

Review Article

Proper Use of Capillary Number in Chemical Flooding

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Capillary number theory is very important for chemical flooding enhanced oil recovery. The difference between microscopic capillary number and the microscopic one is easy to confuse. After decades of development, great progress has been made in capillary number theory and it has important but sometimes incorrect application in EOR. The capillary number theory was based on capillary tube bundles and Darcy's law hypothesis, and this should always be kept in mind when used in chemical flooding EOR. The flow in low permeability porous media often shows obvious non-Darcy effects, which is beyond Darcy's law. Experiments data from ASP flooding and SP flooding showed that remaining oil saturation was not always decreasing as capillary number kept on increasing. Relative permeability was proved function of capillary number; its rate dependence was affected by capillary end effects. The mobility control should be given priority rather than lowering IFT. The displacement efficiency was not increased as displacement velocity increased as expected in heavy oil chemical flooding. Largest capillary number does not always make highest recovery in chemical flooding in heterogeneous reservoir. Misuse of CDC in EOR included the ignorance of mobility ratio, Darcy linear flow hypothesis, difference between microscopic capillary number and the microscopic one, and heterogeneity caused flow regime alteration. Displacement of continuous oil or remobilization of discontinuous oil was quite different.

1. Introduction

Capillary number theory is regarded as the basic theory in polymer flooding, surfactant flooding, polymer-surfactant flooding (SP), and alkali-surfactant-polymer flooding (ASP), which are more appealing enhanced oil recovery (EOR) techniques in low oil price era. The basic mechanism of chemical flooding in EOR can be summarized into mobility control based enlarging sweep efficiency and capillary number theory based improving displacement efficiency. EOR mainly involves how to recover more remaining or residual oil and reducing oil saturation. Recently, there are some misunderstandings about capillary number theory and especially its application in chemical flooding. In petroleum industry, it has been generally recognized that capillary desaturation curve (CDC) reflects the character and arrangements of the pores within the media and the distribution of fluids

within the pores [1]. Capillary number was a dimensionless group describing the ratio of viscous to capillary forces [2–7]. Capillary number was crucial in determining the remaining oil saturation [8]. Some experiment results are summarized in Figure 1. Traditionally, CDC was used to describe the relationship between capillary pressure and wetting/nonwetting phase saturation [1] while it was more and more frequently used in describing relationship between residual oil saturation (S_{or}) and capillary number (N_c) [3, 4, 6, 9–11]. In enhanced oil recovery like chemical flooding CDC has various applications in not only water flooding but also chemical flooding [12–16]; capillary number was frequently cited in explaining the mechanisms [10, 12, 17, 18]. Typical classical CDC showed that larger capillary number leads to lower residual oil saturation and when capillary number increased to some certain critical value, the residual oil saturation could drop to a minimum value even zero. However,

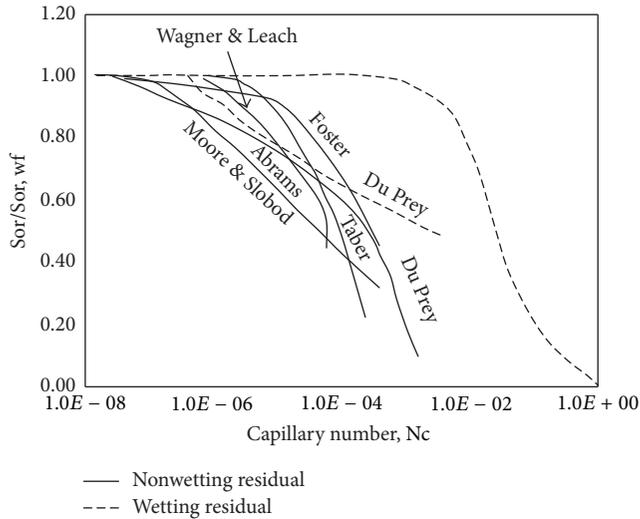


FIGURE 1: Summary of typical CDC [7].

recent literatures showed that CDC was often misunderstood by ignoring the difference between remaining oil saturation and residual oil saturation and the fundamental hypothesis in conducting capillary number definition. The sweep efficiency issue was not discussed in classic CDC and the importance of mobility control was not emphasized as it deserved. A different CDC is got by ASP flooding tests and is helpful to guide the chemical flooding. The hypothesis underlying the deduction of capillary number including capillary bundle and Darcy flow should be checked when capillary number theory is used in low permeability and heavy oil reservoir. In low permeability reservoir, flow behaves as some kind of non-Darcy feature, while in heavy oil chemical flooding the viscosity ratio is big enough to consider the mobility ratio and frontal stability. Systematical review of capillary number in chemical flooding is helpful to understand the importance of mobility control and enlarging sweep volume in chemical enhanced oil recovery (EOR).

2. Capillary Number and CDC

Capillary number was defined as ratio of viscous force to capillary force [7, 11]. However, Mantney et al. [19] defined a new capillary number as the ratio of capillary to viscous force, contrary to classic capillary number definition. The advantage is that its interpretation is more intuitive since for a large capillary number capillary forces dominate. This definition sounds good but few ongoing studies are reported. Laboratory studies have shown that residual oil can be recovered if the displacing phase causes viscous forces acting on trapped residual oil blobs to exceed the capillary retaining forces. The derivation of capillary number can be seen in literature [20]. Recovery factor was found to be dependent on the capillary factor [7]. The capillary number provides satisfactory correlations of mobilization oil with widely different viscosities [5]. Capillary has many different mathematical definitions [4, 5]. Differences were noted in

CDC with different capillary number forms [6], while the most often applied definitions [10] are

$$\begin{aligned} Nc, 1 &= \frac{k \nabla p}{L \sigma}, \\ Nc, 2 &= \frac{v \mu}{\sigma}, \end{aligned} \quad (1)$$

where σ was the IFT, v is the superficial velocity, and μ is the viscosity of the displacing (wetting) phase.

