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# Improved Reservoir Description Using Surface Oil Viscosity Data

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## Abstract

*Subsurface oil viscosity data are usually not readily available for most reservoirs, as they are expensive to acquire. On the other hand, surface oil viscosity is routinely measured and therefore readily available for all producing wells. A method has been developed for converting the surface viscosity to reservoir viscosity data, using SPDC's "Field A" as a case study.*

*Surface oil viscosity data from all producing wells in "Field A" where collected from SPDC-West Production Chemistry laboratory and converted to reservoir viscosity using a simple method that utilises relevant PVT data. The method allows a better and more detailed subsurface description of reservoir viscosity in line with facies variations. The study also shows that reservoir oil viscosity could be lower in some sands than previously estimated. This gave a significant impact on reserves in one of the reservoirs where scope to increase the booked reserves by about 60 MMstb was observed. Opportunity to also increase constrained offtake from 2300 b/d to 3000 b/d in some planned new wells was also observed.*

## Introduction

*"Field A"*, is one of SPDC's giant fields comprising of a group of four fields (field $A_1$, $A_2$, $A_3$ & $A_4$) located some 30 km east of Warri in Licence area OML-30. The Fields have a total expectation STOIIP and oil Ultimate Recovery (UR) of 3.94 and 1.53 billion bbls respectively. Average recovery factor for the field is low at about 39%, and average offtake rate is low such that only 42% of the U.R have been produced over a period of 35 years. These key issues have led to a review of the subsurface realities and oil viscosity among several other factors that could enhance recovery during the planned new field development. Furthermore, a previous extensive study by SPDC's Hans Horikx on the viscosity of reservoir oils in SPDC West noted that the estimated oil viscosities for most of the reservoirs are rather high. This also necessitated a closer scrutiny of oil viscosity in the *"Field A"*.

Past efforts in estimating PVT parameters and oil viscosity tended largely to treat fields $A_1$, $A_2$, $A_3$ & $A_4$ separately. There are relatively few PVT analysis reports across the fields as shown in figure 1, hence, PVT parameters and oil viscosity for most of the reservoirs have been based largely on correlations which use measured surface GOR as a major input. However, the measured surface GOR are usually unreliable in the presence of gaslift gas in most of the producing wells. This study has attempted to integrate the data across *"Field A"* in line with current interpretation of the

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static and dynamic conditions of "**Field A**" reservoirs as shown in figure 2. All the available results from PVT analysis reports have been revalidated and integrated with surface oil analysis data to resolve most of the observed anomalies and achieve a better description of the subsurface realities.

## Theory and Procedure

The value of a physical or thermodynamic property at reservoir temperature and pressure may be related to its value at surface conditions using simple equations of state or some empirical relations. This concept has been used over the years in the definition of oil formation volume factor, Bo, as:

Oil formation volume factor   =

**Oil Volume @ reservoir conditions**
_____   rb/stb
**Oil Volume @ surface conditions**

Using this well-known definition of oil formation volume factor, we define a similar parameter, Oil formation viscosity factor, expressed as:

Oil formation viscosity factor   =

**Oil viscosity, cp @ reservoir conditions**
_____

**Oil viscosity, cp @ surface conditions**

Or,

Oil formation viscosity factor   =

**Reservoir Oil viscosity, cp**
_____

**Surface Oil viscosity, cSt  * Oil density**

Hence, we can define a viscosity relation factor,

Viscosity relation factor        =
**Surface Oil viscosity, cSt**

_____

**Reservoir Oil viscosity, cp**

The Viscosity relation factors for Aferolow reservoirs were established from laboratory PVT analysis reports. It was observed that the PVT analyses undertaken at Shell's KSEPL had sufficient data to establish this parameter. The surface oil samples collected from the wellhead and analysed at the P-C laboratory Warri, were then converted to reservoir properties using the established trends of the Viscosity increase factors.

