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Physical and Chemical impacts on Bituminous core samples under Thermobaric conditions on a deposit in South Western Nigeria

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Abstract

Bitumen is one of the major mineral resources in Nigeria. It is unconventional, with an estimated 38 billion barrels of oil in place. Since after its discovery in 1904, it is yet to be exploited commercially [8]. This research work will examine physical and chemical impacts on bituminous core samples under thermobaric conditions, with the aim of improving physico – chemical based technology suitable for bitumen exploitation in Nigeria. A bitumen core sample with diameter 50mm (fig.3) was obtained from Yegbata, well 1 in Ondo State. The core sample was taken to the laboratory, placed on core cutting machine and cut into rectangular form, all together twelve (12), each with length 40mm , width 18mm and height 20mm (fig.4). A core flood equipment was used in examining the impact of 0.05% concentration of aqueous solution of sodium hydroxide (NaOH), with a volume of $50cm^{3,}$ as injected fluid on the core sample at different time interval and at different temperature values ranging from 20^0C to 75^0C while pressure drop across the core and permeability were recorded (Table 1). The experiment was repeated using solvent combination of 0.1% concentration of aqueous solution of neonol (AF9–12) in addition to 0.1% concentration of potassium hydroxide (KOH), also with $50cm^3$ volume , prepared in the laboratory, just like NaOH. In fig.6 and fig.9, the effects of the different injecting liquids with different concentrations on permeability under thermobaric conditions are presented. From the analysis, it is seen that permeability improves on addition of AF 9-12 to KOH. Fig. 7 and fig. 10 considered the effect of time interval on permeability while fig.8 and fig. 11 present the effects of the different injecting solvents used on the volume of liquid displaced under thermobaric conditions. After the experiment, we realized a 15-20% oil displacement coefficient using AF 9-12 in combination with KOH. This result is economically important for the exploitation of bituminous deposits in Nigeria. This research work was conducted at Research and Education Center "Physico-chemistry of reservoir" «OOO NPO» Himburneft» - KubGTU.

Keywords: Bituminous oil, neonol, alkali, core sample, thermobaric condition

INTRODUCTION

Combined technologies based on a combination of thermal and chemical effects on the reservoir. These technologies for all the many combinations of methods are classified according to the effect of coverage of the intensity of the oxidation process; increase in thermal coverage of the reservoir; strengthening due to physico-chemical and other methods of the effect of displacement of hydrocarbons by the thermal front and non-traditional use of thermochemical effects [1, 2].

When the coverage of the formation is increased by thermal action, methods directed at changing the filtration flux of the fluids, a combination of in-situ burning with flooding, foam systems, polymers, chemical additives, etc. are used.

The negative influence of the reservoir heterogeneity upon thermal action is greatly enhanced due to the high viscous instability of the displaced liquid and displacing agent, which can be reduced by a combination of thermal and physicochemical methods of action. Oil recovery can be substantially increased by improving the ratio of oil and water mobility, that is, by reducing the viscosity of the oil or increasing the viscosity of water, or at the same time by another route. This is facilitated by the technology of thermo-polymer impact on the reservoir aimed at increasing oil recovery, which is intended for use on deposits of high-viscosity oils in terrigenous heterogeneous strata. Reducing the viscosity of oil in it under the influence of thermal effects is supplemented by a decrease in the mobility of the injected water when the polymer additives are dissolved in it [5,7,11].

The combination of thermal and alkaline effects on the bed is based on the thermo-alkaline method, which is developed by pre-injecting into the stratum of the rim of the steam with the subsequent pitting of the rim of the alkali solution. Compared with steam, this effect provides an increase in the scope of the formation by volume of the working agent, a more complete displacement of oil, a reduction in specific steam consumption [2,4,10]. Coefficient of coverage is increased due to the effect of "self-regulation", expressed in a relative increase in the filtration resistance in high-permeability zones of the formation. By injecting steam into the stratum, the injection of chemical reagent is optimized and the mechanism of in-situ emulsification of oil is implemented. When water-soluble alkali reacts with acidic components of oil, alkaline salts are formed, this process is accompanied by a decrease in surface tension at the interfaces "oil-alkali solution". Since, the magnitude of the surface forces is inversely proportional to the coefficient of surface tension at the boundary of the phases, a decrease in the oil content in the layer previously retained by the capillary forces occur[3,6].

