Rheological Effect of Produced Water on Crude Oil Flow in Production Tubing String: A Case Study of Agbami Oil Field, Nigeria

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Abstract: *This research work examined the effects of formation water, Sea water and Injection water on the rheological properties of crude oil from an off- shore field in the Niger-Delta area of Nigeria. Flow properties analyses were determined at ambient temperature (77^0F) and reservoir fluid critical Temperature (177^0F). Analysis of the mixture of the crude oil and water samples were carried out at various ratios of (80/20 and 50/50) % respectively. Test results indicated that the addition of water to crude oil sample increased the values of most of the flow properties at both ambient and critical temperatures. However some crude oil flow properties like (Viscosity, pH, Density, Specific gravity and Electrical conductivity) showed the highest incremental values with formation water sample than in Sea water and Injection water samples at both ambient and formation temperature. At 80/20 ratio the viscosity of crude oil increased from 3.8 cst to 4.2cst with the addition of formation water, 4.0 cst and 3.9 cst with sea water and injection water samples respectively, the values for 50/50 ratio gave 4.5 cst, 4.2 cst and 4.0 cst for formation, sea and injection water samples respectively at ambient temperature. At 80/20 ratio, the pH of the crude oil sample increased from 4.58 to 5.20 on addition of formation water, 4.90 and 4.60 with sea and injection water samples respectively, the values for 50/50 ratios were 7.9, 6.5 and 5.2 for formation water, seawater and injection water samples respectively at ambient temperature. The specific gravity at 80/20 ratio increased from 0.788 to 0.816, 0.806 and 0.797 on dilution with formation, sea and injection water samples respectively, the 50/50 ratio gave 0.993, 0.966 and 0.953 for formation water, sea water and injection water respectively at ambient temperature. The influx of water samples at 80/20 and 50/50 ratio also increased the density of crude oil at both temperatures. Therefore in other to minimize the variation in crude oil properties normally experienced during production, the analysis of the effect of different sources of water on crude oil properties should be employed.*

Keyword: Flow properties, Formation water, Electrical conductivity, viscosity, Density.

1. Introduction

Petroleum was formed many million years ago. It is believed to originate from the remains of tiny aquatic animals and plants that settled with mud and silt to the bottom of ancient seas. As successive layer built up, the deposits were subjected to high pressure and temperature and as a result, underwent chemical transformation leading to the formation of the hydrocarbon and other constituents of crude oil. In many cases the crude oil migrated and accumulated in a porous rock overlaid by impervious rock that prevented further movement. Usually a layer of concentrated salt water underlies the oil pool, therefore an oil reservoir can be defined as a porous and permeable rock containing natural accumulation of hydrocarbon that are confined by impermeable rock and a water barrier system. Thus, reservoir rocks normally contain both petroleum hydrocarbons (liquid and gas) and water. Sources of this water may include flow from above or below the hydrocarbon zone, flow from within the hydrocarbon zone, or flow from injected fluids and additives resulting from production activities. This water is frequently referred to as connate water or formation water and becomes produced water when the reservoir is produced and these fluids are brought to the surface.

Generally, Formation water is the water which is found to be present in the oil reservoir with the crude oil initially without any fluid injection and becomes produced water when the reservoir is produced and these fluids are brought to the surface. This formation water can be classified into three generically group each originating from different sources and also differ in composition. The three groups generally identified are: meteoric water, connate water and mixed water [1].

Meteoric water is the water that has it source from rain water, it is the water that has fallen as rain and as filled up the porous and permeable layer, analysis of this water type shows that it contains combined oxygen chiefly carbon-dioxide. These above the ground water table where oxygen react with the sulphide to produce sulphate and carbon-dioxide react to produce carbonate and bi-carbonates. The presence of carbonate, bicarbonate (hydrogen-carbonate), and sulphate in oil field water suggest that at least some of the water had probably come from the surface [3], [5].

