

SPE 15081

The Effect of Dissolved Gas on Geothermal Brine Viscosity

by R.D. Ostermann, S.G. Paranjpe, S.P. Godbole, and V.A. Kamath, *U. of Alaska*

SPE Members

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This paper was prepared for presentation at the 56th California Regional Meeting of the Society of Petroleum Engineers held in Oakland, CA, April 2-4, 1986.

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ABSTRACT

Reservoir brines typically contain dissolved salts and gases. While correlations have been published for prediction of viscosity as a function of temperature, pressure and salinity, little data is available regarding the effect of dissolved gases on brine viscosity. In the current work, the viscosity of methane and ethane saturated water and brine has been measured at 100, 150, and 250°F over a pressure range of 0-7,500 psig.

For methane in pure water, viscosity increases by up to 6%. At pressures above 2,000 psig, the viscosity is independent of saturation pressure. Dissolved ethane showed no measurable effect on water viscosity. Brine viscosity also increases with methane saturation pressure. A correlation is presented for the correction of brine viscosity to account for gas saturation.

INTRODUCTION

Viscosity is an important physical property influencing the flow of reservoir fluids. In most cases, oil or gas are the mobile phases. Several correlations have been published for the estimation of oil and gas viscosity. Often, however, water is the mobile phase. In this case, an accurate method for the prediction of water viscosity may be required.

The viscosity of water is well known as a function of temperature and pressure. The effects of dissolved salts on viscosity have also been studied. Natural gas is also soluble in water and brine. However, no data have been published regarding the effect of dissolved gas on brine viscosity.

In the current study, the effect of

dissolved methane and ethane on water and brine viscosity was measured experimentally at temperatures of 100, 150 and 200°F and saturation pressures ranging from 0-7,500 psig. A standard RUSKA rolling ball viscosimeter modified for use with electrolyte solutions was used.

Viscosity of Pure Water

Several investigators¹⁻⁴ have studied water viscosity as a function of temperature and pressure. Number⁵ has reviewed the recent data on water viscosity and presented a useful comparison of the published data. Data on the viscosity of pure water is readily found in the Steam Tables in tabular form⁶. A correlation for the viscosity of pure water is presented by Number⁵.

$$\mu_{\text{water}} = 0.02414 \times 10^{(446.04/(T-208))} \quad (1)$$

$$\times [1 + 4.0124 \times 10^{-8} (T-89)(p-p_{\text{sat}})]$$

The saturation pressure may be obtained from the steam tables, or from the correlation presented by Keenan et al.⁶

Viscosity of Brines

Relatively little data has been published on the viscosity of brine at elevated temperature and pressures. Korosi and Fabuss⁷ have measured the viscosities of several binary salt solutions over a wide range of temperatures and pressure. More recently, Ershaghi et al.⁸ have published results of a study of geothermal brine viscosities. Number et al.⁹ have published a review of the subject, and have developed a correlation for relative viscosity for NaCl solutions based on data presented by Korosi and Fabuss⁷. Relative viscosity is defined as the ratio of brine viscosity to the

viscosity of pure water, at the same temperature and pressure. This correlation is presented in Equation 2.

$$\begin{aligned} \mu_{\text{brine}} = & \mu_{\text{water}} \{1 - 0.00187 \times S^{0.5} \\ & + 2.18 \times 10^{-4} S^{2.5} \\ & + (T^{0.5} - 0.0135T) \\ & \times [0.00276 S - 3.44 \times 10^{-4} S^{1.5}]\} \end{aligned} \quad (2)$$

In the development of Equation 2, data on the effect of pressure on brine viscosity was not available. It is assumed that the effect of pressure on brine viscosity is the same as on pure water. Since pressure has a very minimal effect on water viscosity, this might be a reasonable assumption. Therefore, brine viscosity at any temperature and pressure ($T < 572^\circ\text{F}$, $P < 11600$ psi, % NaCl $< 25\%$) is the product of the viscosity of pure water at T and p and the relative viscosity at T and % NaCl.

Solubility of Methane in Water

Methane has a limited but significant solubility in water. Culberson and McKetta¹⁰ have reported the solubility of methane in water over a wide range of temperature and pressure. Their results are summarized in Figure 1. Blount et al.¹¹ have studied the effect of dissolved salts on the solubility of methane in water, and have concluded that methane solubility decreases with increased solids content. Based on the data of Dodson and Standing¹² the following correlation for a salinity correction factor was presented¹³:

$$\frac{R_{\text{sw}}}{R_{\text{B}}} = 1.0 - [0.0753 - 1.73 \times 10^{-4} T] S \quad (3)$$

EXPERIMENTAL SETUP:

A schematic diagram of the experimental setup is shown in Figure 2. The experimental setup consists of a Ruska rolling ball viscometer, heating and timing unit, Ruska mercury pump, standard Heise pressure gauge and fluid injection system with pressure vessels and high pressure needle valves.