In recent years, most research about capillary number is about its application in water and chemical flooding. Hilfer et al. [2] investigated the physical nature of capillary number and capillary saturation and desaturation with consideration of microscopic and macroscopic laws of Newton, Young-Laplace, and Darcy. They found that the capillary number is expressed as a function of saturation (S), velocity (v_i), and model length (L), while in most previous studies the length was seldom given enough attention. They also emphasized the difference between microscopic capillary number and the microscopic one, which is easy to confuse [2]. Many experiments showed that microscopic displacement efficiency increased as capillary number increased to a certain value and the effects of capillary number on residual oil recovery were also studied [3, 5–7, 10, 21, 22]. Both the residual oil saturation (ROS) and the imbibition-drainage hysteresis were found to decrease with an increase in the capillary number [7, 23]. Literature indicated that a model predicated capillary number value of 10^{-3} required to mobilize a single blob trapped in a certain pore and a capillary number of more than 10^{-2} required for complete mobilization [6]. However, the capillary number needed for complete recovery of residual oil was about 100 times, rather than 1000 times in other experiments [7, 24], greater than the critical capillary number for the onset of mobilization in water-wet sandstones [6]. To explain the mechanism, microstructures of residual oil with effects of capillary numbers were studied [25], and it showed that during initial stages of mobilization of residual oil, as capillary numbers exceed critical Nc (1.9×10^{-5} for water-wet sandstones), oil blobs break up into smaller blobs, with a significant fraction being only temporarily mobilized.

Laboratory study [26] showed that the critical capillary or Bond number, which was based on capillary number, observed for strongly water-wet rock was $\sim 10^{-5}$. However, for less water-wet, the critical capillary or Bond numbers may be higher by at least one order of magnitude. The effects of wettability affected the recovery of oil. The wettability effect can also be seen in Figure 1.

When using the capillary number definition, the foundation hypothesis in establishing the equation should be given special attention but was often overlooked. The important two hypotheses of capillary number theory were capillary tube bundles and Darcy law hypothesis. The derivation of capillary number [8, 20] reflects these two hypotheses. Tradition CDC was based on high permeability cores or models, where the capillary tube bundles and Darcy law hypothesis were well met. But these were partly met or even not met in low permeability media because of non-Darcy flow [27, 28] in low permeability media. Thus the theory should be not or

directly used in conditions in which these situations were not met like low permeability cores and high rate turbulent flow which was much different from flow in porous media. Water flooding results of high permeability and low permeability [4] at the same order of capillary number with quite different residual oil saturation supported this conclusion. Capillary numbers for mobilization of residual oil from bead packs were much higher than typical values for sandstones [5]. The critical capillary number of the reservoir cores is found to be reduced when permeability is increased [10]. Though both low permeability media and high permeability media were used to carry out experiment, the permeability dependency of capillary number is seldom studied or noted. Capillary numbers required for different cores were different [11]. Another parameter was the proper viscosity ratio of displacing phase and displaced phase, which was considered in only a few literatures [4]. Though no definite concrete viscosity ratio was advised due to different reservoirs condition and water cut, literatures [29, 30] showed low injection rates based water imbibition can be used to stabilize the waterflooding and improve heavy oil recovery. This is inconsistent with CDC in which higher velocity leads to higher displacement efficiency. Though the saturation in their tests was not residual oil saturation but remaining oil saturation, in short cylindrical cores tests, it is sometimes not easy to distinguish them, and, most importantly, it helps to understand the importance of sweep efficiency in chemical flooding EOR. In fact, residual oil saturation and remaining oil saturation are often mixed in core-flooding experiment. Sometimes this misunderstanding leads to the wrong conclusion.

Classic CDC curves indicate that as capillary number increases, residual wetting/nonwetting phase saturation decreased. When capillary number is below certain value, so-called critical value, the residual wetting/nonwetting phase saturation decreased slowly and this is usually waterflooding capillary number value range. When the capillary number increases beyond the critical value, the residual phase saturation drops drastically. Most CDC shows the residual saturation tends to drop to zero, as can be seen from Figure 1. However, this is not true according to the latest study [2]. The critical capillary number value is often two or three orders of magnitudes; thus the most efficient way to increase capillary number is to reduce IFT by two or three orders of magnitude, since the velocity and viscosity are constrained by pressure drop and formation maximum crack pressure. Many CDC tests were carried out from sandstones reservoirs, while a few were reported in carbonates reservoirs [4, 8, 11, 31]. Effects of core type were given by Garnes and Mathisen [10], and it should be noted that all these three cores are sandstone with different petrophysical parameters, but different CDC. Their tests indicated that critical capillary number correlates to both the dispersibility and the permeability of the cores [10]. The rock type affects geometric characteristics which determines porosity distributions and local percolation feature [32], though thus geometric affection is not directly reflected in N_c parameters. It appears that the critical capillary number of limestones is larger than sandstones. The difference of sandstone and limestone can be seen in [11].

