SPE 59303

Preliminary Testing of a Novel Downhole Fiber Optic Fluid Analyzer

Martin E. Cobern, SPE & William E. Turner, APS Technology, Inc.; John Cooper & Jeffrey F. Aust,
Old Dominion University

Abstract

A novel fiber optic downhole fluid analyzer has been developed for real-time determination of the oil, gas and water fractions of fluids from different zones in a multizone or multilateral completion environment. A near-infrared attenuation measurement provides differentiation among oil, water and gas at all but the highest water cuts. An induced fluorescence measurement unambiguously determines the oil fraction of the fluid as a validity check on the attenuation measurement. The only downhole components of the system are the fiber optic cable, lenses and windows, which may be installed in multiple locations in the well and operated with a single surface unit.

Introduction

As well completions become more complex, including multiple zones and multilateral legs, downhole monitoring of the production from individual zones becomes more essential. Intelligent completions give the operator the means to make changes in production rates, but to do so requires real-time information about fluid types. In particular, determination of the oil, gas and water fractions is necessary to make informed decisions on changes in production controls.

The system described in this paper involves a combination of two optical techniques to determine the mass fractions of oil, water and gas at remote locations within a well. These measurements are carried out remotely through the introduction of optical sensors into the production tubing; the sensors consist solely of inert optical components and are, therefore, extremely robust.

Initial testing of the two methods in the laboratory showed that the output signals produce excellent correlations with the known percentages of oil, gas and water (for the attenuation measurements,) and oil (for the fluorescence measurement.)

The second phase of testing is being conducted in a low-pressure multiphase flow loop constructed for the purpose. Data are being obtained on system performance over a wide range of inclinations, flow rates and flow regimes.

Laboratory Testing & Results

Near-infrared attenuation.

Apparatus & Measurements. The NIR attenuation measurements were carried out in an analogous manner using the apparatus shown in **Fig. 1**. Light from a broad band source covering the near infrared wavelength range of at least 1000 – 1700 nm is sent down an ~ 1 mile long, to simulate field deployment, to a reflectance probe, which is immersed in the oil-water mixture. The reflected light is carried by a second fiber of the same length to the detector system.

The NIR absorption method relies on differences in the opacity of oil and water to the transmission of infrared light. As illustrated in **Figs. 2** and **3**, crude oil absorbs light preferentially at 1220 and 1390 nm; water has a very strong and broad absorption between 1400 and 1500 nm. It is, therefore, possible to distinguish between them based upon variation of the transmitted light intensity as a function of wavelength.

A key element of this apparatus is the solid state InGaAs spectrograph. This device permits the *simultaneous determination of the intensity at all wavelengths of interest*. Standard scanning techniques sample different wavelengths sequentially. Since the local composition and scattering are expected to vary rapidly with time, appropriate correction for scattering requires that the entire spectrum be acquired at once.

Two titrations were performed: water was titrated into oil to 50%, and oil was titrated into water to 50%, in steps of 2.5%. The fluid is constantly stirred to prevent separation. For each mixture, a spectrum was gathered over 0.1 sec, and 100 samples were averaged. Each titration was independently repeated ten times.

Analysis. The results from each titration are shown in **Figs. 4** and **5**. The data are plotted after the normalization described below. A Partial Least Squares (PLS) fit was performed to each data set, with standard errors, as determined by the "leave one out" method of 1.61 and 1.06%, respectively. An additional PLS fit was made to the entire range of concentrations, and is shown in **Fig. 6**; the standard error for the overall fit was 3.36%. Therefore, it is more appropriate to use

a fit optimized to the particular range. In the field implementation of the system, a SIMCA (Soft Independent Modeling by Class Analogy) technique will be used to identify the appropriate region and model to use for the conversion of measured values to component fraction readings.

