



SPE 96013

Viscosity of Formation Water: Measurement, Prediction, and Reservoir Implications

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This paper was prepared for presentation at the 2005 SPE Annual Technical Conference and Exhibition held in Dallas, Texas, U.S.A., 9 – 12 October 2005.

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Abstract

Formation water is invariably produced with petroleum. An estimate of the dynamic viscosity of formation water as a function of pressure, temperature, salt content and preferably dissolved gas, is required for reservoir and petroleum production design and calculations. The extent of available experimental data on the viscosity of live formation water is very limited. In addition, most of the proposed brine viscosity correlations are based on the experimental data of NaCl solutions with no dissolved gas.

Several reconstituted formation water samples were tested in the present study. The total dissolved solids content of the water samples varied between 90,000 to 250,000 mg/L at a gas/liquid ratio of approximately 9.6 scf/stb. Viscosities were measured up to 14,000 psia and temperatures up to 200 °F using both capillary and electromagnetic viscometers calibrated with standard fluids for the interested range of pressure and temperature. Experimental results indicated that viscosity of formation water increases with increasing solids content and pressure as well as with decreasing temperature. The presence of dissolved gases decreased the viscosity of formation water; however, it was not significant. Experimental results were compared against water viscosities predicted by commonly used formation water viscosity correlations. The relative errors for some cases were as high as 200 %. Most correlations over-predicted the viscosities at higher pressures beyond 10,000 psia.

Comparison between reservoir simulation case studies for a base case and 30%-varied formation water viscosity case showed that both predicted oil and water production and water cut during the life of the producing well are significantly affected by the value of the formation water viscosity input.

Introduction

Viscosity is one of the main physical properties that affects the mobility and flow of formation water in the porous media and influences the water production rate from the reservoir. Thus an accurate measure or estimate of formation water viscosity is necessary to interpret or predict fluids production from the reservoir.

There have been a large number of studies on the physical properties of salt water in the last three decades. Two recent publications [1,2] have reviewed the available physical property correlations for salt water. The majority of available viscosity experimental data are for solutions of sodium and calcium chloride in water. Salt content, temperature, and pressure were identified as the main parameters affecting the water viscosity. In addition to experimental data, there is a plethora of viscosity correlations for water viscosity. Majority of these correlations were developed by fitting empirical mathematical expressions to experimental data.

In most cases the effect of dissolved gases have been neglected. There has been contradictory information regarding the amount of dissolved gases in reservoir brines. Adams and Bachu [2] have stated that the amount of dissolved gases is usually small and it does not have a significant effect on the viscosity (no reference was provided for the claim), while Collins [3] stated that the gas content of reservoir brine could be very high and as much as 14 scf/bbl for the samples collected from the GoM region. He was also postulating that the gases in solutions behave entirely different than gases in hydrocarbons. The dissolved gases will cause the water molecules to interact strongly together and thus the viscosity and rigidity will increase. There are only very limited studies on the viscosity of live formation waters [4,5] to either evaluate the available correlations or develop a new one. Therefore it is very common to use the available correlations, which were developed without considering the effect of dissolved gases.

In this study the effect of solution gas on the viscosity of formation water in addition to the effect of salinity, temperature and pressure have been investigated for few live brine samples from the GoM Region. The performance of common water viscosity correlations was also evaluated. Also, the implications of an accurate measurement and/or prediction of formation water viscosity is demonstrated using a simulated case study with a static reservoir simulator.

Viscosity of Formation water

There are very limited number of experimental data on the effect of pressure and dissolved gases on the viscosity of reservoir/formation water. Kestin et al. [6] used an oscillating disk viscometer, which was calibrated with respect to distilled water, to measure and correlate the effect of pressure on the viscosity of aqueous NaCl solutions in the temperature range of 20-150 °C. Authors concluded that for the concentration of NaCl up to 5.4 mole/kg and pressure up to 30 MPa, the viscosity varied in the order of 1% over the entire tested pressure range and thus the pressure effect was only accounted with a linear factor. The developed correlation could reproduce the experimental data with a standard deviation of $\pm 0.5\%$.

Meehan [7] correlated the viscosity of NaCl solutions by a linear relation with the inverse temperature (at temperature up to 200 °C). The correlation constants were a function of NaCl content (up to 26 wt% salinity), while a pressure factor multiplier was used to correct for pressures up to 70 MPa. The maximum reported error was 10% for the water viscosity and 5% for pressure factor.

