Quest Journals
Journal of Software Engineering and Simulation
Volume 7 ~ Issue 11 (2021) pp: 01-07
ISSN(Online) :2321-3795 ISSN (Print):2321-3809
www.questjournals.org

Research Paper

A Comprehensive Analysis of Prospective Enhanced Oil Recovery (EOR) Mechanism in Shale Oil Reservoirs Simulation

TortorJ. Tom
Department of Petroleum and Gas Engineering, Faculty of Engineering,
Nigeria Maritime University, Okerenkoko, P.M.B. 1005, Delta State, Nigeria
johnbull.tortor@nmu.edu.ng

Abstract
Over the years, oil and gas production operation has moved to the exploitation of unconventional shale reservoirs due to a reduction in conventional oil reserves and also, the unfavourable volatile price in the international oil and gas market. Oil production from unconventional shale reservoirs due to the relatively low price experienced during the pandemic is a huge task. Ultimate recovery of shale oil resources is still low compared to conventional oil resources even though a lot of incredible efforts have been taken by industry players to develop the shale resources with relative productivity. Advanced production and stimulation strategies are been developed for the improvement of shale reservoir oil production due to the significant role shale resources will play in the future. However, the simulation approach has proven to be the most potentially low-cost technique to effectively assess shale oil reservoir enhanced oil recovery. Hence, the need to conduct proactive simulation researches and unearthing precise enhanced shale oil recovery for industry application cannot be overemphasized. Therefore, to effectively design field test laboratory demonstration and eventual field application, a computer-based simulation outcome is necessary to verify the laboratory results.
In this research, the simulation approach to appraising shale oil reservoir enhanced oil recovery is extensively reviewed. Key simulation parameters required to accurately model shale oil recovery succinctly evaluated. The study reveals that miscible gas injection as an enhanced shale oil recovery has higher possibilities for industry application. A minimum miscible pressurized gas injection can adequately influence gas-oil miscibility, thereby significantly reducing the oil viscosity for the expansive sweep and also, influencing the pressure maintenance mechanism in the reservoir. Thus, significant oil recovery factor enhancement by gas injection in a shale reservoir exists with high hydraulic fracture potentials.

Keywords*: Shale oil, Gas Injection, Simulation, Model, Enhanced oil Recovery, Hydraulic, fracturing,Mechanism.*

Received 18 October, 2021; Revised: 31 October, 2021; Accepted 02 November, 2021 © The author(s) 2021. Published with open access at www.questjournals.org

1 Introduction

Unconventional oil shale reservoirs all over the world are generally produced through well planned stimulation techniques that are mostly relevant to a given field. The most effective enhance oil recovery (EOR) techniques used and has proven to have better recovery in shale oil and gas production is the transverse multiple horizontal well fracture techniques due to its extensive penetration into the reservoir. Though, there are fewer challenges encountered in the shale gas production when compared with the shale oil production in field application. The ultimate shale oil recovery factors when current techniques such as multi-stage hydraulic fracture is used, could not yield extreme percentage of recoverable shale oil. However, shale reservoir pressure and oil flow-rate drop rapidly whatever technique used.

Most unconventional shale oil still remains unrecoverable even if combined with cost effective horizontal well drilling, and best hydraulic fracturing technique is used. This has resulted in multinational oil and gas producing companies always making continuous exertion to search for the best enhance shale oil recovery techniques. There are variety of simulation models approaches been proposed by industry experts and researchers. Both empirical, mechanistic and simulation studies have been carried out and some verifiable field studies has also been done. Thus, since the shale reservoir (EOR) is a complicated process, most proposed simulations, models and predictions are a combination of all categories of the aforementioned mechanism. In this paper, the main objective is to comprehensively provide review of literature concerning shale oil EOR mechanism and models on gas injection in shale reservoir EOR. Also, survey varioussimulation parameters that provide sound solution to efficient shale oil recovery.

2 Enhanced Shale Oil Recovery Mechanism

A wide range of secondary and tertiary enhance oil recovery techniques were applied to extract hydrocarbon from shale and heavy oil reservoirs over the years. However, the oil recovery outlook drastically changed by development of new technologies in the industry. Compared with in-situ recovery methods, water and gas injection techniques are some of the most general and commonly used methods that enable efficient shale oil production over time.

