

Flow Assurance Testing with Re-livened Oil – A Cost-Effective Analogue for Live Oil

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ABSTRACT

It is widely accepted that the use of live crude oil samples provides the most field representative fluids when investigating asphaltenes and paraffin wax problems in laboratory testing. However, this approach is limited by availability of live samples and the potential that samples collected during drilling will be insufficiently representative due to contamination. Rather than going to the significant expense and operational difficulty and risk of collecting and transporting live samples, it is common practice to use 'dead' crude oil, i.e., that which has been degassed to ambient pressure. This facilitates the use of larger quantities of test samples. However as many of the light hydrocarbon components have been lost, the 'dead' oil is fundamentally different and can display different characteristics to those of live fluids. Asphaltenes deposition occurs as the volume fraction of light ends increases due to depressurisation. Wax solubility is strongly dependent on light end composition, which is significantly different at elevated pressure compared with atmospheric pressure.

We have investigated the use of re-livened oil as an analogue for live oil in flow assurance testing for asphaltenes and waxes. Re-livened oil is composed of dead oil and one or more volatile ends so as to reproduce much of the behaviour of live oil. Where behaviour differs, it does so in a predictable manner that can be readily modelled using an equation of state simulator. Data are presented to compare the behaviour of live oil, dead oil and re-livened oil prepared by adding only gas, only liquid or a mixture of both. We discuss the benefits and drawbacks of each approach as applied to asphaltenes and wax testing with illustrative examples of the behaviour of each fluid using test data from pressurised flow rigs. The test data are also compared with behaviour predicted using the EoS simulator to illustrate that a calibrated model can be used to predict properties and behaviour under a wide range of conditions.

This work provides a quantitative assessment of the suitability of various fluids for flow assurance testing. The conclusions offer an alternative way in which flow assurance testing can be conducted, with reduced cost and increased correlation with field behaviour.

Key words: Live Oil, Flow Assurance, Asphaltenes, Paraffins, Wax, Deposition

INTRODUCTION

Precipitation and deposition of wax or asphaltenes is a commonly encountered issue in the oilfield, causing flow restrictions, compromising the integrity and performance of equipment (some safety critical), limiting access during well interventions, causing “fill” in vessels, stabilizing emulsions and sometimes enhancing corrosion due to under-deposit corrosion and increased biofouling.¹ Developing an effective management strategy that minimizes the total cost associated with these threats requires reliable prediction of whether they will occur, their severity and their location within the production system. Such prediction typically combines the use of compositional data and phase behaviour (typically referred to as “PVT data”) with Equation of State (EoS) modelling plus the experimental measurement of key parameters specific to each issue. For wax these parameters may include the wax content (actually, a rather poorly defined datum), the Wax Appearance Temperature (WAT), the Wax Disappearance Temperature, the Pour Point, as well as the manner in which wax precipitation affects the oil’s rheology. Then, if it is established that a risk of wax precipitation exists within the production system, more complex tests may be performed to establish likely deposition rates and, if found to be required, the effectiveness of wax inhibitors or pour-point depressant (PPD) chemicals. Most of these tests are usually performed on dead oil samples and modelling is used to extrapolate the WAT, for example, to the live fluids present in the production system (most typically, the flowline is of most interest, though wax can also deposit in wells). The accuracy of this extrapolation depends on the type of wax and its molecular-weight distribution, whereas most modelling software tends to rely on correlations based upon average properties for oils of that general type.

Asphaltenes prediction follows two approaches: a series of screens, mostly performed on dead oil, which really do no more than indicate whether this is *likely* to be unstable based on comparison with a wealth of historical measurements performed in a similar manner where those measurements have been correlated with field observations; the other is a measurement of whether and when asphaltenes precipitate from (and potentially re-dissolve in) live oil when subjected to isothermal depressurization to determine the Asphaltenes Onset Pressure (AOP). This typically means that the actual precipitation tendency of an oil that has been identified by screening to be a potential problem cannot be accurately determined without the availability of reliable, relatively uncontaminated live oil.

