

Downhole Fluid Analyzer Development

Phase I Final Report

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Abstract

A novel fiber optic downhole fluid analyzer has been developed for operation in production wells. This device will allow real-time determination of the oil, gas and water fractions of fluids from different zones in a multizone or multilateral completion environment.

The device uses near infrared spectroscopy and induced fluorescence measurement to unambiguously determine the oil, water and gas concentrations at all but the highest water cuts. The only downhole components of the system are the fiber optic cable and windows. All of the active components - light sources, sensors, detection electronics and software - will be located at the surface, and will be able to operate multiple downhole probes. Laboratory testing has demonstrated that the sensor can accurately determine oil, water and gas fractions with a less than 5 percent standard error.

Once installed in an intelligent completion, this sensor will give the operating company timely information about the fluids arising from various zones or multilaterals in a complex completion pattern, allowing informed decisions to be made on controlling production.

The research and development tasks are discussed along with a market analysis.

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Chapter 1

Project Summary

1.1 Executive Summary

In 1997 the Department of Energy's National Energy Technology Laboratory¹ (NETL) issued a Program Research and Development Announcement seeking proposals for the advancement of gas well completion technologies. The NETL approved APS Technology's proposal, "Downhole Fluid Analyzer," to research and develop a fiber optic sensor to measure downhole fluid fractions in real time without interfering with production. The principle of operation is that light passing through a production fluid will be absorbed at specific wavelengths depending on the chemical composition of the fluid. By analyzing this absorption, PetroMax is able determine the chemical composition of the fluid and distinguish between the oil, water and gas fractions. The development objectives included a small downhole presence, the integration of multiple downhole sensors to one surface unit and no downhole electronics.

1.2 Introduction

The objective of Phase I was to research and develop a permanent downhole sensor that optically determines subsurface production fluid concentrations with near-infrared spectroscopy. Goals for the commercial product include a small downhole presence (cross section), the integration of multiple sensors to one surface unit and no downhole electronics. Phase I included lab research

¹Formerly the Federal Energy Technology Center

into the analytical method, sensor design, and evaluation of larger system integration issues. Throughout this phase, APS focused on identifying key system and environmental parameters that would influence the sensor's performance and operating limits. APS also tried to maximize the ruggedness and reliability of the sensor while keeping the cost within the target range. In Phase II, the sensor will undergo field testing in flow loops and downhole environments. The objective will be to quantifying the sensor's performance (accuracy) under diverse operating conditions.

1.3 Phase I Tasks

The Phase I scope of work was modified two times since the original application to address changes in the sensing method. APS's original PRDA application proposed using near infrared spectroscopy with evanescent field absorption. Research conducted between the application submittal and approval showed that this approach would not generate a sufficiently strong signal. A combined fluorescence-conductivity approach was approved as Phase I started. APS's subcontractor, Dr. John Cooper of Old Dominion University, eventually identified a new near infrared approach that did not have the evanescent method's sampling limitations. The Statement of Work was modified in July of 1999 to replace the conductivity method with the new near infrared method. New tasks were added in May, 2000 to address suggestions by potential customers and Phase II partners. Each task in the final scope of work is addressed below along with a summary of the work APS performed.

1.3.1 Scope of Work

Task 1. Information Required for the National Environmental Policy Act

The contractor shall complete all requirements for the National Environmental Policy Act.

The environmental report was submitted in September, 1998.

Task 2. Oil/Water Fraction Sensor Research

The contractor shall construct a sensor prototype for laboratory evaluation. The contractor shall calibrate the prototype under static and dynamic conditions, for a variety of oil types, and under different operating conditions.

The contractor shall analyze the data acquired by the prototype instrument using appropriate statistical techniques and evaluate options for sensor components. The contractor shall use the prototype to determine the general operating limits of the method, how accurate the measurement will be, what parameters influence operation, and the specific limits.

In the fall of 1998, APS Technology and its subcontractor, Dr. John Cooper and his research laboratory at Old Dominion University (hereafter referred to as ODU) began testing the viability of using a laser induced fluorescence method for the quantification of oil and water concentrations in mixtures. Initial results looked promising for near infrared laser induced fluorescence and a commercial-off-the-shelf (COTS) fluorescence instrument was obtained. Testing on oil and water mixtures began in April, 1999 and continued through July, 1999. Various types of crude oils were tested and the data were analyzed using partial least squares analysis. A prediction error of under 3 percent was obtained. After the laboratory testing, the fluorescence instrument was tested in a flow loop (see Task 4). A full discussion of the results is provided in Chapter 2.

Task 3. Gas/Water Fraction Sensor Research

The contractor shall research and design a near infrared analysis probe to distinguish water and gas in the non-oil volume fraction. The contractor shall construct and test the prototype sensor under static and dynamic conditions and examine the effect of various parameters on its output.

The sensing technology proposed in the PRDA application for differentiating between gas, oil and water was based on near infrared spectroscopy. Work between the application date (1997) and the contract acceptance date (1998) indicated that the method for interfacing the production fluid and the light in the fiber was not acceptable; the signal was too weak. Additional research by ODU during the fall of 1998 and spring of 1999 found another method that still used NIR spectroscopy but overcame the interface problems. A technical modification was proposed to NETL in the summer of 1999 and accepted.

NIR spectroscopy has numerous advantages over the fluorescence and electrical conductivity approach originally proposed. Primarily, NIR can sense all three production fluid components: oil, water and gas. Each has a unique vibrational spectra in the 1000 nm to 1600 nm range, which is the “window” for fiber optic sensing. While NIR spectroscopy will be the primary



Figure 1.1: Bench Top Titration Sensor

sensing method, fluorescence can provide a redundant measurement of the oil concentration, providing improved accuracy. The NIR approach keeps with the all-optical goal for the final instrument.

Calibrations were conducted with crude oil, water and isooctane in bench top vessels (Figure 1.1). The isooctane was used as a surrogate for natural gas as it and methane have similar absorbance spectra in the NIR region. It is also safer and easier to use.

Testing in bench top vessels showed that the NIR probe can differentiate between oil, water and gas with a less than five percent error rate. Results of this testing are provided in Section 2.

Task 4. Dynamic Multiphase Testing / High Temperature Testing

The contractor shall test the prototype instrument in a laboratory flow loop and analyze its performance under varying multiphase flow conditions. The contractor shall also conduct high temperature testing of static multiphase mixtures.

APS designed an ambient temperature and pressure flow loop capable of dynamically producing various multiphase mixtures. This system was



Figure 1.2: Flow Loop



Figure 1.3: Flow Loop Adjustable Inclination Section



Figure 1.4: Fluorescence Probe Mounted on Adjustable Inclination Section



Figure 1.5: Near Infrared Sensor Mounted in Flow Loop

designed to allow testing in a wider range of multiphase flow regimes than permitted in bench top testing.

The flow loop consists of two 1,000 gallon tanks, containing water and oil respectively and a 1,000 gallon mix tank. Oil and water are independently pumped at variable flow rates and combined prior to a variable inclination section. The downhole fluid analyzer sensor is mounted on this section. The mixed fluid returns to the mix tank to allow settling. Flow rates up to fifty gallons per minute are achievable. Flows are individually monitored via sensors and recorded digitally. Figures 1.2 through 1.5 show the flow loop, its tanks, the adjustable inclination section, the fluorescence probe and the NIR probe mounted on the section.

The construction of the system was subcontracted out and completed in the fall of 1998. Testing of the fluorescence method started in the spring of 1999 after the initial laboratory testing was complete at ODU and continued through the summer. Testing of the NIR method in the flow loop started the fall of 1999 and continued through the spring of 2000. The flow loop results mirrored the bench testing results with a less than five percent standard error for prediction.

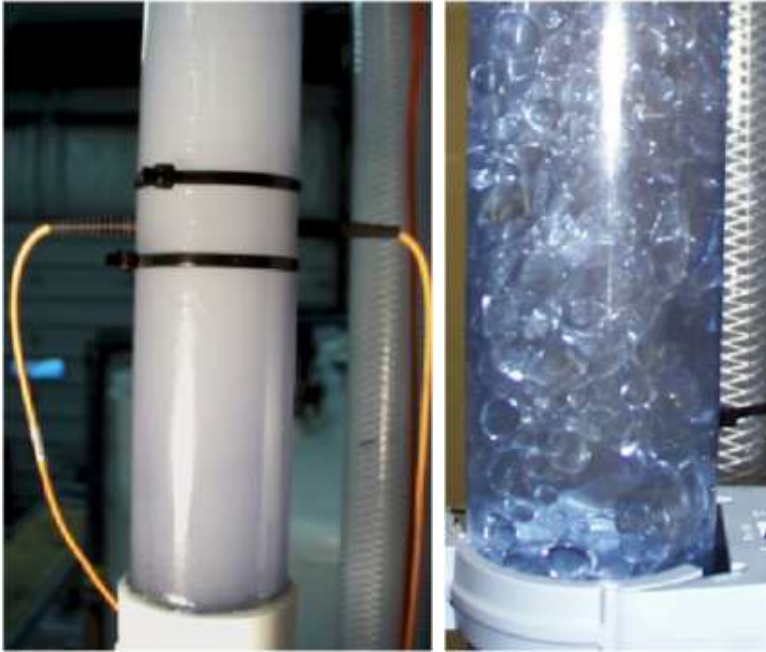


Figure 1.6: Fluid Mixing With and Without a Static Mixer

Task 4A. Multiphase Mixing

The contractor shall research and evaluate options for mixing oil, water and gas multiphase mixtures to ensure that the fluid passing by the sensor is representative of the fluid flowing in the pipe on a time-averaged basis.

Research into mixing options was conducted in the fall of 1999. Several mixer designs were tested in the flow loop, including COTS static mixers and in-house concepts. Testing quickly showed that the effect desired is a more subtle “randomization” rather than a thorough “mixing.” The downhole sensor needs to see a random sample of the fluid flowing in the production tubing, so that the concentration measurement on this sample can be extrapolated to the entire cross section of fluid flowing in the production tubing. Averaging of multiple measurements will increase the accuracy of this extrapolation, and allow accurate measurements under slugging or churn flow conditions (e.g., a section of oil passes the sensor, followed by a section of water, etc.). However, if the fluid is stratified and only one component of the multiphase mixture passes through the optical viewing area, the measurement will be inaccurate. Thus, the mixer has to “randomize” the fluid

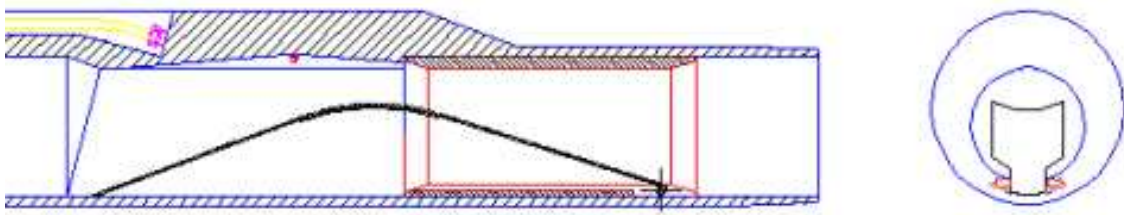


Figure 1.7: Flow Diverter Concept

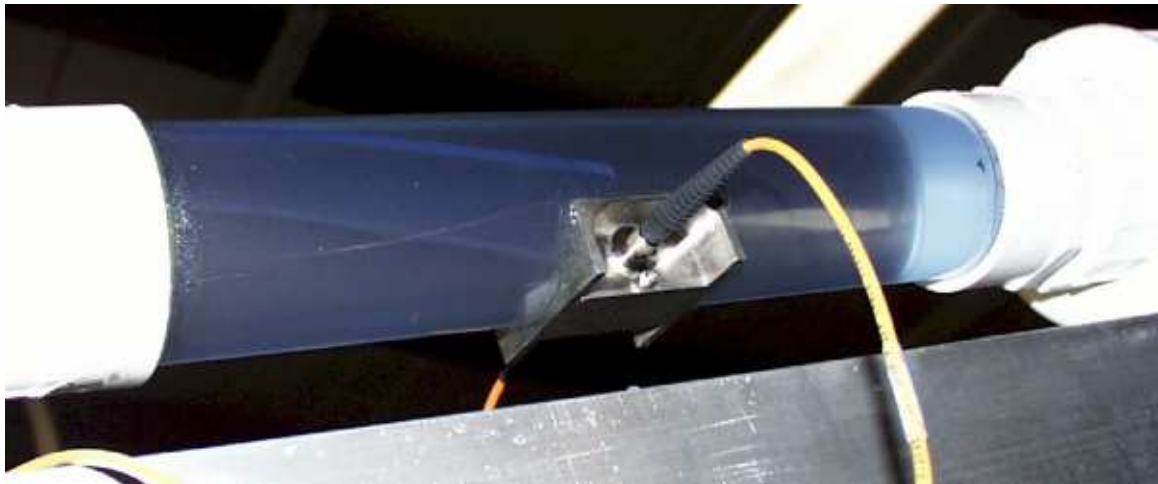


Figure 1.8: NIR Sensor with Flow Diverter Prototype

cross-sectionally.

The level of mixing required for randomization was also tested. It was observed that the amount of mixing necessary for optimal sensor performance is in general minimal. Too much mixing can degrade the sensor's performance. Figure 1.6 shows the amount of emulsification with (left) and without (right) a mixer in the flow loop. In a highly mixed fluid, there is an increase in the number of oil and water fluid interfaces. Some of the light passing through the sensor scatters at each of these interfaces. Once the fluid becomes emulsified, most of the light is scattered and too little is transmitted through the fluid. More importantly, the well operator wishes to have the oil and water mixed as little as possible since they are ultimately separated at the surface.

A third design concern is the mixer's compatibility with the downhole fluid analyzer product and its design criteria. The mixer can not be intrusive and prevent access to the production tubing below the sensor.

A design for a minimally intrusive mixer that would randomize the flow without a high level of mixing is shown in Figure 1.7. This mixer is called a bowspring diverter since it will push to the side of the production tubing to allow tools to pass through and spring back into place. It is designed to force fluid towards the sensor area and provide a minimal amount of emulsification. A prototype was tested in the flow loop with success (Figure 1.8).

In Phase II, the effectiveness of the spring diverter will need to be tested in the field. While simulation and testing in small scale flow loops are valuable for prototyping, multiphase fluid flow is a complex phenomena and the degree of mixing probably can not be accurately predicted a priori. Since the randomization of the fluids is so important to the effectiveness of the downhole fluid analyzer, the initial field deployments without a randomizer should target vertical installations.

Task 5. DFA Design Parameters

The contractor shall research and evaluate the range of design parameters that will allow the DFA to access the majority of the available markets. The significance of each design parameter shall be evaluated to determine limiting factors.

Design parameters were evaluated through literature research, prior experience, oilfield contacts, and vendor input. They were used to guide the design concepts and final layout. A summary of the significant parameters follows.

Downhole Parameters

- Sensor functionality to 20,000 psi and 200 C with a minimum five year operating life.
- Sensor package built to fit 5-1/2" casing with tool outer diameter of 4 3/4".
- No restrictions or obstructions to flow. Passage not less than 2 7/8".
- No fluid flow stagnation or recirculation zones.
- Sapphire windows must be flush with flow passage and must resist abrasion, primarily from sand particles.
- Measurement must be indifferent to changing environmental conditions (fiber bending, temperature, pressure, etc.).

Fiber Parameters

- Use of commercially available telecommunications grade optical fiber.

Surface Parameters

- Use of commercially off the shelf surface equipment that is portable, rugged, and affordable.
- Ability to interface one surface unit with multiple downhole units.
- Remote data collection and management features.
- Low maintenance and user intervention needs.
- PC data collection that will allow easy integration with other equipment.
- Prediction error of five percent or better.

Task 6. Design Concepts

The contractor shall prepare a preliminary layout of the sensor as determined from the design parameters and the laboratory work. The contractor shall address important issues such as integration with production completion systems; analysis of multiphase flow profiles and how they affect the sensor's performance; and downhole ruggedization. The contractor shall initiate a search for a partner company for Phase II, Field Testing.

The design effort began in late 1999 and focused on several key issues:

- Fiber optic cable to downhole sub “wet” connection.
- Maintenance of an unobstructed passage through the center of the sensor.
- Adherence with the minimum bending radius criteria for the optical fiber.
- Randomization of the production fluid to ensure a representative fluid sample passes the sensor.

Major oil producers and service companies were contacted to obtain input on design criteria and establish relationships for potential field testing partnerships in Phase II. Discussions were held with ABB Vecto, Baker Oil Tools, BP Amoco, Chevron Texaco, Halliburton, Pemex, Royal Dutch Shell, Sensa, the University of Tulsa, and The Wood Group throughout Phase I.

Two industry groups have also been contacted for potential field testing partnerships:

- Completion Engineering Association (CEA-125) - a domestic group comprising both operators and service companies focused on the forwarding the development of all types of completion technology. Downhole fluid analyzer presentation in Dallas in October, 2000.
- Downhole Oil Water Separator (DOWS) workgroup - an international body representing both operator and service companies organized to further the application of downhole separators. Presentation in New Orleans in September, 2000.

A technical paper was also presented at the 12th Symposium on Improved Oil Recovery in Tulsa, OK. The paper's SPE reference number is 59303 and was presented in April, 2000.



Figure 1.9: NIR probe, Iteration 1

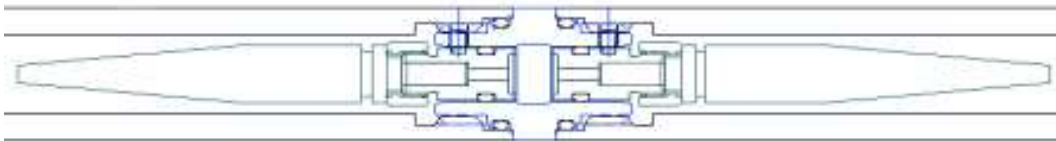


Figure 1.10: NIR probe, Iteration 1 drawing

In late 2003, ChevronTexaco agreed to partner with APS Technology on Phase II of the project.

Task 6A. Optical Alignment

The contractor shall research and evaluate optical alignment issues to ensure that design of the sensor permits maximum light throughput and minimizes loss.

Early prototype sensors demonstrated the extreme sensitivity of signal throughput to optical alignment. The sensor design uses one optical assembly to launch light into the fluid and another to collect the launched light after it has passed through the production fluid. All light returning to the surface must be collected by an optical fiber that is only $125\ \mu\text{m}$ in diameter. A small misalignment in the position one of the two assemblies could cause a significant reduction in signal strength.

The first design of the NIR sensor proved this point well. Figures 1.9

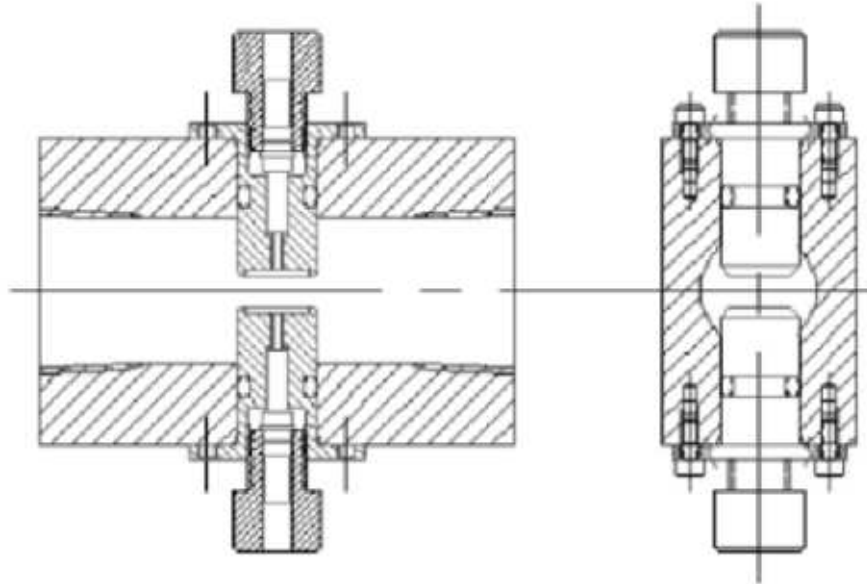


Figure 1.11: NIR probe, Iteration 2 drawing



Figure 1.12: Asphere and GRIN Lenses



Figure 1.13: Sapphire Ball Lens



Figure 1.14: Design Iteration 3

and 1.10 are a picture of a disassembled probe and its drawing. Fluid passes through the slot in the center of the probe while light crosses transversely. The optical assemblies on each side are threaded into the center slot section. The loose tolerances in this design resulted in significant signal loss.

The second design iteration featured a higher tolerance probe housing that slid into a bore in the sensor. Several lens options were then tested, including molded aspheres and gradient index lenses or GRIN lens (Figure 1.12). Aspheric lenses perform better than spherical lenses and the molding technique allows them to be produced much more cheaply than traditional grinding methods. A GRIN lens uses a special glass where the refractive index varies along the optical axis. However, neither of these lenses performed as well as a sapphire ball lens. While the performance of the ball lens may not be as good as the others, its ruggedness and ease of mounting in the sensor are advantageous. The spherical shape of the ball lens will also better compensate for irregularities in the probe. Prototype sensors were made for all three lenses and flow loop testing confirmed the superior performance of the ball lens. All subsequent designs used this lens. Figure 1.14 shows the third design iteration using the ball lens and the precision housings.

Task 6B. Deployment Depth Limitation Study

The contractor shall determine the limits on sensor deployment depth by examining performance improvements in light sources and spectrometers.

The downhole sensor's potential distance from the surface gear is limited by three main factors:

- the amount of light that can enter the fiber at the surface,
- the attenuation of light in the system, and
- the sensitivity of the spectrometer to light.

All three were investigated during Phase I.

The downhole fluid analyzer's light source is a tungsten halogen lamp that produces incoherent light. This light is focused onto a $62.5\ \mu\text{m}$ diameter optical fiber. Optical invariance tells us that when light is focused by a perfect aberration-free lens, there is a minimum size to the source image. Thus, the image of the lamp's filament has a minimum size set by the lens. This size is much larger than the fiber's diameter, so much of the lamp's light is lost. The only way to get more light into the fiber is to use a smaller source size. A mercury xenon arc lamp was investigated. These produce light from an arc that is generated between two electrodes. The arc produces more light from a potentially smaller area than the tungsten halogen lamp's filament.

The broadband light source could be replaced by several lasers. These would be selected to have emission wavelengths at key oil, water and gas absorption areas. The laser's spot size is essentially a point compared to the broadband source, so most of the produced power is coupled into the fiber.

The second area for improvement will be in minimizing the losses of light in the system. This will include maximizing the length of continuous downhole fiber, minimizing the number of connectors between the surface gear and the downhole sensor, and protecting the fiber from damage.

The third area for improvement is in the spectrometer. APS investigated an improved spectrometer over the spectrometer that had been used for most of the Phase I research. Testing on the new instrument indicated ten times better sensitivity over the older instrument.

Improvements in all three areas should extend the downhole fluid analyzer's workable depth from 6000 feet to over 10,000 feet for a non-laser solution. A laser solution may allow the downhole fluid analyzer to access virtually any well, though the system would be more complex and have a higher cost.

Task 6C. Develop Sensor Multiplexing Capability

The contractor shall evaluate and test fiber optic multiplexers for connecting multiple downhole sensors to one surface unit.

A sensor multiplexer will allow one surface package to serve a field of wells. The multiplexer will connect the surface light source to the multiple downhole fibers. Fibers returning back to the surface will not need a multiplexer. They can be combined at the surface into one larger fiber that will interface with the spectrometer. Since the multiplexer will alternate which downhole sensor is illuminated, only one return fiber will illuminate the spectrometer at a time.

