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Scaling for Wettability Alteration Induced by the Addition of Surfactants in Completion Fluids: Surfactant Selection for Optimum Performance

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Abstract

Experimental laboratory evidence of enhanced production by spontaneous imbibition via the addition of surfactants into completion fluids, as well as field observations, indicate a significant improvement in EUR with the use of surfactants to improve oil recovery from unconventional liquid reservoirs (ULR). During a hydraulic fracture treatment, the surfactant molecules interact with the rock surface, altering its wettability and interfacial tension. The wettability alteration of the rock surface from oil-wet to water-wet enables the spontaneous imbibition of water into the matrix, which expels the oil out of the pore space towards the fractures. Several laboratory and numerical studies have investigated the effectiveness of surfactant-assisted spontaneous imbibition (SASI) on various ULR. However, the understanding of surfactant selection for the optimization of enhancing recovery in ULR is not well studied.

Capillary pressure is the dominant force for spontaneous imbibition process. Contact angle (CA) and interfacial tension (IFT) are essential terms in the Young-Laplace capillary pressure equation as well as in published scaling analysis of the spontaneous imbibition process. With the large amount of data released on SASI, it is natural to develop a correlation between the two properties to the recovery factor. However, no work has been conducted to investigate the relationship of contact angle and IFT on ultimate recovery by spontaneous imbibition in ULR. In this manuscript, a compilation of CA, IFT, and spontaneous imbibition experiments from two of the most prolific shale reservoirs is presented to give an insight into the relationship between the three variables. Then, based on the observed trends and correlations, a new scaling model for SASI in ULR is proposed. The ultimate goal is to develop a surfactant selection method based on scaling analysis results and laboratory data for optimal performance in ULR.

A total of 35 independent SASI correlated experiments data were compiled, which includes CA, IFT, recovery factor, porosity, core plug dimensions, and capillary pressure calculated from the Young-Laplace equation. Experimental procedure on each data point followed the robust data gathering methodology that was already developed for the past four years. The reliable procedure ensures the representability of the reservoir condition in the laboratory measurements to provide an accurate description of the effectivity of different surfactants on a corresponding oil/water/rock system. Two systems were analyzed and assembled into three groups, Wolfcamp, Eagle Ford A, and Eagle Ford B. An inversely proportional correlation between CA and recovery factor was observed, while on the IFT and recovery factor analysis, a less apparent correlation was found. Theoretically, a directly proportional correlation between capillary pressure and recovery factor can be expected due to spontaneous imbibition that is primarily dominated by capillary forces, which is consistent with experimental data analysis. The high dependence of recovery factor on contact angle and the less significant effects from IFT lead us to conclude that a substantial wettability altering surfactant is highly preferred to enhance through SASI. In addition, based on the observed correlation, a new dimensionless scaling equation fully accounting for the effect of surfactant addition was developed to generalize the flow behavior of SASI.

Introduction

The significant volume of production from unconventional shale reservoirs has made the United States one of the world's top oil producer in the last five year (Zhang et al. 2018b). Multistage hydraulic fracturing treatment determines the success in developing ULR and also a necessity due to the low porosity and ultra-low permeability that characterizes shale reservoirs (An et al. 2017; Parsegov et al. 2018a). Hydraulic fractures interaction with naturally occurring fractures generates fracture networks, providing sufficient flow paths for hydrocarbons to be produced from the shale reservoirs (Kou et al. 2018; Liu and Valkó 2017; Parsegov et al. 2018b). The Permian Basin and the Eagle Ford are two of the most productive shale plays in the United States. Oil production of the Permian Basin has increased to more than 2.5 million barrels per day, whereas the Eagle Ford has increased its oil production above 1.2 million barrels per day (EIA 2017). However, the recovery factor for these shale reservoirs is usually less than 10% of the original oil in place (Alvarez and Schechter 2017). Methods of improving the production of oil from shale plays are being explored to enhance these low recovery factors (Adel et al. 2018a; Zou and Schechter 2017). Gas injection, where miscibility plays a significant factor (Adel et al. 2016), as well the addition of surfactant into completion fluid are two of the most widely implemented EOR methods (Adel et al. 2018b; Zhang et al. 2018a).

The addition of surfactants into completion fluids is being successfully used as an EOR method in ULR. Improvements in recovery factors have been demonstrated in several laboratory studies (Alvarez et al. 2014) on both the Permian Basin and Eagle Ford reservoirs. The effectiveness of fracture treatments in increasing recovery can be efficiently improved if proper surfactants are added to completion fluids, thereby altering wettability and IFT, and consequently promoting water imbibition. This study systematically evaluates the ability of surfactants to change the wettability, the IFT, and to improve the ultimate oil recovery in unconventional shales by a correlated set of laboratory experiments. Thereby, we propose a surfactant selection method for optimum performance in ULR.

In petroleum systems, wettability is defined as the affinity of either water or oil to spread onto a rock surface. The fluid that has higher affinity to the rock is then called the wetting phase, and the non-wetting phase is the other fluid (Anderson 1986). Surfactant molecules act as a bridge between water and oil phases present in the pore system, and the two parts of the molecule (called head and tail) have different affinities for the aqueous and oleic phases. The head part of the surfactant molecule is hydrophilic, which has a higher affinity towards the aqueous phase. Whereas, the tail part of the surfactant molecule is hydrophobic, and therefore has a higher affinity to oil molecule. Amphiphilic surfactant molecules lead to a decrease in the water-oil interfacial tension. In addition, proper surfactant molecules have the ability to alter the wettability of the rock surface from oil-wet to water-wet, resulting in the spontaneous imbibition of water into the pores. Spontaneous imbibition is mainly dependent on the capillary forces, which is defined by Young-Laplace equation. Capillary forces are significant and complex in shale nanopores as contact angle and IFT change simultaneously. The extent and magnitude of wettability and IFT alteration are rigorously evaluated to understand the performance of surfactants in enhancing oil recovery in ULR.

Complete and systematic laboratory workflows were established to evaluate surfactant related properties on performance in spontaneous imbibition (Alvarez et al. 2017b). The contact angle measurement is the preferred method to determine the wettability of the rock on shale rock. Due to the limitation of injectivity into shale cores, saturation, re-saturation and classic techniques such as the Amott or USBM techniques are not suitable for ULR. Thus we measure the static contact angle of crude on aged shale sample surface which has been extensively reported as the quantitative determination of wettability. Interfacial tension of oil and water is defined as the control variable of the magnitude of the capillary driving force. Measurement of IFT can be performed by different methods, such as spinning drop method, sessile drop method, and pendant drop method. For the laboratory workflow constructed by Alvarez, pendant drop method was selected as the method of measurement as it works accurately in determining IFT in the range of IFT found on all surfactant system tested.

The existing surfactant selection methods are mostly dependent on the IFT value or the charge type of the surfactant's head group. Lower IFT leads to better field performance due to the large imbibition rate in low IFT compared to high IFT systems (Li and Horne 2002). In addition, field tests reveal that low IFT can effectively improve oil recovery in conventional reservoirs. Cationic surfactants or a mixture of cationic and nonionic surfactants have the best performance on enhancing oil recovery in carbonate reservoirs, and anionic surfactants are most effective EOR agents in sandstone reservoirs (Negin et al. 2017). Similarly to other types of recovery enhancement, surfactant EOR method in conventional reservoirs might not work in unconventional shale reservoirs since the characteristics of these two types of reservoirs is entirely different. Conventional surfactant flooding is deemed inapplicable in unconventional reservoirs since injection process into a shale reservoir is strictly impossible due to the ultra-tight nature of the rock. A new selection criterion for the evaluation of surfactant performance in enhancing oil production from shale reservoir needs to be thoroughly studied due to the insufficient number of publications on the surfactant screening in ULR.

Spontaneous imbibition scaling model studied since the 1960's, Mattax and Kyte (1962) initially proposed a dimensionless group that can be used to scale imbibition. The original scaling analysis was intended for understanding the rate of matrix-fracture transfer for a rising water level in a fracture-matrix system with variable matrix block sizes. Schechter and co-workers performed extensive imbibition experiments from reservoir rocks in the naturally fractured Spraberry Trend Area at reservoir conditions (Putra et al. 1997, 1999; Putra and Schechter 1999). The use of imbibition

experiments, both static and dynamic, were utilized to scale lab imbibition rates in order to design water injection rates for individual injection wells in this fractured reservoir. The idea was that there exists a critical injection rate at which capillary forces in the matrix were balanced with the viscous forces in the fractures so that water would soak in the matrix via spontaneous imbibition at approximately the rate at which water was injected. This would reduce water production cycled through the fractures yet maximize injection rate so imbibition could produce at its' maximum natural rate.
Ma et al. (1995) proposed the scaling approach by considering the geometry of the core samples, boundary conditions, and fluid viscosities, which defined as Eq.1, where t is the time of imbibition, k is permeability, ϕ is porosity respectively, σ is IFT, L_c is characteristic length, and μ_w and μ_o are water and oil viscosities. The characteristic length is generally used in spontaneous imbibition models to handle the effect of core geometries. Fischer et al. (2008) investigated various flow regimes and shape of samples for spontaneous imbibition, providing a method to calculate the characteristic length for scaling analysis.