Simulation of response to natural gas. A critical feature of the downhole fluid analyzer will be its ability to identify and quantify the presence of natural gas. Under typical downhole conditions, natural gas is likely to be either in liquid form or in solution. As replication of the downhole conditions requires a high-temperature, high-pressure test apparatus, we elected to study the gas response *via* the use of a proxy

Natural gas consists primarily of methane (CH_4), ethane (C_2H_6) and other small chain hydrocarbons (*e.g.*, propane and butane), which are characterized by the predominant presence of methyl groups (-CH_3). Crude oil, on the other hand, is composed primarily of longer hydrocarbon chains and aromatics, which include some methyl groups, but predominantly methylene groups (-CH_2). Each of these radicals has a distinctive NIR absorption band. Evans and Hibbard[1] used the ratio of these two absorption bands to determine the number of methyl and methylene groups per molecule in paraffins and lubricating oils. The liquid isooctane (2,2,4-trimethylpentane) was, therefore, chosen as a proxy for natural gas because of its high fraction of methyl groups and its ease of handling in the laboratory.

The effect of adding isooctane to crude oil is illustrated in **Fig. 7**, which plots the NIR signals detected as a function of the isooctane content. As the isooctane increases, the measured intensity at the methyl absorption peak (~1195 nm) decreases, while the intensity at the methylene peak (~1210 nm) increases.

In these simulated calibrations, isooctane was titrated into a mixture of crude oil and water. The isooctane percentage was varied from 0 to 20%; 100 spectra of 0.1 sec acquisition time were averaged for each data point, and the titration was repeated five times. After normalization of the data, as described below, a PLS fit was made to the data, and is shown in **Fig. 8**. The standard error was determined to be 0.57%.

These measurements give confidence in the ability to distinguish natural gas, whether in solution or in a liquid state, from crude oil in the downhole environment.

Fluorescence measurements.

Apparatus and measurements. A schematic diagram of the laboratory fluorescence test arrangement is shown in **Fig. 9**. Light from a distributed Bragg reflector (DBR) diode laser at 852 nm is transmitted *via* an ~ 1 mile long optical fiber, to a laboratory probe. This probe, equipped with an appropriate filter, allows the light to enter the oil/water mixture. The fluid is constantly stirred to prevent separation. A second mile-long fiber collects the light from both the input beam and fluorescence and returns it to an optical spectrograph with a charge-couple device (CCD) sensor on the output. The CCD generates a spectrum of the returning light, an example of which is shown in **Fig. 10**. The x-axis is given in pixel number, and corresponds to a range of wavelengths of ~700 – 1300 nm.

The fluorescent light is at wavelengths longer than that of the incident laser.

As in the case of the attenuation measurement, two titrations were studied: water into oil and oil into water. In the first, the water fraction was increased in steps of 2.5% from 0 to 50%; in the second, the oil fraction was increased in similar steps from 0 to 50%. For each mixture, data were acquired for 0.3 sec, and 100 samples were averaged for each data point. Each titration was repeated five times.

Analysis. Data from each set of measurements were normalized by dividing by the measured intensity of the transmitted laser light. This is a critical step, since both the transmitted and fluorescent light are reduces in essentially equal amounts by the effect of scattering in the downhole fluids. Without this step, the measured fluorescence signal would be dependent on the highly variable scattering mechanisms. The normalization technique is described in more detail below.

The resulting responses were fit to the known oil fractions using a partial least squares (PLS) method. Each half range was fitted independently, with the results shown in **Fig. 10** and **Fig. 11**; the full range fit is shown in **Fig. 12**. The range of data points for each composition is an indicator of the repeatability of the measurements. The standard errors were determined by the "leave one out" algorithm. For the fits in **Figs. 10, 11** and **12**, the standard errors were 1.87%, 3.31% and 4.58%, respectively.

Normalization and Elimination of Scattering Effects

One of the difficulties in making an optical measurement in an oil well or similar environment is that there are other phenomena that can interfere with the desired effect. For example, Raman scattering can generate secondary light at wavelengths which are longer than the incident light's, which would overlap with the light generated by fluorescence. By choosing an excitation wavelength in the NIR region, 852 nm, the intensity of Raman scattering is greatly reduced, to the point of being negligible.

A more significant problem is the effect of scattering on all optical measurements. Any measurement that depends upon the intensity of transmitted or generated light will be influenced by the scattering in the fluid. Scattering will be highly variable with time as the composition of the fluid, or the flow regime, changes. Differences in solids content, or the size of zones of a particular phase, can result in significantly different levels of scattering, which can generate large errors if proper corrections are not made.

