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A TYPE CURVE APPROACH TO QUALITATIVE DESCRIPTION OF RESERVOIR FLUIDS

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ABSTRACT

Qualitative description of reservoir fluids is normally based on such parameters as saturation pressure, gas in solution, viscosity and density. Most Engineers ignore compositional data unless when phase behavior predictions or compositional simulation are to be undertaken.

This work describes a simple, quick method of qualitative reservoir crude assessment, using the well known Type Curve matching techniques with fluid compositional data.
The method is demonstrated for some Niger Delta reservoir crudes, and shown to be useful in checking the validity of laboratory PVT results in cases where there are disagreements between the experimental and observed (field) values of saturation pressure. Volatile crudes and condensates can also be readily identified.

It would appear that the method can be applied regionally, as well as locally (in-field) as an aid in reservoir-to-reservoir fluid correlation. It can also help to identify non-equilibrium fluid distribution in large, thick, or segmented reservoirs.

INTRODUCTION

Proper understanding of the nature and phase behavior of reservoir fluids is important in reservoir management (1-2). Thus, reservoir fluid characterization is normally achieved either through laboratory PVT analyses, or by use of mathematical models (Equations of state)(3-4). Experimental investigations normally consists of measurements under static and dynamic conditions. In static measurements, series of constant composition volumetric expansion (CCE) are undertaken on either reservoir or recombined surface samples, in addition to chromatographic analyses. In dynamic measurements however, series of multicontact measurements are undertaken to determine phase compositions under conditions of gas injection. On the whole therefore, PVT analyses are expensive.

However, after the detailed and rather expensive experiments have been undertaken, most engineers make use only of the results of the CCE, and ignore the compositional data, except when compositional simulation or phase behaviour predictions are to be undertaken. In some cases when the experimental saturation pressures are in disagreement with observed (field) values, the whole results could be discarded.

Compositional variations in thick reservoirs, and the implications on reservoir management have been discussed by Schulte (5), while Neveux and Sakthikumar (6) have stressed the importance of proper fluid delineation and correlation before full compositional simulation studies.

In this work, compositional data have been applied to describe qualitatively, a number of reservoir crudes in the Niger Delta. The use of such data in some cases helped to explain observed anomalies between experimental and field values of bubble point pressure.

THEORETICAL BASIS OF THE APPROACH

The use of compositional data for quantitative fluid description is well known, and has being practiced for a long time. The basis of this lies in the fact that for any multicomponent system, the volumetric and thermodynamic properties can generally be described by equations (1), and (2) respectively:-

$$Z = Z(P,T,X) \quad (1)$$

and,

$$f_i = f_i\,(P,T,X) \quad (2)$$

where,

Z = Compressibility factor,
f_i = Fugacity coefficient of component i.
X = Composition.

The Kay's rule expressed in equation (3) also underlines the importance of composition in the determination of the critical properties of fluid mixtures.

$$A_i = \Sigma X_i A_i \quad (3)$$

where,

A = Any property of the component i.

In all the above quantitative equations, fluid composition is prominent. Therefore, if compositional data are useful for quantitative fluid descriptions, they must also be useful for qualitative assessment. Indeed, it is well known that whether a crude will be light or heavy can be determined by the relative cuts of the light and heavy fractions. Similarly, from a geochemical perspective, it is not unreasonable to expect that crudes of similar origin, environment and geological history should have very similar composition. Thus, in the same geological setting, crudes having the same chemical composition can be assumed to have very close semblance in physical characteristics.

From the above, it is clear that a set of Type-Curves can be constructed from a fully characterized fluid, whereas Field Curves can be constructed from uncharacterized fluid samples. The match of the chemical composition of an uncharacterized reservoir fluid (the Field Curves), with the composition of a fully characterized fluid (Type Curve), can be used for a qualitative description of the physical characteristics of the field samples.

The strong dependence of equations (1), (2), and (3) on composition seems to suggest that the use of compositional Type Curves for fluid qualitative description may in fact have more scientific basis for fluid-fluid comparison than the simple use of fluid gravity in current practice.

In applying this principle, the Niger Delta has been treated in this present work as a single region, and the composition of 145 PVT samples of reservoir crude oils, as well as those of 10 condensates were obtained and analyzed. Table 1 gives a sample of the data, while Table 2 gives the mean composition of a Niger Delta reservoir crude oil. These are presented in Figure 1, which can be used as a "Type Curve" in assessing the relative characteristics of any Niger Delta reservoir fluids for which compositional data are available. That is, by comparing the compositional data of any fluid with "type-curve" composition, we can determine the nature of the fluid.