A comprehensive and in-depth set of data on transport, thermodynamic and physical properties of sodium, potassium and calcium chloride brines is provided by Phillips et al. [8]. The authors developed a theoretically based correlation to predict the viscosity of NaCl solutions over the ranges of 10-350 °C, 0.1-50 MPa, and 0-5 mole/kg. The model was originally derived for the viscosity of colloidal suspensions and has been modified for electrolyte solutions such as NaCl. The maximum reported error over the applicable ranges of temperature, pressure and concentration is approximately $\pm 2\%$.

Ershagi et al. [9] measured viscosity of NaCl, KCl, and CaCl_2 at concentrations ranging from 0.99 to 16.67 wt% and at temperatures up to 275°C. The measurements were conducted using a high temperature capillary tube designed to operate up to temperature of 315°C and a pressure of 14MPa. Experimental data indicated that the viscosity of KCl solutions were lower than that of NaCl while CaCl_2 solutions have a higher viscosity than NaCl solutions very similar to the observations by Phillips et al. [8]. A double log function for viscosity versus inverse temperature (cubic function) was developed, with the constants as a function of equivalent NaCl salt concentration. No effect of pressure was incorporated in the model. An error of 22-28% was reported for temperatures as high as 250 °C.

Ostermann et al. [4,5] are the earliest group who studied the effect of dissolved gases on the viscosity of reservoir and geothermal brines. A modified high-pressure rolling ball viscometer was used for brine viscosity measurements. The viscometer was calibrated with pure water and n-pentane. All viscosities were measured at the saturation pressure. To saturate the water sample, the viscometer was charged with sufficient gas equivalent to the gas content at 55 MPa. Water was then added to the viscometer to raise the pressure to 55 MPa. For lower pressures, water was removed from the viscometer. At each pressure below the original bubble point pressure, a gas phase remained in the viscometer. Experimental results indicated that the viscosity of water increased by 6% when saturated with methane at the tested

pressures of up to 48 MPa, while ethane did not have any effect. It was also shown that the effect of dissolved methane on viscosity diminished at higher temperatures. It was also concluded that the effect of gas on brine viscosity is the same as the effect on pure water. A correlation was developed to predict the viscosity of methane-saturated brine to pressures up to 48 MPa, and temperatures up to 120 °C.

McCain [10] correlated the viscosity data of Collins [3] for formation waters with an accuracy of $\pm 4\%$ for pressures up to 70 MPa, and $\pm 7\%$ for pressures up to 103 MPa. The pressure correlation is only recommended for 30 to 75 °C. Again no effect of dissolved gas was considered, or it is not clear if the experimental data included such a data set. It should be noted that McCain's correlation is the only one, which was developed, based on the formation water viscosities rather than solutions of common salts.

Palliser and McKibbin [11] developed a series of correlations for transport, thermodynamic and physical properties of NaCl solutions. Authors used the model of Phillips et al [8] as a basis to develop the viscosity correlation for higher pressure and temperatures. The model was basically applying a correction factor for the effect of temperature and salinity to viscosity of pure water at the same pressure and temperature conditions. The viscosity correlation is valid over a range of 0-800 °C, 1-100 MPa, and 0-1 mass fraction of sodium chloride. No numerical error analysis was provided.

Adams and Bachu [2] reviewed some of the available viscosity models/correlations for brines in terms of both applicability range and viscosity prediction. Due to lack of live formation water viscosities, authors could not conclusively select a proffered model and concluded that the differences between the compared algorithms [6, 8, 10, 11] are small and certainly smaller than the error introduced into calculations by all the errors in measurement and estimates of formation water salinity, pressure and temperature.

Recently Spivey et al [1] have presented new correlations to estimate density, formation volume factor, compressibility, methane solubility, and viscosity for oilfield brines at temperatures from 0 to 275 °C, pressures to 200 MPa, and salinities to 5.7 mole/kg. For viscosity, authors extrapolated Kestin et al [6] model for higher pressures and temperatures. No experimental data was available to verify the model except for pure water. For pure water, the viscosity was estimated with a maximum error of 1.7%.

It is evident that all of the available viscosity models for formation water suffer from the fact that they were not verified for live formation water viscosity data. As such the prediction error for the cases of actual formation water viscosity is not determined.