For emulsification adequate is the maximum mass concentration of 0.1-1.0% alkali which does not decompose under the influence of temperatures, does not cause corrosion of metals coated with a protective layer. When flooding heterogeneous reservoirs with high-viscosity petroleum alkaline hot water, an increase in oil recovery by 14.5% is observed compared to flooding with hot water or displaced steam from the oil. The main limitations of the application of the method are the presence of calcium and magnesium ions, over 5 mg.eq / l ^{2} in the formation and injected waters and clays in the rock (more than 15-20%). The effectiveness of the technology of thermal alkaline flooding also depends on the composition of the reservoir oil. If the latter has an acidity index (the ratio of potassium hydroxide to oil) is less than 0.5 mg / l, then the method is not applicable. Unlike all other physicochemical methods, alkaline solutions can be used at temperatures up to 15^{0}C - 200 ^{0}C, as well as in carbonate formations. Increasing the wettability of the formation water, alkaline solutions have the advantage over other methods for use in preferably hydrophobic and hydrophobic layers [2,6,7].

Investigations carried out at the VNIIneft Institute, Russia established that the use of a hot alkaline solution makes it possible to increase the oil displacement ratio in comparison with the displacement of oil by water of the same temperature. Studies on the displacement of oil by rims of alkali, promoted by water, have shown that the use of a rim instead of a continuous injection of alkali does not reduce the oil displacement coefficient. Thus, when the Yaregskoye oil was displaced with a 0.15% aqueous solution of NaOH with a concentration of 40% of the pore volume of the reservoir model, the displacement coefficient reached 0.61, which is 20% higher than the displacement coefficient for pumping water at a temperature of 120 ° C [1,3,5].

Regional Geological Setting , Structure and Tectonics

The tar sands of southwestern Nigeria lie inland near the boundary between the coastal plain and uplands. In geologic terms, the tar belt straddles the Ilesha Spur (Okitipupa High), a structural and slight topographic divide. To the west are plains and uplands of the Benin Basin; to the east are the valley and delta of the Niger River system that is developed above the subsurface Anambra Basin. The coastal plain, underlain by sedimentary strata, forms a land surface of generally low relief. Drainage is moderately integrated but most rivers are relatively small and have drainage basins either within the coastal plain or the adjoining uplands. Much of the land surface has a well-developed lateritic soil cover and bedrock is not generally exposed except in artificial cuts or excavations. The northern part of the coastal plain lies atop sands and clays of cretaceous and tertiary age, some of which are relatively unconsolidated. The southern part of the coastal plain is a coastal lowland band, widening slightly to the east, dominated by marsh and beach-ridge topography. Alluvial valley deposits of Quaternary age border the larger rivers. The uplands, to the north of the tar belt, constitute a region of more elevated topography underlain by basement rocks. Gneiss, quartzite, granite and schist dominate this suite of igneous and metamorphic rocks of Precambrian age. In a few places, sedimentary strata atop hills of basement rock indicate the tendency for strata to overlap the basement surface as it rises toward the north. To the south, basement underlies the sedimentary succession at progressively greater depths.

The Benin basin is named for the nation that borders Nigeria to the west. It has been called the Dahomey Basin and the Cotonou Basin. The basin is a post-rift basin in a marginal position, it developed in a shallow embayment of the coastline of western Africa following the opening of the equatorial Atlantic Ocean during early Cretaceous time. The Benin basin is elongated in an east-west direction, parallel to the coastline, extending from the Ilesha spur and the tarbelt in the east to the coastal lowlands of Ghana in the west. The northern edge of the basin is marked by the basement exposure, which is located as much as 130 km from the coast along the central axis of the basin near the Nigeria – Benin border. The southern limit of the basin is poorly defined and lies beneath the seafloor beyond the continental shelf. The Anambra basin to the east of the tar belt is the geologic region underlying the western onshore part of the Niger Delta. Like the Benin basin, it originated in the early Cretaceous time as a rift structure, it differs by being elongated toward the northeast as one of a series of structural troughs caused by crustal thinning along a failed rift axis perpendicular to the mid-Atlantic spreading center. The most relevant part of this system is the Benin Hinge, the distinct northeast-trending structure, where the northwest flank of the basin meets the Ilesha spur [8, 9].