More so, beside the hydraulic fracturing stimulation and drilling horizontal wells through the reservoir as some of the shale oil recovery approach, a number of other enhance oil recovery mechanism have been either tried or offered to be tested in the shale industry, Wan *et al*, (2013) and Long *et al*, (2019).Roger Butler (1982), was the first to describe Steam-Assisted Gravity Drainage (SAGD) technique which includes drilling two parallel wells as one on top the other for heavy oil production, Cenk *etal* (2019). Chen*et al* (2013), sequentially investigate significance of reservoir heterogeneity on cyclic carbon dioxide (CO_2)injection into shale reservoirs as a recovery technique. Though the outcome shows promising results, however, the volume of shale oil recovered werenot extremelysignificant as expected. Researchers such as Gamali*et al*, *(2013),* has likewise proposed further, cyclic gas injection as a means of (EOR) in shale reservoirs rock formation. Apparently, there are no reported case of successful application of gas injection in oil shale reservoirs. However, Kovscek and Takahashi, (2009) reported a study on the impact of dissimilar brine formulations on tight reservoir formations with appreciable results. More recent case of viable options is the study of Makhanov*et al*, (2012) which investigate transfer of reservoir fracture fluids to the Canadian, Horn's River shale reservoir rock matrix, which may perhaps be a feasible imbibition mechanism for the shale industry.

The effects of water compositions which are (salinity, acid, and alkali) on EOR potential water imbibition was studied by Morsy*et al.* (2013) and Fakcharoenphol*et al.* (2013) suggested that due to increase in reservoir pressure and decrease in reservoir temperature, water flooding modifies the formation in-situ stresses by way of reactivating natural fractures and also, creating fresh fractures that enhance shale formations oil recovery. However, conventional water flooding in oil production is a secondary oil recovery technique that is already in existence in the industry, its commercial application has not been widely tested in shale oil and gas reservoirs, until lately. Yasi Shahzad, (2019), stated that, because of the ultra-low permeability of shale oil reservoirs, water or gas flooding may have significant concerns with fracture recovery fluid injection and recovery rate.

2.1 Analysis of Shale oil reservoir (EOR)Models

Rubin (2010) developed a very reasonably small grid model to imitate fracture flow in shale reservoir flow mechanism. Rubin assumed (0.001ft) small cells of actual width of fractures in other to get the flow from the matrix to the fractures in the model acknowledged. He also, shows that it is possible to accurately model and mimic reservoir flow pattern, using logarithm shale reservoir fracture spacing and locally refining grids symbolizing fractures by conservation of the same conductivity by 2.0ft-wide grid-cells compared to the (0.001ft) fractures initially assumed. However, by using the above approach, with modern technology, fracture associated reservoir flows can be stimulated with lesser grid-cells.

As shown in (Fig. 1) below, Wan (2013) deploy Rubin's method in other to build a prototype model at a measurement of (200ft length, 1000ft width, and 200ft thickness) in view of simulating horizontal well that contains a transverse fracture.

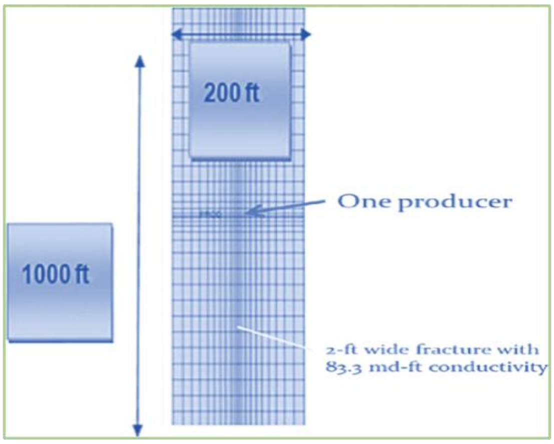

Fig.1. Reservoir Cyclic gas injection simulation model (Wan, 2013)

A2ft heterogenous grid cells with a conductivity of 83.3md/ft, permeability of 41.65md, and water flooding factor of 2ft were used as the bases for mimicking the definite fracture values of 0.001ft wide and 83.300md. Hence, the information of the reservoir properties as utilized by Wan (2013) as stated above, are with all respect similar to that found in the Eagle Ford shale data shown in Table 1 below.