There is one feature of scattering which aids in its elimination – the scattering cross section is a slowly-varying and predictable function of the wavelength. Over the rather narrow bands of wavelength used in these two methods, it can be considered to be virtually wavelength-independent. By performing an overall normalization of the measured spectra, and thereby basing the analysis on the *shape*, rather than the overall magnitude of the detected light, we can greatly reduce or eliminate the effect of scattering upon the determination of the composition.

There are a number of possible means of normalizing the measured spectra, I_i. For the fluorescence measurement, the area of the transmitted laser peak gives an accurate measurement of both the effects of scattering in the fluid and any variations in transmission efficiency of the optical fiber. For the NIR absorption measurements, a more elaborate method is required. After surveying a number of possible techniques, we chose to use the vector length, f, as the normalization factor:

$$f = \sqrt{\sum_{i=1}^{m} I_i^2} \quad \text{...(1)}$$

The spectrum is replaced by the normalized spectrum. IN_i:

$$IN_i = I_i \big/ f \quad \text{..(2)}$$

Once the spectrum is properly normalized, the partial least squares fitting technique is applied to determine the appropriate weights for each component, as described below.

Calibration of the PLS Models

Regardless of whether the attenuation or fluorescence method of analysis was used, the concentration of each constituent (oil, water, gas) of interest is determined from the equation:

$$C_{kn} = \sum_{i=1}^{m} b_{ik} \cdot IN_{in}^{a_i} + b_k \quad \text{...(3)}$$

That is, the concentration C_{kn} of the kth component in the nth sample fluid is expressed as a weighted sum of the normalized intensities IN_{in} at the ith wavelength in the sample. The coefficients, b_{ik} are the weights, and b_k is an additive constant. The exponents, a_i, are generally taken to be 1, for a linear fit. (**Note**: For the attenuation measurements, the fit is performed to the *logarithms* of the intensities, IN.)

The weighting factor, b_{ik}, measures the extent to which the intensity of the light at a given wavelength is a predictor of the concentration of oil, water, or gas. These factors are determined by a PLS regression from the calibration measurements on the titrated sample sets. PLS regression is a procedure that simultaneously estimates the eigenvectors in both the spectral data and the sample property data. A weighting factor, b, is obtained for each of the wavelengths to be used in the algorithm. The normalized intensity (**IN**) of the light component at each wavelength is multiplied by the b for the particular wavelength. The normalized and weighted intensities are summed to calculate the concentration of oil, water, or gas. While there are a number of techniques available for solving these types of problems, the PLS gave the most consistent results in determining the appropriate weights.

A "leave one out" validation technique was employed to check the accuracy of the calibration. Specifically, the PLS regression was run for each mixture used in the calibration, except one, and the resulting algorithm was then used to calculate the concentration of oil in the mixture omitted, and this computed value was compared to the actual value. The quality of the fits can be seen in **Figs. 4-6, 8** and **11-13**.

Flow Loop Testing & Results

Description of multiphase flow loop.

A small-scale flow loop (shown in **Fig. 14**) was built to test the effect of various flow conditions that resembled downhole flow patterns on the sensor response. The design of the flow loop was loosely based on an experimental multiphase facility at the University of Tulsa[2]. While bench top testing in a beaker can produce mixtures with varying proportions of oil, water and "gas", the macroscopic phase properties can not be controlled. The mixture is typically well mixed or begins to separate. With the flow loop, the proportions of the phases can be varied independently of variation in the multiphase properties (*e.g.*, slug flow, bubble flow, annular flow, *etc.*).

The flow loop consists of feed tanks, centrifugal pumps, flow meters, 2-inch PVC pipe and a settling tank. The loop is operated in batch mode. Tap water and refined mineral oil (ρ_o/ρ_w=0.85, μ_o/μ_w=13) are separately pumped from their respective feed tanks and measured before being combined and circulated through the loop. The fluid emerging from the loop enters the mixture tank where it is allowed to separate *via* gravity.

