Effect of Wettability on High-Velocity Coefficient in Two-Phase Gas/Liquid Flow

Myeong Noh* and **Abbas Firoozabadi,** SPE, Reservoir Engineering Research Institute (RERI)

Summary

Gas-well productivity is affected by two distinct mechanisms: liquid blocking and high-velocity flow in two-phase flow. The former has been studied extensively recently, but the understanding of the latter is limited. High-velocity gas flow in single phase has been studied thoroughly by a large number of authors. Despite the fact that high-velocity coefficient in the presence of an immobile and a mobile liquid phase is much higher than that in single phase, only a handful of studies have been made on the subject. In this work, we have measured the high-velocity coefficient, β, in steady-state two-phase gas/liquid flow. The results are presented as a function of liquid relative permeability and liquid saturation. In our measurements, the wetting state is varied by the treatment with a fluorochemical compound. Then, the effect of wettability on the high-velocity coefficient in two-phase flow is investigated. Results show that when the liquid is strongly wetting, the high-velocity coefficient increases approximately 270-fold in water/gas two-phase flow. However, our data show a systematic reduction of high-velocity coefficients for the altered wetting state in two-phase flow. We present measurements of the velocity coefficients in single-phase flow and two-phase flow, for both oil/gas and water/gas flow and strong liquid-wetting and altered-wetting states. On the basis of our measurements, we conclude that the treatment of the wellbore region can result in significant improvement in well deliverability from the large reduction of high-velocity coefficients.

Introduction

Gas deliverability in gas-condensate reservoirs can be significantly affected by liquid blocking, either from condensate accumulation or water blocking, and high-velocity flows in the near-wellbore. Hydrocarbon blocking in gas-condensate reservoirs results in a significant loss of well productivity; water blocking from hydraulic-fracturing operation often limits the advantage of fractures. In addition to liquid blocking, the increased pressure drop, caused by inertial effects at high gas velocity in both low-permeability and hydraulically fractured reservoirs, can also result in low productivity. The focus of this work is on the high-velocity gas flow in two-phase gas/liquid flow in gas reservoirs.

Darcy's law is inadequate to describe high-velocity gas flow in porous media. Through the high-velocity coefficient, β, Darcy's law is modified, and the additional pressure drop from high-velocity flow can be expressed as the Forchheimer equation (1901). The general understanding is that the high-velocity coefficient in two-phase flow is higher than in single-phase gas flow in a dry rock. However, very few attempts have been made for conclusive experiments in determining the high-velocity coefficient in two-phase gas/liquid flow because of experimental difficulties in maintaining a constant liquid saturation for different pressure drops.

Gas flow at low velocity is governed by Darcy's law, which describes a linear relationship between pressure gradient and volumetric flux. At high gas velocity, the pressure gradient required to maintain a certain flow rate through porous media is higher than that predicted by Darcy's law. The effect of inertia has to be added. The result is the Forchheimer equation expressed by

$$-\nabla p = \frac{\mu_g}{k_g} u_g + \beta \rho_g u_g^2, \quad \ldots\ldots (1)$$

where μ_g is gas viscosity, k_g is the effective gas permeability, u_g is the gas volumetric flux, β is a high-velocity coefficient, and ρ_g is gas density.

Eq. 1 is valid both for single-phase gas flow and for two-phase gas/liquid flow, provided that the capillary effect is negligible. In 1D, one may integrate Eq. 1 to obtain

$$\frac{M(p_1^2 - p_2^2)}{2\mu_g ZRTLj_g} = \frac{1}{k_g} + \beta \frac{j_g}{\mu_g}. \quad \ldots\ldots (2)$$

Here, p_1 and p_2 are the inlet and outlet pressure; M and j_g are molecular weight and mass flux of gas, respectively; R and Z are the gas constant and the gas deviation factor, respectively; T is temperature; and L is the length. Effective gas permeability and high-velocity coefficient are determined by plotting $M\Delta p^2/2\mu_g ZRTLj_g$ vs. j_g/μ_g, provided that the saturation is constant. **Fig. 1** shows a schematic of determining the effective gas permeability and the high-velocity coefficient. Note that the effective permeability in Eq. 2 becomes the absolute permeability when the rock is dry ($S_g = 100\%$, $k_{rg} = 1.0$).

There has been much work in the literature on high gas velocity in single-phase flow in dry rocks. There has also been a fair amount of work in single-phase gas flow with immobile liquid saturation. Very little work, however, has been done in two-phase gas/liquid flow at high gas velocity. In the following, we will briefly review the literature in experimental studies and set the stage for our work in two-phase gas/liquid flow at high gas velocity.

For describing the high-velocity coefficient, it has been suggested (Firoozabadi and Katz 1979; Kalaydjian et al. 1996) that the curvature of streamlines results in extra pressure loss, and the cross section of the flow channel increases and decreases alternately. The contraction and expansion through pore throat and pore body cause acceleration and deceleration of the fluid, and, as a result, additional pressure drop occurs. Therefore, the high-velocity coefficient varies with characteristics of pore structure. Li and Engler (2001) reviewed literature on high-velocity coefficients and summarized empirical correlations in single-phase and two-phase flow. The different correlations result from pore geometry and lithology variation. In single-phase gas flow, the permeability has been considered as the most important parameter.