So, while for wax the unavailability of live oil may introduce a degree of inaccuracy into the predictions, which may be operationally significant, with asphaltenes the non-availability of live oil has often precluded the confident determination of whether there is a precipitation tendency at all. This is problematic because the availability of live oil samples is almost invariably very limited, in particular, at the project stage of the life cycle, when the wax and asphaltenes control strategies are being formulated. Such samples are extremely costly and when taken pre-First Oil are sometimes so contaminated that predictions using them are of questionable value; and unfortunately, this only becomes evident after the test, when a dead sample is available for chemical analysis.

The frequent non-availability of live samples of sufficient quantity and/or quality gave the impetus for the current work: to determine whether more readily available, better characterized dead oil samples could be “re-livened” and used in place of live ones without unacceptably compromising the reliability of the predictions, both for asphaltenes and wax. Re-livening is the process of adding light alkanes to dead crude, either gas, liquid or (more typically) both, to obtain samples that behave in a similar manner to live oil with respect to a specific property (in this case, wax or asphaltenes solvency). Paramount in this

approach is that, though live and re-livened oil are different, these differences can be modelled, such that the re-livened properties can be related to those of the real oil in the production system.

The approaches described here to support the prediction of organic deposits can also be applied to more realistic laboratory testing of control chemicals without the need for live oil, but that will be reported in a later publication.

THEORETICAL BASIS

Live versus Dead Oil Wax Testing

Prediction of all oilfield deposits (scale, wax, asphaltenes, naphthenates, hydrates, diamondoids, *etc.*) needs to address whether there is an issue, and if so, how much, how fast and when. For paraffin wax, the primary determinant of *whether* there is a risk is the WAT, in that remaining at or above this temperature should preclude precipitation and potential deposition. The WAT is most typically measured on dead oil at around ambient pressure, either using visual observations (cross-polarized microscopy) or indirect methods, such as differential scanning calorimetry, rheometry, filter plugging, deposition on a cold finger, *etc.* The WAT depends on pressure even for dead oil, but for most pressures of interest this dependence is opposite to that for live systems (shown schematically in Figure 1). This is because the primary effect of pressure increases the WAT (a result of the volume change upon dissolution, according to the Clausius-Clapeyron equation)², whereas with live fluids, increasing the pressure condenses light ends from the gas, which are good solvents for wax; similar behaviour as for dead oil is then seen above the bubble point, when condensation ceases.

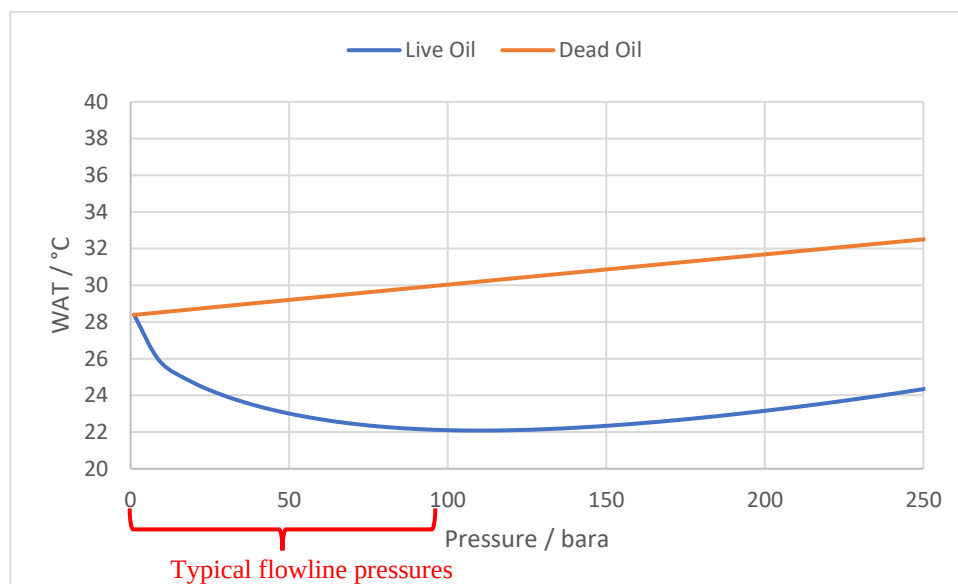


Figure 1: Example to show dependence of WAT on pressure for dead and live oil.