The rolling ball viscosimeter is a standard laboratory device routinely used for the measurement of viscosity at elevated temperature and pressure. The device consists of an enclosed, inclined tube, through which a ball is allowed to roll. The velocity of the ball is directly related to the viscosity of the fluid and the buoyant forces on the ball. In practice, the velocity is determined by measuring the time required for the ball to fall a fixed distance between the electromagnetic ball release at the top of the tube and an electrical sensor at the bottom of the tube. The arrival of the ball at the bottom of the tube is indicated by the completion of a circuit between the side of the tube and a sharp electrical contact at the bottom.

This design is configured for use with non-electrolyte fluids. With water or brine, the mechanism for sensing the arrival of the ball at the bottom of the tube is deactivated, since the circuit is completed by the fluid itself. For the purposes of this study, the viscosimeter was modified. A diaphragm and sensitive microphone were attached directly to the pin located at the bottom of the tube through the existing electrical contact port. With the microphone and a simple amplifier, it was possible to detect the arrival of the ball by an audible click. A simple switching circuit was designed to stop the existing viscosimeter clock upon arrival of the ball.

Many other modifications are possible which would have accomplished the same goal, and which may be more appropriate for a permanent installation. However, we found this arrangement to be quick, simple and inexpensive.

Calibration of Rolling Ball Viscosimeter:

Hubbard and Brown¹⁴ have discussed the theory and operation of rolling ball viscosimeter in details. For stable flow regimes, viscosity is proportional to the product of density difference between the ball and fluid, and roll time (reciprocal velocity), as represented in Equation 4.

$$\mu = \alpha (\rho_{\text{ball}} - \rho_{\text{fluid}}) t_{\text{roll}} + \beta \quad (4)$$

The constant α and β are evaluated with calibration fluids of known viscosity and density. Fluids with viscosities similar to the "unknown" fluid are used.

For this study, water and pentane were used as calibration fluids. The viscosity of water was obtained from the Steam Tables⁵. Water density was calculated from a correlation presented by Rowe and Chou¹⁵. Viscosity and density of pentane were obtained from Hubbard and Brown¹⁶ and Starling¹⁷. The density of the ball was calculated from Equation 5, provided by the equipment manufacturer.

$$\rho_{\text{ball}} = 7.754 - 0.000048 T \quad (5)$$

The viscosimeter was calibrated at 100, 150, and 250°F, at pressures up to 8000 psi. Sample calibration curves are presented in Figure 3.

Viscosity Measurement

To determine the viscosity of a fluid, the roll time, ball density and fluid density are required. Ball density was calculated from Equation 5. Brine density was calculated from Equation 6.

$$\rho_{\text{B}} = \frac{\rho_{\text{B}}^0 + 7.527 \times 10^{-6} R_{\text{swB}}^{\text{MW}}}{B_{\text{WB}}} \quad (6)$$

where ρ_g , R_{sw} , B_{wb} can be calculated from published correlations as indicated in Appendix I. In general R_{sw} and B_{wb} depend on salinity and gas saturation pressure.

SATURATION TECHNIQUE

All viscosity measurements were made on water or brine at the gas saturation point. For each series of experiments, the viscosimeter was charged with sufficient gas to saturate the water at 8000 psi or above. The pressure was then raised to 8000 psi by injecting water. Sufficient time was allowed for equilibrium to be attained. Pressure was then reduced by removing water from the bottom of the viscosimeter (See Figure 2).

The pressure was lowered to 7000 psi for the first viscosity measurement. The pressure was subsequently dropped to lower pressures by water removal. At each pressure below the original bubble point, a gas phase remained in the viscosimeter.

RESULTS AND DISCUSSION

The relationship between viscosity and gas saturation pressure and R_{sw} at 100°F is shown in Figure 4. The same data for 150 and 250°F are presented in Figures 5 and 6. In general, it can be seen that the viscosity increases to nearly 6% above the value reported for pure water. The increase is somewhat greater for the 100°F case as opposed to the 150°F, and 250°F cases. This is due to the increased solubility of gas in water at 100°F. Examination of Figure 1 shows that the gas solubility passes through a minimum at approximately 200°F. At higher temperatures, the solubility increases considerably. As our equipment had an upper operating limit of 300°F, it was not possible to obtain measurements in this high temperature region.

Figure 7 presents a "relative viscosity" defined as gas saturated viscosity divided by pure water viscosity at the same temperature and pressure, as a function of gas saturation pressure.

No data have previously been reported specifically for the effect of dissolved natural gas on brine viscosity. Our data indicates that the relative effect of dissolved gas on brine viscosity is the same as the effect on pure water viscosity. The presence of salt does not interfere with the effect of the gas on viscosity. Although ethane is soluble in water, we were not able to detect any effect on viscosity.

