

Review Paper

Laboratory to field scale assessment for EOR applicability in tight oil reservoirs

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ABSTRACT

Tight oil reservoirs are contributing a major role to fulfill the overall crude oil needs, especially in the U.S. However, the dilemma is their ultra-tight permeability and an uneconomically short-lived primary recovery factor. Therefore, the application of EOR in the early reservoir development phase is considered effective for fast-paced and economical tight oil recovery. To achieve these objectives, it is imperative to determine the optimum EOR potential and the best-suited EOR application for every individual tight oil reservoir to maximize its ultimate recovery factor. Since most of the tight oil reservoirs are found in wide spatial source rock with complex and compacted pores and poor geophysical properties yet they hold high saturation of good quality oil and therefore, every single percent increase in oil recovery from such huge reservoirs potentially provide an additional million barrels of oil. Hence, the EOR application in such reservoirs is quite essential. However, the physical understanding of EOR applications in different circumstances from laboratory to field scale is the key to success and similarly, the fundamental physical concepts of fluid flow-dynamics under confinement conditions play an important role. This paper presents a detailed discussion on laboratory-based experimental achievements at micro-scale including fundamental concepts under confinement environment, physics-based numerical studies, and recent actual field piloting experiences based on the U.S. unconventional plays. The objective of this paper is to discuss all the critical reservoir rock and fluid properties and their contribution to reservoir development through massive multi-staged hydraulic fracture networks and the EOR applications. Especially the CO₂ and produced hydrocarbon gas injection through single well-based huff-n-puff operational constraints are discussed in detail both at micro and macro scale.

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1. Introduction

Crude oil from tight oil reservoirs (TOR) is the fastest-growing hydrocarbon resource worldwide and these reservoirs are being developed usually through horizontal drilling and multistage hydraulic fracturing. According to Energy Information Administration (EIA), the technically recoverable shale hydrocarbon resources are summed up to more than 350 billion barrels, globally. These reserves are present in shale formations laying under different international territories which is almost 10% of the total known fossil oil in the world. The estimated amount of technically recoverable top 10 shale oil reserves is listed in Table 1. Among the top 10

countries with maximum shale oil reserves, the United States falls in 2nd place after Russia with approximately 17% of the total global shale oil. China, Argentina, and Libya are the next biggest shale oil holders (EIA, 2013). The regional estimate of the technically recoverable shale oil share to the world is shown in Fig. 1. This distribution is based on 46 countries across the world with North America having the highest technically recoverable share due to competitive technical advancement (EIA, 2017).

Fig. 2 presents the significance of the U.S. shale oil production that is contributing more than half of the whole U.S. oil production as of 2022. Among seven different regions of the U.S., the Permian basin located in the South West region alone contributed the most to the total U.S. shale crude oil production. It can be noticed in Fig. 2 that the overall shale U.S. crude oil production jumped from 5 to 8 MMbbl per day just in a couple of years i.e. from 2018 to 2020 and also the progressive trend of the U.S. shale reservoirs' rapid development can be noticed in the same figure. In early 2020, due to the global

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Table 1

Top 10 countries with technically recoverable shale oil resources (Data collected and summarized from EIA, 2013; 2021a; 2021b).

Rank	Country	Shale oil, billion bbl	Global shale oil reserves, %
1	Russia	75	21.7
2	USA	58	16.8
3	China	32	9.8
4	Argentina	27	7.8
5	Libya	26	7.5
6	Australia	18	5.2
7	Venezuela	13	3.7
8	Mexico	13	3.7
9	Pakistan	9	2.6
10	Canada	9	2.6
	Total	345	

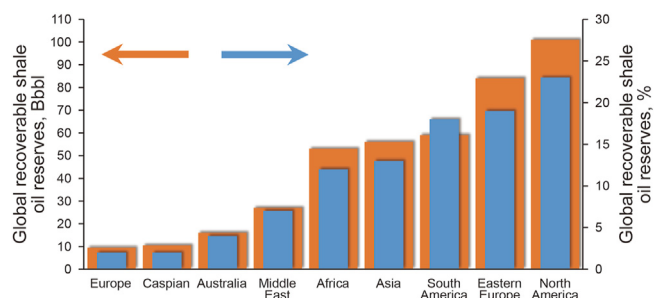


Fig. 1. Regionally technically recoverable shale oil reserves (Data collected and summarized from EIA, 2021a, 2021b; Syed et al., 2022a).

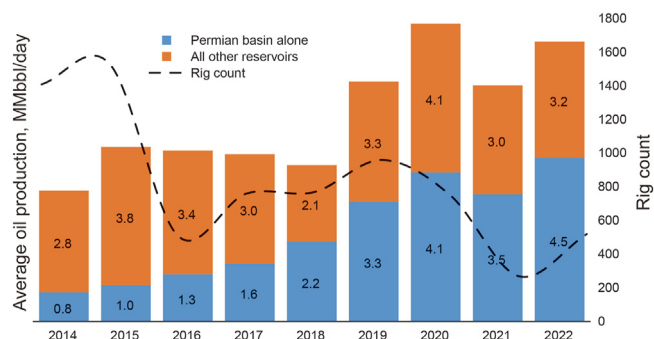


Fig. 2. U.S. tight oil recovery performance and the tight oil reservoirs development through rig counts (Data collected and summarized from multiple sources as mentioned in the context).

pandemic situation, the oil production was significantly cut down, globally, that is getting back on the same trend as pre-pandemic in 2022. Table 2 summarizes the reserves distribution based on individual basins and/or reservoirs (EIA, 2017; Long, 2022).

Based on the experiences shared in this paper from laboratory to field scale, a fact is established that the process of finding the most effective way to develop a shale reservoir is critical and time-consuming because of multiple factors including extremely small pore size, low and dual porosity distribution, and most importantly the ultra-tight permeability distribution (Du and Nojabaei, 2019). In the last decade, a considerable advancement is done to finally acknowledge a couple of techniques including horizontal well drilling and multistage massive hydraulic fracturing in tight formations as the most successful ones to develop TORs more effectively. A rapid increase in total oil production using these techniques is evidence of their success that could be noticed that resulted in a boost of total oil production to almost double since 2010 (EIA, 2021b). Fig. 3 is presenting the production history and

Table 2

Technically recoverable shale oil resources in the U.S. per basin/reservoir as of January 2020 (EIA, 2017).

Region	Basin/Reservoir	Technically recoverable shale oil per region, billion bbl
East	Appalachian	4.4
	Illinois	
	Michigan	
Gulf Coast	Black Warrior	31
	TX-LA-MS Salt	
	Western Gulf (Eagle Ford)	
Midcontinent	Anadarko	2.6
	Arkoma	
	Black Warrior	
South West	Fort Worth	112.6
	Permian	
Rocky	Denver	25.1
Mountain/	Grater Green River	
Dakotas	Paradox	
	Powder River	
	San Juan	
	Southwestern Wyoming	
	Uinta Piceance	
	Wind River	
Northern	Montana Thrust Belt	18.9
Great	North Central Montana	
Plains	Powder River	
	Williston (Bakken)	
West Coast	Columbia	0.4
	San Joaquin/Los Angeles	

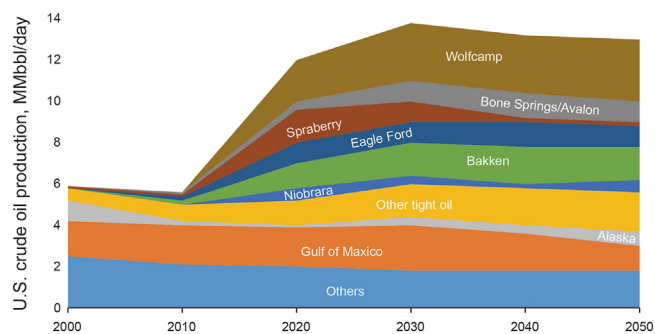


Fig. 3. Projected U.S. tight oil production profiles of all major plays (Data collected and summarized from multiple sources as mentioned in the context).

the projection of the U.S. shale oil production that is expected to hit the peak of 12 million barrels per day by the end of this decade using the current technology. However, these anticipated numbers would increase with further advancement in technology over time. In Fig. 3, it is notable that tight oil is even today contributing around 70% to the total oil production (Ahmed and Meehan, 2016). EIA also reported that only 15% of the total crude oil in the U.S. used to be produced through horizontal wells that jumped to 96% of the entire oil production by the end of 2018 through optimized horizontal drilling mainly in TORs. However, in parallel about 88,000 pre-existing vertical wells are also producing but to a very minor contribution towards the total volume and that are considered to keep producing until they become uneconomic. Fig. 4 shows the status of the total vertical and horizontal well count in the major unconventional plays of the U.S. as of 2019 (EIA, 2019; Kurtoglu et al., 2013a; Perrin, 2019).

Apart from tight hydrocarbon (oil and gas) reservoirs, deep natural gas, geo-pressurized zones, coalbed methane, and methane hydrate reservoirs are also commonly referred as unconventional reservoirs. For such complex reservoirs, a horizontal well provides comparatively greater contact to the reservoir and enhances the

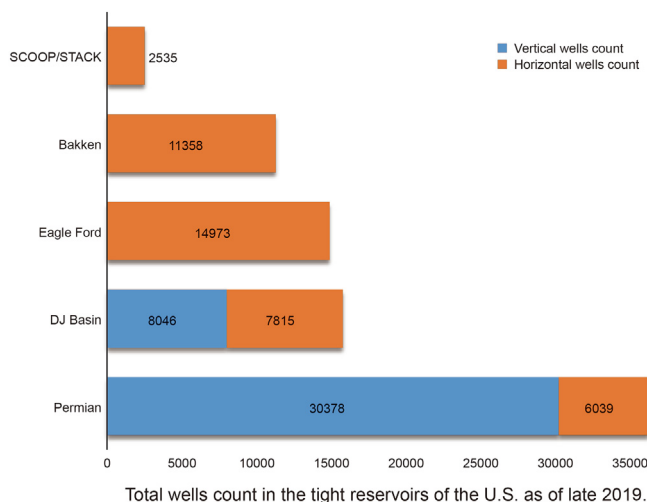


Fig. 4. Existing vertical and horizontal well count in the U.S. reservoirs as of 2019 (Data collected and summarized from Kurtoglu et al., 2013a; Perrin, 2019).

wellbore exposure to produce plenty of additional hydrocarbon that is why the horizontal wells are also known as Maximum Reservoir Contact (MRC) wells and their drilling process is called Extended Reached Drilling (ERD) (Syed et al., 2016). However, MRC wells and hydraulic fractures make a great combination to generate greater exposure of the hydrocarbon to flow from the matrix to the fractures through primary depletion with a higher differential pressure across the wellbore that results in an incredible increase in production (Butler et al., 2021; Muther et al., 2020a; Sprunger et al., 2021; Syed et al., 2021). Nevertheless, it has been a common observation in almost all the TORs that the resulting increased oil production does not sustain for long and comes to a rapid decline after some time that ranges between a few months to a couple of years (Khan et al., 2016; Todd and Evans, 2016). A schematic of a horizontal well with induced hydraulic fractures deep into the matrix is shown in Fig. 5 with the reference of a vertical well.