## Results and Discussion

Figure 3 below shows a plot of the observed oil viscosity trends in Aferolow. The three complexes that extend across the entire Aferolow (J2, L1/O9 and M1/P0) are saturated reservoirs and show a linear trend in viscosity from about 10 cp in J2/O2 sand to about 1 cp in the M1.00 and P1.00 sands. The second trend comprises the shallow, heavy, undersaturated reservoirs from J2.09X to O8.4X, with reservoir viscosity varying between 10 cp and 40 cp. In the deep, undersaturated reservoirs, viscosity declines from about 7 cp in the P2.00X to less than 1 cp in the P5 and P6 sands.

In a similar way, Table -1 shows the Viscosity relation factors in Aferolow as obtained from the KSEPL PVT reports. The Table shows that in the saturated oil reservoirs, the viscosity relation factor is fairly a constant of about 9.3 cSt/cp, while it is about 3.4 cSt/cp in the undersaturated oil reservoirs.

Table –2 shows a comparison of the results of this study with those of a previous study by SPDC's Hans Horikx and the booked values for J2 and J3 sands. The results obtained in this study compares well with Horikx relations and confirm that the previous booked estimates are rather pessimistic.

Table –3 shows the detailed results of estimated subsurface oil viscosity obtained from surface oil analysis results. It can be observed that the variation in reservoir oil viscosity followed the same pattern observed in geological facies

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variations. This is particularly evident in the O9, P0 and P4 reservoir complexes that have several sub-units. It therefore can be concluded that in general, the use of surface oil analysis data could allow a more detailed estimation of viscosity in various sand units, especially in complexes where a general average obtained from PVT analysis or correlation was previously used. Table –4 shows the gradation observed across the fields. It is obvious that this technique could save significant PVT analysis costs in fields where 3D simulation require detailed reservoir fluid description.

Figure –4 shows the impact of viscosity on oil recovery in Eriemu J2 sand. Using SPDC's reservoir simulator, MoRes, it was observed that with a reduction of viscosity from 40 cp to 15 cp, the constrained production rate from a well could be conveniently increased from about 2300 bopd to 3000 bopd. The recovery also improved by about 50% at the lower viscosity. A comparison of the production performance of some wells completed on the J2.0 and P4.0 complexes (figure 5) show similar trends. Furthermore, RST measurements across the P4.0 complex (with viscosity of about 7cp) show good sweep without reasonable bypass of oil as shown in figure 6. The planned development wells on the J2 are therefore expected to have similar performance to those on the P4.

## Fluid Properties Gradation

In the P4.00 complex, gradation of fluid properties and composition was clearly demonstrated from the four available PVT analysis results. In the other sands, the degree of variation was investigated using surface oil analysis data. Slight gradation in fluid properties is discernible especially in the J2/O2 and M1/P1 sands as shown in Table –4.

## Conclusion

A simple technique has been developed to utilise production data and surface viscosity oil measurements to improve reservoir fluid characterisation. The results have shown that the oil viscosities of the different reservoir complexes in Aferolow could be significantly less than the current booked estimates. This observation was demonstrated to have significant impact on reserves estimates, and an increase of 62 MMstb was observed in the J2.00 sand.

Hence, from the results of this study, its hereby recommended that this technique be used in improving reservoir fluid characterisation especially in fields were post production data is scarce.

## References

1. "Field A" Field Review - O7 Sand Supplement." By EPD/33, Report No. EP95-2500. Issued December 1995.

2. "Field A" Field Review - J3.1/O4 Sand Supplement." By SIEP, EPT-IF, Report No. SIEP 97-5775. Issued December 1997.