Viscosity rises to a value which is nearly constant at a saturation pressure of about 2000 psi. Since the overall magnitude of the correction is small in any event, it is more expedient to make use of the "plateaued" value as opposed to developing a correlation including the pressure sensitive region. Moreover, for most applications the pressure will exceed 2000 psi.

At 100°F, the average value for relative

viscosity above 2000 psia is 1.06005. At 150°F and 250°F, the values are 1.0438 and 1.0277 respectively. These values can be correlated against temperature as indicated in Equation 7 and plotted in Figure 8.

$$\frac{\mu_{\text{saturated}}}{\mu_{\text{gas free}}} = 1.109 - 5.98(10^{-4}) T \quad (7) \\ + 1.0933(10^{-6}) T^2$$

As this value is independent of saturation pressure above 2,000 psia, it follows that viscosity is not dependent on the amount of gas dissolved above 2000 psi. Since the primary effect of increased gas gravity is a decrease in solubility, the gravity of natural gas should not be a factor as long as the partial pressure of methane is above 2,000 psia.

It was anticipated that the effect of dissolved gas on viscosity would be small. The data reported in this paper supports that expectation, with a maximum deviation of less than 8%. In Figure 7, it can be seen that the change in viscosity due to gas decreases with temperature. Since the solubility of gas at 150°F is less than the solubility at 100°F, this is to be expected. However, the solubility at 250°F is greater than the solubility at 150°F, yet the effect on viscosity is smaller. Thus it would appear that increased temperature tends to decrease the magnitude of the effect of the gas on viscosity. At considerably higher temperatures, the solubility increases significantly. However, since the magnitude of gas solubility does not affect viscosity above 2000 psi, the present data would suggest that the effect of gas on viscosity would continue to decrease at higher temperatures.

At the outset, it was presumed that the dissolved gas would serve to decrease the water viscosity. The increase noted in the study was unexpected. We hypothesize that this unexpected behavior is due to the highly dissimilar nature of water and methane. This behavior is similar to that encountered with emulsions.

CONCLUSIONS

1. The viscosity of water increases by up to 6% upon saturation with methane at moderate pressures. No effect was observed with ethane.
2. The effect of gas on brine viscosity is the same as the effect on pure water viscosity.
3. At higher temperatures, the magnitude of the effect decreases.
4. A correlation has been developed which can be used to predict the viscosity of methane saturated water and brine.

NOMENCLATURE

B_w = formation volume factor for water

B_{wb} = formation volume factor for brine

p = pressure (psi.)
 p_{sat} = saturation pressure (psi.)
 R_{sw} = gas solubility (SCF/STB)
 S = salinity (wt. % NaCl)
 t_{roll} = roll time (sec.)
 T = temperature ($^{\circ}$ F)
 μ = viscosity (cp)
 ρ = density (g./cc.)

Subscripts:

B = brine

g = gas

Superscripts:

o = standard conditions

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Appendix I: Effect of Salinity and Gas Solubility on Brine Density:

Brine density can be calculated from Equation 6. However the effect of salinity and gas solubility on formation volume factor and gas solubility must be accounted for.

Gas Solubility in Brine

The solubility of methane in brine can

be calculated as:

$$R_{swB} = R_{sw} \left(\frac{R_{swB}}{R_{sw}} \right)$$

where the salinity correction is calculated from Equation 3.

Brine Formation Volume Factor

The brine formation volume factor can be calculated as: (after 13)

$$B_{wB} = B_w [(5.1 \times 10^{-8} P + [5.47 \times 10^{-6} - 1.95 \times 10^{-10} P] (T - 60) + [-3.23 \times 10^{-8} + 8.5 \times 10^{-13} P] (T - 60)^2) S + 1]$$

where

$$B_w = A + BP + CP^2$$

with A, B, C for gas saturated water as:

$$A = 0.9911 + 6.35 \times 10^{-5} T + 8.5 \times 10^{-7} T^2$$

$$B = -1.093 \times 10^{-6} - 3.497 \times 10^{-9} T + 4.57 \times 10^{-12} T^2$$

$$C = -5 \times 10^{-11} + 6.429 \times 10^{-13} T - 1.43 \times 10^{-15} T^2$$

and with A, B, C for gas free water as:

$$A = .9947 + 5.8 \times 10^{-6} T + 1.02 \times 10^{-6} T^2$$

$$B = -4.228 \times 10^{-6} + 1.8376 \times 10^{-8} T - 6.77 \times 10^{-11} T^2$$

$$C = 1.3 \times 10^{-10} - 1.3855 \times 10^{-12} T + 4.285 \times 10^{-15} T^2$$