Classic CDC was based on Newton fluid, while non-Newton fluid like polymer fluid was adopted in test recently [13, 14, 33–36]. It is worth mentioning that the viscosity of polymer is not accurately calculated or given in these references. Literature [13] reported viscoelasticity affected CDC with artificial core models and ASP solution. Polymer (HPAM) with different concentration was used to change parameter of viscoelasticity. Test results indicated higher viscoelasticity made lower residual oil saturation and higher displacement efficiency. This conclusion needs more tests and further study. Capillary number correlations for gas-liquid systems were less studied and it was found that the critical capillary number for a gas-liquid system was very different from that of an oil-water system in the same type of rock [37]. The critical capillary number was determined to be 2×10^{-8} for gas-water systems, while for oil-water systems it was 10^{-5} . The easy deformation of gas compared with liquid in porous media may account for this, though further study is suggested to investigate the mechanism.

3. Relative Permeability

Relative permeability was quite complex and important. Factors such as rock type, wettability, and pore geometry, imbibition, or drainage, capillary end effects [38], even method [39], affected relative permeability significantly [7, 9, 31, 40–42]. Fulcher Jr. et al. [7] studied the effect of capillary number on two phase relative permeability curves and gave informative conclusions. Their experiments showed that the nonwetting (oil) phase relative permeability was a function of IFT and viscosity variables individually rather than a function of capillary number, while the wetting (water) phase behaved as functions of capillary number. Insignificant IFT effects were observed on both oil and water relative permeability until a certain value, 2.0 mN/m, was obtained, below which the relative permeability increased as IFT decreased. The experiment also showed that at very low IFT the relative permeability curves straightened out and approached the theoretical X-shape present at zero IFT. No rate effects were observed for the limited range within that study (16 to 80 ft/D). However, literature [31] reported cores with length of 22.2 cm and results showed that relative permeability depended on the flow rate as well as capillary number.

The relative permeability curve dependence on rate was controversial probably because the capillary effect was/was not accounted for [42]. It seemed that capillary number in certain range affected relative permeability. When the critical capillary number value [42] was in certain range, the relative permeability curve became rate dependent. It appeared that there were great variations in the shape of the relative permeability curves when the interfacial tension dropped below certain value (0.04 mN/m) in both vapor/liquid and water/oil systems [24]. Although literatures showed that only when IFT reduced to a certain value, effects of IFT on flow in porous media started [7, 24], however, the threshold IFT value differed.

Capillary end effects accounted for the effects of rate on relative permeability. Studies [38, 43] indicated that observed rate dependency of wetting phase experiment results at high

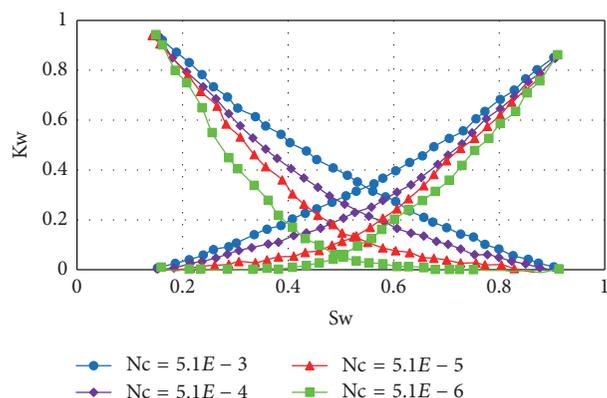


FIGURE 2: Capillary number affected relative permeability [46].

IFT was reproduced by simulations with constant relative permeability (K_r) and capillary pressure (P_c), while observed rate effects of wetting phase in experiments were at low IFT systems and were interpreted as a result of rate dependency in the K_r function. Their experiment results supported by simulation results showed the remaining wetting phase saturation depends on capillary end effects at lower N_c . At higher N_c , the remaining wetting phase was found to be dependent on both N_c and the number of PVs injected. Thus in experiment, the capillary end effects should be overcome in tests [39]. To minimize the capillary end effects, it is often recommended to use higher flow rates or/and longer core samples [44]. This may involve the scale dependence, as emphasized by Hilfer et al. [2].

Subsequent experimental results [45] showed that the relative oil/water permeabilities at any given saturation were affected substantially by IFT values lower than a value (10^{-1} mN/m). Obviously, this critical value is one order higher than that in reference. This may be attributed to the porous media difference and also scale dependent characterization of the microstructure [32]. They also showed that relative oil/water permeabilities increased with decreasing IFT (increasing N_c). This residual saturation shows excellent linear correlations with capillary number on a log-log plot. What is more, the water/oil relative permeability curves were correlated with the capillary number and fluid saturation. Relative oil and water permeabilities can be correlated with IFT through the capillary number. Differences existed between steady- and unsteady-state relative permeabilities. Unsteady-state relative oil permeabilities did not show any significant change with IFT except at low oil saturation, while the unsteady-state relative water permeabilities, however, increased with decreasing IFT. One typical capillary number affected relative permeability curve often used in numerical simulation can be seen in Figure 2 [46].

By using steady-state method and X-ray CT scanning technique, however, a quite different relative permeability curve regarding to capillary number was given [47]. The relative permeabilities for the oil and water phases were higher at lower pressure gradient, which was not in agreement with other literatures [45, 48]. These two pressure gradients correspondent to capillary numbers were 1.3×10^{-6} and

3.3×10^{-5} , respectively, which belonged to a region where no dependence on capillary number occurred [45, 48]. The capillary end effect was not regarded as the cause either, since it should result in higher relative permeabilities at higher pressure gradient, but the reverse occurred. This significant difference was attributed to the significant nonuniform fluid distributions indicated by X-ray CT scanning, which violated the assumption of uniform fluid saturation. This study indicated that capillary end effects cannot explain all relative permeability rate dependence, while wettability difference accounted for this [38]. These studies reflected the complexity and importance of relative permeability. Hilfer et al. [2, 32] went further to investigate the flow in porous media and capillarity from different scales. Different from petroleum industry interest of capillary number application in enhanced oil recovery and oilfield development, they tried to look into its physical nature.