The key feature of the loop is a movable section (**Fig. 15**) which can operate at any inclination between horizontal and vertical. This leg is composed of several easily interchangeable sections to facilitate the rapid placement of sensors, mixers, *etc*. in different orientations. It is made of clear PVC to enable the observation and recording of the actual flow conditions at the measurement points. Typical operating conditions include:

> **total flow rates**: 10 to 60 gpm
> **velocities**: 0.5 to 6 ft/sec
> **Reynolds numbers**: 500 to 100,000

Produced multiphase conditions range from very fine dispersions to large bubbles or churn flow to stratified flow. It is recognized that the conditions at which each of these multiphase flow regime is produced will be different in the flow loop than in downhole situations. These differences are not significant, given that the objective of the flow loop testing is to track the response downhole fluid analyzer to each condition, model the variations, and determine the operating limits of the system, as well as the averaging necessary to obtain reliable data.

Given the limited objective above, some approximations were made which facilitate the observations. Mineral oil was substituted for crude oil. While the response of the NIR attenuation measurement will be different for mineral oil, we may track the *variation* of this response with changing flow regimes and conditions. Air bubbles, rather than the dangerous natural gas, are used to see the effect of bubble flow on the responses, rather than to measure the absolute detection of natural gas.

Finally, in testing the fluorescence measurement, we note that mineral oil does not fluoresce under infrared excitation. To track the variation of the fluorescence reading, we add a fluorescent dye to the *water* component, and track the inverse response (*i.e.*, the water fluoresces, rather than the oil) to see the effect of flow conditions. These compromises are necessary expedients to allow the timely optimization of the sensor geometries, mixers, *etc*. More realistic testing is planned for the next phase (see below.)

Conclusions & Future Plans

Based on the laboratory and flow loop testing, a field prototype sensor assembly will be designed and assembled. This unit will be used first in one or more high-temperature, high-pressure multiphase flow loops to verify the performance and accuracy of the sensors under more realistic field conditions. Once the design has been properly qualified, prototype systems will be installed in producing wells of increasing complexity. These tests will be run for extended periods to verify not only the performance, but also the long-term reliability of the system and its ability to avoid fouling and damage.

Nomenclature

b_k = additive constant for k^{th} component
f = vector length of measured spectrum (counts)
$''_i$ = order of fit for i^{th} component (usually = 1)
$\$_{ik}$ = weighting factor for i^{th} wavelength contribution to the kth component
$\boldsymbol{m}$ = viscosity (cp)
$\boldsymbol{r}$ = density (kg/m^3)
I_I = intensity of ith component of spectrum (counts)
IN_i = normalized intensity of ith component (counts)
m = number of wavelength components used in analysis

Subscripts

i = counter indicating wavelength component
k = fluid component (oil, water or gas)
o = oil
w = water

Acknowledgements

References

1. Evans A. and Hibbard, R.R.: "Determination of Carbon-Hydrogen Groups in High Molecular Weight Hydrocarbons by Near Infrared Absorption," Analytical Chemistry, vol. 23, no. 11 (1951), 1604-1610.
2. Flores, J., *et al*., "Characterization of Oil-Water Flow Patterns in Vertical and Deviated Wells," SPE 38810, 1997

SI Metric Conversion Factors

cp × 1.0*	E–03 = Pa$^.$s
in × 2.54*	E–02 = m
gpm × 6.309	E–05 = m^3/s
mi × 1.6093	E+03 = m