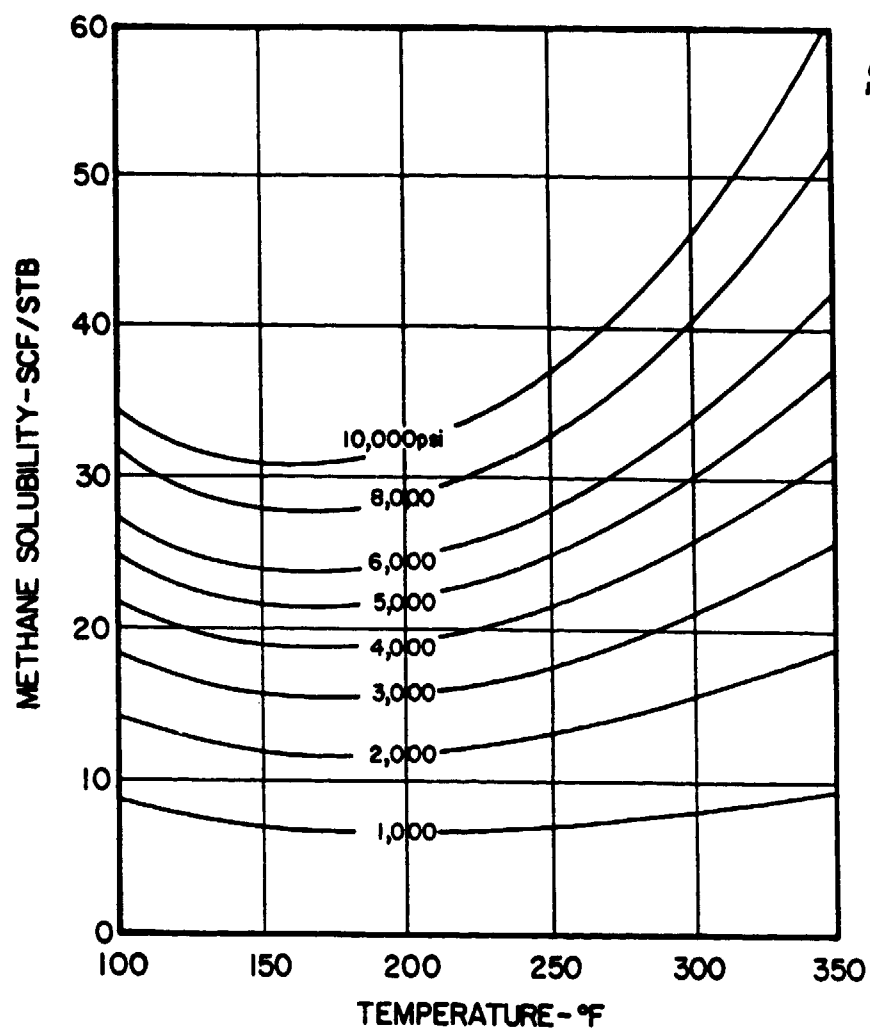


Fig. 1—Solubility of methane in water (after Culberson and McKetta¹⁰).