There are several types of fiber optic multiplexers commercially available. Telecommunications grade fiber optic switches are the most common. They are high performance, reliable products but are not suitable for the downhole fluid analyzer application. Telecom fiber is typically single mode ($5\text{ }\mu\text{m}$ in diameter) while the downhole fluid analyzer uses multimode fiber ($62.5\text{ }\mu\text{m}$ in diameter). The diameter mismatch between the downhole fluid analyzer fiber and the switch fiber would cause significant light loss.

There are commercially available multiplexers for spectrographic instruments and fiber optic sensors. These meet most of the needs for the downhole fluid analyzer: computer controlled, rugged, low optical attenuation. However, they target the larger diameter optical fiber typically used in industrial sensing, 400 to 600 μm . If these multiplexers are used, a large diameter fiber will collect the light from the source and transmit it to the switch. The fiber exiting the switch will also be large diameter and will connect to the $62.5\text{ }\mu\text{m}$ subsurface fiber. There will be light loss here with only about ten percent of the light transmitting into the smaller fiber. However, the large diameter fiber collects about 100 times more light than $62.5\text{ }\mu\text{m}$ fiber at the light source. Thus, the amount of light reaching the subsurface fiber will not be much less with a multiplexer. Alternatively, large diameter fiber could be deployed from the surface gear to the downhole sensor (see discussion under Task 6B).

Task 7. DFA Final Design

The contractor shall prepare the final design of the instrument which shall be capable of meeting the overall instrument goals based on the research, design work and laboratory evaluation conducted. This design shall also be compatible with the Phase II field-testing conditions.

Work on the final design started in early 2000. A layout and solid model of the prototype sub are shown in Figures 1.15 and 1.16.

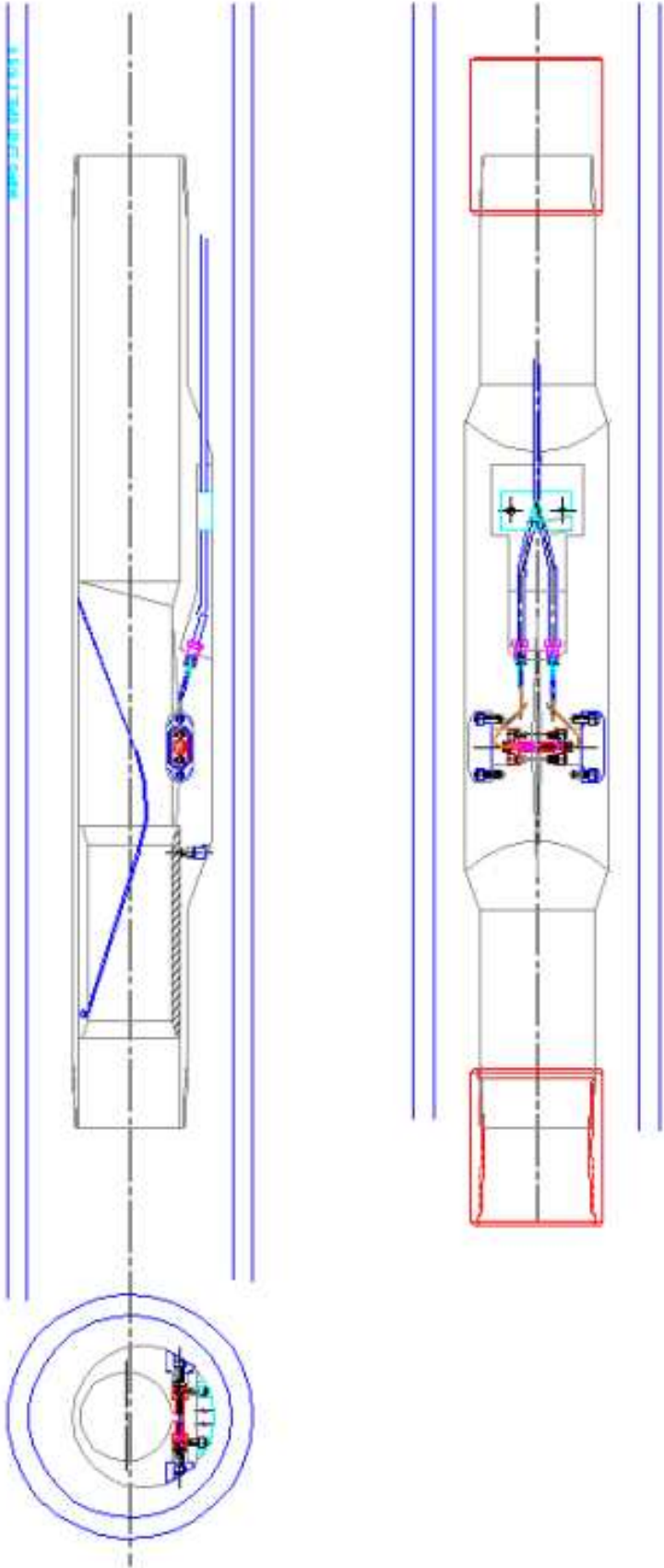


Figure 1.15: Project Summary

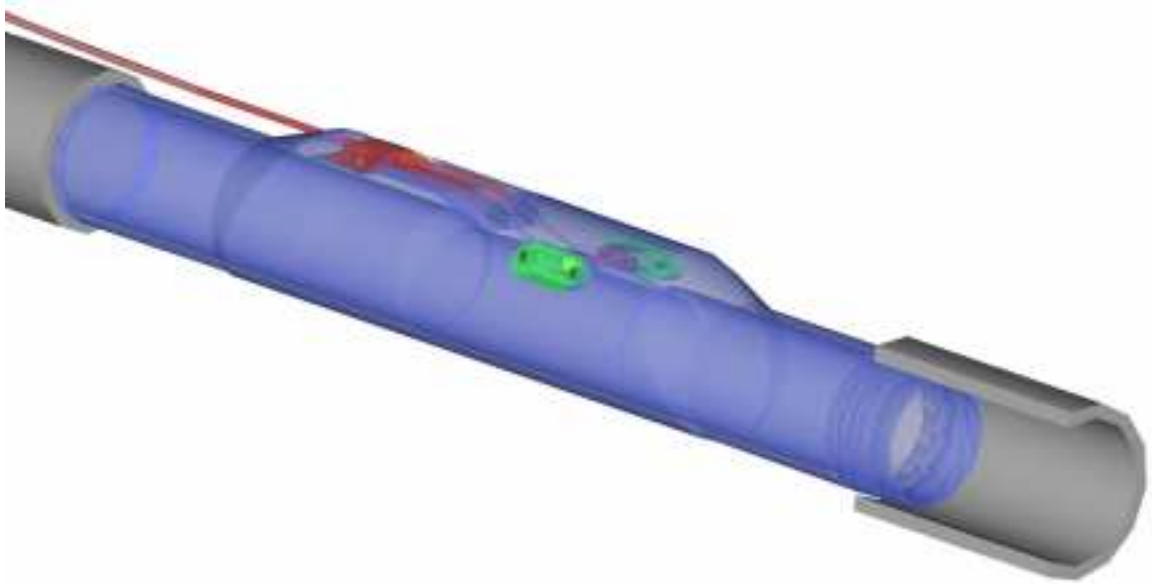


Figure 1.16: Prototype Sub Solid Model

Task 8. DFA Prototype Manufacturing and Testing

The contractor will manufacture one full-scale prototype instrument for evaluation and will include all equipment to be used in the final product. The contractor shall bench test all system components.

Based on the design completed in Task 7, a full scale prototype was manufactured. Production began in early 2000 and was completed by summer. The prototype is a complete DFA system and consists of:

- a spectrometer,
- fiber optic cable,
- sensor housing,
- optical housing and associated optics.

The sensor housing produced is shown in Figure 1.17. This type of housing flange mounts in a flow loop or possibly a surface production line. The full downhole design was not produced for two reasons. The required diameter of the downhole sub will not be known until the actual Phase II field test well is



Figure 1.17: Prototype Sensor Housing

selected. Second, based on suggestions from potential partner companies, the first test in Phase II will probably be in a surface production line. This would use the prototype design manufactured in Task 8 rather than the downhole design.

Prototype optical housings were designed and produced by a subcontractor. They included a sapphire optical window brazed into the housing with 20,000 psi pressure rating, 200 C temperature rating and corrosive service use.

Task 8A. Three Phase Calibration Cell Manufacturing

The contractor shall manufacture a high temperature / high pressure fluid cell for conducting three phase calibrations of the sensor with oil, natural gas and water.

A pressure vessel was purchased and modified to conduct high pressure and temperature testing of the sensor. The pressure vessel consists of an Autoclave Engineers EZE-Seal 500 mL reactor with internal mixer. It is capable of temperatures to 200 C and pressures to 3000 psi. Figure 1.18 shows the vessel, the nitrogen gas cylinder used for pressurization, data ac-



Figure 1.18: Pressure Vessel Setup



Figure 1.19: Pressure Vessel Close Up

quisition equipment used for monitoring temperature and pressure and the spectrometer computer. Figure 1.19 shows a close up of the vessel.

Since the internal volume of the high pressure cell is small and there were limited options for getting the fiber into the vessel, a special fiber optic sensor needed to be designed and manufactured. The pressure vessel was received in fall 2001 and the probe was designed and manufactured in early 2002. Pressure vessel testing was conducted in late 2002.

The results of this testing showed that the spectra of the production fluids will shift with changes in temperature and pressure. The pressure effects are due to the compressibility of the fluids. At higher pressures slightly more fluid is between the sensor's two windows. This increases the absorption. Changes in temperature shift the spectra due to vibrational changes in the molecules. Both of these effects will need to be accounted for in the downhole fluid analyzer's calibration.

Task 9. Study of Technical and Economic Merits of Instrument

The contractor shall prepare a detailed assessment of the potential market for the DFA and competitive methods to ensure development of the instrument during Phase II addresses industry's requirements.

See chapter 3 of this report.

Task 10. Phase I Final Summary Report

The contractor shall prepare a final report for Phase I of the project.

The final report was completed in spring of 2003, reviewed by the DOE and submitted in final form in March, 2004.

1.3.2 Project Timeline

<u>Date</u>	<u>Event</u>
Jul. '97	FETC issues PRDA
Oct. '97	APS submits proposal
Jun. '98	FETC approves APS's proposal
Sep. '98	Contract signed, work begins
Jul. '99	APS submits Technical Modification Request due to changes in the sensor's analytical method.
Apr. '00	APS presents SPE Paper 59303, "Preliminary Testing of a Novel Downhole Fiber Optic Fluid Analyzer," at the 2000 SPE DOE Improved Oil Recovery Symposium, Tulsa, Oklahoma
May '00	APS submits Phase I Status Summary and Modification Request identifying work completed not specifically identified in original scope and proposing additional tasks.
Jan. '03	APS completes Phase I tasks
Jun. '03	Final technical report submitted

1.4 Phase II Tasks

The planned scope of work for Phase II is provided below.

Task 11. Flow Loop Testing

The contractor shall test the DFA prototype constructed in Phase I at a commercially available, large-scale flow loop facility to determine system performance under realistic field conditions. The contractor shall evaluate:

- *the performance and reliability in vertical and deviated situations under two and three phase flow conditions (gas-water, oil-water and gas-oil-water.)*
- *the performance of the DFA, compared to conventional production logging tools and multiphase flow meters*

Task 12. 1st Well Test

The contractor shall field test the DFA in a natural gas well determined by the contractor and the Phase II partner. The DFA shall be deployed as part of a completion system and the instrument shall be operated continuously to monitor sensor performance and reliability and to gather production data for sensor evaluation. The contractor shall use a combination of phase monitoring at the surface and production logging for verification of operating conditions and validation of the DFA's performance. The contractor shall evaluate the condition of the downhole components to determine wear or damage due to harsh conditions.

Task 13. Instrument Redesign

Upon completion of the first field test, the contractor shall evaluate the DFA data, well operating conditions, data from the validation methods and other resources to determine the performance of the instrument. From these evaluations, the contractor shall make necessary redesigns or modifications to the instrument before the next field test.

Task 14. 2nd Well Test

The contractor shall field test the instrument in a second natural gas well, preferably a horizontal well.

Task 15. Instrument Redesign

Upon completion of the second field test, the contractor shall evaluate the DFA data, well operating conditions, data from the validation methods and other resources to determine the performance of the instrument. From the evaluations, the contractor shall make necessary redesigns or modifications to the instrument before the next field test.

Task 16. 3rd Well Test

The contractor shall test the instrument in a third natural gas well, preferable in an advanced completion offering multiphase challenges.

Task 17. Instrument Redesign

The contractor shall evaluate the results from the third field test and make any design changes or modifications to the instrument deemed necessary.

Task 18. Phase II Final Report

The contractor will prepare a final report detailing the Phase II testing.

Chapter 2

Research Results and Discussion

2.1 Introduction

A discussion of the research results is provided here. The patent “Apparatus and Method for Analyzing Fluids” provides detailed information and is attached in Appendix B.

Testing of the near infrared and fluorescence 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.) A second phase of testing was conducted in a low-pressure multiphase flow loop over a wide range of inclinations, flow rates and flow regimes. A third phase of testing was conducted in a pressure vessel capable of medium pressures and high temperatures.

2.2 Laboratory Testing & Results

2.2.1 Near Infrared Attenuation

Apparatus & Measurements

The NIR attenuation measurements were carried out with the Downhole Fluid Analyzer setup shown in Figure 2.1. Light from a broad band source covering the near infrared wavelength range of at least 1000 – 1700 nm is sent down a one mile long optical fiber, 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 spectrometer.

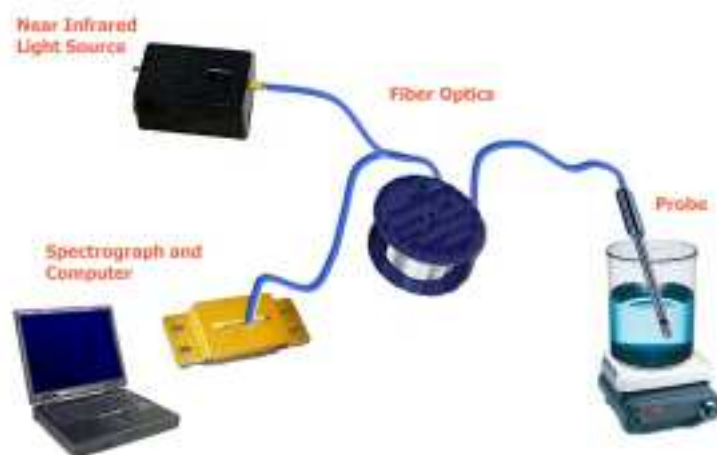


Figure 2.1: Instrumental Arrangement for Measuring NIR Absorption of Crude Oil and Water Mixtures

The NIR absorption method relies on differences in the opacity of oil and water to the transmission of infrared light. As illustrated in Figures 2.2 and 2.3, 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 spectrometer. 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.

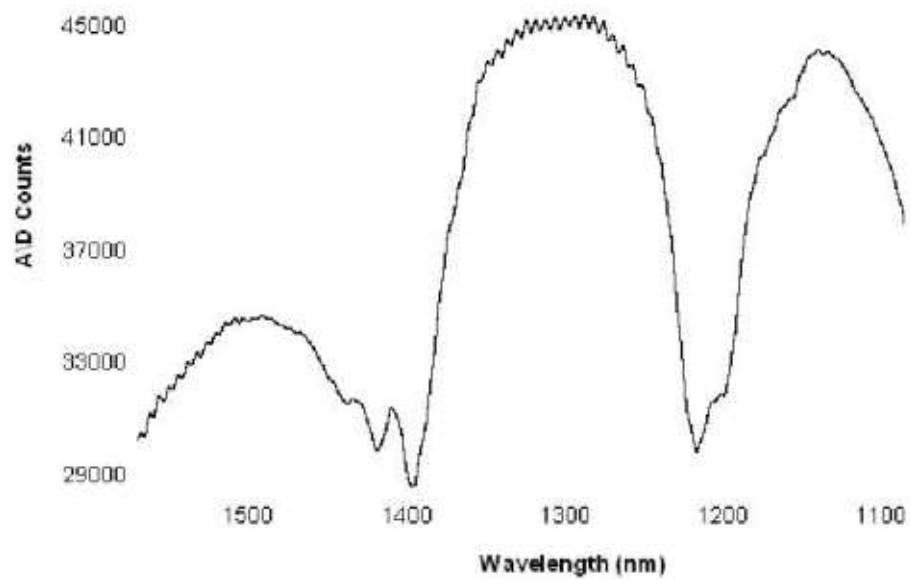


Figure 2.2: Typical transmission spectrum measured through crude oil. Note the strong absorption minima near 1390 and 1220 nm.

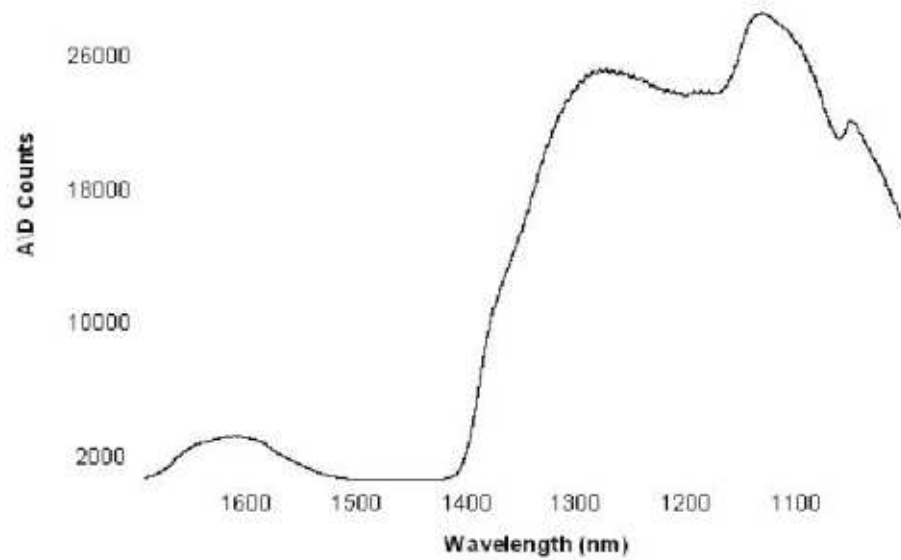


Figure 2.3: Typical transmission spectrum measured through water. Note the strong, broad absorption minimum between 1400 and 1500 nm.

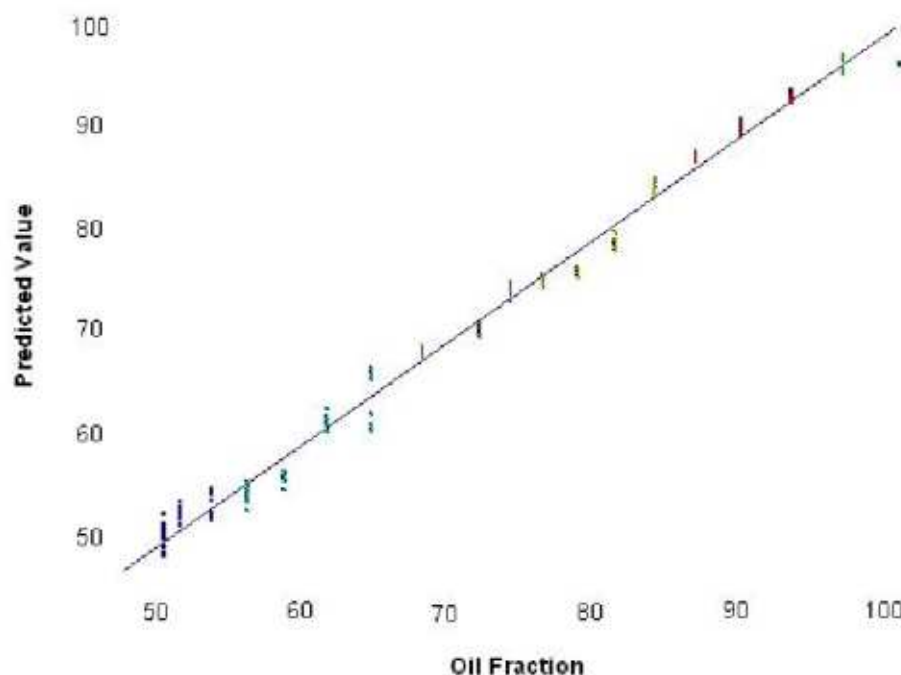


Figure 2.4: PLS fit to NIR absorbance data from water titration into oil. Oil fraction: 100 - 50%.

Analysis

The results from each titration are shown in Figures 2.4 and 2.5. 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 Figure 2.6; 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.

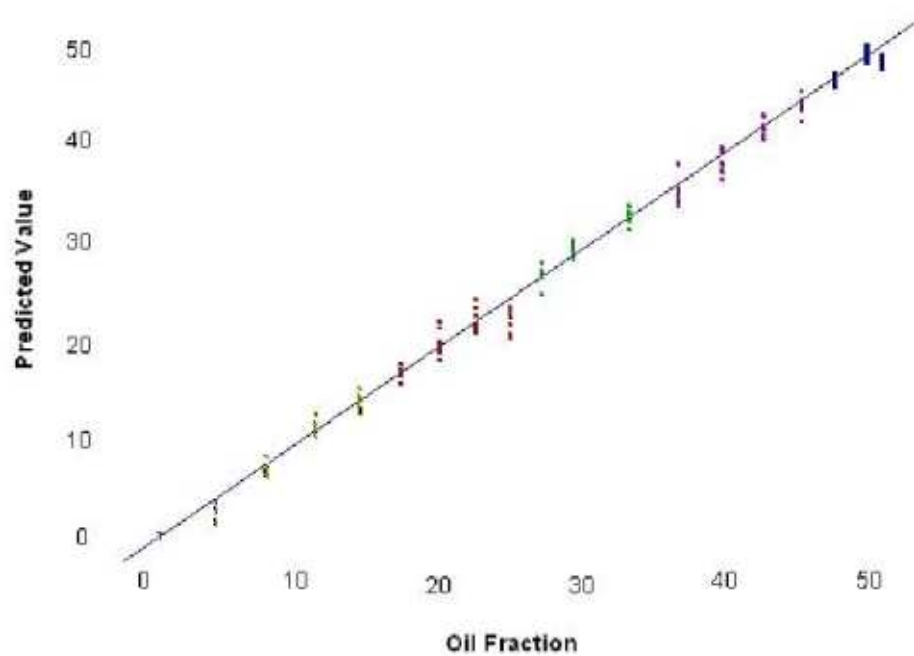


Figure 2.5: PLS fit to NIR absorbance data from oil titration into water. Oil fraction: 0 - 50%.