To determine the high-velocity coefficient, at least two measurements are required for different pressure drops at a constant liquid saturation. With two data points, the high-velocity coefficient and effective gas permeability can be calculated by Eq. 2. Experimental studies have been carried out to determine the high-velocity coefficient when the liquid phase is immobile. Gewers and Nochol (1969) conducted tests using nitrogen and glycerine, which has relatively low vapor pressure and served as the immobile liquid phase. They showed that the high-velocity coefficient first decreases slightly and then increases rapidly as the saturation of the immobile liquid phase increases. The slight decrease of β at low immobile liquid saturation was explained by the streamlining of pores by the liquid (i.e., the liquid tends to round off sharp edges of the pores). The high-velocity coefficient increased by an order of magnitude over that of a dry core for immobile liquid saturation of 20 to 30%.

Very few attempts have been made for conclusive experiments in two-phase gas/liquid flow because of the difficulty in maintaining constant liquid saturation at different pressure drops. Wong

* Now with Chevron Corporation.

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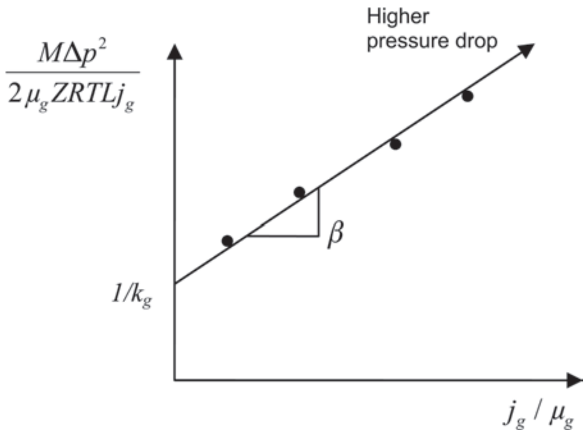

Fig. 1—Schematic of effective permeability and the high-velocity-coefficient determination at a fixed saturation.

(1970) studied the effect of the flowing liquid phase on the high-velocity coefficient in steady-state experiments for nitrogen/water two-phase flow. Six experimental points were used for three different water saturations; data were taken at only two pressure drops for each saturation. He observed that the increase of the water saturation from 40 to 70% resulted in as much as an eight-fold increase in the high-velocity coefficient. Evans and Evans (1988) demonstrated that a low mobile-liquid saturation might increase the high-velocity coefficient by an order of magnitude in proppants pack. Al-Rumhy and Kalam (1996) reported a significant increase in the high-velocity coefficient with mobile water saturation. The measurements of high-velocity coefficients were performed by single-phase gas injection in a brine-saturated core (i.e., unsteady-state flow test). The high-velocity coefficient at water saturation higher than 60% was not measured. Water saturations were measured both gravimetrically and volumetrically. In their work, the increase of the high-velocity coefficient was higher for the high water saturation (>50%) than for the low water saturation (<30%). Grigg and Hwang (1998) performed experiments with brine/nitrogen two-phase flow and confirmed that the high-velocity coefficient increases significantly with brine saturation. The high-velocity coefficient was measured by the unsteady-state method. Mobile liquid had a greater effect on the high-velocity coefficient than the immobile liquid; this result is consistent with the conclusion by Al-Rumhy and Kalam (1996). Recently, Lombard et al. (2000) performed tests of gas and condensate flow at an irreducible water saturation of 24.8% and determined a single high-velocity coefficient at a narrow range of condensate saturation (55, 58, 60, and 61%). The high-velocity coefficient at $S_w=24.8\%$ and $S_c\approx58.6\%$ was 2.5 times greater than that at $S_w=24.8\%$ and $S_c=0\%$.

In this work, we suggest an alternative approach to determine the high-velocity coefficient in two-phase flow. Assuming that the saturation is a function of liquid relative permeability only, the high-velocity coefficient and the effective gas permeability can be determined as a function of liquid relative permeability. The laboratory measurements of high-velocity coefficients for Berea cores for both two-phase water/gas and oil/gas flow are presented.

In general, the increase in permeability and porosity results in the decrease of β. Inertial effect increases with aspect ratio, surface roughness, and coordination number (i.e., average number of throats that connect with each pore—that is, pore connectivity) (Noman and Archer 1997). Ma and Ruth (1997) showed that the inertial effect is significant at high Reynolds numbers. Kalaydjian et al. (1996) summarized the effect of pore structure parameters on the high-velocity coefficient. However, the effect of wetting state on β has not yet been studied, to the best of our knowledge. Using the fluorochemical treatment at high temperature and high pressure, the wettability of Berea cores can be altered to intermediate gas-wetting (Fahes and Firoozabadi 2007; Noh and Firoozabadi 2006; Tang and Firoozabadi 2002). The measurements in this paper cover the high-velocity gas flow for various wetting states.

The liquid saturation can be estimated by the exponential relative-permeability model using the published Berea core data. Therefore, the conversion of the liquid relative permeability to liquid saturation is presented in our measurements. The consideration of gas slippage effect is also discussed.

This paper is structured along the following: We first present the experimental setup and our procedure to determine the high-velocity coefficient in two-phase flow. Next, we present the results of our measurements, followed by concluding remarks.