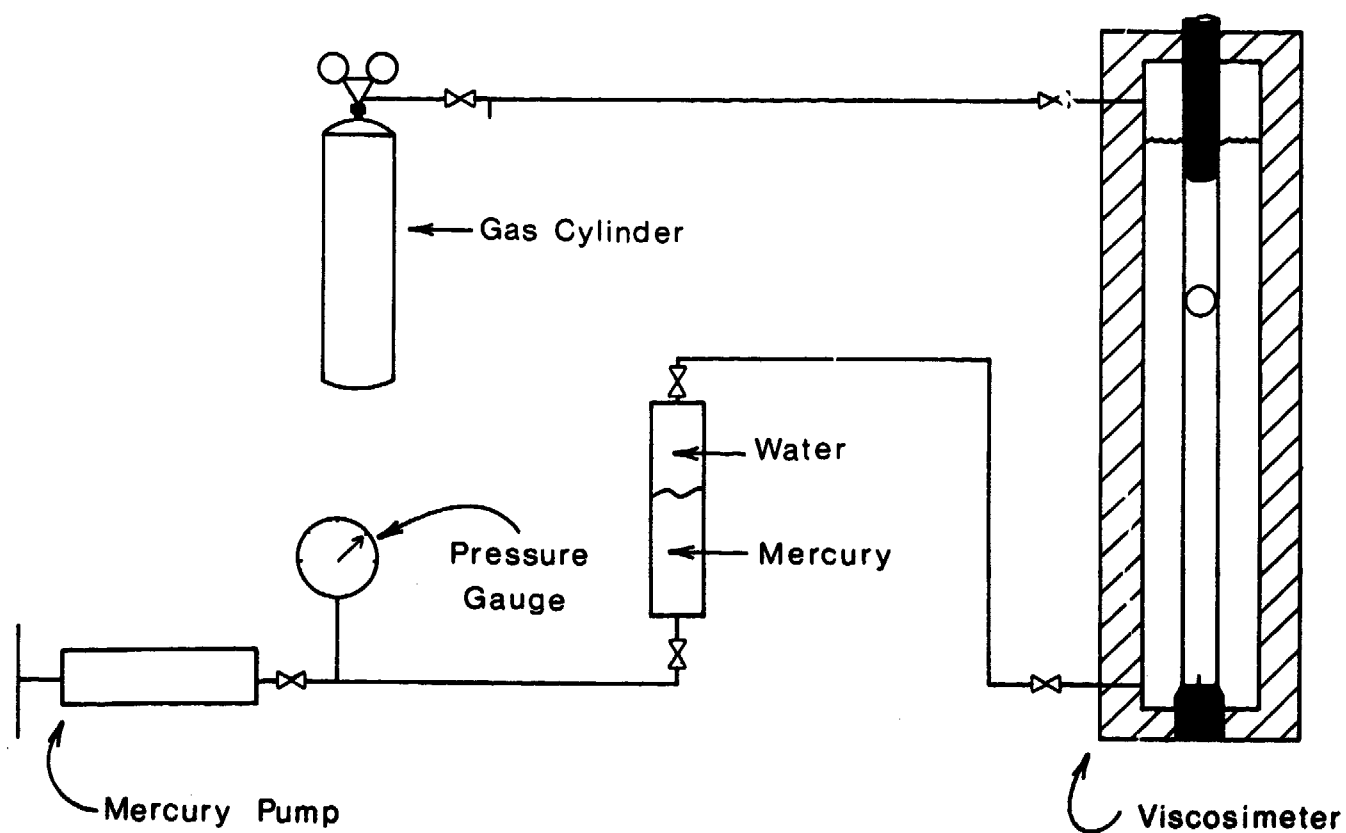


Fig. 2—Schematic diagram of experimental setup.

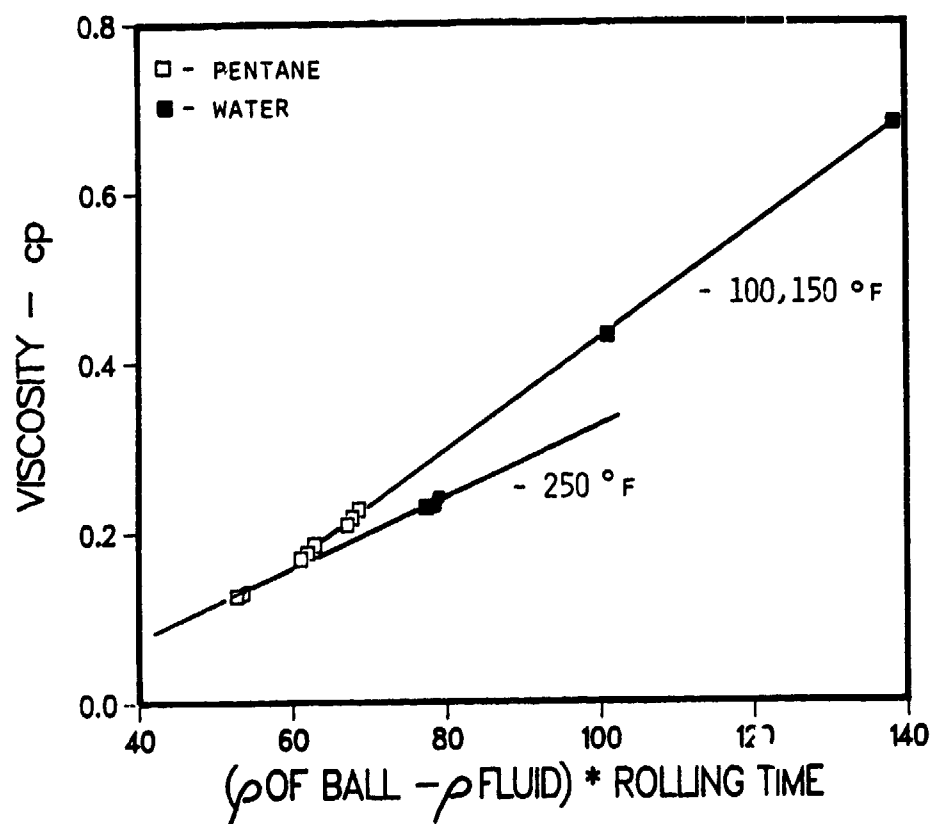


Fig. 3—Calibration curves for rolling ball viscosimeter.