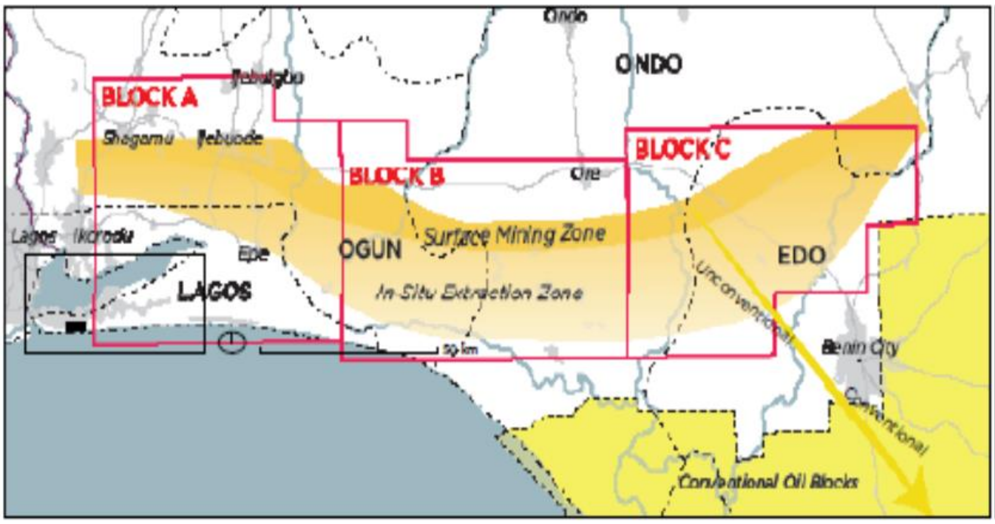

Figure 1: Nigerian bitumen belt showing bitumen main blocks A, B and C which where subdivided into 10 sub-blocks. Conoco 1991.

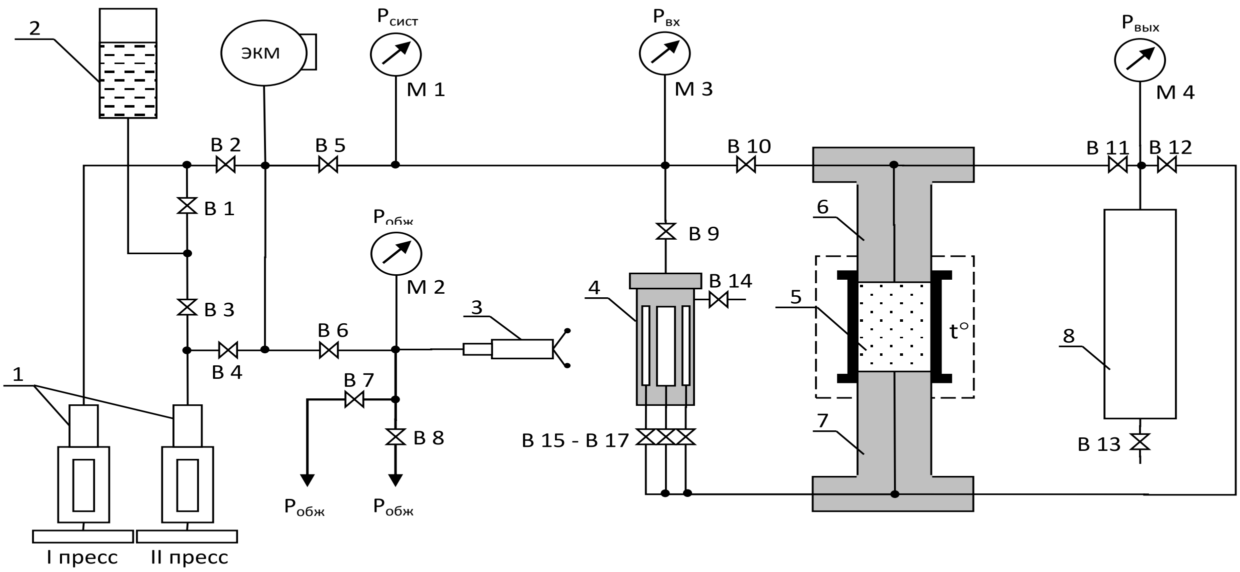

Figure 2: Schematic diagram for modified installation for the study of core permeability (coreflood set-up) used in this research work