2. Major shale oil plays

Bakken play is one of the most producing U.S. shale oil play that is aerially lying over Montana and North Dakota in north-central

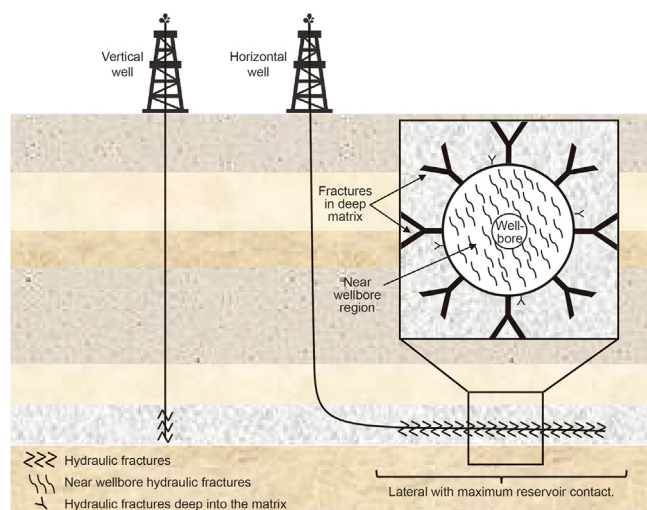


Fig. 5. Horizontal well schematic with stimulated hydraulic fractures and the vertical well for reference.

America and a part of it lying in south-central Canada. This play is relatively thin layering in the central part and quite deep at the Williston Basin and it includes both conventional as well as unconventional reservoirs. The entire Bakken formation is consisting of three major parts including lower, middle, and upper Bakken, out of which, middle Bakken is the primary production zone. The original oil in place is estimated at approximately 300–900 billion barrels while the technically recoverable reserves based on today's technology are approximately 5–25 billion barrels (Li et al., 2018; Wang et al., 2020).

Eagle Ford is the second most producing play that is lying in south Texas with approximately 5–30 billion barrels of original oil in place. It mainly consists of higher carbonate shale percentage i.e. around 70% mainly in south Texas with Kerogen Type II while possessing higher shale content in the northwest region. The higher carbonate content makes it more brittle and hence it becomes more conductive for the hydraulic fracture operations. Currently, Eagle Ford is contributing with under 1 million barrels of oil production per day (DiStefano et al., 2019; Liang and Zhao, 2019; Zhao et al., 2020).

Another major shale oil play in the U.S. is Wolfcamp that is lying in the midland basin, which is a major oil resource of the Permian Basin. It is having approximately 30 billion barrels of original oil in place. The Kerogen type for this play is found to be varying in the overall region between Type II and Type III. It is one of the most developed shale oil resources with more than 6500 producers and over 200 active rig counts (Casey et al., 2018; Gherabati et al., 2020; Smye et al., 2020).

The next is the Niobrara shale formation that is lying northeast of Denver, Colorado, with the presence of both conventional and unconventional oil resources. The Niobrara is consisting of three isolated zones i.e. Niobrara A, B, and C which are sitting on the top of Codell and Greenhorn formations. It is one of the deepest shale formations in the U.S. with approximately 7000 ft vertical depth with the formation thickness ranging between 150 and 300 ft (Heart Energy, 2020; McCormack et al., 2021; Yue et al., 2021).

The Utica shale is another important shale oil play in the U.S. that is a stacked play, that includes both the Utica formation and the underlying Point Pleasant formation of the Late Ordovician age. The formation extends in the subsurface from New York State in the north to northeastern Kentucky and Tennessee in the south. The typical depth of the formation varies from 2000 to 14,000 ft and a wide range of thickness covering 70–750 ft (Heart Energy, 2020; Gittings and Roach, 2020; Goodman et al., 2019). Fig. 6 is presenting the boundaries, structure (elevation of the opt contours), and isopachs (thickness contours) of all five plays discussed above. While Table 3 summarizes the overall characteristics of all five plays.

Apart from the U.S., Russia, and China are having the largest shale oil resources with approximately 75 and 32 billion barrels of technically recoverable oil. Globally, shale oil resources are facing the same issue of short production life and very low ultimate oil recovery that typically ranges between 3% and 10%. Fig. 7 presents an image of a typical well's average annual production rate decline percentile for the first year of production from different major shale oil plays of the U.S. It can be observed that oil production decreases rapidly as high as 50% of the initial flow rate. Therefore, to increase the oil recovery factor and the reservoir over all potential, secondary/tertiary oil recovery has to be considered from day one of the field development. Due to ultra-tight permeability, gas injection is the only best-suited option that has been tested in a few pilots and found considerable results, especially with CO₂ injection.

3. Field Development Planning

The conventional reservoirs with good permeability distribution are more likely to be developed with natural depletion drive. Whereas, water flooding is the most economical secondary drive

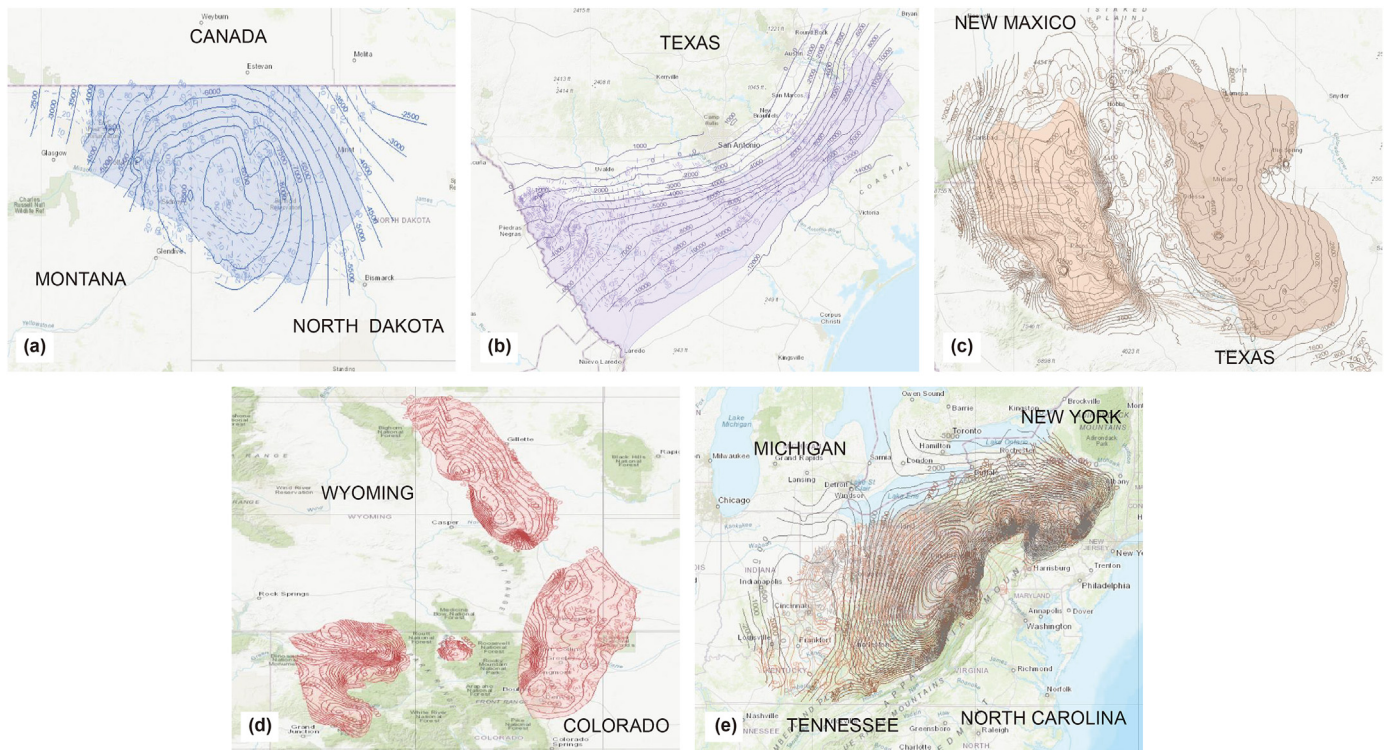


Fig. 6. Boundary, structure (elevation of the top contours), and isopachs (thickness contours) of (a) Bakken, (b) Eagle Ford, (c) Wolfcamp, (d) Niobrara, (e) Utica Shale (Maps gathered from [EIA, 2022](#)).

Table 3
 Summary of U.S. Tight oil plays characteristics.

U.S. plays	Bakken	Utica Shale	Eagle Ford	Wolfcamp	Niobrara
Geological age	Late Devonian & Early Mississippian	Middle Ordovician	Early Cretaceous	Permian	Late Cretaceous
Basin	Williston Basin	Appalachian	Maverick Basin	Permian	Denver-Julesburg
Geographic location	North Dakota & Montana	Eastern United States	South Texas	West Texas & SE New Mexico	NE Kansas, NE Colorado, SW Nebraska & SE Wyoming
Average depth, ft	6000	5000–11000	7000	10,000–12000	3000–14000
Average thickness, ft	22	100–400	200	1200–2000	450
Average porosity, %	8	2–8	9	5–9	6–9
TOC, %		5–8	4.25	2–5	3

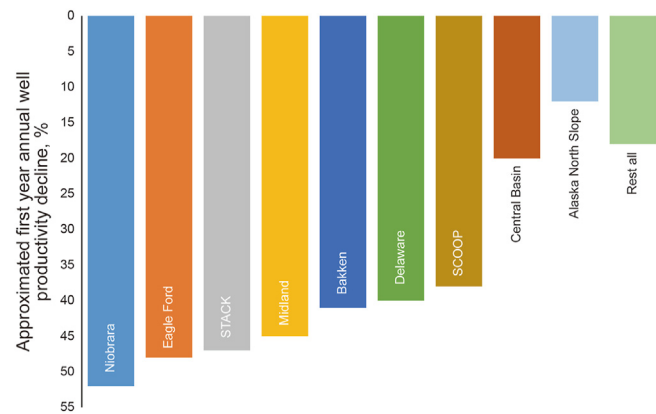


Fig. 7. First year annual oil production rate decline percentile (Data collected and summarized from [Barree et al., 2009](#)).

mechanism that aids oil recovery improvement, that usually followed by Enhanced Oil Recovery (EOR)/tertiary recovery applications. The most common EOR applications include HC and non-HC gas injection for miscible and immiscible gas flooding, etc. The EOR processes are those that improve recovery from the injection of non-native fluid or energy deep into the reservoir. Chemical and thermal EOR methods are also very commonly adopted to develop and/or to re-develop conventional oil reservoirs ([Syed et al., 2011, 2016, 2019](#)). But unlikely, the unconventional oil reservoirs do not give any response to natural depletion or water injection due to very low water injectivity because of ultra-tight permeability and the poor rock pores and pore throat size distribution that keep the oil as isolated trapped droplets ([Sheng and Chen, 2014; Sheng, 2015](#)). The contribution of rock structure and their mineralogy cannot be neglected either which is responsible for creating such ubiquitous matrix nature. For example, [Fig. 8](#) presents a schematic of pore throat size, structure, and types for the unconventional

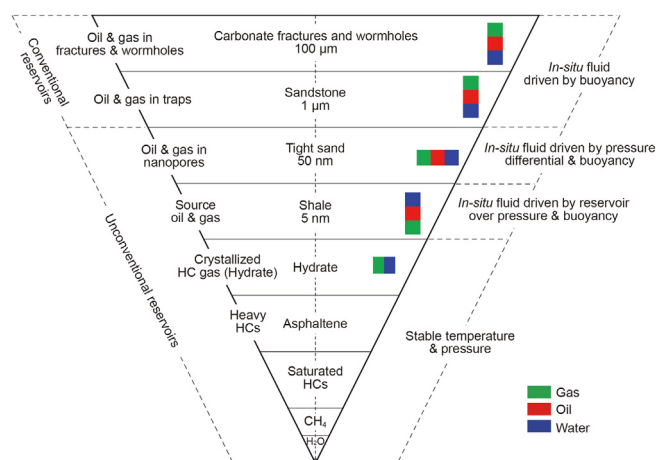


Fig. 8. Type, size, and structures of pore throats in conventional and unconventional reservoirs (modified from Hoteit and Firoozabadi, 2006).

reservoirs with reference to conventional reservoirs. The hydrocarbon accumulation in conventional reservoir rock usually possesses a pore throat diameter of 1 μm that causes reservoir fluid accumulation and migration based on buoyancy factors. On contrary, the unconventional reservoirs usually own pore throats with lesser than the 1- μm diameter, and fluid migration and accumulation happen by different mechanisms including overpressure, buoyancy, stable temperature, and pressure.