*Conversion factor is exact
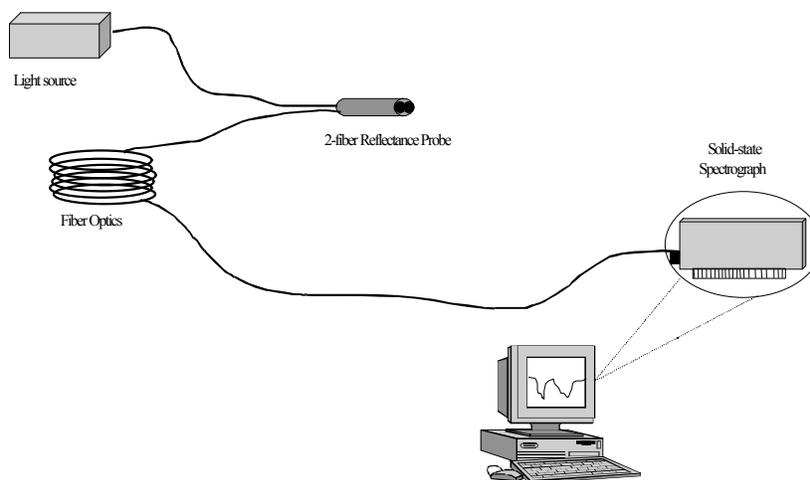
Fig. 1: Instrumental Arrangement for Measuring NIR Absorption of Crude Oils
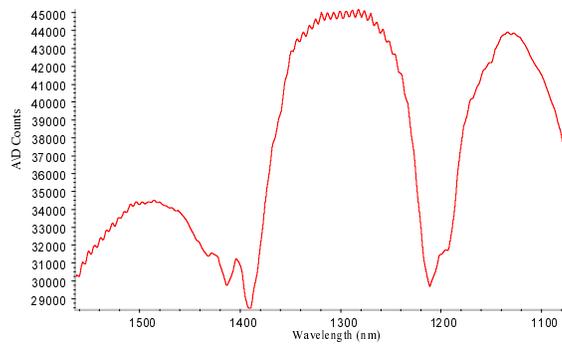
Fig 2: Typical transmission spectrum measured through crude oil. Note the strong absorption minima near 1390 and 1220 nm.
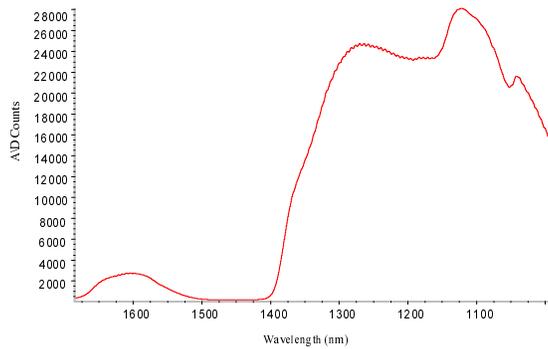

Fig 3: Typical transmission spectrum measured through water. Note the strong, broad absorption minimum between 1400 and 1500 nm.
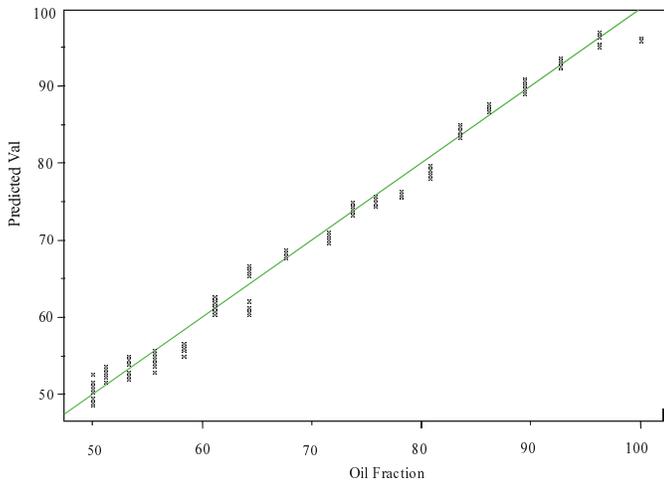