1 - injection presses; 2 - a tank with oil; 3 - booster press; 4 - 3 chamber capacity; 5 - core, 6, 7 - upper and lower plungers of the core clamp; 8 - compensating capacity; B 1 - B 17 - valves; ECM - electrocontact manometer; M 1 - M 4 – manometers

METHODOLOGY

Before the core flooding experiment, the following parameters where examined and recorded; age of the rocks Maastricht, reservoir temperature (T) 25.5 ° C, the density (ρ) of hydrocarbons 1.5 g / cm^3, the reservoir pressure (P) 82 atm, the depth of core sampling along the vertical (H) 750 m, the porosity (m) 30% and the reservoir thickness 25-30 m.

The work is carried out in three stages. The sequence of filtration of liquids through the core sample and the direction of filtration are chosen so as to approximate the impact on the core sample to reservoir conditions. At the first stage, the oil model in the core set up is filtered in the direction corresponding to the direction of the formation fluid movement and to the bottom of the well. The formation fluid model enters the sample under study from below along the horizontal channel in the upper part of the plunger, which is closed by a valve. After passing through the core sample, the fluid enters the central channel of the upper plunger, in the upper part of which there is a thermo-well sleeve. The annular space between the sleeve and the channel walls communicates with two narrow channels. Through the valve, the outgoing fluid is directed to the measuring devices. In several modes of fluid flow at different pressure differences, the permeability of the core sample is determined.

The flow rate of the liquid through the core sample depends on the speed of the plunger presses, which are connected in such a way that when the gears rotate, their plungers move in mutually opposite directions. Press drive consists of an electric motor that, through a worm gear, rotates the input shaft of a friction-planetary gearbox designed to regulate the speed of rotation. When the plunger of the press moves along the position of the measuring pointer, the amount of displaced liquid is determined with an accuracy of 1 cm^3, which corresponds to a displacement of the plunger by 1 mm.

In the second step, after determining the initial permeability of the core sample through the valve, the injecting fluid enters the core sample in the opposite direction to the formation fluid movement. Through the core sample, the injecting fluid is pumped in an amount of not less than 5 volumes of pore space of the core sample.

In the third stage, after the injecting fluid is exposed to the core sample along the horizontal channel in the upper part of the plunger at certain time interval, the formation fluid is again pumped in several modes and the residual permeability of the core sample is determined. The displaced resident fluid (hydrocarbon) which the injected fluid floods from the core sample is collected and measured in a measuring cylinder.

Figure 3: Cylindrical bitumen core sample from Yegbata Well 1, before cutting into rectangular shapes

a

b

Figure 4: Rectangular bitumen core samples (a) before experiment, (b) after experiment

Figure 5: Displaced fluid with high concentration of hydrocarbon

RESULTS AND DISCUSSION

It was assumed that the liquid, penetrating into the image of the rock, would react with the hydrocarbons in it, and displace them. The core sample in appearance is a breccia of supposedly intrusive and metamorphic rocks, gneisses from acidic to medium composition. Fragments of weakly coagulation with a size of 0.5 to 1 cm, the rock are weakly cemented. The cement is basal type and is a mixture of heavy hydrocarbons, sand and clay.

The degree of displacement of hydrocarbons was estimated by the following two criteria:

1. Change in permeability as a result of pressure drop across the core which corresponds to ΔP for the sections of the formation from the wellbore, which were not affected by well-bore repression. Because permeability is an indicator of the total area (μm^2) of the cross-section of the filtration channels in the sample, a change in this index at the end of the experiment with respect to the beginning, with other equal conditions, may indirectly characterize the degree of displacement of the hydrocarbon.