Considering the facts discussed above, EOR projects are capital intensive, time-consuming, and highly uncertain processes that commercially require careful and systematic evaluation for a successful unconventional field development planning. A well-defined staged evaluation process for the field development mainly relies

on consistent comparison of processes and the involvement of updated available and applicable technology. The maximum chances of success depend on the process of minimizing efforts spent on inappropriate scenarios and the communication with multi-disciplinary teams as well as the commercial stakeholders. To present the complex nature of unconventional reservoirs, multiple formation rock & fluid characteristics, and rock mineralogy are summarized in Table 4.

The unconventional resources tend to be laterally extensive but only developed through diffusion-based processes since the unconventional hydrocarbons are not found within the discrete closures. That is why the presence of huge but inherent heterogeneities requires hundreds of wells to target sweet spots for the commercial-scale field development. Table 5 enlists all the major reservoir specifications and the field development considerations usually taken into account while developing two different types of reservoirs.

Whereas, Table 6 lists the summary of typical well properties drilled in different U.S. TORs to give an idea about the estimated cost for individual well drilling operation and the expected estimated ultimate oil recovery for the net profit approximation.

3.1. Field Development Stages & Planning Strategy

It is a common practice to develop tight oil reservoirs in multiple stages and each stage could take several years to complete, therefore, the development of such reservoirs is comparatively expansive and becomes mega-multibillion-dollar projects. In the initial stage, the exploration is performed for the confirmation of the existence of the technically recoverable hydrocarbons. The geological investigation from the existing wells in the neighboring areas could be an easy start to have clear signs of hydrocarbons in the targeted area. On positive signs, detailed preliminary geological

Table 4

Typical rock/formation and fluid properties of shale oil reservoirs.

Reservoir formation, rock and fluid properties	Typical range (Collected from literature)	References
Permeability	1E-5–0.1 mD	Alvarez and Schechter, 2016
Porosity	2%–18%	Alfarge et al., 2017a, 2017b
Reservoir temperature	200–240 °F	Alvarez et al., 2017
Formation pressure	3000–8000 psi	Alharthy et al., 2018a, 2018b
Saturation pressure	2500–3500 psi	Adel et al., 2018
Ney pay thickness	8–2600 ft	Aziz et al., 2021
Formation depth	2000–14000 ft	Bireselioglu, 2016
Drive mechanism	Poor sweep and low-pressure connectivity	Caineng et al., 2013
Initial water saturation	25%–50%	Cho et al., 2016
Pressure gradient	0.42–0.7 psi/ft	Dawson et al., 2015
Rock type	Mixed-silt, limestone, sand & shale	Fragoso et al., 2018
Thermal maturity (R_o)	0.6%–1.8%	Jin et al., 2016
Wettability	Mixed to oil-wet	Kurtoglu et al., 2013b
Contact angle	80°–145°	Kurtoglu et al., 2014
Oil–water interfacial tension (IFT)	17–34 mN/m	Karimi et al., 2019
Natural fracture intensity	0–32 per ft	Kerr et al., 2020
Clay content	7%–30%	Li et al., 2019
Total organic content	0.1%–12%	Morsy et al., 2013
Bulk density	2.3–2.5 g/cm ³	Morsy and Sheng, 2014
Grain density	2.5–2.7 g/cm ³	Pu and Li, 2016
Rock grain size	Below 62.5 μm	Rassenfoss, 2017, 2014
Average pore radius	0.01–0.03 μm	Sanaei et al., 2018
Oil density	38–42 API	Valluri et al., 2016
Oil viscosity	Below 4.2 cP	Wang et al., 2011, 2012, 2014, 2016
Gas oil ratio (GOR)	500–1800 scf/stb	Wang et al., 2016
Oil polarity	More towards paraffinic	Yu and Sheng, 2016
Fluid pH	Acidic	Yu et al., 2014
Total acid number	0.02–0.36 mg KOH/g	Yin et al., 2017
Total base number	0.12–1.16 mg KOH/g	Zhang et al., 2013b
Brine specific gravity	Heavy	Zhang, 2016
Brine salinity	High	
Brine total dissolved solids (TDS)	228,500–285,000	

Table 5

Reservoir specifications and field development differences between conventional & unconventional reservoirs.

	Conventional reservoirs	Unconventional reservoirs
Reservoir specifications	Found in localized structural traps Relatively smaller original oil in place Higher to moderate porosity Possesses inter-granular porosity Permeability ranges >0.1 mD Follow traditional phase behavior Primary recovery ranges between 15% and 35%	Found in aerially continuous thin formation deposits Relatively larger original oil in place Moderate to lower porosity Other/complex porosity types Permeability ranges < 0.1 mD Mostly works on complex PVT behavior Primary recovery ranges between 2% and 8%
Field development planning	Shows sustainable production & injection operations Few wells are reliable enough for commerciality Field development assessments before development drilling Field development uncertainty/risk factor ranges from Low to medium Both vertical and horizontal wells work with hydraulic fractures Follow natural depletion process Hard to find – Easy to produce	Rapidly declines production and shows poor injectivity Several wells are required for commercial field development Field development assessments during development drilling and the development plan keep on updating based on the regional flow performance Always high uncertainty and the field development risk factor Horizontal wells are necessarily required with hydraulic fractures to maximize reservoir contact Artificial/manufacturing process Easy to find – Hard to produce

Table 6

Typical wells information from major U.S. shale oil plays (Heart Energy, 2020).

	First production	Well cost, \$MM	EUR, million bbl	Well spacing, ft	Average well lateral, ft
Bakken	2008	Approx. 8.5–9	700	160	8500–10000
Eagle Ford	2006	Approx. 6–9	600	40–80	6000–7000
Wolfcamp	2011	Approx. 7–8	650–750	80	4500–6700
Niobrara	2006	Approx. 3–5.5	250–450	160	4000–5100
Utica	2011	Approx. 6–8	3.6–5.4	160	500–900

and geophysical surveys are performed for the confirmation of the hydrocarbon existence. During the same stage, the land acquisition and the drilling permits are obtained from the local and the federal authorities (if needed), which could take more or less a year. The second stage involves the seismic survey, its evaluation, and its characterization. The major objectives of this survey include the overall formation extent determination to define formation boundaries, a rough reserves estimation, and the most favorable exploratory well drilling spot determination.

For exploration purposes, initially, a vertical well is drilled to obtain multiple well logs and core samples for the actual reservoir formation and *in-situ* fluid characterization. While developing unconventional reservoirs, comprehensive Rock-Eval pyrolysis is performed to determine basic properties including total organic carbon (TOC), the thermal maturity (T_{max}), hydrogen index (HI), etc. In addition, the geochemical properties such as rock traceability and the brittleness index are also measured in this step that is compulsorily needed for the optimum sweet spot determination while hydraulic fracturing the well. This entire exploration process approximately takes more than a year which is usually followed by drilling a few horizontal wells aided with multi-stage hydraulic fracturing networks for the early stage, usually single well based, hydrocarbon productivity estimation. Usually, micro-seismic surveys are also conducted to evaluate the hydraulic fracturing treatments and completion techniques optimization. The development of tight hydrocarbon reservoirs, the application of massive and multi-staged hydraulic fractures is a common practice to provide optimum reservoir contact and the flow channels for the *in-situ* fluid that do not flow easily from tight matrix pores.

The next stage is comprised of hydrocarbon production potential analysis, analytically and numerically. After having enough confidence in the collected data and their analysis, a commercial field development plan is prepared (Syed et al., 2020c). As a part of a commercial development plan, full-field drilling permits, pipeline, and facility construction permits are acquired from the

concerned authorities. Finally, after having all the legal permits, the entire field is developed on a commercial scale that might include drilling smaller spaced a few hundred to more than a thousand horizontal wells. Not only primary production but also EOR application could be part of the full field development planning.

Due to ultra-tight permeability, usually, unconventional oil reservoirs are developed regionally through the individual well-based huff-n-puff mechanism that is also known as cyclic solvent injection (CSI). Apart from the well completion design, the hydraulic fracture design plays an important role to improve the EUR, however, a detailed sensitivity analysis on every individual well is necessarily required to determine the optimum well design and the hydraulic fracture design as well as the EOR operational design (Muther et al., 2020a, 2020b; Syed et al., 2022b). A detailed numerical simulation study is performed to evaluate the effects of multiple cluster count as presented in Fig. 9, as well as the effects of fracture half-length, fracture spacing, and fracture effective permeability (Muther et al., 2021b, 2022b; Syed et al., 2021b, 2022b). A few results of the numerical simulation-based study are presented in Fig. 10 that clearly illustrate that the increasing

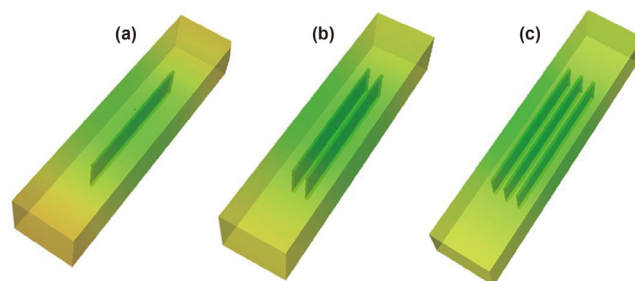


Fig. 9. 3D Numerical model representation of (a) a single, (b) dual, and (c) triple clusters per fracture as presented by Syed et al. (2022b).