$$t_D = t\sqrt{\frac{k}{\emptyset}}\frac{\sigma}{\sqrt{\mu_o\mu_w}}\frac{1}{{L_c}^2} \text{ ……………………… (1)}$$

Gupta and Civan (1994) introduced the wettability term into Ma's model via the contact angle. The scaling model proposed as Eq. 2, where θ is contact angle. Contact angle and IFT are the two dominant parameters in capillary force from the Young-Laplace equation. The mechanism of surfactant-assited spontaneous imbibition is wettability alteration and IFT reduction. In this study, we focus on spontaneous imbibition by wettability and IFT alteration to enhance oil recovery in ULR. The Gupta's scaling model is fitting our reserch objectives. Therefore, we propose a new scaling model for unconvention rock by modifying Eq.2.

$$t_D = t\sqrt{\frac{k}{\emptyset}}\frac{\sigma\cos\theta}{\sqrt{\mu_o\mu_w}}\frac{1}{{L_c}^2} \text{ ………………………..… (2)}$$

Li and Horne (2002) defined a generalized scaling approach for spontaneous imbibition; their model considered almost all the parameters that dominant spontaneous imbibition. This scaling approach includes relative permeability, mobility, and capillary pressure term, which is shown as Eq. 3, where c is a constant value for the ratio of the gravity force to the capillary force; k_{re}^* is the relative permeability pseudofunction of the two phases at S_{wf}; P_c^* is capillary pressure at S_{wf}; S_{wi} is the initial water saturation, and $\mu_e$is the effective viscosity of the two phases. proposed models to The capillary pressure and relative permeability for spontaneous imbibition can be estimated by the models proposed by (Deng and King 2015, 2018).
This model has been validated under the conventional rock system. However, it cannot be easily applied to unconventional rock system due to the limitation of measuring capillary and relative permeability in ULR.

$$t_D = c^2\frac{kk_{re}^*}{\phi}\frac{P_c^*}{\mu_e}\frac{S_{wf}-S_{wi}}{L_c^2}t \text{………………………..… (3)}$$

This study is intended to develop a reliable method for surfactant selection which was based on the analysis of the performance of surfactants in enhancing oil production in ULR. In addition, a new general scaling model for Surfactant-Assisted Spontaneous Imbibition (SASI) is proposed that incorporates all observed correlations from experimental data analysis. Interfacial tension, contact angle, and oil recovery of spontaneous imbibition from previously published experimental data were compiled and analyzed. The analysis was conducted systematically on the correlations of all available properties of the experimental measurements to the recovery factor. It is expected to shed some light on the mechanism of which SASI is based on. The new scaling group can also be used to provide an approximation of the field-scale analysis of the SASI efficacy as its based on upscaling the laboratory-scale experimental results.

Methodology

This project aimed at studying the potential of various surfactants in enhancing oil recovery from the Permian Basin and Eagle Ford cores. Thereby, proposing a reliable surfactant selection method and a spontaneous imbibition scaling model in ULR. Laboratory evaluations were performed on the core plugs as well as the oil sample from the same field. Correlated experiments were designed to investigate the complex rock-fluid interaction.

Experimental Data Gathering

Contact angle, oil-water interfacial tension, and oil production curve from spontaneous imbibition correlated experiments are the three essential data that were analyzed in this study for both the surfactant selection process and dimensionless time analysis. Most studies on the subject of surfactant addition to shale oil reservoir incorporate those three data measurements due to their ability to represent the effect of surfactant addition and the relatively uncomplicated procedure to measure them. As mentioned earlier, capillary pressure is the primary driving force of production enhancement from the Addition of surfactants. Wettability and interfacial tension directly control the capillary pressure as shown by the Young-Laplace equation, validating the importance of measuring the two properties.

This study compiled all experimental data that have been published previously (Alvarez et al. 2017a; Alvarez et al. 2017b; Alvarez and Schechter 2015; Alvarez and Schechter 2017; Saputra and Schechter 2018; Zhang et al. 2018b), and is still highly critical to understand the methodology or the basic concept of the measurement. Contact angle data shown in this study were measured by utilizing the captive bubble method. Rock chips retrieved from sidewall cores of each corresponding well were aged first in their corresponding oil to return the properties of the rock surface to its original reservoir conditions. Surfactant solutions were prepared and heated to bring the system temperature to the reservoir temperature. Aged rock chips were positioned on a stage, submerged in the surfactant solution. A J-shaped needle was utilized to dispense as well as position oil bubble to the bottom-facing surface of the rock chip. Image of the bubble was recorded to calculate an approximation of the contact angle value of the bubble by built-in software.

Interfacial tension of oil and water was measured through a procedure based on a modified version of pendant drop method. Oil as dispensed upward through a J-shaped needle, submerged in the surfactant solution. Interfacial tension was calculated by measuring the volume of oil bubble forming at the tip of the needle with the addition of density data of both oleic- and aqueous-phase as input data. Volume measurement was conducted by capturing the image of the oil bubble and submitting the image to built-in software that has the capability of volume approximation. It is also critical to state that the volume measurement must be performed on the largest possible bubble volume or the point of where formed oil bubble almost detaches from the needle.

Spontaneous imbibition experiments were selected as the ultimate tests of the surfactant performance in enhancing production from the shale oil reservoir. In this test, core plugs obtained from the sidewall cores were aged in their corresponding oil for a minimum period of three months. The aging process is necessary to restore the wettability condition of the rock surface as well as the oil saturation of the core plug. A surfactant solution is prepared by mixing distilled water with 4 wt% of KI and surfactant on its respective concentration. Aged core plugs are then submerged in the surfactant solution in a modified Amott Cell with the temperature controlled by placing the whole set-up in an oven set to reservoir temperature. Oil production from each experiment was monitored for ten days. In addition, all spontaneous imbibition experiments were scanned using the CT-Scan to visualize the fluid movement inside the core plug. However, the scan results are not presented in this study.

Capillary Pressure

Spontaneous imbibition via the addition of surfactant into the completion fluid can improve oil recovery from ULR by wettability alteration and IFT reduction. Spontaneous imbibition is primarily dominated by capillary forces which defined by Young-Laplace equation (Eq. 4) relating capillary forces with contact angle, IFT, and pore radius. Since surfactant affects capillary pressure and spontaneous imbibition is driven by capillary force, it is essential to study the correlation between capillary forces and ultimate oil recovery.

$$P_c = \frac{2\sigma \cos\theta}{r} \text{ .... (4)}$$

Due to the limitation of measuring pore radius of shale cores, we cannot calculate capillary pressure from Young-Laplace equation directly. Leverett (1939) defined pore radius regarding permeability and porosity. The capillary forced equation can be presented as Eq. 5 by considering Leverett radius.

$$P_c = \frac{2\sigma \cos\theta}{\sqrt{\frac{k}{\emptyset}}} \text{ .... (5)}$$

Spontaneous Imbibition Scaling Model in ULR

Contact angle and interfacial tension are the most critical parameters for spontaneous imbibition in ULR. The existing scaling groups failed to generalized capture the imbibition behavior of shale rock. To improve scaling approach and consistency of the correlations for spontaneous imbibition data in ULR, we proposed a new imbibition model by modifying Gupta's model (Eq. 2) which includes both the wettability and the IFT terms. The defined dimensionless time is an empirical correlation, which is presented as Eq. 6. The general scaling approach was validated against the experimental results of surfactant-assisted spontaneous imbibition in various formation shale rocks from the Permian Basin and Eagle Ford with different porosities and sizes. The experimental data indicate that lower porosity of core samples leads to higher oil recovery from spontaneous imbibition. We introduce the ϕ^2 term to eliminate the effect of porosities for shale rock samples. The IFT cannot display a noticeably correltion with ultimate oil recovery. Additonally, the recovery neither too high nor too low when IFT close to 0. Thus, we use $abs(log(\sigma))$ to decrease IFT effect in scaling apporach.

$$t_D = t\sqrt{\frac{k}{\phi}}\frac{abs(log(\sigma))\,cos(\theta)}{\sqrt{\mu_w\mu_o}}\frac{1}{L_c^2}\times\phi^2 \;\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \;(6)$$

The new imbibition scaling model applied to the experimental data of surfactant-assisted spontaneous imbibition in different ULR cores from the Permian Basin and Eagle Ford. The shale core samples retrieved from one Permian Basin region and two Eagle Ford regions, we investigated the scaling of experimental data based on the area separately. Then, we plot normalized recovery vs. dimensionless time using new scaling approach for all the experimental data. The scaling results of new dimensionless time compared with the scaling results using the existing dimensionless time to confirm the new imbibition model functions satisfactorily for spontaneous imbibition in unconventional rock system.

Results And Discussion

Compilation of over 30 experiments with IFT, CA, and Spontaneous imbibition data included are presented in this study. Data were gathered from several published data from our laboratory, consisting of work done on Wolfcamp and Eagle Ford system (Alvarez et al. 2017a; Alvarez et al. 2017b; Alvarez and Schechter 2015; Alvarez and Schechter 2017; Saputra and Schechter 2018; Zhang et al. 2018b). On the first part of the discussion, all IFT, CA, and imbibition production curve data are presented and grouped based on the reservoir region. With all data gathered, analysis on the correlation of IFT and CA data to recovery factor from imbibition will be presented afterward which also provides suggestions on the surfactant selection for optimal production enhancement from surfactant addition. On the last part of the discussion, a new scaling approach for spontaneous imbibition in ULR based on the observed correlations will be proposed and compared with the existing widely-used scaling models.