Experimental

Four formation water samples were used in this study. All four samples were recombined samples based on the live formation water properties. Two of the recombined samples are based on the original water composition, while the other two are recombined by both increasing and decreasing the original total dissolved solids of one of the samples by 50000ppm.

Chemical Analysis. Chemical analyses of the water samples were performed in a third party laboratory. The chemical analysis included total dissolved solids (TDS),

cations, anions, pH, etc. Table 1 shows the complete analysis information for all four samples and the corresponding Stiff diagram [12] is shown in Figure 1.

Sample preparation. The formation water samples were received as an STO sample in a nitrogen gas blanketed glass bottle. It was clear from the glass sample bottles that inorganic solids have precipitated from the water sample and partially adsorbed to the surface of the glass bottle and may have not been recovered completely. In order to homogenize the water sample for recombination, the water sample was heated to approximately 50 °C (122 °F) and agitated continuously for a period of 24 hours before a sub-sample was transferred to the recombination cylinder. A recombined fluid was prepared according to the gas-water ratio (GWR) and gas composition. Table 2 shows the composition of the recombination gas. The GWR of Formation Water #1 and Synthetic Water # 1 & 2 was 9.6 scf/stb and the GWR of the Formation Water #2 was 6.4 scf/stb.

Viscosity Measurement. For viscosity measurements, an EMV model SPL440 viscometer was used. The instrument is capable of continuous operation to 140 MPa (20,000 psia) and 190 °C (374 °F). It performs viscosity measurements over the range of 0.1 to 10,000 mPa.s on very small volumes of fluid.

The SPL440 Viscometer is easy to install, operate and service and has only one moving part, a small magnetic stainless steel piston located inside the sensor that is driven up and down using coils, simplifying installation and servicing. The measurement chamber, connected to both top and bottom system lines, allows for easy introduction, measurement, and removal of a fluid from the Viscometer. For the interested range of viscosity (0.2-2.0 mPa.s), the accuracy of the measurement is within $\pm 3\%$ of the full scale. The viscometer was evaluated against pure water viscosities. Figure 2. Shows the viscometer performance evaluation with pure water viscosity data.

Results and Discussion

Effects of solution gas, temperature, total dissolved solids, and pressure on the viscosity of formation waters are discussed below.

Effect of Solution Gas. Figure 3 shows the effect of solution gas on the viscosity of Formation Water #1 at 82 °C. The amount of dissolved gas is 9.6 scf/stb. The viscosity of water has decreased as the pressure increased. The available data is limited; however, if the trend is correct, it means that dissolved natural gas affects the viscosity of water in the same fashion as it affects the viscosity of hydrocarbon fluids. There is as much as 4% reduction in the viscosity at the maximum pressure of 96 MPa. Note that the observed trend is opposite to what has been postulated by Collins [3] and measured by Ostermann et al. [4, 5].

Effect of Temperature. Increase in temperature decreases the viscosity of formation water. Figure 4 depicts the effect of temperature on the viscosity of Formation Water #1 at temperatures of 72, 75, 82, and 93 °C for pressures up to 96 MPa. Viscosity decreased by 25% on average for a 30% increase in temperature (72 to 93 °C) over the entire range of tested pressure.

Effect of Salinity. Figure 5 shows the effect of total dissolved solids on the viscosity of formation water at 82 °C

and for four different total dissolved solids content. Data indicates that the viscosity almost doubled as total dissolved solids content increased from 92473 to 251400 mg/l.

Effect of Pressure. Increase in pressure increases the viscosity of formation water. Results indicate that the viscosity increases with almost the same slope on a linear scale of the tested range of pressure. Effect of pressure is not as significant as the effect of temperature or total dissolved solids on viscosity. For the available data i.e. a pressure range of approximately 7 to 100 MPa, the viscosity increase varied between 4 to 11%. This variation particularly at pressures beyond 70 MPa is not as much as suggested by other studies [3, 6].

Predicted versus Measured Viscosities. The predicted viscosities of formation water by correlations of Kestin et al. [6], Meehan [7], McCain [10], and Palliser and McKibben [11] were compared with the measured viscosities in this study. Figure 6 shows the predicted versus measured comparison. Kestin et al. and McCain correlations generally over-predicted the viscosities of formation water particularly at high pressures. Note that the Kestin et al. correlation was only valid to 30 MPa. Both Meehan and Palliser and McKibben correlations predicted the viscosities reasonably well particularly Meehan's correlation considering the simplicity of the correlation.