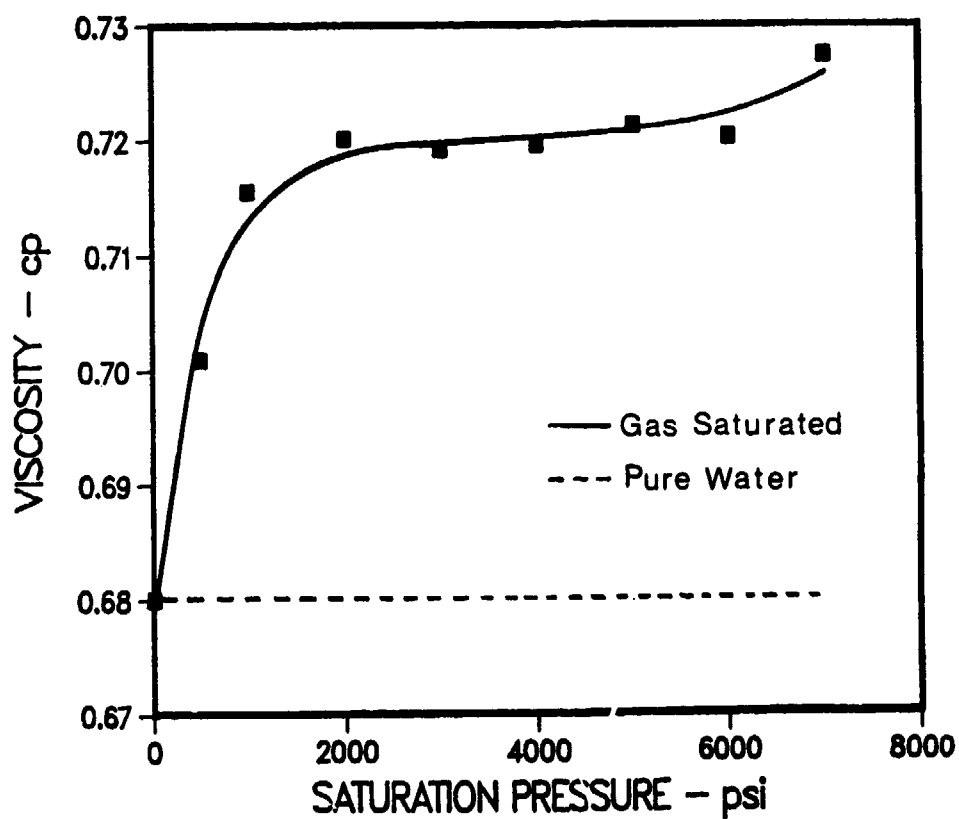


Fig. 4—Viscosity of methane-saturated water at 100°F.

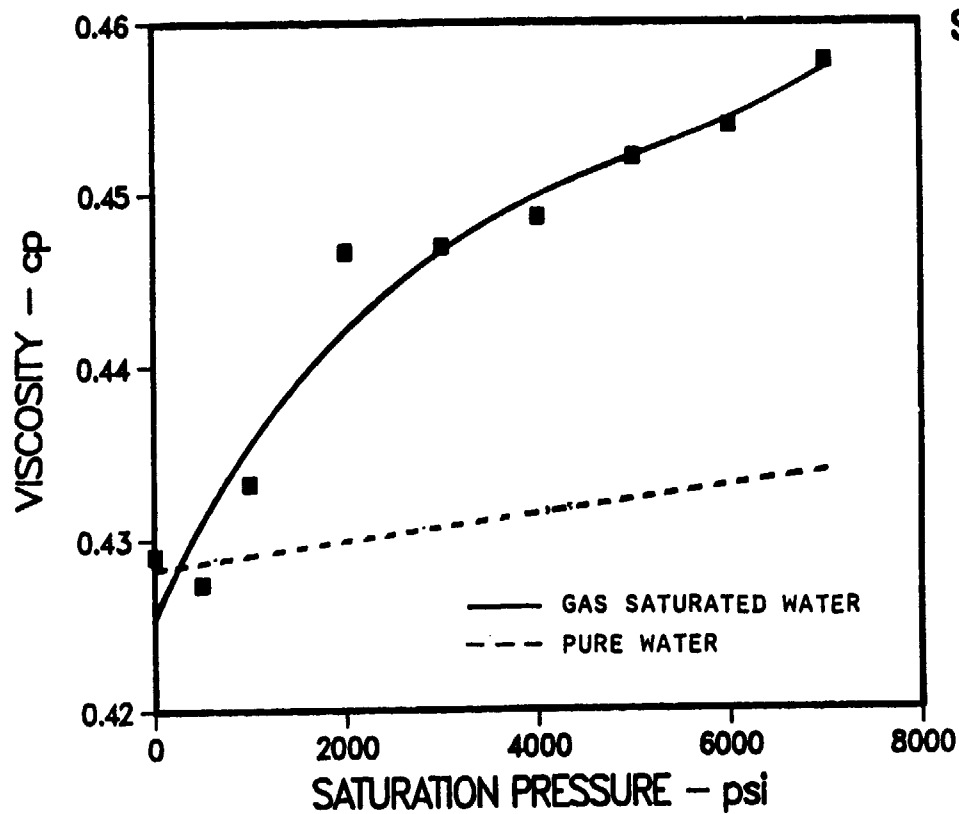


Fig. 5—Viscosity of methane-saturated water at 150°F.