It was well accepted that wettability obviously affected relative permeability. The relative permeability curves for mixed-wet media lay between those for water-wet media and oil-wet media except in the vicinity of residual saturation [49]. The residual oil saturation (S_{or}) in a mixed-wet rock was lower than the S_{or} in an oil-wet rock, and the residual water saturation (S_{rw}) in mixed-wet rock was lower than the S_{rw} in a water-wet rock under identical flooding conditions.

4. Wettability Effects

Reservoir wettability can cover a wide spectrum of conditions [50], and wettability is a very important factor in determining the outcome of core floods [51], as well as relative permeability [44, 48, 49, 52]. In fact, rock wettability affected the nature of fluid saturation and the general relative permeability characteristics of a fluid/rock system [53]. The location of a phase within pore structure depends on the wettability of that phase. Considering the effect of wettability on fluid distributions, it is easy to rationalize that relative permeability curves are strong functions of wettability [53]. For water-wet system, water surrounds oil and contacts grain. For oil-wet system, oil contacts rock. It is much easier to recover water-wet rock oil than oil-wet because for water-wet rock oil is in pore centers. Water-wet rock oil is easy to flood. Reservoirs wettability may significantly impact the design of enhanced oil recovery processes [26]. The effects of wettability on CDC have been studied [7, 11]. The wetting and nonwetting phase behaved differently in CDC [43, 48, 49, 54]. The typical wetting and nonwetting phase CDC could be seen in Figure 3 [38, 48]. The critical N_c to displacement wetting phase and nonwetting phase is quite different, and the CDC slope is also different, which reflects the ease of displacement of nonwetting phase by wetting phase. Both steady- and unsteady-state test data indicated less water-wet rock surfaces with decreasing IFT [45]. Higher capillary numbers were required to mobilize the wetting phase than the nonwetting phase residual saturation. The critical capillary number was about one order of magnitude higher for oil-wet conditions than that under water-wet conditions [25].

It should be noted that not all capillary number equations/definitions considered the effect of wettability; thus

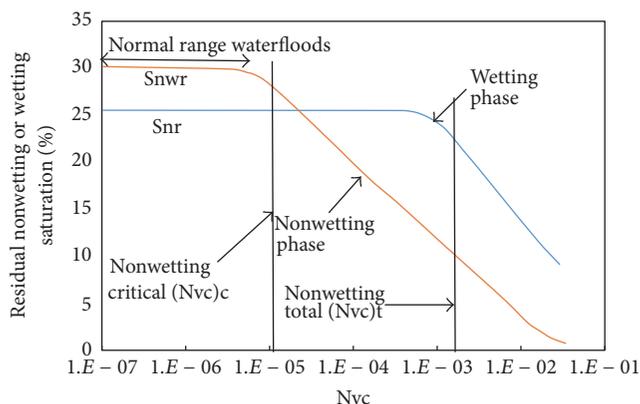


FIGURE 3: Schematic wettability affected CDC [25, 53].

some equation contains a factor of $\cos \theta$. Herein θ is wetting angle, but this is invalid in mixed wetting. Systems of intermediate or mixed wettability were quite common, whereas very strong water-wet systems may be a rarity [50, 52]. As water-wet and oil-wet phase CDC has well studies for decades, the mix wet is drawing attention recently. Most reservoirs are assumed to be mixed-wet, based on core-scale index such as Amott-Harvey and USBM [55]. Thus, the mix wet may be more crucial in revealing wettability affecting chemical flooding mechanism. The different CDC of water-wet, oil-wet, and mixed-wet media was studied [49]. CDC for a mixed-wet medium lay in between those curves for strongly oil-wet and strongly water-wet media. For mixed wettability cores, two distinct populations of oil have been identified and the critical N_c was different [11]. In literature [10], the Tarbert cores had a steeper slope of CDC compared to Berea cores, which were very similar in mineralogy, pore size distribution, permeability, and dispersivity, while the shift was attributed to the mix wet behavior of Tarbert cores. Nonuniform wettability, which could be further subdivided into fractional wettability and mixed wettability, was simulated by incorporating pore wetting effects into steady-state model [52]. According to the modeling and computed relative permeability, the fractional wet relative permeability curve shifted towards lower water saturation as the oil-wet pore fraction increased, while such general trend was not so apparent in mix wet model, and the crossover point no longer moved towards lower water saturation as the oil-wet pore fraction increased. These simulations may provide good choice for reservoir wettability modeling while no satisfactory test existed as claimed in the literature. With full understanding of wettability, more and easy recovery can be attained.

