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DISPLACEMENT EFFICIENCY IN TIGHT SANDSTONE BASED ON FRACTIONAL FLOW CURVE USING RELATIVE PERMEABILITY DATA

Abstract: In tight gas sandstone, relative permeability is an essential special core analysis dynamic test that can be used to estimate injectivity, secondary recovery, production rate, reservoir simulation, residual gas saturation, and effective water management. Having about 65% of hydraulic fracturing fluid not to flow back and stay in the reservoir results in having the tight sandstone gas reservoir to involve multi-phase flow, namely water and gas. During the hydraulic fracturing job both imbibition and forcibly imbibition processes take place while during fracturing fluid cleanup and gas production drainage flow becomes dominant.

The steady state flooding process was used to measure the relative permeability curves for a tight sandstone core sample collected from Travis Peak Formation at a depth of 8707 ft. The measurement process involved the performance of a series of steady state experiments with different gas-water injection ratios. The fractional flow curve has been plotted, based on the measured relative permeability, and used to calculate the displacement efficiency for flow through such tight porous media. The measurement showed relatively high irreducible water saturation (31%) and low residual gas saturation (6%). The measured gas relative permeability decreased slowly at a constant rate with increased wetting fluid saturation. The obtained fractional flow curve does not follow the s-shape behavior observed in a conventional reservoir. The results obtained showed that displacement efficiency can be enhanced by increasing water viscosity. Water viscosity can be increased by adding some polymer materials, however this is beyond the scope of this paper.

Keywords: tight sandstone, relative permeability, fractional flow curve, displacement efficiency

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1. Introduction

Gas produced from tight sandstone reservoirs is growing in popularity because of advancements in horizontal drilling, multistage hydraulic fracturing and technology [1–6]. Gas produced from tight reservoirs and shale source rock in the USA increased from 5.7 tcf in 2000 to 27.4 tcf in 2020 and is expected to reach 38.7 tcf gas production in 2050 [7]. Tight and shale gas resource development leads to natural gas production increasing, not only in the USA but worldwide.

In order to exploit a tight gas reservoir, it has to be fracked and re-fracked as the production declines. Tight gas production declines by 70% during the first year of production. Fracking has a significant effect on tight gas development [8]. It is well known that a frack job requires 15–23 million liters of water [9], where about 65% of the injected fracturing fluid does not flow back. As a consequence, a large amount of the fluid used in hydraulic fracturing stays in the reservoir and constrains gas production from tight formations. As long as re-fracking is carried out continuously to restore/increase production, water production impacts gas production. The water effect on gas production from tight formations becomes more significant during the late stages of tight gas reservoir development.

Since the tight gas reservoir contains two fluids, water and gas, then effective/relative permeability has to be considered to evaluate this multiphase flow system. Gas flow in tight sandstone reservoirs, in the presence of water, is affected significantly by the following: pore size and pore size distribution, sandstone wetting characteristics and fluid saturation [1–3].

Reliable effective or relative permeability data are required input data in computerized reservoir simulation models as well as simple analytical models [10]. Numerous authors have conducted both experimental and theoretical work to estimate gas-absolute and relative permeability in tight sandstone [1–3, 10–12]. There are different lab methods available to measure core plug gas–water relative permeability. Some methods are based on steady and unsteady state flow processes [10, 12]. Variation in water saturation and overburden pressure values significantly affect absolute and relative gas permeability [1, 13]. It has been shown experimentally that increased confining pressure results in a significant reduction in gas absolute permeability for core plugs retrieved from the Travis Peak formation [1].

In this paper, the quantification of the displacement efficiency in tight sandstone is based on the measured relative permeability values of gas and brine. Gas and brine relative permeability were experimentally measured using the steady-state flow process. After measuring the relative permeability, a fractional flow curve was constructed and used to calculate displacement efficiency in tight sandstone. In addition, the sensitivity of the calculated displacement efficiency to water mobility has also been demonstrated.

2. Method section

2.1. Relative permeability measurement method

The studied core sample was collected from a tight gas reservoir in the Travis Peak formation. The core plug size was 8.7 cm long and 3.8 cm in diameter. The core porosity was 7% and absolute permeability is in the range of microdarcy [1]. The measured gas and water absolute permeability, for the same core plug but at different confining pressures, are shown in Table 1 [1]. Table 1 shows that absolute permeability for gas and water always decreases with increasing confining pressure. Table 1 shows that an increase in overburden pressure from 13.8 to 20.7 MPa resulted in gas permeability decrease of 20.98% and a water permeability decrease of 22.73%. The increase of overburden pressure from 20.7 to 27.6 MPa resulted in a decrease of 17.81% and 31.20% in gas and water permeabilities, respectively. There are many factors that affect both the porosity and permeability of the sandstone such as: particle size (sphericity and angularity); packing; sorting; cementing materials; vugs/dissolutions/fractures; and overburden stress (compaction). The above-mentioned decrease in permeability can be attributed mainly to the overburden pressure effect on permeability.