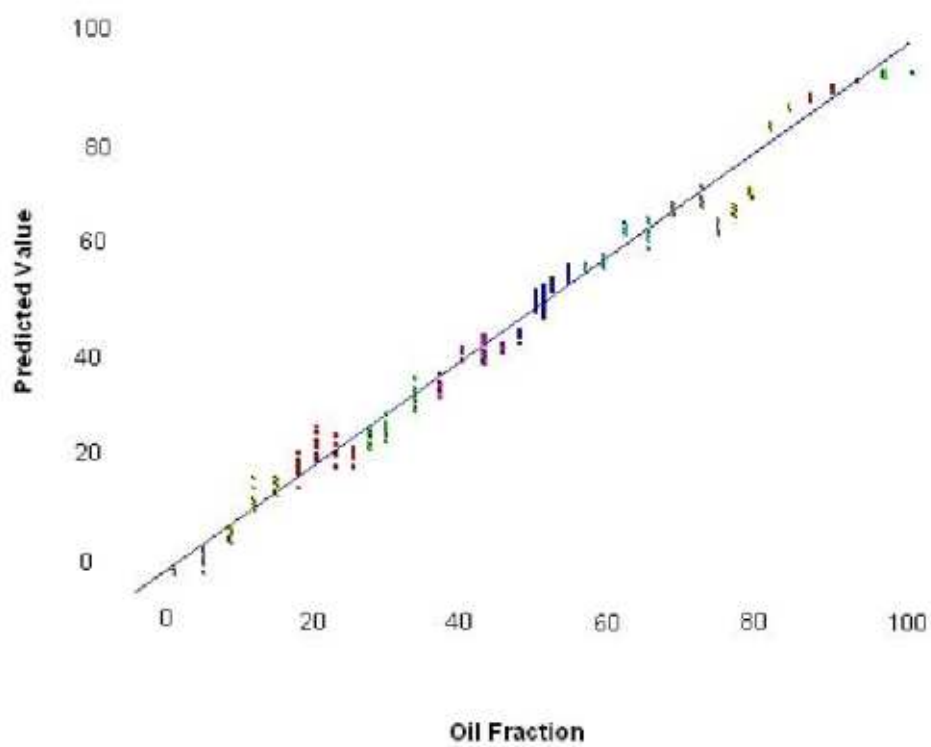


Figure 2.6: PLS fit to NIR absorbance data from both titrations above. Oil fraction: 0 - 100%.

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 ($-\text{CH}_3$). Crude oil, on the other hand, is composed primarily of longer hydrocarbon chains and aromatics, which include some methyl groups, but predominantly methylene groups ($-\text{CH}_2$). Each of these radicals has a distinctive NIR absorption band. Evans and Hibbard¹ 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 Figure 2.7, 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%; one hundred 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 Figure 2.8. 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.

¹Evans 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.

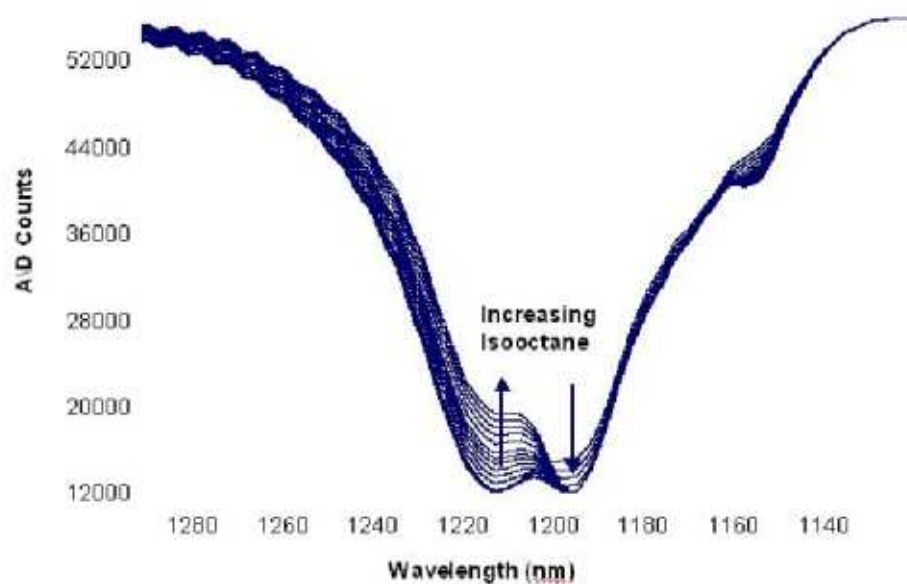


Figure 2.7: Variation of NIR spectrum of crude oil with the addition of isooctane. Note the increased absorption at 1195 nm, while the absorption at 1210 nm decreases.

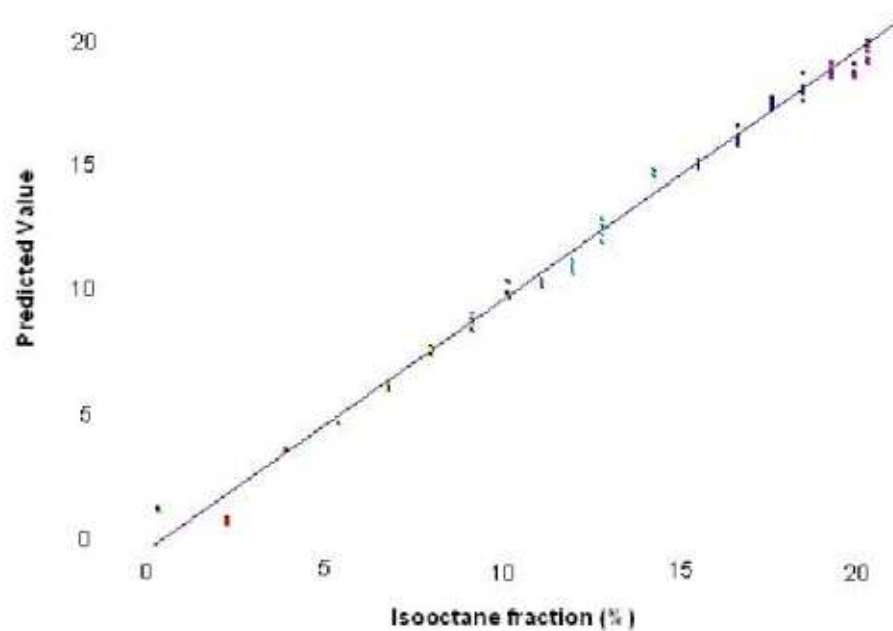


Figure 2.8: PLS fit to NIR absorbance data from isooctane titration into oil-water mixture. Isooctane fraction: 0 - 20%.



Figure 2.9: Instrumental arrangement for measuring fluorescence of crude oil and water mixtures

2.2.2 Fluorescence Measurements

Apparatus and Measurements

A schematic diagram of the laboratory fluorescence test arrangement is shown in Figure 2.9. Light from a distributed Bragg reflector diode laser at 852 nm is transmitted via a one 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 Figure 2.10. 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 one hundred samples were averaged for each data point. Each titration was repeated five times.

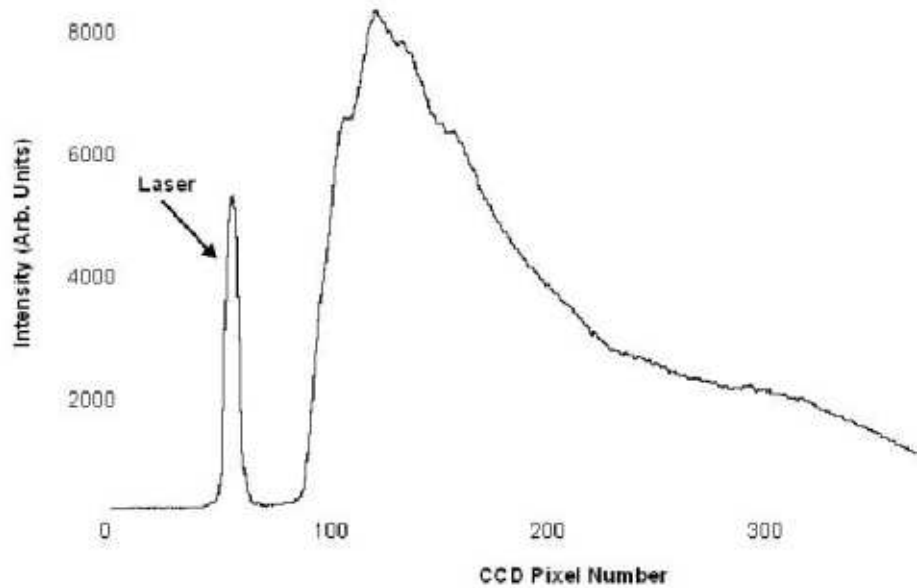


Figure 2.10: Fluorescence spectrum of crude oil with 852 nm excitation

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 reduced 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 Figures 2.11 and 2.12; the full range fit is shown in Figure 2.13. 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 Figures 2.11, 2.12 and 2.13, the standard errors were 1.87%, 3.31% and 4.58%, respectively.

2.3 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

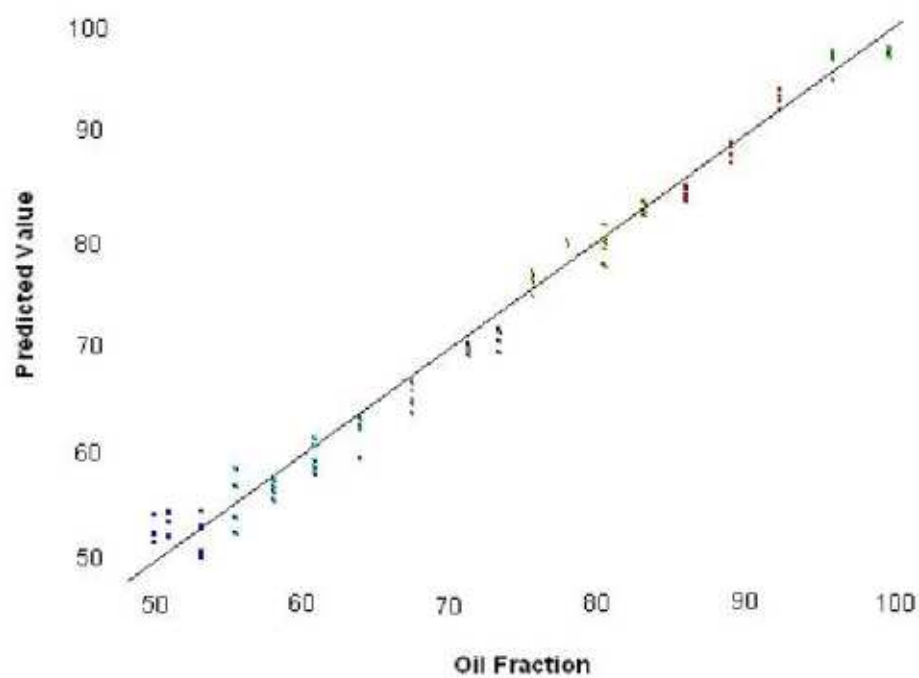


Figure 2.11: Partial Least Squares (PLS) fit to measured fluorescence data (Oil Concentration: 50-100%)

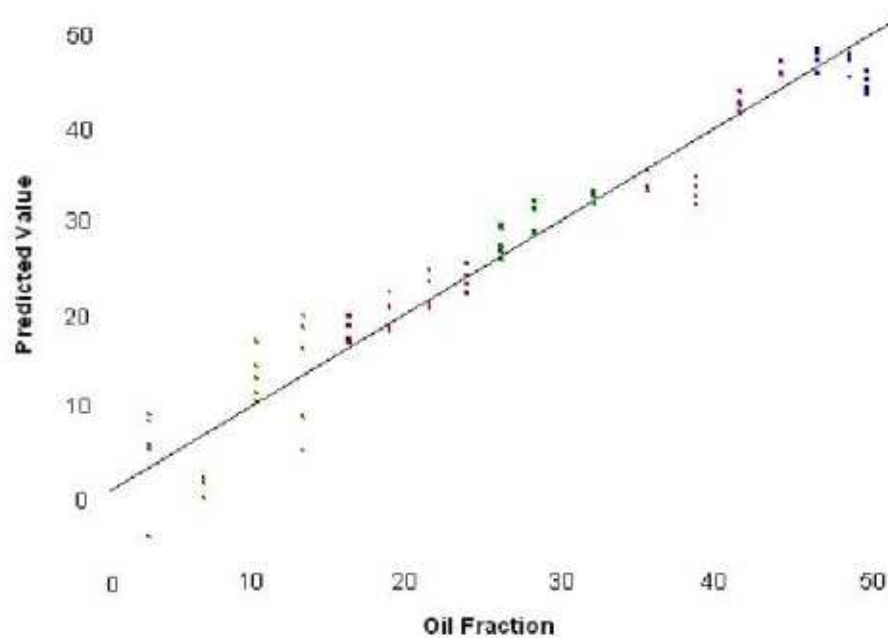


Figure 2.12: PLS fit to measured fluorescence data (Oil Concentration: 0-50%)

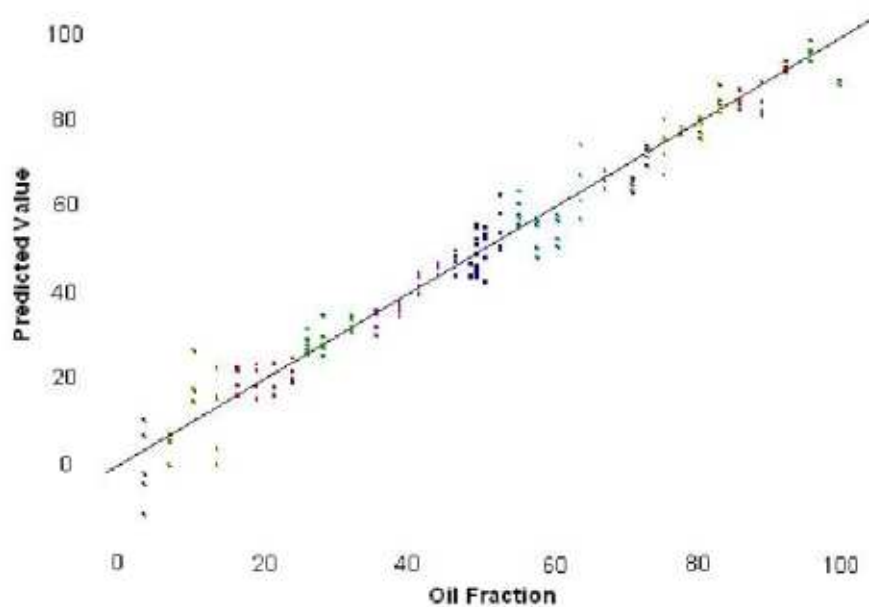


Figure 2.13: PLS fit to measured fluorescence data (Oil Concentration: 0-100%)

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 near infrared 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:

$$f = \sqrt{\sum_{i=1}^m I_i^2} \quad (2.1)$$

The spectrum is replaced by the normalized spectrum IN_i :

$$IN_i = \frac{I_i}{f} \quad (2.2)$$

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.

2.4 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:

$$C_{kn} = \sum_{i=1}^m \beta_{ik} \cdot IN_{in}^{\alpha_i} + b_k \quad (2.3)$$

That is, the concentration C_{kn} of the k^{th} component in the n^{th} sample fluid is expressed as a weighted sum of the normalized intensities IN_{in} at the i^{th} wavelength in the sample. The coefficients, β_{ik} , are the weights, and b_k is an additive constant. The exponents, α_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, 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 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 factor 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 Figures 2.4–2.6, 2.8 and 2.11–2.13.

2.5 Flow Loop Testing and Results

2.5.1 Description of Multiphase Flow Loop

A small-scale flow loop 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 Tulsa². 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.).

²Flores, J., et al., “Characterization of Oil-Water Flow Patterns in Vertical and Deviated Wells,” SPE 38810, 1997

The flow loop consists of feed tanks, centrifugal pumps, flow meters, two inch PVC pipe and a settling tank (Figure 1.2). The loop is operated in batch mode. Tap water and refined mineral oil 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 which can operate at any inclination between horizontal and vertical (Figures 1.3 and 1.4). 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 gallons per minute
- velocities: 0.5 to 6 feet per second
- 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.

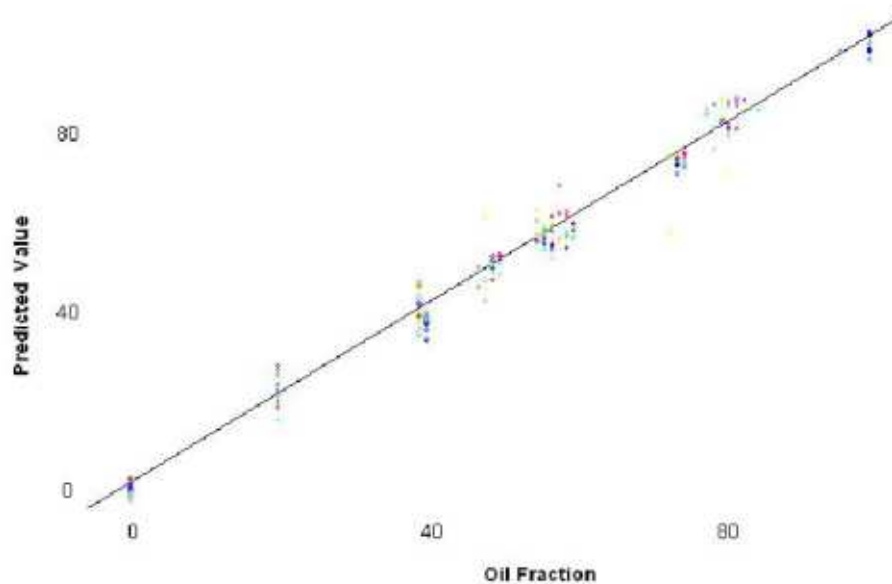


Figure 2.14: PLS fit to NIR absorbance measured in the flow loop with the measurement section vertical

Using the flow loop tests were performed at a variety of flow rates and conditions. As is shown in Figure 2.14, a correlation between calculated and actual oil fraction was obtained in a vertical section. Testing evaluated 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.

2.6 Pressure Vessel Testing

The effect of temperature and pressure on hydrocarbons has been examined previously by others. Mullins reported that absorption increased and spectra broadened with increasing pressure and decreasing temperature for the C-H two stretch band in both methane and heptane³. Further analysis showed that absorption depends on density but not independently on pressure or

³Mullins, Joshi, Groenzin, Daigle, Crowell, Joseph, Jamaluddin, "Linearity of Near-Infrared Spectra of Alkanes," *Applied Spectroscopy*, 54(4), 2000, pp. 624-9.

temperature. The effect of pressure and temperature on heptane is much less due to its low compressibility compared to methane.

Spectra were acquired with a similar setup as used in the laboratory and flow loop testing. Lucent hard clad silica step index fiber with a 400 μm core connected the probe to the spectrometer and the light source.

The pressure vessel probe utilized 180 degree collection geometry and had a path length of 2.5 mm. The probe was placed in an Autoclave Engineers 500 mL pressure vessel. Pennsylvania crude oil, water, and gas mixtures were heated to 200 C and pressurized to 3000 psi with nitrogen. An integral mixer reduced stratification of the insoluble phases. The collected transmission spectra were transformed to absorbance spectra, vector length normalized, and mean centered.

The results of this testing showed that the spectra of the production fluids will shift with changes in temperature and pressure. However, the change is small compared to changes that occur with different compositions. Figure 2.15 shows the minimal change in spectra for oil transmission between atmospheric pressure and 1000 psi. The pressure effects are due to the compressibility of the fluids. At higher pressures slightly more fluid is between the sensor's two windows which increases the absorption. Changes in temperature shift the spectra due to vibrational changes in the molecules. Both of these effects will need to be accounted for in the downhole fluid analyzer's calibration for the highest accuracy.

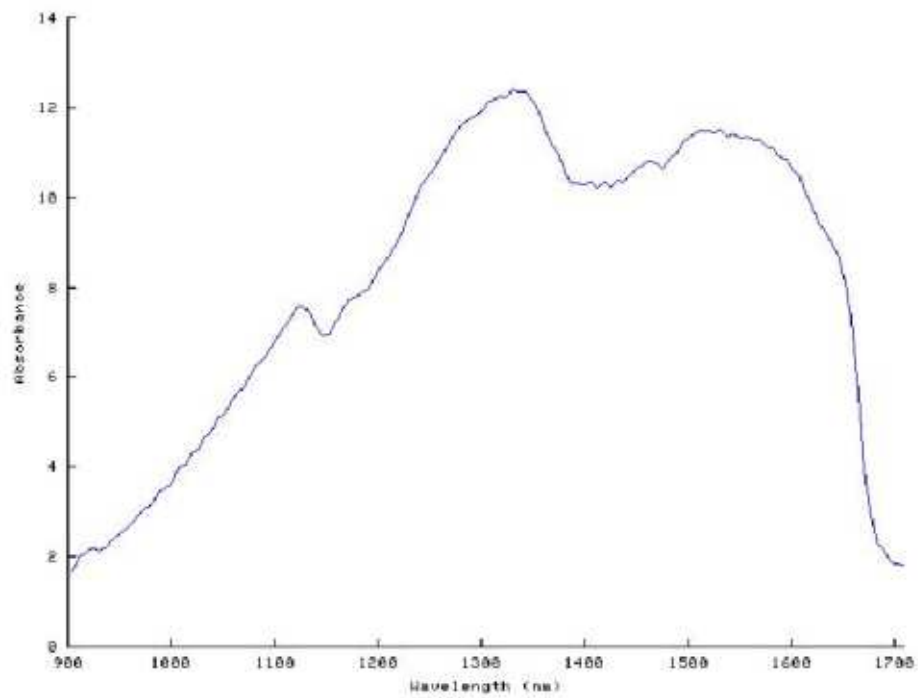


Figure 2.15: Slight shift in oil transmission spectra with changes in pressure between 0 and 1000 psi.

Chapter 3

Technical and Economic Merits

3.1 Market

The PetroMax technology has potentially broad market appeal. Six applications have been identified:

1. Provide an accurate, real time concentration measurement of a reservoir's produced fluids enabling operators to optimize production.
2. Provide residual oil monitoring in the water production from downhole separators where this water is destined for disposal by re-injection into the formation.
3. Monitor produced fluids in subsea completions where surface installations are prohibitively expensive and production can typically be monitored only on a multi-well or co-mingled basis.
4. Monitor fluid levels in downhole pumps to prevent them from running dry.
5. Provide multiphase monitoring of hydrocarbon fluids being pumped at the surface to gathering stations.
6. Monitor hydrocarbon contamination in produced fluids from industrial processes.

APS is currently aggressively pursuing PetroMax product development to satisfy applications 1, 2 and 3. Preliminary discussions with potential clients have begun on application 4. Applications 5 and 6 may be pursued later.

Intelligent Well Market

With the advent of intelligent completion technology, oil and gas producers have increased control over fluid production. The two key components of an intelligent completion are well monitoring and management. Permanent downhole sensors provide the operator with a better understanding of subsurface conditions, while new mechanical devices permit the remote opening and closing of valves or downhole processing of reservoir fluids. The intelligent well allows the operator to:

- Better understand production performance through monitoring of produced fluid properties such as temperature, pressure and composition.
- Obtain data on individual well performance in multi-well installations, such as offshore platforms, where production is typically co-mingled from multiple well bores prior to the surface.
- Selectively and remotely control drawdown and production from individual production zones, which can result in the elimination of costly surface processing equipment.
- Reduce or eliminate the need for remedial procedures requiring costly well interventions and temporary loss of overall production.
- Dispose of produced water downhole without losing oil to re-injection.

Likely candidates for intelligent completions are those where the costs of access and intervention are high:

- multi-laterals
- extended reach horizontal wells
- subsea wells
- deep water applications
- remote operations

The total market for intelligent well completions is forecast to grow from around thirty million dollars in 1999 to a hundred million dollar market by mid-decade. The PetroMax technology is of particular interest in many

of the 700 horizontal wells that are completed a year, particularly in multi-lateral developments and in those fields where cross-flow between production wells occurs. Applications also exist in subsea completions, of which there have been 180 to 200 installations per year over the last three years. Geographically, the Gulf of Mexico, the North Sea, West Africa and Brazil are anticipated to be the strongest markets.

The sensors in intelligent wells are traditionally strain gauge or quartz temperature and pressure sensors requiring the use of downhole electronics and electric lines run back to surface. More recently, fiber optic sensors have been developed for this application. The main advantage is the typical fiber optic sensor does not have any downhole electronics, which can be unreliable. BP-Amoco has collected reliability data on conventional sensors that illustrates only 88% of the sensors installed within the two years previous to the study remain operational. Going back four, and six years, the sensor installations that remain operational decline to 55% and 42% respectively. There is a belief among operators that performance improvements in conventional sensors will not be significant in the future and that there needs to be an alternative technology. This contributes to the growing interest in fiber optic technology, where sensor reliability is potentially much higher due to the inherent lack of downhole electronic components. However, the fiber cable linking the sensor back to the surface is potentially more unreliable than the traditional electric line.