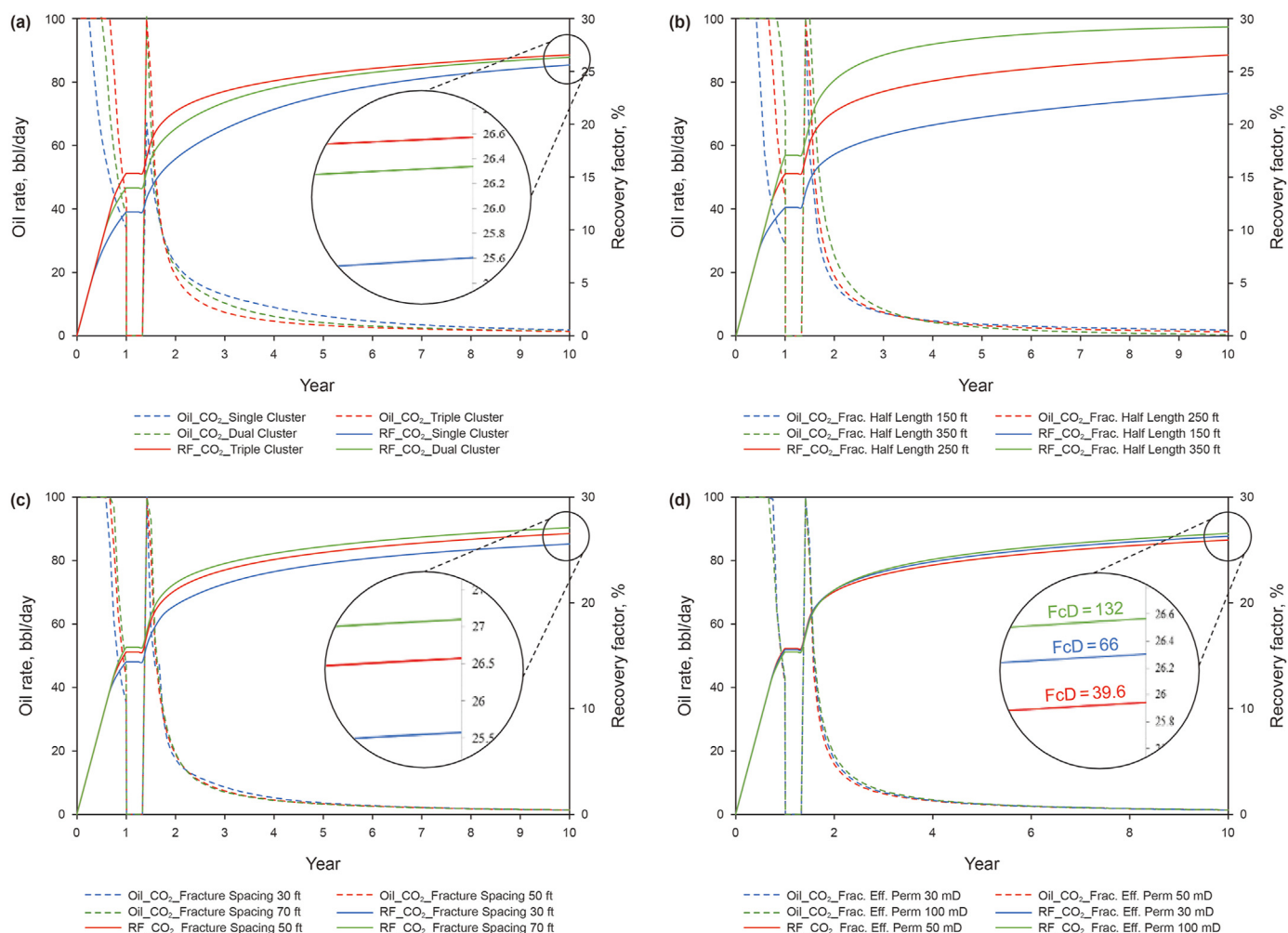


Fig. 10. Recovery response for (a) cluster count per fracture, (b) fracture half-length, (c) fracture spacing, and (d) effective fracture permeability as presented by Syed et al. (2022b).

number of clusters per fracture helps to improve the oil recovery but the stimulated reservoir volume (SRV) is the limiting factor that determines the optimum number of clusters required in each scenario. In addition, the effect of incremental fracture half-length, spacing, and the effective permeability or the fracture conductivity positively improves the recovery factor significantly.

In addition to the hydraulic fracture design, the huff-n-puff operational scheme is also an important factor to consider with any injection solvent for the development of an unconventional oil reservoir (Syed et al., 2021d). Considering CO₂ as an example, the incremental number of huff-n-puff injection and soaking cycles play an effective role to improve the oil recovery significantly as presented in Fig. 11. It can be noticed from the first figure that the ultimate oil recovery significantly improved with an incremental number of huff-n-puff cycles. However, the recovery/fluid-flow response deteriorates as the result of every individual cycle in a row due to reducing residual oil saturation near wellbore and near fractured zone (Syed et al., 2022b).

3.2. Conventional vs. Unconventional EOR

On a bigger picture, the exploration and development of tight reservoirs require early integration of geoscience and engineering skills. In addition, the early development decisions for the TORs must be made without the benefit of local well production data

because over large areas, the unconventional/tight hydrocarbon accumulations can contain extremely large in-place volumes (Balasubramanian et al., 2018). Horizontal wells and infill drilling is one of the commonly applied short-term practices to increase rapid production, the maximum reservoir contact and the spacing between the wells vary based on the rock and the stimulated reservoir volume as well as the fluid quality (Al-Farsi et al., 2012). Lower the quality of oil and the rock permeability, more closer will be the infill wells with extended lateral lengths (Syed et al., 2021, 2022b). Before getting into more details about the EOR applications applicable in the TORs, let us look at the major differences between the conventional and the unconventional EOR schemes as briefly listed in Table 7.

3.3. From laboratory to field scale – lessons learned

Because of the complicated nature of TORs, the EOR applications in conjunction with horizontal drilling are getting significant attention and motivation as discussed earlier. However, due to a poor understanding of geological constraints and the fluid flow performance in a TOR, the proper selection of an optimal EOR application, hydraulic fracture design, and the planned operational strategy is still a big challenge (Syed et al., 2021, 2022b). There has been a lot of development research conducted over the years regarding the implementation of EOR in different U.S. TORs. A

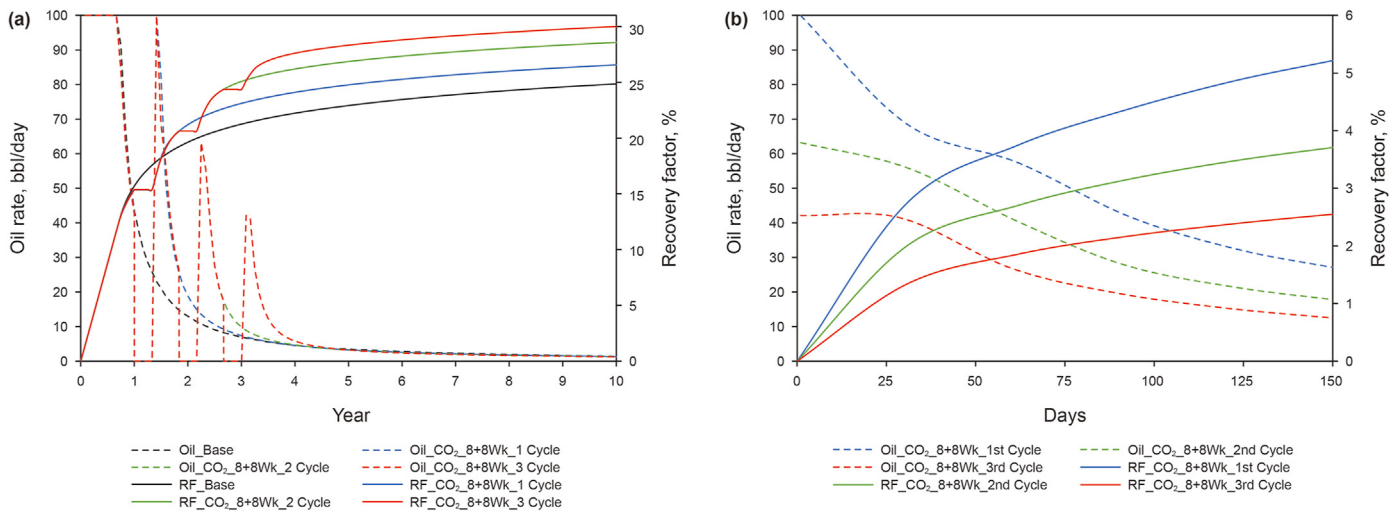


Fig. 11. Effect of multiple huff-n-puff cycles on (a) ultimate oil recovery, and (b) individual fluid-flow and recovery response after each huff-n-puff cycle as presented by Syed et al. (2022b).

Table 7
 Conventional vs. unconventional EOR mechanisms and development strategies.

Conventional EOR	Unconventional EOR
Long term increase in EUR Considerable recovery enhancement Sustained injection of external fluids Fluid flow mechanism observed through the matrix Fluid flow physics is relatively well understood IFT, wettability, and miscibility improvements are the key parameters to improve oil recovery Targets in-place reservoir volume Development plans based on multiple productions & injection wells It's a mid to late life-cycle application Shows low to medium uncertainty and risk factor	Only short-term production restoration Quick hydrocarbon production acceleration Unable to sustain injection/limited external fluid injectivity Complex fluid flow through natural fractures and nano-pores Fluid flow physics & chemical processes are still not completely explainable Effects of these parameters are still not completely understood Only near-wellbore/locally fractured areas (SRV) is the goal Usually, individual well (huff-n-puff) development plans work more efficiently Early life-cycle application Mostly uncertain applications with a high-risk factor

summarized evaluation of different EOR techniques based on laboratory analysis, numerical simulation, and field implementation is provided in Table 8. Whereas several experimental research projects are conducted on a laboratory scale that is summarized in Table 9.

Based on the collective learnings from the experimental core scale and the numerical field-scale simulation studies, several pilots were historically planned and conducted in the U.S. Some of them presented impressive recoveries as a result of CO₂ EOR, while, a few of them ended up with no success but left lots of learning for better assessment and implementation in the future. A typical description of different US field development pilot projects for unconventional reservoirs is summarized in Table 10.

4. Potential unconventional EOR techniques & recovery mechanisms

As discussed in Table 6, the EOR applications in TORs are quite different in comparison to conventional reservoirs due to complex reservoir rock mineralogy and the flow behavior. Due to the rapid production decline of unconventional tight hydrocarbon wells and low EUR, IOR/EOR techniques are essentially required to improve and sustain the production profile, economically. The only viable unconventional EOR technique so far is gas (CO₂, enriched/associated hydrocarbon) injection. During recent years, numerous studies have been conducted on various types of EOR applications in TORs and a large volume of material has been presented in technical

literature by academia and industry researchers (Alfarge et al., 2017a, 2017b; Syed et al., 2021, 2022b).