Table 1. Absolute gas and water measured permeability

Confining pressure [MPa]	Permeability [μd]	
	Gas	Water
13.8	31.58	5.06
20.7	24.93	3.91
27.6	20.49	2.69

In the displacement experiments, high purity nitrogen (99.99%) was used as a gas phase and 7.0 wt. % concentrated brine was used as a liquid phase. The brine used is potassium chloride based. Any possible reaction between the injected water and the slot and solution type core plug used is minimized by dissolving the salt in deionized water. Consequently permeability alteration is also minimized. Steady state flow experiments, utilizing a benchtop relative permeability system shown in Figure 1, were used to measure the brine-gas relative permeability.

Fig. 1. Bench-top relative permeability system

The benchtop steady and unsteady state relative permeability system (Fig. 1) is used to determine liquid/liquid and liquid/gas relative permeability on core sample with a diameter of one inch or 1.5 inches and a length of one to three inches at an overburden pressure of up to 350 bar (5000 psi). The relative permeability was measured at an ambient temperature. The core saturation was determined by measuring the volume produced with a video separator. Liquid flow rate was controlled by a pump which was used to inject the liquid fluid into the core sample, while the gas flow rate was monitored using a gas mass flow controller.

The steady state flow process procedure used started with a core plug fully saturated with the prepared brine and continued as follows:

1. Brine was injected through the core plug to measure absolute permeability.
2. A mixture of brine and nitrogen was injected where the initial fraction of nitrogen was small.
3. After reaching a steady-state in terms of the flow rate of both fluids, inlet pressure, outlet pressure and flow rates were recorded.
4. Core fluid saturation was measured based on the volumes produced.
5. Effective permeability was calculated.
6. Relative permeability was calculated as a ratio between effective and absolute.
7. Steps 1 to 6 were repeated with a higher fraction of nitrogen than in step 2. The measurement process was continued until irreducible brine saturation was reached.

The effective permeability of the brine (k_w) and gas (k_g) phases was calculated using equations (1) and (2), respectively [14]:

$$k_w = \frac{q_w \mu_w L}{A(p_1 - p_2)} \cdot 10^3 \tag{1}$$

$$k_g = \frac{2 p_a \mu_g L}{A(p_1^2 - p_2^2)} \cdot 10^3 \tag{2}$$

where k_w is the effective permeability to brine, md; k_g is the effective permeability to gas, md; q_w and q_g are the brine and gas flow rate, mL/s; A is the core cross sectional area through which the flow takes place, cm^2; L is the length of the core plug, cm; μ_w and μ_g are the brine and gas viscosity, cP; p_1 and p_2 are the inlet and outlet pressure, MPa; and p_a is atmosphere pressure, MPa.

The relative permeability of brine (k_{rw}) and of gas (k_{rg}) phases are calculated as shown in equations (3) and (4), respectively:

$$k_{rw} = \frac{k_w}{k} \tag{3}$$

$$k_{rg} = \frac{k_g}{k} \tag{4}$$

3. Results and discussion

3.1. Relative permeability

The relative permeability values for gas–brine flow through a slot and solution core plug has been measured under lab room temperature, a confining pressure of 13.8 MPa and atmospheric outlet pressure. With the measured inlet pressure and gas and brine flow rates, the gas–brine relative permeability of the slot and solution core plug was calculated using equations (1)–(4) and plotted in Figure 2. The relative permeability of the Travis Peak sandstone core used does not resemble a permeability jail and behaves in a way similar to high permeability sandstone.

From Figure 2 one can notice that the irreducible water saturation value is S_{wi} = 31%, while the residual gas saturation value is S_{gr} = 6%.