It is clear that most of the available correlations are not able to provide an accurate estimate of the live formation water viscosity and the predicted viscosities could be as high as 200% or more compared to measured viscosities. More experimental data for the viscosity of live formation water is required to develop more accurate correlations. No attempt was made to correlate the available live formation water viscosity data.

Implications on reservoir simulation. Knowledge of reservoir fluid properties is necessary to simulate a realistic production scenario from the reservoir or to design optimum production systems. For majority of such studies, the viscosity of formation water is estimated with the available correlations. The variation of formation water salinity and particularly viscosity has many implications on the oil production from reservoir. Higher salinity (higher viscosity) water provides:

- More favorable Mobility ratio
- Reduced viscous fingering
- Delayed water break through
- Increased sweep efficiency and recovery factor in active aquifer drive reservoirs.

Although higher salinity case will have positive implications in terms of reservoir behavior, it may have adverse effect or at least unfavorable implications on the hydraulics of sub-sea equipment and tieback lines.

In this section a black oil steady state reservoir simulator is used to compare two production scenario cases and investigate the effect of salinity and in particular viscosity and density on the hypothetical performance of the reservoir. Table 3 shows some of the required information for the reservoir simulation cases. Note that the main difference between the two case studies is approximately 30% variation in the viscosity of formation water. The variation in density for the two cases is not significant.

Figure 7 shows the results of the reservoir simulation studies. For the low salinity case, combination of lower density and lower viscosity of formation water significantly impacts:

- Oil production rate
- Lead to higher water cut, which impacts the ability to maintain well flow.
- Oil rate drops off more quickly.
- Density is affecting water coning.

The results of the simulation cases clearly show that variation in the input properties of formation water and in particular the viscosity of formation water will affect the performance of the simulated reservoir in terms oil and water production, which in turn may affect the strategic decision of development or abandonment of the field.

Conclusions

The following conclusions are made based on the experimental results and reservoir

- Variation of the live formation water viscosity with temperature, pressure, and salinity is similar to what have been observed previously i.e. increase in viscosity with decrease in temperature, and increase in pressure and salinity.
- Dissolved natural gas, reduces the viscosity of live formation water.
- Increase in viscosity is not as drastic as has been suggested from few of the previous studies at pressures beyond 70 MPa.
- Error in the predicted live formation water viscosity with the available correlations may be as high as 200% particularly at pressure beyond 70 MPa.
- Simulation case studies indicated that variation in the viscosity of formation water has a significant effect on the oil and water production from the reservoir.

Acknowledgements

Authors would like to thank Oilphase-DBR laboratories in Houston and Edmonton for performing viscosity measurements. Permission to publish this work is greatly appreciated.

Nomenclature

- Q_o , Oil flow rate in stb/day (Figure 7)
 Q_w , Water flow rate in stb/day (Figure 7)

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Table 1: Formation Water Analysis Data

Analysis Item	Unit	Formation Water #1	Synthetic Water #1	Synthetic Water #2	Formation Water #2
Chloride	mg/L	80115	108230	52002	132407
Sulfate	mg/L	15.85	21.41	10.29	1053.45
Carbonate	mg/L	0.067	0.09	0.043	1.007
Bicarbonate	mg/L	180	243	117	257
Iron	mg/L	0.9	1.22	0.6	26.0
Silica	mg/L	46			938
Sodium	mg/L	52189	70505	33872	75126
Potassium	mg/L	269	365	175	318
Calcium	mg/L	7365	9951	4781	8572
Magnesium	mg/L	2065	2790	1340	1558
Strontium	mg/L	164	222	106	260
Barium	mg/L	107	144.4	69.4	96.4
Specific Gravity	mg/L	1.11			1.17
TDS	mg/L	142473	192473	92473	251400
pH		6.610			5.45
Turbidity	NTU	454			>1500
Zinc	mg/L	5.81			6.79
Lead	mg/L	<0.05			3.24
Alkalinity @pH 8.3	mg CaCO ₃ /L	<0.05			nd
Total Alkalinity	mg CaCO ₃ /L	145			764
Total Hydroxide	mg/L	<0.05			nd
Salinity	mg/L	10			2
Calcium Hardness	mg/L	18390			18459
Total Hardness	mg/L	26893			24877

Table 2. Composition of the Synthetic Gas

Component	MW (g/mol)	Formation Water #1	Formation water #2
		Mole %	Mole %
CO ₂	44.01	0.66	9.97
N ₂	28.01	0.00	3.02
C ₁	16.04	98.33	87.01
C ₂	30.07	0.93	0.0

Table 3. Reservoir, Oil, and Water Production Information for the Simulation Case Studies.