3.2 Competitive Products and Technologies

There are several companies involved in intelligent well completions. They range from those simply providing sensor measurements using either conventional electrical and hydraulic communications to those companies who combine these measurements with mechanical control devices and integrate fiber sensors in the system.

ABB Seatec

This company is active in fiber optics development and has distributed temperature and pressure fiber optic technology. ABB has installed its pressure sensor on a Shell North Sea project.

Baker Oil Tools

The leading provider of conventional completions has regrouped from a failed joint venture with Schlumberger. Baker has up to one hundred people assigned to intelligent completions projects and has acquired in-house fiber optic expertise. In a 2000 meeting with APS Technology, Baker declared that it had no intention of being a sensor developer and intended to be the integrator and service provider. It currently offers no fiber optic services.

Halliburton / Petroleum Engineering Services (PES)

PES is a wholly owned subsidiary of Halliburton and has established itself as the market leader. PES has established a strong position in intelligent well completion technology. The complexity of their conventional product offering, and its reliance on downhole electronics, has created reliability issues which continue to dog them. PES is not a provider of fiber optic services.

In April 2000, Halliburton and Shell announced the establishment of a 50/50 joint venture company called WellDynamics to be based in Aberdeen, Scotland. WellDynamics combines Shell's iWellTM intelligent well technology and Halliburton's SmartWellTM intelligent completion technology.

Pruett Industries

Pruett was the first provider of DTS fiber optic temperature services in California and Indonesia and has established markets in Central America, Venezuela and Indonesia. Pruett offers a pump down fiber service in a capillary tube (see description under Schlumberger).

Schlumberger

Known to be working on fiber optic technology, Schlumberger has not had huge success fielding its products. Schlumberger has the capability to acquire fiber optic technology if its own internal efforts are unsuccessful.

Schlumberger purchased Sensa, a U.K. based company in 2001. Sensa did not specialize in sensor design but rather the integration of existing sensors and the provision of well surveillance services. Their service offering includes a DTS where a specially coated optical fiber is pumped into a quarter inch U-tube placed in the completion without actual intervention into the well and subsequent loss of production. Laser light pulses are passed down the

fiber and create reflected signals along its length, which are detected at the surface. As the reflection at each point depends on the temperature, this signals can be decoded and displayed. The pressure sensor utilizes an optical technique to measure small changes in distance between two points in a ceramic sensor head and uses the DTS for thermal compensation. The combination of temperature and pressure data can enable optimized reservoir management. Sensa also developed an acoustic sensor that could 1) be mounted on downhole pumps or motors to monitor vibration monitoring, 2) be used as a an indicator of flow rate, or 3) provide a means to monitor sand production. At the time of acquisition, Sensa was also developing a suite of similar products to be used for pipeline monitoring.

Weatherford

Weatherford purchased its downhole fiber optic technology from CiDRA, a privately held company based in Connecticut. CiDRA offered distributed temperature sensors (DTS) and single and two phase downhole flowmeter. These sensors are based upon Bragg gratings embedded in the fiber. CiDRA had secured distributor relationships with companies such as the Wood Group. CiDRA does not provide well service. In September, 2000 CiDRA secured primary vendor status and an annual consulting contract with BP-Amoco for fiber optic services. Under this contract CiDRA is now responsible for the identification of new technologies such as which could be potentially combined with their own product line. Weatherford's SubTech division also offers traditional pressure and temperature gauges.

Wood Group

The Wood Group is primarily a service provider involved in conventional gauge instrumentation, but is able to offer fiber optic services as a distributor for CiDRA.

There are several options for clients seeking fiber optic pressure and temperature technology. CiDRA and Schlumberger(Sensa) are working on flow sensors that will give them a competitive edge. APS's Downhole Fluid Analyzer technology provides the critical piece of the reservoir production puzzle

<u>Company</u>	<u>Dist. Temp.</u>	<u>Pressure</u>	<u>Flow</u>	<u>Water Cut</u>	<u>Multi- phase</u>
ABB	✓	✓			
Baker					
Schlumberger	✓	✓	under dev.		
Sensor Dynamics	✓	✓	?		
Weatherford	✓	✓	✓	✓	?
- Nova	✓	✓			
- Pruett Intl.	✓	Weatherford & capillary			
Wood Group	✓	✓			

Table 3.1: Downhole Fiber Optic Sensors Offered by Service Providers

in terms of enabling the determination of fluid fractions in combination with temperature, pressure and fluid flow all without the use of active downhole components.

3.3 Market Strategy

The objective of APS Technology's PetroMax project is to establish APS as a market leader in downhole multiphase sensor technology by:

- developing a reliable and accurate downhole multiphase fluid sensor,
- partnering with service providers,
- combining PetroMax with their sensors where appropriate, and
- delivering interpretative services to clients utilizing networked communications and centralized data processing.

The PetroMax commercial product will be comprised of the following elements:

1. A downhole tool which would typically consist of a length of production tubing with a precision mounted optic sensor containing two opposing lenses, each connected by a single optical fiber to the surface equipment.

2. A fiber optic cable connecting the downhole tool to the surface. A third party with whose own sensors PetroMax will be combined will typically provide this cable.
3. A wellsite surface computer and spectrograph linked by telecommunications to an APS office. Proprietary analytical software will be installed on the computer.

Chapter 4

Conclusion

4.1 Conclusion

The goal of Phase I of the Downhole Fluid Analyzer project was to research and develop of a fiber optic sensor to measure downhole fluid fractions in real time without interfering with production. The principal design objectives that were met included:

- a small downhole presence,
- the integration of multiple downhole sensors to one surface unit,
- no downhole electronics, and
- a low system cost.

The sensor has two analytical techniques at its disposal that can differentiate between oil, water and gas in a production fluid. Bench-top and flow loop testing showed that the standard error for each method was less than 5 percent. Site specific calibration for the type of oil and expected temperatures and pressure will provide the highest accuracy, although a generic calibration can be used at a lower accuracy.

Phase I was successfully completed with basic research, flow loop testing, the production of a prototype system and issuance of a patent. A partner company for Phase II field testing was found and the results are highly anticipated.

4.2 References

Cobern, Turner, Cooper, Aust, "Preliminary Testing of a Novel Downhole Fiber Optic Fluid Analyzer," SPE 59303.

Turner, Biglin, Cooper, Aust, "Apparatus and Method for Analyzing Fluids," U.S. Patent No. 6507401.

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4.4 List of Acronyms and Abbreviations

APS	APS Technology, Inc.
FETC	Federal Energy Technology Center
NETL	National Energy Technology Laboratory
NIR	near infrared
ODU	Old Dominion University (specifically Dr. John Cooper, Department of Chemistry and his research laboratory)
PLS	Partial Least Squares
PRDA	Program Research and Development Announcement
SIMCA	Soft Independent Modelling of Class Analogy

4.5 Patentable Subject Matter

The Department of Energy requires an identification of patentable subject matter in technical reports (see Part III, Section J, Attachment B, page B-1 of contract DE-RA26-97FT34174).

1. Patentable subject matter is disclosed in this report.
2. An invention disclose has been submitted to the DOE Patent Counsel.
3. There are no patent related objections to the release of this report.

Appendix A

Final Hazardous Waste Report

Contract Info

DOE Award: DE-AC26-98FT40481
Report Date: December, 2002
Contractor: APS Technology
800 Corporate Row
Cromwell, CT 06416

Hazardous Wastes

No hazardous wastes, as defined under Title 40 of the Code of Federal Regulations, Part 261, Subpart D, were generated in the performance of this contract.

Appendix B

Downhole Fluid Analyzer Patent



US006507401B1

(12) **United States Patent**
Turner et al.

(10) **Patent No.: US 6,507,401 B1**
(45) **Date of Patent: Jan. 14, 2003**

(54) **APPARATUS AND METHOD FOR
ANALYZING FLUIDS**

(75) Inventors: **William Edward Turner**, Palmyra, PA
(US); **Denis P. Biglin, Jr.**, Glastonbury,
CT (US); **John B. Cooper**, Virginia
Beach; **Jeffrey F. Aust**, Chesapeake,
both of VA (US)

(73) Assignees: **APS Technology, Inc.**, Cromwell, CT
(US); **Old Dominion University
Research Foundation**, Norfolk, VA
(US)

(*) Notice: Subject to any disclaimer, the term of this
patent is extended or adjusted under 35
U.S.C. 154(b) by 0 days.

(21) Appl. No.: **09/453,003**

(22) Filed: **Dec. 2, 1999**

(51) **Int. Cl.**⁷ **G01N 21/64**

(52) **U.S. Cl.** **356/436; 356/417**

(58) **Field of Search** **356/70, 317, 417**

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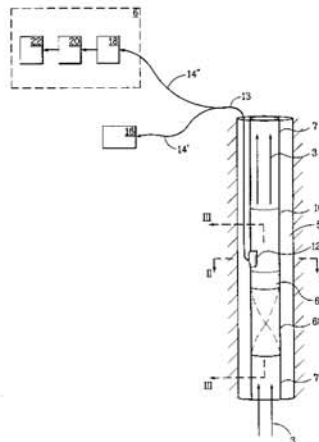
Primary Examiner—Richard A. Rosenberger

(74) *Attorney, Agent, or Firm*—Woodcock Washburn LLP

(57) **ABSTRACT**

A method and apparatus for determining the concentration
of a constituent in a fluid by directing a beam of light into
the fluid and sensing the intensity of components of the light
emerging from the fluid at various wavelengths. The light
emerging from the fluid can be light that has been attenuated
by absorption or induced by fluorescent radiation. The effect
of scattering on the light is minimized by normalizing the
component intensities, which are then applied to an algo-
rithm incorporating weighting factors that weighs the influ-
ence that the intensity at each wavelength has on the
determination of the concentration of the constituent for
which the algorithm was developed. The algorithm is devel-
oped by a regression analysis based upon a plurality of
known mixtures containing various concentrations of the
constituent of interest.

53 Claims, 13 Drawing Sheets



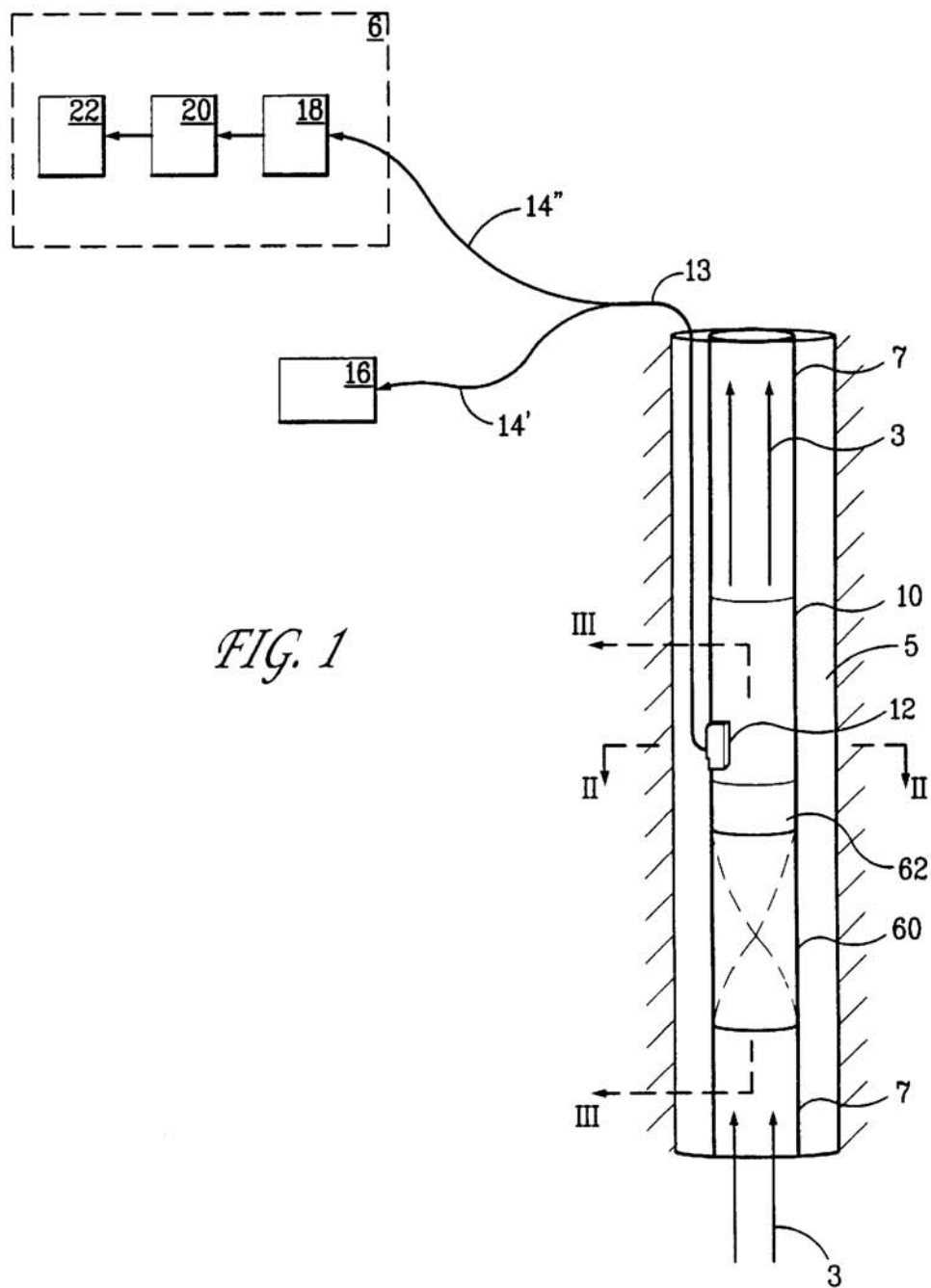
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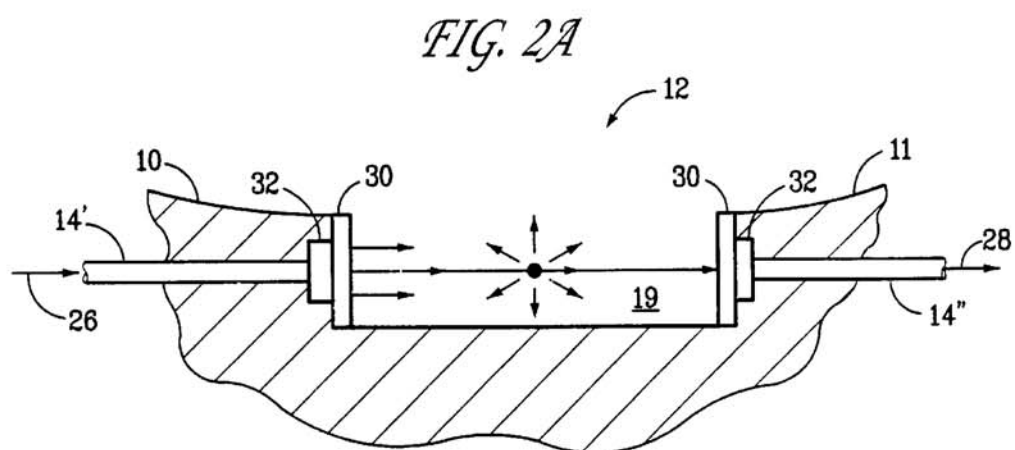
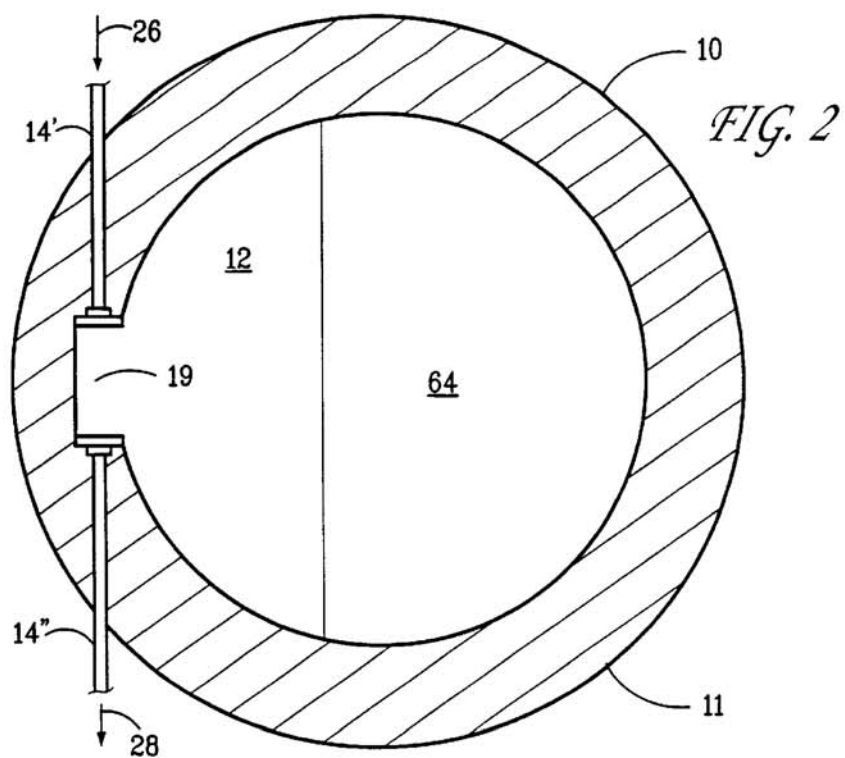
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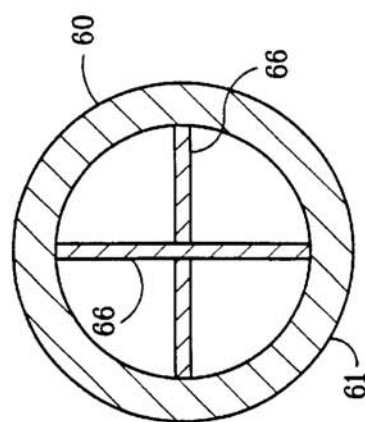
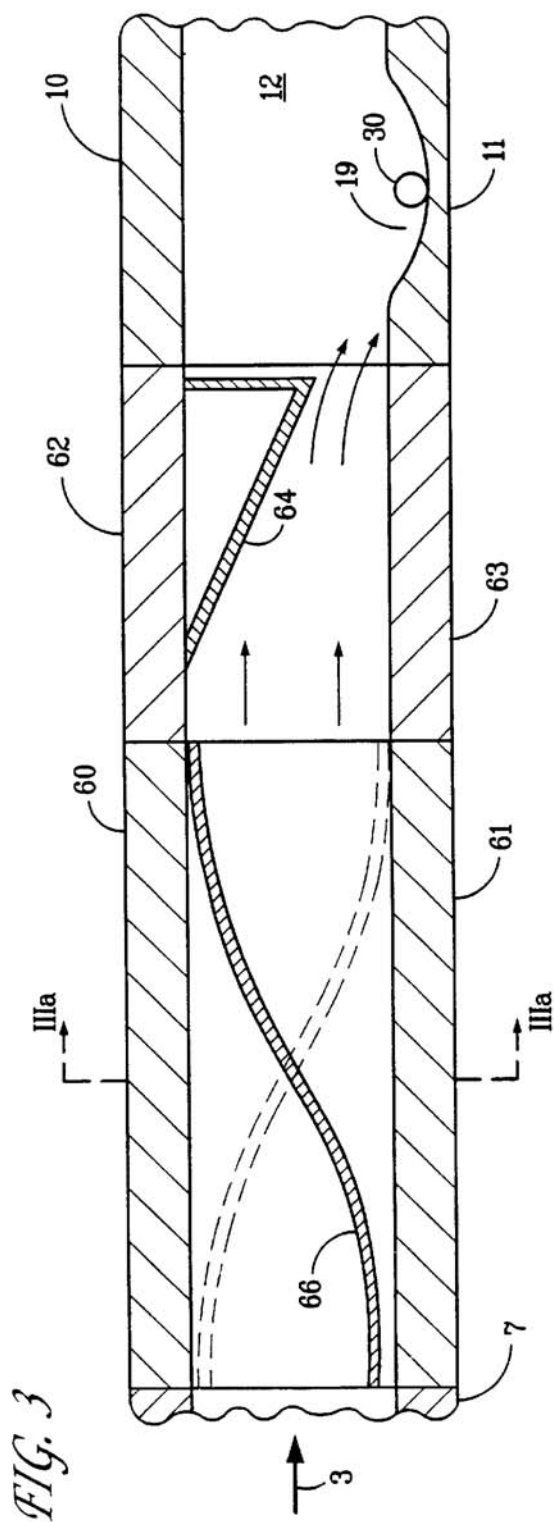
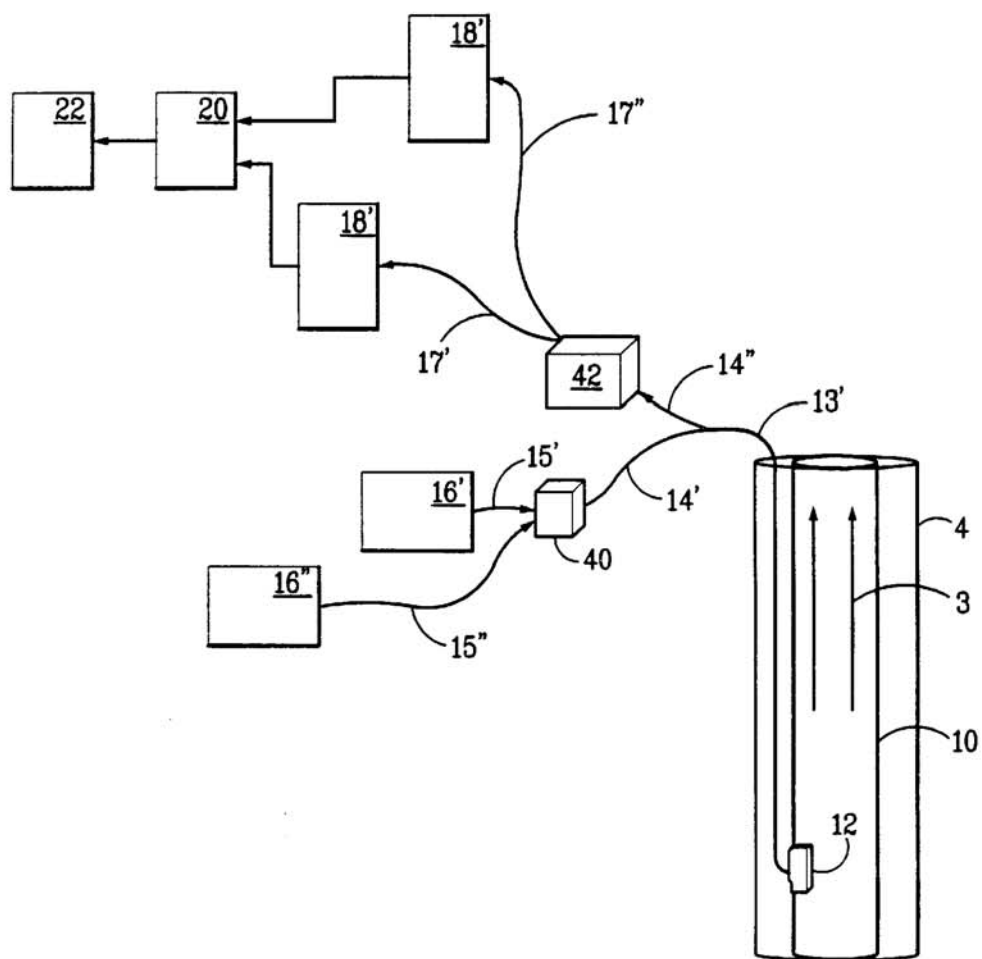