Experimental Setup and Procedure

Treatment for Wettability Alteration. Fluorinated silane, L-18941 (Lot 2), is used to alter the wettability of Berea cores to intermediate gas wetting. In the treatment process, the gas-saturated core is placed in an oven at 140°C and 200 pounds/square in. gauge (psig). We inject 5 pore volumes (PV) of the chemical solution, which consists of ethanol, acid, water, and the chemical. Various concentrations of Lot 2 are applied to study the effect of wetting state on high-velocity gas flow. We age the core overnight (approximately 15 hours) at 200 psig and 140°C. Thereafter, we inject 20 PV of water to test durability of the chemical adsorption on the pore surface. The fluorochemical FC-X is also used for the wettability alteration. The details of the treatment process are described elsewhere (Fahes and Firoozabadi 2007; Noh and Firoozabadi 2006). **Table 1** shows the relevant data for the cores used in this study. The cores Br-un, Br-4, Br-8, and Br-25 are used for water/gas two-phase flow tests; the cores Br-un, Br-una, Br-8a, and Br-25 are used for oil/gas two-phase flow tests. High-velocity coefficients in single-phase gas flow (β^{sp}) are measured to be about 0.1 to 0.9×10^6 cm^{-1} for 550- to 830-md cores with lower value for the higher-permeability core. These measurements are in agreement with the literature (Gewers and Nichol 1969; Geertsma 1974). The cores Br-8 and Br-4 are treated using a two-step process in which ethanol with the chemical is injected first, followed by the injection of ethanol with acid and water. In the past, we have found that the two-step process is less effective for wettability alteration to intermediate gas wetting. In this work,

TABLE 1—PROPERTIES OF CORES

Core ID	Br-25	Br-8†	Br-4†	Br-un	Br-una	Br-8a
Length (mm)	151.1	151.2	151.2	151.2	151	151
Diameter (mm)	25.9	25.7	25.7	25.7	25.8	25.8
Absolute perm.* (md)	820	556	586	750	824	345
Porosity (fraction)	0.22	0.22	0.22	0.22	0.22	0.22
High-velocity coeff. (β^{sp}**, $10^6 cm^{-1}$)	0.33	0.59	0.59	0.51	0.13	0.95
Chemical conc. (wt%)	25%, Lot 2	8%, Lot 2	4%, Lot 2	–	–	8%, FC-X

*Absolute permeability is measured using nitrogen.
**Measured at dry condition.
†Treated by the two-step process.

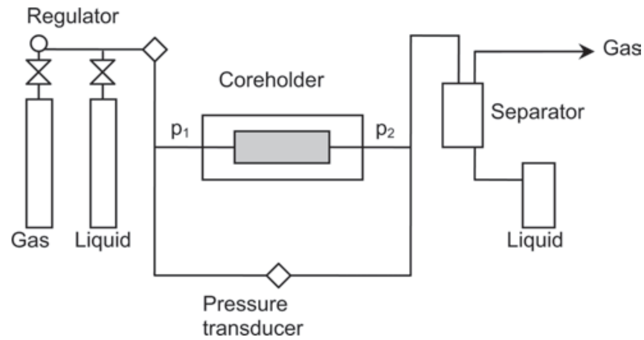

Fig. 2—Schematic of the apparatus for flow tests.

we use the treated cores to investigate the effect of wetting state on the high-velocity coefficients for two-phase flow.

Apparatus for Flow Tests. Steady-state two-phase relative-permeability tests are performed to determine the high-velocity coefficients. **Fig. 2** shows a schematic of the experimental setup. The coreholder is placed horizontally, and the tests are carried out at a room temperature of 20°C. Brine (1.0 wt% of NaCl) and nitrogen are used as water and gas phases, respectively. Density and viscosity of the brine are 1.0 g/cm^3 and 0.97 cp at 20°C. Gas gravity of pure nitrogen is 0.967. Normal decane (n-C_{10}) is used as an oil phase. Density and viscosity of decane are 0.73 g/cm^3 and 0.91 cp, respectively, at 20°C. Gas injection rate is controlled by a pressure regulator; gas flow rate is measured at the outlet. Liquid is injected at a constant flow rate. Relatively high liquid flow rates are used to reduce the capillary end effect. Richardson et al. (1952) showed that the capillary end effect exists for about 3% of the total length at the outlet when the gas (helium) pressure gradient is 0.41 psi/cm and oil (kerosene) saturation is 80% in the 30.7-cm Berea core (permeability around 100 md). In our experiments, liquid flow rates of 0.4 to 1.2 cm^3/min are used at 0.45 to 2 psi/cm of gas pressure gradients. The permeability of Berea cores is much higher than that in the work of Richardson et al. (1952); therefore, it is believed that flow rates are high enough to neglect the capillary effect. Note that even at the high flow rates used in our experiments, liquid flow can be described by Darcy's law.

In this work, we keep the liquid relative permeability constant during a run by keeping the ratio of liquid flow rate to pressure drop constant. Several data points for $M\Delta p^2/2\mu_g ZRTLj_g$ and j_g/μ_g in Eq. 2 are then obtained to determine the high-velocity coefficient and the effective gas permeability simultaneously for a given liquid relative permeability. In subsequent runs, we perform measurements at other various liquid relative permeabilities. At the end of the tests, the liquid saturation of the core is determined by weighing the core. Gravimetric or volumetric saturation measurements for all relative permeabilities during the tests are not performed because they are believed to be less accurate in steady-state relative permeability tests with a heavy core holder (≈20 lbm). Therefore, for all of our data sets, liquid saturation values are obtained only at the end of a given test. Both effective gas permeability and high-velocity coefficient are determined for various wetting states.