For the crude-oil brine micromodel systems studied, oil recovery by waterflooding increased with change in wettability from strongly water-wet to a maximum at close-to-neutral wettability [56]. The effects of wettability on recovery can be seen in Figure 4 [56]. Further studies [57] also confirmed that changes in waterflood recovery with wettability changes induced by adsorption of asphaltene indicated a maximum in oil recovery at very weakly water-wet conditions. Compared to figures in literatures [58],

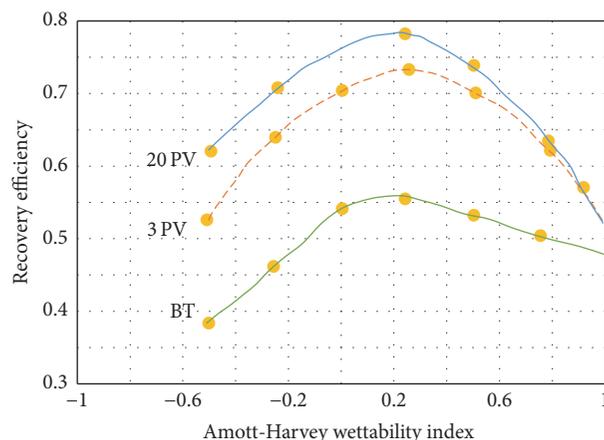


FIGURE 4: Recovery efficiency versus wettability index [56].

simulated capillary pressure data demonstrated that standard wettability tests (Amott-Harvey and free imbibition) may give misleading results when the sample was fractionally wet in nature [58]. Changes in waterflood recovery with wettability changes induced by adsorption of asphaltene indicated a maximum in oil recovery at very weakly water-wet conditions [57]. The residual oil saturation S_{or} for oil-wet or mixed-wet samples can be more than 15–20 saturation units lower than that of water-wet samples [59]. Study showed that the residual oil saturation ranged between 15% for the mixed-wet samples and nearly 50% for the strongly water-wet samples [60], and it was also shown that weakly water-wet and mixed-wet water samples produced more oil, although at slower rate during spontaneous imbibition than strong water-wet samples. Recent studies showed that positive effect of decreasing IFT was larger in mixed-wet formations than in water-wet formations [61]. Spontaneous imbibition tests at water-wet and mixed-wet conditions indicated that the spontaneous imbibition rate at mixed-wet conditions was slower and the oil production was much smaller than at water-wet [44].

Carbonates cores tests showed optimum oil recovery shifted towards less water-wet conditions when the capillary number increased [8, 20], and the oil recovery was observed to have a maximum value when the wettability was about $I_w = 0.3$, which is in agreement with literature [56].

5. A Different CDC

Classic CDCs all showed residual oil saturation decreased continuously as capillary number increased. Recently, some different CDC curves were published in SP and ASP flooding study. After many flooding tests, Qi et al. [33–36, 62] gave a CDC quite different from all previous ones, seen in Figure 5. They called this curve *New CDC*. Since these curves were got based on ASP flooding tests in compacted cementation slab models (4.0 cm × 4.0 cm × 30 cm), which are quite different from previous cylinder cores used in typical CDC tests, this CDC cannot be regarded as real typical CDC. Otherwise, we should enlarge the models used for CDCs. From this curve, it is clear that the shape is different from previous curve,

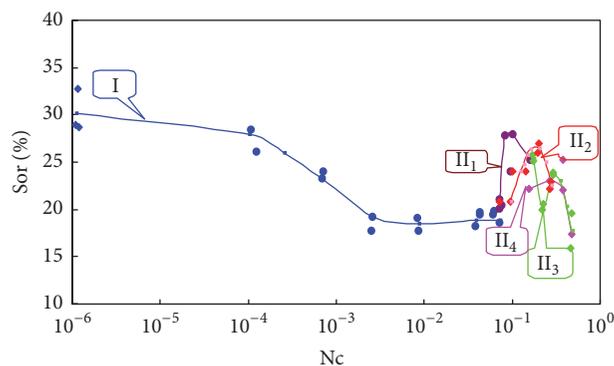


FIGURE 5: Different CDC [33–36, 62].

especially when capillary number is high. This curve indicates that capillary number is no longer the higher the better, which is basic conclusion from traditional CDCs. These differences are related to residual oil saturation concept. It is remaining oil saturation rather than residual oil saturation in their studies [33–36, 62]. The difference between remaining oil saturation and residual oil saturation lies in the fact that the sweep volume fraction is whether 100% swept or not as cylindrical. Though in classic CDC tests the sweep efficiency is also not 100% because of microscopic heterogeneity, most researchers consider the oil or water saturation in cylindrical cores at high enough injection/flooding rate after enough injected porous volume (PV) as residual saturation. In some other tests, if the injection rate is not high enough, or the injection volume is not enough, or serious heterogeneity exists, or the mobility is not adequate, not all areas are flood; thus this is the remaining oil saturation. The difference between remaining oil and residual oil is easy to mix. Thus, in every core-flooding test, one should be aware of the difference.

Though the CDC in Qi et al. [33–36, 62] is not real CDC, it still attracted attention from chemical flooding application perspective. From this curve (Figure 5), we can see that with different chemical systems, after capillary number increased to a certain value, the remaining oil saturation (not residual oil saturation) may increase or decrease as capillary number goes on increasing. What is more, according to this curve, the final remaining oil saturation was quite more than zero, rather than the near zero value of classical typical CDC [25, 48]. According to previous study, with the attainment of ultra-low IFTs (10^{-3} mN/m) and with adequate mobility controls, all the oil contacted can conceivably be displaced [45]. Although their results required more tests to repeat and verify, the experiment results were in very good agreement with literature [14], seen in Figure 6. Pursuit of ultra-low IFT and highest Nc is not advisable according to this curve. The mobility control should be given priority rather than lowering IFT. This conclusion was in agreement with literatures [63, 64]. It should be noted that these literatures [14, 25, 33–36, 48] used three layer heterogeneous compacted cementation slabs also known as artificial cores in chemical flooding tests, and viscosity of ASP or SP in these two tests was viscosimeter measured apparent viscosity rather than effective viscosity