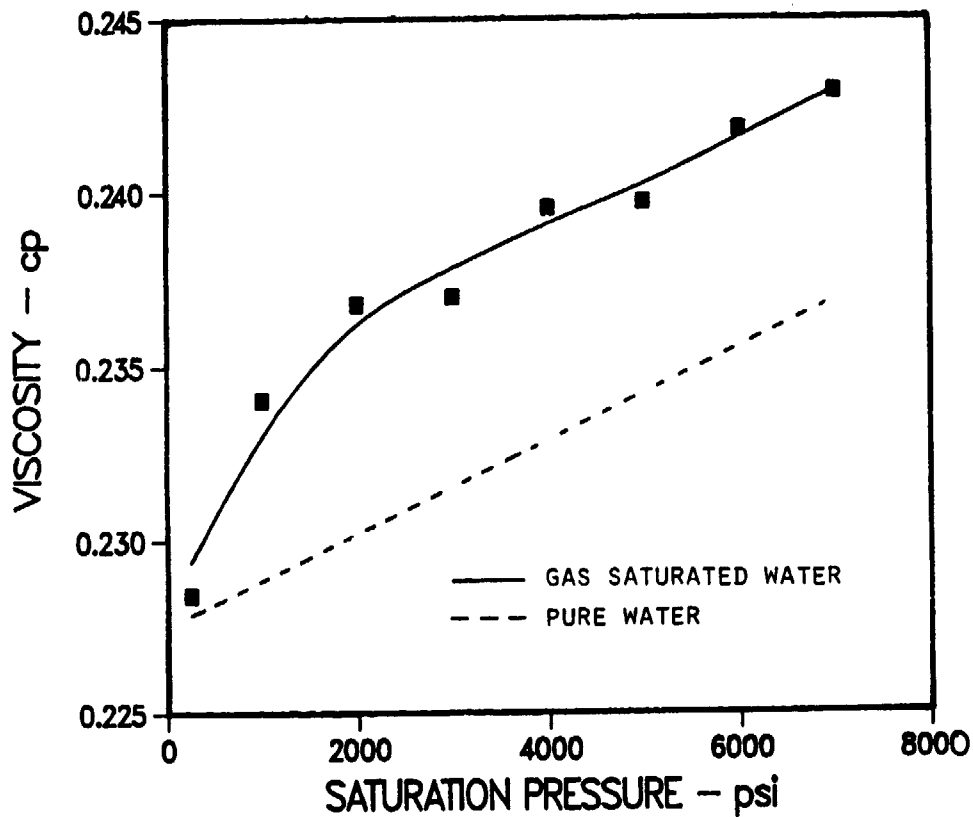


Fig. 6—Viscosity of methane-saturated water at 250°F.