Property	Value	Unit
Reservoir Information		
Reservoir Pressure	83	MPa
Reservoir Temperature	86	°C
Reservoir Permeability	150-300	mD
Initial Water Saturation (S_{wi})	20	%
Mapped Aquifer (HCPV)	3	X
Oil Production Information		
Oil Viscosity	1.6	mPa.s
Oil Gravity	21	°API
Gas Oil Ratio (GOR)	825	scf/stb
Low Salinity Water Simulation Case		
Total Dissolved Solids (TDS)	142000	mg/l
Density	1.09	g/cm ³
Viscosity	0.55	mPa.s
High Salinity Water Simulation Case		
Total Dissolved Solids (TDS)	251000	mg/l
Density	1.17	g/cm ³
Viscosity	0.71	mPa.s

Figure 1. Stiff Diagrams for Four Formation/Synthetic Water Samples

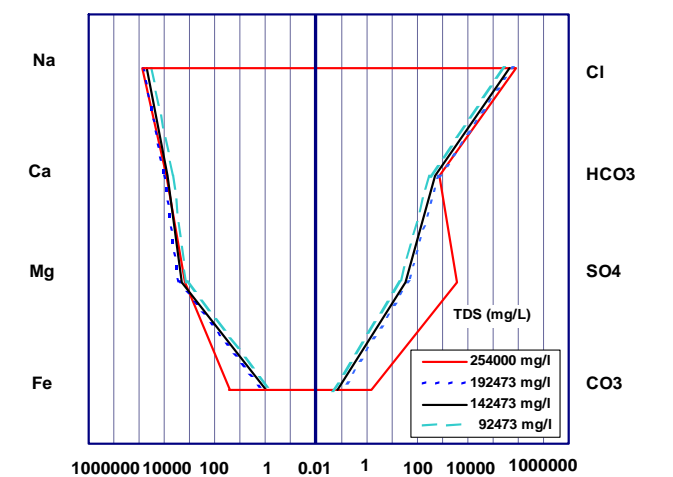