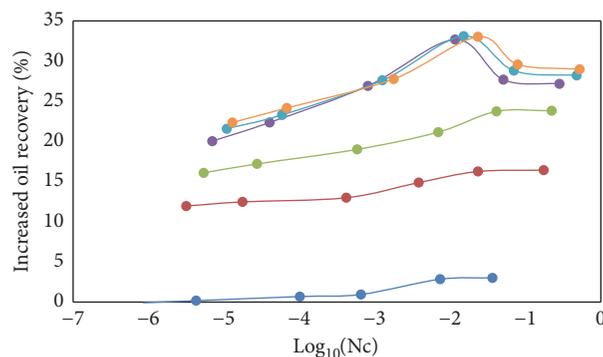


FIGURE 6: SP recovery with different capillary numbers [14].

in porous media. The relative permeability change due to capillary number increase, as indicated in literature [31], and the capillary number difference caused displacement difference and viscous fingerings [65] may account for these CDCs differences. Flow regimes [46] change from capillary dominated flow to viscous dominated flow or interchange, which may be attributed to these phenomena. Much experimental and theoretical work remains to be done in order to clarify these issues.

All previous CDCs had been got from tests in relative high permeability cores, and thus the conclusion that high capillary number of about 10^{-2} could make zero residual oil saturation [9, 25] should not be directly used or not used in low permeability cores since the pores structures were so complex and different from high ones. In CDC, there is no sweep efficiency issue and it is all about displacement efficiency. However, in enhanced oil recovery or oil production process, both displacement efficiency and sweep efficiency should be considered. The flow in low permeability porous media often showed obvious non-Darcy effects according to literatures [66, 67]. This non-Darcy effect behaves as nonlinear relationship between flow and pressure difference, and threshold pressure gradient is used to revise Darcy's law, seen in [27]. While the possibility of departures from Darcy's law at low superficial velocities has not received attention in the petroleum industry, it has been recognized in some of the major literatures dealing with the flow of fluids through porous media [28]. From the low permeability core ($K = 32$ mD and 26 mD) waterflood results [4], the residual oil saturation was 17.6% and 18.2% at a capillary number of 10^{-3} and 10^{-2} , respectively, while for high permeability core ($K = 1150$ mD) the residual oil saturation at capillary number of 10^{-2} was 7.8%. Theoretically, in higher permeability rocks the Nc versus Sor curve was shifted towards larger Nc if the pore-throat size distribution was similar in shape [49]. Darcy's law would be expected to apply and the relative permeability concept would be valid where water and oil are flowing concurrently as continuous phases [45]. Thus, relative permeability of water/oil was different in continuous saturation and in discontinuous saturation, and such difference of experiments making CDCs in literatures was easily and often neglected. It is obvious that the different CDC [33–36, 62]

curve was under condition of waterflood discontinuous saturation.

$$u = \frac{q}{A} = \frac{K}{\mu} \left[\frac{\Delta p}{\Delta L} - \left(\frac{\Delta p}{\Delta L} \right)_{cr} \right], \quad (2)$$

$$\text{when } \frac{\Delta p}{\Delta L} > \left(\frac{\Delta p}{\Delta L} \right)_{cr};$$

see [27].

$$u = 0, \quad \text{otherwise.} \quad (3)$$

The difference of two kinds of CDC may also be attributed to the absence of viscosity ration (μ_o/μ_w) in most capillary numbers, though it has been incorporated in some definition expression [4]. Researchers [49] found that curve was strongly affected by the viscosity ratio (μ_o/μ_w) and as this ratio decreased, so did the residual oil saturation. In application of capillary number relationships, the possible effects of viscosity ratio and wettability also must be considered [6]. It can be concluded that IFT was not the lower the better while in CDC application. Experiment and simulation tests [40] in a mixed-wet media both showed that viscosity ratio had an influence on the displacement effects. Simulation results [68] of polymer displacing viscous oil indicated that the oil recovery decreased significantly as polymer/oil viscosity ratio decreased. The viscosity ratio affected imbibition rate and also recovery [69]; thus it should be considered in capillary number. Many capillary numbers were defined without considering the viscosity ratio effect; thus these definitions without considering viscosity ratio should be carefully or not used in heavy oil waterflooding characterization since the viscosity ratio between oil and water is huge and greatly affects the results. Literature [30] indicated that low injection rate was beneficial to stabilize the waterflood and final recovery of heavy oil. In their test, the breakthrough recovery decreased as the capillary number increased with the exception of lowest injection rate (1 mL/min), and the major difference between conventional oil and heavy oil waterfloods accounted for that at water breakthrough, and residual heavy oil was bypassed due to adverse mobility ratio, not from capillary trapping. The importance of frontal stability of surfactant flooding without mobility control at velocity less than critical one required for a gravity stable displacement was well studied [15, 16]. Their studies indicated that higher velocity may cause unstable displacement front, which may not make the lowest residual oil saturation.