Table 1. Experimental data summary from all three systems

	Fluid	D	L	ϕ	CA	IFT	k	RF	Pc
		inch	inch	%	deg.	mN/m	nd	%	psi
Wolfcamp	DW1	0.99	1.451	6.50	121	21.8	400	7.60	-286.25
	DW2	0.98	1.451	6.50	110.9	21.8	400	7.15	-198.27
	DW3	0.973	1.78	6.80	108.7	21.8	400	10.55	-182.26
	Surf1	0.982	1.702	6.30	62.6	9.8	400	18.37	113.20
	Surf2	0.98	1.593	6.40	57.4	0.4	400	33.95	5.45
	Surf3	0.982	1.536	6.50	56.6	9.8	400	19.73	137.54
	Surf4	0.974	1.96	6.50	55	0.4	400	24.30	5.85
	Surf5	0.974	1.887	6.50	50	3.9	400	32.60	63.91
	Surf6	0.99	2.037	6.80	47	0.9	400	18.90	16.01
	Surf7	0.989	1.777	6.80	39	8.9	400	47.30	180.36
	Surf8	0.979	1.481	6.40	32.4	0.4	400	28.51	8.54
EF-A	DW4	0.995	2.585	8.60	108.17	31.43	200	3.11	-406.48
	Surf9	0.992	2.350	8.60	85.90	15.32	200	6.89	45.43
	Surf10	1.001	2.393	8.60	69.05	10.25	200	19.77	151.99
	Surf11	0.999	2.170	8.60	57.32	7.17	200	16.64	160.56
	Surf12	1.002	2.639	8.60	51.53	5.85	200	24.06	150.93
	Surf13	0.994	2.154	8.60	34.67	17.14	200	29.70	584.63

	Fluid	D	L	ϕ	CA	IFT	k	RF	Pc
		inch	inch	%	deg.	mN/m	nd	%	psi
EF-B	DW5	0.995	2.585	12.00	127	34.4	200	2.10	-1014.21
	DW6	0.997	2.288	12.26	94.7	34.03	200	1.97	-138.07
	DW7	0.999	1.165	12.00	93.2	34.03	200	2.90	-93.06
	Surf14	0.991	1.819	13.17	77.5	7.25	200	3.11	80.53
	Surf15	0.998	1.451	12.00	55	0.7	200	6.50	19.67
	Surf16	1.001	2.214	12.00	50	2.3	200	5.80	72.43
	Surf17	0.994	1.959	13.00	46	1.2	200	4.50	42.50
	Surf18	0.995	2.071	12.00	46.4	2.33	200	7.61	78.72
	Surf19	0.9935	1.953	13.17	41.2	4.48	200	3.60	173.00
	Surf20	0.998	1.453	12.00	40.3	0.22	200	6.84	8.22
	Surf21	0.993	2.028	12.26	39.9	1.76	200	9.32	66.86
	Surf22	0.955	2.0695	13.17	39.2	2.89	200	4.60	114.94
	Surf23	1.002	2.391	12.00	38	6.9	200	9.00	266.37
	Surf24	0.995	1.643	12.00	36.4	1.76	200	10.05	69.40
	Surf25	0.991	2.253	12.26	35.8	0.22	200	6.74	8.84
	Surf26	1.0005	2.214	12.26	34.3	2.33	200	7.06	95.31
	Surf27	0.996	2.587	5.86	21.9	17.140	200	18.23	544.58
	Surf28	1.000	2.394	12.18	20.8	6.900	200	14.11	318.32

Data Compilation

Interfacial tension and contact angle data are presented in **Fig. 1**, in which the left column displays the all IFT data, and the right column illustrates the CA data. DWs are base cases where no surfactant was added into the aqueous-phase and Surfs are cases where the aqueous-phase contained surfactants. For simplification, both DW and Surf cases are presented with the nomenclature of numbers.

In line with all of the previously published studies, the addition of surfactant reduced the water-oil interfacial tension with each surfactant possessing different extent of reduction. Most of the surfactants presented have the IFT values of larger than 1 mN/m, which is considerably higher than surfactant system used for water-flooding conventional reservoirs. For the contact angle, the addition of surfactant to an oil/water/rock system altered the wettability of the rock surface as has been observed in multiple studies. Different surfactants showed different strength in wettability alteration as shown in **Fig. 1**. It is necessary to consider that the initial wettability of the rock surface on both Wolfcamp and the two Eagle Ford systems fell into the oil-wet region.

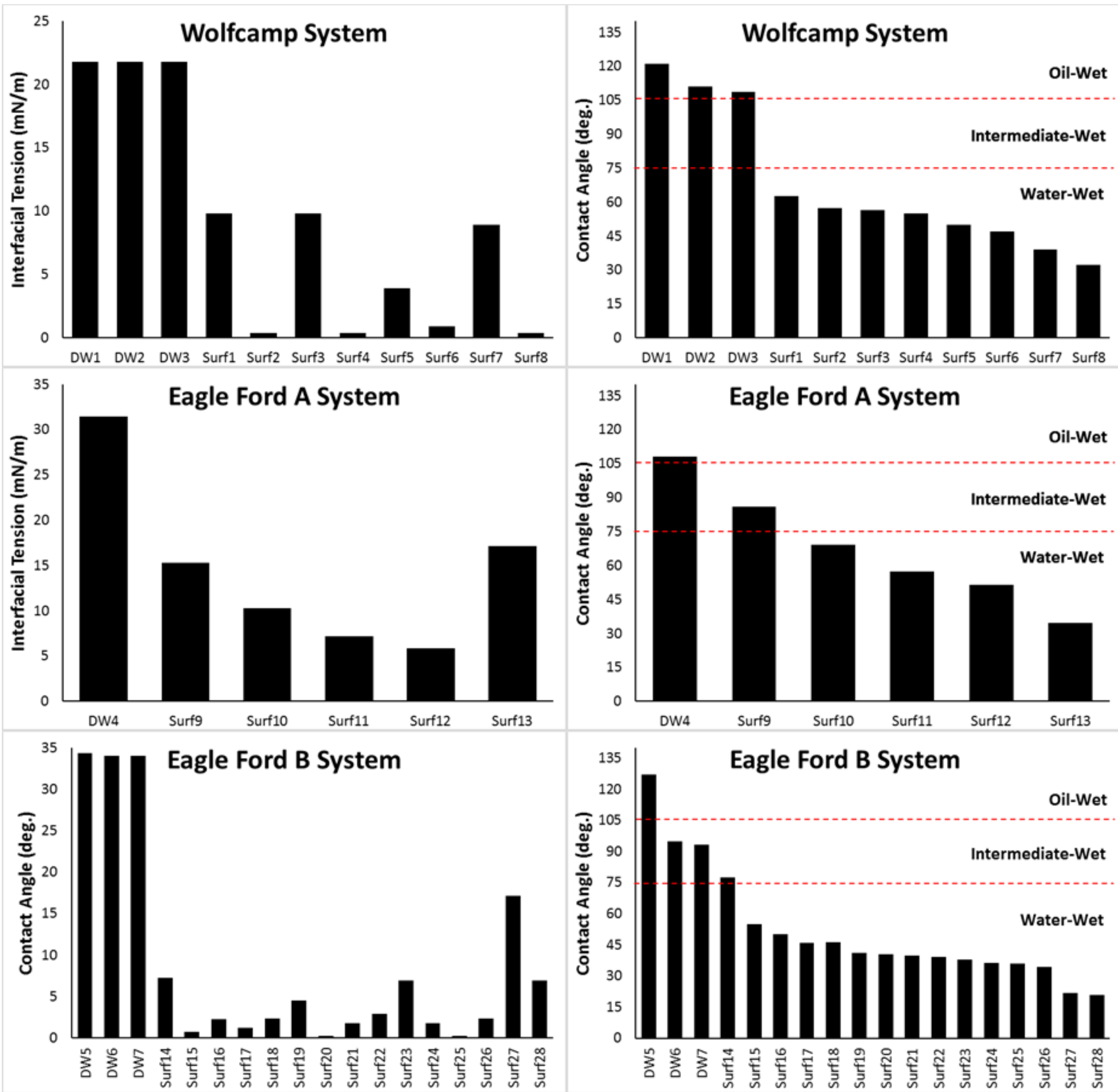

Fig. 1. Compilation of interfacial tension and contact angle data on three systems

Spontaneous imbibition experiments provided the oil production curve from the capillary-driven imbibition with the data presented in **Fig. 2**. Due to a large number of data on the Eagle Ford B system, production curve data for this system were shown in two sub-figures. Oil production was still observed for core plugs submerged in water as indicated by the case of DW1 to DW7. Moreover, it can also be perceived that every imbibition experiment involving surfactant in the aqueous-phase increased the recovery factor. Recovery factor from the base was observed to fall in the range of 0-10% of OOIP and addition of surfactant improved the cumulative production to over 45% of OOIP. In addition to the increase in the quantity of oil produced, surfactant addition also enhanced the production rate of the oil, which can be achieved by analyzing the time it takes to produce half of the total recovery factor. Wettability altered into the water-wet region by surfactant addition, which leads to a change of the capillary pressure to be beneficial to oil production as the increment of oil production showed.