**Fig. 4: PLS fit to NIR absorbance data from water titration into oil. Oil fraction: 100 – 50%.**
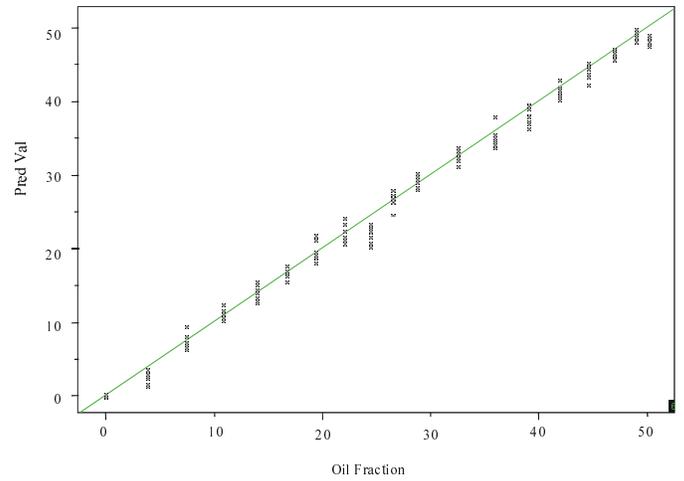
**Fig. 5: PLS fit to NIR absorbance data from oil titration into water. Oil fraction: 0 – 50%.**
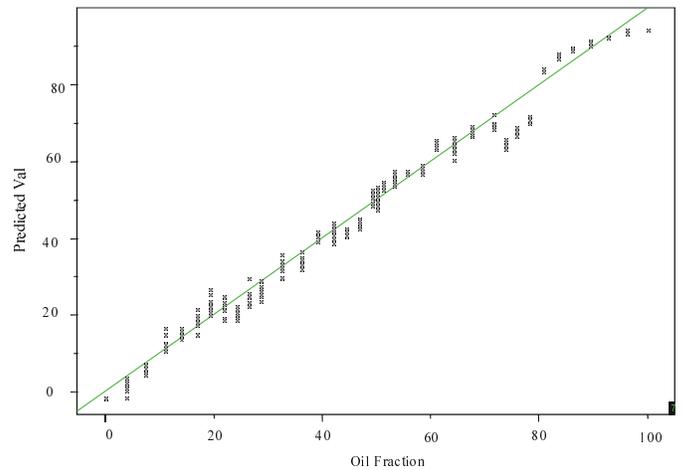
Fig. 6: PLS fit to NIR absorbance data from both titrations above. Oil fraction: 0 – 100%.
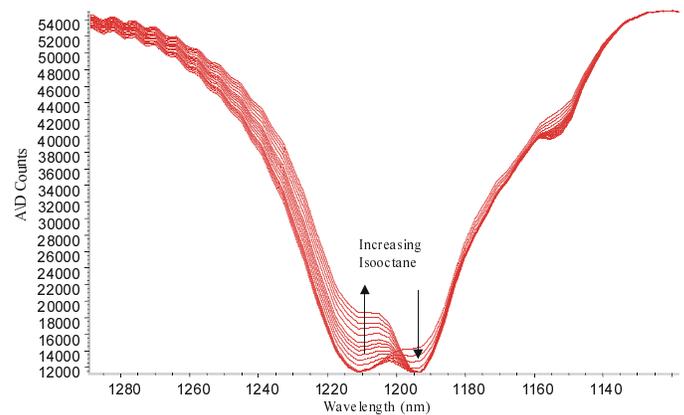
Fig. 7: Variation of NIR spectrum of crude oil with the addition of isooctane. Note the increased absorption at ~1195 nm, while the absorption at ~1210 nm decreases.
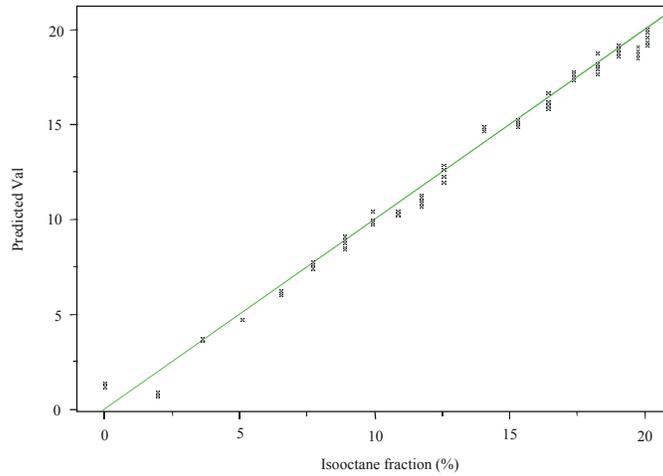