Connate water is generally believed to be sea water, in which marine sediment were deposited presumable it originally filled all the pores, it is doubtful, however, whether connate water are actually the original water in place, the current usage is that connate water is the insterstial water existing in reservoir prior to the disturbance of the reservoir by drilling, but actually most reservoir water quite different in chemical composition from sea water, they are undoubtedly circulated and moved in fact have probably been completed replaced since sediments are deposited. Most formation water are brines, characterized by an abundance of chloride especially so called chloride, and they often have concentration of dissolved solid many times greater than mother see water. This means if the dissolved mineral content of the ancient sea was approximated the same as that of present sea, that original water has acquired some additional mineral matter since it entered the rock [5]. The chemical analysis of mixed water shows that it is

characterised by both a chloride and sulphate carbonate-bicarbonate content. This suggests a multiple origin. Presumably meteoric connate mixed with or partially displaced the connate water of the rock mixed water may occur near the present ground surface or may be found below unconformities [8], [2].

In oil exploitation, the situation arises when the percentage of water composition at the well head and that at the processing station differ, hence it can be inferred that there is an influx of surface water into the crude oil in the pipeline during transportation to the separating station which may be due to breakage in pipe carrying the crude oil from the well head to the station, on analysis it is observed that this water has the same composition as injected water usually sea water. This could be another source of water inherent in crude oil and produced as produced water at the surface facilities.

Also when the production from an oil well has become abnormally low, that is when the primary oil recovery has reached it limit, there is a need to carry out secondary recovery process by injecting specially formulated water in the producing reservoir, this is necessary to in order boost the reservoir pressure to its initial pressure and also to sweep the remaining oil toward the production well and thereby increasing the ultimate oil recovery from the producing reservoir. Hence produced water from an oil well can either be formation water, injection water or surface (sea) water or either two or three of them.

Produced water is not a single commodity. The physical and chemical properties of produced water vary considerably depending on the geographic location of the field, the geological formation with which the produced water has been in contact for thousands of years, and the type of hydrocarbon product being produced. Produced water properties and volume can even vary throughout the lifetime of a reservoir. If water-flooding operations are conducted, these properties and volumes may vary even more dramatically as additional water is injected into the formation.

Produced water is usually considered as by product of hydrocarbon production by operators since its presence in production tubing string constitutes a lot of problems among which are low pressure drop, variation in flow properties, unnecessary volume increase, corrosion and separation problems. However samples and analysis of same water can provide vital information for field development plan, including optimization of completion design, material selection and hydrocarbon recovery.

Finally an integrated approach to produced water analysis in every well from reservoir to disposal (or back to reservoir for pressure maintenance) will bring immediate and long time saving cost. An integrated water management service is envisioned as the key to reservoir production optimization by providing the means for producing additional recoverable reserves. While water control services will provide the bulk of progress, a downhole factory-built on the well pad factory concept-will minimize produced water-handling costs, and optimized facilities processes could turn waste into a commodity, which will further enhance the recovery factor,

nevertheless the real money comes from the potential increase in oil production.

The objective of this research work therefore is to analyse the effect of produced waters; formation water, injection water as well as surface water on the rheological flow properties of crude oil in production tubing string.

2. Materials and Methods

Sampling: All the collected samples were preserved in accordance with guidelines and International Standards. All other QA/QC procedures relevant to sample collection, custody and analyses were strictly adhered to (ASTM D1250, ASTM D4052, ASTM D5002, DIN 51757, ISO 12185, ASTM D4806, IP 365, ASTM D5931 AND ASTM D6226-05).

The crude oil sample was obtained from Agbami oil field, Nigeria and water samples of formation water, sea water, and injection water were injected into the crude oil for analysis. The flow properties determined were specific gravity, API gravity, Potential hydrogen oil concentration, Electrical conductivity and viscosity. Due diligent were taken to prepare the samples for specified test as indicated below:

Viscosity determination: The crude sample was charged into the viscometer and placed in the water bath which was then switch on. The thermostat set at 35^0 F was inserted into the bath to regulate the temperature of the water in the bath. The temperature was set and placed inside the water bath through an opening made for it. The crude sample was adjusted to a set mark in viscometer, the stop clock is started and the time at which the crude flow from the upper mark to the lower mark was recorded and the viscosity was calculated from its flow rate as follows.

$$K_V = C_V \text{ X T}$$

Where K_V = Kinematic viscosity (cst), C_V= Viscosity constant = 0.09636 and T = flowing time (secs).