Gas injection and most importantly the combination of the huff-n-puff process is the more frequently adopted technique to develop shale reservoirs in the U.S. since 2010, and most of the recent wells are drilled as MRC wells. The multi-stage fracturing is another factor that adds value to the process with either continuous gas injection in closed spacing infill wells or huff-n-puff on widely spaced individual wells (Hoffman, 2018b; Thomas et al., 2016; Todd and Evans, 2016). It was found from the literature that most of the recent research on U.S. TORs is conducted on Eagle Ford, Bakken, and Barnett formations to understand the applicability of different EOR techniques (Alfarge et al., 2017a). From the IOR and EOR standpoint, several applications have been successfully tested in conventional fields but unfortunately, due to different reservoir rock architecture, mineralogy and the fluid flow performance in ultra-tight pores and the pore throats make it almost impossible to adopt any of the conventional applications at least without any modifications. There are hundreds of studies found to be very impressive in literature with improved recovery but at the same time, many other studies strongly contradict their findings (Alvarez et al., 2014; Dawson et al., 2015; Sanchez-Rivera et al., 2015; Shuler et al., 2011; Wang et al., 2011, 2012).

The recovery mechanisms are not the same for the unconventional tight reservoirs as the conventional reservoirs due to different rock properties and heterogeneity distribution, fluid phase behavior as well as fluid flow mechanism, and the mass

Table 8

Working phenomenon and lab/simulation/field tests of different EOR techniques in tight oil reservoirs.

EOR technique	Base phenomenon	Observations & learnings	References
Miscible & immiscible gas injection (CO ₂ , HC, lean natural gas, and N ₂)	• Molecular diffusion • Capillary pressure, wettability, fluid density, and viscosity reduction • High compressibility to push the oil towards the producer • Pressure maintenance • Oil swelling • Combination of all or some of the working mechanisms listed above	• Tested in almost all the U.S. reported TORs including Eagle Ford and Upper, Middle, and Lower Bakken formations. • Most importantly, reservoir pressure maintenance and oil swelling were the dominant factors to provide a considerable recovery factor. • Huff-n-puff proved to be an important player with cyclic miscible (CO₂, HC gas) as well as immiscible (N₂) gas injection in field pilots. • CO₂ is being tested more often in both the field and the lab tests. • Apart from field tests, there are several simulation and lab tests reported in the literature. • In lab and numerical studies, the gas molecular diffusion phenomenon is found to be more important to make a remarkable recovery in comparison. • Also, huff-n-puff gas injection is found to be considered successful in most of the simulation studies.	Chen et al., 2016 ; Hawthorne et al., 2019 ; Hoffman, 2012, 2018a ; Kurtoglu and Salman, 2015 ; Li et al., 2015 ; Sheng, 2015 ; Sheng and Chen, 2014 ; Song and Yang, 2017 ; Syed et al., 2020a, 2020b ; Todd et al., 2017 ; Tovar et al., 2018 ; Akbar et al., 2021 ; Dawson et al., 2015 ; Karadkar et al., 2019 ; Nguyen et al., 2014 ; Sanchez-Rivera et al., 2015 ; Shuler et al., 2011 ; Wang et al., 2012, 2011 ; Zhang et al., 2018
Chemical flooding (alkaline, surfactant & polymers)	• Oil-water interfacial tension reduction • Wettability alteration	• A couple of field pilots were tested but no conclusive recovery performance review is presented in the literature. • In the lab, surfactants showed considerable results. • Also, anionic, and non-ionic surfactants are tested in the lab. • Most of the lab experiments are performed on the core samples taken from the Bakken formations. • Additionally, on a field scale, simulation studies are conducted that present promising results.	Akbar et al., 2021 ; Dawson et al., 2015 ; Karadkar et al., 2019 ; Nguyen et al., 2014 ; Sanchez-Rivera et al., 2015 ; Shuler et al., 2011 ; Wang et al., 2012, 2011 ; Zhang et al., 2018
Low salinity water flooding	• Clay swelling • Shale mineral cracking • Wettability alteration • Water imbibition • Osmotic Effect	• No field trials are found in the literature • However, several experimental studies are conducted • Most of the studies in the lab are conducted on a core scale • Remarkable recovery performance is observed, noticeably due to shale cracking by clay swelling • But not conclusively understood to apply in the field. Most probably due to clay swelling that might play a negative role to make the permeability worse. • Also, a poor sweep and conformance control is expected.	Morsy and Sheng, 2014 ; Morsy et al., 2013 ; Valluri et al., 2016 ; Wang et al., 2011, 2014 ; Zhang et al., 2013b
Carbonated water flooding	• Oil viscosity reduction • Oil swelling – increase in oil saturation and the relative permeability • Reduction in oil-water interfacial tension	• Lab experiments are performed, and remarkable results are found to reduce residual oil saturation as low as 15% under reservoir operating conditions. • Also, water alternate gas with CO₂ is tested in the lab and found good results • Requires limited modifications on surface water flooding facilities to implement in fields. • Comparatively more suitable in certain environments such as places with a limited supply of CO₂ and difficult to build a recycling plant to capture or recycle CO₂ like on offshore platforms.	Dong and Hoffman, 2013 ; Li et al., 2019 ; Zou et al., 2018
Carbonated silk water	• Used for hydraulic fracturing and post fracturing EOR technique • Near wellbore and fracture. • Oil viscosity reduction • Oil swelling – increase in oil saturation and the relative permeability • Reduction in oil-water interfacial tension	• During lab experiments, fractures induced by pure CO₂ are much more complex with larger surface areas compared to fractures induced by water. • A significant reduction in viscosity as a function of shear rate is observed with silk water in comparison to water or foamed water under reservoir operating conditions.	Ribeiro et al., 2017 ; Wan et al., 2015 ; Yin et al., 2017 ; Zhang et al., 2017

transfer mechanism ([Dawson et al., 2015](#); [Syed et al., 2022a](#)). The most expected mechanisms during gas (CO₂ or HC) injection through the huff-n-puff processes include molecular diffusion in nano-pores, single-way mass transfer, or gaseous phase evolution/expansion ([Luo et al., 2018](#)). In addition, the cyclic pressurization and the resultant phenomenon of near-wellbore/fracture oil swelling, viscosity reduction, and vaporizing gas drive are the

expected mechanisms. With the above discussion, the EOR potential in major U.S. plays is listed in [Fig. 12](#) and consequently, a huge number of studies are conducted from laboratory scale to field pilot scale. The distribution in percentage is shown in [Fig. 13](#) for both, studies conducted on various scales and the major U.S. plays for which these studies are conducted.

Table 9

Experimental research conducted on the U.S. shale reservoir rock and fluid samples.

Core samples	Permeability, mD	Porosity, %	Injection gas	Recovery mechanism	Oil recovery factor, %	Reference
Eagle Ford	<0.001	4.4	N ₂	Flooding	17.94	Sheng and Chen, 2014
	0.004	13.1			19.88	
	<0.001	4.4		Huff-n-puff	22.52	
	<0.001	13.1	CO ₂	Huff-n-puff 7-h soaking	24.13	Li et al., 2019 Alvarez et al., 2017; Hawthorne et al., 2019
	0.0024	7.28		Huff-n-puff 5 cycles	56.8	
	—	—		Huff-n-puff 3 cycles	31	
	—	—		CO ₂ Above miscible	41	
	—	—		CO ₂ Way above miscible	49	
	—	—		CO ₂ Immiscible	0.9	
	0.005	5	N ₂	Cyclic gas injection	14.23–39.66	Zhu et al., 2021 Todd and Evans, 2016
	—	7.7	CO ₂		20–71	
Mancos	—	5	N ₂	Cyclic gas injection 1-day soaking	10–63	Jin et al., 2019
	—	—		Cyclic gas injection 2-day soaking	13.5	
Bakken	0.27–0.83	18.6–23.1	CO ₂	Cyclic gas injection 3-day soaking	16.96	Syed et al., 2020a; Wang et al., 2010
	—	—	—	Near miscible Huff-n-puff 40-h soaking	19.59	
	—	—	—	Miscible Huff-n-puff 60-h soaking	63	
	—	—	—	Immiscible Huff-n-puff 60-h Soaking	61	
	—	—	—	CO ₂ WAG	42.8	
	0.29–0.44	18.9–23.6	Water + CO ₂		80.1–88.1	
Upper Bakken	—	—	CO ₂	Oil extraction	10–43	Dong and Hoffman, 2013 Yang et al., 2015 Sheng, 2015 Sheng and Chen, 2014
Middle Bakken	0.081–1.03	4.4–5.4	C ₁		>90	
			C ₂		~100	
Lower Bakken	0.081–1.03	4.4–5.4	C ₁ –85% - C ₂ –15%		>90	
			CO ₂		>90	
			N ₂		26	
			C ₁		~18	
			C ₂		~27	
			C ₁ –85% - C ₂ –15%		~32	
			CO ₂		<10	Sheng and Chen, 2014
					8–48	
Barnett	—	—	N ₂	Cyclic gas injection 1-day soaking	6.5–17.79	Sheng and Chen, 2014

Table 10

Observations and learnings collected from the field pilots conducted on unconventional shale reservoirs of the U.S.

Reservoir	Year	Injectant	EOR technique	Observations & learnings	References
Bakken	2008	CO ₂	Huff-n-puff	Reported a successful injectivity test with no incremental oil recovery because of injection. The injectivity was successful due to 1–2 miles of horizontal well and massive hydraulic fracturing network.	Sheng and Chen, 2014
	2009			Found a successful injectivity test with a minor increase in oil rate and recovery. The minor increase is likely caused by frac-hits.	
	2012	Water		Successful injectivity test with water but almost no incremental recovery. After multiple huff-n-puff cycles, observed an incremental oil response possibly due to the late reach of CO ₂ deeper into the formation.	Adel et al., 2018; Kurtoglu et al., 2013b; Song and Yang, 2017; Sheng and Chen, 2014 Sheng and Chen, 2014
	2012		Flood	Limited success in waterflood conductivity test with no incremental oil recovery and early water breakthrough (within a month). The oil rates were reduced because of the large amount of water restricting oil flow.	
	2014	CO ₂	Gas injection	Reported unsuccessful experience because of CO ₂ breakthrough at an offset well on the same day with a huge CO ₂ content possibly due to a connected thief zone among the two wells.	
	2014	Water	Flood	Successful water flooding injectivity test with no incremental oil recovery due to early water breakthrough and its rapid increase (within a week) in one of the offset wells.	
	2014	Produced HC gas		After an unsuccessful experience with water flooding in 2012, produced HC gas with around 90% of C ₁ and C ₂ mixture injected for a couple of months that partially resulted in improved oil recovery from the offset wells. But, due to some major stimulation events and high GOR in offset neighboring wells made this experience quite complicated to call a success story.	
Eagle Ford	2012	Produced lean HC gas	Huff-n-puff	However, the provided operational data including GOR trends seems unrealistic (GOR found to be low during the HC gas injection) but still, the overall recovery performance was found good with a cyclic trend of improved oil rates after every injection and soaking cycle of 4–6 weeks.	Hoffman, 2018b; Thomas et al., 2016
	2015	Produced HC gas	Gas injection	Based on the decline curve analysis, both pilots showed a considerable incremental recovery with natural gas injection.	
	2015	Produced HC gas			Hoffman, 2018b
	2015	Produced HC gas	Huff-n-puff	Like previous experience, also this pilot showed promising results with an incremental oil recovery because of hydrocarbon gas injection.	
	2015	Produced rich HC gas		It is quite difficult to conclude results for these pilots due to the unavailability of enough performance data.	
	2016	Produced HC gas		It is a huge huff-n-puff, multiple wells-based field-scale pilots started in mid-2016 that showed impressive results with notable incremental oil recovery.	