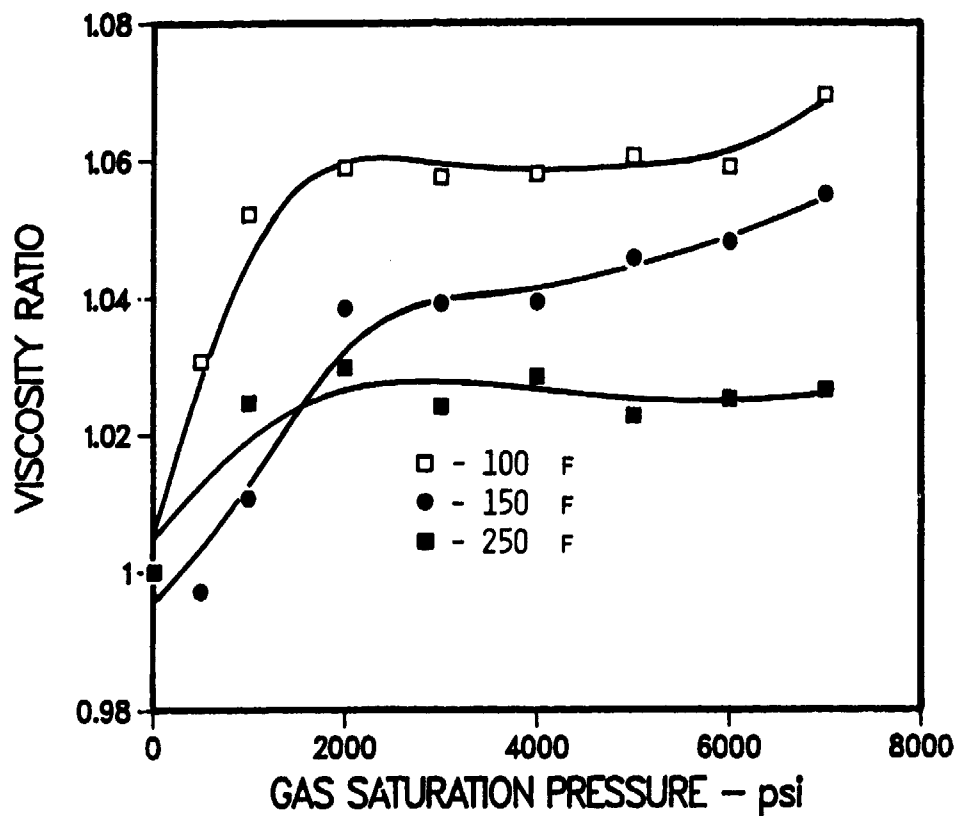


Fig. 7—Relative viscosity.

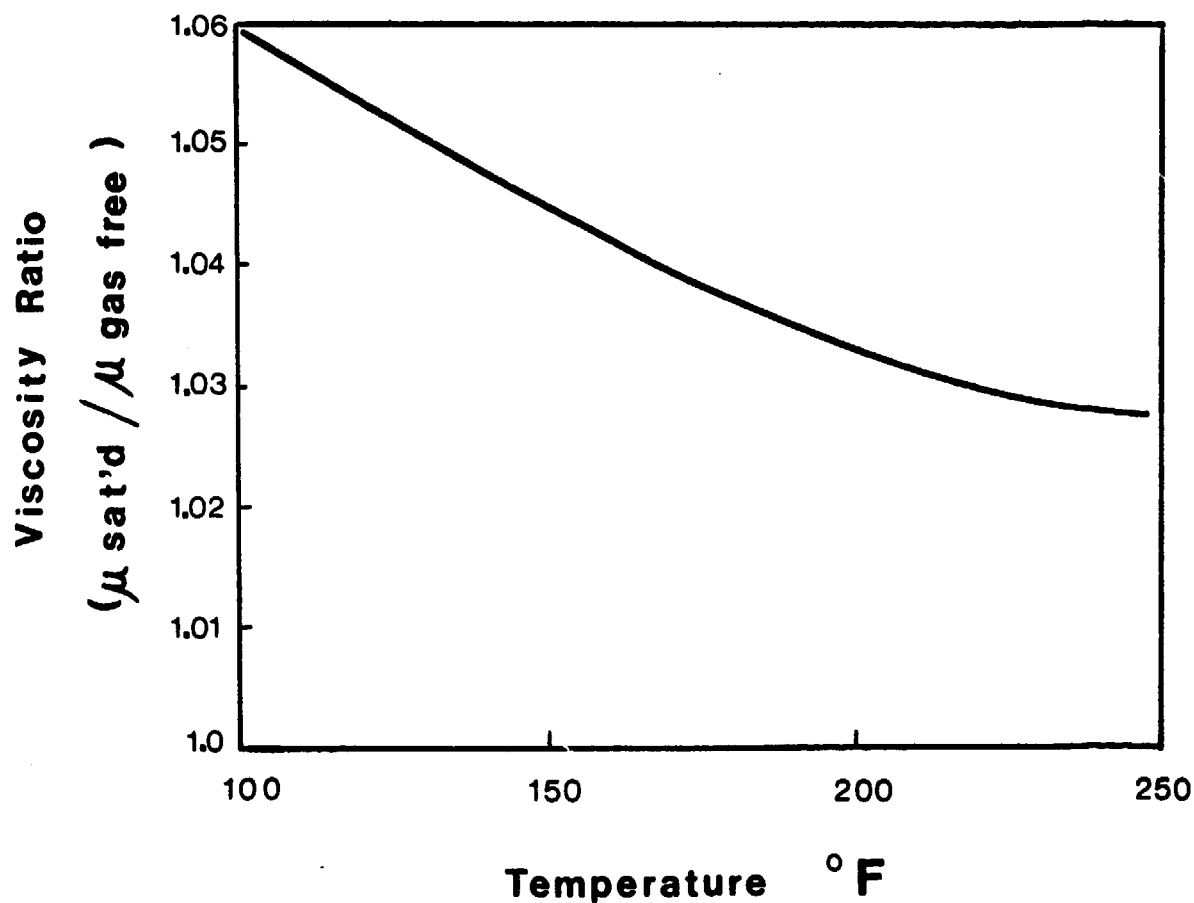


Fig. 8—Average relative viscosity as a function of temperature.