6. CDC Application

CDC has various applications in not only water flooding but also chemical flooding [12, 13, 15, 16, 40]. According to capillary number theory and critical capillary number requirement, to get best/highest oil recovery, the capillary number must be increased to two or three orders of magnitude [4], as can be seen from Figure 1. This may be attained by reducing IFT to three orders of magnitude, or increasing water viscosity and velocity. The water viscosity may be increased by adding polymers which could increase water viscosity from

10^{-1} to 10^2 ; however, this potential was restrained by the polymer compatibility and injection pressure. The potential of increasing water velocity was limited due to the pressure drop and the great difficulty. Relative permeability tests at different displacement velocity ranging from 80 mL/hr to 400 mL/min showed little or no significant change [7]. Water flood experiments also showed that subsequent 100 and 500 times increase in injection rate of water could not reduce oil saturation established in normal water flood [4]. Similarly, flow rate of vapor increased 72 times (1.66×10^{-4} to 1.2×10^{-2} cm³/s) was observed the same final recovery and unchanged residual fluid saturation [24]. Once trapping occurred in a normal waterflood, it has been estimated that the oil was held by capillary forces of such a magnitude that interfacial tension reduction to values of the order of 10^{-3} to 10^{-4} mN/m was required to remove significant quantities of oil under the flow conditions obtainable in the reservoir [4]. Achievement of capillary number of 10^{-3} , which was necessary for oil recovery by immiscible displacement, required that the interfacial tension be lowered to about 10^{-2} to 10^{-3} mN/m [5]. Thus, the most practical technique was to reduce IFT between water and oil to a very large scale, and it leads to the requirement of 10^{-3} mN/m in most surfactants screening in SP flooding or ASP flooding practice, especially in China, where the most chemical flooding field tests happen. Simply guided by classic CDC, it seemed that pursuit of ultra-low IFT as low as possible would make highest displacement efficiency, while the different CDC proved this was not always true. Even though the different CDC reflects remaining oil saturation rather residual typical oil saturation, it is valuable in guiding application. The IFT level needed to mobilize capillary trapped oil is proportional to the heterogeneity, and IFT reduction down to 1 mN/m was found sufficient for heterogeneities of length scale 10 cm [40]. Apart from heterogeneity required adequate mobility control, researchers pointed out that further increase of N_c more than 10^{-2} may be not necessary [45]. Adequate IFTs for ASP have been studied with heterogeneous physical model and test results indicated that recovery of 10^{-2} mN/m IFT system was higher than that of 10^{-1} mN/m and 10^{-3} mN/m systems [63, 64]. These phenomena may be attributed to the absence of viscosity ration (μ_o/μ_w) in most capillary numbers, though it has been incorporated in one expression [4]. Researchers [49] found that curve was strongly affected by the viscosity ratio (μ_o/μ_w) and as this ratio decreased, the residual oil saturation decreased. It can be concluded that IFT was not the lower the better while in CDC application. Experiment and simulation tests [40] in a mixed-wet media both showed that viscosity ratio had an influence on the displacement effects. Simulation results [68] of polymer displacing viscous oil indicated that the oil recovery decreased significantly as polymer/oil viscosity ratio decreased. We should be aware that interfacial tension of 10^{-3} was not always necessary and interfacial tension of 10^{-2} could make better recovery than 10^{-3} with proper design [33–36, 62].

The hypotheses in the setting up of capillary number should have been given attention. Many CDCs were conducted on high permeability cores tests and it seems that

the residual oil saturation would decrease to a value near zero at very high capillary number; even the permeability is ultra-low according to the classic CDCs. It seemed that permeability had no effects on CDC, while most tested have been conducted with relative high permeability cores. Up to present, no systematic study on permeability effect on CDC is seen. It was concluded that the critical capillary number of the reservoir cores was found to be reduced when permeability was increased [10]. Based on Darcy's linear flow hypothesis, however, the CDC should not be used or directly used in low permeability formation since flow in which often behaved nonlinearly [27, 28]. The relatively low permeability samples generally gave higher S_{or} values than the high permeability Berea samples, but there was no strong general correlation between permeability and S_{or} [6]. Low permeability chalks based CDC indicated that the minimum residual oil saturation was about 0.2 when capillary number increased to 10^{-2} , and some of the curves have a trend of dropping to zero while other curves did not according to the wettability difference [20]. It seemed that the residual oil saturation would not drop to zero even at high capillary number of 10^{-2} . One possible explanation of the high residual oil saturation at high capillary number was oil trapped by capillary end effects [38]. Separate studies should be given on this issue.

Another condition to note was the difference of continuous and discontinuous saturation in conducting a CDC [6]. Chatzis and Morrow [6] pointed that for sandstones, for a given reduction of S_{or} (more than 50%), the corresponding capillary number for the displacement of continuous oil was significantly smaller than that required for mobilization of discontinuous oil, while at reduced S_{or} below 50% the capillary number curves for the displacement of initially continuous and discontinuous oil fell close together. Remobilization of discontinuous oil after waterflooding was primary concern in enhanced oil recovery not only in chemical flooding but also in marginal field like post-polymer flooding in China. While typical CDC discusses the relationship between residual wetting or nonwetting phase saturation and capillary number, remaining oil saturation is often used instead of residual oil saturation in laboratory studies. One reason is that it is sometimes hard to distinguish them in short cylindrical core tests, since microscopic displacement efficiency and sweep efficiency are difficult to differentiate in one dimension model without accurate test technique like CT and NMR. Only in two or three dimensional models, the difference between sweep efficiency and displacement efficiency becomes drastic and obvious.

