



Review of fundamental studies of CO₂ fracturing: Fracture propagation, propping and permeating

Lei Hou^{a,*}, Sheng Zhang^a, Derek Elsworth^b, Honglei Liu^c, Baojiang Sun^d, Xueyu Geng^{a,**}

^a School of Engineering, The University of Warwick, Coventry, CV4 7AL, UK

^b Energy and Mineral Engineering, EMS Energy Institute and G3 Center, Pennsylvania State University, University Park, 16802, USA

^c SINOPEC Research Institute of Petroleum Engineering, Beijing, 100101, China

^d School of Petroleum Engineering, China University of Petroleum (East China), Qingdao, 266580, China

ARTICLE INFO

Keywords:

CO₂ fracturing
Proppant transport
Permeability evolution
Pump rate
Viscosity

ABSTRACT

CO₂ fracturing is one potential technique to relieve environmental issues related to the massive hydraulic fracturing of hydrocarbon reservoirs. We summarize fundamental studies on overall procedures of CO₂ fracturing and analyze research progress related to fracturing, the propping of the induced fractures and permeating CO₂ into, then recovering hydrocarbons from, the formation. The key controlling characteristics in CO₂ fracturing at each stage are defined, together with a definition of their relative dominance. Fractures generated by CO₂ fracturing are typically viewed as of superior complexity but increased tortuosity. Proppant transport during CO₂ stimulation is evaluated through consideration of particle settling, remobilization and flowing behaviours. New views of permeability evolution in propped fractures as a function of CO₂ saturation are presented. Correlations among each procedure are revealed to identify common issues and key technical details illuminated through multidisciplinary efforts. The field case studies of CO₂ fracturing are collected for the analysis of hydraulic parameters and then compared against water-based fracturing. The mismatch between pumping rate and CO₂ viscosity is highlighted, suggesting that the role of wellbore friction is an important topic requiring resolution. Suggestions for the optimization of CO₂ thickening, the usage of fine proppants and injected form of CO₂ are discussed and illustrated. Other open questions remain with respect to the nature of CO₂-rock interactions and their resultant impact on permeability evolution and fracture generation – key issues are identified for future investigations to promote the popularization of CO₂ fracturing for the concurrent and complementary recovery of native hydrocarbons and sequestration of carbon emissions.

1. Introduction

The application of CO₂ for the improved recovery of oil and gas (mainly for reservoir stimulation) has a long history for its high performance in enhancing hydrocarbon production (Cao and Gu, 2013; Mukherjee and Misra, 2018) and concomitantly reducing carbon emissions by the co-sequestration of CO₂ in reservoirs (Godec et al., 2013; Bielicki et al., 2018; Goodman et al., 2019). CO₂ flooding increases oil mobility via CO₂-hydrocarbon interaction (Jia et al., 2019; Martin and Taber, 1992; Cao and Gu, 2013; Kolster et al., 2017). CO₂ fracturing was initially proposed as early as the 1960s (Crawford et al., 1963) as an alternative to water-based fracturing for environmental issues that were largely sidelined with the popularization of massive hydraulic

fracturing. Large scale water consumption for fracturing, in arid areas, such as Shanxi (China), North Dakota, Kansas and Colorado (US), has impacted the widespread granting of fracturing permits (Rahm, 2011; Vengosh et al., 2014). For a typical shale gas well, approximately 30,000 tons of freshwater and 150 tons of chemicals are injected into the target reservoir (Gallegos et al., 2015; Clark et al., 2013; Gregory et al., 2011). 30–90% of the injected material is unrecyclable and trapped underground (Lester et al., 2015; Gregory et al., 2011), including non-degradable chemicals, such as acids, heavy metals and high-molecular polymers, which potentially threaten the underground ecology (Michalski and Ficek, 2015; Stringfellow et al., 2017). Therefore, CO₂ fracturing has regained attention and is considered as a potential solution to the current environmental concerns induced by the

* Corresponding author.

** Corresponding author.

E-mail addresses: lei.hou@warwick.ac.uk (L. Hou), xueyu.geng@warwick.ac.uk (X. Geng).

<https://doi.org/10.1016/j.petrol.2021.108823>

Received 7 October 2020; Received in revised form 23 March 2021; Accepted 12 April 2021

Available online 3 May 2021

0920-4105/© 2021 Elsevier B.V. All rights reserved.

use of water-based fracturing fluids (Middleton et al., 2015; Mosher et al., 2013; Yu et al., 2015).

CO₂, as a fracturing fluid, exhibits unique advantages. Typically, tensile strength, triaxial compressive strength, and elastic modulus of the rock all decrease with exposure to CO₂, reducing the required operating pressure during fracturing (Ao et al., 2017; Rutqvist et al., 2008; Viète and Ranjith, 2006). CO₂-hydrocarbon interactions (*i.e.* competitive adsorption between CO₂ and CH₄) increase the available mass of free gas and the fluidity of native condensate oils (Liu and Wilcox, 2011; Alvarado and Manrique, 2010; Stanwix et al., 2018). Field tests of CO₂ fracturing, performed both in China and North America, have achieved higher stimulated production than water-based fracturing (Asadi et al., 2015; Siwei et al., 2019). However, the high leak-off of CO₂ constrains its application mainly to unconventional reservoirs with ultra-low permeability, *e.g.* shale or tight gas and oil (Zhou and Burbey, 2014; Busch et al., 2008b). The limited scale (fractured and injected volume of proppant and CO₂) of CO₂ fracturing indicates its imperfection in becoming a regular technique (Asadi et al., 2015; Cui et al., 2017; Fujioka et al., 2010). The low-viscosity of CO₂ and resultant limited ability to transport proppant is considered one of the main limitations (Liu et al., 2014; Li et al., 2015; Ha et al., 2018).

CO₂ fracturing may be restricted by poor performance at any step in the serial fracturing processes (creating fractures, proppant transport and fracture permeation) or in their coordination (Fig. 1). We summarize fundamental studies on overall procedures of CO₂ fracturing with a focus to (i) analyze current research progress, (ii) reveal associations among each procedure and (iii) propose enhancements and improvements to CO₂ fracturing to realize the true advantages of CO₂ fracturing and promote both the recovery of native hydrocarbons and the sequestration of carbon emissions.

2. Current state-of-the-art/practice

The characteristics of CO₂ (acidity, viscosity, diffusibility) and its strong interaction with the host rock (dissolution, adsorption, swelling) result in unique fracturing behaviour of fracture generation, proppant transport and hydrocarbon recovery. The injected CO₂ damages the reservoir and creates an initial fracture network. The following slurry (mixture of CO₂ and proppant) then carries proppant into fractures to prop them. Then ultimately, the final production varies with the evolution of permeability in this propped fracture and the feeder fractures into the main fluid-driven fracture. A review of fundamental studies on the overall procedure diagnoses the root of bottlenecks in the method and defines correlations among each step within CO₂ fracturing.

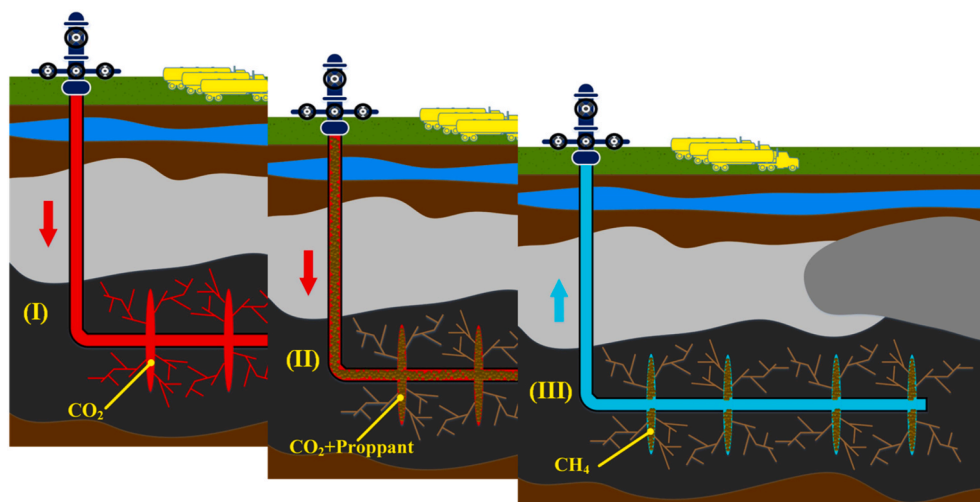


Fig. 1. Schematic of overall procedures of CO₂ fracturing for reservoir stimulation. (I) Fracturing; (II) Propping; (III) Permeating.

2.1. Fracture generation by CO₂

Mineral dissolution by supercritical CO₂ (Sc-CO₂), under reservoir conditions, may etch pores and increase the porosity and permeability by orders of magnitude (Yin et al., 2016; Zou et al., 2018; Jia et al., 2018). The removal into solutions of carbonate minerals weakens the fabric of the rock matrix (reduction in tensile and compressive strengths and elastic modulus), decreases the breakdown pressure and enhances the fracability of the targeting formation (Jiang et al., 2016; Qin et al., 2019; Kharaka et al., 2006). The ultra-low viscosity of CO₂ promotes complexity of the fracture network, thus increasing the stimulated reservoir volume (SRV) (Zhou et al., 2018; Gan et al., 2015).

2.1.1. Breakdown behaviour

The strength tests on shales soaked in Sc-CO₂ exhibit significant reductions in tensile and compressive strengths and elastic modulus, following negative exponential trends with increasing treatment time, as shown in Fig. 2 (Ao et al., 2017; Hol and Spiers, 2012). Correspondingly, the breakdown pressure using Sc-CO₂ decreases approximately by 15%–50% when compared with that for liquid CO₂ or water fracturing, as shown in Table 1 (Zhang et al., 2017a). Lower breakdown pressures (usually the peak pressure during the fracturing operation) preserves safety margins for higher pump rates that is essential for the subsequent

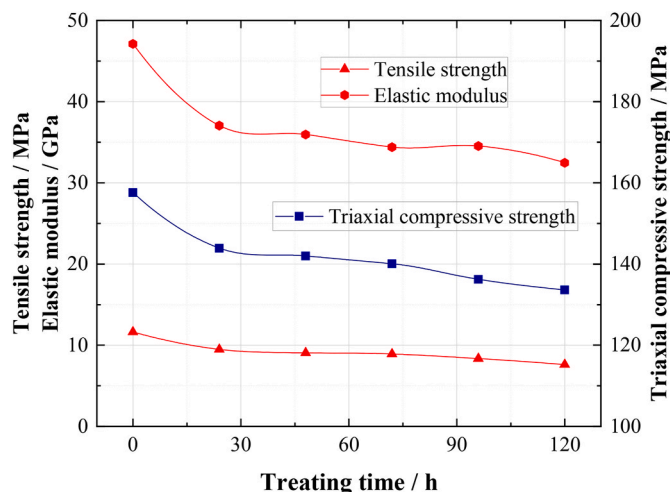


Fig. 2. Evolution of shale strength (tensile, triaxial compressive strength and elastic modulus) relative to CO₂ treatment time (Ao et al., 2017).

Table 1

Comparison of breakdown pressure for various fracturing fluids (Zhang et al., 2017a).

Fracturing fluid	Breakdown pressure/MPa		
	Sample #1	Sample #2	Sample #3
Water	31.79	29.70	30.87
Liquid CO ₂	17.30	18.76	16.99
Sc-CO ₂	15.16	14.40	14.19

transport of proppant (Barati and Liang, 2014b; Cheng, 2012). The restrained breakdown pressure also saves on the usage of pumps and related safety at the wellhead, considerably reducing costs to offset the increased expense of CO₂ fracturing operations (Middleton et al., 2014).