3. "Field A" Field Review - L1/O9 and M1/P0/P1 Sand Supplement." By SPDC-W, DTW-ISS. Unpublished report

4. "Field A" PVT Analysis reports

5. "Field A" Surface Oil Analysis Reports

## Abbreviations

| | |
|---|---|
| SPDC | Shell Petroleum Development Company of Nigeria. |
| PAW-DEV | Production Area Team A (Development). |
| STOIIP | Stock Tank Oil Initially In Place. |
| GOR | Gas oil Ratio. |
| RST | Reservoir Saturation Tool. |
| SCSSV | Surface Controlled Sub-Surface Safety Valve. |
| PDL | Production Data Log. |

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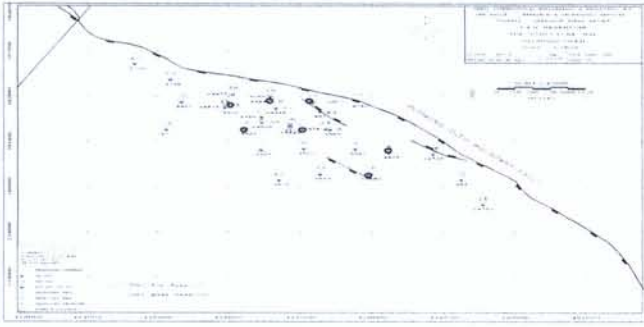
Figure 1:  Map showing wells where PVT data were obtained in Olomoro-Oleh field
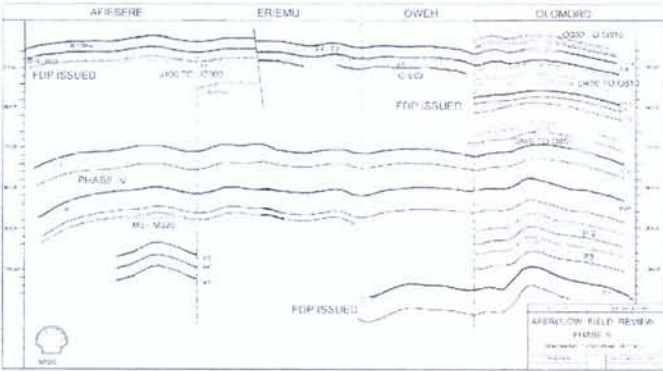


Figure 2:  Cross-Section of Aferolow Field Structure



Figure 3: Graph of Depth Vs Reservoir Viscosity for Aferolow reservoirs

Fig 4:  Graph showing Impact of Viscosity on Oil Recovery
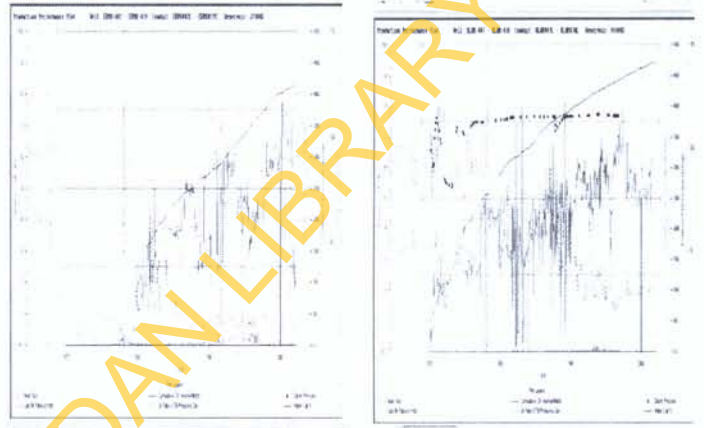


Fig 5:  Graph showing Production performance of J2 & P4 Reservoir complexes



Clean Sweep observed from RST in Olom-05 P4.0X reservoir

Figure 6: PDL showing results of RST in Olom-05 P4.0 reservoir

| Reservoir | Pr, psia | Tr, oF | Visc. Res<br><br>Oil, cp<br><br>(Measured) | Separator<br><br>Oil, cp<br><br>(Measured) | Visc.<br>Surface<br>Oil, Cst<br>@ 100F | Oil Viscosity<br>relation<br>factor, Cst/cp |
|---|---|---|---|---|---|---|