Table 1: Base model reservoir properties (Wan, 2013)

Reservoir properties	Values	Units
Initial reservoir pressure	6425	*psi*
Porosity of shale matrix	0.06	-
Initial water saturation	0.3	-
Compressibility of shale	$5 \, x \, 10^{-6}$	Psi^{-1}
Shale matrix permeability	0.0001	mD
Reservoir temperature	255	^{0}F
Gas specific gravity	0.8	-
Reservoir thickness	200	ft
Oil bubble point	2398	*psi*

As can be seen from the (Table 1) above, the reservoir permeability is in nano-Darcy to the (100nD).This suggest that, irrespective of the variation of the other variables such as the initial reservoir pressure (6425 psi) and porosity (0.06),the model results will be considerable valid in most shale formation, with a 2500*psi*bottomholepressure(BHP) primary production value (Chen, 2013).

2.2 Miscible Displacement Performance simulation

A miscible displacement performance simulation technique was first adopted for enhance oil recovery by Todd and Longstaff in (1972) without consenting for fundamental configuration of the model sequence. In the model, an adjustment parameter symbolized as (X) that signifies the degree of mixing amid the miscible fluids within as relating to grid block of the model. A corresponding value of zero (0) represent miscible displacement, whereas a value of one (1) was selected to represent a corresponding complete mixing within the system. Solvent and oil mixing is controlled by a pressure-reliant mixing parameter in the (Omegaos) oil simulator denoted as (Xo). This procedure has been adopted by other researchers such as Rubin, (2010). Once a single pressure block is considerably reduced than the lowest pressure of miscibility (LPM), (Xo) is regarded as equal to (0.0). Thus, gas is said to be the causative factor for the oil immiscibility movement in the system. Subsequent incrementation of the block pressure also means gradual incrementation of the mixing parameter until the mixing parameter will attain a maximum (Wo_{max})value as shown in (Fig. 2) below.

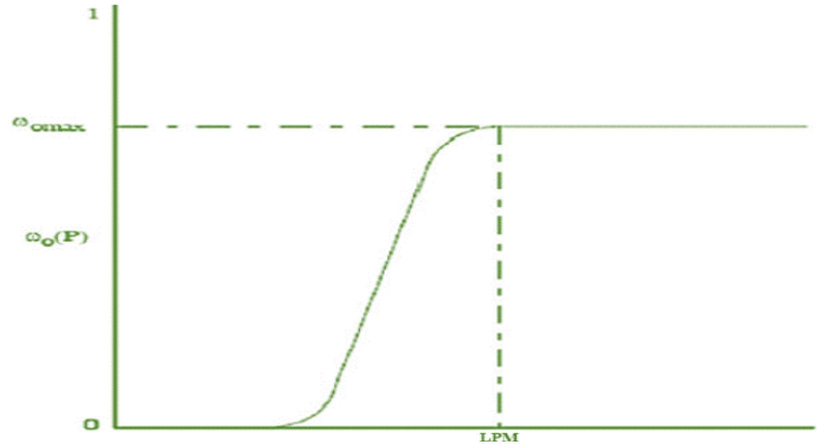

Fig.2. $\dot{\omega}_{omax}$ *. X versus pressure (Yasir, 2020)*

However, in a situation that there are no available data, most miscible displacement performance simulator such as (IMEX), suggest initial base estimate values ranging from 0.5 to 0.8 (Raffa, 2016), (Bo, 2003) and (de Loubens, 2018). Most black oil recovery simulator such as (IMEX) accepts 4-component, three phase process for the miscible flooding simulation. The acceptable three phases include:

- Water phase
- Oil phase and
- Gas phase

These comprises injected gas in addition with dissolved gas in the free gas phase. While the 4-component includes oil, water, dissolved gas and injected gas solvent that is required. Though, it is worthy to note that both the novel gas and the gas dissolved that is injected into the formation has analogous (similar) chemical properties (Jingfu, 2017). Oil compressibility factor is given as $(1 \times 10^5 psi^{-1}$, while specific gravity is approximately 0.8, (Liu, 2018) in such cases. Free gas – solvent mixing can be controlled in the simulator and it is assumed to be independent of the shale reservoir formation pressure (Han, 2007).