2.1.2. Morphology of fractures generated by CO₂

The CT scanning of fractures generated by water and CO₂ are compared in Fig. 3 (Ranjith et al., 2019). The case for water presents a single straight fracture of broad width, while that for CO₂ tends to create multiple narrow fractures with higher tortuosity. The DR scanning results indicate that the fracture surface area created by CO₂ is ~1.24-fold larger ($5.87 \times 10^4 \text{ mm}^2$) than that created by water-based fluids, due to the tortuosity and increased number of fractures (Zhang et al., 2017a). The low viscosity and high diffusivity of CO₂ each benefit its entry into micropores and in connecting multiple natural fractures, thus increasing the complexity and connectivity of the fracture network (Li et al., 2016; Lv et al., 2019; Kim et al., 2017).

The resulting fracture width and tortuosity are major differences between water-fracturing and CO₂-fracturing. With the decreasing viscosity of the fluid (CO₂, slickwater and cross-linked guar), the fracture width decreases approximately by half, as shown in Fig. 4 (a). The branching of fractures splits and distributes the fracturing fluid, resulting in narrow fracture networks for low-viscosity injectates (Zou et al., 2018; Perkins and Kern, 1961; Montgomery, 2013). Meanwhile, fracture tortuosity increases by a factor of ~5–15% when fractured by Sc-CO₂ in Fig. 4 (b) (Jia et al., 2018; Chen et al., 2015; Wang et al., 2017a). An incremented tortuosity is also apparent for Sc-CO₂ fracturing comparing with that for liquid CO₂ fracturing by evaluating the change in resulting fractal dimension (Ishida et al., 2012).

Higher fracture tortuosity, however, hinders proppant transport by increasing proppant settling. Narrower fractures aggravate the difficulty in effective proppant transport (Raimbay et al., 2016; Liu and Sharma, 2005). The boosted SRV (Stimulated reservoir volume) resulting from CO₂ injection requires a match in high-efficiency fracture-propping in order to enhance the discharge area for subsequent oil and gas production.

2.2. Proppant transport in Sc-CO₂ fracturing

The high viscosity (10^2 cp level) of gel-based fracturing fluids for

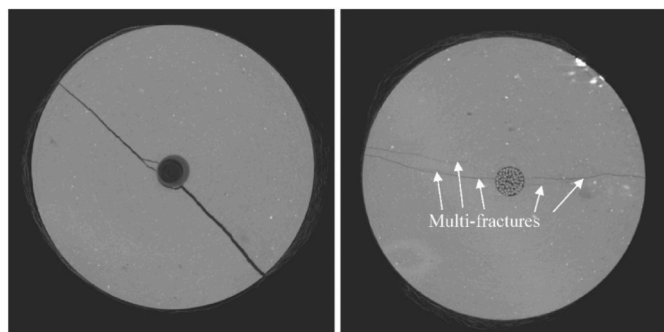


Fig. 3. CT scanning of shale samples fractured by water (left) and CO₂ (right) (Ranjith et al., 2019).

conventional reservoirs suspends the proppant for hours to days during slurry injection, largely distributing the proppant uniformly within fractures (Barati and Liang, 2014a; Patankar et al., 2002; Novotny, 1977). Therefore, viscosity is commonly used as the criterion in evaluating proppant transport capacity of a fracturing fluid (Malhotra et al., 2014). The supercritical state of CO₂ under reservoir conditions is suspected as a key feature in limiting proppant carrying capacity due to its ultra-low viscosity (10^{-2} cp level) (Wang et al., 2012). The same problem exists for slickwater (10^1 cp level) fracturing but is typically solved by increasing the pump rate by a factor of 2 or 3 to carry proppant with the high flow rate (Fink, 2020) – a useful technique that could be a reference for CO₂ fracturing. Proppant settles (I) initially in low-viscosity fluids and then may be remobilized (II) and carried (III) in the form of a migrating dune, as shown in Fig. 5. To restrain dune height (i.e. preventing screen out) and enable the long-range transport of proppant along the fracture, high pump rates and low concentrations of proppant are typically recommended (Hu et al., 2018; Sahai et al., 2014; Wang et al., 2003).

2.2.1. Particle movements in Sc-CO₂ fracturing

Proppant transport in Sc-CO₂ follows a similar rule to that for the mobilization of proppant in slickwater (Wang et al., 2018; Huo et al., 2017). Particle movement (Fig. 6) may be characterized and compared with that in slickwater transport to identify the relative capacity for proppant transport. Key features of this are:

- (I) The equilibrium settling velocity of the transported proppant particles in Sc-CO₂ is closer to the fluid velocity in liquid CO₂ than that in gaseous CO₂ (Table 2) – due to the similarity of forces (drag force, buoyance, etc.) acting on the particle (Hou et al., 2015; Liangchuan et al., 2011).
- (II) The enhanced driving force (Magnus force generated by particle spin) and reduced resistance force (non-cohesive-force due to the non-interfacial-tension characteristic) results in easier restarting of the particles in Sc-CO₂ with an averaged Shields number of 0.0028 (Table 2) – identifying a reduced drag force required to drive particle restarting in Sc-CO₂ (Hou et al., 2019).
- (III) The measured particle velocity in the flowing direction reaches ~90% of the averaged fluid flow velocity under high flow-rate condition, demonstrating the high particle transport capability of Sc-CO₂ (Hou et al. 2016, 2017b). The comparisons of Fig. 7 show the relative performance characteristics for proppant, which is sensitive to the flow rate in the case of Sc-CO₂.

2.2.2. CO₂ thickening

The application of thickening agents to CO₂ improves proppant transport, restrains the excessive leak-off of CO₂ into the formation and also benefits the sweep efficiency of CO₂ flooding for EOR (enhanced oil recovery) by narrowing the viscosity gap between CO₂ and crude oil (Blunt et al., 1993; Gilfillan et al., 2009). CO₂ is a weak solvent for common polymer thickeners, due to its non-polar nature. Attempts have confirmed the potential of specific polymers (siloxane, fluorinated and hydrocarbon polymer) (O'Brien et al., 2016; Enick et al., 1998; Sarbu et al., 2000), low-molecular-weight compounds (hydrogen-bonding and organometallic compound) (Shi et al., 1999; Raveendran and Wallen, 2002) and surfactants (fluorinated, siloxane and hydrocarbon surfactant) (Harrison et al., 1994; Fink and Beckman, 2000; Liu et al., 2001) in thickening fracturing fluids. The potential agents and their thickening efficiencies are summarized in Table 3.

2.3. Permeability evolution in propped fractures with the saturation of CO₂

Fracture permeability or conductivity (fracture permeability times width) governs the final production of hydrocarbons from the reservoir after fracturing (Warpinski et al., 2009). The interaction between

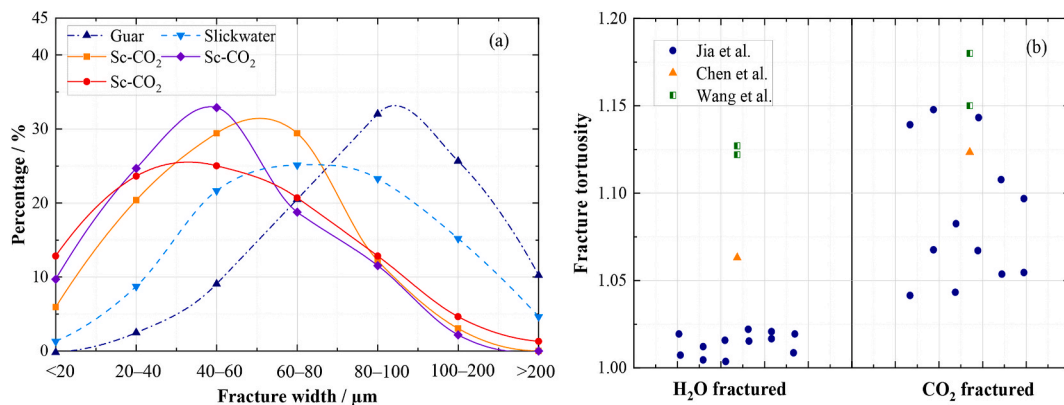


Fig. 4. Fracture morphology generated by CO₂ and water-based fracturing fluids. (a) Fracture width created by guar, slickwater and Sc-CO₂ (Zou et al., 2018); (b) Fracture tortuosity of CO₂- and H₂O-created fractures (Jia et al., 2018; Chen et al., 2015; Wang et al., 2017a).

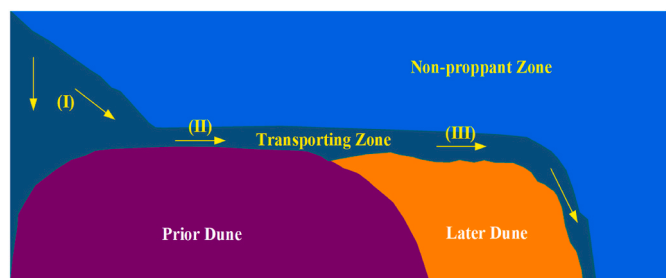


Fig. 5. Schematic of proppant transported by low-viscosity fluid within a fracture. (I) Proppant settling (II) Remobilization/entrainment of settled proppant; (III) Proppant transport with the fracturing fluid (Patankar et al., 2002).

fracture surface and fracturing fluid affects the permeability, as well as the distribution of proppant, closure stress, formation temperature and pressure (Arshadi et al., 2017; Zhang et al., 2015b; Wen et al., 2007). With the saturation of CO₂, the phase states (sub- and super-critical), adsorption and resultant embedment and swelling dominate the permeability evolution (Mazumder and Wolf, 2008; Busch and Gensterblum, 2011).

2.3.1. Embedment and swelling induced by CO₂ adsorption

An approximately 10–60% reduction in fracture aperture caused by proppant embedment is found with a subsequently greater than 50% reduction in oil and gas recovery (Zhang and Hou, 2016; Santos et al., 2018). Proppant embedment may lead to conductivity loss in siltstones of 78.42%, in mudstones of 81.89%, in conglomerates of 91.55% and in shales of 78.05% (Bandara et al., 2019). The mineral composition and mechanical characteristics of the formation significantly impact

embedment and resulting permeability loss (Tang and Ranjith, 2018; Reinicke et al., 2010; Cai et al., 2014). When saturated by CO₂, swelling (induced by CO₂ adsorption in the rock matrix) increases embedment by a factor of 1.84–1.93 ($\Delta b_3/\Delta b_1$), schematically illustrated in Fig. 8. The swelling independently contributes 9–56% ($(\Delta b_2 - \Delta b_3)/(\Delta b_2 - \Delta b_1)$) of the total sorbing-induced fracture loss, which may be evaluated from the adsorbed mass (Hou et al., 2020).

The sorbing CO₂ swells the matrix, shrinks the fracture aperture and then leads to a reduction in permeability. This follows the Langmuir isotherm and reaches maximum influence at approximately twice the Langmuir pressure (Wang et al., 2011; Cai et al., 2014; Liu et al., 2011). The competition between swelling and effective stress results in a typical U-shaped curve for permeability as a function of increasing gas pressure for both integral and split samples (Kumar et al., 2015; Izadi et al., 2011).

2.3.2. Permeability variation with phase states of CO₂

Injected as liquids in most cases for fracturing, CO₂ experiences a phase transition to supercritical under typical reservoir conditions (exceeding 31 °C and 7 MPa), which is found to significantly impact the evolution of permeability (Buschek et al., 2016), as shown in Fig. 9. A V-shaped variation around the critical point is observed when gaseous CO₂ transforms into supercritical CO₂ (Hou et al., 2020; Zhi et al., 2019). In contrast, the permeation of liquid CO₂ remains continuous after phase transition and increases more moderately as the gas pressure also increases. Different mechanisms of permeability variation are discussed between liquid and supercritical transitions – suggested by differences in the subsequent permeability trends at high pressure. The liquid case is explained by the sudden volume change during the phase transition for a relatively stable pressure (Li et al., 2017; Van Der Waals and Rowlinson, 2004). The supercritical case may be due to the increasing adsorbed-phase-density (intensifying the swelling that narrows the

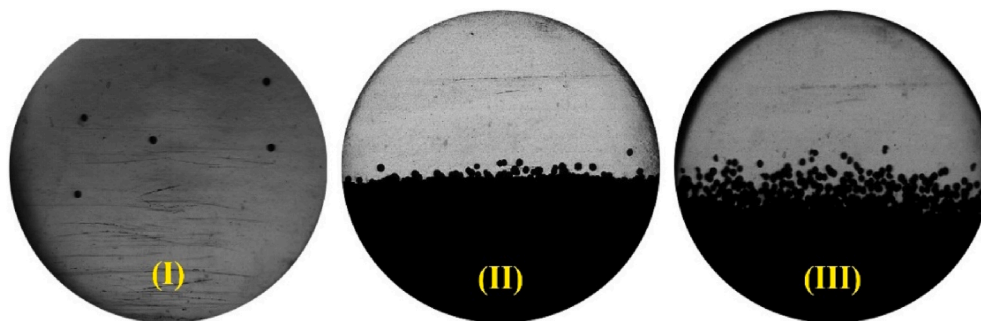


Fig. 6. Experimental observations of proppant transport in supercritical CO₂. (I) Proppant settling (II) Remobilization of settled proppant; (III) Proppant transported with the fluid (Hou et al. 2016, 2019).