The rate effect on relative permeability is ignored. In strong liquid wetting, this assumption is valid. Previous works (Noh and Firoozabadi 2006; Tang and Firoozabadi 2002) have revealed that water relative permeability at a given saturation may increase about two to three times in treated cores because of the rate effect in some saturation ranges. As we will see later, the effect of wettability on the high-velocity coefficient may be much more pronounced. Therefore, our assumption of the relation between liquid relative permeability and saturation is justified.

Results and Discussions

In this section, we first report the results of our work on contact angle and spontaneous imbibition of water and oil in air-saturated cores. Measurements of high-velocity coefficients for water/gas and oil/gas flow and effective gas permeability are then presented.

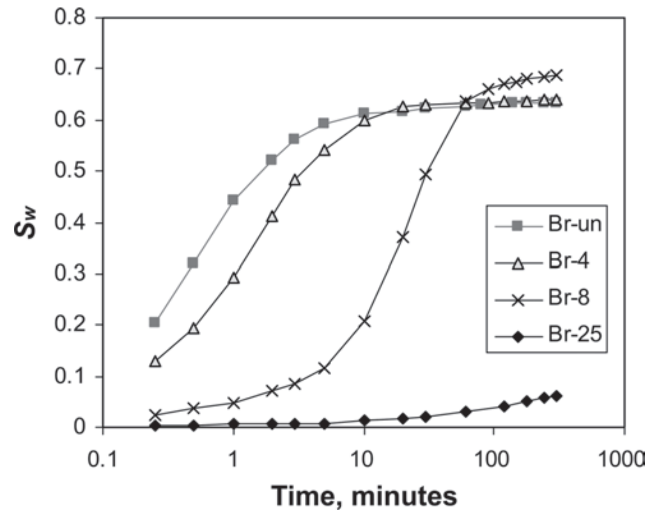

Fig. 3—Spontaneous water imbibition for Berea cores.

Contact Angle and Spontaneous Imbibitions. We have measured the contact angle and the spontaneous water and oil imbibition for cores with different wetting states. In contact angle measurements, a liquid drop is placed onto the core surface. Water quickly imbibes in the untreated cores, Br-un and Br-una. The water contact angles on the treated cores, Br-4 (4% Lot 2), Br-8 (8% Lot 2), and Br-25 (25% Lot 2), are 90°, 150°, and 150°, respectively. For untreated cores, a drop of oil quickly imbibes. The oil contact angles on the treated cores, Br-8a and Br-25, are approximately 60°. In the spontaneous imbibition measurements, the air-saturated core is immersed in liquid, and the core weight is recorded with time so the liquid saturation can be determined. **Figs. 3 and 4** show water and oil saturation histories by spontaneous imbibition, respectively. In Fig. 3, the cores Br-4 and Br-8, which are not treated as effectively as core Br-25, show imbibition results between cores Br-un and Br-25. Water saturations of cores Br-4, Br-8, and Br-un at the time of termination (300 minutes) are approximately the same (around 65%). Imbibition for Br-25 is very low, around 6% at test termination. Oil imbibition tests in Fig. 4 show that the treatment with FC-X, or Lot 2, resulted in the delay of imbibition because of the wettability alteration. The core Br-25 has lower oil saturation than the core Br-8a. However, the three cores have similar oil saturations of approximately 71% at 300 minutes. We do not see a tangible correlation between the

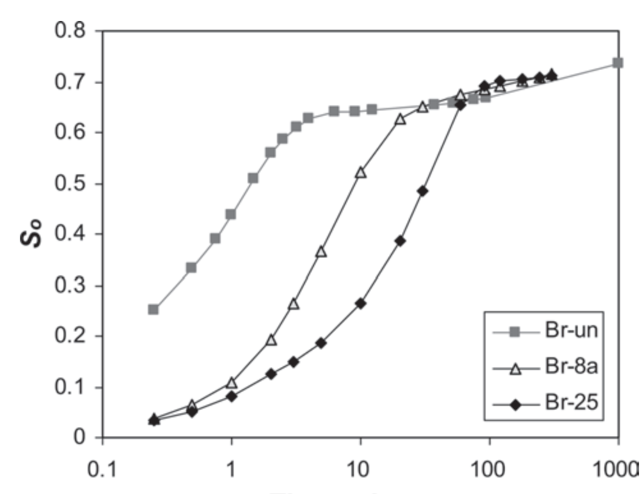

Fig. 4—Spontaneous oil imbibition for Berea cores.

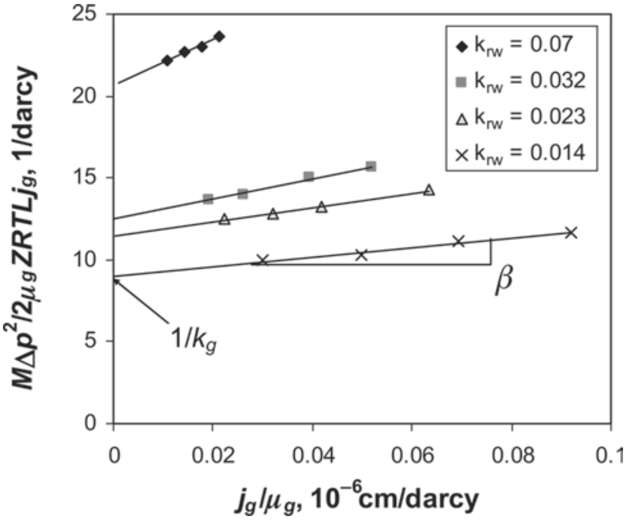

Fig. 5—Water/gas flow tests: Br-un, untreated.