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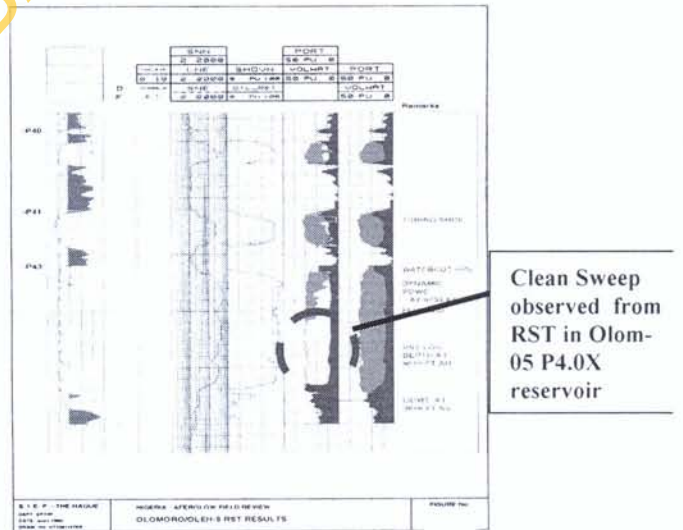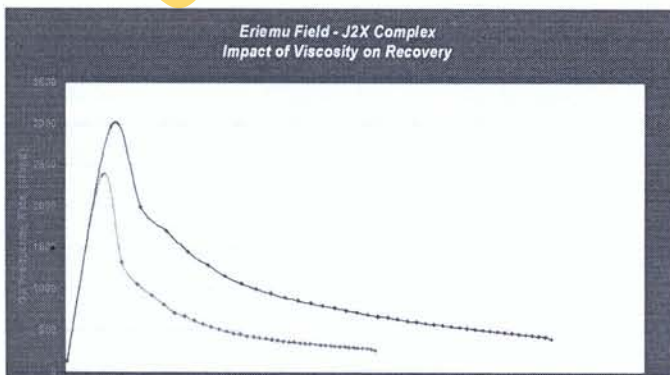| | | | | | | |
|---|---|---|---|---|---|---|
| Oweh 02.0 | 2884 | 130 | 10.71 | 46.56 | 114.4 | 10.7* |
| Afsr J209 | 2900 | 120 | 28.79 | 67.5 | 122 | 4.2 |
| Afsr J209 | 2900 | 120 | 38.66 | 73.69 | 122 | 3.4 |
| Afsr J3.1/2 | 2900 | 119 | 43.5 | 52.15 | 125.1 | 3.5 |
| Olom O7.6 | 3207 | 135 | 27.11 | 51.8 | 156 | 5.8 |
| Ermu M1.0 | 3427 | 154 | 0.83 | 4.5 | 7.5 | 9.0* |
| Olom P1.0 | 3740 | 165 | 1.08 | 3.29 | 9 | 8.3* |
| Olom P3.0 | 3914 | 165 | 5.2 | 6.75 | 23.44 | 4.5 |
| Olom P4.0 | 4202 | 174 | 6.75 | 6.09 | 23 | 3.4 |
| Olom P4.3 | 4234 | 171 | 7 | 5.79 | 23 | 3.3 |

**TABLE 1: Conversion of Surface to Reservoir Oil Viscosity (cp)**
* Saturated Reservoirs.

| | | | | | |
|---|---|---|---|---|---|
| M1/P1 | API Grav. | 25.66 | 26.69 | 27.47*** | 25.63 | *** Fig. for Oweh PO.3 |
| | Vis. CSt | 9.4 | 7.56 | 7.3*** | 9.39 | |
| P4 | API Grav. | | | 21.8 | 23.02 | |
| | Vis. CSt | | | 22.6 | 19.2 | |