Hence, it is clear that the live-fluid WAT (or a similar parameter, the Critical Wax Deposition Temperature^{3,4}) is the more important to assess whether wax deposition is likely to occur. Similarly, besides affecting the WAT, the degree of “live-ness” will also affect the wax-deposition properties because the rheology, wall shear and essentially all the transport properties of the oil (viscosity, diffusion coefficients, thermal conductivity) will also be affected, many of which play an important role in the deposition process.⁵

The difference between readily measured properties performed on dead oil and more costly, difficult ones on live oil (actually different degrees of live-ness depending on pressure) is normally modelled, which can introduce significant uncertainty, depending on the correctness of the model and the availability of

calibration data. The PVT properties and composition of the live oil (usually known) plus a measured value for the WAT at ambient pressure is really the minimum input to obtain reasonable data.⁽¹⁾ The dead-live extrapolation is also likely to be improved by entering a measured value of the wax content, though most models are not sufficiently sophisticated to account for different types of wax that may be present, which could affect how they precipitate.

Hence, a rather high degree of confidence can be obtained for a modelled WAT for live oil starting from a dead oil value. However, this is less true for the deposition behaviour of live oil once the ambient conditions go below the WAT and there is a temperature difference between the bulk oil and the pipe walls. For deposition, there are too many input parameters that are not only significantly different between dead and live oil. It is also more difficult to model, which means the use of dead oil plus modelling for the evaluation of deposition behaviour and perhaps the testing of wax control chemicals (inhibitors and PPDs) will lead to significant uncertainty. Hence, reported here is an approach by which the dead oil can be re-livened such that key properties are much closer to those of live crude in the production system, such that such tests can be performed using more readily available dead oil, which can be properly quality checked before testing is begun.

The methodology used here is to re-liven the dead oil with methane by allowing as much to dissolve as can under conditions typical of those in the part of the production system of interest (usually the flowline) and then to add sufficient *liquid solvent* to the resulting modelled mixture that the heavier components are all present in the molar concentrations present in the live oil. This generally gives a methane content for the re-livened liquid that is close to that predicted for the live oil under the same conditions and means the concentration of waxy components are very similar in the live and re-livened oil. The only difference is that the C2 – C6 components can differ substantially between the two liquids, with C3, C4 and C6 typically being lower in the re-livened oil, but adjusted using a suitable liquid solvent providing comparable solubility properties). The result is that a liquid is generated with similar solvency characteristics to that of true live oil (as will be demonstrated later in the paper) and, moreover, is likely to have transport properties much closer to that of live oil, too.

Live versus Dead Oil Asphaltenes Testing

Various screening methods are available to orientate a particular crude against potential instability with respect to asphaltenes “self-scaling” (*i.e.*, precipitation caused by changes in pressure and temperature alone, without commingling with other streams), such as the De Boer plot, the SARA cross-plot, the Colloid Instability Index, the p-value, the oil-maturity plot (API gravity *versus* asphaltenes content).⁶ While some screens can virtually preclude the possibility of precipitation for some oils, they generally only orientate the oil’s stability in terms of broad likelihood of operational issues. The only confirmatory test normally performed is an AOP test, in which the monophasic live oil (gas-saturated reservoirs do not normally experience asphaltenes issues) is isothermally depressurized from reservoir conditions (following the stippled green line in Figure 2), and a detection method is used to determine whether and at what pressure asphaltenes precipitate. If they do, this defines the intersection of the green vertical line in Figure 2 with the Upper AOP (U_AOP), which is a key calibration point for asphaltenes modelling. By continuing depressurization along the vertical green line, the test can also indicate whether asphaltenes re-dissolve, which is not typically used for modelling but has operational consequences. In principle, re-dissolution may occur anywhere below the bubble-point line (which is the pressure at which asphaltenes solubility is at a minimum), but it tends to be very slow until the pressure is close to or below the Lower AOP (L_AOP), whereupon the extent of re-dissolution depends on both the oil and the conditions.⁷

⁽¹⁾ The WAT can be estimated just from a well-characterized composition of the oil up to high carbon number, though the expected accuracy is generally worse than ± 6 °C.