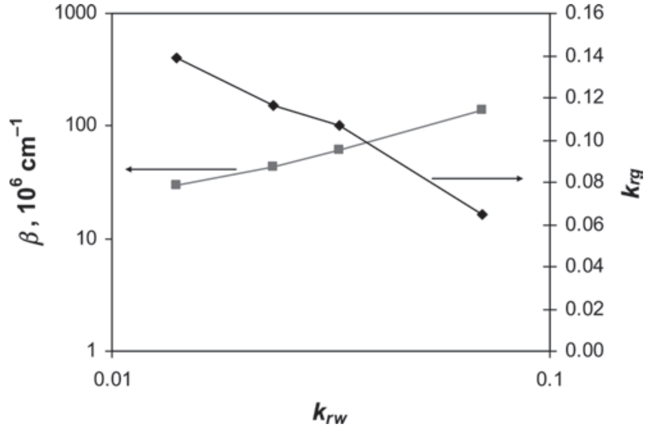

Fig. 6—Relative permeability and high-velocity coefficient in water/gas flow: Br-un, untreated.

contact angle and spontaneous imbibition tests, but there is a trend for low imbibition with high contact angle caused by wettability alteration. In this work, the wettability is quantified by contact angle.

High-Velocity Coefficient Measurements. Relative permeability and high-velocity coefficients are measured at room temperature. We present in detail the water/gas two-phase flow tests in the untreated core, Br-un, and show the results for the rest. Overburden pressure of 1,000 psig is applied throughout the measurements. Water is injected to saturate the core and subjected to a vacuum. Then the core outlet is opened to atmosphere. Water and gas phases are simultaneously injected to measure the drainage relative permeability and high-velocity coefficients. **Fig. 5** shows the results for the 16 measurements of water/gas flow tests on the core Br-un. Four points are obtained for each water relative permeability; note the linear trend in Fig. 5. Generally, when k_{rw} is high (i.e., water saturation is high), the slope, or β, is high. The intercept represents the reciprocal of effective gas permeability; it increases with water relative permeability. From 16 measurements, we obtained four data sets of gas-phase relative permeabilities and high-velocity coefficients, as shown in **Fig. 6.** High-velocity coefficients increase and gas relative permeabilities decrease with increasing water relative permeability (water saturation). It is interesting to note that β increases to around 138×10^6 cm^{-1} at $k_{rw}=0.07$ compared to 0.51×10^6 cm^{-1} in gas-saturated condition. From the literature (Gewers and Nichol 1969), the increase of immobile water saturation to 20% results in approximately an order-of-magnitude increase in β. There is further increase of an order-of-magnitude when water saturation increases from 40 to 70% (Wong 1970). The increase of β is more significant when the liquid saturation is high (Al-Rumhy and Kalam 1996). We observe a 270-fold increase of β at high water saturation.

We also perform oil/gas two-phase flow tests for untreated cores Br-un and Br-una. The results of our measurements for high-velocity coefficients in oil/gas flow are presented in **Fig. 7.** In this figure, we also depict the results for the water/gas flow from Fig. 6. Note that we have plotted our results in terms of dimensionless high-velocity coefficient (β_r). We define $\beta_r=\beta/\beta^{sp}$ to present the relative increase of the high-velocity coefficient in going from two-phase to single-phase flow. For oil/gas flow, the high-velocity coefficient is less than that of water/gas flow because the oil saturation is lower than the water saturation at the same liquid relative permeability. In Fig. 7, the relative value of high-velocity coefficient for water/gas flow at 52.8% of water saturation is close to that for oil/gas flow at 53.5% of oil saturation. Saturation values given in Fig. 7 and subsequent figures are from direct measurements.

Effect of Wettability on High-Velocity Coefficients. The alteration of wettability has a strong effect on the high-velocity coefficient in water/gas and oil/gas flow. **Fig. 8** presents the high-velocity coefficient ratio vs. k_{rw} for water/gas flow. The high-velocity coefficient for the core Br-25 with the most pronounced wettability alteration is approximately 8.6×10^6 cm^{-1} at $k_{rw}=0.07$. For the untreated core, Br-un, it is $\beta=138\times10^6$ cm^{-1} at the same

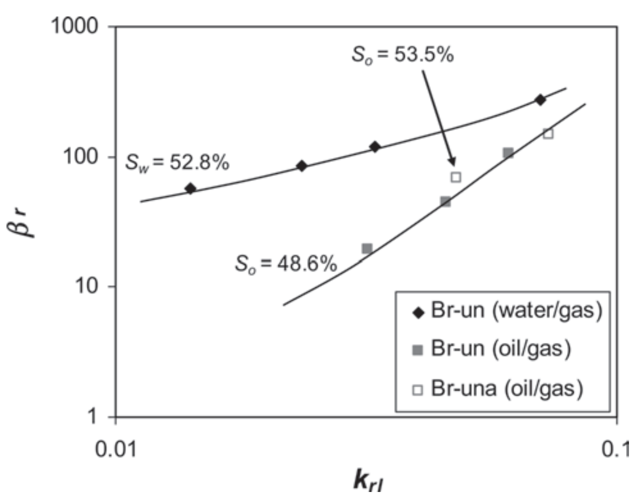

Fig. 7—Relative high-velocity coefficients for water/gas and oil/gas flow: Br-un, untreated, and Br-una, untreated.