2.3 The Cartesian Shale Oil Recovery Simulation Models

Sustainable shale reservoir development, and reliable improvement of shale oil recovery has become a novel challenge due to the growing interest for shale oil production shown by majoroperators (Yang *et al*, 2016). Thus, in order to maximize shall oil production, *Yuan et al.* (2016), posited that there is need for a combined approach in other to efficiently evaluatefracturing stimulation for predicting shale well productivity performance where ultimate recovery can be realized (Zhu, 2015).Consequently, Yang *et al*, (2016) conduct a laboratory experiment to perform a gas injection in shale plugs and develop a three (3) dimension(3-D) cartesian shale reservoir oil recovery simulation model using flooding, Huff-n-Puff processes for shale oil ultimate recovery. The 3-D cartesian discretized grid blocks domain mimicking a shale matrix of$[33 \times 1 \times 10]$ grid block and$[4 \times 1.5 \times 1.5]$inch dimension is as shown in (Fig. 3) below.

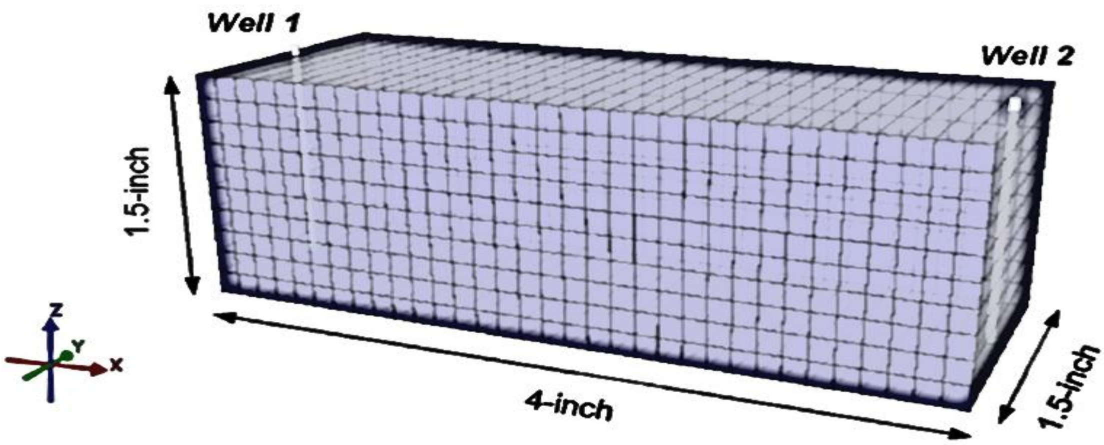

Fig.3. A 3-D Cartesian reservoir simulation model (Y.Yu et al., 2016)

From the above model, Well-1 and Well-2 are constructed at the two vertical extreme ends of the reservoir to carry out the gas injection and shale oil recovery (flooding, and huff-n-puff processes). Well-1 is used as the gas injection well for the process of flooding at the X-cartesian direction while Well-2 plays the role ofproduction well. Gas injection was done Continuously from Well-1 for the whole duration of the operation. However, for the huff-n-puff process of recovery, both wells (Well-1 and Well-2) are designed as injector wells for gas injection into the reservoir formation at the same time. In attaining the desired injection pressure, both Well-1 and Well-2 are shut-in for a period known as the soaking-phase (Y. Yu *et al*, 2017). The wells are reopened for production of the recovered oil once the designated soaking period elapse. This is referred to as one cycle of the huff-n-puff operation and it is repeated throughout the duration of the shale oil recovery operation as shown in Table 2 below.

Table 2. Reservoir recovery conditions with reservoir properties (Y.Yu et al, 2016)

Property	Value	Units
Gas injection pressure. Pin	1000	*psi*
Production pressure, Pout	14	*psi*
Shale matrix permeability	400	nD
Shale matrix porosity	9.70%	fraction
Initial oil saturation	100%	fraction
Initial core pressure	14	*psi*
Reservoir temperature	72	^{0}F
Shale compressibility	$5\ x\ 10^{-6}$	psi^{-1}
Injected gas	N_2	N/A
operation period	3	days

Table 2above shows the reservoir properties as well as the recovery conditions used in the Y.Yu*et al.*, (2016) base model, indicating a 1000psi gas injection pressure and 4000nanoDarcy reservoir matrix permeability. All other reservoir shale matrix properties such as absolute permeability, oil saturation, porosity, compressibility, reservoir temperature, etc., are assumed to be homogeneously distributed.