APPLICATION AND RESULTS

The Type-Curve technique has been applied to a number of Niger Delta cases to demonstrate some of the advantages of using the method. We present five typical cases.

CASE 1: A TYPICAL NIGERIAN LIGHT CRUDE

This is a typical light crude for the Niger Delta. The reservoir was in saturated condition with an initial pressure of about 3760 psia. Initial observations from the RFT tests, as well as estimated reservoir fluid density of 0.59 g/cc had raised suspicion of very light crude or condensate. Figure 2 gives the match of the analysis of the reservoir fluid with the "Type Curve", and shows clearly that the fluid is typically a normal light crude.

CASE 2: VOLATILE OIL WITH PHASE REDISTRIBUTION

The reservoir pressure of 3450 psia, was well above the saturation pressure of about 1280 psia. The density of the reservoir fluid was established at 0.61 g/cc. The reservoir temperature was 264 °F. Ordinarily, one would have expected a normal crude oil. Figure 3 shows the match of the Field Curve with the typical Niger Delta Type Curve. Clearly, some anomalies are easily recognised. The methane content was rather low for a 0.6 g/cc crude. The C2-C6 showed a slight increase over the average trend, while the C7+ was as expected. A case of phase redistribution following a pressure drawdown during sampling is suspected. This is a typical occurrence in reservoirs with volatile oils. Core analyses and production tests confirmed the reservoir fluid to be a volatile crude.

CASE 3: HEAVY CRUDE

This was a sample from a shallow reservoir. Reservoir pressure and temperature were 2360 psia and 123 ^{o}F respectively, while the density of saturated oil was established at 0.886 g/cc. Figure 4 is the match curve for this case, and clearly shows a low methane cut and a high cut of the heavier components (C7+). This is typical for heavy crudes.

CASE 4: VOLATILE CRUDE / CONDENSATE

This sample was from a reservoir with a pressure of 3544 psia, and temperature of 218 ^{o}F. However, the saturation density was found to be 0.493 g/cc, while the separator GOR was 6850 scf/stb. Figure 5 is the Type-Curve match of the composition of this fluid. The match clearly shows a rather high cut of the C1, and very low cut of the heavy fractions. This is typical of a very volatile crude/condensate.

CASE 5: DEPLETED RESERVOIR OIL SAMPLE

This sample was taken from a reservoir whose pressure had depleted from the initial 2420 psia by about 100 psia. Are the results of this PVT analysis useful? We believe that the compositional data can be analyzed for useful information on the nature of the reservoir fluid. The Type-Curve match of the reservoir fluid is given in Figure 6. It clearly shows that we are dealing with a typical Nigerian crude. If we assume that the reservoir depletion has affected the fluid composition, then it would have resulted in the faster depletion of the light ends, and an apparent increase in the heavy fraction cut. This would be consistent with the Type-Curve match data and the conclusion of a normal Nigerian crude.

DISCUSSION

The typical "Type-Curve" obtained for Niger Delta reservoir fluids, presented in Figure 1, shows that for the normal light crude, methane cut, as well as the C7+ fraction are about 43% respectively. The C2-C6 fractions are low, while Nitrogen and CO_2 content are very low on the average. For Condensates, the average methane cut is about 80%, while C7+ is about 5%. Nitrogen and CO_2 cuts are relatively higher in the condensates than normal crudes.

The case studies presented above, clearly show that for any uncharacterized field sample, agreement with, or deviations from the normal trends established for the Niger Delta is indicative of the crude type. Anomalies such as in Case 2 can equally be readily recognised, and investigated.

It is instructive to note that the principle which has been described on a regional basis for the Niger Delta, can equally be applied within the region to obtain local or zonal "Type - Curves" such as the Bonny light, Pennington light, or Forcados blend, which are composition-derived.

CONCLUSION

Using the average composition of typical Niger Delta reservoir crudes, a Type-Curve has been constructed and used for qualitative description of Nigerian reservoir crudes. The Type Curve approach has provided a wider scope of application of compositional data in qualitative reservoir oil characterization than has hitherto been known. It has the capacity for use as a quick fluid-type recognition technique, as well as a means of establishing non-equilibrium fluid distribution in large or thick or segmented reservoirs. Problems of phase redistribution which could be encountered in certain cases during sampling, and may otherwise be unexplained can be recognized.

NOMENCLATURE

- A Fluid property as defined in equation (3).
- f Fugacity Coefficient.
- P Pressure, psia
- T Temperature, ^{o}F.
- X System Composition.
- Z Compressibility factor.

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TABLE 1: COMPOSITION OF NIGER DELTA RESERVOIR CRUDES.