FIG. 3A

FIG. 4



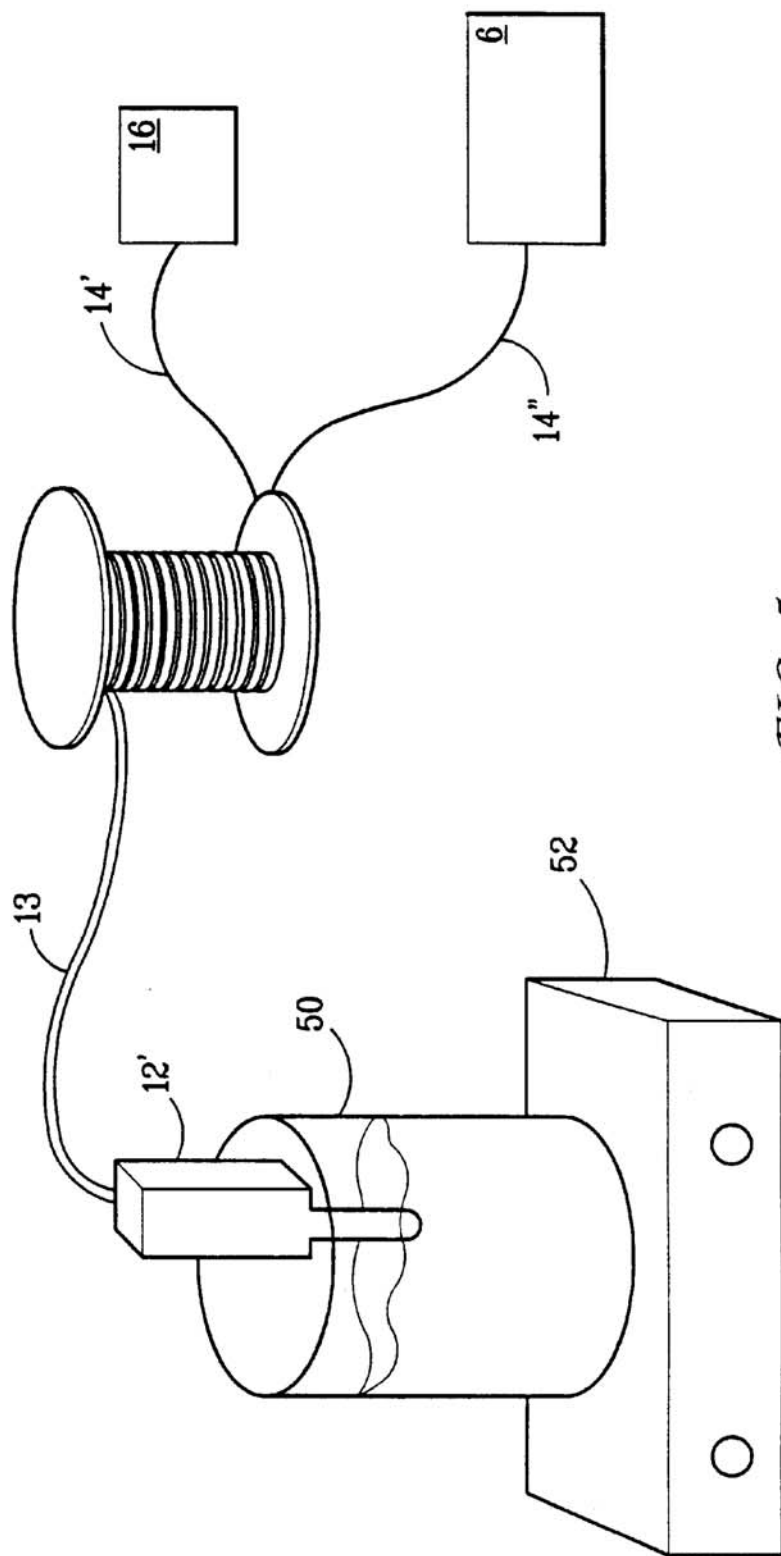


FIG. 5

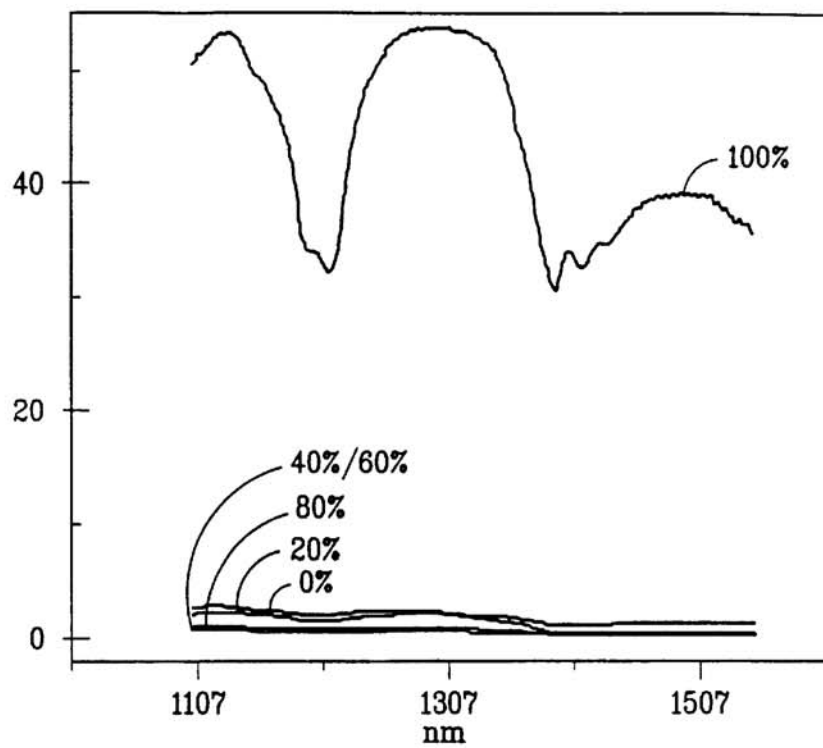
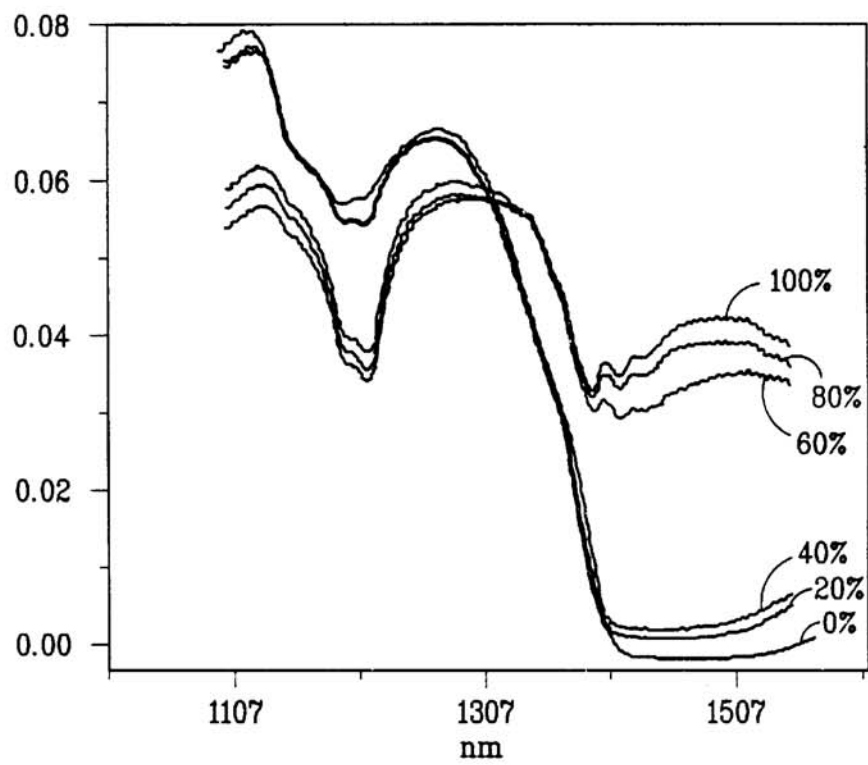
FIG. 6*FIG. 7*

FIG. 8

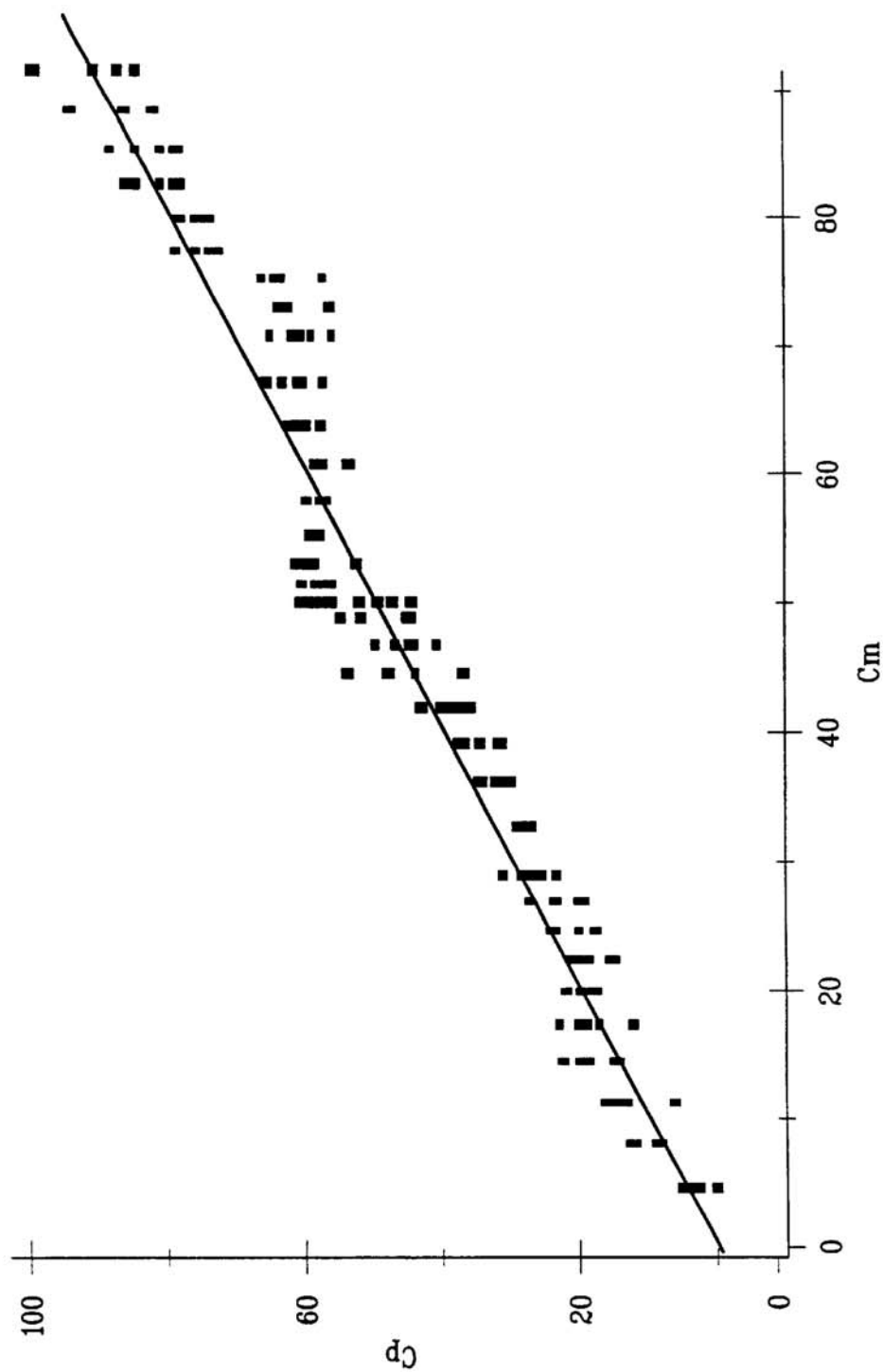
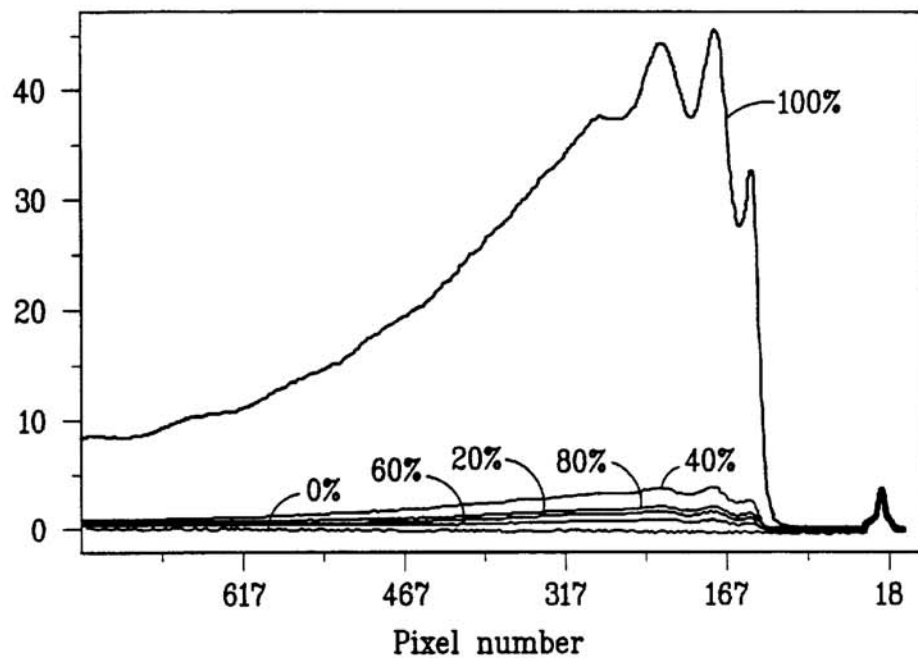
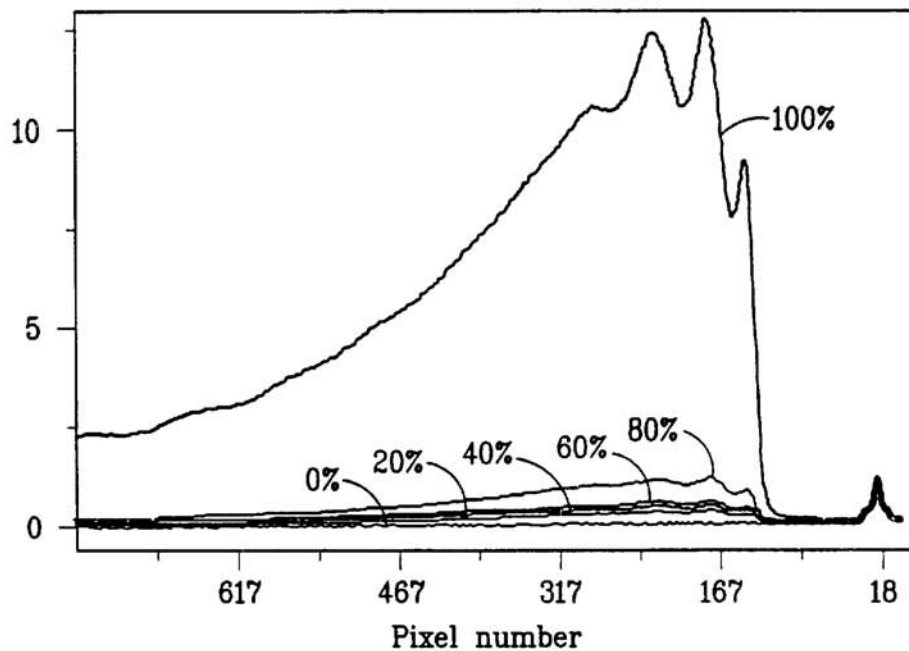