| Reservoir | Visc. (cp) from PVT | ESTIMATED VISCOSITY (cp) | | | Surface Oil visc. (Cst) | API Gravity |
|---|---|---|---|---|---|---|
| | | Booked | Horikx | This Study | | |
| Afsr J200 | NA | 40 | 14.5 | 12.7 | 114.2 | 18.56 |
| Afsr J209 | 30 | 40 | 20 | 27.6 | 121.9 | 17.78 |
| Afsr J31/2 | 39 | 40 | 32.4 | 36 | 115.2 | 17.86 |
| Ermu J200 | NA | 40 | 12.8 | 11.3 | 101.6 | 18.08 |
| Ermu J31/2 | 39 | 40 | 33.6 | 37.5 | 120.4 | 18.27 |
| Olom O00 | NA | 14.57 | 13 | 12.6 | 113.5 | 17.75 |
| Oweh O20 | 10.71 | 32 | 13.8 | 12.7 | 114.4 | 18.05 |

**TABLE –2: Comparison of reservoir Oil Viscosity results for Aferolow J2/J3 sands**

### TABLE 4: FLUID PROPERTIES GRADATION FROM SURFACE OIL ANALYSIS

| Reservoir | | AFSR | ERMU | OWEH | OLOM | COMMENTS |
|---|---|---|---|---|---|---|
| J2/O2 | API Grav. | 18.53 | 18.08 | 18.05 | 17.75* | * Figure for Olom O0.0 |
| | Vis. CSt | 114.2 | 101.6 | 114.4 | 113.46* | |
| J3/O4 | API Grav. | 17.86 | 18.27 | NA | NA | |
| | Vis. CSt | 123.3 | 120.4 | NA | NA | |
| J4/O5 | API Grav. | 17.35 | 17.15 | NA | 17.5 | |
| | Vis. CSt | 135 | 159.31 | NA | 89.99 | |
| L1/O9 | API Grav. | 23.62 | 23.58 | 27.79* | 21 | * Figure for Oweh PO.1 |
| | Vis. CSt | 21.6 | 18.07 | 6.44* | 41.15 | |
| L1/O9 | API Grav. | 21.96 | NA | 27.35** | 21.57 | ** Figure for Oweh PO.2 |
| | Vis. CSt | 26.5 | NA | 7.3** | 25.41 | |