PH Value determination: A 4 parts pH measuring system was used for ph determination namely: a ph sensing electrodes, electronic circuit that translate the signal into readable reference for the user and the sample being measured. A 9 volt battery was connected to the ph meter, the cover was adjusted to desired view angle, the meter was switch on and the mode was set to ph position, this activated the liquid crystal display, the cable was connected to the BNC input and the electrode was conditioned in buffer 7.0 solution until the LCD is stable (30 sec) the temperature control was adjusted to ambient temperature, the buffer and the samples was allowed to come to this ambient temperature ,the calibration control was adjusted in such a way that the LCD showed the value of buffer 7.0 at 250oF,the electrode was then rinsed with buffer 4.0, blot dry and immersed in buffer 4.0 when the LCD is stable (30sec) the slope control was adjusted to make LCD show the value of 4.0 solution, the system has now been calibrated to read sample with different ph values. The electrode was the rinsed with a small portion prepared crude sample, blot dry

and immerse in the sample. This was repeated for measuring the ph value of all the prepared crude samples.

Density determination: 50 ml pycometer (density bottle) was rinsed with distilled water and dry with acetone, the mass of empty pycometer was measured and recorded using analytical balance, the pycometwr was then filled with distilled water, the stopper was inserted and the stopper hole was also filled with distilled water, it mass was measured recorded, the pycometer was then filled with distilled water and dry with acetone, the pycometer was the filled to the brim with the crude oil sample, the pycometer was then hanged in thermostat bath at the given temperature and was allowed for a few minutes to reach equilibrium, the pycometer was the removed from the bath, wipe dry and weigh on an analytical balance, the density of oil sample was obtained as

$$D = \frac{M_W}{V_M}$$

Where D = density (lb/bbl), M_W = Molecular weight (lb) and V_M = volume (bbl)

Determination of specific gravity 60^0F : The sample was prepared and transferred into a clean gravitometer cylinder, the gravitometer was then lowered gently into the sample and it was sealed, it was then depressed to about two scale division into the liquid and then it was sealed, sufficient time was then allowed for the gravitometer to become completely stationary and for air bubbles to surface, when the gravitometer finally comes to rest and floating freely, the Gravitometer was read to the nearest scale division, the correct reading is that point on the gravimeter scale at which the liquid cut the scale. The point was determined by placing the eye slowly below the level of the liquid and raising it slowly unto the surface until a disturbed eclipse appears to be a straight- line crossing the gravimeter scale. Note that for conversion of specific gravity at laboratory temperature (^{0}F) to value at 60 ^{0}F, the equations below were used

$$SG = \frac{\rho_F}{\rho_W}$$

Where SG =Specific Gravity (dimensionless), ρ_F = Density of fluid (kg/m^3) and ρ_W = Density of water (kg/m^3).

API gravity determination: The sample was prepared and transferred into a clean gravitometer cylinder, the gravitometer was then lowered gently into the sample and it was sealed, it was then depressed to about two scale division into the liquid and then it was sealed, sufficient time was then allowed for the gravitometer to become completely stationary and for air bubbles to surface, when the gravitometer finally comes to rest and floating freely, the Gravitometer was read to the nearest scale division, the correct reading is that point on the gravimeter scale at which the liquid cut the scale. All the samples for ph measurement were maintained at 60^0F, and the ph was calculated from the correlation.

$$°API = \frac{141.5}{SG \ @60°F} - 131.5$$

Electrical conductivity (EC) determination: A saturated paste of samples of crude oil was prepared. The electrical conductivity of the sample was determined electrometrically with a calibrated electrical conductivity meter.

Heavy Metals Determination (AAS): Samples were pre-treated with 2ml conc. HNO3 per litre of sample. The equipment was conditioned by auto-zeroing it with distilled water and with conc. HNO3. The pre-treated sample was analysed for heavy metals using the appropriate hollow cathode element of each metal of interest at the appropriate wavelength, lamp current, band-pass, and background correction.

Oil and Grease Determination (ASTM D 3921): About 100ml acidified sample (pH 2) was measured into a graduated glass bottle. 4ml of an organic solvent was added to the sample and the bottle vigorously shook for 2mins. The contents of the bottle were emptied into a separating funnel and shook vigorously. The stopper of the funnel was intermittently opened to release pressure build up. The contents of the funnel were allowed to settle. The bottom layer of the solution was transferred into a clean beaker using glass funnel previously stuffed with cotton wool and 1g anhydrous sodium sulphate at the aperture of the glass funnel to absorb water.