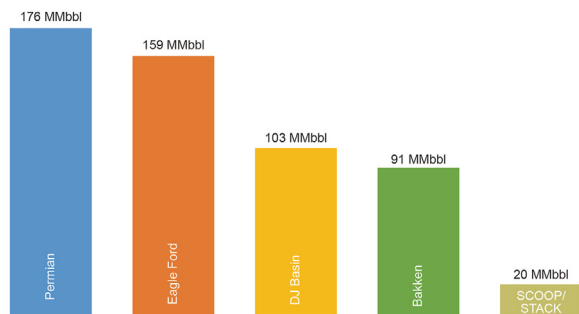


Fig. 12. EOR potential in the U.S. reservoirs as of 2020.

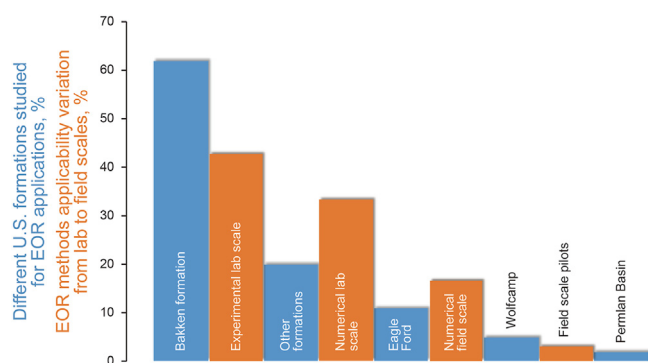


Fig. 13. Formations & the tools (lab to field scale) used for the EOR applications on tight oil reservoirs of the United States.

5. UEOR physics & fluid flow mechanism at nano-pore scale

As discussed in earlier sections the hydraulic fractures are compulsorily generated to develop unconventional reservoirs but the proper dealing with the interaction between the matrix and the

hydraulically induced fractures is very important. Hydraulic fractures are usually in macro size as compared to the natural fractures that are usually found in micro size; therefore, the hydraulic fractures help to enhance the economical fluid flow through improved flow channels for the hydrocarbons from matrix nano-pores (Hakimov et al., 2022). As a part of post-fracture operations, the micro seismic data is usually gathered to understand the effectiveness of hydraulic fractures and the subsequent development of the fracture network (Barree et al., 2015; Shuler et al., 2011; Xie et al., 2015). Due to tight permeability and poor injectivity as well as productivity, the huff-n-puff is the most preferred gas injection/EOR mechanism that is applied in TORs. The huff-n-puff operation is performed in three steps as explained on a micro/pore-scale level in Fig. 14. During huff-n-puff, CO₂ is injected into the reservoir through the fractures while the concentration gradient pushes CO₂ to invade into the matrix in the first step. During the second step, the well is shut-in that allows CO₂ to interact with the formation oil that resulting in oil swelling and oil viscosity reduction. Finally, in step 3, the miscible or immiscible oil and CO₂ migrate out of the pores towards the fracture by diffusion, injected CO₂ equalizes pressure inside the rock pores, and the excess CO₂ plus the heavy hydrocarbons stay back into the rock pores.

It is foremost important to study dynamic fluid flow properties under nano-confinement. However, it is very hard, time-consuming, and expensive to capture physics through experimental studies at a nano-pore scale therefore dynamic molecular simulation has become a powerful tool to analyze the molecular structure and their dynamic behavior. There are two commonly used simulation methods in molecular modeling including Monte Carlo (Alder and Wainwright, 1959) and molecular dynamics (Alder and Wainwright, 1957; EIA, 2021a). There are several studies recently conducted on different EOR/fluid-fluid and fluid-nano-pore interaction mechanisms. Most importantly, each EOR mechanism behaves differently to target different fluid-fluid and fluid-nanopore interaction properties. Table 11 presents a summary of a few UEOR physics-based dynamic molecular simulation studies for different injection solvents.

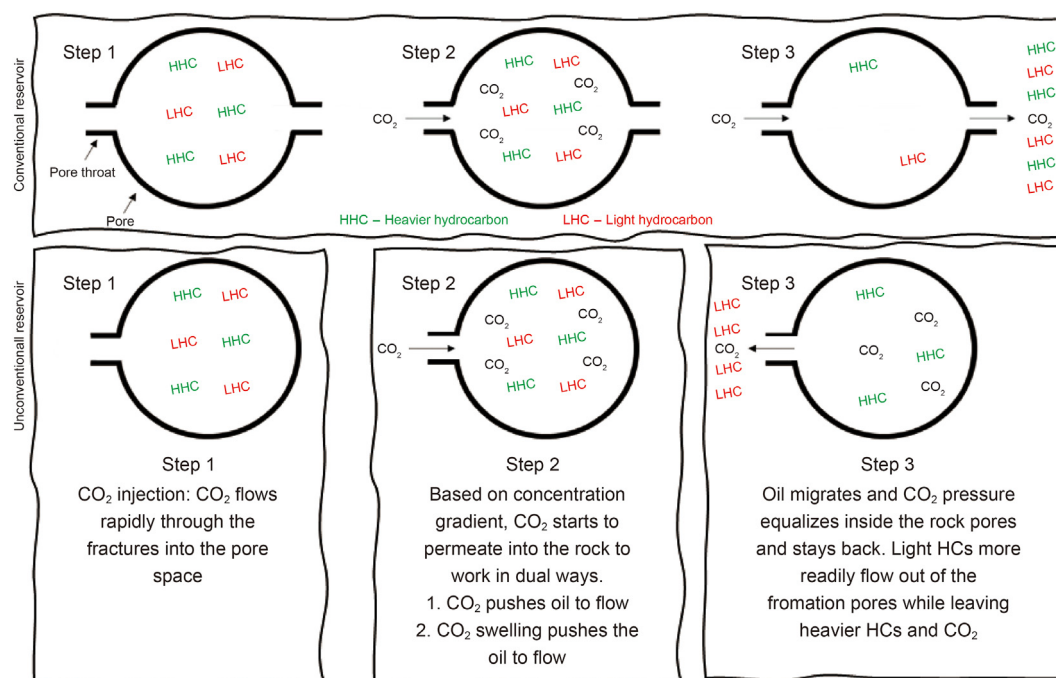
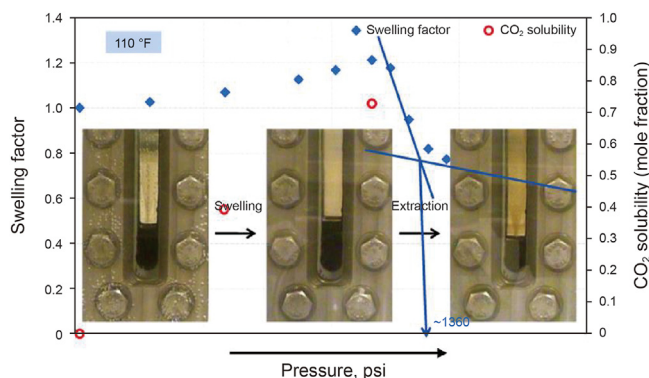


Fig. 14. Stages of CO₂ huff-n-puff in fractured oil reservoir on a micro/pore level in comparison of continuous gas injection in conventional oil reservoirs (Syed et al., 2022b).

Table 11
UEOR physics-dynamic molecular simulation studies.

EOR mechanism	Fluid-fluid and fluid-nano-pore interaction mechanisms	References
CO ₂ injection	Oil swelling	Li et al., 2019a Liu et al., 2016 Muther et al., 2021a
	Viscosity reduction	Muther et al., 2021a Zhao et al., 2015
	Oil/water interfacial tension (IFT)	de Lara et al., 2012 Makimura et al., 2013 Zhang et al., 2013a
N ₂ , CH ₄ & C ₂ H ₆ injection	Oil/water interfacial tension (IFT)	Li et al., 2020; Li et al., 2019a, 2019b Muther et al., 2021a; Abbasi et al., 2021a, 2021b; Al-Yaseri et al., 2022 Syed et al., 2012, 2021a
	Minimum miscibility pressure (MMP)	Syed, 2012 Chun et al., 2015 Peng et al., 2018
	Self-assembly structure	Cai et al., 2018 Jalili and Akhavan, 2009 Ruiz-Morales and Romero-Martínez, 2018 Tang et al., 2014
Surfactant–chemical EOR	Surface adsorption	Memon et al., 2020, 2021 Muther et al., 2021a, 2022a, 2022c Qu et al., 2016
	Temperature sensitivity	Chen and Xu, 2013 Sammalkorpi et al., 2007
	Salt resistance	Li et al., 2019b Sammalkorpi et al., 2007 Yan et al., 2010
	Effect of surfactant or surfactant/nanoparticles on oil/water IFT	Metropolis and Ulam, 1949 Vu and Papavassiliou, 2019

CO₂ or any other solvent injection process into the reservoir matrix through fractures, at first it helps to maintain the reservoir pressure and secondly the miscibility between the oil and the gas is expected to be achieved after multiple contacts. The molecular diffusion mainly determines the rate and the maturity of the miscibility between oil and the injected gas. Fig. 15 presents a three-step miscibility development from the lower to higher pressure in a visual PVT cell for an oil sample taken from one of the U.S. unconventional reservoirs. In the first step i.e. the swelling pressure range, the CO₂ dissolves into the oil phase that causing the oil volume to increase (oil swelling). While it can be observed in the transition from 2nd to 3rd step, with further increase in pressure,

**Fig. 15.** Interactions (swelling and solubility) between CO₂ and crude oil under different pressure conditions (Tsau, 2011).

the oil volume decreased and the gas color on the top changed that indicated that oil got extracted into the gas phase where the pressure point exists before the pressure reaches MMP. The discussed example leads to a conclusion that the unidirectional diffusion can be considered for the low-pressure gas injection and production process but mostly, the reservoir pressure is well above the MMP, especially for the shale oil reservoirs. Therefore, careful binary interaction and multicomponent diffusion coefficients selection is the key to performing realistic physics-based numerical simulation, and also the upscaling process from lab to field scale will be more meaningful with the correct diffusion parameters selection.