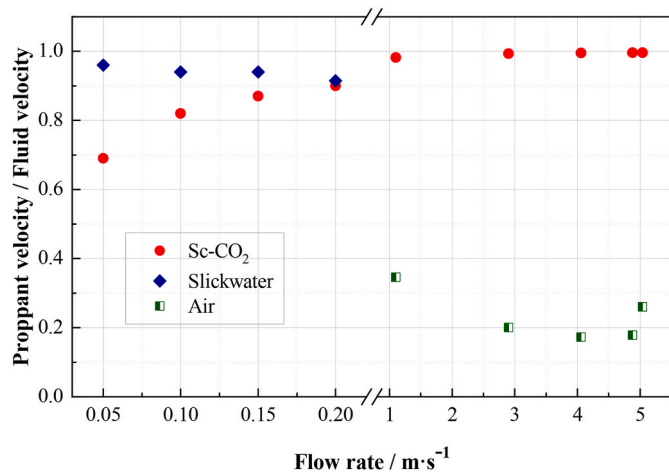


Fig. 7. The following performance of proppant (ratio between proppant horizontal velocity and fluid velocity) for various fluids (Hou et al., 2016).

Table 2
Essential kinematic parameters of a particle transported by various fluids.

	Viscosity cp	Settling velocity m/s	Shields number
Supercritical CO ₂	0.026–0.064	0.13–0.36	0.0015–0.004
Liquid CO ₂	0.1	0.11–0.23	N/A
Gaseous CO ₂	0.01	3.12–7.21	N/A
Water	1	N/A	0.01–0.1

Table 3
Summary of CO₂ thickeners and enhanced viscosities.

Agent	Solution wt %	Thickening result	Reference
Vinyl Benzoate/ Heptadecafluorodecyl acrylate co-polymers	5	483 times	Sun et al. (2018b)
P-1-D/Piso-VBE/PVEE	0.81–5	0.07–0.18 cp	Al Hinai et al. (2018)
Polydimethylsiloxanes	8–18	4–20 times	O'Brien et al. (2016)
Fluoropolymer & surfactant	0.25–1.5	1.3–9.3 cp	Meng et al. (2016)
Amphiphilic surfactant	3	8.2–20 cp	Luo et al. (2015)
Poly (vinyl ethyl ether) and poly (1-decene)	0.56–0.81	13–14 times	Zhang et al. (2011b)
Fluorinated-di-chain-surfactant	1–10	1–2 times	Trickett et al. (2010)

effective aperture) and resultant swelling stress (counteracting the confining pressure that releases the effective aperture).

CO₂ in its supercritical state interacts with both organic and inorganic constituents of the permeated rock matrix (Busch et al., 2008a; Karacan and Mitchell, 2003; Garcia et al., 2012), which may result in the repeated parabolic evolution of the permeability curve first below and then above the critical point in the propped shale fracture (the Sc-CO₂ case with higher permeabilities in Fig. 9). The inorganic interactions are apparent in abnormal increments of permeability recovery for He-repeat tests with penetration of supercritical CO₂ compared with the penetration of subcritical CO₂ (Fig. 10). The dehydration of clay (competitive adsorption between CO₂ and H₂O) and dissolution of carbonate (co-existence of released water and CO₂) may improve the permeability recovery (Bowers et al., 2017; Weniger et al., 2010; Gaus, 2010). The contribution of inorganic adsorption to permeability evolution has an estimated fraction of 60–70% under supercritical condition (Hou and Elsworth, 2021).

2.4. Case studies

CO₂ fracturing is usually applied as a candidate strategy in water-sensitive reservoirs or in arid regions where potable water is particularly valuable (Wang et al., 2016; Ribeiro and Sharma, 2013). The major difference between CO₂ fracturing and water-based fracturing sites is the sealed blinder that mixes proppant with CO₂ under pressure - a specialized piece of equipment with high cost and low market maintenance (Liu et al., 2014; Hou et al., 2013). Due to this difficulty, many cases of CO₂ fracturing are operated without proppant injection - known as CO₂ hybrid fracturing that pumps pure CO₂ initially as the pre-pad fluid to create complex fracture networks and then applying water-based fluid for the carrying of proppant (Ribeiro et al., 2017; Li et al., 2019b). Stimulation parameters for CO₂ fracturing are summarized in Table 4. The targeting formations are tight sands or shales with ultra-low permeabilities that restrain CO₂ leak-off (Li and Zhang, 2019; Li and Elsworth, 2015; Jin et al., 2017). Both the pump rate and sand ratio are much lower than for slickwater- or gel-based fracturing cases. The current scale of fracturing (injected volume of CO₂ and proppant) is incomparable with that for water-based fracturing, thus limiting its popularization.

3. Discussions

A summary of current studies reveals correlations among fracturing procedures, from which common issues are extracted to complete the technical details of CO₂ fracturing. Various solutions and relevant research topics are proposed and modified based on current progress. Feasible measures for field practice are also discussed, which may increase the scale of fracturing and stimulated production and lead to its ultimate adoption.

3.1. Mismatch between pump rate and fluid viscosity

The viscosities of guar, slick-water and supercritical CO₂ (three successive generations of fracturing fluid) decrease from $\sim 10^2$ to $\sim 10^1$ then to the $\sim 10^{-2}$ cp level (Thomas et al., 2019; Zhang et al., 2017b). Low viscosity leads to high leak-off and potentially poor fluid efficiency in fracture generation and proppant transport (Ishida et al., 2004; Shimizu et al., 2011). The success of slickwater-fracturing relies on the enhanced pump rate that can compensate for the low fluid efficiency (Table 5). For CO₂, increasing the pump rate eliminates the slip velocity between proppant and the carrying fluid (Fig. 7), and boosts proppant transport along the fluid-driven fracture. This also compensates for the fluid loss by leak-off, which may dissipate up-to half of the total fluid volume during the pumping (Shiozawa and McClure, 2016; Wang et al., 2017b; Lv et al., 2017). A high pump rate cleans proppant settlement in the wellbore, especially in horizontal wells, and controls the height of the evolving proppant dune within the fracture (Fig. 5), thus ensuring continuous proppant injection and preventing proppant plugging and screen-out (Tong and Mohanty, 2016; Dontsov and Peirce, 2014; Osiptsov, 2017).

The fracture-entry width, determining the potential for proppant infusion, is sensitive to the injection rate. The maximum fracture width increases by a factor of 60% as the pump rate of CO₂ increases from 3 to 7 m³/min, as shown in Fig. 11 (Wang et al., 2019; Yushi et al., 2017). High pump rates also generate a more complex fracture network that increases the stimulated reservoir volume (Hou et al., 2014; Zou et al., 2016). With the lowest viscosity of these three fluids, CO₂ fracturing may require even higher injection rates. However, the mismatch between viscosity and pump rate during CO₂ fracturing may result in low fluid efficiency for fracturing and subsequent proppant carrying capacity even at the smallest fracturing scale and proppant ratio (Table 5).

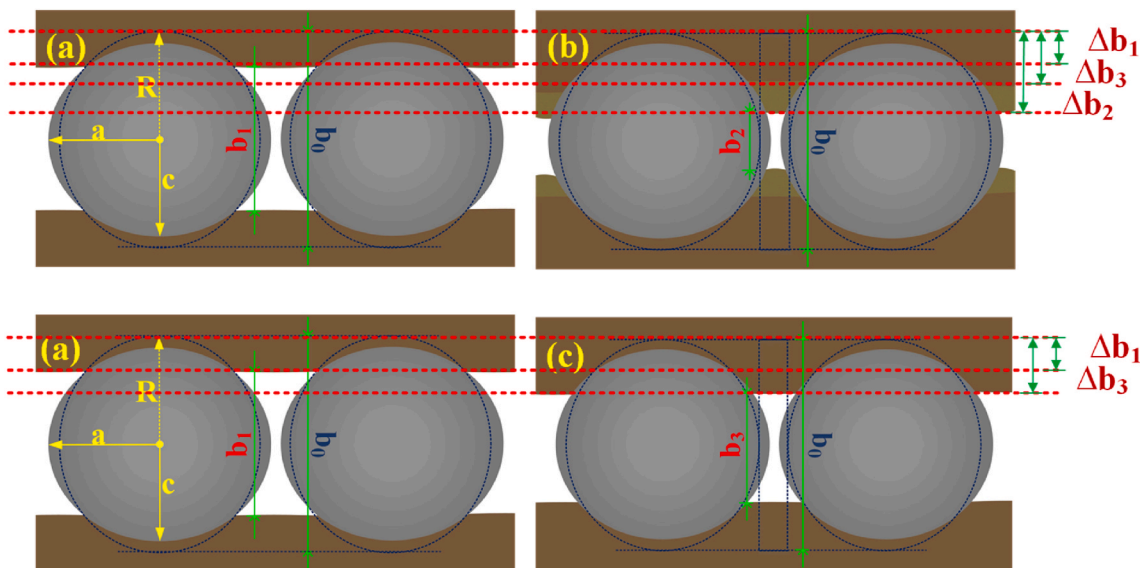


Fig. 8. Schematic of proppant embedment and swelling with penetration of CO₂. (a) Initial embedment without CO₂ (Δb_1); (b) Embedment and swelling saturated by CO₂ (Δb_2); (c) Embedment after recovery of swelling (Δb_3) (Hou et al., 2020).

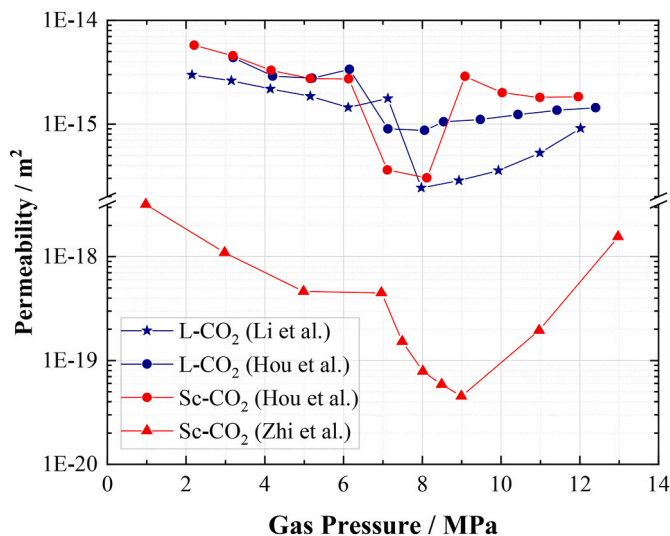


Fig. 9. Permeability evolution relative to gas pressure with phase transitions of CO₂ from gaseous to liquid (L-CO₂) and then to supercritical states (Sc-CO₂) (Li et al., 2017; Hou et al., 2020; Zhi et al., 2019).