3.2. Displacement efficiency analysis

To understand the fractional flow behavior in tight sandstone, the Buckley and Leverett theory is applied [15]. The relative permeability curves obtained were based on the steady state procedure of one dimensional flow through an incompressible tight sandstone with a valid

Darcy's law where the fluids were considered to be immiscible and incompressible. During the measurement of relative permeability, the core holder was placed horizontally, which means the flow dip angle is zero, gravity and capillary pressure are ignored. Thus, the fractional flow equation, based on these assumptions, can be written as follows [16, 17]:

$$f_w = \frac{1}{1 + \frac{\mu_w}{k_{rw}} \frac{k_{rg}}{\mu_g}} \tag{5}$$

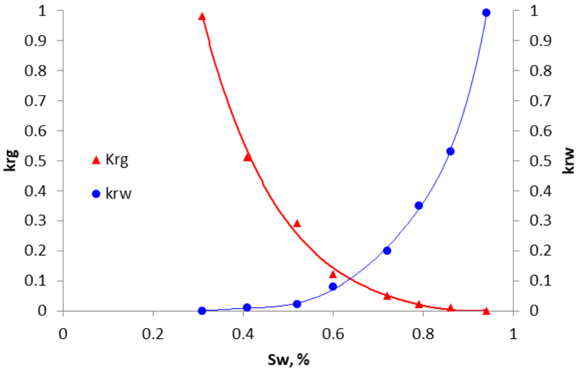

Fig. 2. Gas-water relative permeability curves

Due to the saturation dependence of the relative permeability curves, for constant gas and brine viscosities the fractional flow curve can only be expressed as a function of saturation. Water and gas fractional flow (f_w and f_g) can be determined as a function of total flow rate ($q_t = q_w + q_g$), using equations (6) and (7), respectively [18]:

$$f_w = \frac{q_w}{q_t} \tag{6}$$

$$f_g = \frac{q_g}{q_t} \tag{7}$$

It is clear from equations (6) and (7) that the fractional flow of both water and gas always add to unity. This means that with the knowledge of water and total flow rate, one can calculate both water and gas flow rates.

Water saturation can appear explicitly in equation (5) by applying the nonlinear regression analysis to relative permeability data (Fig. 2) to have relative permeability to water and gas calculated by equations (8) and (9), respectively:

$$k_{rw} = 164.15 S_w^6 - 540.94\, S_w^5 + 722.09\, S_w^4 - + 495.06\, S_w^3 + 183.84\, S_w^2 - 35.08\, S_w + 2.69 \tag{8}$$

$$k_{rg} = 9.31\, S_w^4 - 29.50\, S_w^3 + 36.30\, S_w^2 - 20.83\, S_w + 4.74 \tag{9}$$

Using the measured relative permeability data, nitrogen viscosity of 0.0189 cP, brine viscosity of 0.89 cP and equation (5), the water fractional flow curve was calculated for the slot and solution core plug, as shown in Figure 3, while Figure 4 shows both water and gas fractional flow curves.

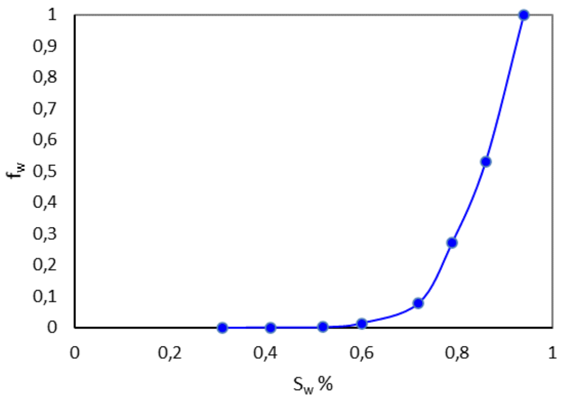

Fig. 3. Water fractional flow curve for the relative permeability data of Figure 2

It is clear from Figure 3 that the obtained curve is different from the fractional flow curve of conventional reservoirs, which is an S-shape. This is due to different reasons such as very low viscosity and density of gas compared to water that result in gravity override. The application of the Welge method [19] to compute the gas recovery from the water drive (where the outlet pressure is atmospheric at which the displaced gas is incompressible), using Figure 4, results in having no point of tangency for the line drawn from S_{wi}, instead the line will intersect with the flow curve at $f_w = 1$ which means that water saturation at the displacement front is equal to the average water saturation in the plug water bank ($\bar{S}_w$) and the average water saturation at the breakthrough ($\bar{S}_{wbt}$).