SAMPLE	C1	C2	C3	I-C4	N-C5	C6	$C7^+$	N_2	CO_2
10	37.64	0.26	0.00	0.00	0.01	0.04	61.77	0.00	0.25
20	37.98	0.62	0.06	0.05	0.06	0.06	60.94	0.02	0.15
30	43.09	2.29	0.35	0.25	0.17	0.32	51.81	0.32	0.99
40	41.67	3.77	3.41	1.26	0.73	1.19	45.41	0.00	0.58
50	47.50	4.95	0.43	1.18	1.27	1.96	40.94	0.04	1.35
60	33.06	2.12	0.10	0.13	0.03	0.20	63.61	0.03	0.62
70	39.05	2.46	0.19	1.19	0.77	1.50	53.41	0.09	1.08
80	43.19	0.47	0.03	0.02	0.03	0.13	56.01	0.00	0.08
90	43.61	0.93	0.08	0.02	0.01	0.05	55.11	0.01	0.14
100	41.97	6.58	4.45	1.15	1.15	4.31	36.64	0.00	0.00
110	36.44	3.98	0.89	0.35	0.30	0.79	56.02	0.14	0.21
120	35.53	3.68	3.65	0.86	0.32	0.74	51.31	0.02	2.40
130	52.90	5.42	5.76	1.75	1.57	2.14	23.98	0.02	1.87
140	43.98	0.37	0.01	0.12	0.00	0.55	54.63	0.04	0.00

TABLE 2: MEAN COMPOSITION OF NIGER DELTA RESERVOIR FLUIDS.

COMPONENT	MOLE PERCENT	
	CRUDE OIL	CONDENSATE
N_2	0.13	0.37
CO_2	0.72	1.39
C1	43.24	79.62
C2	3.92	5.20
i - C4	1.09	1.01
n - C4	1.49	1.52
i - C5	0.95	0.69
n - C5	0.79	0.60
C6	1.70	0.78
$C7^+$	43.16	4.99
Sat. Density, g/cm^3	0.717	
Res. Pressure, Psia.	3363	
Sep. GOR, Scf/Stb	994	

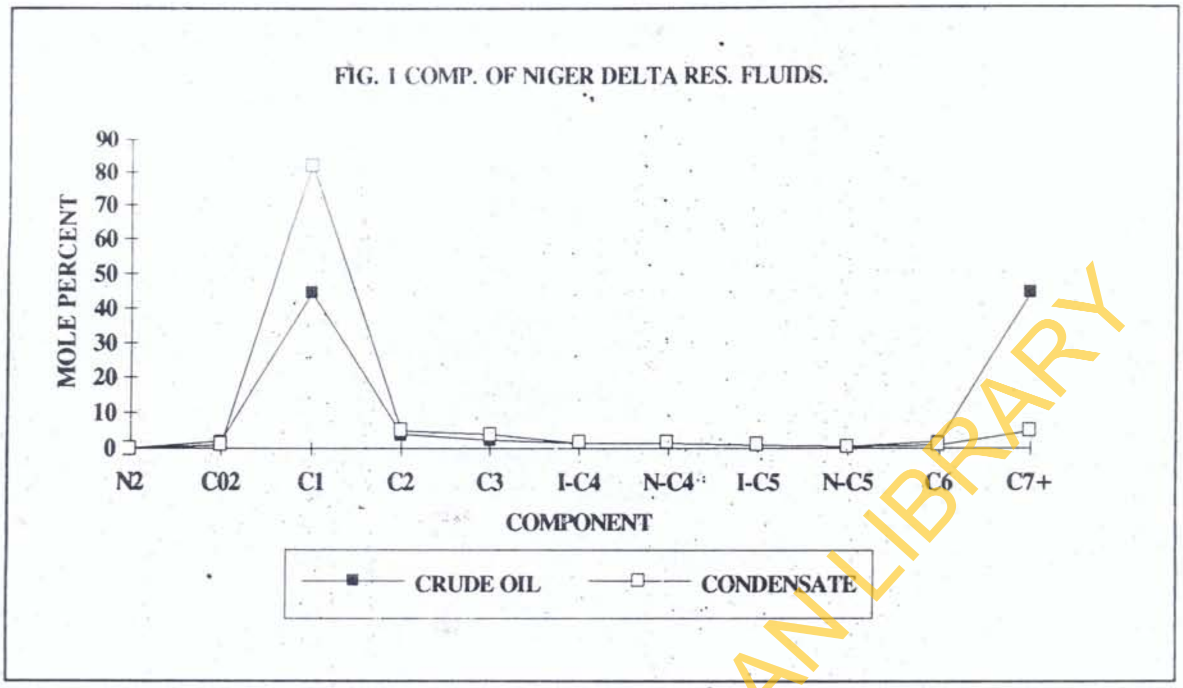
FIG. 1 COMP. OF NIGER DELTA RES. FLUIDS.
MOLE PERCENT
90
80
70
60
50
40
30
20
10
0
N2
C02
C1
C2
C3
I-C4
N-C4
I-C5
N-C5
C6
C7+
COMPONENT
CRUDE OIL
CONDENSATE