Fig. 8: PLS fit to NIR absorbance data from isooctane titration into oil-water mixture. Isooctane fraction: 0 – 20%.
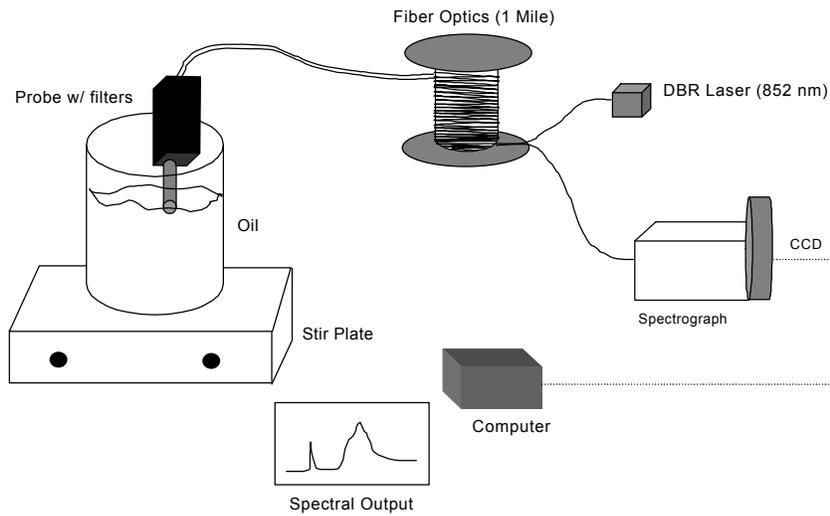
Fig. 9: Instrumental Arrangement for Measuring Fluorescence of Crude Oil – Water Mixtures
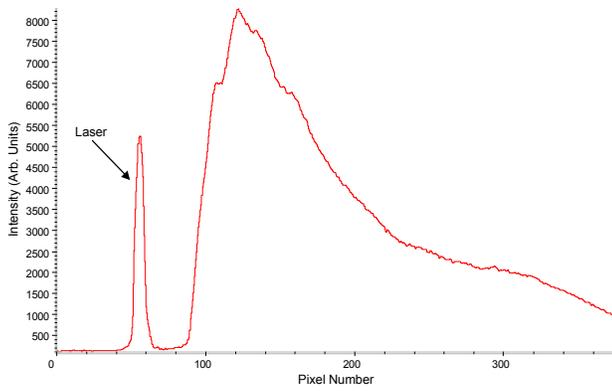
Fig. 10: Fluorescence spectrum of crude oil - 852 nm excitation
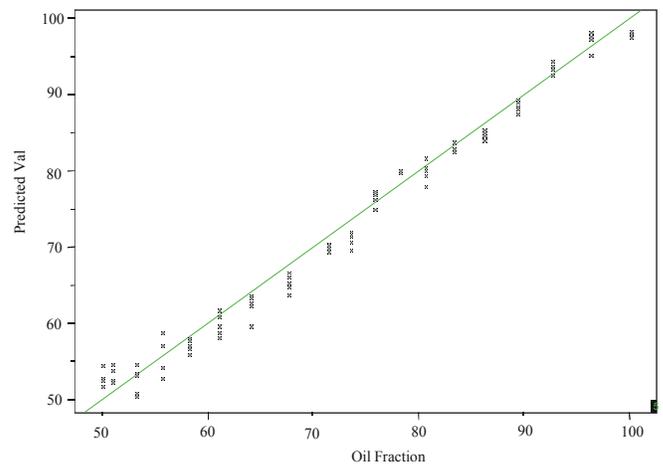
Fig. 11: Partial Least Squares (PLS) fit to measured fluorescence data (Oil Concentration: 50-100%)
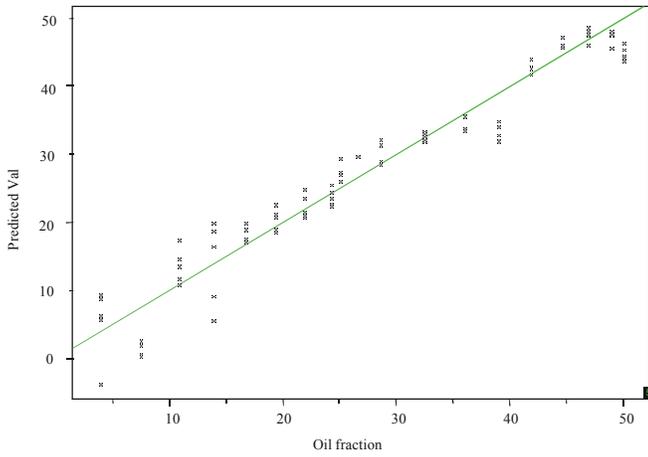
**Fig. 12: PLS fit to measured fluorescence data (Oil Concentration: 0-50%)**