3. Discussion and Results

The test results of the flow properties Table 1 indicated that while most of the measured flow properties in water samples showed lowest values in the injection water sample, the values were higher in sea water sample and highest in formation water sample. Formation water sample at (77^0F) has a density of 10.07 lb/gal, while crude oil sample, Sea water samples and injection water samples has 6.60 lb/gal, 9.29 lb/gal and 8.26 lb/gal. This could be attributed to the higher concentration of brine inherent in formation water. The Electrical conductivity of formation water sample was 241μScm^{-1} , while Sea water, crude oil sample and injection water sample has 120 μScm^{-1}, 105 μScm^{-1}, 90 μScm^{-1} respectively. This is a reflection of the concentration of Total Dissolved Solid in the samples. Higher concentration increases Electrical conductivity.

Table 1: Analysis of the flow properties of crude oil and water samples

Properties	A	B	C	D	E	F	G	H
Temperature (^{0}F)	77	177	77	177	77	177	77	177
PH	4.54	5.12	8.1	9.34	7.1	8.9	6.03	7.99
Viscosity (Cst)	3.8	1.69	1.71	1.61	1.15	1.097	1.13	0.55
Specific Gravity	0.788	0.764	1.258	1.16	1.115	1.074	1.035	1.006
^{0}API / ^{0} Baume	48	54	25	20	15	10	5	1
TDS (mg/l)	51	78	120	430	98	120		
EC (μScm^{-1})	105	155	241	850	120	150	90	150
Colour (PtCo)	20	10	10	3	7	2	0	0
Density (lb/Gal.)	6.6	6.35	10.07	9.67	9.29	8.95	8.62	8.38

A= 100% Crude oil (77^0F), **B** = 100% Crude oil (177^0F), **C** = 100% Formation water (77^0F), **D** = 100% Formation water (177^0F), **E** = 100% Sea water (77^0F), **F** = 100% Sea water (177^0F), **G** = 100% Injection water (77^0F), **H** = 100% Injection water (177^0F),

Table 2 (80/20) % ratio indicated that the addition of water samples to crude oil samples increased most of the flow properties of the crude oil at both ambient and formation temperature. While viscosity of crude oil sample at ambient temperature was 3.8 cst, this was increased to 4.2 cst on

addition of formation water, 4.0 cst and 3.9 cst on addition of sea water and injection water respectively, this trend was also seen at critical formation temperature. This could be attributed to increase in the degree of interaction or bonds between crude oil molecules on addition of water. Specific gravity also increased from 0.788 at ambient temperature to 0.816 on addition of formation water, 0.806 and 0.797 for sea water and injection water respectively, critical formation temperature also followed the same trend, and this could be attributed to increase in density. The higher the density the higher Specific gravity. The TDS at ambient temperature was increased from 51mg/l to 70 mg/l on addition of formation water, 60 mg/l and 54mg/l on addition of sea water and injection water samples respectively, this could be attributed to a higher concentration of suspended and dissolved solid inherent in formation water samples.

Analysis of (50/50) ratio of crude oil and water samples (Table 3) also showed similar trend with that of Table 2, but there were much more increase in most of the flow properties at this ratio than 80/20 ratio at both ambient and formation temperature. Viscosity increased from3.8 cst at ambient temperature to 4.5 cst on addition of formation water, 4,2 cst and 4.0 with sea water and injection water respectively, the same trend was seen at higher temperature, this could be attributed to an increase in molecular bond and interaction between water molecule on addition of water,

Comparing Table 1 and Table 2, it was observed that the higher the ratio of water samples added to the crude oil sample the higher the increase in the flow properties of the crude oil. While the viscosity of crude oil with formation at 80/20 gives 4.2 cst, it was 4.5cst at 50/50 ratio both at ambient temperature, this could be attributed to a much more increase in molecular bond and interaction between water molecule on addition of higher ratio of water sample. Density also increased from 6.79 lb/gal at 80/20 to 8.27 lb/gal at 50/50 ratio on dilution with formation water at ambient temperature. Specific gravity increased from 0.816 at 80/20 to 0.993at 50/50 ratio on dilution with formation water at ambient temperature. Electrical conductivity and TDS increased from 70 μScm^{-1},115 mg/l at 80/20 ratio to 105 μScm^{-1} and 205 mg/l respectively at 50/50 ratio on dilution with formation water at ambient temperature.