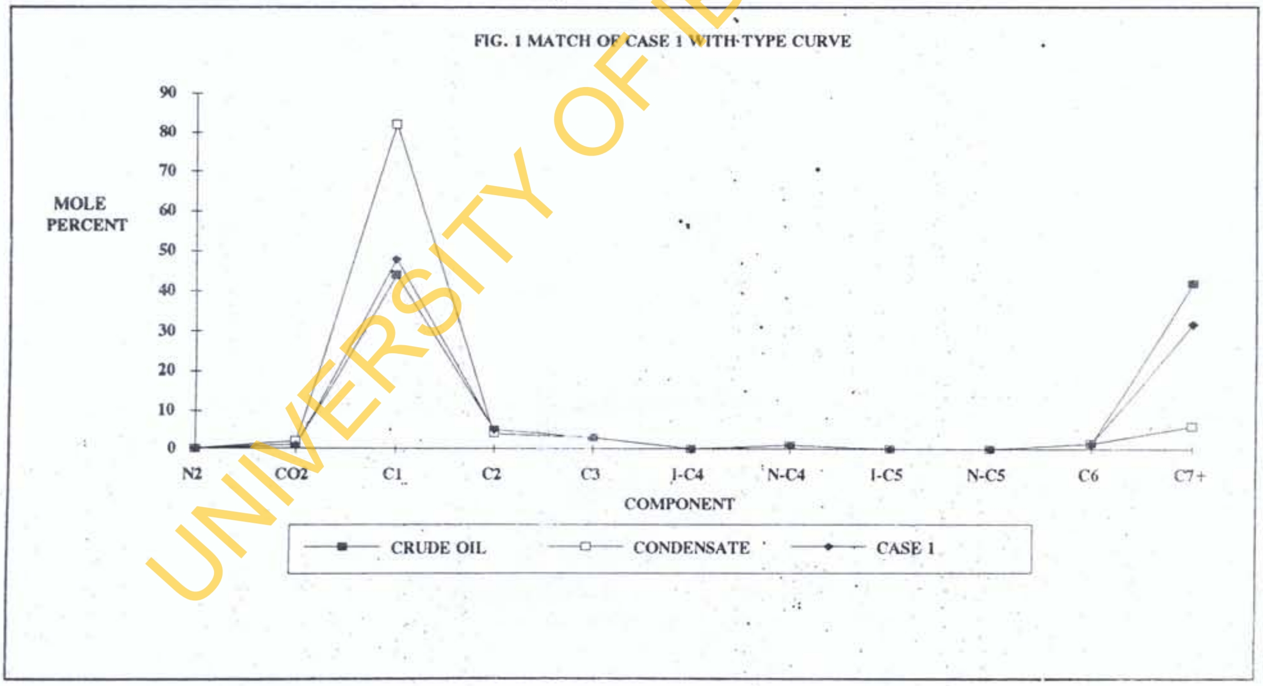
FIG. 1 MATCH OF CASE 1 WITH TYPE CURVE
MOLE PERCENT
90
80
70
60
50
40
30
20
10
0
N2
CO2
C1
C2
C3
I-C4
N-C4
I-C5
N-C5
C6
C7+
COMPONENT
CRUDE OIL
CONDENSATE
CASE 1