Fig. 13: PLS fit to measured fluorescence data (Oil Concentration: 0-100%)

Fig, 14: Multiphase flow loop for testing sensors. From left to right, tanks are for mineral oil, water and collection (mixture).

Fig. 15: Movable section of flow loop showing fluorescence test fixture.
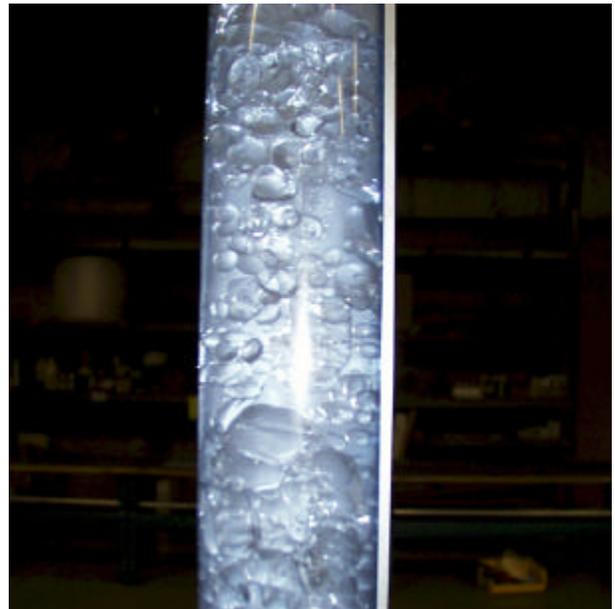
Fig. 16: Example of flow pattern observed in test section while in vertical orientation; oil droplets suspended in water.

SPE 59303

Preliminary Testing of a Novel Downhole Fiber Optic Fluid Analyzer [ADDENDUM]

Martin E. Cobern, SPE & William E. Turner, APS Technology, Inc;
John Cooper & Jeffrey F. Aust, Old Dominion University

Addendum

In the months since the paper was submitted, additional testing has been performed at APS, both in the multiphase flow loop and on the benchtop. A brief summary of these results is presented here.

Using the flow loop shown if **Figs. 14 – 16**, tests were performed at a variety of flow rates and conditions. As is shown in **Fig. 17**, a correlation between calculated and actual oil fraction was obtained in a vertical section. Ongoing tests are evaluating the ability of the system to make measurements at differing inclinations and flows, and whether it will be necessary to include diverters, mixers or multiple sensors to make accurate measurement under these conditions.

During the course of discussions with major producers, another potential application for this technology was raised – the monitoring of the residual oil fraction in the water phase after a downhole separation. To evaluate this possible use, a low oil fraction titration was performed using Pennsylvania light crude oil. The results, shown below in **Fig. 18**, show that determination of the oil fraction to $\pm \sim 300$ ppm is possible in the range of 0 – 2.5% oil. This is consistent with the performance specifications for this application.
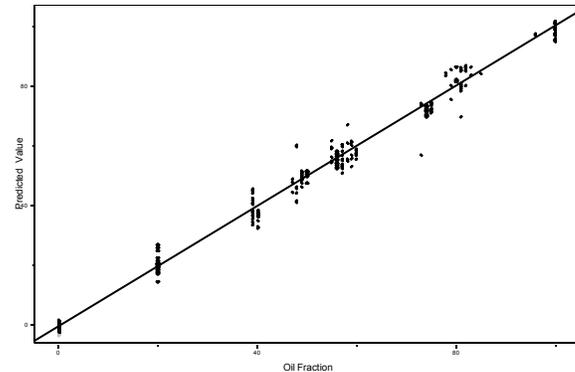

Fig. 17: PLS fit to NIR absorbance measured in APS flow loop with measurement section vertical.
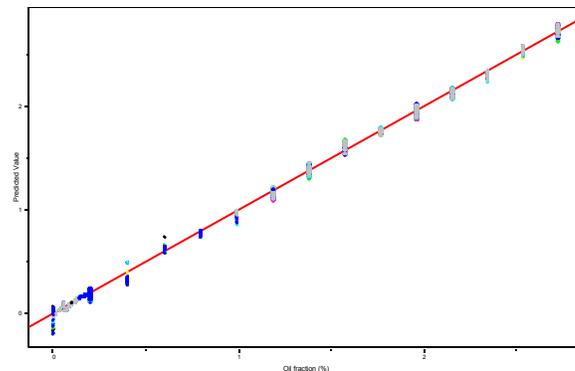

Fig. 18: PLS fit to NIR absorption results for low oil titration using Pennsylvania light crude: oil fraction 0 – 2.5%