In application of capillary number relationships, the possible effects of viscosity ratio and wettability also must be discussed in previous parts. The wettability effect was considered [6]. The critical capillary number was about one order of magnitude higher for oil-wet conditions than that under water-wet conditions [70]. The CDC in capillary number in mixed-wet systems was between water-wet and oil-wet system [49]. In the capillary number definition, contact angle was incorporated to reflect the influence of wettability [5]. The application of the correlation has not been established for systems where $\cos \theta$ closely approached

zero [71]; thus trends of behavior of intermediate wetting conditions have yet to be measured [6].

Though the wettability was studied in many references [4, 21, 49, 56, 72, 73], the viscosity ratio was considered in few literatures [4]. The viscosity ratio affected imbibition rate and also recovery [69]; thus it should be considered in capillary number. Many capillary numbers were defined without considering the viscosity ratio; thus they may be not valid in application in heavy oil waterflooding characterization since the viscosity ratio varied greatly. Literatures [29, 30] indicated that low injection rate was beneficial to stabilize the waterflood and final recovery of heavy oil. In their test, the breakthrough recovery decreased as the capillary number increased with the exception of lowest injection rate (1 mL/min), and the major difference between conventional oil and heavy oil waterflooding was attributed to different water breakthrough timing, and that residual heavy oil was bypassed due to adverse mobility ratio, not capillary trapping. Though there is difference between imbibition and displacement tests, the displacement efficiency and recovery are the same focus in almost all tests. The importance of this study is that it is contrary to previous conclusion of CDCs, if only judged from the relationship between capillary number and recovery. It was also shown that lower injection rate produced a higher additional recovery after waterflooding and imbibition caused by injection rate which allowed capillary force to aid recovery accounted for this [29]. This is quite different from previous conclusion in light oil that higher injection rate leads to higher recovery. Pavone [65] used molding technique to characterize the viscous fingering by considering both viscosity ratio $F\mu$ and capillary number difference, ΔNc . He found that three kinds of displacement can occur. Displacement was stable at low $(F\mu - 1) \Delta Nc$ values and the front was almost flat and no viscous fingering occurred. Increasing $(F\mu - 1) \Delta Nc$ resulted in macroscopic viscous fingering and decreased recovery at breakthrough. Increasing $(F\mu - 1) \Delta Nc$ further did not increase more microscopic viscous fingering but decreased sweep efficiency at pore level and thus lowered the recovery. The results can be seen in Figure 7 [65]. This is in agreement with literatures [36, 62]. The conclusions may help to account for the different CDC in literatures [33–36]. In other works, the so-called New CDC curve can be supported by other researchers; thus this phenomenon has both theoretical and practical meaning in chemical EOR in both light oil reservoir and heavy oil reservoir.

7. Conclusions

Capillary number which denotes viscous force diving capillary force is the main factor affecting displacement efficiency. Capillary number theory is very important for chemical flooding enhanced oil recovery. The difference between microscopic capillary number and the microscopic one is easy to confuse.

The capillary number theory was based on capillary tube bundles and Darcy's law hypothesis, and this should always be kept in mind when used in chemical flooding EOR. The flow in low permeability porous media often shows obvious non-Darcy effects, which is beyond Darcy's law. Capillary number definition should take viscosity ratio into consideration.

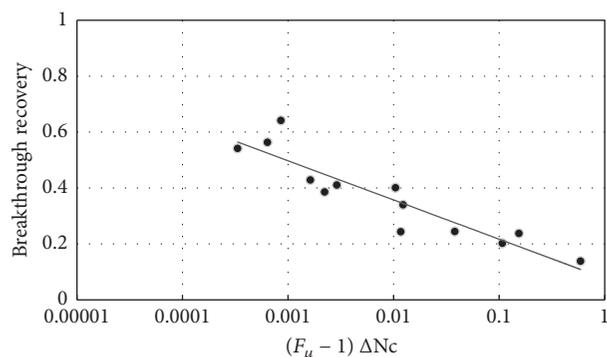


FIGURE 7: Decrease of breakthrough recovery versus $(F\mu - 1) \nabla Nc$ [65].

Typical classical CDC showed that larger capillary number leads to lower residual oil saturation and when capillary number increased to a certain critical value, the residual oil saturation could drop to a minimum value even zero. As for low or ultra-low permeability media, whether the residual oil saturation could drop to zero or not is worth investigation since previous tests were mainly carried out on high permeability cores. The critical capillary number for a gas-liquid system was different from that of an oil-water system in the same type of rock.

A typical CDC was observed for the nonwetting phase with a characteristic shape with a saturation plateau below a critical Nc and a decline slope above the critical Nc . CDCs of wetting phase have different critical Nc and decline slope.

Relative permeability was proved function of capillary number; its rate dependence was affected by capillary end effects. While some researchers disagree with this, more studies on physical nature may help correct understanding and use of CDC.

The mobility control should be given priority rather than lowering IFT. The displacement efficiency was not increased as displacement velocity increased as expected in heavy oil chemical flooding. Largest capillary number does not always make highest recovery in chemical flooding in heterogeneous reservoir. Misuse of CDC in EOR included the ignorance of mobility ratio, Darcy linear flow hypothesis, difference between microscopic capillary number and the microscopic one, and remaining oil and residual oil.

Nomenclature

Nc:	Capillary number
IFT:	Interfacial tension
CDC:	Capillary desaturation curve
ASP:	Alkali-surfactant-polymer
SP:	Surfactant-polymer
Sor:	Residual oil saturation
Srw:	Irreducible water saturation
Krw:	Water relative permeability
Kro:	Oil relative permeability.

Disclosure

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Competing Interests

The authors declare that there is no conflict of interests regarding the publication of this paper.

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