FIG. 9*FIG. 10*

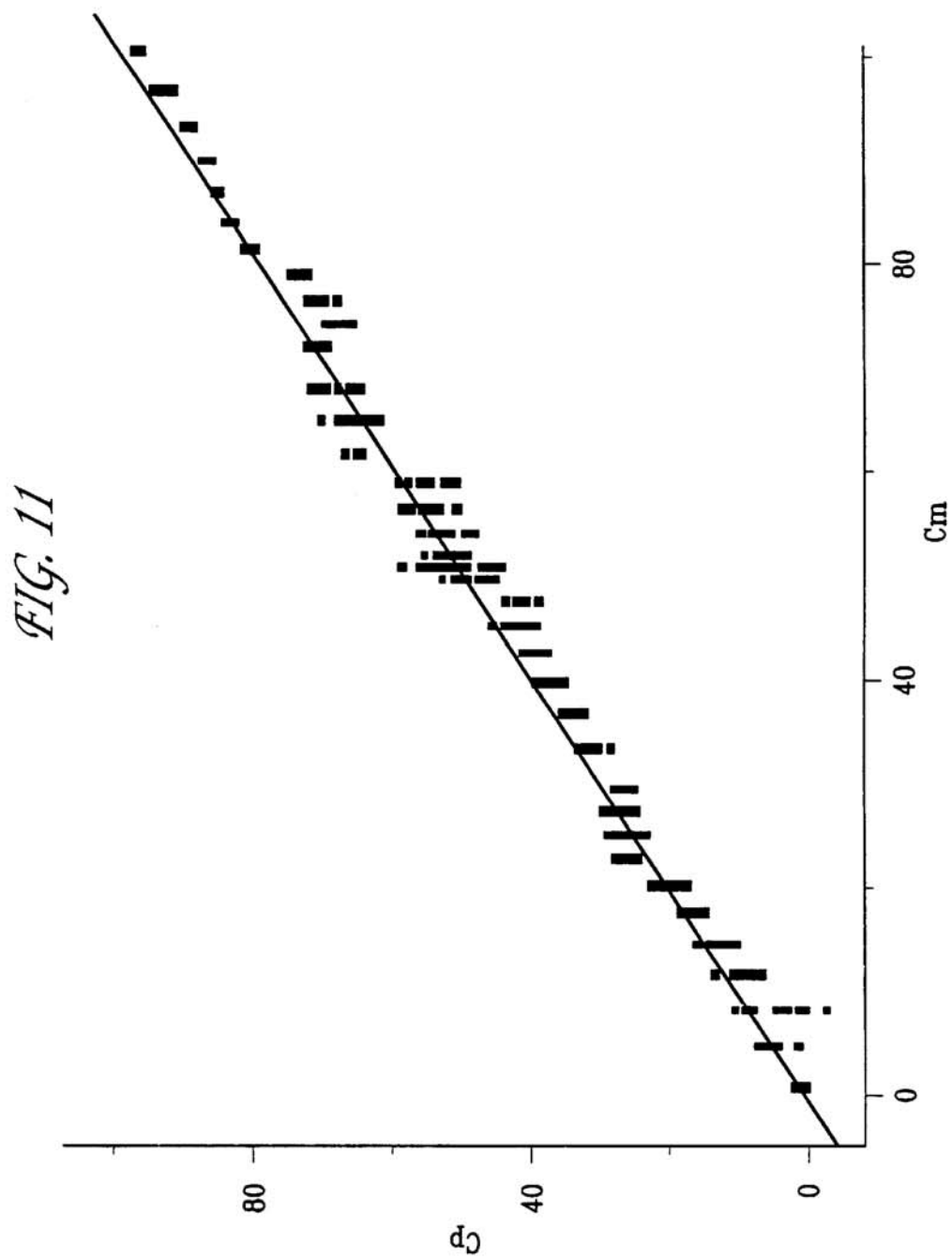


FIG. 12

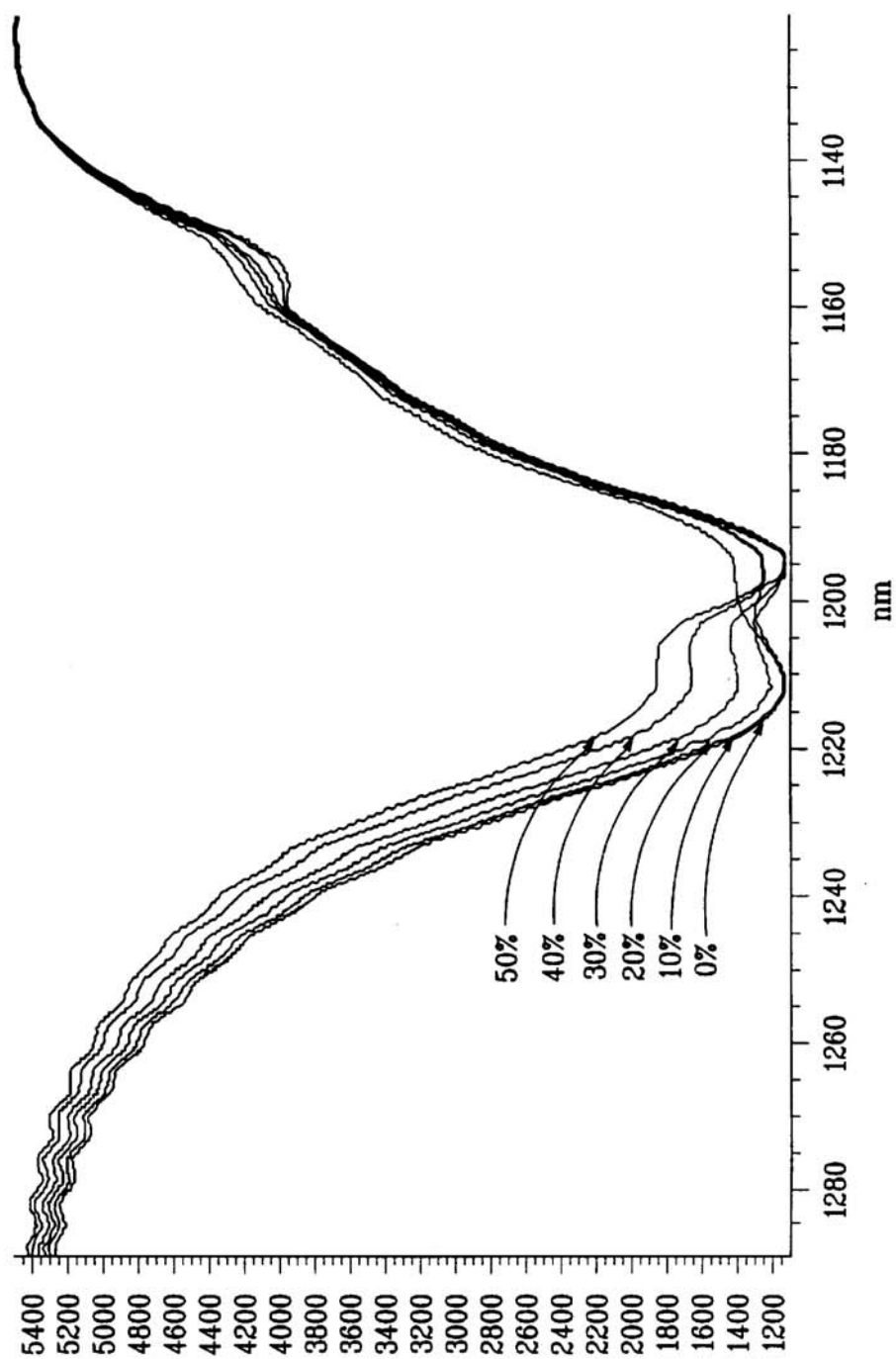


FIG. 14

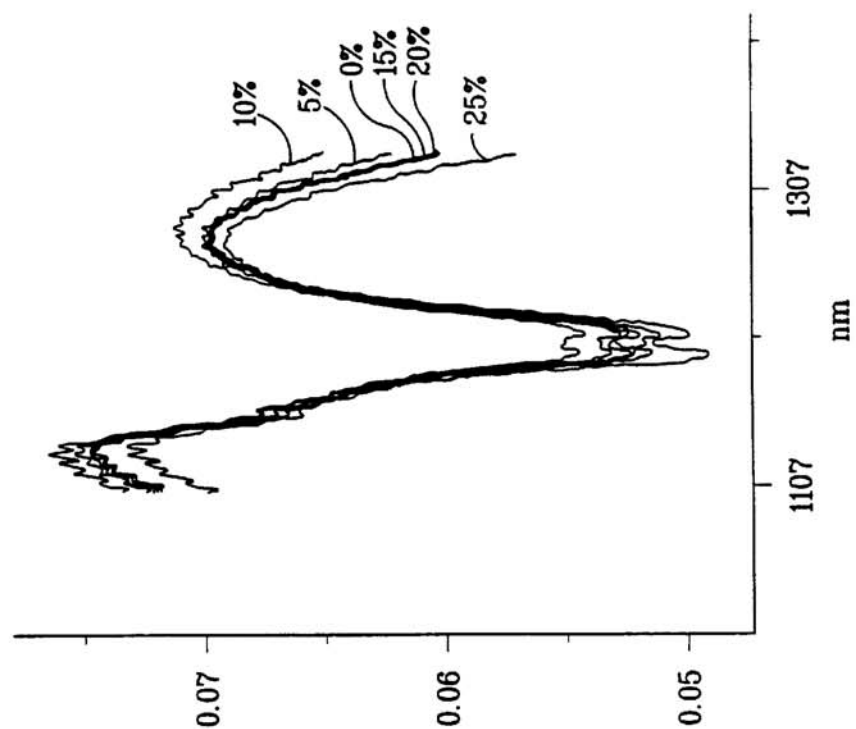


FIG. 13

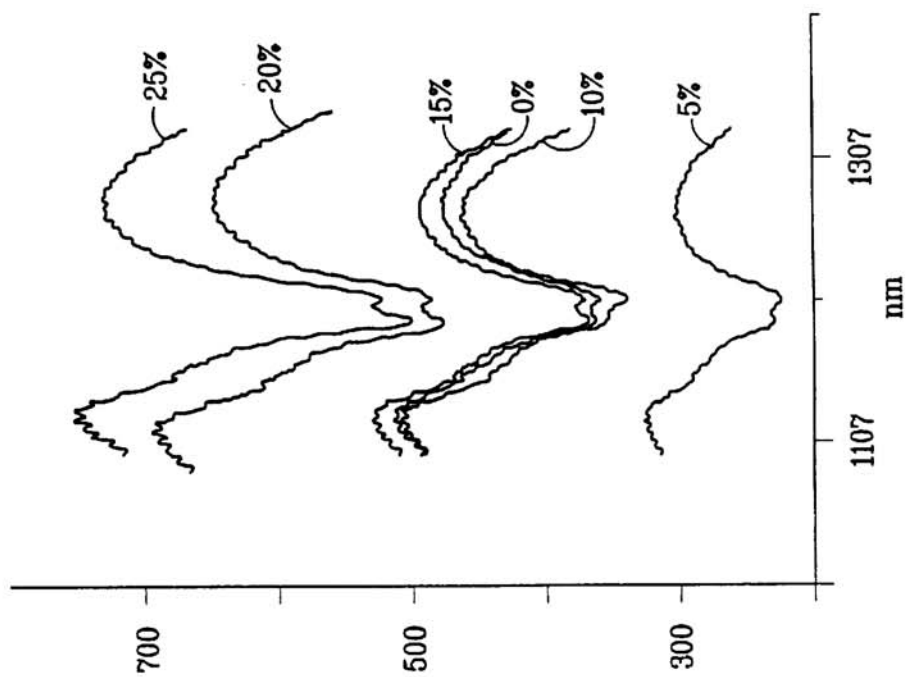


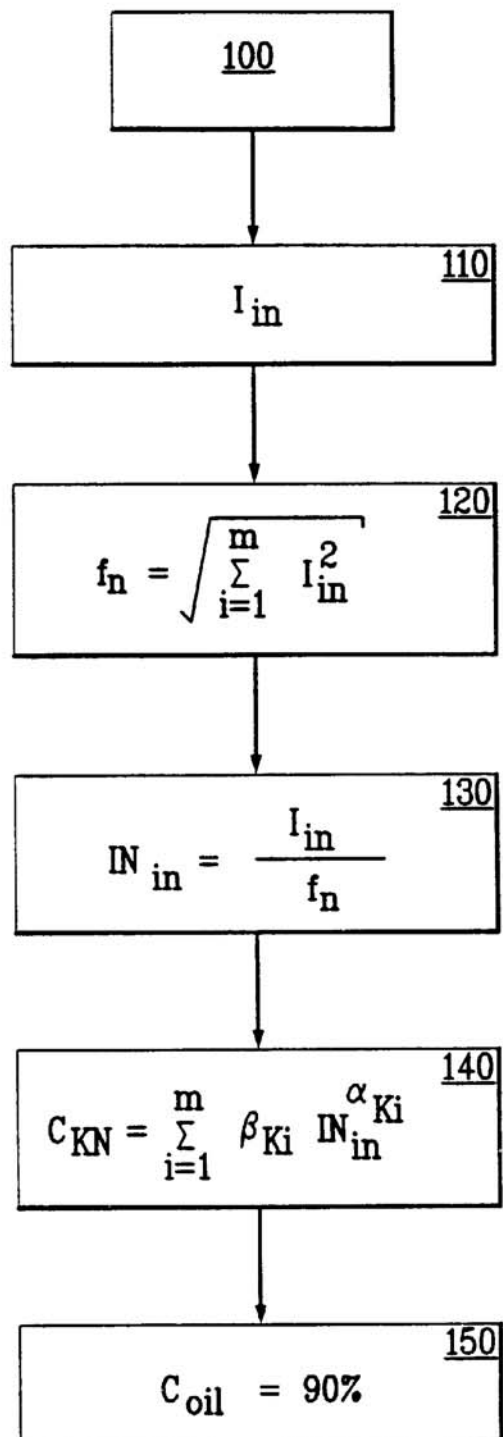
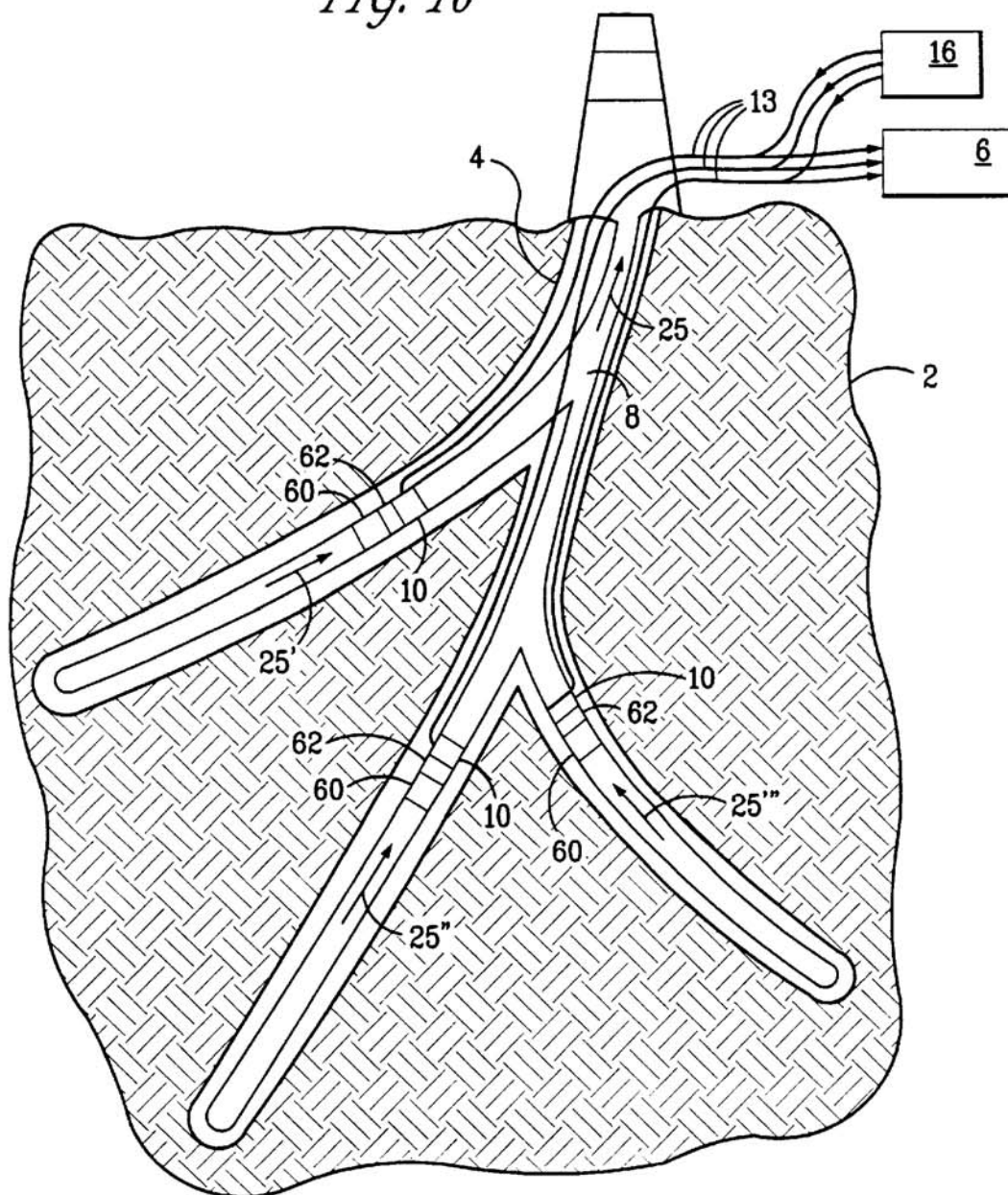
FIG. 15

FIG. 16



APPARATUS AND METHOD FOR ANALYZING FLUIDS

FIELD OF THE INVENTION

The current invention is directed to the analysis of fluids. More specifically, the current invention is directed to the compositional analysis of fluids, such as fluids produced by oil wells, that contain constituents that fluoresce and/or absorb radiation, such as near-infrared radiation.

BACKGROUND OF THE INVENTION

Monitoring of the fluids produced by an oil well, such as compositional analysis, provides valuable information that allows production to be optimized. In the past, such monitoring was performed by analyzing fluid samples brought to the surface, typically using techniques such as ultraviolet-visible (UV-Vis) absorbance spectroscopy, infrared (IR) absorbance spectroscopy, UV fluorescence spectroscopy, nuclear magnetic resonance spectroscopy, mass spectrometry, and gas chromatography.

Unfortunately, these traditional surface fluid analysis techniques are of limited value in many wells created using modern drilling and production methods. This is so because modern methods often result in the creation of complex and/or difficult to monitor wells, such as multizone, horizontal, or multilateral wells. In such wells, fluid produced from different zones of the well may be combined downhole so that the fluid discharged at the surface is a mixture. Analysis of this mixture provides little information concerning the component of the fluid production associated with any of the individual zones of the well, which is necessary to maximize the overall production of oil while minimizing the production of water. For example, if one zone were producing fluid with a high water content, a control device could be operated to limit or cease production from that zone. Subsurface monitoring at the source is also advantageous where accurate knowledge of various field's production rates are required. For example, in subsea applications, fluid from different reservoirs may be combined at a subsea manifold. Production monitoring at this point is desirable to allow the operator to make control decisions regarding individual wells.

Another disadvantage of surface techniques is that they analyze the fluid after it has flowed through a long production tubing, which can alter the phase properties of the fluid (e.g., induce slugging). By contrast, downhole analysis provides real time data on conditions occurring at the point of production in the well.

Consequently, it would be desirable to provide a system and method for analyzing fluid produced in each individual zone of the well prior to intermixing—that is, in a downhole environment.

The ability to remotely sense the presence of certain fluids, such as oil, in a flowing stream, is also desirable in situations other than in oil wells. For example, it is sometimes desirable to determine when a fluid, such as discharge water, that should not contain oil has become contaminated with oil. Consequently, it would be desirable to provide a system and method for analyzing the presence of certain fluids in a flowing stream.

When light strikes a fluid, several phenomena may occur. A portion of the light may be reflected from the surface, while another portion will enter the fluid. The portion of the light entering the fluid may be transmitted through the fluid

or subjected to scattering or absorption. Very often, all of these mechanisms occur simultaneously.

Light may scatter as a result of several different mechanisms. If more than one phase is present in the fluid, light will be scattered by reflection and refraction at the interfaces between the phases. Scattering will also occur as a result of the Rayleigh mechanism. Light scattered by the Rayleigh mechanism has the same wavelength as that of the incident light. In some substances, such as oil, scattering also occurs by the Raman phenomenon. Raman scattering produces extremely low intensity light (relative to the intensity of the incident light) having wavelengths both above and below that of the incident light, so that even monochromatic light yields scattered light in a range of wavelengths. Thus, when analyzed by a spectrograph, Raman scattering produces lines on both sides of the Rayleigh line that are a characteristic of the substance and upon which the light is incident can be used its composition.

Previously, it has been proposed to use Raman scattering to determine the composition of certain types of hydrocarbons in refineries, such as disclosed in U.S. Pat. No. 4,620, 284 (Schnell et al.). However, Raman analysis cannot be used to determine the composition of a mixture of crude oil and water, such as that flowing through a well, for two reasons. First, crude oil is highly fluorescent so the fluorescent radiation, which has a longer wavelength than the incident light, would overwhelm the Raman signal even when using a near infrared excitation source. Second, the light emitted as a result of Raman scattering is too low in intensity to be transmitted to the surface for analysis, while the down hole environment is too harsh to permit the use of the sensitive equipment, such as a spectrograph and charged couple device, necessary to conduct a Raman analysis down hole.

In addition to scattering, a portion of the light entering the fluid may be absorbed. The amount of light absorbed at a given wavelength is a characteristic of the substance. Therefore, the constituents of a substance can be determined by comparing the spectrum of the light directed into the fluid with that of the light that has been transmitted through it so as to determine the spectrum of the light absorbed by the fluid. This spectrum may be expressed, for example, as $-\log_{10}$ of the ratio of the light directed to the fluid and the light transmitted through the fluid. Although compositional analyses using absorption have been proposed in the past, they suffer from the fact that the intensity of the light transmitted through the fluid depends on scattering, as well as absorption. Whereas absorption is primarily a function of the constituents of the fluid, scattering also depends on the physical form of those constituents. For example, in an emulsion, such as a mixture of water and oil, the more finely dispersed the oil droplets the greater the scattering. The increase in scattering associated with the reduction in droplet size will reduce the intensity of the transmitted light, despite the fact that the composition of the fluid, in a quantitative sense, has remained unchanged. Scattering can, therefore, lead to significant errors in systems measuring the absorption spectra of the fluid.

U.S. Pat. No. 4,994,671 (Safinya et al.) discloses a method for analyzing the composition of fluid in a well by suspending within the well a tool that contains a spectrograph and an incandescent tungsten-halogen lamp. The lamp is characterized as being relatively bright in the 1000 to 2500 nm range and down to about 500 nm and having acceptable emissions from 350 to 500 nm. The lamp directs light onto a sample of fluid that is admitted into the tool. Different sections of a fiber optic bundle receive the light transmitted across the

fluid sample, as well as the light back-scattered from the sample. The spectra of both the transmitted light and the back scattered light are measured by a spectrograph and the data are digitized and transmitted electronically to a computer at the surface. Two absorption spectra for the fluid are determined by dividing the transmitted light spectrum and the back scattered light spectrum by the spectrum of the source light. If the fluid is sufficiently transparent to transmit an adequate amount of light through it, Safinya recommends the use of the transmitted light; otherwise the back-scattered light may be used. The computer determines the constituents of the fluid sample by comparing the transmitted or back-scattered absorption spectra to a data base containing reference spectra for water, gas and various types of oils, and using a least squares or principal component analysis method. Since the spectra may vary with the temperature and pressure, Safinya discloses that in order to obtain an accurate analysis, the data base should contain reference spectra for the various constituents at a variety of pressures and temperatures. Unfortunately, Safinya's method suffers from a variety of drawbacks that have made it unsuitable for use in practical applications.

First, as indicated in U.S. Pat. No. 5,266,800 (Mullins), the computations necessary to perform the analysis taught by Safinya are computationally intensive and required an extensive data base of spectra for water, gas and oils.

Second, and perhaps more importantly, Safinya does not account for the effect of variations arising from scattering. The flow of a multicomponent fluid (e.g., oil, water and gas) through a production well has very complex multiphase properties. Variations will occur not only in terms of the relative proportion of the constituents but also in multiphase characteristics, such as droplet or bubble size and the composition of the continuous and dispersed phases (e.g., oil and gas bubbles dispersed in water, oil droplets dispersed in gases, etc.). Additionally, there may be particulate matter suspended in the fluid, which can add to the scattering. As discussed above, variations in these physical characteristics of the fluid will cause variations in the intensity of the transmitted or back scattered light that, according to Safinya's method, will cause an apparent, but erroneous, change in the composition of the fluid. For example, suppose that the spectrum is obtained of a fluid flowing through a well that is initially a 50/50 mixture of oil and water, with the water occurring in relatively large droplets. Further suppose, although this is not by any means to be expected, that comparison to the spectra in the data base using Safinya's method results in the correct determination of the composition. If the fluid remains a 50/50 mixture but the water and oil become more finely dispersed, the intensity of the transmitted light will decrease at all wave lengths, including the intensity of the light in the wave lengths associated with water, which will be interpreted as a greater absorption in the water-associated wave lengths. This, in turn, will lead to the erroneous conclusion that the concentration of water in the fluid has increased.

U.S. Pat. No. 5,166,747 (Schroeder) recognizes that scattering in Safinya's method can cause the intensity of the transmitted light to undergo swings so wide that they cannot be handled by the spectrograph. Schroeder's approach to this challenge was, through an opto/mechanical means, to redistribute the composition of the transmitted light reaching the spectral analyzer. Through optical diffusers or misalignment of the input and output fibers, the spectral analyzer received less directly transmitted light and more forward scattered light. The forward scattered light still indicated the absorbance of the sample, but it is of reduced intensity. The

weaker signal was an acceptable tradeoff for signal stability. However, this approach is not feasible where the light source and spectral analyzer are at the surface. In such circumstances, the signal intensity is of paramount concern due to the losses that can occur if the sampling portion of the sensor is many kilometers from the surface. Also, the potential for errors due to scatter will still occur and, perhaps, be even greater than those associated with Safinya's method because the strength of the original signal is reduced.

SUMMARY OF THE INVENTION

It is an object of the current invention to provide a method for determining the concentration of a constituent, such as oil or gas, in a fluid flowing in a remote location, such as downhole in an oil well. This and other objects is accomplished in a method of determining the concentration of at least one predetermined constituent in a fluid flowing through a downhole portion a well, comprising the steps of (i) generating a beam of light, (ii) directing the beam of light into the fluid flowing through the downhole portion of the well so as to cause light to emerge from the fluid, the emerging light having been scattered by the fluid and comprised of components each of which has a different wavelength, (iii) transmitting at least a portion of the emerging light to a location proximate to the surface of the earth, (iv) measuring the intensity of each of at least a portion of the components of the transmitted light, each of the light components in the portion of light components having a wavelength falling within a predetermined range of wavelengths, the light component intensity measurements being conducted at the location proximate the surface, (v) normalizing at least those of the measured light component intensities having selected wavelengths so as to reduce the effect of the scattering of the light components on the measured intensities, (vi) exponentially raising and then multiplying each of the normalized light component intensities at the selected wavelengths by a predetermined weighting factor based upon its respective wavelength, and (vii) summing the weighted and normalized light component intensities at the selected wavelengths so as to calculate the concentration of the constituent.

In one embodiment, the method further comprises the step of determining the weighting factors by (i) directing a calibration beam of light into a plurality of fluid calibration mixtures so as to cause light to emerge from each of the calibration mixtures that is comprised of components each of which has a different wavelength, with each of the calibration mixtures containing predetermined varying concentrations of the constituent, (ii) measuring the intensity of each of the components of the light emerging from the calibration mixtures having a wavelength falling within the predetermined range of wavelengths, (iii) normalizing at least a selected portion of the measured intensities of the light components emerging from the calibration mixtures, and (iv) performing a regression analysis on the normalized intensities of the calibration mixtures so as to determine the weighting factors.

The invention also encompasses an apparatus for determining the concentration of a predetermined constituent in a fluid flowing through a downhole portion a well, comprising (i) means for generating a beam of light, (ii) means for directing the beam of light into the fluid flowing through the downhole portion of the well so as to cause light to emerge from the fluid which light is comprised of components each of which having a different wavelength and that has been scattered by the fluid prior to emerging therefrom, (iii)

means for transmitting at least a portion of the emerging light to a location remote from the downhole portion of the well, (iv) means for measuring the intensity of each of the components of the transmitted light having a wavelength falling within a predetermined range of wavelengths at the remote location, (v) means for exponentially raising and normalizing at least a selected portion of the measured component intensities so as to minimize the effect of the scattering to the light emerging from the fluid has been subjected on the component intensities, (vi) means for determining the concentration of the constituent based upon the normalized component intensities.

In one embodiment, the apparatus further comprises a computer, and the means for means for normalizing the selected portion of the measured component intensities and the means for determining the concentration of the constituents comprises software programmed into the computer.

BRIEF DESCRIPTION OF THE DRAWINGS

FIG. 1 is schematic diagram of the fluid analysis system according to the current invention installed in a section of pipe.

FIG. 2 is a transverse cross-section through the sensor shown in FIG. 1, taken along line II—II.

FIG. 2a is a detailed view of the sensor shown in FIG. 2.

FIG. 3 is a longitudinal cross-section taken along line III—III shown in FIG. 2.

FIG. 3a is a transverse cross-section through the mixer shown in FIG. 3, taken along line IIIa—IIIa.

FIG. 4 is schematic diagram of an alternate embodiment of the fluid analysis system according to the current invention installed in a section of pipe.

FIG. 5 is schematic diagram of the equipment for performing a calibration according to the current invention.

FIG. 6 is a plot of measured light intensity versus wavelength for oil/water mixtures ranging from 0 to 100% oil using the near-IR attenuation method. The X-axis is the light wavelength in nanometers. The Y-axis is the instrument's response in analog to digital converter counts.

FIG. 7 is a plot of normalized light intensity versus wavelength based on the data shown in FIG. 6. The X-axis is the light wavelength in nanometers. The Y-axis is the instrument's response in analog to digital converter counts.

FIG. 8 is a plot of predicted concentration C_p versus measured concentration C_m for oil using an algorithm according to the current invention based on the data shown in FIG. 6.

FIG. 9 is a plot of measured light intensity versus wavelength for oil/water mixtures ranging from 0 to 100% oil using the near-IR fluorescence method. The X-axis is the wavelength in Pixel number. The Y-axis is the instrument's response in arbitrary units.

FIG. 10 is a plot of normalized light intensity versus wavelength based on the data shown in FIG. 9. The X-axis is the wavelength in Pixel number. The Y-axis is the response in arbitrary units.

FIG. 11 is a plot of predicted concentration C_p versus measured concentration C_m for oil using an algorithm according to the current invention based on the data shown in FIG. 9.

FIG. 12 is a plot of measured light intensity versus wavelength for isooctane/oil/water mixtures ranging from 0–50% isooctane using the near-IR attenuation method. The X-axis is the wavelength in nanometers. The Y-axis is the response in arbitrary units.