For the objective of this study, the dimension of each core plugs, along with its porosity and permeability were required for scaling group analysis, and capillary pressure data were needed for correlation analysis. The capillary pressure of each experiment was calculated by Eq. 4. All of these data for each imbibition cases are presented in **Table 1**.

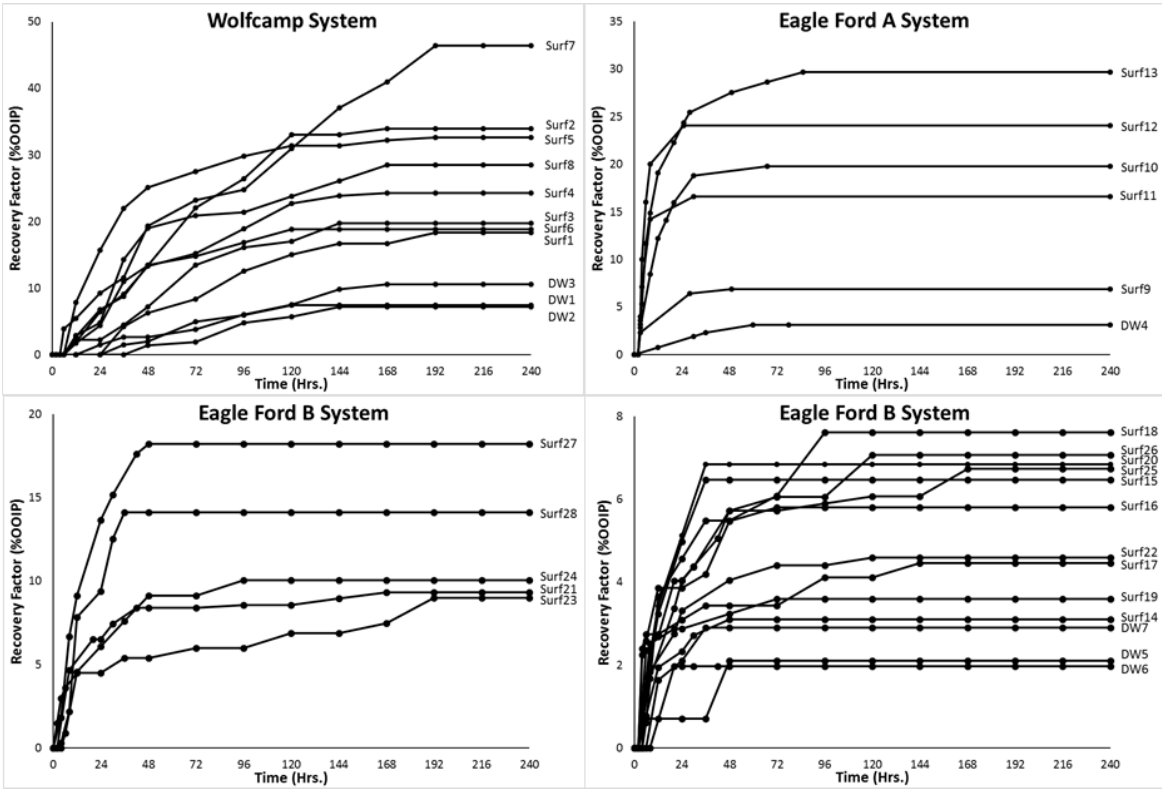

Fig. 2. Production curve from spontaneous imbibition experiment

Experimental Data Analysis on Wolfcamp System

Correlation between CA and IFT to the recovery factor of imbibition experiment from Wolfcamp system were analyzed by plotting the recovery factor on the y-axis and CA and IFT on the X-axis on separate graphs. Plots of the correlation are shown in **Fig. 3** which compare all three base cases and eight surfactant cases on Wolfcamp cores. A clear correlation between the contact angle and the recovery factor was observed with higher contact angle correlates to lower oil recovery as well as the lower value of contact angle results in higher recovery factor. As mentioned before, the capillary pressure was determined as the driving force of oil production enhancement in this experiment. Therefore, it is logical to achieve the observed correlation between CA and RF. Contact angle value represents the degree of wettability of the rock surface, a higher magnitude of CA implies more oil wetness and smaller value denotes a more water-wet surface. The negative correlation between contact angle value and recovery factor was observed since oil-wet surface would hinder the production from capillary pressure and vice versa. The spread of data on the plot could be explained by the heterogeneity existing in the core plugs; it is commonly found that shale rock sample has a high degree of heterogeneity.

On the IFT vs. RF plot, no clear correlation was perceived. A slightly negative trend between the two variables is visible, but the large spread of the data made it difficult to conclude an apparent relationship between these two parameters. Even though that the correlation between IFT and RF could not be found, this could give another insight on the importance of wettability alteration by surfactant on optimizing the production enhancement from this method.

The capillary pressure was calculated for each case by applying the equation shown previously. Investigating the correlation between capillary pressure and recovery factor is highly critical as it was determined that capillary pressure is the dominant driving force of the production enhancement. The plot of Pc and RF is shown on the right sub-figure in **Fig. 3**. A positive correlation was observed between capillary pressure and recovery factor from imbibition.

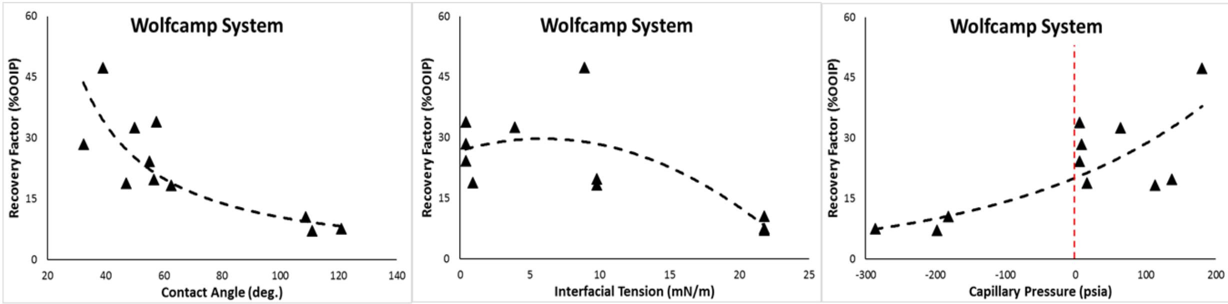

Fig. 3. Plots of CA, IFT, and Pc to recovery factor from Wolfcamp system

Experimental Data Analysis of Eagle Ford A System

A similar examination was performed on the results of CA, IFT, and spontaneous imbibition experiments from the Eagle Ford A system. One base case and five different surfactant cases were included in the analysis of the plot of CA-RF and IFT-RF which are presented in **Fig. 4**. A similar trend that was observed on the Wolfcamp system was also noted on the Eagle Ford A system on both IFT and CA correlation to recovery factor. The negative correlation between CA and RF with an asymptotic forming at the lower end of the contact angle value was detected, similar to the observation on Wolfcamp system. IFT and RF plot was also found to be relatively more random compared to the CA and RF plot with a slight negative correlation between them was observed, similar to Wolfcamp system as well. Capillary pressure and recovery factor were also correlated, and a positive correlation between the two parameters was observed as well. Similar to the Wolfcamp system, this analysis signifies the importance of wettability alteration property of the surfactant to optimally enhance oil production from shale reservoir.