It is a well-understood fact that gravity drainage, physical diffusion, viscous flow, and capillary forces are the driving forces for the fluid flow in porous media. However, one force is usually found more dominating on others depending on the reservoir rock and fluid properties as well as on the operating conditions. In unconventional reservoirs with ultra-low matrix permeability, the gravity drainage is considered inefficient; molecular diffusion plays an important role in fluid flow. Molecular diffusion is defined as the molecular movement caused by Brownian motion or fluid composition gradient in a mixture of fluids (Yu et al., 2014). As discussed previously, most of the TORs are developed through EOR application, either continuous injection or huff-n-puff technique, that mainly led by the molecular–diffusion mechanisms. The correct identification of molecular diffusion is necessarily important in the numerical simulation process that defines the miscibility process between the injected gas and the formation. In literature, a dimensionless number called Peclet number (Pe) is widely used to measure the relative importance of molecular diffusion flow to the convection flow. The Pe is expressed as shown below;

$$Pe = \frac{\text{Diffusion time}}{\text{Convection time}} = \frac{L^2/D}{L/v} = Lv/D$$

where v is the bulk velocity, L is a characteristic length, and D is the molecular diffusion coefficient. Mathematically, Pe below unity defines the molecular diffusion-based fluid flow and the dispersion flow is considered when the Pe ranged between unity to 50 and above 50, convection is considered as the dominant flow in the porous media (Mohebbinia and Wong, 2017).

5.1. Molecular diffusion

Hawthorne et al. (2013) extensively investigated the CO₂ diffusion-mechanism on a laboratory scale using core samples gathered from the Bakken formation and conceptually concluded that the injected solvent (CO₂) flows into and through the fractures and it floods the rock driven by the pressure differential across the injection and the outlet points. It is also concluded that the oil migrates from nano-pores to bulk fractures via swelling and reduced viscosity on mixing with the injected solvent, and as the pressure gradient reduces, the oil production process gradually shifts from pressure gradient to concentration-gradient diffusion from pores into the fractures (Alfarge et al., 2017c; Hawthorne et al., 2013; Sigmund, 1976).

Generally, a couple of empirical correlations driven by Sigmund (Holm and Josendal, 1980; Sigmund, 1976), and Wilke and Chang (1955) are used in commercial simulators, such as CMG GEM, for the diffusion coefficient estimation in the bulk phase. In Sigmund correlation, the binary interaction coefficient (D_{ij}) between two components is given by;

$$D_{ij} = \frac{\rho_k^0 D_{ij}^0}{\rho_k} \left(0.99589 + 0.096016 \rho_{kr} - 0.22035 \rho_{kr}^2 + 0.032874 \rho_{kr}^3 \right)$$

where $\rho_k^0 D_{ij}^0$ is the zero-pressure limit of the density-diffusion coefficient product in phase k ; ρ_k and ρ_{kr} are the molar density and reduced molar density of the diffusion mixture, respectively. Also, $\rho_k^0 D_{ij}^0$ and ρ_{kr} are mathematically defined as;

$$\rho_k^0 D_{ij}^0 = \frac{0.0018583 T^{1/2}}{\sigma_{ij}^2 \epsilon_{ij} R} \left(\frac{1}{M_i} + \frac{1}{M_j} \right)^{1/2}$$

$$\rho_{kr} = \rho_k \frac{\sum_{i=1}^{n_c} y_{ik} v_{ci}^{5/3}}{\sum_{i=1}^{n_c} y_{ik} v_{ci}^{2/3}}$$

where M_i is the molecular weight of component i ; σ_{ij} is the collision diameter; ϵ_{ij} is the collision integral of the Lennard-Jones potential; y_{ik} is the mole fraction of component i in phase k ; v_{ci} is the critical volume of component i . Whereas, the components σ_{ij} and ϵ_{ij} are calculated using the following expressions;

$$\sigma_{ij} = \frac{\sigma_i + \sigma_j}{2}$$

$$\sigma_i = (2.3551 - 0.087 \omega_i) \left(\frac{T_{ci}}{P_{ci}} \right)^{1/3}$$

$$\epsilon_{ij} = \frac{1.06036}{T_{ij}^{0.1561}} + \frac{0.193}{\exp(0.47635 T_{ij})} + \frac{1.03587}{\exp(1.52996 T_{ij})} + \frac{1.7674}{\exp(3.89411 T_{ij})}$$

where ω is the acentric factor; T_{ci} and P_{ci} are the critical temperature and pressure, respectively. Finally, the diffusion coefficient of component i in a multicomponent mixture of phase k is calculated by;

$$D_{ik} = \frac{1 - y_{ik}}{\sum_{i \neq j} (y_{jk} / D_{ij})}$$

Similarly, Wilke-Chang proposed a diffusion coefficient based on a series of laboratory measurements for various hydrocarbon solvents and other systems in the literature (Christiansen and Haines, 1987). The mathematical expression is given below;

$$D_{ik} = \frac{7.4 \times 10^{-8} (M'_{ik})^{1/2} T}{\mu_k v_{bi}^{0.6}}$$

$$M'_{ik} = \frac{\sum_{j \neq i} y_{jk} M_j}{1 - y_{ik}}$$

where M'_{ik} is the molecular weight of the solvent; μ_k is the viscosity of phase k ; and v_{bi} is the partial molar volume of component i at the boiling point.

5.2. Minimum miscibility pressure

Minimum miscibility pressure (MMP) is the lowest pressure at which the interfacial tension (IFT) between the two fluids (oil and

injected solvent) vanishes completely after multiple contacts and both fluids become miscible. MMP is usually measured in the lab through multiple techniques including the sand-packed slim tube method (Rao, 1997), rising bubble method (Stalkup, 1987), and the vanishing IFT method (Zick, 1986). The presence of porous media is not a compulsory factor for the measurement of MMP and that is fine for the conventional reservoirs where the large pores phase behavior is not affected by confinement. However, measuring MMP with real confinement for the unconventional tight formation is a significant challenge and practically it is not yet well defined. Therefore, MMP measurement with good accuracy can be determined numerically through fluid-flow and thermodynamic phase-equilibrium principles.

Numerically, there are multiple approaches to calculate MMP including 1D compositional gas-oil fluid-flow slim tube simulation (Wang and Orr Jr, 1997), no-flow predetermined mixing technique using single or multiple connecting cells (Teklu et al., 2014), and the method of characteristics (Muther et al., 2022c). Teklu et al. (2014) investigated MMP for Bakken oil sample with CO₂ as the effects of capillary pressure, the change in critical-property on phase behavior, and the IFT in the thermodynamics in nano-pores. Table 12 presents the unconventional Bakken reservoir oil composition, gas composition, and other reservoir and fluid properties that were invested in the study. Fig. 16 presents the MMP results of 100% CO₂ gas injection in the Bakken oil sample for the pore radii of 4 and 20 nm with the reference of no confinement case.

Table 12
Bakken oil composition and EOS parameters – $T_{res} = 241$ °F (Teklu et al., 2014).

Components	Oil	T_c , °F	P_c , psi	ω	Binary interaction coefficients		
					CO ₂	C ₁	C ₂
CO ₂	—	87.60	1071	0.225	—	—	—
C ₁	0.367	–124.66	655.02	0.010	0.100	—	—
C ₂	0.148	89.97	721.99	0.102	0.130	0.0050	—
C ₃	0.093	205.97	615.76	0.152	0.135	0.0035	0.0031
C ₄	0.057	299.208	546.46	0.189	0.130	0.0035	0.0031
C ₅₋₆	0.064	415.479	461.29	0.268	0.125	0.0037	0.0031
C ₇₋₁₂	0.158	593.25	363.34	0.429	0.120	0.0033	0.0026
C ₁₃₋₂₁	0.073	872.10	249.61	0.720	0.120	0.0033	0.0026
C ₂₂₋₈₀	0.037	1384.5	190.12	1.015	0.120	0.0033	0.0026

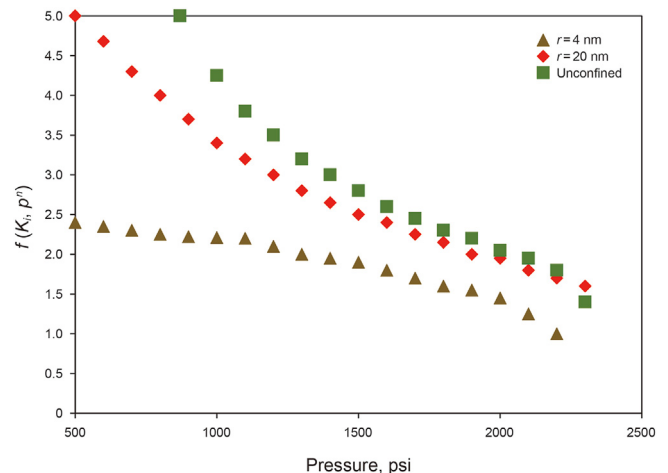


Fig. 16. The $f(K_i, p^i)$ vs. pressure for Bakken oil and 100% CO₂ injection gas at different pore radii (modified from Teklu et al., 2014).

$$f(K_i, P^n) = \min \left[\sqrt{\sum_{i=1}^{N_c} (1 - K_i)^2} \right]$$

where K is the equilibrium constant; P represents pressure; and N_c is the number of components in the above expression.

Compared with the unconfined case, the MMP for the Bakken oil reduced approximately by 130 psi for the 4 nm case in comparison to the unconfined case. As far as the 20 nm case is concerned, a similar MMP is noticed as the unconfined case (Muther et al., 2022a). Another study suggests that Ethane is a strong EOR solvent (MMP = 1343 psi) as compared to CO₂ (2523 psi) at 100 °C for the Bakken oil. Whereas, methane and nitrogen are having considerably high MMP of 4510 and 14,706 psi, respectively (O'Bryan and Bourgoyne, 1990).

5.3. Solubility

Solubility is defined as the ability of a solvent to dissolve in oil that directly influences oil recovery. Higher solubility factor causes oil swelling and oil viscosity reduction and both help oil to migrate from nano-pores to wellbore via fractures. The pressure-composition experiments are evident that CO₂ is the most likely soluble solvent in oil (Williams et al., 2004). However, methane and CO₂ both show high solubility but the CO₂ achieves a certain number solubility level at a much lesser pressure than methane need to achieve (Li and Luo, 2017). This effect can also be defined through the gas-oil ratio (GOR) for the oil-saturated with CO₂ as a function of pressure. Fig. 17 is a good example of measured GOR of live oil with different high-pressure solvents (Habibi et al., 2017b). It is noticeable that natural gas and enriched natural gas showed reasonable solubility and adding CO₂ into the system improved the solubility significantly at lower saturation pressure.

5.4. Oil swelling

Oil swelling due to dissolved high-pressure injection solvents is another important factor to highlight that generates a localized pressure gradient, which causes oil to migrate from pores to fractures. Therefore, solvents that cause more swelling of the reservoir oil are good candidates for the EOR. An excellent visual example of crude oil swelling due to dissolution of high-pressure CO₂ and Nitrogen injection is presented in Fig. 18 (Habibi et al., 2017a; Pereira et al., 2016; Li et al., 2019b). The oil volume increased significantly with CO₂ in comparison to nitrogen at the same elevated pressure observed after the same period.

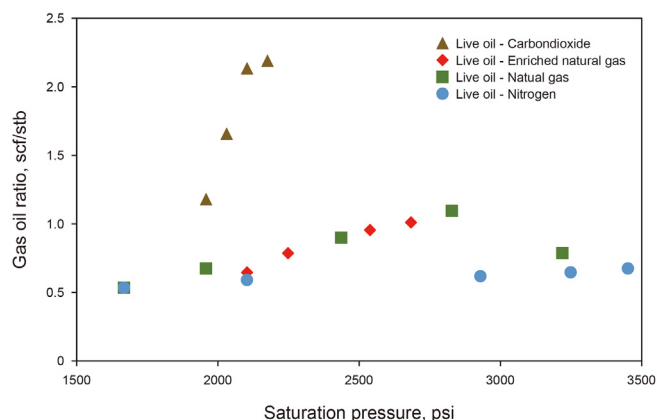


Fig. 17. Measured gas/oil ratios of live oil with different high-pressure gases (modified from Habibi et al., 2017b).