FIG. 13 is a plot of measured light intensity versus wavelength for isooctane/oil/water mixtures ranging from 0–25% isooctane using the near-IR attenuation method. The X-axis is the wavelength in nanometers. The Y-axis is the instrument's response in arbitrary units.

FIG. 14 is a plot of normalized light intensity versus wavelength based on the data shown in FIG. 13. The X-axis is the wavelength in nanometers. The Y-axis is the response in arbitrary units.

FIG. 15 is a schematic diagram showing the software programed into the computer portion of the fluid analyzer shown in FIG. 1.

FIG. 16 is a schematic diagram of a multilateral well into which downhole fluid analyzers according to the current invention have been incorporated.

DESCRIPTION OF THE PREFERRED EMBODIMENT

According to the current invention, the concentration of certain constituents in a fluid can be determined by directing light to the fluid, sensing the light emerging from the fluid, measuring the relative intensity of the components of the sensed light at selected wavelengths, and then treating these relative component intensities according to an algorithm, developed for the particular fluid being analyzed, that weights the component intensities using predetermined weighting factors based on the wavelength associated with each component. As such, the method of the current invention realizes four important advantages over prior methods of analysis. First, once the algorithm has been properly generated, only the components of the light intensity at wavelengths within a predetermined range need be analyzed—that is, it is not necessary to analyze the entire spectrum of the light emerging from the fluid being analyzed. Second, it is not necessary to maintain a large data base of spectra of fluids of known compositions. Third, it is not necessary to compare the measured data to a data base of the spectra of fluids of known composition. Fourth, the effects of scattering are eliminated by normalizing the individual intensities of the emerging light at each of the selected wavelengths.

According to the current invention, the algorithm to be used in calculating the concentration of a particular constituent can be developed by measuring the intensity of the components of the light emerging from various known mixtures of the fluids to be analyzed over a range of wavelengths. These mixtures are formed by varying the concentration of the particular constituents in the fluid in a known way. After normalizing the component intensities, a regression analysis, such as a partial least squares regression, is used to determine the weighting factors that indicate the weight to be attached to the normalized component intensity at each wavelength. Based on these weighting factors, an algorithm is developed for calculating the concentration of the constituent.

As discussed in detail below, in the practice of the current invention, either the phenomenon associated with the attenuation of radiation (e.g., as a result of absorption) or the excitation of fluorescent radiation may be used to determine the concentration of a particular constituent of the fluid. In particular, a beam of light is directed to the fluid. As a result of its passing through the fluid, the emerging light may be attenuated as a result of absorption and/or scattering. In addition, the light may induce fluorescence. Thus, compared to the light directed to the fluid, the light emerging from the fluid will be attenuated and/or comprises fluorescent radia-

tion. The analysis of the emerging light permits the determination of concentration.

Whether the attenuation or fluorescence phenomenon is used to determine concentration depends on the constituent whose concentration is to be determined. The concentration of oil, for example, can be determined using either method. The concentrations of water and natural gas, which do not fluoresce, can only be directly determined using the attenuation method. When using the attenuation method, the light directed to the fluid should encompass a broad range of wavelengths. However, when the fluorescence method is used, the wavelength of the light directed to the fluid should lie within a narrow range, and preferably the light should be monochromatic. In some circumstances, such as when remotely determining the concentration of mixtures of oil, water and/or gas using the attenuation method, the light directed to the fluid is preferably in the near infrared ("near-IR") range—that is, having a wavelength from approximately 800 nm to 3000 nm.

In both the attenuation and fluorescence method, analysis of the emerging light is based on measurement of the intensity of its components at various predetermined wavelengths. Importantly, the measured intensities are normalized to minimize the errors resulting from scattering. When the attenuation method is used, each of the measured component intensities is preferably normalized by dividing it by an intensity characteristic associated with all, or at least most, of the components of the emerging light within a predetermined range of wavelength. When the fluorescence method is used, normalization is preferably accomplished by dividing the measured component intensities by an intensity characteristic of the laser light used to induce the fluorescence.

I. Analysis Based on Light Attenuation

As discussed above, as the light travels through the fluid, a variety of phenomena arise. Some of the components of the light at discrete wavelengths (or wavelength ranges) are absorbed depending to the chemical constitution of the fluid. In addition, some of the light is scattered in all directions due to the physical constitution of the fluid (emulsions, bubbles, binary mixtures, etc.), and some of the light is transmitted. Thus, the light entering the fluid is either absorbed, scattered, or transmitted through it.

The amount of light absorbed at a given wavelength is a characteristic of the substance through which the light travels. While the light that is absorbed cannot be directly measured, the light emerging from the fluid can be measured. As a result of absorption, the intensity of the emerging light will be reduced or "attenuated." The amount of attenuation of the light for any given composition will vary as a function of its wavelength. Thus, for a given source light spectrum, evaluating the intensity of the components of the emerging light at selected wavelengths provides information about the composition of the fluid.

Scattering also causes attenuation of the light intensity. However, whereas attenuation as a result of absorption causes relative changes in the light intensity as a function of wavelength, i.e., there is a change in the shape of the broadband spectrum, attenuation due to the scattering of light is much less dependent on its absolute wavelength; it has a slow, monotonic dependence on wavelength. The scattering of the light, therefore, results in a drop in the light intensity at all wavelengths so that at any given wavelength, the intensity does not change appreciably relative to the intensity at other wavelengths. For fluids which both scatter and absorb light, the net result is that even though the absolute magnitude of the collected light as a function of

wavelength it is not uniquely related to chemical composition, the relative light intensity as a function of wavelength is related to the chemical composition.

Therefore, according to the current invention, the effects of scattering can be effectively eliminated by normalizing the intensity of the collected light components at each wavelength utilized in the algorithm to the intensity over a broad band of wavelengths. Thus, an analysis of the relative attenuated components of the light emerging from the fluid can be used to accurately determine the concentration of its constituents, despite the simultaneous presence of scattering.

When the attenuation method of analysis is used, the light directed to the fluid preferably encompasses a broad band of wavelengths that, most preferably, is sufficiently broad to encompass all, or at least most, of the major absorption peaks associated with the constituents whose concentration is to be determined. For example, oil and natural gas have absorption peaks at 1200 nm and 1400 nm. Water has absorption peaks at 1150 nm and 1450 nm. Thus, the light should have wavelengths that at least encompass the 300 nm range as associated with these peaks (i.e., from 1150 nm to 1450 nm). Thus, in the case of mixtures of oil, water, and gas, the light directed to the fluid preferably has wavelengths in the near-IR range—that is, having a wavelength from approximately 800 nm to 3000 nm. More preferably, the light is in the range of about 900 nm to 2000 nm, more preferably still in the range of about 1100 nm to 1800 nm, and most preferably in the range of about 1100 nm to 1550 nm.

II. Analysis Based on Fluorescence

Depending upon on the material, the absorption of light may not only result in attenuation of the light intensity at certain wavelengths but may also result in generation of radiation at other wavelengths, specifically, due to fluorescence. Fluorescence is a type of luminescence—that is, light emitted by a process other than combustion or incandescence. When a fluorescent substance is illuminated with light of the appropriate wavelength it absorbs energy which, in turn, excites the absorbing species to a higher energy electronic state. When the absorbing species returns to its electronic ground state, a photon of light is emitted. If the excited state from which the absorbing species decays has the same multiplicity as the ground state, the time between absorption and emission is relatively short and the process is called fluorescence. If the excited state from which the absorbing species decays has a different multiplicity from that of the ground state, the time interval is relatively long, and the process is referred to as phosphorescence. The light generated by fluorescence is always of longer wavelength than the incident light. Thus, in fluorescence, the absorption of light of one wavelength results in the emission of light of longer wavelengths.

Certain molecular arrangements within fluorescent substances, called chromophores, are the centers of fluorescent activity. Not all chromophores respond to light in the same way. In general, compounds with fused aromatic rings or compounds with a greater number of conjugated multiple bonds, such as crude oil, can fluoresce when subjected to light at longer wavelengths, specifically, in the visible to near-IR range. Less complex, low molecular weight compounds, such as the simple hydrocarbons found in natural gas, either do not fluoresce or fluoresce only at shorter wavelengths (in the ultra violet range) but not in the near-IR range. Water does not fluoresce. Other substances that do not fluoresce when excited by light in the near-IR range are sand and silt.

In general, using excitation light having shorter wavelengths will result in fluorescent radiation of greater intensity, making analysis easier. However, according to the current invention, the excitation light from the light source is generated at one location, preferably the surface, and transmitted through fiber optic cables over long distances to fluid at a remote location, such as downhole in an oil well. Light having short wavelengths, such as ultraviolet radiation, is difficult to transmit over such long distances and can result in excessive Raman scattering. By contrast, light in the near-IR range can be readily transmitted over long distances. In addition, shorter wavelength light may induce fluorescence in too many substances, making analysis of a particular constituent more difficult. In any event, near-IR excitation light causes oil, but not natural gas or water, to emit relatively intense fluorescent radiation. Consequently, according to the current invention, the concentration of oil is preferably determined using excitation light having a wavelength within or somewhat below the near-IR range.

When the fluorescence method is used, laser light having a relatively narrow wavelength band, and preferably 2 nm FWHM (i.e., full width at half maximum) or less, is directed to the fluid. Preferably, the source should emit light having wavelengths from somewhat below the near-IR range to about the mid near-IR range—that is, from about 500 nm to 1700 nm range. More preferably, the excitation light should be in the range of about the 600 nm to 1000 nm, more preferably still in the range of about the 780 nm to 900 nm, such as laser light having a wavelength of about 780 nm, 808 nm, or 852 nm.

As the laser light passes through the fluid, some of the light is absorbed by and re-emitted as fluorescent light at longer wavelengths than the absorbed light. Some of this fluorescent light is collected, along with some of the laser light that was transmitted through the fluid. For fluids that are highly scattering, the collected laser light intensity will be lower than for fluids that are not highly scattering since in the latter case a greater percentage of the laser light will be collected. Consequently, the laser light scattered by the fluid can be used as a means for monitoring its scattering characteristics.

The collected fluorescence light will be dependent on both the concentration of fluorescent species present in the fluid and the scattering properties of the fluid. As the concentration of fluorescent species increases, the collected fluorescent light will increase. As the scattering characteristics of the fluid increase, the collected fluorescent light will decrease. Thus, the influence of the scattering properties of the fluid can be corrected for by normalizing the collected fluorescent intensity to the collected laser intensity. (In some circumstances, it may also be desirable to normalize the collected laser intensity itself by the laser intensity at the surface, in order to correct for optical power fluctuations in the laser.) In any event, in the fluorescence method of analysis, evaluation of the normalized intensity of the fluorescent light emitted by the fluid can be used to accurately determine the concentration of its constituents, despite the presence of scattering.

III. Apparatus

A. Hardware

One embodiment of an apparatus according to the current invention is shown in FIG. 1 applied to an instrumented section of pipe 10, which in some applications may be incorporated into production piping 7 disposed in a well bore 5, through which the fluid 3 to be analyzed flows. Depending on the detailed components selected, each of which is discussed further below, the apparatus shown in

FIG. 1 can be optimized for use with either the attenuation or fluorescence methods of analysis.

1. Sensor

As shown in FIG. 1, the instrumented pipe section 10 comprises a sensor 12 that has been incorporated into the pipe. Although only one sensor 12 is shown in FIG. 1, it may be desirable to incorporate a number of sensors into the instrumented section 10, for example, by spacing two or more sensors circumferentially around the pipe at the same axial location and/or spacing two or more sensors axially along the pipe. The use of multiple sensors 12 will reduce errors associated with the fact that the fluid flowing through the instrumented section 10 may not be uniform across its cross-section or along the length of the section.

A diagram of one sensor 12 suitable for use in the current invention is shown in FIGS. 2 and 2a and comprises a notch 19 formed in the inner wall of the pipe section 10. Optically transparent windows 30 are formed on opposing walls of the notch 19. A focusing lens 32, to which fiber optics 14 are coupled, is located behind each window 30. The light 26 from the source 16 exits the first fiber optic 14', passes through the first lens 32, and then the first window 30. The light subsequently passes into and interacts with the fluid stream 3. As shown in FIG. 2a, the light emerging from the fluid stream passes through the second window 30 and is focused by the second lens 32 so that it is collected by the second fiber optic 14".

As shown in FIG. 1, in some applications, it may be desirable to incorporate a mixing device 60 upstream of the instrumented section 10 so as to ensure adequate mixing of the fluid 3 to be measured. As shown in FIGS. 3 and 3a, the mixer 60 may comprise a section of piping 61 incorporated into the production piping 7 and into which helically extending mixing vanes 66 have been installed to swirl the fluid, thereby ensuring adequate mixing of the constituents before they reach the instrumented section 10.

As also shown in FIG. 1, it may also be desirable in some applications to incorporate a diverter section 62 upstream of the instrumented section 10 to ensure the proper flow of fluid 3 into the notch 19. As shown in FIG. 3, the diverter 62 may comprise a section of piping 63 incorporated into the production piping 7 and into which a baffle 64 has been installed. The baffle 64 is preferably angled toward the notch 19 of the sensor 12, most preferably at an angle with respect to the axis of the piping that is equal to or greater than the angle of the sloping side wall 19 of the notch, so as to deflect at least a portion, preferably a major portion, of the fluid 3 so that it is directed into the notch 19. This not only ensures that the fluid flowing through the notch 19 is representative of the fluid 3 flowing through the production piping 7 but also ensures that the fluid in the notch is not stagnant so as to flush the notch and prevent the buildup of deposits or debris that could interfere with the operation of the sensor 10.

The sections of piping forming the mixer 60, diverter 62 and instrumented section 10 could be joined to each other, and to the production piping 7, by threaded or welded connections. Alternatively, these components could be incorporated into a single section of piping that was joined to the production piping 7 or they could be inserted directly into inside diameter of the production piping 7 itself.

When laser light is used, a filter, such as a dielectric filter (not shown), may be incorporated at the probe to filter out emission lines around the laser wavelength so as to eliminate the effect of glass Raman scattering.

2. Fiber Optic Cables

Each sensor 12 is optically connected to a light source 16 and a remote fluid analyzer 6 by a fiber optic cable 13

containing a pair of optical fibers 14' and 14". Preferably, the optical fibers, which may comprise a bundle of optical fibers, are of the multimode type. The first optical fiber 14' is coupled to a light source 16, which is preferably located at a remote location, such as the surface. The second optical fiber 14" is coupled to a fluid analyzer 6, which is also preferably located a remote location, such as the surface. Thus, the fiber optic cable 13 transmits light from the light source 16 to the sensor 12 and transmits light from the sensor to the fluid analyzer 6.

3. Light Source

When used in connection with the attenuation method, a broadband light source 16 should be used, such as a quartz tungsten halogen lamp. Preferably, the light source 16 emits light having wavelengths sufficiently broad to encompass the major absorption peaks of the constituents whose concentration is to be determined, as previously discussed. In the case of mixtures of oil, water and/or natural gas, the wavelength of the light should encompass the ranges previously discussed in section I.

When used in connection with the fluorescence method, the light source 16 should be an extremely narrow band source, and preferably be a monochromatic light source, such as a diode laser or a diode-pumped solid state (DPSS) laser. When used in circumstances requiring transmission of light over long distances, the light source 16 emits light having a wavelength in the ranges previously discussed in section II.

4. Fluid Analyzer

As shown in FIG. 1, the fluid analyzer 6 comprises a spectrographic detector 18, a computer 20, and an indicator 22. The spectrographic detector 18 includes a spectrograph for dispersing the light from the collection fiber into its component wavelengths and a detector for sensing the intensity at each of these wavelengths.

Depending on the analysis technique to be utilized, the detector may comprise an InGaAs diode array to detect the intensity at each of the dispersed wavelengths. Such an array typically has a spectral sensitivity from 900 nm to 1700 nm. The primary advantage of using an array for detection is its ability to detect the light intensity simultaneously at every detected wavelength. For scanning systems, whether of interferometric or grating type, each wavelength's intensity is detected at a different discrete time. Since downhole scattering is a temporal phenomenon, this would make the measured effect of the scattering appear to be wavelength dependent. With the use of a diode array, the simultaneous detection of intensity at all detected wavelengths ensures that the effects of scattering are common to all wavelengths and facilitates the use of a normalization method to correct for scattering.

Alternatively, in connection with fluorescence analysis methods, a charge coupled device silicon array may be used for the detector. As a further alternative when using the fluorescence method, a filter or beam splitter can be used to direct the collected laser signal to one detector while the fluorescent signal is directed to a second detector. In this case, the detectors can be single element detectors that effectively integrate the signal intensities for all of the impinging wavelengths. The output of the detector for the laser signal is proportional to the integrated laser intensity and the output of the detector for the fluorescent signal is proportional to the integrated fluorescence signal. Normalization can be performed by taking the ratio of the two detector outputs in either analog or digital form.

Regardless of the type of detector used, the computer 20 is programmed with software that allows it to read the array of intensities from the spectrographic detector 18.

Regardless of whether the attenuation or the fluorescence analysis technique is used, in operation, the output of the light source 16 is directed into the proximal end of the first fiber optic 14' located at the surface, as shown in FIG. 1. The fiber optic 14' permits the transmission of the light downhole to the remote sensor 12. The sampling portion of the remote sensor 12 is in contact with the downhole fluid stream 3 that is to be analyzed. After exiting the fiber optic 14', the source light interacts with the fluid 3, as shown in FIG. 3, causing the fluid to absorb, scatter, transmit and/or fluoresce light. Subsequently, the second fiber optic 14" collects a portion of the light which is emerging from the fluid stream 3 (which may include scattered light from the source, transmitted light, and fluorescent radiation) and transmits this light to the surface, where its intensity is detected as a function of wavelength using the spectrographic detector 18. The data from the spectrographic detector 18 is then input into the computer 20.

The computer 20 is programmed with software containing an algorithm that determines the composition of the fluid 3—that is, the concentrations of predetermined constituents, for example, the percentages of oil and water—based on the intensity of the light emerging from the fluid at one or more selected discrete wavelength or range of wavelengths, as determined by the spectrographic detector 18. These concentrations are indicated on the indicator 22, which may be a digital readout device.

An apparatus for simultaneously employing both the fluorescence and attenuation methods of analysis is shown in FIG. 4. In this case, two separate light sources 16' and 16" and two separate spectrographic detectors 18' and 18" are utilized. The first light source 16' is used for the fluorescence portion of the analysis and, as discussed above, preferably generates monochromatic light. The second light source 16" is used for the attenuation portion of the analysis and, as discussed above, preferably generates broad band light. The first spectrographic detector 18' is used for the fluorescence analysis and, as discussed above, preferably comprises a diode array. The second spectrographic detector 18" is used for fluorescence analysis and, as discussed above, preferably comprises a charged couple device.

Light from the two sources 16' and 16" may be directed by optic fibers 15' and 15" into a common optic fiber 14' by using a beam combining device 40. The beam combining device 40 may consist of a dichromatic beam splitter, a fiber optic coupler, a fiber optic multiplexer, or a similar type of device. Light from both light sources 16' and 16" is carried downhole by the common fiber optic 14' to a common sensor 12, such as that previously discussed. After interaction of light from both sources 16' and 16" with the fluid stream 3, light from the fluid stream is collected and returned to the surface by a common carrier fiber optic 14". Light exiting from the fiber 14" is split into two signals of having light in two different wavelength ranges by a splitter device 42, which may be a filter, a filter set, a beam splitter, a fiber optic splitter, a fiber optic demultiplexer, a grating, or a similar device.

One signal comprises light in the wavelength range that incorporates the wavelengths of the first, monochromatic light source 16' and the wavelengths of the fluorescence that was generated downhole by the interaction of light from the monochromatic source and the fluid stream 3. This signal is directed to the first spectrographic detector 18' by means of fiber optic 17'. The second signal comprises the wavelength range that incorporates the wavelengths of the second, broadband source light source 16". This signal is directed to the second spectrographic detector 18" by means of fiber

optic 17". The processing of these independent signals is performed by the computer 20 using the software and algorithms of the current invention, as discussed further below—specifically, a first algorithm developed from an attenuation-based calibration would be used to determine concentration based on the attenuation analysis and a second algorithm developed from a fluorescence-based calibration would be used to determine concentration based on the fluorescence analysis. The concentration resulting from the two methods of analysis could then be compared for verification.

B. Algorithms/Software

Using techniques well known in the art, the computer 20 is programed with software, shown schematically in FIG. 15, for determining the concentration based on the light components measured by the spectrographic detector 18. As shown in FIG. 15, in operation, in the first step 100, the computer 20 first directs the light source 16 to transmit a beam of light to the sensor 12, which directs the light emerging from the fluid to the spectrographic detector 18. In the second step 110, the computer directs the spectrographic detector 18 to determine the intensity of the components of the emerging light at wavelengths within a predetermined range. In step 120, the normalization factor f_n is calculated from the measured intensities, for example using the equation indicated. In step 130, the measured intensities at selected wavelengths, preprogramed into the computer, are normalized using the normalization factor determined in step 120. In step 140, the normalized intensities are applied to one or more algorithms preprogramed into the computer so as to calculate the concentration of the constituents of interest. In step 150, the calculated concentration, for example 90% oil, is displayed on the indicator 22. The normalization techniques applied in steps 120 and 130 and the algorithm applied in step 140 are discussed in detail below.

As previously discussed, according to an important aspect of the current invention, the measured intensities of the light emerging from the fluid are normalized to eliminate the effect of scattering on the analysis. When a light attenuation method is used, normalization is preferably performed using a characteristic of the intensity of the light emerging from the fluid over a range of wavelengths. Preferably, the vector length of the emerging light spectrum is used. Mathematically, the vector length is represented as:

$$f_n = \sqrt{\sum_{i=1}^m I_{in}^2} \quad [1]$$

where:

n =a number representing the particular mixture being analyzed,

i =represents discrete wavelengths or wavelength ranges,

I_{in} =the measured intensity of the component of the emerging light for mixture n existing at wavelength i ,

f_n =the vector length for mixture n ,

m =the total number of component intensities used in the normalization (e.g., the total number of component intensities measured over a predetermined wavelength range).

Note that for purposes of the current invention, preferably, the measured intensity I_{in} at any given wavelength is determined by integrating the intensity over at least a small wavelength band about the given wavelength in order to minimize errors due to slight deviations in wavelength

detection. Thus, for example, the measured intensity at a wavelength of 1100 nm, I_{1100} , is determined by integrating the intensity over a wavelength band from 1095 nm to 1105 nm. Alternatively, the integrated intensity over a relatively large band of wavelengths (e.g., 950 to 1000 nm) could be used if such a band contained valuable information on the concentration of a particular constituent.

Normalization is performed by dividing the measured intensity I_{in} in at each wavelength in the n^{th} spectrum by the vector length f_n so that

$$IN_{in} = I_{in} / f_n \quad [2]$$

Where IN_{in} =the normalized intensity of mixture n at wavelength i .

Although vector normalization is a preferred method, those knowledgeable in the art will recognize that other normalization routines may be used. For example the spectral data can be normalized to the area of the spectrum:

$$f_n = \sum_{i=1}^m |I_{in}| \quad [3]$$

or to the intensity at a specific wavelength, or to the integrated intensity across one or more spectral regions.

Note that, according to the current invention, when using the attenuation method, it is not necessary (although it is not prohibited) to normalize the measured intensities to the spectrum of the light from the light source 16 that is directed to the fluid. This is due to the fact that changes in light source intensity at the surface are expected to be relatively wavelength independent and thus will not effect the analysis according to the current invention, in which only the relative intensities, not the absolute magnitudes, are used.