3.2. Friction reducers for CO₂

The friction of pure CO₂ decreases with increasing Reynolds number. The friction factor is proportional to CO₂ viscosity (temperature) and inversely proportional to injection rate and CO₂ density (pressure) – thus, liquid CO₂ generates higher friction than does Sc-CO₂ (Wang et al., 2014; Brkić, 2011). Approximately 5–20 MPa of pressure loss per kilometre is observed in pipe-flow tests (Jinqiao et al., 2015). The pressure lost by friction in CO₂ is comparable (slightly lower) to that loss by friction in pure water (Li et al., 2019c). Theoretically, a ~70% reduction in friction should be achieved, similar to that the friction reducer achieves in slickwater, to elevate the pump rate and make-up the mismatch between pump rate and viscosity (Table 5). A fluoropolymer is presented to reduce the frictional pressure of liquid CO₂ by a factor of 13.3–45% (Scharmach and Kelly, 2019; Kelly et al., 2017). Besides, few studies are reported on the friction reducer for CO₂.

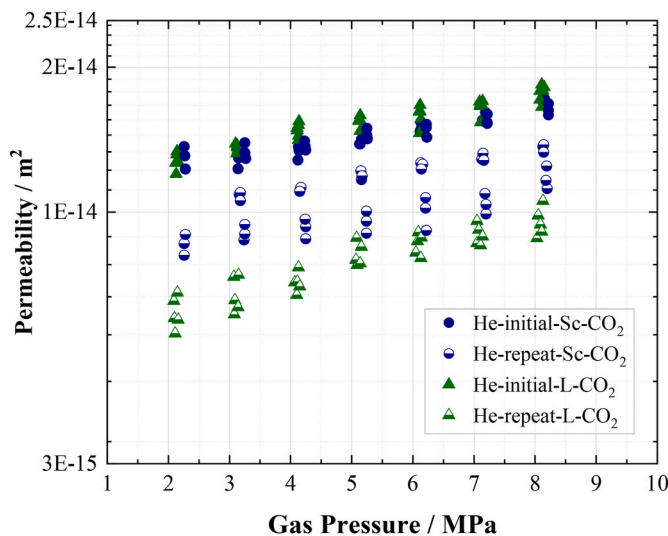


Fig. 10. Permeability recovery of He before (initial) and after (repeat) the penetration of CO₂ (Hou and Elsworth, 2021).

3.3. Sc-CO₂ thickening

3.3.1. Targeting viscosity optimization

The appropriate usage of thickener benefits costing control and environmental protection. The evaluation of the enhancement in proppant transport by thickener suggests that the effect of Sc-CO₂ viscosity is significant at its low-value range, while the increased density of CO₂ also makes a contribution (Fig. 12). An optimum value of enhanced Sc-CO₂ viscosity is proposed of ~0.001 Pa s, about 50 times higher than the original value (Hou et al., 2017a). Besides, higher viscosity of CO₂ also restrains leak-off and benefits the growth in fracture width, an important consideration in the optimization of viscosity.

3.3.2. Shear resistance of thickened CO₂

An increasing pump rate requires higher shear resistance of the thickened CO₂. The shear viscosity of the thickened CO₂ is often left undefined during the thickener investigations that measure zero shear viscosity by falling-ball viscometer (Sun et al., 2018a; O'Brien et al.,

Table 4
Summary of fracturing parameters of CO₂ fracturing in field tests.

Type	Target reservoir	Location	Well depth	Pump rate	Sand ratio	Treating pressure	CO ₂ Scale	Production	Reference
CO ₂ hybrid fracturing	Tight sand oil	Jilin China	3600 m	3.0 m ³ /min	N/A	50–60 MPa	450 tons	3.8–6.4 t/d	Lei and Wenzhi (2020)
CO ₂ fracturing	Shale gas	British Columbia, Canada	2999–3615 m	N/A	2.6%	N/A	552.5 tons	1.9 times	Qinghai et al. (2018)
CO ₂ fracturing	Tight oil	Jilin China	1935 m	4–7.5 m ³ /min	6.2%	28 MPa	653.5 m ³	N/A	Cui et al. (2017)
CO ₂ fracturing	Tight oil	Jilin China	2000 m	3.8 m ³ /min	5.6%	38–63 MPa	290–601 m ³	N/A	Meng et al. (2016)
CO ₂ fracturing	Tight sand oil	Oklahoma U.S.	3213 ft	11–20 BPM	0.2–0.84 PPG	650–1500 PSI	92.8 m ³	17–21 BOPD	Asadi et al. (2015)
CO ₂ fracturing	Tight sand oil	Sulige China	3240 m	2.0–4.0 m ³ /min	3.5%	28–46 MPa	254 m ³	30,000 m ³ /d	Zhenyun et al. (2014)
CO ₂ hybrid fracturing	Shale gas	Shanxi China	1400–1600 m	2.0 m ³ /min	N/A	7 MPa	40–120 m ³	N/A	Xiangzeng et al. (2014)
CO ₂ fracturing	Sand gas	Pennsylvania U.S.	2800 ft	20–45 BMP	1.0–4.0 PPG	4000–5000 PSI	N/A	8.5 MMcf/d	Harris et al. (1998)
CO ₂ fracturing	Shale gas	Kentucky U.S.	3656–4041 ft	25–48 BPM	1.4–2.9 PPG	3000–4000 PSI	190–240 tons	14.3–41.5 MMcf	Yost et al. (1994)
CO ₂ fracturing	Shale gas	Kentucky U.S.	2976–3748 ft	33–44 BPM	1.9–3.1 PPG	1171–3187 PSI	120–160 tons	4.8 times	Yost et al. (1993)
CO ₂ fracturing	Tight sand gas	Oklahoma U.S.	2500–16,440 ft	8–40 BPM	4 lbs/gal	700–12,500 PSI	5.7–54 tons	1.5–3 times	Lillies and King (1982)

Table 5
Hydraulic parameters of gel, slick-water and CO₂ fracturing.

	Proppant size mesh	Pump rate m ³ /min	Viscosity cp	Fracturing Scale m ³	Proppant ratio %
Guar	30–50 & 20–40	3–5	~10 ²	~10 ³	~50
Slick-water	100 & 40–80	10–20	~10 ¹	~10 ⁴	~20
CO ₂	100 & 40–80	3–7	~10 ⁻²	~10 ²	~10

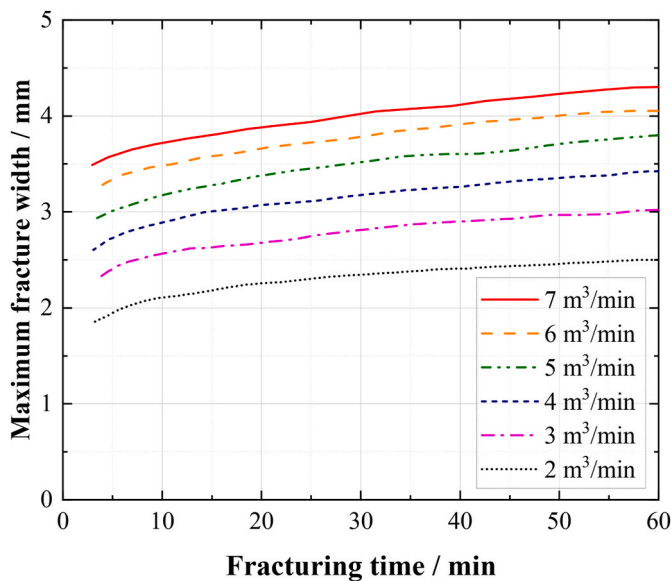


Fig. 11. Maximum fracture width versus fracturing time for various CO₂ pump rates (Wang et al., 2019).

2016). However, the capillary viscometer, measuring the pressure drop of the flowing CO₂ mixture in a tube, is able to quantify both the shear viscosity and friction, and thus is suitable for evaluating the mixture system with both reducer and thickener (Enick et al., 2012; Zhang et al., 2011a; Li et al., 2019a). The thickened viscosity of CO₂ decreases approximately by half of the initial value with increasing shear rate (Fig. 13). Meanwhile, the friction coefficient also drops with increasing

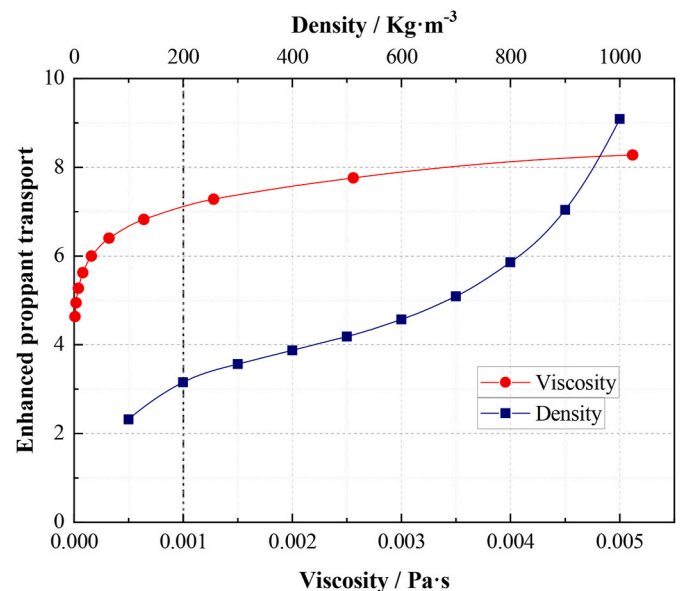


Fig. 12. Effects of CO₂ density and viscosity on enhanced proppant transport in the thickened CO₂ (Hou et al., 2017a).

flow rate (Luo et al., 2015). The temperature, pressure and contents of agents may also evolve the shear viscosity of the thickened CO₂, which should be better defined.

3.4. Permeability evolution in fractures generated by CO₂

Permeability evolution in unpropped samples shows similar trends to

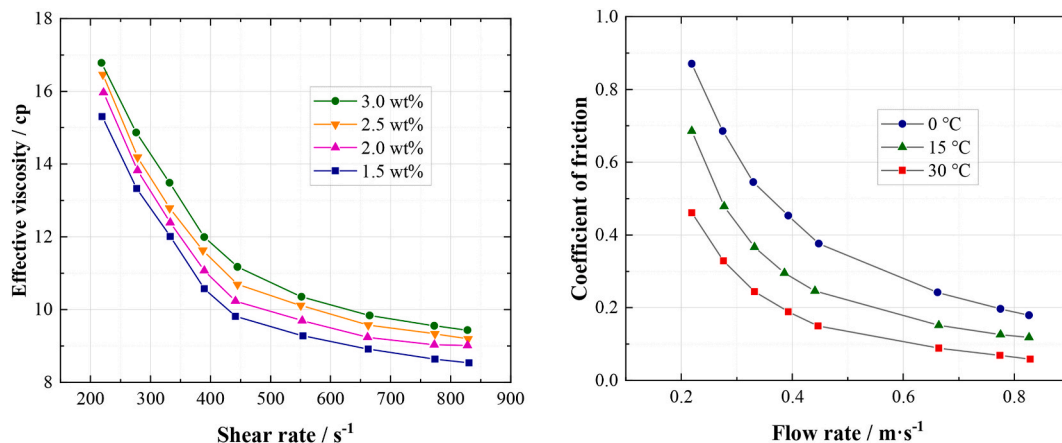


Fig. 13. Effective viscosity and friction coefficient of thickened CO₂ relative to shear rate and flow rate under various thickener concentrations (wt%) and temperatures (Luo et al., 2015).

those with the propped case – due to the swelling stress in forcing the closure of fractures and in depressing the potential for permeation (Wang et al., 2015; Wang et al., 2013). The injection of sorbing CO₂ aggravates such phenomena and may result in rapid depletion of production with the decreasing pore pressure (Fig. 9). Therefore, proppant is crucial in CO₂ fracturing to maintain effective apertures. #100 mesh proppant may be an alternative when larger sizes of proppant encounter problems entering narrow and tortuous fractures, as well as ultra-lightweight porous ceramic proppants (Rickards et al., 2013; Ely et al., 2014; Alotaibi and Miskimins, 2015).