2. Change in the degree of saturation of the color of the fluid of the effect at the exit from the sample.

The permeability was calculated with a laminar, rectilinear flow of liquid according to the formula Kp = $(Q \times \mu \times L)/_{F \times \Delta P}$, μm^2

Where: Q - volumetric fluid filtration rate, $cm^3/_s$

μ is the viscosity of the liquid at a given temperature, cP or mPa.s;

L is the length of the sample, cm;

F is the cross-sectional area of the sample, cm^2;

ΔP - pressure difference at the inlet and outlet ends, atm.

From the research, the following results were obtained.

Table 1: Experiment 1, using 0.05% NaOH as the displacement agent

Pressure difference, ΔP, (atm)	Temperature t (^{0}C)	Permeability K, (mD)	Time interval T (hr)	Volume of liquid displaced , V(cm^3)
2	20	20	0	12
2.5	25	0.3944	1	5
2	27	0.049	2	5
2	50	0.137	3	7
7	50	0.0225	4	4
7	75	0	5	0

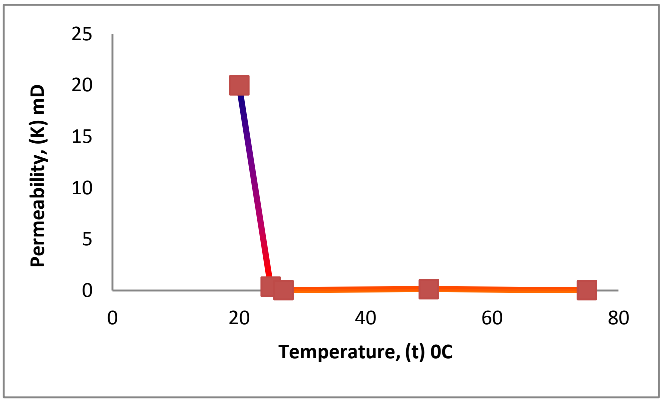

Figure 6: Permeability and temperature graph at pressure drop for 0.05% NaOH

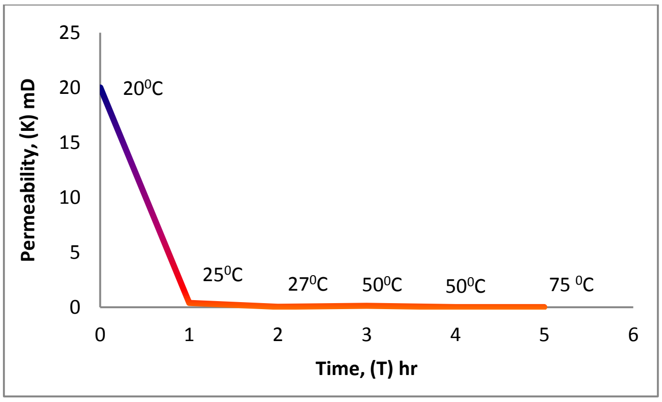

Figure 7: Permeability and time graph at a pressure drop for 0.05% NaOH

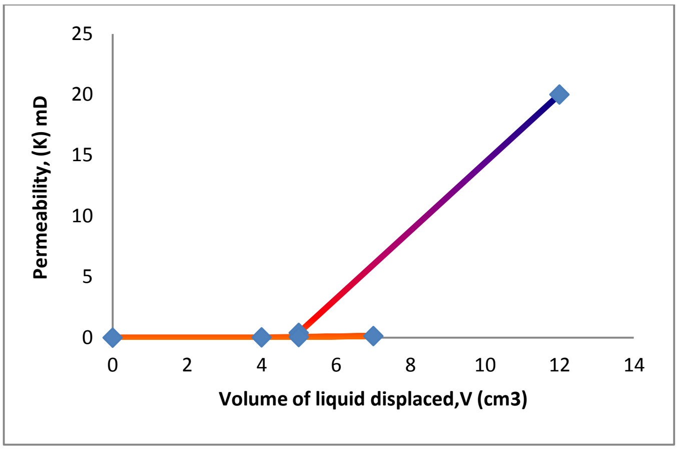

Figure 8: Permeability and volume of liquid displaced graph at pressure drop for 0.05% NaOH

Table 2: Experiment 2, using 0.1% KOH + 0.1% AF 9 - 12 as the displacement agent.