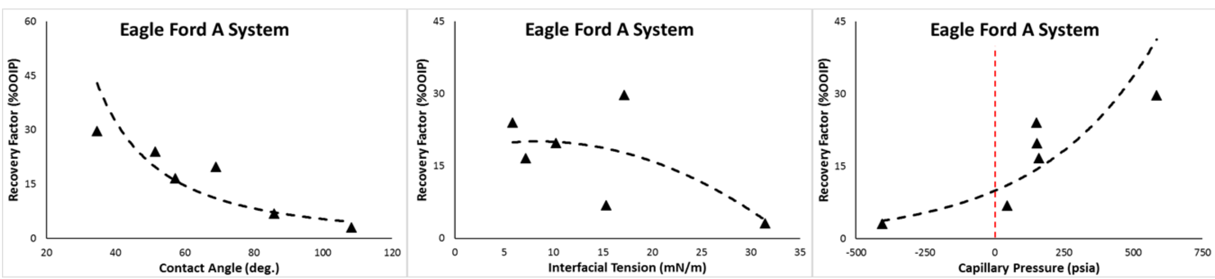

Fig. 4. Plots of CA, IFT, and Pc to recovery factor from Eagle Ford A system

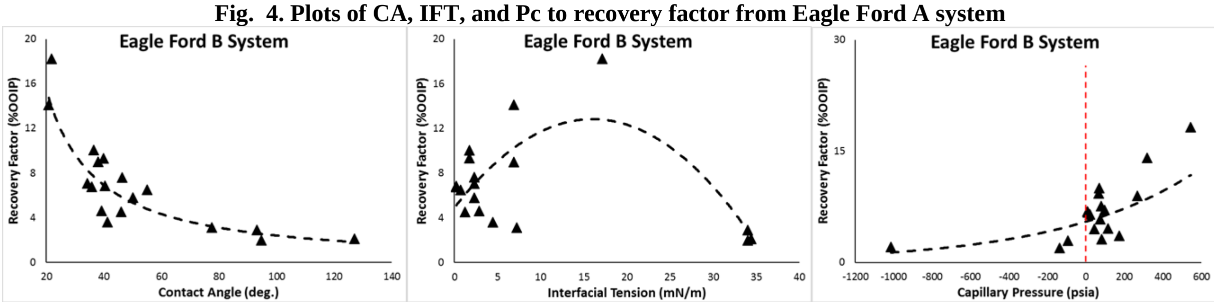

Fig. 5. Plots of CA, IFT, and Pc to recovery factor from Eagle Ford B system

Experimental Data Analysis of Eagle Ford B System

Another similar examination was conducted, but this time on the experimental data compiled from Eagle Ford B system. A total of 18 data points were analyzed, consisting of 3 base cases and 15 surfactant cases. As shown in **Table 1**, the significant difference between the two Eagle Ford systems presented in this work was the porosity value of each system. The porosity of Eagle Ford A was found to be smaller compared to Eagle Ford B with the value of 8.6% compared to 12-13% respectively. However, despite the porosity difference, a similar trend to the two previous systems was observed on the CA-RF and IFT-RF plots. Plot analysis for Eagle Ford B system is presented in **Fig. 5**. Negative correlation with asymptotic forming at the lower end of CA value between the CA and RF was observed, similar to the two previously analyzed systems. For the IFT-RF, the parabolic trend was seen where an optimal point of IFT that would produce the most oil was observed. However, the extensive data spread would mean that more IFT data (especially on the 10-30 mN/m region) is still required to draw any reliable conclusion. The capillary pressure was calculated and correlated to the recovery factor as well. A positive correlation between the two was observed.

Experimental Data Analysis on Base Case Data

In addition to the analysis of the correlation between CA, IFT, and Pc to RF, a more profound analysis of the data from the base case was also conducted which is provided in **Fig. 6**. All base case from all three systems were combined and analyzed, totaling in nine data points. The top-left plot on the figure correlates the IFT to RF, top-right plot correlates CA to RF, bottom-left plot correlates Pc to RF, and bottom-right plot correlates porosity to RF. It is interesting to note that, unlike the surfactant cases, no clear correlation was observed on the CA-RF plot. For the base case, the wettability of rock surface remained as intermediate-wet that CA cannot determine the ultimate oil recovery. However, the absence of clear correlation between IFT-RF on the surfactant cases did not translate to the base cases analysis as well. A negative correlation between IFT and RF was detected, lower IFT would cause higher RF due to the absence of wettability alteration event on the base cases which means that the capillary pressure is still in the negative zone. Lower IFT then would reduce the negative capillary pressure, allowing more oil to be produced by spontaneous imbibition.

The negative correlation between porosity and recovery factor was also observed as lower porosity on the base case resulted in the higher recovery and higher porosity resulted in lower recovery. The results of these relationships investigate indicate that the correlation takes the form of $RF \propto 1/\phi^2$ which can be used as another base to propose the new dimensionless time formulation. The correlation can be used to remove the porosity variable for constructing production curve in the dimensionless realm.

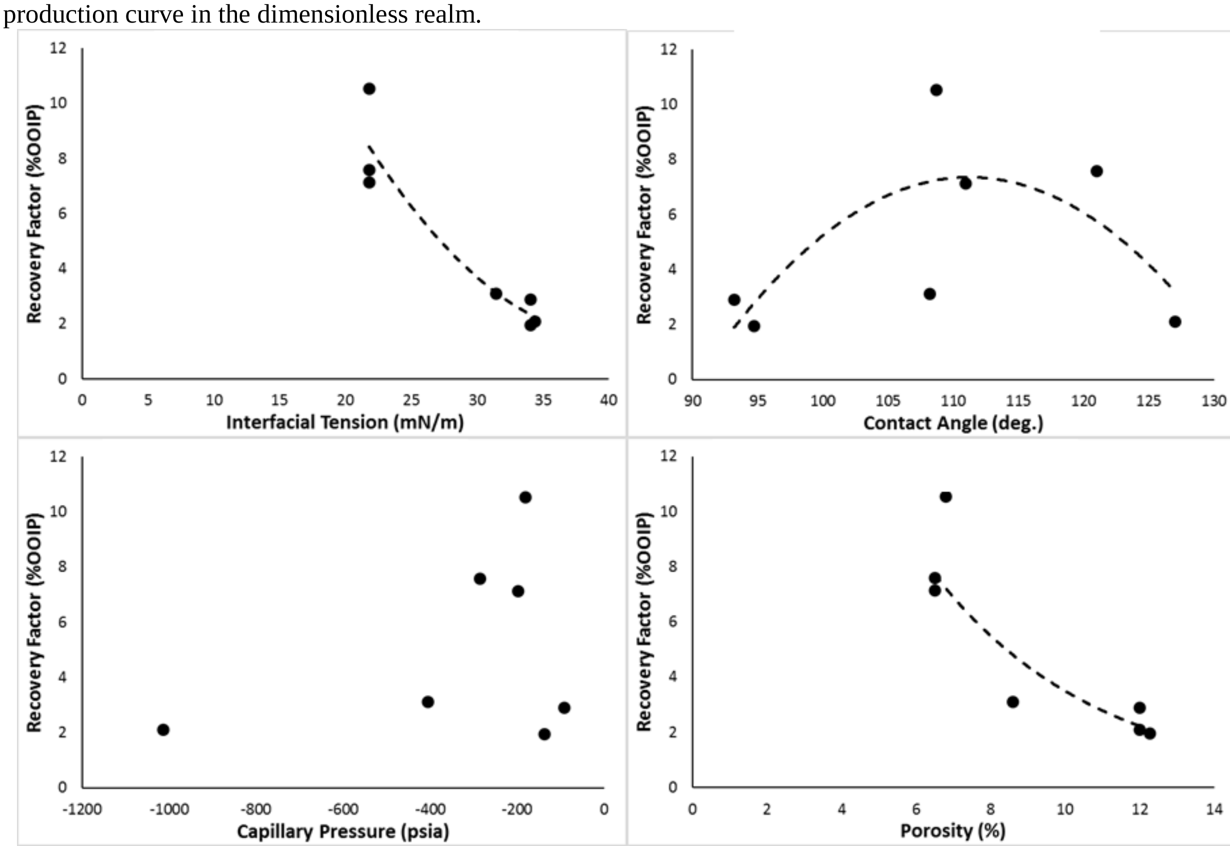

Fig. 6. Plots of CA, IFT, Pc, and ϕ to recovery factor from base cases of all system

Combined Experimental Data Analysis

For the last part, analysis of CA, IFT, and Pc to RF was performed on all of the experimental data from Wolfcamp, Eagle Ford A, and Eagle Ford B systems. A total of 35 data points with CA, IFT, Pc and RF data were plotted against each other as shown in **Fig. 7**. Compared to individual assessment on each system, the combined analysis revealed a relatively more data spread. A similar trend can be perceived in CA, IFT, and Pc plots against RF in **Fig. 7**, but when compared to individual analysis shown in **Fig. 3** to **Fig. 5**, the trend is less visible. Going back to the porosity effect on recovery factor as observed in the analysis of spontaneous imbibition base cases, an attempt was made to enhance the plot by modifying the recovery factor of all cases based on the correlation of $RF \propto 1/\phi^2$. Plots of CA, IFT, and Pc against the modified RF are presented in **Fig. 8** – **Fig. 10**.