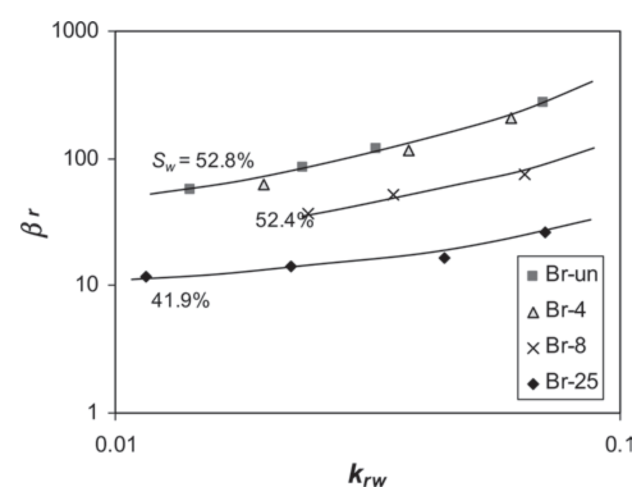

Fig. 8—Effect of wettability on high-velocity coefficient in water/gas flow.

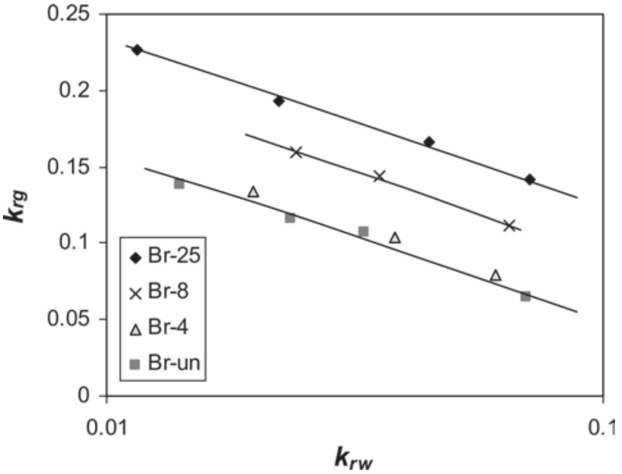

Fig. 9—Relative permeability including high-velocity coefficient in water/gas flow.

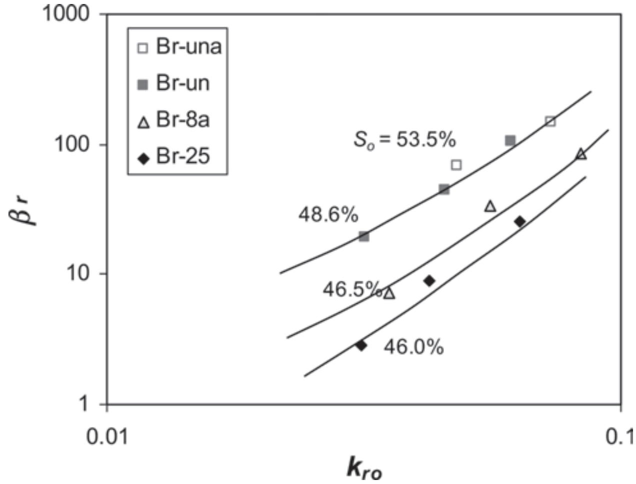

Fig. 10—Effect of wettability on high-velocity coefficient in oil/gas flow.

water relative permeability. The increase of β in the core Br-25 is approximately 10 times less than the core Br-un as a result of wettability alteration. Fig. 8 reveals a trend for change in β with wettability. As the liquid wetting decreases, the high-velocity coefficient also decreases. The high-velocity coefficient for the core Br-8 is less than that for Br-4. The results in Fig. 8 are consistent with imbibition measurements in Fig. 3.

We have determined gas relative permeability for all the cores. **Fig. 9** shows that the gas relative permeability increases at a given water relative permeability when the core becomes intermediate gas wetting. The results are consistent with the previous works (Fahes and Firoozabadi 2007; Noh and Firoozabadi 2006). A 4% treatment on Br-4 shows little improvement in gas relative permeability, in line with the spontaneous-imbibition results shown in Fig. 3. A systematic increase of relative permeabilities with wettability in Fig. 9 is in accord with the change of high-velocity coefficient and spontaneous imbibition measurements.