As indicated in Tables 1-3, the influx of water into crude oil increase the flow properties of crude oil at ambient and formation temperature except the API gravity, this also validate previous study on this by Suttermain, 1979 who predicted that the presence of water in crude oil may alter the flow properties of the crude oil and the degree of alteration depend on the constituents of the water.

Table 2: Analysis of 80: 20 ratios of Crude oil and water samples

S/N	Properties	A	B	I	J	K	L	M	N
1	Temperature (^{0}F)	77	177	77	177	77	177	77	177
2	PH	4.54	5.12	5.2	6.1	4.9	5.3	4.6	5
3	Viscosity (Cst)	3.8	1.69	4.2	2.9	4	2.6	3.9	2.1
4	Specific Gravity	0.788	0.764	0.816	0.802	0.806	0.784	0.797	0.78
5	^{0}API	48	54	42	45	44	49	46	50
6	TDS (mg/l)	51	78	70	90	60	78	54	69
7	EC (μScm^{-1})	105	155	115	150	110	130	105	125
8	Colour (PtCo)	20	10	17	9	15	5	10	0
9	Density (lb/Gal.)	6.6	6.35	6.79	6.68	6.71	6.53	6.64	6.49

A= 100% Crude oil (77^{0}F), **B** = 100% Crude oil (177^{0}F), **I** = 80% Crude oil +20% Formation water (77^{0}F), **J** = 80% Crude oil +20% Formation water (177^{0}F), **K** = 80% Crude oil + 20% Sea water (77^{0}F), **L** = 80% Crude oil + 20% Sea water (177^{0}F), **M** = 80% Crude oil + 20% Injection water (77^{0}F), **N** = 80% Crude oil + 20% Injection water (177^{0}F)

Table 3: Analysis of 50: 50 ratios of Crude oil and water samples

S/N	Properties	A	B	O	P	Q	R	S	T
1	Temperature (^{0}F)	77	150	77	150	77	150	77	150
2	PH	4.54	5.12	7.9	8.1	6.5	7.2	5.2	6.4
3	Viscosity (Cst)	3.8	1.69	4.5	3.2	4.2	3	4	2.9
4	Specific Gravity	0.788	0.764	0.993	0.973	0.966	0.959	0.953	0.928
5	^{0}API	48	54	11	14	15	16	17	21
6	TDS (mg/l)	51	78	105	120	73	108	55	72
7	EC (μScm^{-1})	105	155	205	375	193	270	150	210
8	Colour (PtCo)	20	10	25	19	22	17	15	10
9	Density (lb/Gal.)	6.6	6.35	8.27	8.1	8.04	7.99	7.94	7.73

A = 100% Crude oil (77^{0}F), **B** = 100% Crude oil (177^{0}F), **O** = 50% Crude oil +50% Formation water (77^{0}F), **P** = 50% Crude oil +50% Formation water (177^{0}F), **Q** = 50% Crude oil + 50% Sea water (77^{0}F), **R** = 50% Crude oil + 50% Sea water (177^{0}F), **S** = 50% Crude oil + 50% Injection water (77^{0}F), **T** = 50% Crude oil + 50% Injection water (177^{0}F)

4. Conclusion

At the end of this study the following inferences were made; influx of water into crude oil increased the viscosity of crude oil, salt content is the predominant water property that affects the viscosity of crude oil. Properties like Ph, Density, TDS, and Electrical conductivity also increased in proportional with the quantity of water in the crude oil. API gravity varies inversely with quantity of water in crude oil. Also crude oil specific gravity is inversely related with API

gravity. Therefore in other to maximize productivity of an oil well, analysis of the effect of produced water on crude oil flow in production string should be employed. Detailed experimental investigation of the thermodynamic behaviour of crude oil should also be carried out as the next step of research or as the future scope of this study.

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