FIG. 3 MATCH OF CASE 2 WITH TYPE CURVE

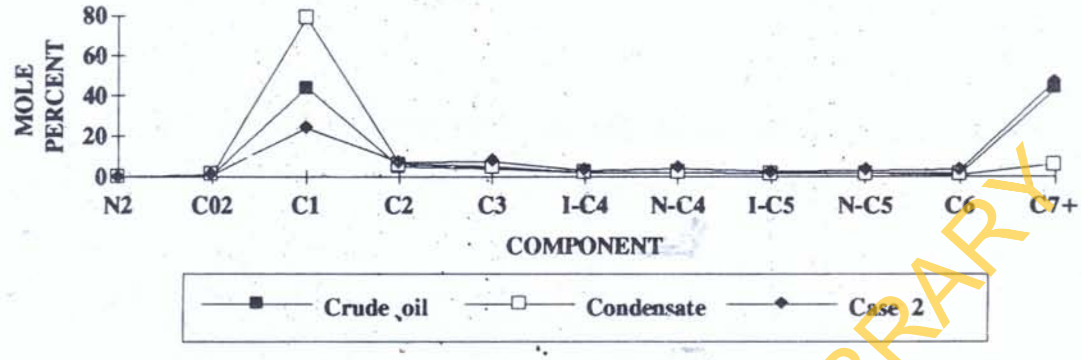

FIG. 4 MATCH OF CASE 3 WITH TYPE CURVE

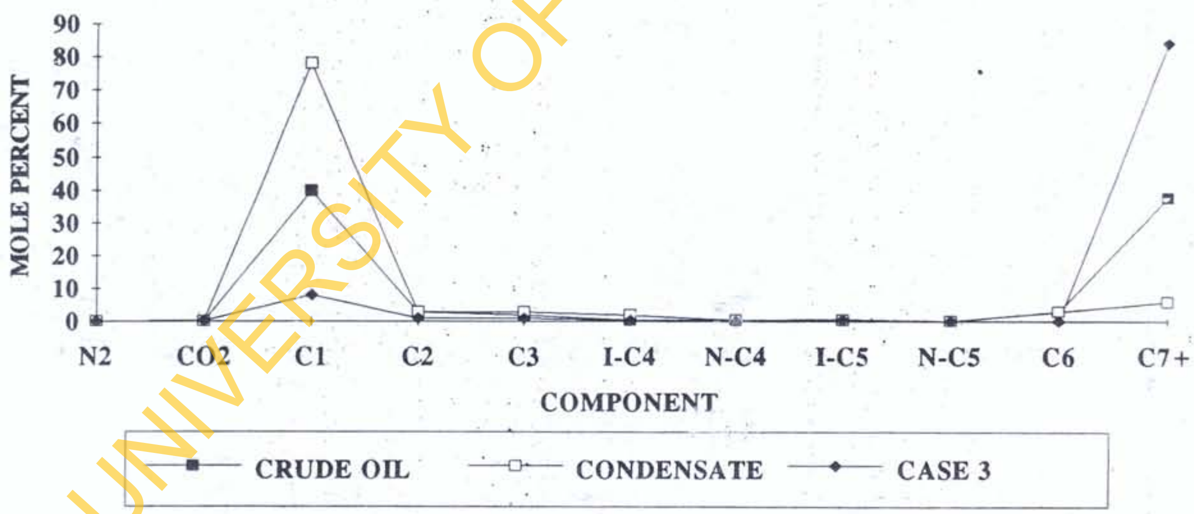

FIG. 5 MATCH OF CASE 4 WITH TYPE CURVE

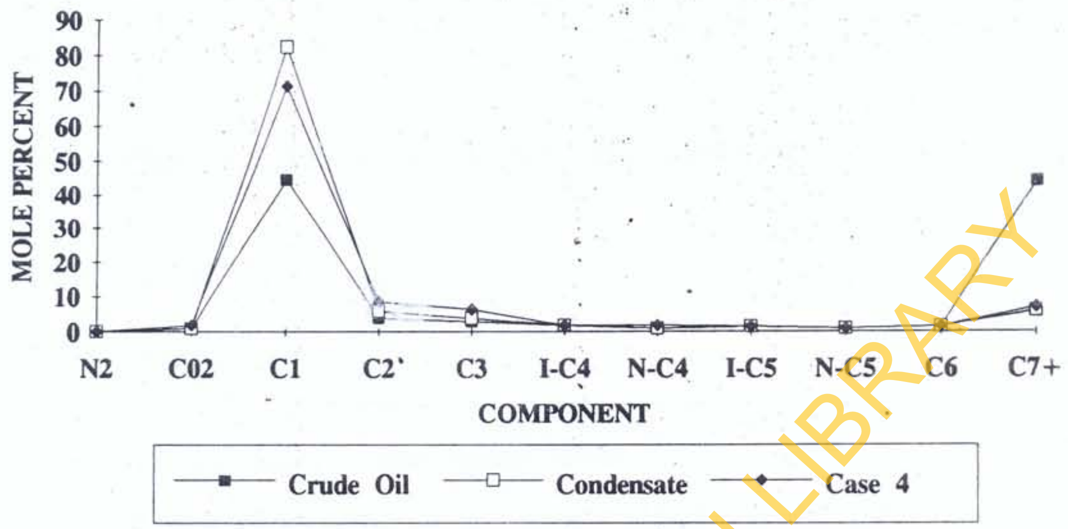

FIG. 6 MATCH OF CASE 5 WITH TYPE CURVE