Figure 2. Validation of Viscosity Measurement by EMV Viscometer

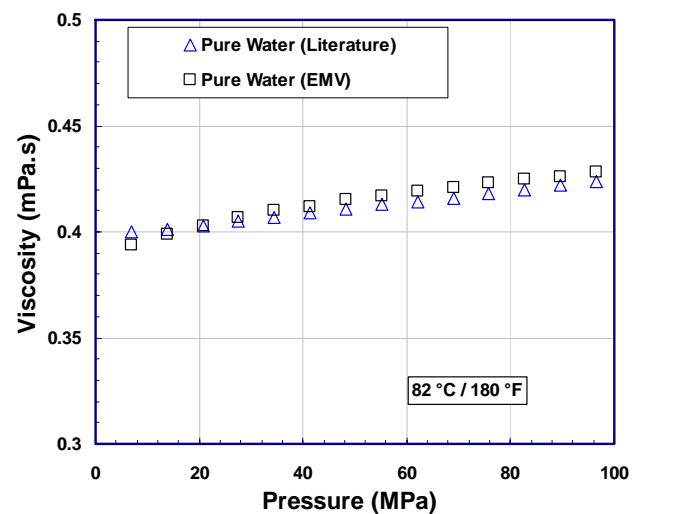


Figure 3. Effect of Dissolved Gas on the Viscosity of Formation Water

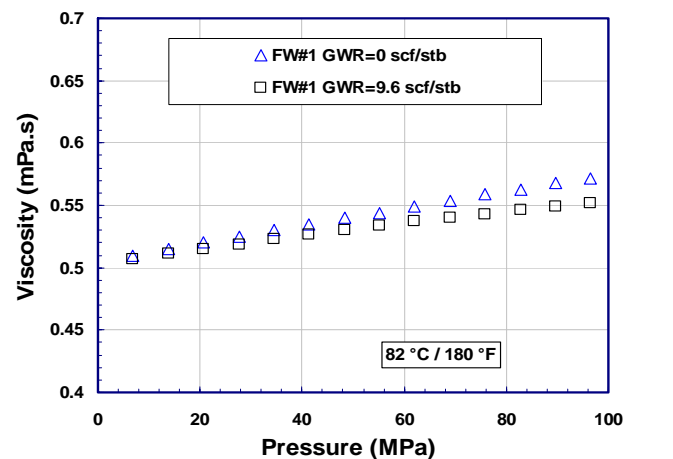


Figure 4. Effect of Temperature on the Viscosity of Formation Water

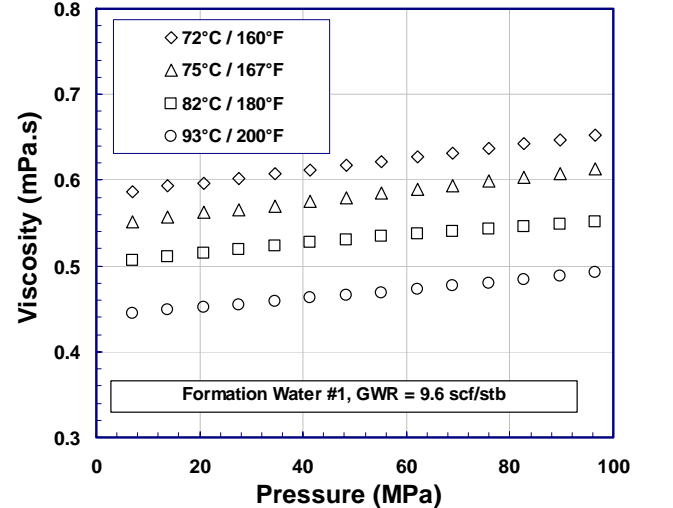


Figure 5. Effect of Salinity on the Viscosity of Formation Water

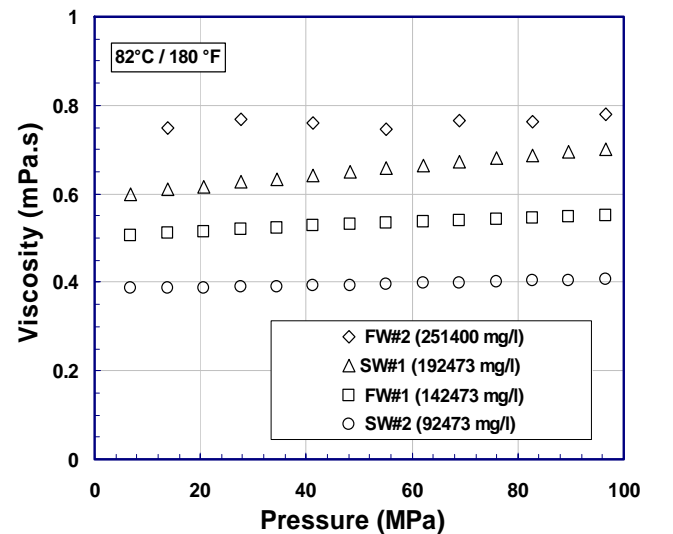


Figure 6. Comparison of Various Viscosity Models

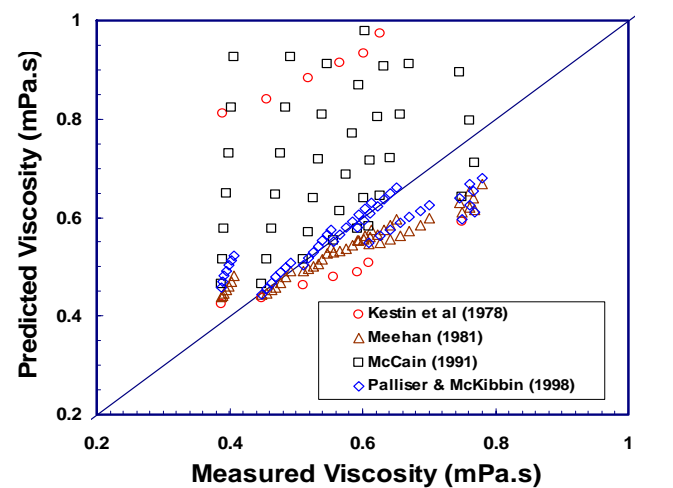


Figure 7. Effect of Viscosity and Density Variation on the Performance of the Reservoir (Simulation Results)