### TABLE –3: SUMMARY OF AFEROLOW SURFACE OIL ANALYSIS

| Field | Reservoir | Gravity ° API | Visc. @100 oF Cst. | Booked Visc. @RC, cp | This Study Av. Visc, cp | Hans Horikx Av. Visc. cp |
|---|---|---|---|---|---|---|
| AFSR | J2.00 | 18.58 | 114.20 | 40.00 | 12.69 | 14.49 |
| AFSR | J2.09 | 18.63 | 121.90 | 40.00 | 36.17 | 19.61 |
| AFSR | J3.10 | 17.86 | 123.30 | 40.00 | 34.20 | 32.41 |
| AFSR | J4.00 | 17.35 | 135.00 | 10.50 | 15.00 | 19.68 |
| AFSR | L1.00 | 23.62 | 21.60 | 1.65 | 2.40 | 2.55 |
| AFSR | L1.10 | 21.96 | 26.50 | 1.65 | 2.94 | 2.89 |
| AFSR | M1.00 | 25.66 | 9.40 | 1.17 | 1.05 | 1.32 |
| AFSR | M3.00 | 32.70 | 3.60 | 0.60 | 0.60 | 1.00 |
| AFSR | M4.00 | 33.70 | 3.83 | 0.57 | 0.60 | 1.00 |
| AFSR | M8.20 | 34.80 | 3.76 | 1.26 | 0.60 | 3.00 |
| ERMU | J2.00 | 18.08 | 101.60 | 40.00 | 11.29 | 12.79 |
| ERMU | J3.33 | 18.27 | 120.40 | 40.00 | 35.73 | 33.55 |
| ERMU | J4.00 | 17.15 | 159.31 | 10.81 | 17.70 | 22.17 |
| ERMU | J6.00 | 16.78 | 177.70 | 16.67 | 19.74 | 20.90 |
| ERMU | L1.00 | 23.58 | 18.07 | 1.65 | 2.00 | 2.29 |
| ERMU | M1.20 | 26.69 | 7.56 | 1.17 | 0.84 | 1.16 |
| ERMU | M3.20 | 36.30 | 2.63 | 0.57 | 0.50 | 0.50 |
| ERMU | M4.50 | 34.90 | 3.50 | 0.47 | 0.60 | 0.60 |
| OLOM | O.00 | 17.75 | 113.46 | 14.57 | 12.61 | 13.04 |
| OLOM | O5.0 | 17.50 | 89.99 | 14.86 | 10.00 | 12.08 |
| OLOM | O7.0 | 17.28 | 128.37 | 25.74 | 14.26 | 47.18 |
| OLOM | O7.1 | 17.50 | 138.04 | 25.74 | 15.00 | 50.00 |
| OLOM | O7.6 | 18.52 | 137.22 | 25.00 | 24.07 | 79.48 |
| OLOM | O8.4 | 18.20 | 83.02 | 12.29 | 11.86 | 29.71 |
| OLOM | O9.0 | 20.37 | 41.15 | 2.38 | 4.57 | 4.28 |
| OLOM | O9.1 | 21.57 | 25.41 | 4.64 | 2.82 | 6.20 |
| OLOM | O9.12 | 19.33 | 66.60 | 4.64 | 7.40 | 12.41 |
| OLOM | P0.0 | 27.57 | 7.03 | 1.02 | 0.85 | 1.48 |
| OLOM | P0.2 | 27.32 | 7.62 | 1.02 | 0.92 | 1.57 |
| OLOM | P0.5 | 26.99 | 9.29 | 1.02 | 1.03 | 1.81 |
| OLOM | P1.0 | 25.63 | 9.39 | 1.02 | 1.08 | 2.56 |
| OLOM | P2.0 | 21.23 | 26.53 | 4.95 | 4.88 | 11.96 |
| OLOM | P2.1 | 21.20 | 25.58 | 5.69 | 4.84 | 11.65 |
| OLOM | P3.0 | 21.65 | 23.12 | 3.98 | 5.14 | 7.33 |
| OLOM | P4.0 | 21.74 | 22.66 | 7.00 | 6.67 | 31.85 |
| OLOM | P4.01 | 21.96 | 22.48 | 7.00 | 6.61 | 31.63 |
| OLOM | P4.05 | 21.76 | 22.99 | 7.00 | 6.76 | 32.27 |
| OLOM | P4.1 | 21.67 | 23.47 | 7.00 | 6.90 | 31.43 |
| OLOM | P4.3 | 21.71 | 23.25 | 7.00 | 7.03 | 32.59 |
| OLOM | P6.4 | 36.30 | 3.30 | 1.10 | 0.60 | 26.00 |
| OWEH | O2.0 | 18.05 | 114.40 | 32.00 | 10.71 | 13.75 |
| OWEH | O4.0 | 33.90 | 2.41 | 40.00 | 1.00 | 1.00 |
| OWEH | P0.1 | 27.79 | 6.44 | 1.02 | 0.80 | 1.03 |
| OLOM | O8.5 | 27.05 | 19.36 | 15.37 | 4.26 | 20.26 |
| OLOM | O9.0 | 27.36 | 18.51 | 16.11 | 4.23 | 20.80 |
| OLOM | O9.1 | 27.67 | 17.66 | 16.85 | 4.19 | 21.34 |
| OLOM | O9.12 | 27.98 | 16.80 | 17.59 | 4.16 | 21.87 |
| OLOM | P0.0 | 28.29 | 15.95 | 18.33 | 4.13 | 22.41 |
| OLOM | P0.2 | 28.60 | 15.10 | 19.07 | 4.09 | 22.95 |