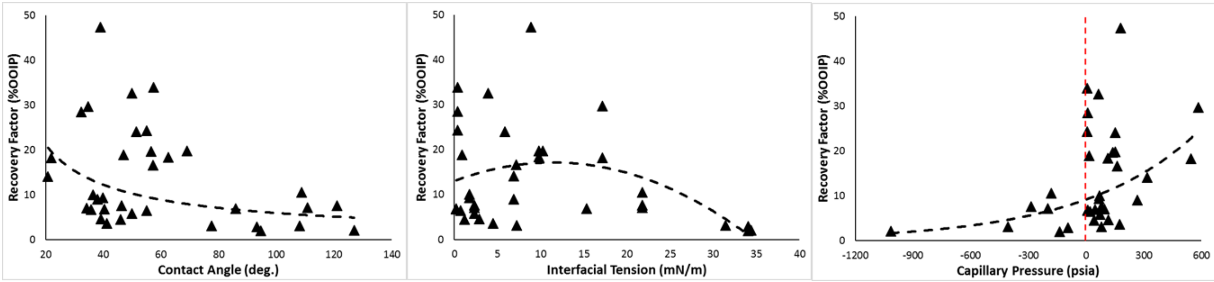

Fig. 7. Plots of CA, IFT, and Pc to recovery factor from all three systems

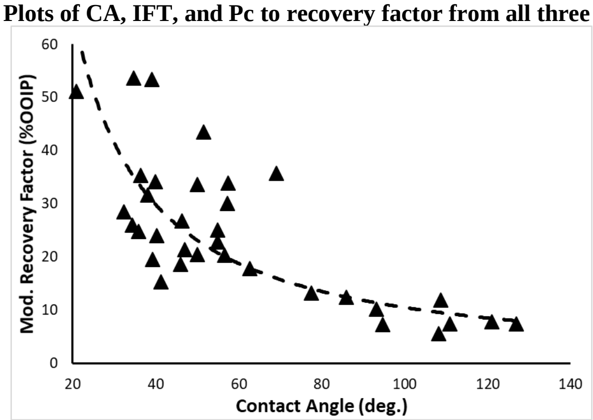

Fig. 8. The plot of CA to modified recovery factor on all systems

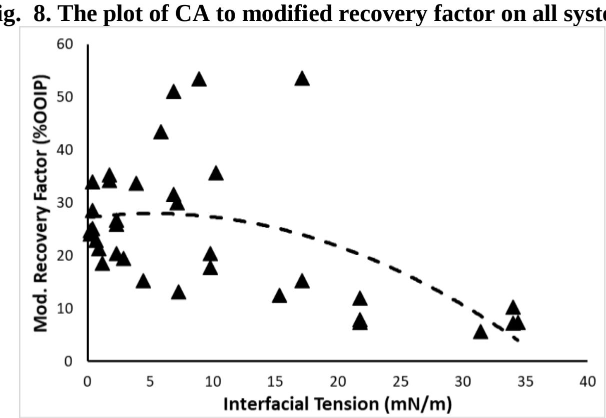

Fig. 9. The plot of IFT to modified recovery factor on all systems

Modifying RF with the term $1/\phi^2$ was able to provide a better trend on CA, IFT, and Pc to the production by imbibition. At this point, a conclusion on the effect of surfactant on a general shale reservoir system then can be made with the further application of suggestion on surfactant selection for the optimum result on enhancing oil production by surfactant addition. **Fig. 8** indicates that much lower contact angle value or stronger water-wet surface is preferable as it shows a higher recovery factor based on all the experimental data. IFT displayed a weak negative correlation to RF as shown in **Fig. 9** but failed to show a strong correlation as also shown by the individual assessment of each system. However, the strong correlation of IFT to RF was observed on the base case analysis where no wettability alteration occurred as no surfactant was added into the system. This finding could imply the dominance of wettability over IFT on oil production. On the plot of Pc to modified RF as shown in **Fig. 10**, a positive correlation observed between the two acts as another proof of the capillary-driven mechanism for spontaneous imbibition as well as another proof of the importance of altering capillary pressure to be more favorable for oil production.
Surfactant possessing an effective wettability alteration capability can change the wettability of rock surface from oil-wet to the water-wet region, which is essential for the surfactant to achieve optimum oil recovery. Correlation analysis

of IFT and RF did not show a noticeable trend. Compared with IFT, contact angle plays a more significant role in enhancing oil recovery by spontaneous imbibition. In addition, a clear positive correlation between the value of Pc and RF was concluded from Fig. 10. Thus, the surfactant possesses a strong wettability alteration ability and keeps the capillary pressure relatively high probably can recover more oil compared to other types of surfactants.

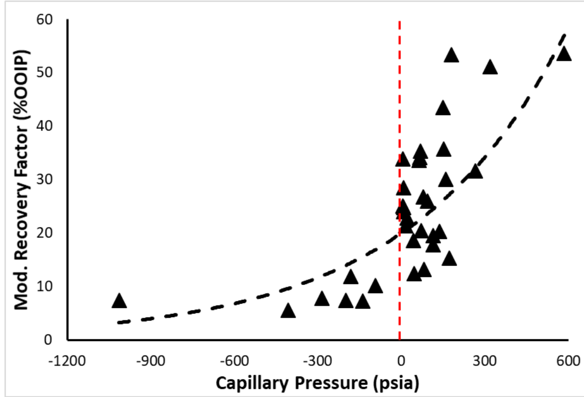

Fig. 10. The plot of Pc to modified recovery factor on all systems

Spontaneous Imbibition Scaling Approach

The proposed scaling model (Eq. 6) and existing scaling models (Eq.1 and Eq. 2, named as Model 1 and 2) were used to investigate the spontaneous imbibition flow behavior in unconventional cores. The other scaling approaches (such as Eq. 3) cannot be applied to scale the spontaneous imbibition experiments on ULR cores due to the limitation of measuring relative permeability and mobility on shale cores. The experimental data listed in **Table 1** were performed to characterize water spontaneously imbibing into oil-saturated shale cores and verify the proposed scaling mothed. In this section, we scaled the experimental data from Wolfcamp, Eagle Ford A, and Eagle Ford B regions separately by using new dimensionless time and two existing dimensionless time and then plotted all the scaling results in the same figure. The comparison scaling results are used to validate the proposed scaling model.

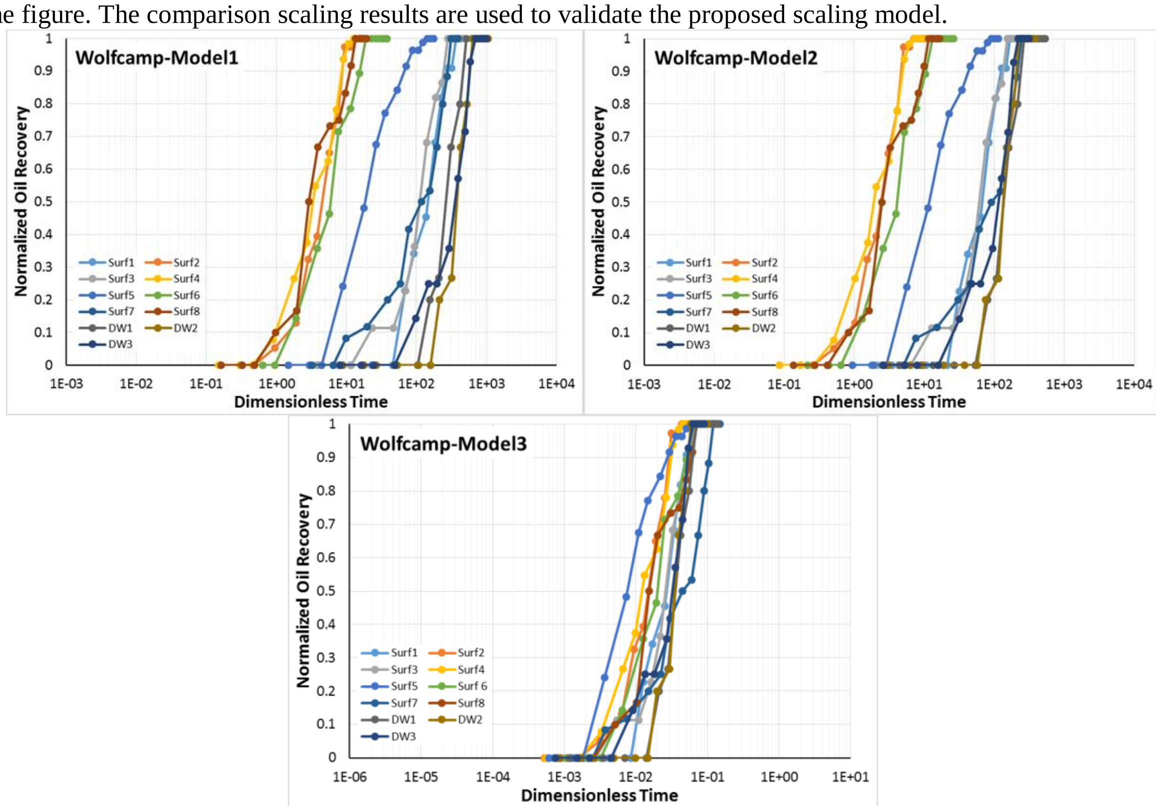

Fig. 11. Scaling results using Model 1, Model 2, and the new model on Wolfcamp system

Scaling for experimental data of Wolfcamp cores

Oil production data from spontaneous imbibition experiments performed on Wolfcamp cores were scaled by using the two existing models and our new scaling model (named as Model 3). Curves are shown in the top portion of **Fig. 11** indicate the dimensionless scaling with Model1 and Model2 while the bottom portion presents the scaling done with the new Model3. Quickly comparing the scaling results of the three methods, it can be seen that the new Model3 works better as a close group of production curves was observed compared to scaling performed with Model1 and Model2. Application of logarithm operator on the IFT as well as the addition of squared porosity as derived by observing the effect of porosity to the recovery factor was the primary difference on the new proposed Model3. Moreover, as shown in the figure, this modification provided a better grouping on the dimensionless group analysis. Surf7 which performed the best production enhancement should come out as the most-right line on the dimensionless scaling, providing another proof that the proposed new scaling more applicable on surfactant-assisted spontaneous imbibition in ULR cores.

