2024) Elsevier.

captured CO_2 from power plants to oil and gas fields. Pipelines may be necessary for the continuous transport of CO_2 for huff-and-puff, EOR or direct storage in relatively fixed sites (Onyebuchi et al., 2018). Trucks may be essential for fracturing operations to transport CO_2 from one site to another (Gao et al., 2011). Both pipelines and trucks will increase the investments in construction and equipment, as well as the potential for extra CO_2 emissions. Therefore, CO_2 transport has become a common issue for all kinds of CO_2 storage because of the geographical distance between CO_2 sources and storage sites. For CO_2 fracturing, a hybrid transport system may be a solution to improve the flexibility of CO_2 transport from site to site.

4.3 Gap between theory and practice

Although fundamental research has highlighted the advantages and feasibility of CO_2 fracturing, field trials have encountered significant challenges, as summarized in Table 3. To reveal the disparity between the theory and practice of CO_2 fracturing, we compared key injection parameters recorded during field operations using different fracturing fluids, as presented in Figure 8. Initially, in conventional reservoirs, guar gel (referred to as the first generation of fracturing fluid) was used to create large bi-wing fractures with a high concentration of large proppants. Subsequently, slickwater (with lower viscosity) was employed at a much higher pump rate to carry smaller proppants at lower concentrations, achieving a

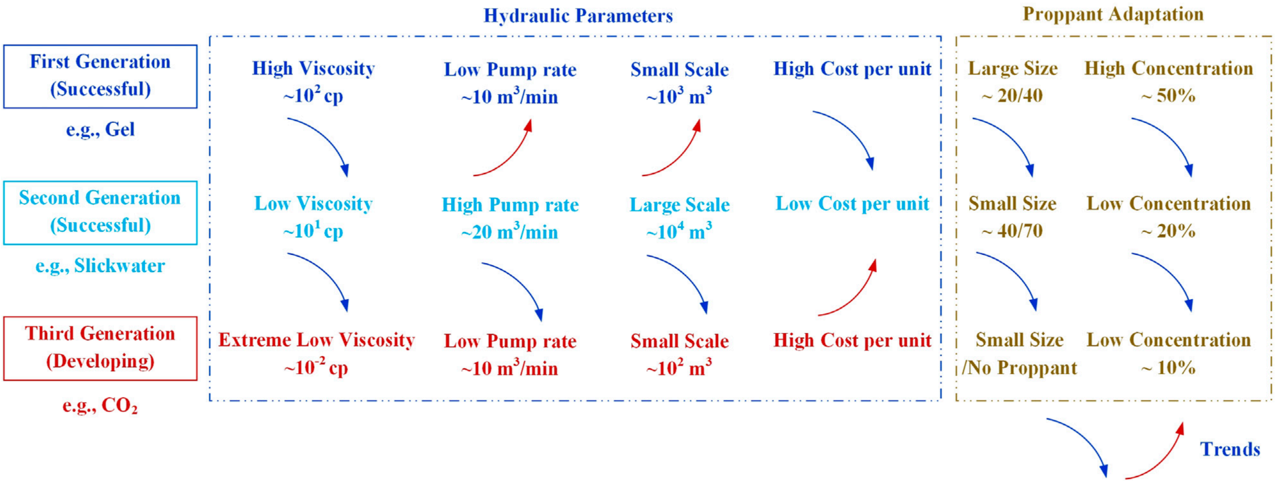

FIGURE 8
Comparison of hydraulic parameters for field operations among the three generations of fracturing fluid.

balance between fracturing efficiency and investment-production ratio (Barati and Liang, 2014; Zhang et al., 2017b). CO_2 fracturing, known as the third generation of fracturing fluid, is considered environmentally friendly. Pump rates and injection scales are both reduced for CO_2 fracturing, reflecting its status as a developing technique.

Compared to conventional fluids, the disparity between fundamental research and field application primarily lies in pump rate and operation scale, as depicted in Figure 8. Current efforts to thicken CO_2 may draw inspiration from the success of first-generation fluids, characterized by high viscosity gel. However, the second-generation fluid (represented by low-viscosity slickwater) compensates for the low-viscosity drawback with a high pump rate, which offers valuable insights. Therefore, the utilization of friction reducers becomes another crucial technique for CO_2 fracturing. Correspondingly, the performance of CO_2 thickener (enhanced CO_2 viscosity after the high-pump-rate shear) becomes an essential criterion for the relevant research, which currently is barely reported. Other valuable insights include enhancing fracturing scales through the development of low-cost additives, increasing the proportion of fine proppant, and adopting hybrid approaches that incorporate water-based fluids (inspired by Cases B and C).

The relatively low pump rate may represent one of the most significant gaps between the theory and practice of CO_2 fracturing. Firstly, the proppant usually settles down rapidly in low-viscosity fluids (CO_2 and slickwater). The horizontal transport distance of the proppant before its settlement reduces under a low pump rate condition due to the lower horizontal dragging force (Hou et al., 2017b; Hou et al., 2019). This significantly constrains the proppant transport capability of supercritical CO_2, and then the scale of proppant injection in fields (Table 3). Secondly, the high diffusion feature of supercritical CO_2 induces a high leak-off of fluid from fractures into the formation. The low pump rate may weaken the supplementary fluid in fractures, thus constraining the propagation of fracture networks. Meanwhile, the relatively low fracturing scale further deteriorates the development of underground fractures. Correspondingly, the stimulated reservoir volume is restricted for enhancing oil/gas production. Regarding the CO_2 storage concern, the low fracturing scale reduces the usage of CO_2 during fracturing operations. The limited artificial fracture volume will further decrease the inventory capacity of CO_2 storage in unconventional reservoirs, because the artificial fracture may contribute most to the capacity of CO_2 storage (Hou et al., 2024a; Hou et al., 2024b). Therefore, the relatively low fracturing scale may represent the other critical gap between the theory and practice of CO_2 fracturing in accordance with the aforementioned rationale.

5 Conclusion

(1) The primary disparity between theory and practice in CO_2 fracturing lies in pump rate and operation scale.
(2) New research directions for improving both fracture propagation and proppant transport in CO_2 fracturing include the use of friction reducers, addressing flow loss caused by leak-off and distribution in fracture networks, and enhancing the shear viscosity of thickened CO_2.
(3) Field operations of CO_2 fracturing can be optimized by enhancing scales through the incorporation of low-cost additives, increasing the proportion of fine proppant, and utilizing a hybrid approach that integrates conventional fluids.

Author contributions

LH: Conceptualization, Funding acquisition, Methodology, Writing–original draft, Writing–review and editing. JL: Writing–review and editing. PG: Data curation, Methodology, Writing–review and editing. YJ: Conceptualization, Investigation, Writing–review and editing. LZ: Data curation, Investigation, Writing–review and editing.

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Conflict of interest

Author PG was employed by Shengli Oilfield Service Corporation.

The remaining authors declare that the research was conducted in the absence of any commercial or financial relationships that could be construed as a potential conflict of interest.

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