3 Review of Key Simulation Parameters

Simulation parameters enable researchers analysequantitatively the influence of such parameters in the modelling process. It is required to ascertain the significant parameters which could affect the productivity performance of shale oil reservoirs (James, 2014). Thus, some of the key parameters are evaluated below.

3.1 Fracture half-length

Fracture half-length as a simulation parameter enable the determination of gas flooding production performance. Yasir (2020), demonstrated the effect of fracture half-length in flooding production with a 365ft, and 245ft fracture half-length as comparison for the gas flooding production operation. The simulation result presents a rapid decrease in the reservoir pressure in cases where longer fracture half-length are assumed to be the primary production retro. However, a longer fracture length has advanced drainage volume of the reservoir fluid, which tend to create consistentlyprogressiveoil production and the gas injection methodwill have a good result in sustaining the reservoir pressure over a long period (Qiong*et al*, 2020).In order words, this sustained reservoir pressure could result to high cumulative shale oil production with a high recovery factor over a period of time.

3.2 The Flowing Bottom-Hole Pressure

Another sensitive parameter to consider is the flowing bottom-hole pressure (FBHP). In other to perform a gas flooding process for a simulation, there is need for one to assume a system where pressure is kept constantly high in other to ensure a single phase exist in the reservoir during the gas flooding process (Chen *et al*, 2013). Thus, different pressure range can be tested in order to ascertain which of the pressure range can yield the most desired result of high productivity index (PI) for a given shale formation.However,during primary production period, a lower FBHP can give a higher oil recovery factor and a higher flowrate can be obtained (Yasir, 2020).

3.3 Shale Matrix Permeability

Also, shale matrix permeability plays a key role in the shale oil recovery simulation. Yasir, (2020) demonstrated the importance of matrix permeability with regards to shale oil recovery factor. See (Fig. 4) below.

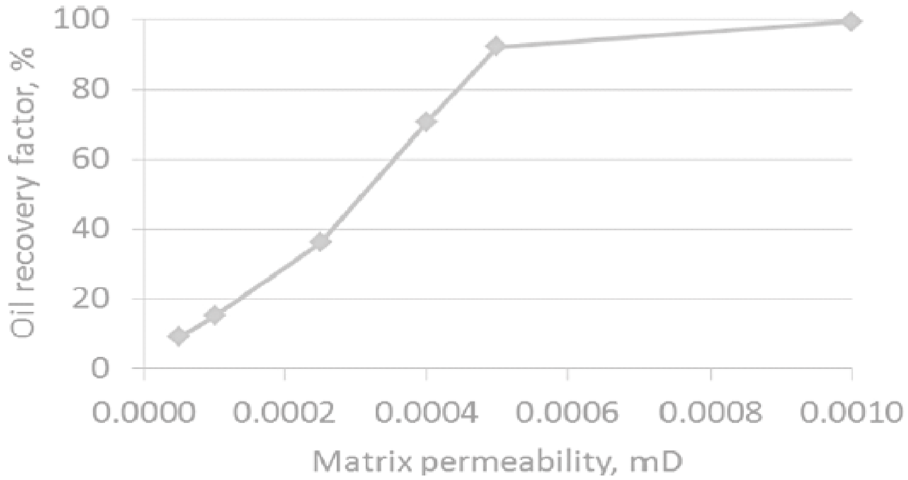

Fig. 4. Oil recovery factor versus matrix permeability (Yasir, 2020)

As can be seen from the above (Fig.4), there is a huge sensitivity between shale oil recovery factor and the shale matrix permeability which shows a linear upward progression. Thus, a higher permeability of the matrix will result to improved hydraulic conductivity in the reservoir, which in turn result to an advanced proportional flowrate and higher cumulative shale oil production for a greater investment return.