The smaller size of proppant mitigates embedment since the embedment depth is proportional to the proppant diameter, as shown in Fig. 14 (Kewen Li and Lyu, 2015; Alramahi and Sundberg, 2012; Zhang et al., 2015a), thus mitigating effective aperture loss with the saturation of CO₂. Besides, fine proppant also blocks natural fractures and macropores and enhances the fluid efficiency for fracture propagation (Dahi-Taleghani and Olson, 2013; Gale et al., 2014). CO₂-rock interactions revealed in permeability tests may also influence the fracturing procedure, especially the swelling stress that may counteract the confining pressure (Zhang et al., 2018), reduce the difference between max- and min-stress and enhance the complexity of the fracture network (Hoek and Bieniawski, 1965; Soliman et al., 2010).

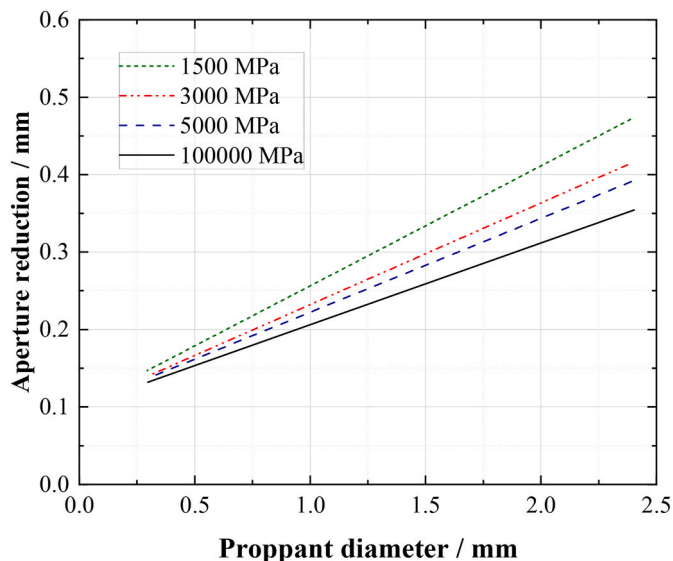


Fig. 14. Reduction of fracture aperture versus proppant diameter with various elastic modulus of proppant (Kewen Li and Lyu, 2015).

4. Recommendations

Despite abundant fundamental studies on overall procedures for CO₂ fracturing, several essential issues remain to be resolved, and are discussed as follows (Fig. 15):

- i. **Fracturing:** Increasing pump rate promotes the evolution of high pressure within fractures. The addition of thickener and fine proppant both enhance fluid efficiency by restraining CO₂ leak-off, thus boosting the growth in fracture width and in improving subsequent proppant transport, especially for larger sized proppant.
- ii. **Propping:** Pump rate appears to dominate the CO₂ capacity of proppant transport, especially when CO₂ is thickened to an optimal viscosity. The higher tortuosity of fractures generated by CO₂ may require higher pump rates and smaller sizes of proppant than water-based fracturing.
- iii. **Permeating:** Permeation behaviour of CO₂ in propped fractures with fine proppants should be further defined. The definitions of CO₂-organic and CO₂-mineral interactions and the resultant swelling stresses improve predictions of permeability and production. The effect of swelling stress on fracture propagation requires further definition.
- iv. **Agents for CO₂:** Developing friction reducers for CO₂ should take top priority over other agents. Relevant thickeners may be tested for optimization or used as the cosolvent. The shear resistance of thickened CO₂ should be investigated, as well as the effects of temperature, pressure and relative proportions of agents.
- v. **Field practice:** Hybrid CO₂ fracturing may be an option in developing CO₂ fracturing, although the ratio of CO₂ in the mixture needs to be optimized. #100 mesh proppant may be necessary for propping tortuous and narrow fractures. Injecting CO₂ in its supercritical state may reduce the friction loss over that for liquid CO₂.
- vi. **Multidisciplinary breakthroughs:** Breakthroughs in CO₂ fracturing may be achieved in fundamental studies of additive agents and CO₂-rock interactions, which involve interdisciplinary fields of Sc-CO₂ extraction, CO₂ flooding, CO₂ adsorption and CO₂ sequestration.

5. Conclusions

Fundamental studies on overall procedures for CO₂ fracturing (fracture-propagation, propping and permeating) are summarized and analysed to disclose gaps between field practices and nascent research. The major conclusions may be generalized as follows:

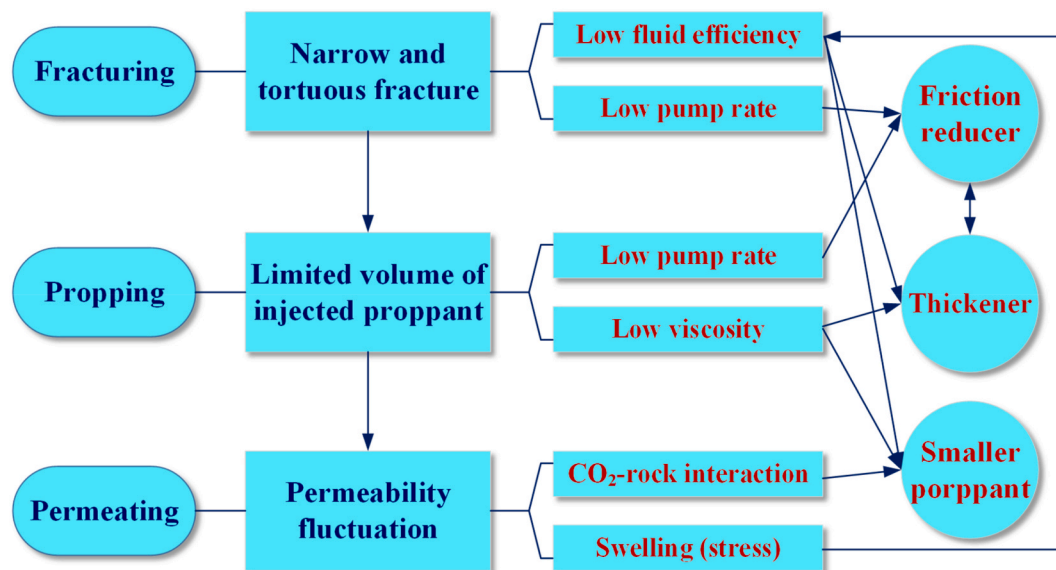


Fig. 15. Schematic of fundamental studies and suggestions on overall procedures of CO₂ fracturing and their associations.

- (1) Higher tortuosity and narrower width of fractures generated by CO₂ enhance the stimulated reservoir volume as a result of the low viscosity and high diffusivity of CO₂, yet also aggravate the difficulty of subsequent proppant transport by hindering proppant entry into the fracture and in increasing proppant settlement, thus limiting fracturing scale in field tests.
- (2) The mismatch between pump rate and CO₂ viscosity is apparent in comparing hydraulic/pumping parameters apparent in field cases. Increasing the pumping rate in CO₂ injection simultaneously improves fracture generation and proppant transport. A higher pump rate expands fracture width by making up for CO₂ leak-off and thereby boosting the effective pressure within fractures. It also eliminates the slip velocity between proppant and the proppant-carrying CO₂, cleans the settled proppant from the wellbore and controls the evolving and maximum dune height in fractures.
- (3) Reductions in rock strength that accompany saturation by CO₂ lower the breakdown pressure to fracturing, which reserves a safety margin against raising pump rate. Research on friction reducers for CO₂ modification is insufficient and should take top priority. Relevant thickeners may be optimized or used as cosolvents. Besides, injecting CO₂ in a supercritical state automatically reduces the friction loss relative to that for liquid CO₂.
- (4) Thickeners for CO₂ may target a lower enhanced-viscosity due to the contribution of CO₂ density. The shear resistance of thickened CO₂ becomes more crucial with an increase in the injection rate. Fine proppant (*i.e.* #100 mesh) may be an alternative when larger sizes of proppant are inapplicable. This will prop tortuous and narrow fractures, mitigate against embedment and control leak-off by blocking natural fractures and macropores.
- (5) Other open research questions persist, including the effect of swelling stress on fracture propagation, the definition of CO₂-organic and CO₂-mineral interactions and resultant effects on permeability evolution, the optimization of CO₂ usage for the hybrid fracturing.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.



Acknowledgements

This research has received funding from the European Union's Horizon 2020 research and innovation programme under the Marie Skłodowska-Curie grant agreement No. 846775.

References

- Al Hinai, N.M., Saeedi, A., Wood, C.D., Myers, M., Valdez, R., Sooud, A.K., Sari, A., 2018. Experimental evaluations of polymeric solubility and thickeners for supercritical CO₂ at high temperatures for enhanced oil recovery. *Energy Fuel*. 32, 1600–1611.
- Alotaibi, M.A., Miskimins, J.L., 2015. Slickwater proppant transport in complex fractures: new experimental findings & scalable correlation. In: SPE Annual Technical Conference and Exhibition. Society of Petroleum Engineers.
- Aramahi, B., Sundberg, M., 2012. Proppant embedment and conductivity of hydraulic fractures in shales. In: 46th US Rock Mechanics/Geomechanics Symposium. American Rock Mechanics Association.
- Alvarado, V., Manrique, E., 2010. Enhanced oil recovery: an update review. *Energies* 3, 1529–1575.
- Ao, X., Lu, Y., Tang, J., Chen, Y., Li, H., 2017. Investigation on the physics structure and chemical properties of the shale treated by supercritical CO₂. *J. CO₂ Util.* 20, 274–281.
- Arshadi, M., Zolfaghari, A., Piri, M., Al-Muntasheri, G.A., Sayed, M., 2017. The effect of deformation on two-phase flow through proppant-packed fractured shale samples: a micro-scale experimental investigation. *Adv. Water Resour.* 105, 108–131.
- Asadi, M., Scharmach, W., Jones, T., Sampayo, A., Chesney, E., Unruh, D., 2015. Water-free fracturing: a case history. In: SPE/CSUR Unconventional Resources Conference. Society of Petroleum Engineers.
- Bandara, K.M.A.S., Ranjith, P.G., Rathnaweera, T.D., 2019. Improved understanding of proppant embedment behavior under reservoir conditions: a review study. *Powder Technol.* 352, 170–192.
- Barati, R., Liang, J.-T., 2014a. A review of fracturing fluid systems used for hydraulic fracturing of oil and gas wells. *J. Appl. Polym. Sci.* 131 (n/a-n/a).
- Barati, R., Liang, J.-T., 2014b. A review of fracturing fluid systems used for hydraulic fracturing of oil and gas wells. *J. Appl. Polym. Sci.* 131.
- Bielicki, J.M., Langenfeld, J.K., Tao, Z., Middleton, R.S., Menefee, A.H., Clarens, A.F., 2018. The geospatial and economic viability of CO₂ storage in hydrocarbon depleted fractured shale formations. *Int. J. Greenh. Gas Contr.* 75, 8–23.
- Blunt, M., Fayers, F.J., Orr Jr., F.M., 1993. Carbon dioxide in enhanced oil recovery. *Energy Convers. Manag.* 34, 1197–1204.
- Bowers, G.M., Schaefer, H.T., Loring, J.S., Hoyt, D.W., Burton, S.D., Walter, E.D., Kirkpatrick, R.J., 2017. Role of cations in CO₂ adsorption, dynamics, and hydration in smectite clays under in situ supercritical CO₂ conditions. *J. Phys. Chem. C* 121, 577–592.