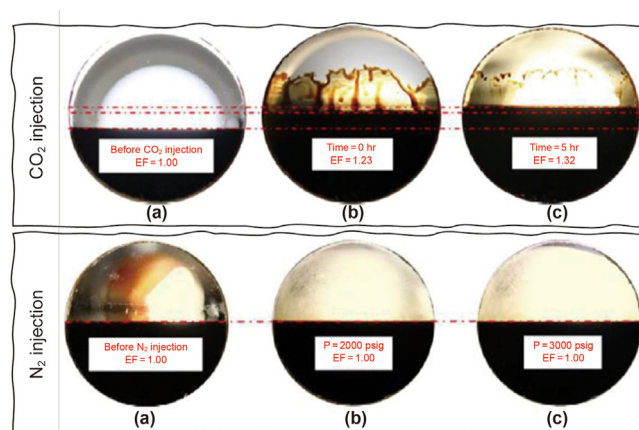


Fig. 18. Oil interface with CO₂ and N₂ injection at elevated pressure. (a) Only crude oil, (b) oil with injection solvents at elevated pressure, (c) oil with injection solvents at elevated pressure after 5 h (Habibi et al., 2017a).

5.5. Oil viscosity

Another important interaction parameter is the reduced oil viscosity as the result of high-pressure solvent dissolution into the crude oil. The reduced oil viscosity aids the oil in its displacement from the pores to fractures. This effect of viscosity reduction is more prevalent with CO₂ as compared to any other solvents. Fig. 19 is an excellent example of the effect of dissolved CO₂ and other solvents on the viscosity of a live oil sample taken from the Bakken formation (Zhao et al., 2015). It is clear from the figure that, as the saturation pressure increases, the viscosity of the crude oil and CO₂ mixture rapidly declines in comparison to other solvents.

5.6. Interfacial tension

Last but not the least, interfacial tension (IFT) reduction due to the dissolution of elevated pressure solvents into crude oil is a critical parameter that helps to improve oil recovery. The IFT reduction with increasing pressure is the most dramatic in the gas phase. Focusing on CO₂ injection, as the pressure increased, CO₂ invades into a less compressible liquid phase causing the decrease in IFT with an increase in pressure. However, the IFT plays a major role in conventional reservoirs but not in the unconventional oil reservoirs where the CO₂ is pushed into the pores primarily by diffusion processes (EIA, 2022).

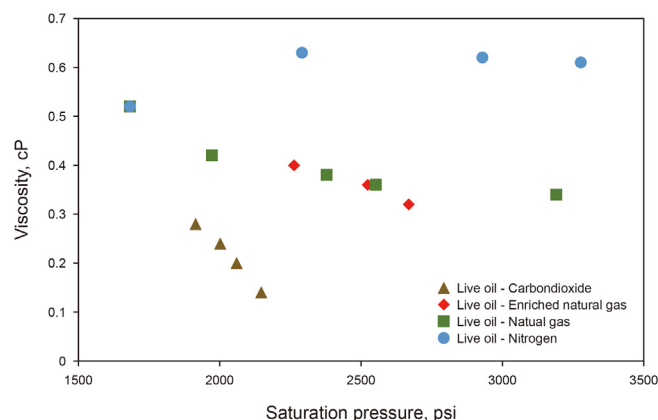


Fig. 19. Measured viscosities of live oil with different elevated pressure solvents (modified from Habibi et al., 2017b).

6. Discussion

Tight reservoirs are well-known hydrocarbon-bearing formations that have recently been under focus for unconventional oil and gas exploration in several countries. Specifically, tight oil is a liquid hydrocarbon resource found in ultra-low porosity and permeability rocks such as shale, siltstone, sandstone, and carbonate, which are mostly considered as the source rock. TORs are usually found in the depressions and slopes of basins, close to extensive, mature, and organic-rich source rocks. These are considerably large-scale reservoirs with nanoscale pore networks and the local sweet spots with easier oil production regions. The sweet spots in tight reservoirs are mainly recognized with the key features including the source type, lithology, reservoir quality, rock brittleness i.e. related to Young's modulus and Poisson's ratio, oil-bearing property, and the stress anisotropy. The United States is having the world's second-largest technically recoverable shale oil resources. Among seven different regions of the U.S., the South West region is having most of the tight oil resources. The main reservoirs in this region include Permian and Fort Worth Basins. Eagle Ford, Bakken, Wolf-Camp, and Niobrara are also major and well-known shale oil plays that are situated in South Texas, Montana and North Dakota, Midland Basin, and Denver, Colorado.

The tricky part while developing TORs is the sustainable hydrocarbon production that barely lasts from a few months to a couple of years without any external support because of their complex geology. Oil wells in almost all major tight oil plays including Eagle Ford, Bakken, Niobrara, etc. face the same problem of rapid production decline within the first year of their production life. On average, the daily production rate declines to half within a year, therefore EOR application along with the massive stimulation (hydraulic fracturing) on individual well bore is nowadays considered a compulsory factor for its development. In addition, because of limited inter-pore connectivity, TORs are mostly developed through an independent huff-n-puff process. In most of the numerical simulation and laboratory cases, it is observed in the literature that even though the ultimate oil recovery does not improve but the recovery significantly accelerates. It is important to note that even a single percent increase in EUR could result in extra million barrels of oil; therefore, even a single percent increase is significant while developing TORs.

For the huff-n-puff process, there are various factors to keep under consideration including the well and the hydraulic fracture design, selection of the injection solvent type, slug size, the soaking time, etc. Hydraulic fracture design parameters mainly include fracture half-length, height, and the number of stages as well as the number of clusters per stage. The fracture stress shadow is another important factor to keep in mind, especially while designing a hydraulic fracture numerically because it is unlikely to have all fractures operational in the actual field. Hydraulic fracture design optimization depends on the rock quality, its brittleness and rock stresses, etc. Usually, in TORs, the individual wells are designed with multiple stages and clusters depending on the targeted area of interest, the lateral length of the drilled horizontal well, and the neighboring wells. As far as the injection solvent type is concerned, CO₂ and the produced hydrocarbon gas are the most common choices because of poor injectivity. Due to ultra-low permeability of the formation rock, only highly volatile fluids i.e. gases can easily be injected and CO₂ being a greenhouse and the critical gas with lower minimum miscibility pressure is an ideal candidate that mainly depends on its economical availability. Fig. 20 presents the maximum availability of CO₂ and the multiple sources currently available in different regions of the United States. While the cost of CO₂ from natural sources is tied to the crude oil price while for the industrial sources of CO₂, the overall expenses cover the capturing,

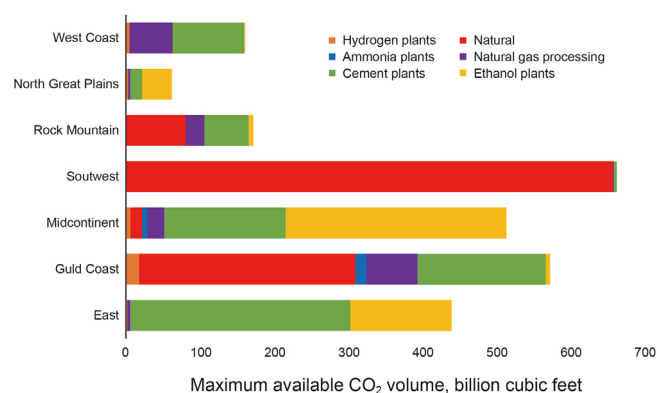


Fig. 20. Maximum availability and the sources of CO₂ from different regions of the United State as of March 2022.

Table 13

Overall average cost of CO₂ capture, compression, and transportation from various industrial sources (EIA, 2017).

CO ₂ industrial source	Average overall \$/million cubic feet of CO ₂
Hydrogen plants	7.8–22.2
Ammonia plants	2.9–3.0
Ethanol plants	2.3–5.4
Cement plants	6.5–15.7
Natural gas processing	2.1–4.0

compressing, and transportation cost. Table 13 summarizes the average overall cost of CO₂ per million cubic feet taken from different industrial sources.

There are several laboratory and field-scale EOR applications reported in the literature that were conducted with different injection solvents including miscible and immiscible gases, chemicals, low salinity water, carbonated and silk water, etc. Gas injection mainly helps to improve oil recovery through molecular diffusion, capillary pressure, wettability, *in-situ* fluid density, and viscosity reduction while chemical flooding targets the interfacial tension reduction and the wettability alteration. The low salinity water flooding improves oil recovery through clay swelling, shale mineral cracking, and wettability alteration. Similarly, the carbonated and silk water flooding aids oil recovery through *in-situ* oil swelling and the reduction in reservoir oil viscosity and interfacial tension.

Most of the laboratory scale research was conducted on core samples collected from the U.S. reservoirs including Eagle Ford, Mancos, Bakken, and Barnett through CO₂ injection under miscible and immiscible conditions. While the actual field EOR pilots were conducted with CO₂ and produced hydrocarbon gas in Bakken and Eagle Ford formations. The initial EOR pilots conducted in Bakken formation with CO₂ huff-n-puff showed limited oil recovery improvement while the later pilot in the same formation with water flooding followed by produced hydrocarbon gas injection wasn't found successful due to poor injectivity and early gas breakthrough in the neighboring well. Whereas the pilots conducted in Eagle Ford with produced hydrocarbon gas injection showed limited recovery improved with both gas flooding and cyclic gas injection.

7. Summary

In closing, the lessons learned from all the experiences discussed from lab to field-scale unconventional EOR studies are summarized below.

- Apart from hydraulically induced artificial hydraulic fracture networks, the EOR application is a must thing to develop an unconventional reservoir for fast-paced economical oil recovery.
- Depending on the original oil in place, a single percent increment in oil recovery through a single or multiple EOR applications on a tight oil reservoir could add up to several extra billion barrels of oil.
- The conversion of existing vertical wells into horizontal wells with maximum reservoir contact could add up a significant incremental oil recovery.
- CO₂ and produced hydrocarbon injection are proven successful EOR applications for decades in conventional oil reservoirs however, its success in unconventional reservoirs is so far inconclusive due to limited information availability of the actual field pilots.
- However, from the available field pilots, laboratory experiments, and numerical studies, CO₂ and produced HC gas with huff-n-puff operation managed to provide an extra couple of percent of incremental oil recovery.
- Along with EOR applications in SORs, hydraulic fracturing and re-fracking operation in multiple stages could further improve the oil recovery.
- Based on individual well operation, the huff-n-puff cycling EOR technique has also provided limited yet promising results in the field to improve oil recovery.
- There is a high risk in UEOR due to a lack of long-term production. In addition, the UEOR mostly does not increase the overall recovery but accelerates the production significantly.

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