4 Conclusion and Scope for Future Research

In this study, different enhance shale oil recovery simulation model, parameters and processes were discussed in detail. Several model approaches developed by different researchers were presented. From the reviewed investigations it is concluded that enhanced shale oil recovery is affected by several parameters and factors. Therefore, there is scope for further development on shale oil enhance recovery simulation as enumerated below:

- ❖ Matrix permeability is observed as a key causative factor for the low shale reservoir oil recovery. This point is widely noted by several authors on the literature reviewed, hence, should be considered critical in developing shale oil recovery simulation model.

- ❖ Fracture spacing is also considered significant on shale reservoir oil production. It is principal in terms of high initial production rate and a good miscible gas flooding sweep effectiveness.

- ❖ It isalso observed that the fundamental mechanism for gas injection into shale oil reservoir enhance recovery is the pressure maintenance within the reservoir. This is due to the ultra-low permeability of shale reservoirs, which means that injected gas can only be miscible within oil at the fractured portion of the reservoir.

- ❖ Due to the ultra-low permeability of shale reservoirs, simulation results from literatures showed low injectivity and low productivity connection without conclusive investigation on water-shale rock interface that can ultimately improve the poor shale reservoir waterflooding behaviour. More research still needs to be done in this regard.

- ❖ Gas injection is still observed to be the most viable option for shale reservoir enhance oil recovery and improved shale oil production.

- ❖ Consequential analysis of gas flooding, water flooding and primary production in shale reservoirs still need to be critically evaluated. This will enable operators assess the best method that will be effective for field application in order to maximize shale oil and gas production.

Nomenclature

EOR	Enhanced Oil Recovery
SAGD	Steam-Assisted Gravity Drainage
CO_2	Carbon dioxide
BHP	Bottomhole pressure
FBHP	Flowing bottom-hole pressure
PI	Productivity index
LPM	Lowest pressure of miscibility

References

[1]. Long Yu, Jinjiang, Chong Wang, andDaixin Chen (2019): Enhanced Tight Oil Recovery by Volume Fracturing in Chang 7 Reservoir: Experimental Study and Field Practice,Published: 24 June2019, energies.

[2]. Boysen, D.B., Boysen, J.A., Boysen, J.E., 2002. Creative strategies for produced water disposal in the Rocky Mountain Region. In: Ninth Annual International Petroleum EnvironmentalConference, Albuquerque, NM, October 22–25,2002. Availableat:http://ipec.utulsa.edu/Conf2002/boysen89.pdf (accessed 10 June, 2020).

[3]. Chen, C., Balhoff, B., Mohanty, K.K., 2013. Effect of reservoir heterogeneity on improved shale oil recovery by CO2 Huff-n-Puff, SPE164553-MS, presented at2013 SPE Unconventional Resources Conference, Woodlands, Texas, USA, April 10–12.

[4]. Dahm, K.G., Guerra, K.L., Xu, P., Drewes, J.E., 2011. A composite geochemical database for coalbed methane produced water quality in the Rocky Mountain Region. Environ. Sci. Technol. 45 (18), 7655–7663.

[5]. DNRC, Montana Online Oil and Gas Information System, Montana Department of NaturalResourcesandConservation 2010.Available at: http://bogc.dnrc.state.mt.us/jdpintro.asp(accessed 07.12.10).

[6]. Dong, Z., Holditch, S.A., McVay, D.A., Ayers, W.B., 2012. Global unconventional gas resource assessment. SPE Economics & Management Journal, 222–234.

[7]. GWI, 2011. Produced water market: Opportunities in the oil, shale and gas sectors in North America. Global Water Intelligence (March 17).

[8]. Makhanov K., Dehghanpour H., and Kuru E. 2012. An experimental study of spontaneous imbibition in Horn River shales. SPE-162650-MS presented at SPE Canadian Unconventional Resources Conference, Calgary, Alberta, Canada, October 30–November 1.

[9]. Morsy, S., Sheng, J.J., Soliman, M.Y. 2013b. Improving hydraulic fracturing of shale formations by acidizing, paper SPE 165688 presented at the SPE Eastern Regional Meeting held in Pittsburgh, Pennsylvania, USA, August 20–22.