- Brkić, D., 2011. Review of explicit approximations to the Colebrook relation for flow friction. *J. Petrol. Sci. Eng.* 77, 34–48.
- Busch, A., Alles, S., Gensterblum, Y., Prinz, D., Dewhurst, D., Raven, M., Stanjek, H., Krooss, B., 2008a. Carbon dioxide storage potential of shales. *Int. J. Greenh. Gas Contr.* 2, 297–308.
- Busch, A., Alles, S., Gensterblum, Y., Prinz, D., Dewhurst, D.N., Raven, M.D., Stanjek, H., Krooss, B.M., 2008b. Carbon dioxide storage potential of shales. *Int. J. Greenh. Gas Contr.* 2, 297–308.
- Busch, A., Gensterblum, Y., 2011. CBM and CO₂-ECBM related sorption processes in coal: a review. *Int. J. Coal Geol.* 87, 49–71.
- Buscheck, T.A., White, J.A., Carroll, S.A., Bielicki, J.M., Aines, R.D., 2016. Managing geologic CO₂ storage with pre-injection brine production: a strategy evaluated with a model of CO₂ injection at Snøhvit. *Energy Environ. Sci.* 9, 1504–1512.
- Cai, Y., Liu, D., Mathews, J.P., Pan, Z., Elsworth, D., Yao, Y., Li, J., Guo, X., 2014. Permeability evolution in fractured coal—combining triaxial confinement with X-ray computed tomography, acoustic emission and ultrasonic techniques. *Int. J. Coal Geol.* 122, 91–104.
- Cao, M., Gu, Y., 2013. Oil recovery mechanisms and asphaltene precipitation phenomenon in immiscible and miscible CO₂ flooding processes. *Fuel* 109, 157–166.
- Chen, Y., Nagaya, Y., Ishida, T., 2015. Observations of fractures induced by hydraulic fracturing in anisotropic granite. *Rock Mech. Rock Eng.* 48, 1455–1461.
- Cheng, Y., 2012. Impact of water dynamics in fractures on the performance of hydraulically fractured wells in gas-shale reservoirs. *J. Can. Petrol. Technol.* 51, 143–151.
- Clark, C.E., Horner, R.M., Harto, C.B., 2013. Life cycle water consumption for shale gas and conventional natural gas. *Environ. Sci. Technol.* 47, 11829–11836.
- Crawford, H.R., Neill, G.H., Bucy, B.J., Crawford, P.B., 1963. Carbon dioxide - a multipurpose additive for effective well stimulation. *J. Petrol. Technol.* 15, 237–242.
- Cui, W., Cui, M., Wang, C., Liang, C., 2017. Waterless stimulation for unconventional shales: an alternative to conventional water-based fracturing techniques. In: Abu Dhabi International Petroleum Exhibition & Conference. Society of Petroleum Engineers.
- Dahi-Taleghani, A., Olson, J.E., 2013. Numerical modeling of multistranded-hydraulic-fracture propagation: accounting for the interaction between induced and natural fractures. *SPE J.* 16, 575–581.
- Dontsov, E., Peirce, A., 2014. Slurry flow, gravitational settling and a proppant transport model for hydraulic fractures. *J. Fluid Mech.* 760, 567–590.
- Ely, J.W., Fowler, S.L., Tiner, R.L., Aro, D.J., Sicard Jr., G.R., Sigman, T.A., 2014. Slick water fracturing and small proppant: the future of stimulation or a slippery slope?. In: SPE Annual Technical Conference and Exhibition. Society of Petroleum Engineers.
- Enick, R., Beckman, E., Yazdi, A., Krukonic, V., Schonemann, H., Howell, J., 1998. Phase behavior of CO₂-perfluoropolyether oil mixtures and CO₂-perfluoropolyether chelating agent mixtures. *J. Supercrit. Fluids* 13, 121–126.
- Enick, R.M., Olsen, D.K., Ammer, J.R., Schuller, W., 2012. Mobility and conformance control for CO₂ EOR via thickeners, foams, and gels—A literature review of 40 Years of research and pilot tests. In: SPE Improved Oil Recovery Symposium. Society of Petroleum Engineers.
- Fink, J., 2020. Hydraulic Fracturing Chemicals and Fluids Technology. Gulf Professional Publishing.
- Fink, R., Beckman, E.J., 2000. Phase behavior of siloxane-based amphiphiles in supercritical carbon dioxide. *J. Supercrit. Fluids* 18, 101–110.
- Fujioka, M., Yamaguchi, S., Nako, M., 2010. CO₂-ECBM field tests in the ishikari coal basin of Japan. *Int. J. Coal Geol.* 82, 287–298.
- Gale, J.F., Laubach, S.E., Olson, J.E., Eichhubl, P., Fall, A., 2014. Natural fractures in shale: a review and new observations. *Natural fractures in shale: a review and new observations.* AAPG Bull. 98, 2165–2216.
- Gallegos, T.J., Varela, B.A., Haines, S.S., Engle, M.A., 2015. Hydraulic fracturing water use variability in the United States and potential environmental implications. *Water Resour. Res.* 51, 5839–5845.
- Gan, Q., Elsworth, D., Alpern, J.S., Marone, C., Connolly, P., 2015. Breakdown pressures due to infiltration and exclusion in finite length boreholes. *J. Petrol. Sci. Eng.* 127, 329–337.
- Garcia, D.J., Shao, H., Hu, Y., Ray, J.R., Jun, Y.-S., 2012. Supercritical CO₂-brine induced dissolution, swelling, and secondary mineral formation on phlogopite surfaces at 75–95 °C and 75 atm. *Energy Environ. Sci.* 5.
- Gaus, I., 2010. Role and impact of CO₂-rock interactions during CO₂ storage in sedimentary rocks. *Int. J. Greenh. Gas Contr.* 4, 73–89.
- Gilfillan, S.M., Lollar, B.S., Holland, G., Blagburn, D., Stevens, S., Schoell, M., Cassidy, M., Ding, Z., Zhou, Z., Lacombe-Couloume, G., 2009. Solubility trapping in formation water as dominant CO₂ sink in natural gas fields. *Nature* 458, 614–618.
- Godec, M., Koperma, G., Petrusak, R., Oudinot, A., 2013. Potential for enhanced gas recovery and CO₂ storage in the Marcellus Shale in the Eastern United States. *Int. J. Coal Geol.* 118, 95–104.
- Goodman, A., Sanguinito, S., Tkach, M., Natesakhawat, S., Kutchko, B., Fazio, J., Cvetic, P., 2019. Investigating the role of water on CO₂-Utica Shale interactions for carbon storage and shale gas extraction activities – evidence for pore scale alterations. *Fuel* 242, 744–755.
- Gregory, K.B., Vidic, R.D., Dzombak, D.A., 2011. Water management challenges associated with the production of shale gas by hydraulic fracturing. *Elements* 7, 181–186.
- Ha, S.J., Choo, J., Yun, T.S., 2018. Liquid CO₂ fracturing: effect of fluid permeation on the breakdown pressure and cracking behavior. *Rock Mech. Rock Eng.* 51, 3407–3420.
- Harris Jr., R.P., Ammer, J., Pekot, L.J., Arnold, D.L., 1998. Liquid carbon dioxide fracturing for increasing gas storage deliverability. In: SPE Eastern Regional Meeting. Society of Petroleum Engineers.
- Harrison, K., Goveas, J., Johnston, K.P., O'Rear III, E.A., 1994. Water-in-carbon dioxide microemulsions with a fluorocarbon-hydrocarbon hybrid surfactant. *Langmuir* 10, 3536–3541.
- Hoek, E., Bieniawski, Z., 1965. Brittle fracture propagation in rock under compression. *Int. J. Fract. Mech.* 1, 137–155.
- Hol, S., Spiers, C.J., 2012. Competition between adsorption-induced swelling and elastic compression of coal at CO₂ pressures up to 100MPa. *J. Mech. Phys. Solid.* 60, 1862–1882.
- Hou, B., Chen, M., Li, Z., Wang, Y., Diao, C., 2014. Propagation area evaluation of hydraulic fracture networks in shale gas reservoirs. *Petrol. Explor. Dev.* 41, 833–838.
- Hou, L., Bian, X., Geng, X., Sun, B., Liu, H., Jia, W., 2019. Incipient motion behavior of the settled particles in supercritical CO₂. *J. Nat. Gas Sci. Eng.* 68.
- Hou, L., Elsworth, D., 2021. Mechanisms of Tripartite Permeability Evolution for Supercritical CO₂ in Propped Shale Fractures. *Fuel*, p. 292.
- Hou, L., Elsworth, D., Geng, X., 2020. Swelling and embedment induced by sub- and super-critical-CO₂ on the permeability of propped fractures in shale. *Int. J. Coal Geol.* 225.
- Hou, L., Jiang, T., Liu, H., Geng, X., Sun, B., Li, G., Meng, S., 2017a. An evaluation method of supercritical CO₂ thickening result for particle transporting. *J. CO₂ Util.* 21, 247–252.
- Hou, L., Sun, B., Geng, X., Jiang, T., Wang, Z., 2017b. Study of the slippage of particle/supercritical CO₂ two-phase flow. *J. Supercrit. Fluids* 120, 173–180.
- Hou, L., Sun, B., Jiang, X., Geng, X., Wang, Z., Li, Q., 2016. Calculation on the following performance of proppant in supercritical CO₂. *Acta Petrol. Sin.* 37, 1061–1068.
- Hou, L., Sun, B., Li, Y., Du, Q., Yan, L., 2013. Impact of unconventional oil and gas exploitation on fracturing equipment and materials development [J]. *Nat. Gas. Ind.* 33, 105–110.
- Hou, L., Sun, B., Wang, Z., Li, Q., 2015. Experimental study of particle settling in supercritical carbon dioxide. *J. Supercrit. Fluids* 100, 121–128.
- Hu, X., Wu, K., Li, G., Tang, J., Shen, Z., 2018. Effect of proppant addition schedule on the proppant distribution in a straight fracture for slickwater treatment. *J. Petrol. Sci. Eng.* 167, 110–119.
- Huo, H.-J., Wang, R.-h., Ni, H.-J., Li, Y.-x., Tan, C.-y., Xue, S., 2017. Study of critical annulus up-returning velocity of cuttings carried by supercritical CO₂ in deviated well. *J. CO₂ Util.* 20, 105–112.
- Ishida, T., Aoyagi, K., Niwa, T., Chen, Y., Murata, S., Chen, Q., Nakayama, Y., 2012. Acoustic emission monitoring of hydraulic fracturing laboratory experiment with supercritical and liquid CO₂. *Geophys. Res. Lett.* 39 (n/a-n/a).
- Ishida, T., Chen, Q., Mizuta, Y., Roegiers, J.-C., 2004. Influence of fluid viscosity on the hydraulic fracturing mechanism. *J. Energy Resour. Technol.* 126, 190–200.
- Izadi, G., Wang, S., Elsworth, D., Liu, J., Wu, Y., Pone, D., 2011. Permeability evolution of fluid-infiltrated coal containing discrete fractures. *Int. J. Coal Geol.* 85, 202–211.
- Jia, B., Tsau, J.-S., Barati, R., 2019. A review of the current progress of CO₂ injection EOR and carbon storage in shale oil reservoirs. *Fuel* 236, 404–427.
- Jia, Y., Lu, Y., Elsworth, D., Fang, Y., Tang, J., 2018. Surface characteristics and permeability enhancement of shale fractures due to water and supercritical carbon dioxide fracturing. *J. Petrol. Sci. Eng.* 165, 284–297.
- Jiang, Y., Luo, Y., Lu, Y., Qin, C., Liu, H., 2016. Effects of supercritical CO₂ treatment time, pressure, and temperature on microstructure of shale. *Energy* 97, 173–181.
- Jin, L., Hawthorne, S., Sorensen, J., Pekot, L., Kurz, B., Smith, S., Heebink, L., Herdogen, V., Bosshart, N., Torres, J., 2017. Advancing CO₂ enhanced oil recovery and storage in unconventional oil play—experimental studies on Bakken shales. *Appl. Energy* 208, 171–183.
- Jinqiao, W., Xiao, S., Xiangzeng, W., Xiaobing, L., Liang, X., 2015. Experimental study on pipe friction characteristics of liquid CO₂. *Appl. Chem. Ind.* 44, 1796–1798.
- Karacan, C.O., Mitchell, G.D., 2003. Behavior and effect of different coal microlithotypes during gas transport for carbon dioxide sequestration into coal seams. *Int. J. Coal Geol.* 53, 201–217.
- Kelly, R.M., Scharmach, W.J., Renz, W.L., 2017. Fracturing Fluid Composition and Method Utilizing Same. Google Patents.
- Kewen Li, Y.G., Lyu, Youchang, 2015. New mathematical models for calculating proppant embedment and fracture conductivity. *SPE J.* 20, 1–12.
- Kharaka, Y.K., Cole, D.R., Hovorka, S.D., Gunter, W., Knauss, K.G., Freifeld, B., 2006. Gas-water-rock interactions in Frio Formation following CO₂ injection: implications for the storage of greenhouse gases in sedimentary basins. *Geology* 34, 577–580.
- Kim, T.H., Cho, J., Lee, K.S., 2017. Evaluation of CO₂ injection in shale gas reservoirs with multi-component transport and geomechanical effects. *Appl. Energy* 190, 1195–1206.
- Kolster, C., Masnadi, M.S., Krevor, S., Mac Dowell, N., Brandt, A.R., 2017. CO₂ enhanced oil recovery: a catalyst for gigatonne-scale carbon capture and storage deployment? *Energy Environ. Sci.* 10, 2594–2608.
- Kumar, H., Elsworth, D., Liu, J., Pone, D., Mathews, J.P., 2015. Permeability evolution of propped artificial fractures in coal on injection of CO₂. *J. Petrol. Sci. Eng.* 133, 695–704.
- Lei, C., Wenzhi, T., 2020. Application of carbon dioxide miscible fracturing technology in block G. *Chem. Eng. Oil Gas* 49, 69–72.
- Lester, Y., Ferrer, I., Thurman, E.M., Sitterley, K.A., Korak, J.A., Aiken, G., Linden, K.G., 2015. Characterization of hydraulic fracturing flowback water in Colorado: implications for water treatment. *Sci. Total Environ.* 512–513, 637–644.
- Li, Q., Wang, Y., Wang, X., Yu, H., Li, Q., Wang, F., Bai, H., Kobina, F., 2019a. An application of thickener to increase viscosity of liquid CO₂ and the assessment of the reservoir geological damage and CO₂ utilization. *Energy Sources, Part A Recovery, Util. Environ. Eff.* 41, 368–377.