Scaling for experimental data of Eagle Ford A cores

We use the proposed dimensionless time, and two existing dimensionless time to scale the spontaneous imbibition data for Eagle Ford A region, the scaling results are shown in **Fig. 12**. The shape of the curves on the figure of Model3 are similar to the curves in other two scaling approach, which used to validate the proposed model can characterize spontaneous imbibition flow behavior. The layout of **Fig. 12** is same as that in **Fig. 11**.

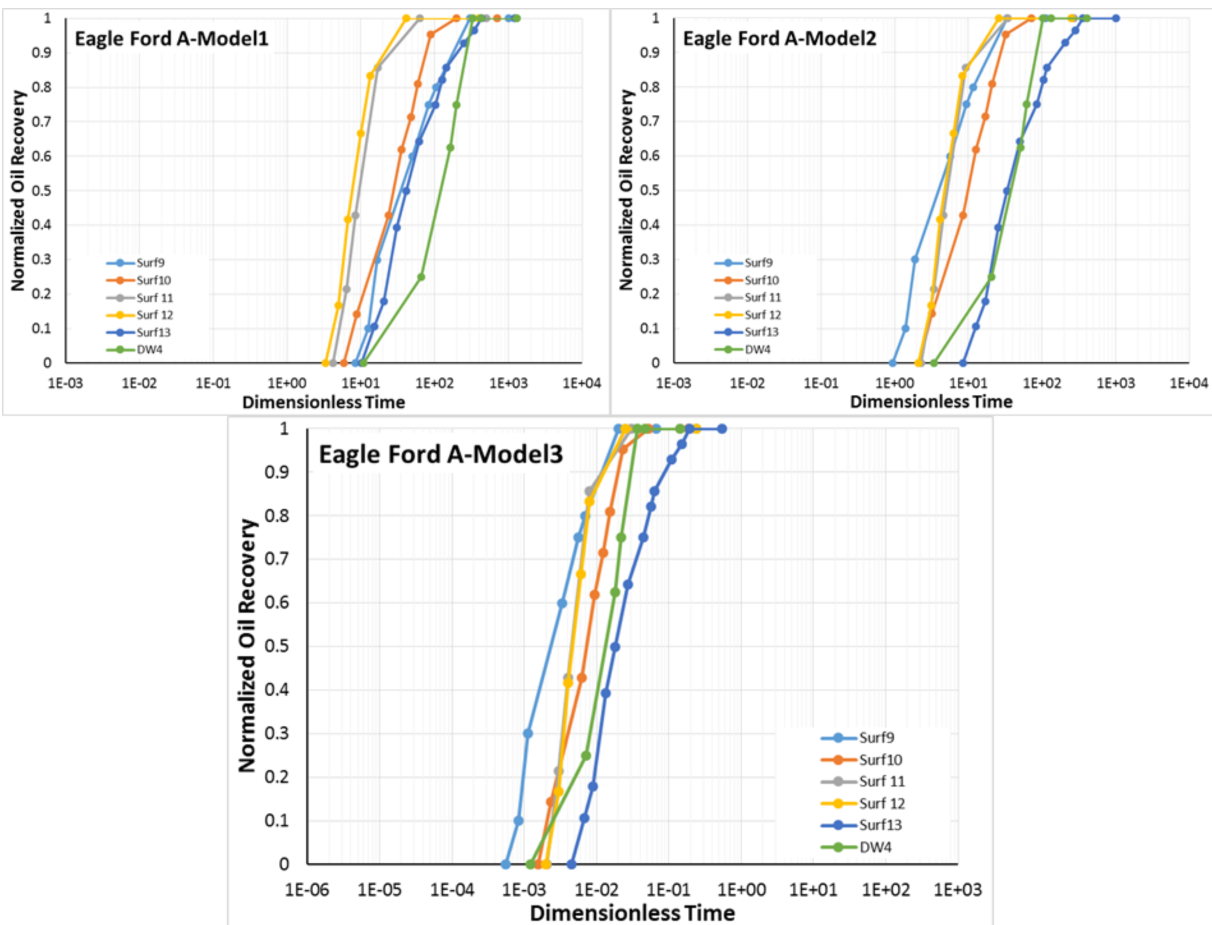

Fig. 12. Scaling results using Model 1, Model 2, and the new model on Eagle Ford A system

The scaling results presented in **Fig. 12** depict that all three models can be used to scale the data of spontaneous imbibition experiments conducted on Eagle Ford A cores. The Model 3 shows a better performance than the other two models. The experimental data for Eagle Ford A shown in **Table 1** demonstrate that porosities as well as IFTs of these data are similar. The new proposed model had less enhanced effect if the spontaneous imbibition experiments data have similar porosity and IFT. The surfactant with the best performance to recover oil from Eagle Ford A cores is positioned on the far right in new scaling model figure.

Scaling for experimental data of Eagle Ford B cores

Three scaling models including new scaling approach and Model1 and Model2 were used to scale experimental data of Eagle Ford B region; we plotted the scaling results in **Fig. 13**. For the experimental data for Eagle Ford B cores, a more extensive range of data was available as the CA varied in the range of 20 to 127 degree and IFT values (0.2 to 34 mN/m) were almost in two orders difference. This case study would be a good test to verify the new proposed model applicable to imbibition data from general Eagle Ford region.

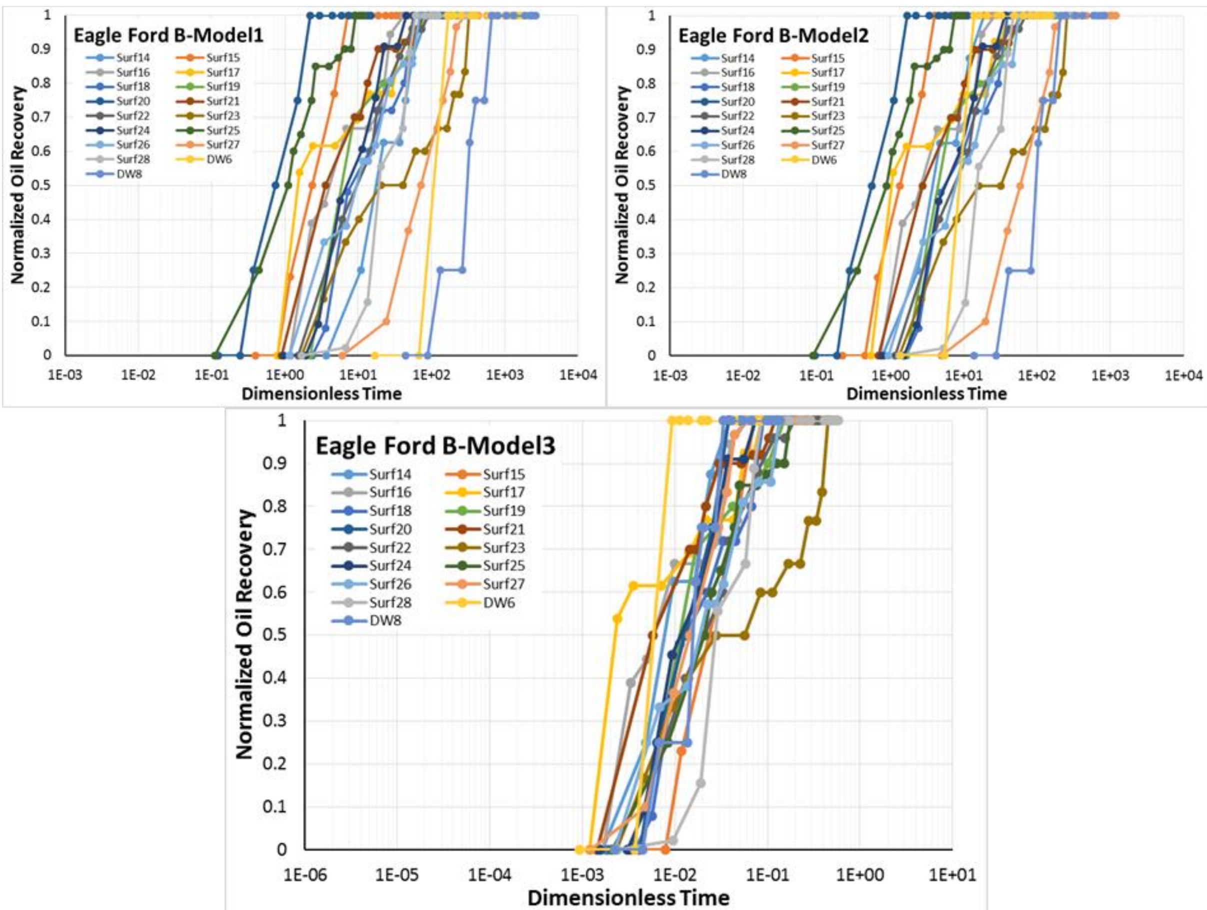

Fig. 13. Scaling results using Model 1, Model 2, and the new model on Eagle Ford B system

Fig. 13 indicates that spontaneous imbibition data for Eagle Ford 2 cores at different surfactant solution could not be appropriate scaled using Model1 and Model2. However, the proposed scaling approach captured the spontaneous imbibition flow behavior for Eagle Ford B data, as the commonly used scaling models failed. Based on scaling results shown in Fig. 13, the new Model3 was capable of scaling for spontaneous imbibition data in general Eagle Ford reservoirs. The curve shape of Surf17 and Surf23 were dissimilar as all the other surfactants. The mechanism of these two surfactants in enhancing oil recovery might be different from any other surfactant. Thus, the flow behavior of the spontaneous imbibition using these surfactants was unlike any of the commonly used surfactants. For these two surfactants, Surf23 recovered more oil from spontaneous imbibition, also positioned on the right side of Surf17. The Surf 28 which possessed the best oil production enhancement located at the far right on Model3 exclusive of Surf17 and Surf23.