[10]. Morsy, S., Sheng, J.J., Hetherington, C.J., Soliman, M.Y., Ezewu, R.O. 2013d. Impact of matrix acidizing on shale formations, paper SPE 167568 presented at the Nigeria Annual International Conference and Exhibition held in Lagos, Nigeria, August 5–7.

[11]. Rubin, B. 2010. Accurate simulation of non-Darcy flow in stimulated fractured shale reservoirs, paper SPE 132093 presented at the SPE Western Regional Meeting, Anaheim, California, May 27–29.

[12]. Todd, M.R., Longstaff, W.J., 1972. The Development, testing, and application of a numerical simulator for predicting miscible flood performance. J. Pet. Technol. 24 (7), 874–882.

[13]. Wan, T., Sheng, J.J., and Soliman, M.Y. 2013a. Evaluation of the EOR potential in shale oil reservoirs by cyclic gas injection, paper SPWLA-D-12-00119 presented at the SPWLA 54th Annual Logging Symposium held in New Orleans, Louisiana, June 22- 26.

[14]. Wood, T., Milne, B. 2011. Waterflood potential could unlock billions of barrels: crescentpointenergy.http://www.investorvillage.com/uploads 44821/files/CPGdundee.pdf(accessed June 10, 2020).

[15]. Bo, Q.; Zhong, T.; Liu, Q. Pore Scale NetworkModelingofRelative permeabilityinChemicalflooding.In Proceedings of the SPE International Improved OilRecoveryConference in AsiaPacific, Kuala Lumpur,Malaysia, 20–21 October 2003.

[16]. de Loubens, R.; Vaillant, G.; Regaieg, M.; Yang, J.; Moncorgé, A.; Fabbri, C.; Darche, G. Numerical Modelingof UnstableWaterfloods and Tertiary Polymer Floods into HighlyViscous Oils. SPE J. **2018**, 23, 1909–1928.

[17]. Guo, Y.; Zhang, L.; Zhu, G.; Yao, J.; Sun, H.; Song,W.; Yang, Y.; Zhao, J. A Pore-ScaleInvestigation of ResidualOil Distributions and Enhanced Oil Recovery Methods. Energies**2019**, 12, 3732.

[18]. Jingfu, D.; Yunpeng, L.; Xiaofei, J.; Xiaohui, W.; Bin, L. Dynamic Inverting Method for theRelative PermeabilityCurves in the Stable Polymer Flooding and Its Application. Pet. Geol.Oilfield Dev. Daqing **2017**, 36, 106–109.

[19]. Bingyan, H.; Xu, C.; Gen, K.; Qiong, L.; Yong, L.; Ke, A. Inverse of parameters of core polymer flooding using iterative ensemble Kalman filter. Prog. Geophys. **2018**, 33, 23302335.

[20]. Liu, Y.; Hou, J.; Liu, L.; Zhou, K.; Zhang, Y.; Dai, T.; Guo, L.; Cao, W. An Inversion Method of Relative Permeability Curves in Polymer Flooding Considering Physical Properties of Polymer. SPE J. **2018**, 23,1929–1943.

[21]. Jin, M. A Study of Nonaqueous Phase Liquid Characterization and Surfactant Remediation. Ph.D. Thesis, The University of Texas at Austin, Austin, TX, USA, 1995.

[22]. Majid Ali Abbasi, Daniel Obinna Ezulike, Hassan Dehghanpour, Robert V. Hawkes. A Comparative Study of Flowback Rate and Pressure Transient Behavior in Multi-fractured Horizontal Wells Completed in Tight Gas and Oil Reservoirs. *Journal of Natural Gas Science and Engineering***17**, 82–93 (2014).

[23]. Hawthorne, S. B. *et al*. Measured Crude Oil MMPs with Pure and Mixed CO2, Methane, and Ethane, and Their Relevance to Enhanced Oil Recovery from Middle Bakken and Bakken Shales. Presented at the SPE Unconventional Resources Conference, Calgary, Alberta, Canada. 15-16 February. SPE-185072-MS (2017).
[24]. Whitson, C. H. & Brulé, M. R. *Phase Behavior*. (Henry L. Doherty Memorial Fund of AIME, Society of Petroleum Engineers Inc., 2000).