Pressure difference, ΔP, (atm)	Temperature, t (^{0}C)	Permeability, K (mD)	Time interval, T(hr)	Volume of liquid displaced ,V (cm^3)
2	25	138	0	15
2	25	44.5	1	10
2	25	15.1	2	8
2	25	6	3	12
2	50	0.93	4	2
2	75	0.025	4.5	2

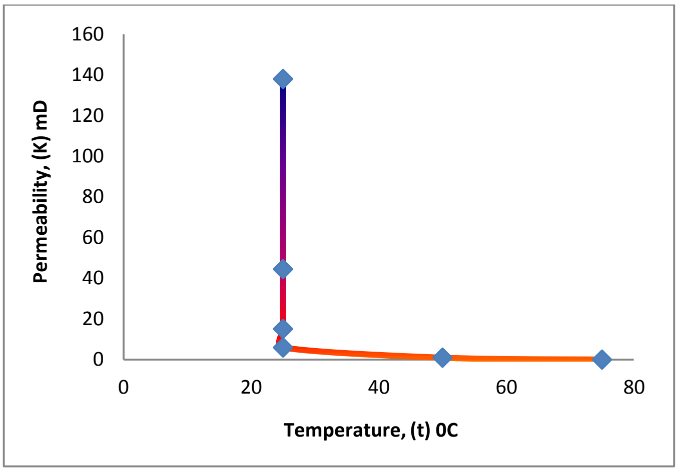

Figure 9: Permeability and temperature graph at a pressure drop for 0.1% KOH+0.1% AF9-12

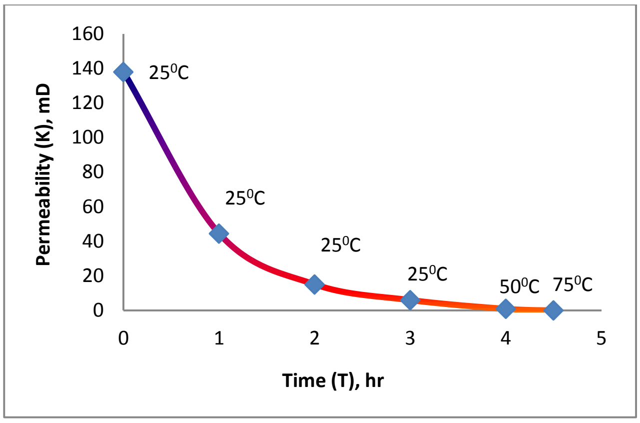

Figure 10: Permeability and time graph at pressure drop for 0.1% KOH+0.1% AF9-12

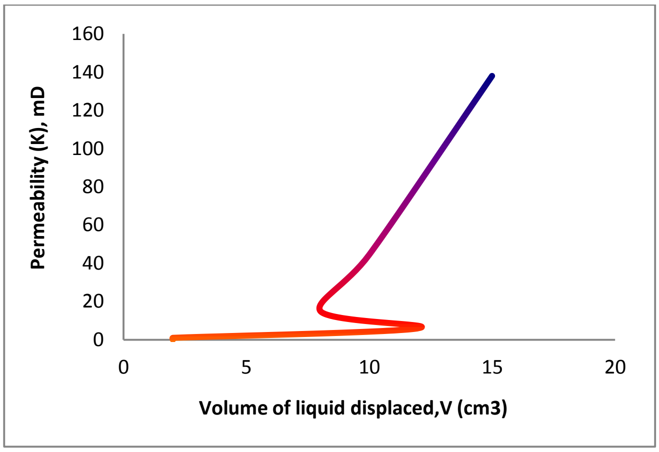

Figure 11: Permeability and volume of liquid displaced graph at pressure drop for 0.1% KOH+0.1% AF9-12

CONCLUSION

With an increase in the temperature of the alkaline solution with the addition of neonol from 20 ° C to 75 ° C and at a pressure of 2 atm to 7 atm, the oil displacement coefficient increased by 15-20%. Judging from experiments No. 1 and 2, with the addition of neonol in the second experiment, the core permeability increased. During the experiment, the permeability of the core increased with increasing temperature, then fell from further temperature increase. This is due to some characteristics of the reservoir rocks. With the help of combined methods, it is possible to create technologies with a focus on universality, reliability of control and regulation, environmental friendliness, safety and high profitability.

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