- Li, S., Li, Z., Dong, Q., 2016. Diffusion coefficients of supercritical CO₂ in oil-saturated cores under low permeability reservoir conditions. *J. CO₂ Util.* 14, 47–60.
- Li, S., Zhang, D., 2019. How effective is carbon dioxide as an alternative fracturing fluid? *SPE J.* 24, 857–876.
- Li, S., Zhang, S., Ma, X., Zou, Y., Li, N., Wu, S., Zhang, Z., 2019b. Coupled Physical-Chemical Effects of CO₂ on Rock Properties and Breakdown during Intermittent CO₂-Hybrid Fracturing. *Rock Mechanics and Rock Engineering*, pp. 1–19.
- Li, X., Elsworth, D., 2015. Geomechanics of CO₂ enhanced shale gas recovery. *J. Nat. Gas Sci. Eng.* 26, 1607–1619.
- Li, X., Feng, Z., Han, G., Elsworth, D., Marone, C., Saffer, D., Cheon, D.-S., 2017. Permeability evolution of propped artificial fractures in green river shale. *Rock Mech. Rock Eng.* 50, 1473–1485.
- Li, X., Li, G., Sepehrnoori, K., Yu, W., Wang, H., Liu, Q., Zhang, H., Chen, Z., 2019c. Estimation and analysis of carbon dioxide friction loss in wellbore during liquid/supercritical carbon dioxide fracturing. *SPE Prod. Oper.* 34, 244–259.
- Li, Y., DiCarlo, D., Li, X., Zang, J., Li, Z., 2015. An experimental study on application of nanoparticles in unconventional gas reservoir CO₂ fracturing. *J. Petrol. Sci. Eng.* 133, 238–244.
- Liangchuan, L., Zaiming, W., Zhengsong, Q., 2011. An experimental study on carrying cuttings features for supercritical carbon dioxide drilling fluid. *Acta Pet. Sin.* 32, 355–359.
- Lillies, A.T., King, S.R., 1982. Sand fracturing with liquid carbon dioxide. In: *SPE Production Technology Symposium*. Hobbs, New Mexico.
- Liu, H., Wang, F., Zhang, J., Meng, S., Duan, Y., 2014. Fracturing with carbon dioxide: application status and development trend. *Petrol. Explor. Dev.* 41, 513–519.
- Liu, J., Chen, Z., Elsworth, D., Qu, H., Chen, D., 2011. Interactions of multiple processes during CBM extraction: a critical review. *Int. J. Coal Geol.* 87, 175–189.
- Liu, J., Han, B., Li, G., Zhang, X., He, J., Liu, Z., 2001. Investigation of nonionic surfactant Dynol-604 based reverse microemulsions formed in supercritical carbon dioxide. *Langmuir* 17, 8040–8043.
- Liu, Y., Sharma, M.M., 2005. Effect of fracture width and fluid rheology on proppant settling and retardation: an experimental study. In: *SPE Annual Technical Conference and Exhibition*. Society of Petroleum Engineers.
- Liu, Y., Wilcox, J., 2011. CO₂ adsorption on carbon models of organic constituents of gas shale and coal. *Environ. Sci. Technol.* 45, 809–814.
- Luo, X., Wang, S., Wang, Z., Jing, Z., Lv, M., Zhai, Z., Han, T., 2015. Experimental investigation on rheological properties and friction performance of thickened CO₂ fracturing fluid. *J. Petrol. Sci. Eng.* 133, 410–420.
- Lv, J., Chi, Y., Zhao, C., Zhang, Y., Mu, H., 2019. Experimental study of the supercritical CO₂ diffusion coefficient in porous media under reservoir conditions. *R Soc Open Sci* 6, 181902.
- Lv, Q., Li, Z., Li, B., Zhang, C., Shi, D., Zheng, C., Zhou, T., 2017. Experimental study on the dynamic filtration control performance of N₂/liquid CO₂ foam in porous media. *Fuel* 202, 435–445.
- Malhotra, S., Lehman, E.R., Sharma, M.M., 2014. Proppant placement using alternate-slug fracturing. *SPE J.* 19, 974–985.
- Martin, D.F., Taber, J.J., 1992. Carbon dioxide flooding. *J. Petrol. Technol.* 44, 396–400.
- Mazumder, S., Wolf, K.H., 2008. Differential swelling and permeability change of coal in response to CO₂ injection for ECBM. *Int. J. Coal Geol.* 74, 123–138.
- Meng, S., Liu, H., Xu, J., Duan, Y., Yang, Q., Yao, Z., 2016. Optimisation and performance evaluation of liquid CO₂ fracturing fluid formulation system. In: *SPE Asia Pacific Oil & Gas Conference and Exhibition*. Society of Petroleum Engineers.
- Michalski, R., Ficek, A., 2015. Environmental pollution by chemical substances used in the shale gas extraction—a review. *Desalin. Water Treat.* 57, 1336–1343.
- Middleton, R., Viswanathan, H., Currier, R., Gupta, R., 2014. CO₂ as a fracturing fluid: potential for commercial-scale shale gas production and CO₂ sequestration. *Energy Procedia* 63, 7780–7784.
- Middleton, R.S., Carey, J.W., Currier, R.P., Hyman, J.D., Kang, Q., Karra, S., Jiménez-Martínez, J., Porter, M.L., Viswanathan, H.S., 2015. Shale gas and non-aqueous fracturing fluids: opportunities and challenges for supercritical CO₂. *Appl. Energy* 147, 500–509.
- Montgomery, C., 2013. Fracturing fluids. In: *ISRM International Conference for Effective and Sustainable Hydraulic Fracturing*. International Society for Rock Mechanics and Rock Engineering.
- Mosher, K., He, J., Liu, Y., Rupp, E., Wilcox, J., 2013. Molecular simulation of methane adsorption in micro- and mesoporous carbons with applications to coal and gas shale systems. *Int. J. Coal Geol.* 109, 36–44.
- Mukherjee, M., Misra, S., 2018. A review of experimental research on Enhanced Coal Bed Methane (ECBM) recovery via CO₂ sequestration. *Earth Sci. Rev.* 179, 392–410.
- Novotny, E., 1977. Proppant transport. In: *SPE Annual Fall Technical Conference and Exhibition*. Society of Petroleum Engineers.
- O'Brien, M.J., Perry, R.J., Doherty, M.D., Lee, J.J., Dhuwe, A., Beckman, E.J., Enick, R. M., 2016. Anthraquinone siloxanes as thickening agents for supercritical CO₂. *Energy Fuel* 30, 5990–5998.
- Osiptov, A.A., 2017. Fluid mechanics of hydraulic fracturing: a review. *J. Petrol. Sci. Eng.* 156, 513–535.
- Patankar, N.A., Joseph, D., Wang, J., Barree, R., Conway, M., Asadi, M., 2002. Power law correlations for sediment transport in pressure driven channel flows. *Int. J. Multiphas. Flow* 28, 1269–1292.
- Perkins, T., Kern, L., 1961. Widths of hydraulic fractures. *J. Petrol. Technol.* 13, 937–949.
- Qin, C., Jiang, Y., Kang, Z., Song, X., Liu, H., 2019. Experimental study on tensile strength and acoustic emission characteristics of shale exposure to supercritical CO₂. *Energy Sources, Part A Recovery, Util. Environ. Eff.* 1–16.
- Qinghai, Y., Siwei, M., Tao, F., Yongwei, D., Shi, C., 2018. Well and layer selection method study of CO₂ waterless fracturing. In: *SPE Kingdom of Saudi Arabia Annual Technical Symposium and Exhibition*. Society of Petroleum Engineers.
- Rahm, D., 2011. Regulating hydraulic fracturing in shale gas plays: the case of Texas. *Energy Pol.* 39, 2974–2981.
- Raimbay, A., Babadagli, T., Kuru, E., Develi, K., 2016. Quantitative and visual analysis of proppant transport in rough fractures. *J. Nat. Gas Sci. Eng.* 33, 1291–1307.
- Ranjith, P.G., Zhang, C.P., Zhang, Z.Y., 2019. In: *Experimental Study of Fracturing Behaviour in Ultralow Permeability Formations: A Comparison between CO₂ and Water Fracturing*. Engineering Fracture Mechanics, p. 217.
- Raveendran, P., Wallen, S.L., 2002. Cooperative C-H...O hydrogen bonding in CO(2)-Lewis base complexes: implications for solvation in supercritical CO(2). *J. Am. Chem. Soc.* 124, 12590–12599.
- Reinicke, A., Rybacki, E., Stanchits, S., Huenges, E., Dresen, G., 2010. Hydraulic fracturing stimulation techniques and formation damage mechanisms—implications from laboratory testing of tight sandstone–proppant systems. *Geochemistry* 70, 107–117.
- Ribeiro, L., Sharma, M., 2013. Fluid selection for energized fracture treatments. In: *SPE Hydraulic Fracturing Technology Conference*. Society of Petroleum Engineers.
- Ribeiro, L.H., Li, H., Bryant, J.E., 2017. Use of a CO₂-hybrid fracturing design to enhance production from unpropped-fracture networks. *SPE Prod. Oper.* 32, 28–40.
- Rickards, A.R., Brannon, H.D., Wood, W.D., 2013. High strength, ultralightweight proppant lends new dimensions to hydraulic fracturing applications. *SPE Prod. Oper.* 21, 212–221.
- Rutqvist, J., Birkholzer, J., Tsang, C.-F., 2008. Coupled reservoir–geomechanical analysis of the potential for tensile and shear failure associated with CO₂ injection in multilayered reservoir–caprock systems. *Int. J. Rock Mech. Min. Sci.* 45, 132–143.
- Sahai, R., Miskimins, J.L., Olson, K.E., 2014. Laboratory results of proppant transport in complex fracture systems. In: *SPE Hydraulic Fracturing Technology Conference*. Society of Petroleum Engineers.
- Santos, L., Dahi Taleghani, A., Li, G., 2018. Expandable proppants to moderate rate production drop in hydraulically fractured wells. *J. Nat. Gas Sci. Eng.* 55, 182–190.
- Sarbu, T., Styrane, T., Beckman, E.J., 2000. Non-fluorous polymers with very high solubility in supercritical CO₂ down to low pressures. *Nature* 405, 165–168.
- Scharmach, W.J., Kelly, R.M., 2019. Fracturing Fluid Composition and Method Utilizing Same. Google Patents.
- Shi, C., Huang, Z., Kilic, S., Xu, J., Enick, R., Beckman, E., Carr, A., Melendez, R., Hamilton, A., 1999. The gelation of CO₂: a sustainable route to the creation of microcellular materials. *Science* 286, 1540–1543.
- Shimizu, H., Murata, S., Ishida, T., 2011. The distinct element analysis for hydraulic fracturing in hard rock considering fluid viscosity and particle size distribution. *Int. J. Rock Mech. Min. Sci.* 48, 712–727.
- Shiozawa, S., McClure, M., 2016. Simulation of proppant transport with gravitational settling and fracture closure in a three-dimensional hydraulic fracturing simulator. *J. Petrol. Sci. Eng.* 138, 298–314.
- Siwei, M., He, L., Qinghai, Y., 2019. Exploration and practice of carbon sequestration realized by CO₂ waterless fracturing. *Energy Procedia* 158, 4586–4591.
- Soliman, M.Y., East, L.E., Augustine, J.R., 2010. Fracturing design aimed at enhancing fracture complexity. In: *SPE EUROPEC/EAGE Annual Conference and Exhibition*. Society of Petroleum Engineers.
- Stanwix, Paul L., Rathnayake, Narmada M., de Obanos, Fernando & P., 2018. Characterising Thermally Controlled CH₄-CO₂ Hydrate Exchange in Unconsolidated Sediments. *Energy & Environmental Science*.
- Stringfellow, W.T., Camarillo, M.K., Domen, J.K., Sandelin, W.L., Varadharajan, C., Jordan, P.D., Reagan, M.T., Cooley, H., Heberger, M.G., Birkholzer, J.T., 2017. Identifying chemicals of concern in hydraulic fracturing fluids used for oil production. *Environ. Pollut.* 220, 413–420.
- Sun, B., Sun, W., Wang, H., Li, Y., Fan, H., Li, H., Chen, X., 2018a. Molecular simulation aided design of copolymer thickeners for supercritical CO₂ as non-aqueous fracturing fluid. *J. CO₂ Util.* 28, 107–116.
- Sun, W., Sun, B., Li, Y., Huang, X., Fan, H., Zhao, X., Sun, H., Sun, W., 2018b. Thickening Supercritical CO(2) with Pi-Stacked Co-polymers: Molecular Insights into the Role of Intermolecular Interaction, vol. 10. *Polymers*, Basel.
- Tang, Y., Ranjith, P.G., 2018. An experimental and analytical study of the effects of shear displacement, fluid type, joint roughness, shear strength, friction angle and dilation angle on proppant embedment development in tight gas sandstone reservoirs. *Int. J. Rock Mech. Min. Sci.* 107, 94–109.
- Thomas, L., Tang, H., Kalyon, D.M., Aktas, S., Arthur, J.D., Blotvogel, J., Carey, J.W., Filshill, A., Fu, P., Hsuan, G., 2019. Toward better hydraulic fracturing fluids and their application in energy production: a review of sustainable technologies and reduction of potential environmental impacts. *J. Petrol. Sci. Eng.* 173, 793–803.
- Tong, S., Mohanty, K.K., 2016. Proppant transport study in fractures with intersections. *Fuel* 181, 463–477.
- Trickett, K., Xing, D., Enick, R., Eastoe, J., Hollamby, M.J., Mutch, K.J., Rogers, S.E., Heenan, R.K., Steytler, D.C., 2010. Rod-like micelles thicken CO(2). *Langmuir* 26, 83–88.
- Van Der Waals, J.D., Rowlinson, J.S., 2004. On the Continuity of the Gaseous and Liquid States. *Courier Corporation*.
- Vengosh, A., Jackson, R.B., Warner, N., Darrah, T.H., Kondash, A., 2014. A critical review of the risks to water resources from unconventional shale gas development and hydraulic fracturing in the United States. *Environ. Sci. Technol.* 48, 8334–8348.
- Viète, D.R., Ranjith, P.G., 2006. The effect of CO₂ on the geomechanical and permeability behaviour of brown coal: implications for coal seam CO₂ sequestration. *Int. J. Coal Geol.* 66, 204–216.