High-velocity coefficients for oil/gas two-phase flow are presented in **Fig. 10.** As we discussed earlier for the water/gas two-phase flow, the β is lower for the treated core Br-25 than that for the untreated cores Br-un and Br-una. In oil/gas two-phase flow, β_r for Br-25 is about four times less than that for Br-un at the oil relative permeability of 0.062. The high-velocity coefficient for Br-8a is between Br-25 and Br-un. The results are consistent with the spontaneous imbibition shown in Fig. 4. The decrease of β_r after the treatment for oil/gas two-phase flow is less pronounced than that for water/gas flow, which is also in qualitative agreement with the spontaneous imbibition, considering that water imbibition is much less than oil imbibition for the core Br-25. The oil saturations at the oil relative permeability of 0.03 are 46.6% and 46.0% for Br-un and Br-25, respectively. Unlike water/gas flow, the difference of oil saturation at the same oil relative permeability is negligible. Therefore, the effect of wettability alteration on the relative permeability is marginal, as shown in **Fig. 11.** The gas relative permeability of Br-25 improves slightly compared with that of Br-un. The treatment with FC-X also results in the alteration of wettability as discussed in the change of contact angle, the decrease of spontaneous imbibition, and the high-velocity coefficient. However, 8% FC-X treatment for the core Br-8a does not result in the improved relative permeability.

High-Velocity Coefficient vs. Saturation. Using the exponential model of relative permeability, we relate liquid relative permeability to liquid saturation. The exponential model is given by

$$k_{rl} = k_{rl}^0 \left(\frac{S_l - S_{lr}}{1 - S_{lr} - S_{gr}} \right)^{nl}. \quad \ldots\ldots (3)$$

Here, k_{rl}^0 is the endpoint liquid relative permeability; S_{lr} and S_{gr} are residual liquid saturation and gas saturation, respectively. Superscript nl is the relative permeability exponent. Based on the published data for nitrogen/water relative permeability in the Berea cores (Tang and Firoozabadi 2002; Oak 1990), we obtain $k_{rw}^0 = 0.2$, $S_{wr} = 0.35$, $S_{gr} = 0.25$, and $nw = 3.2$ for water relative permeability as a function of water saturation. This approximation is in good agreement with the saturation measurement shown in Fig. 7 for $k_{rw} = 0.014$ at $S_w = 0.528$. For the treated cores, there is higher k_{rw}^0 and lower S_{wr} because of the wettability alteration to intermediate gas wetting (Fahes and Firoozabadi 2007; Noh and Firoozabadi 2006; Tang and Firoozabadi 2002). For example, for the treated core Br-25, we obtain $k_{rw}^0 = 0.3$ and $S_{wr} = 0.23$ by using the measured data point of $k_{rw} = 0.12$ at $S_w = 0.419$ in Fig. 8. From Eq. 3, we then determine the high-velocity coefficients in water/gas flow as a function of water saturation. The result is depicted in **Fig. 12.** Note that this figure is based on regression from the literature data and four of our own saturation measurements. Similarly to the plot of the high-velocity coefficient vs. the relative permeability (Fig. 8), the plot of high-velocity coefficient vs. water saturation, shown in Fig. 12, also shows a pronounced effect of wettabilty alteration. We perform the same analysis to convert oil relative permeability to oil saturation; the results in **Fig. 13** are consistent with Fig. 10.

Effect of Gas Slippage. In our experiments, the high-velocity coefficient measurements can be affected by gas slippage factor. Dranchuk and Kolada (1965) have included gas slippage in their work; then, Eq. 2 can be modified to

$$\frac{M(p_1^2 - p_2^2)(1 + b/\bar{p})}{2\mu_g ZRTLj_g} = \frac{1}{k_g} + \beta \frac{j_g}{\mu_g}(1 + b/\bar{p}). \quad \ldots\ldots (4)$$

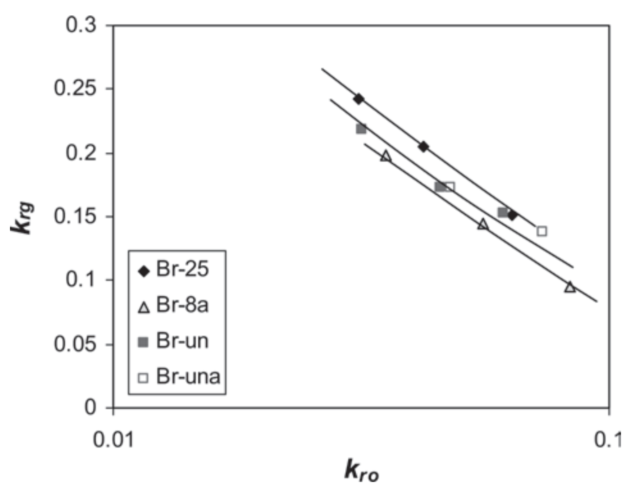

Fig. 11—Relative permeability including high-velocity coefficient in oil/gas flow.

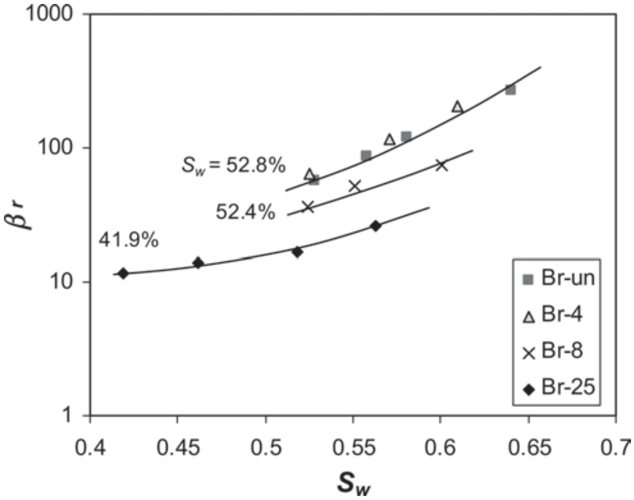

Fig. 12—High-velocity coefficient in water/gas flow as a function of water saturation.