Scaling for experimental data of all cores

To further confirm the new proposed model, we investigated the experimental data from different ULR regions at various wettability and IFT. All of the experimental data listed in Table 1 were used to test the capability of new proposed scaling approach. The scaling results of all the spontaneous imbibition experimental data using new scaling model and existing models are presented in **Fig. 14**.

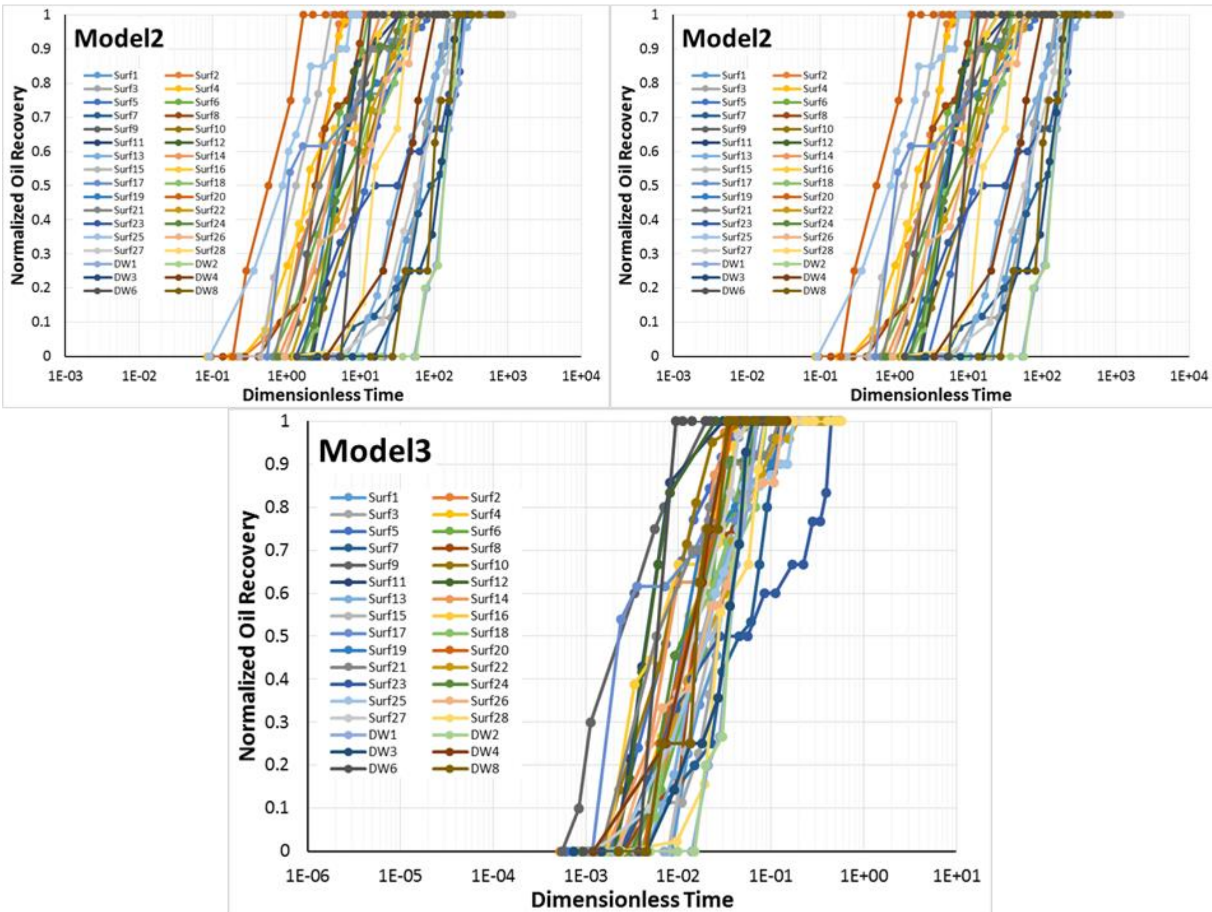

Fig. 14. Scaling results using Model 1, Model 2, and the new model on all systems

Fig. 14 demonstrates the scaling results of the proposed scaling approach performed better than the existing methods for unconventional systems. Scaling approaches of Model1 and Model2 were inapplicable to the spontaneous imbibition data for ULR while the new proposed model Model3 worked. The general scaling approach proposed in this study was applicable on both Wolfcamp and Eagle Ford rocks. In addition, the corresponding surfactant of the curve located at the most-right in the scaling results plot of Model3 probably performed best on enhancing oil recovery in ULR. Three critical factors were observed in the previous part and were applied in the construction of the new scaling model. Contact angle which represents wettability must be taken into account as it was observed that wettability plays a significant role in determining the recovery factor of oil from the experiments. Interfacial tension showed the insignificant effect, and this finding was represented into the new equation by applying a logarithmic operation to the IFT variable. The proposed scaling model includes the IFT term but lessens the effect of IFT into the model. Correlation of recovery factor from spontaneous imbibition to porosity as presented before was also implemented by the addition of porosity-squared into the equation. These changes managed to improve the accuracy of the model as shown by a better grouping of all the imbibition production curves when compared to the other two previous models.

In the end, the application of the dimensionless scaling is to enable the process of upscaling observed laboratory-scale results to the field-scale. Observation of the efficacy of surfactant on the field-scale is highly essential as it would determine the economic balance of surfactant addition. Upscaling the results to a field-scale through dimensionless scaling could give an approximation on the quantity of oil production improvement which could be tied-back to the economic return. Extra expenditure from the application of surfactant must be at least covered if not overshadowed by the increment of income from the improved oil production.

Summary

In this study, we developed a reliable surfactant selection method and proposed a new scaling model for spontaneous imbibition in ULR. Experimental data of spontaneous imbibition in ULR cores indicated that the wettability and the IFT alterations could improve oil recovery in ULR. Correlations of contact angle, IFT, capillary pressure, and porosity to the ultimate recovery were revealed by systematically analyzing the correlated experimental data. Recovery factor was observed to highly depend on the contact angle, where the larger value of contact angle resulted in lower recovery factor as well as smaller contact angle leads to higher recovery factor. The interfacial tension did not show any robust correlation to recovery factor. Capillary pressure controlled the recovery factor by having a direct correlation, where higher capillary pressure leads to higher recovery factor and vice versa. From the analysis of the spontaneous imbibition experimental results using water alone, recovery factor was observed to have inversed relation to porosity. Based on these results, surfactant selection method was suggested as well as a new scaling model for spontaneous imbibition in ULR.

The new scaling approach proposed in this study was tested to scale the experimental data of spontaneous imbibition in different ULR. The existing models are inapplicable to characterize spontaneous imbibition in unconventional rock systems. The general scaling model for spontaneous imbibition in ULR possibly can be used to predict the surfactant performance in the field. Based on the scaling results, the surfactant corresponding to the right-most curve in the scaling results graph has a better performance on improving oil recovery in ULR.

Conclusion

1. Addition of surfactants into completion fluids can enhance oil recovery by altering the wettability and the IFT in unconventional liquid reservoirs.
2. A correlation between contact angle and ultimate oil recovery of spontaneous imbibition in ULR is shown from experimental data. We observe an increase in ultimate oil recovery as the contact angle decreases.
3. The recovery factor via spontaneous imbibition increases as capillary pressure increases.
4. A reliable surfactant selection method for optimum performance in ULR is developed in this study. Proper surfactant selection can efficiently alter the contact angle to a lower value and preserve a relatively high capillary pressure, which has a substantial potential to recover more oil by spontaneous imbibition in ULR cores.
5. A generalized scaling model was developed for spontaneous imbibition in ULR.
6. The proposed dimensionless scaling model generalizes the flow behavior of SASI in ULR, accounting for the effect of the addition of low concentration surfactant solutions in completion fluids.
7. The results of this study indicate that SASI should be extended to treatments in depleted wells and investigated as an EOR technique with injection and production wells.

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Nomenclature

c	= Constant value in Eq. 3
L_c	= Characteristic length
k	= Permeability
k_{re}^*	= The relative permeability pseudo-function of the two phases
P_c	= Capillary pressure
r	= Pore radius
S_o	= Oil saturation
S_{wf}	= Water saturation
S_{wi}	= Initial water saturation

t	= Laboratory time
t_D	= Dimensionless time
θ	= Contact angle
μ_e	= Effective viscosity of the water and oil phases
μ_o	= Oil viscosity
μ_w	= Water viscosity
σ	= Interfacial tension (IFT)
$\emptyset$	= Porosity

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