The gas displacement efficiency (E_d) can be calculated as follows [19]:

$$E_d = 1 - \frac{S_{gr}}{S_{gi}} \tag{10}$$

where, S_{gr} and S_{gi} are the residual and initial gas saturations, respectively. By definition, it is known that:

$$S_g + S_w = 1.0 \tag{11}$$

Accordingly, $S_{gi} + S_{wi} = 1.0$, that yields $S_{gi} = 1.0 - S_{wi}$. Also, $S_{gr} = 1 - S_{wbt}$, then equation (10) can be written as:

$$E_d = \frac{S_{gi} - S_{gr}}{S_{gi}} = \frac{S_{wbt} - S_{wi}}{1 - S_{wi}} \tag{12}$$

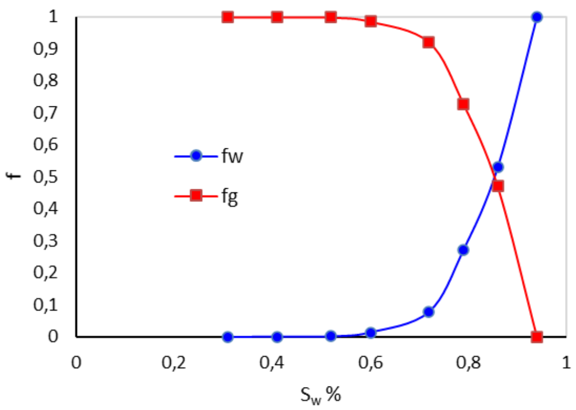

Fig. 4. The fractional flow curves for the relative permeability data of Figure 2

The calculated displacement efficiency is 0.913 which is the largest possible value for the kind of relative permeability curves measured. The minimization of the flowing water fraction at any core plug location results in enhancing displacement efficiency; this can be achieved by increasing the gas/water ratio. The highest displacement efficiency value is obtained at the lowest water saturation displacement efficiency as shown in Figure 5, therefore, f_w has to have the smallest possible value. Analyzing equation (5) results in determining how displacement efficiency is affected by the different reservoir properties and variables. Gas recovery is a strong function of fluid mobility (k_f/μ_f) and can be improved by decreasing (k_w/μ_w) and/or increasing (k_g/μ_g).

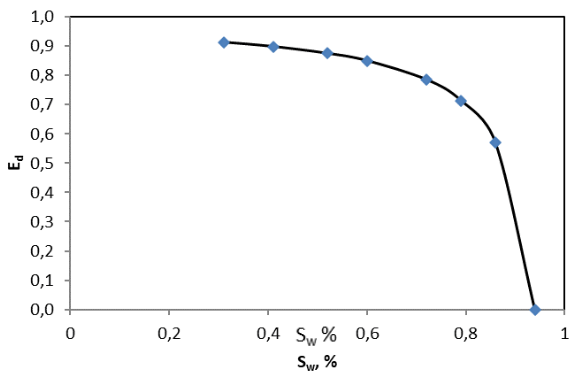

Fig. 5. Displacement efficiency changes

Displacement efficiency can be improved by decreasing the gas viscosity (temperature and pressure effects) or by increasing the water viscosity (by means of the addition of polymers). Gas viscosity will not change significantly; therefore, the displacement efficiency enhancement will be minimal. The water viscosity effect on f_w curve is shown in Figure 6 for different values of brine viscosity.

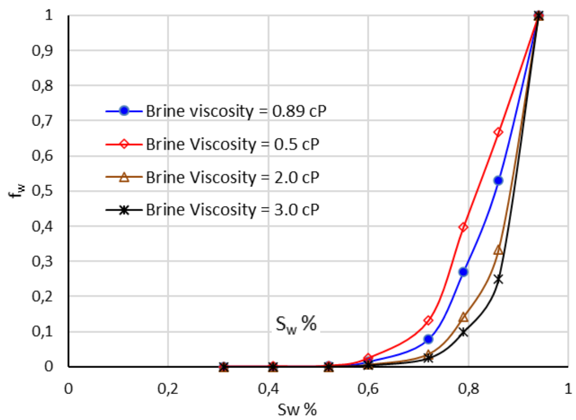

Fig. 6. The effect of brine viscosity on f_w behavior

Figure 6 shows that higher brine viscosity results in a better sweep efficiency and consequently better displacement efficiency.

4. Conclusions

The steady state flooding process was used to measure gas–brine relative permeability properties for slot and solution tight gas sandstone. The measurement showed high irreducible water saturation, indicating that the core sample used is of the water-wet rock type. The study showed that the relative permeability data did not yield the s-shape fractional flow curve for unconventional tight sandstone. The obtained value of irreducible water saturation indicated that the core rock used is water-wet where the wetting phase brine preferentially wets the solid rock surface and the brine is drawn into smaller pore space of the rock while gas flows in the larger pores.

The study showed that gas displacement efficiency in the considered tight sandstone can be increased by having better control over the mobility of the brine. Increasing the viscosity of the brine resulted in having a better control over wetting phase mobility and thus better displacement efficiency.

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