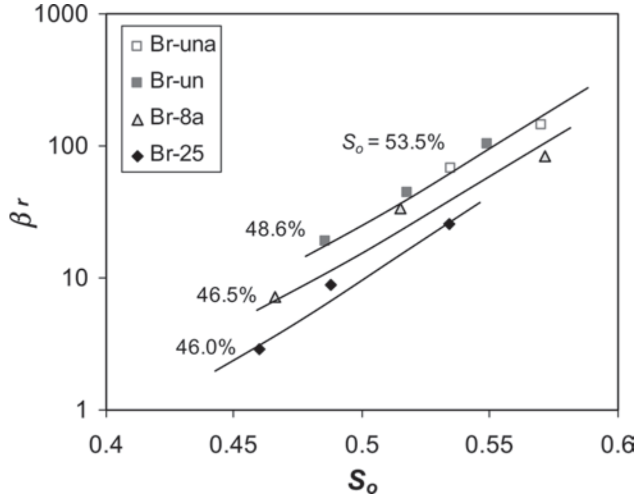

Fig. 13—High-velocity coefficient in oil/gas flow as a function of oil saturation.

Here, b is the gas slippage factor, and $\bar{p}$ is the mean pressure. Effective gas permeability and high-velocity coefficient are determined by plotting $M\Delta p^2(1+b/\bar{p})/2\mu_g ZRTLj_g$ vs. $j_g(1+b/\bar{p})/\mu_g$, provided that the saturation is constant. Including a constant gas slippage factor in Eq. 4 results in the decrease of high-velocity coefficients. Al-Rumhy and Kalam (1996) reported that reservoir cores with 700 to 800 md permeability and 0.25 to 0.27 porosity have a gas-slippage factor of approximately 0.1 atm. When we set $b=0.1$ atm in Eq. 4, the high-velocity coefficient decreases by 20 to 30%. However, the gas-slippage factor is also a function of liquid saturation (Al-Rumhy and Kalam 1996), and application of constant gas slippage in Eq. 4 may be inappropriate. Further work is needed to determine high-velocity coefficient, gas-slippage factor, and gas relative permeability simultaneously in steady-state two-phase flow tests.

Conclusions

In the past several years, the focus of our research has been the increase in relative permeability through the alteration of wettability to intermediate gas wetting. We have now found out another important benefit from wettability alteration—a significant decrease in the high-velocity coefficient in two-phase flow. The following can be concluded from this study:

1. The high-velocity coefficient in two-phase liquid/gas flow is measured as a function of liquid relative permeability, assuming that the average liquid saturation is fixed by maintaining a constant liquid relative permeability.
2. There is a significant effect of the mobile liquid phase on high-velocity coefficient in two-phase gas/liquid flow. The measured increase in this work is as high as 270-fold for strongly liquid-wetting rock.
3. When the wettability is altered from strongly liquid wetting to intermediate gas wetting, the increase in high-velocity coefficient from saturation increase becomes much less pronounced. The effect of wettability on the high-velocity coefficient is in qualitative agreement with spontaneous imbibition measurements.
4. Wettability alteration to intermediate gas wetting increases gas relative permeability by improving water mobility and reducing water saturation. The improvement is more significant when the core is treated with higher chemical concentration. However, the effect of wettability alteration on relative permeability is less pronounced for oil/gas flow.
5. Including the gas-slippage factor in the expression for gas flow results in the reduction of the high-velocity coefficient. Since the gas-slippage factor is also a function of liquid saturation, further work is needed to properly determine high-velocity coefficient, gas-slippage factor, and gas relative permeability simultaneously in steady-state gas/liquid flow.

Nomenclature

b = gas slippage factor, atm
j = mass flux, g/cm^2-s
k = permeability, md
L = length, cm
M = molecular weight, gmole
p = pressure, psi
u = volumetric flux, cm^3/cm^2-s
R = gas constant, cm^3-atm/gmole-K
S = saturation, dimensionless
T = temperature, K
Z = gas deviation factor, dimensionless
β = high velocity coefficient, cm^{-1}
μ = viscosity, cp

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SI Metric Conversion Factors

cp × 1.0*	E−03	= Pa·s
psi × 6.894 757	E+00	= kPa

*Conversion factor is exact.

Myeong Noh is a research engineer at Chevron Corp. in Houston, Texas. His research interests include multiphase flow in porous media, carbon dioxide sequestration, and enhanced oil recovery for heavy oil reservoirs. He holds a BS degree from Hanyang University, Seoul, and MS and PhD degrees from the University of Texas at Austin, all in petroleum engineering. **Abbas Firoozabdi** is senior scientist and director at the Reservoir Engineering Research Institute (RERI) in Palo Alto, California and a professor of chemical engineering at Yale University at New Haven, Connecticut. His main area of focus is hydrocarbon energy production and environmental stewardship from thermodynamics and mathematical analysis. Firoozabadi holds a BS degree from the Abadan Institute of Technology at Abadan, Iran and MS and PhD degrees from the Illinois Institute of Technology, Chicago, all in gas engineering. He is the recipient of the 2002 SPE Anthony Lucas Gold Medal and the 2004 SPE John Franklin Carll Award.