- Wang, H., Li, G., Shen, Z., 2012. A feasibility analysis on shale gas exploitation with supercritical carbon dioxide. *Energy Sources, Part A Recovery, Util. Environ. Eff.* 34, 1426–1435.
- Wang, H., Wang, M., Yang, B., Lu, Q., Zheng, Y., Zhao, H., 2018. Numerical study of supercritical CO₂ and proppant transport in different geometrical fractures. *Greenh. Gases: Sci. Technol.* 8, 898–910.
- Wang, J., Elsworth, D., Wu, Y., Liu, J., Zhu, W., Liu, Y., 2017a. The influence of fracturing fluids on fracturing processes: a comparison between water, oil and SC-CO₂. *Rock Mech. Rock Eng.* 51, 299–313.
- Wang, J., Joseph, D.D., Patankar, N.A., Conway, M., Barree, R.D., 2003. Bi-power law correlations for sediment transport in pressure driven channel flows. *Int. J. Multiphas. Flow* 29, 475–494.
- Wang, J., Sun, B., Wang, Z., Zhang, J., 2017b. Study on filtration patterns of supercritical CO₂ fracturing in unconventional natural gas reservoirs. *Greenh. Gases: Sci. Technol.* 7, 1126–1140.
- Wang, J., Elsworth, D., Sun, B., Gao, Y., Wang, X., Fu, W., 2019. Optimization design of hydraulic parameters for supercritical CO₂ fracturing in unconventional gas reservoir. *Fuel* 235, 795–809.
- Wang, L., Yao, B., Cha, M., Alqahtani, N.B., Patterson, T.W., Kneafsey, T.J., Miskimins, J. L., Yin, X., Wu, Y.-S., 2016. Waterless fracturing technologies for unconventional reservoirs-opportunities for liquid nitrogen. *J. Nat. Gas Sci. Eng.* 35, 160–174.
- Wang, S., Elsworth, D., Liu, J., 2011. Permeability evolution in fractured coal: the roles of fracture geometry and water-content. *Int. J. Coal Geol.* 87, 13–25.
- Wang, S., Elsworth, D., Liu, J., 2013. Permeability evolution during progressive deformation of intact coal and implications for instability in underground coal seams. *Int. J. Rock Mech. Min. Sci.* 58, 34–45.
- Wang, Y., Liu, S., Elsworth, D., 2015. Laboratory investigations of gas flow behaviors in tight anthracite and evaluation of different pulse-decay methods on permeability estimation. *Int. J. Coal Geol.* 149, 118–128.
- Wang, Z., Sun, B., Wang, J., Hou, L., 2014. Experimental study on the friction coefficient of supercritical carbon dioxide in pipes. *Int. J. Greenh. Gas Contr.* 25, 151–161.
- Warpinski, N.R., Mayerhofer, M.J., Vincent, M.C., Cipolla, C.L., Lolon, E., 2009. Stimulating unconventional reservoirs: maximizing network growth while optimizing fracture conductivity. *J. Can. Petrol. Technol.* 48, 39–51.
- Wen, Q., Zhang, S., Wang, L., Liu, Y., Li, X., 2007. The effect of proppant embedment upon the long-term conductivity of fractures. *J. Petrol. Sci. Eng.* 55, 221–227.
- Weniger, P., Kalkreuth, W., Busch, A., Krooss, B.M., 2010. High-pressure methane and carbon dioxide sorption on coal and shale samples from the Paraná Basin, Brazil. *Int. J. Coal Geol.* 84, 190–205.
- Xiangzeng, W., Jinqiao, W., Juntao, Z., 2014. Application of CO₂ fracturing technology for terrestrial shale gas reservoirs. *Nat. Gas. Ind.* 34, 64–67.
- Yin, H., Zhou, J., Jiang, Y., Xian, X., Liu, Q., 2016. Physical and structural changes in shale associated with supercritical CO₂ exposure. *Fuel* 184, 289–303.
- Yost, A., Mazza, R., Gehr, J., 1993. CO₂/Sand fracturing in devonian shales. In: *SPE Eastern Regional Meeting*. Society of Petroleum Engineers.
- Yost, A., Mazza, R., Remington, R., 1994. Analysis of production response to CO₂/sand fracturing: a case study. In: *SPE Eastern Regional Meeting*. Society of Petroleum Engineers.
- Yu, W., Lashgari, H.R., Wu, K., Sepehrmoori, K., 2015. CO₂ injection for enhanced oil recovery in Bakken tight oil reservoirs. *Fuel* 159, 354–363.
- Yushi, Z., Xinfang, M., Tong, Z., Ning, L., Ming, C., Sihai, L., Yinuo, Z., Han, L., 2017. Hydraulic fracture growth in a layered formation based on fracturing experiments and discrete element modeling. *Rock Mech. Rock Eng.* 50, 2381–2395.
- Zhang, J., Hou, J., 2016. Theoretical conductivity analysis of surface modification agent treated proppant II – channel fracturing application. *Fuel* 165, 28–32.
- Zhang, J., Ouyang, L., Zhu, D., Hill, A., 2015a. Experimental and numerical studies of reduced fracture conductivity due to proppant embedment in the shale reservoir. *J. Petrol. Sci. Eng.* 130, 37–45.
- Zhang, J., Ouyang, L., Zhu, D., Hill, A.D., 2015b. Experimental and numerical studies of reduced fracture conductivity due to proppant embedment in the shale reservoir. *J. Petrol. Sci. Eng.* 130, 37–45.
- Zhang, M., de Jong, S.M., Spiers, C.J., Busch, A., Wentinck, H.M., 2018. Swelling stress development in confined smectite clays through exposure to CO₂. *Int. J. Greenh. Gas Contr.* 74, 49–61.
- Zhang, S., She, Y., Gu, Y., 2011a. Evaluation of polymers as direct thickeners for CO₂ enhanced oil recovery. *J. Chem. Eng. Data* 56, 1069–1079.
- Zhang, S., She, Y., Gu, Y., 2011b. Evaluation of polymers as direct thickeners for CO₂Enhanced oil recovery. *J. Chem. Eng. Data* 56, 1069–1079.
- Zhang, X., Lu, Y., Tang, J., Zhou, Z., Liao, Y., 2017a. Experimental study on fracture initiation and propagation in shale using supercritical carbon dioxide fracturing. *Fuel* 190, 370–378.
- Zhang, X., Wang, J., Gao, F., Ju, Y., 2017b. Impact of water, nitrogen and CO₂ fracturing fluids on fracturing initiation pressure and flow pattern in anisotropic shale reservoirs. *J. Nat. Gas Sci. Eng.* 45, 291–306.
- Zhenyun, S., Weidong, S., Yanzeng, Y., Yong, L., Zhihang, L., Xiaoyu, W., 2014. Experimental studies of CO₂/sand dry-frac process. *Nat. Gas. Ind.* 34, 55–59.
- Zhi, S., Elsworth, D., Liu, L., 2019. W-shaped permeability evolution of coal with supercritical CO₂ phase transition. *Int. J. Coal Geol.* 211, 1–14.
- Zhou, D., Zhang, G., Wang, Y., Xing, Y., 2018. Experimental investigation on fracture propagation modes in supercritical carbon dioxide fracturing using acoustic emission monitoring. *Int. J. Rock Mech. Min. Sci.* 110, 111–119.
- Zhou, X., Burbey, T.J., 2014. Fluid effect on hydraulic fracture propagation behavior: a comparison between water and supercritical CO₂-like fluid. *Geofluids* 14, 174–188.
- Zou, Y., Li, N., Ma, X., Zhang, S., Li, S., 2018. Experimental study on the growth behavior of supercritical CO₂ -induced fractures in a layered tight sandstone formation. *J. Nat. Gas Sci. Eng.* 49, 145–156.
- Zou, Y., Zhang, S., Ma, X., Zhou, T., Zeng, B., 2016. Numerical investigation of hydraulic fracture network propagation in naturally fractured shale formations. *J. Struct. Geol.* 84, 1–13.