When using the fluorescence method, normalization is performed by reference to the intensity of the portion of the collected light that represents the scattered laser light, determined by detecting the intensity of the collected light in a small band of wavelengths around the wavelength of the laser. For example, the measured intensities can be normalized by dividing the intensity of the fluorescent radiation at each wavelength I_i by the intensity of the transmitted laser light IL (e.g., determined by measuring the intensity of the transmitted light component at the wavelength of the laser light) so that:

$$IN_{in} = I_{in} / IL \quad [4]$$

Other laser light intensity related values could also be used for the normalization, such as the area under the transmitted laser light spectrum.

Regardless of whether the attenuation or fluorescence methods of analysis are used and regardless of which normalization technique is used, the concentration of each constituent of interest is preferably determined from an equation of the type:

$$C_{kn} = \sum_{i=1}^m \beta_{ki} IN_{in}^{a_{ki}} + b_k \quad [5]$$

where:

k =A number representing the particular constituent of interest (for example, 1=oil, 2=water, and 3=gas)

C_{kn} =The concentration of constituent k for mixture n (for example, C_{12} is the percentage of oil for mixture 2).

n =A number representing the particular fluid that is the subject of the analysis (for example, $n=1$ represents a fluid flowing in an oil well that consists of a mixture of 10% water and 90% oil, $n=2$ represents the well fluid at a later point in time, when its relative constituents may have changed).

i =A number representing the selected key wavelengths (for example, 1=1000 nm (or 950 to 1050 nm), 2=1110 nm (or 950 to 1050 nm), etc.).

m =The total number of light components whose intensities are used in the algorithm, which may, but need not be, the same as the number of light component intensities used in calculating the vector length or other normalization factor.

β_{ki} =The weighting factor for constituent k at each of the selected wavelengths or wavelength ranges i , discussed further below.

IN_{ni} =The normalized intensity of the component of the light at wavelength i for fluid mixture n determined as discussed above.

α_{ki} =Exponents for constituent k at each of the selected wavelengths or wavelength ranges i . Preferably, α is 1 so that the algorithm will be linear. However, in some circumstances, linearity may not yield sufficient accuracy, in which cases α may have values other than 1. Moreover, all of the α_i values may not be the same. For example, $\alpha_1=2$, $\alpha_2=1/2$, etc.

b_k =A constant.

Essentially, the weighting factor β_{ki} for each constituent shows the relative weight to be given the intensity at each of the selected wavelengths in determining the concentration of that constituent—that is, the extent to which the intensity of the light component at a given wavelength is a predictor of the concentration of the constituent of interest. The larger the variation in the intensity of the component of the emerging light at a given wavelength as the concentration of a particular constituent varies, relative to the intensity variation at that wavelength as the concentration of other constituents varies, the larger the weighting factor β_{ki} for that particular constituent at that wavelength. The weighting factors may be positive or negative. If all of the wavelengths are used, rather than only the most significant, then, some of the weighting factors may be zero.

In any event, the normalized intensity of the light component at each wavelength to be used in the algorithm is multiplied by a weighting factor the value of which is dependent upon the wavelength. The normalized and weighted intensities are then summed to arrive at the concentration of the constituent for which the algorithm was developed.

For the sake of illustration, consider a highly-simplified example of fluid flowing downhole in a well in which the concentration of three constituents—oil, water, and gas—are to be determined using linear algorithms based on the normalized light component intensities at five selected wavelengths ($m=5$) from a set of five wavelengths—1100, 1200, 1300, 1400, and 1500 nm. Further suppose that, as a result of the application of a regression technique to a set of calibration data, discussed further below, values for the weighting factors β at each wavelength were determined for the three constituents as follows:

Wavelength (i)	Weighting Factors (β)		
	Oil	Water	Gas
1100	100	400	200
1200	250	400	0
1300	130	100	80
1400	0	225	30
1500	150	0	20

Equation 5 would then result in the following algorithms for concentrations of oil, water, and gas:

$$C_{oil}=100 IN_{1100}+250 IN_{1200}+130 IN_{1300}+0 IN_{1400}+150 IN_{1500} \quad [5a]$$

$$C_{water}=400 IN_{1100}+400 IN_{1200}+100 IN_{1300}+225 IN_{1400}+0 IN_{1500} \quad [5b]$$

$$C_{gas}=200 IN_{1100}+0 IN_{1200}+80 IN_{1300}+30 IN_{1400}+20 IN_{1500} \quad [5c]$$

For the sake of simplicity, all of the wavelengths used for the three equations above were drawn from the same five wavelength set. However, in actual practice, the selected wavelengths for each constituent might come from completely different sets of wavelengths. However, generally, all of the wavelengths used in each of the algorithms would fall within the same range of wavelengths. For example, when using a method based on the attenuation of near-IR light or the inducement of fluorescence caused by near-IR light, the wavelengths used in the algorithm would all fall somewhere within the near-IR range (e.g., in the range from 800 nm to 1600 nm).

Although only five wavelengths were used in the algorithms in the example above, in practice, a greater number of wavelengths may often be used. For example, the algorithm might contain each wavelength in the 1100 to 1500 nm range—that is, four hundred wavelengths ($m=400$)—so that there were four hundred weighting factors, each of which is applied to the component of the normalized intensity at the respective wavelength. Alternatively, in the limit, an algorithm utilizing only a single wavelength could also be used—example, $C_{oil}=200 IN_{1300}+12$ —provided that it yielded sufficient accuracy for the particular application.

In any event, during operation, the intensity of the light components at the prescribed wavelengths of the light emerging from the fluid flowing in the well is measured using either an attenuation or fluorescence technique. These measured component intensities are then normalized, as discussed above. For example, if vector length normalization were used, the vector length of the spectrum over a range of wavelengths (for example, all of the wavelengths in the 1100 to 1500 nm range) would be calculated from the measured intensities and the measured intensity at each of the wavelengths used in the algorithm would then be divided by the vector length so as to arrive at normalized intensities for those wavelengths. For example, a set of normalized intensities might be:

Wavelength (i)	Normalized Intensity (IN)
1100	.06
1200	.04
1300	.05
1400	.03
1500	.02

Substituting these normalized intensities into equations 5a, 5b and 5c would yield concentrations of 52% oil, 26% water, and 17% gas.

In some applications, the algorithm might involve two or more equations for each constituent, each covering a different concentration range—for example, one equation for oil concentrations between 0% and 50% and another equation, with different weighting factors and/or selected wavelengths, for oil concentrations between 50% and 100%, etc.

When using several algorithms covering different ranges for the same constituent, it is desirable to identify into which subset range of concentrations a particular mixture being measured belongs before choosing the algorithm to determine the concentration. Thus, an algorithm generated for concentrations over the entire 0 to 100% concentration range could be used to preliminarily screen the data and, based on the concentration calculated using that algorithm, a more accurate, narrower range algorithm could be used for the final calculation. Alternatively, a Soft Independent Modeling by Class Analogy (SIMCA) could be used. In this method, a classification model is generated based on the light intensities of mixtures that fall into the different concentration ranges selected. The model is then used to predict into which concentration range an unknown mixture falls. Once a mixture has been assigned to a certain subset range of concentrations, a calibration algorithm optimized for that range can be used to more accurately determine the concentration of the constituents of interest. One knowledgeable in the art will realize that classification models other than SIMCA can be used to achieve the same goal, such as K-nearest neighbors, discriminate analysis, principal component analysis, and neural nets.

In addition to the software for calculating concentrations, the computer 20 may also be programmed with software for performing the calculations associated with the development of the specific algorithm from the calibration data—that is, the identification of the weighting factors used to weight the importance of the intensities at various wavelengths in determining concentration, as discussed further below.

IV. Development of the Concentration Algorithm

A. Equipment

The specific form of the algorithm discussed above and shown as equation is developed for each constituent by identifying a range of wavelengths that encompasses those wavelengths whose intensities are likely to provide the maximum information about the concentration of that constituent, determining the weighting factors β_{ik} associated with each of the wavelengths in the range, and selecting those wavelengths to be used in the algorithm based on the weighting factors. This is done by performing a calibration for the particular type of fluid to be analyzed—for example, the fluid from the well into which the sensor 12 will be installed—and the particular constituents for which concentration is to be determined—for example, the particular type of crude oil being produced by the well.

Calibration is performed by obtaining quantities of each constituent and preparing various mixtures of differing concentrations that preferably span the range of concentrations to be encountered in operation. For example, if a mixture of crude oil and water from a producing well is to be analyzed, a quantity of pure crude oil extracted from the fluid produced by the well is obtained. The sensor 12 is then installed onto a container 50, as shown in FIG. 5. A stirring device, such as a stir plate 52, is used to mix the oil and water in the container 50. The sensor 12, which may be similar to the sensor 12 shown in FIGS. 2 and 3, is coupled to the fluid analyzer 6 and light source 16 using a fiber optic cable 13. The light source 16 and fluid analyzer 6 are as discussed above in connection with FIG. 1. Preferably, the same type

and length of fiber optic cable 13 that will be used in actual service is employed so as to remove the effects of attenuation of the light as it travels through the long fiber optic cable on the calibration results.

B. Acquisition And Normalization of Calibration Intensities

1. Experiment 1—Oil Concentration Using Attenuation

The method for acquiring and normalizing the component light intensities to be used in developing the details of the concentration algorithm will now be discussed by way of example—specifically, an experiment that was conducted using the near-IR attenuation method, portions of the spectra resulting from this method are shown in FIGS. 6 and 7.

The equipment set up used is shown in FIG. 5. Initially, the container 50 was filled with pure crude oil. In actual practice, the crude oil would be extracted from the fluid produced by the well. For purposes of this experiment, light Pennsylvania crude oil was used. The light source 16 used for this experiment was a quartz tungsten halogen lamp, which generated light having wavelengths that encompass the 1100 nm to 1550 nm range. The intensity of the source was set just below saturation of the detector at 0.1 sec integration (~50,000 counts/sec). This light was directed by the fiber optic 14' to the sensor 12, which then directed it to the oil in the container 50. The light emerging from the oil was collected by the sensor 12 and transmitted by fiber optic 14" to the fluid analyzer 6.

The fiber optics 14' and 14" were each approximately nine feet long. The fluid analyzer 6 employed a diode array to measure the intensity of the emerging light versus its wavelength so as to essentially develop the spectrum of light emerging from pure oil of the type produced by the well. This data was then stored in the computer 20. Since crude oil has absorption peaks at about 1200 nm and 1400 nm, it was determined that the range of wavelengths to be used in the calibration was 1100 nm to 1520 nm. The spectrum of light emerging from pure crude oil in this wavelength range is shown in FIG. 6. Since the intensity of the light emerging from the fluid is reduced at those wavelengths at which appreciable absorption occurs, the areas of greatest absorption appear as troughs in the spectrum of the emerging light. Thus, the spectra shown in FIG. 6 and utilized according to the current invention are not the spectra of the absorbed light but rather the spectra of the emerging light from the fluid, which contains those portions of the light that are scattered by or transmitted through the fluid (i.e., not absorbed).

Next, water was added in carefully titrated increments to the container 52 and additional spectra were obtained and stored in the computer until spectra were acquired over a range of crude oil concentrations down to 50%. This procedure was repeated starting with a container of pure water and adding oil in carefully titrated increments until spectra were acquired over a range of water concentrations down to 50%. In this experiment, spectra were obtained at a total of thirty eight different concentrations spanning 0% to 100% oil concentrations. For simplicity, eleven of these spectra (i.e., in 10% increments) are shown in FIG. 6 over wavelengths in the approximately 1100 nm to 1550 nm range. As discussed below, in actual practice, the number of spectra used for the calibration may depend on the regression technique utilized during the calibration calculations.

In this experiment, the stir plate 52 was used to maintain good mixing of the oil and water. In actual practice, the degree of mixing during data acquisition should approximate that of the fluid to be encountered in actual service—for example, the degree of mixing associated with the fluid flowing down hole in the well.

At each concentration, a spectrum for the 1100 nm to 1550 nm range was obtained by measuring the intensity of the light component at each wavelength within the range so that intensity was measured at a total of 450 wavelengths. The intensity of the light from the fluid was measured simultaneously at all wavelength over a 0.1 second period. This measurement was repeated one hundred times and the readings averaged to arrive at a final intensity value for each wavelength. Data acquisition was repeated ten times so that ten sets of data was obtained for each mixture.

As can be seen in FIG. 6, the absolute intensity of the spectra vary quite dramatically with concentration. Specifically, higher concentrations of oil yield low absolute spectral intensities at the wavelengths for which absorption is high. As previously discussed, this results from two phenomena associated with the presence of oil—increased scattering and increased near-IR absorption. However, as also previously discussed, whereas the amount of absorption is a function of only the concentration of oil, the amount of scattering depends upon both the concentration and various multiphase characteristics, such as droplet size. Therefore, according to an important aspect of the current invention, the effect of scattering is minimized by normalizing the spectra. Thus, using the method previously discussed, the vector length of each of the spectra in FIG. 6 was calculated. Each spectrum was then divided by its own vector length so as to generate the normalized spectra shown in FIG. 7. As can be seen, the peak intensity trends follow concentration, indicating that the normalized spectra are independent of the scattering properties of the various mixtures.

Based upon the normalized spectra shown in FIG. 7, the weighting factors β for each wavelength in the 1100 nm to 1550 nm range were determined (a total of 450 weighting factors) using a partial least squares regression technique, discussed below. Based on these weighting factors, an algorithm was developed in the form of equation 5 (linear, with $\alpha=1$) for the calculation of the concentration of oil, C_{oil} , in mixture n based on normalized intensity IN at each wavelength in the 1100 nm to 1520 nm range:

$$C_{oil,n} = \beta_{oil,1100\text{ nm}} IN_{n,1100\text{ nm}} + \beta_{oil,1101\text{ nm}} IN_{n,1101\text{ nm}} + \dots + \beta_{oil,1520\text{ nm}} IN_{n,1520\text{ nm}} \quad [6]$$

A leave one out validation technique was employed to check the accuracy of the algorithm. Specifically, the partial least squares 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 left out and this computed value was compared to the actual value. This procedure was repeated for each mixture used in the calibration and the predicted versus actual values are shown plotted in FIG. 8. These data revealed a standard error for the algorithm of only 2.9% in the percentage concentration value.

2. Experiment 2—Oil Concentration Using Fluorescence

The calibration procedure described above, as well as the procedure for determining weighting factors at each wavelength, as discussed below, are essentially the same whether the absorption or fluorescence methods are used to generate the emerging light from the fluid. Thus, a second experiment was conducted using the near-IR fluorescence method. The equipment used in this experiment was the same as that shown in FIG. 5 and discussed above in connection with the near-IR attenuation experiment, except in this case, the light source 16 was DBR laser, which emitted monochromatic light at a wavelength of about 852 nm, and a CCD was used for the spectrograph detector 18. The same ratios of oil/water concentrations were used to

generate the spectra based on near-IR attenuation shown in FIG. 6 were used and the intensities were measured using a similar procedure. Data was acquired for each mixture five times. In this case, the intensity was determined at each pixel in about the 18 to 770 pixel range (corresponding to approximately 850 nm to 1300 nm). The resulting raw spectra ranges are shown in FIG. 9. The scattered laser light is clearly visible at a pixel number slightly greater than 18. The measured intensity at each wavelength was then normalized by dividing it by the peak amplitude of the scattered laser light so as to obtain the normalized spectra shown in FIG. 10.

Based upon the normalized spectra shown in FIG. 10, the weighting factors β for each pixel in the 18 to 770 pixel range were determined (a total of 752 weighting factors) using a partial least squares regression technique, discussed below. Based on these weighting factors, an algorithm was developed in the form of equation 5 (linear, with $\alpha=1$) for the calculation of the concentration of oil, C_{oil} , in mixture n based on normalized intensity IN at each wavelength in the 18 to 770 pixel range:

$$C_{oil,n} = \beta_{oil,18} IN_{n,18} + \beta_{oil,19} IN_{n,19} + \dots + \beta_{oil,770} IN_{n,770} \quad [7]$$

A leave one out analysis revealed a standard error for this algorithm of 5.6%. The oil concentrations predicted by the near-IR fluorescence algorithm are shown graphed versus the actual concentration values in FIG. 11.

3. Experiment 3—Gas Concentration Using Attenuation Method

The attenuation method of the current invention can also be used to determine the concentration of natural gas in a fluid flow. A simulation of natural gas dissolved in crude oil, or a crude oil/water mixture, was performed using isooctane (2,2,4-trimethylpentane) as a proxy for the natural gas. Natural gas consists mainly of methane (CH_4), ethane (C_2H_6) and other small chain hydrocarbons (e.g., propane and butane), which are characterized by the presence of methyl groups ($-CH_3$). Isooctane has a high percentage of methyl groups and its addition to crude oil flow would closely mimic the near-IR absorption behavior of an addition of liquefied or dissolved natural gas. The temperatures and pressures that exist downhole would generally cause natural gas to be in a liquid state. Crude oil consists several different lengths of chain hydrocarbons, which consist of some methyl groups (CH_3) but predominantly methylene groups (CH_2). Both groups have distinct absorption bands in the near-IR region. Evans et. al, Analytical Chemistry, vol. 23, no. 11 (1951) used the ratio of these two absorption bands to determine the number of methyl and methylene groups per molecule in paraffins and lubrication oils. FIG. 11 shows near-IR spectra of crude oil with varying amounts of isooctane (0–50%). As the isooctane concentration increases, the methyl spectral band grows in intensity relative to the methylene band, which allows the method described above to distinguish between the two organic fluids.

A mixture composed of 67% oil and 33% water was prepared as a starting point. Using the set up shown in FIG. 5, the mixture was analyzed using the near-IR attenuation method. Light from a quartz tungsten halogen lamp 16 having strong emissions in the near-IR range was the directed to the mixture and analyzed by the InGaAs diode array. Additional measurements were taken as isooctane was subsequently added until a concentration of 25% isooctane was achieved. The intensity was measured at each wavelength in the 1100 nm to 1300 nm range (a total of 200 wavelengths). FIG. 13 shows the raw spectra taken from the

mixtures of crude oil, water, and isooctane. The measured intensities were normalized using the spectrum vector lengths. The resulting normalized spectra are shown in FIG. 14.

Based upon the normalized spectra shown in FIG. 14, the weighting factors β for each wavelength in the 1100 nm to 1300 nm range were determined (a total of 200 weighting factors) using a partial least squares regression technique, discussed below. Based on these weighting factors, an algorithm was developed in the form of equation 5 (linear, with $\alpha=1$) for the calculation of the concentration of "gas" (i.e., isooctane), C_{gas} , in mixture n based on normalized intensity IN at each wavelength in the 1100 nm to 1300 nm range:

$$C_{gas,n} = \beta_{gas,1100\text{ nm}} IN_{n,1100\text{ nm}} + \beta_{gas,1101\text{ nm}} IN_{n,1101\text{ nm}} + \dots + \beta_{gas,1520\text{ nm}} IN_{n,1520\text{ nm}} \quad [8]$$

A leave one out analysis revealed a standard error for this algorithm of only 0.55% in the percentage in the percentage concentration value.

C. Determination Of Weighting Factors

Once the spectral data are normalized to remove the effects of scattering, any one of a number of well known regression techniques, some of which are discussed below, can be used to determine the weighting factors β to be used in weighing the values of the normalized component intensities measured in actual service in order to calculate concentration. The preferred regression technique is partial least squares regression. In some cases, two or more techniques may be employed—for example, an initial regression model may be determined based on a partial least squares regression technique and then refined using a multiple least squares regression technique.

Univariate regression is by far the most familiar technique for correlating spectral data to concentration. In chemical analysis this amounts to correlating the value of the peak spectral intensity IN_n of spectrum n with the concentration C_n of the constituent k of interest associated with that spectrum. The sequence of observations of IN_n and C_n from mixtures at each of the concentrations to be used in the calibration are used to derive a linear equation:

$$C_n = \beta \cdot IN_n + b \quad [9]$$

where:

β —the slope of the linear equation

b —the concentration at zero intensity (i.e., the y-axis intercept)

This equation is optimized by minimizing the sum of the squares of the differences (residuals) between the predicted and true values; minimizing the residuals being one of the common threads that ties the various forms of regression together. These values of β and b thus developed are used in equation 5 to determine the concentration of constituent k —for example, oil—in actual service. These calculations would be repeated for other constituents for which concentration was to be calculated—for example, gas—so that a equation in the form shown in equation 5 would be derived for each constituent, with each constituent having different values for the weighting factor β and b .

Although univariate least squares regression is computationally simple, it will not offer sufficient accuracy in most applications since only the normalized intensities at one wavelength (that at which the intensity is a maximum) are used in the model. Therefore, more sophisticated regression techniques, such as those discussed below are preferred.

Multiple least squares (MLS) regression is another well known regression technique. Although the goal of MLS

regression is identical to univariate least squares, i.e., to minimize the sum of the squares of the residuals, it allows more than one variable (i.e., normalized intensities at more than one wavelength) to be used in the regression analysis:

$$C = \beta_0 + \beta_1 \cdot IN_1 + \beta_2 \cdot IN_2 + \dots + \beta_m \cdot IN_m + e \quad [10]$$

where m refers to the total number of collected wavelengths i and e represents the error of the simple model. The coefficients β are essentially weighting factors that relate how much information each measured intensity, at each individual wavelength, contains concerning the concentration C . The largest values of the weighting factors β are associated with the wavelengths that have the most influence on the determination of concentration.

MLS regression is an adequate procedure in some situations. However, it requires independence of the elements in the matrix subject to inversion—an unlikely situation for collinear spectroscopic data. Also, significant amounts of irrelevant information are likely to be incorporated into the model since every variable is included in the model.

In recent years, principal component regression (PCR) methods have been used to solve a wide variety of chemical problems which require the use of multivariate analysis. PCR involves decomposition of a row matrix containing the normalized intensity spectra into a loading matrix and a score matrix so that the product of these two matrices yields the original normalized intensity spectra. Each row vector in the loading matrix is referred to as a principal component and consists of a single loading value L for each spectral wavelength. Hence, the first row vector in the loading matrix corresponds to principal component 1 (PC_1), the second row to PC_2 , and so on.

The magnitude of a particular loading for a given principle component indicates how much information that wavelength contributes to the principle component. Inspection of the loading matrix may reveal which wavelengths contain the most information about the concentration of the constituent of interest. The scores matrix simply relates the principal components back to the original spectra, i.e., the scores define how much a particular principal component contributes to a spectrum. Thus the first row vector of the scores matrix tells how much PC_1 , PC_2 , etc., contribute to the particular spectrum. The principal components are ranked in order of variance, i.e. PC_1 accounts for the greatest amount of variance in the set of input spectra. For this reason, the vast majority of the spectral information is included in the first few principal components, while the higher principal components are comprised mostly of noise.

The reduction of data dimension and the elimination of noise makes PCR the obvious choice over MLS regression. However, PCR suffers from a disadvantage in that the correlation between the property of interest and the spectral intensities is not included in the generation of the principle components.

Partial least squares (PLS) regression, also known as Projection to Latent Structures, is described, for example, in Wold, "Partial Least Squares," in Encyclopedia of Statistic Sciences, Vol. 6, Katz and Johnson, Ed. (Wiley 1985), pp. 581–591 and Manne, "Analysis of Two Partial-Least-Squares Algorithms for Multivariate Calibration," Chemom. Intell. Lab. Syst. (1987) 2:187–197, each of which is hereby incorporated by reference. PLS regression is a procedure that simultaneously estimates the eigenvectors in both the spectral data and the sample property data. Although PLS regression is fundamentally similar to PCR, it has the additional advantage of ordering its factors by considering both the variance of the spectral data and its correlation to

the property of interest. Generally, this results in an equivalent or slightly more reliable model than PCR generates. An additional advantage of PLS regression involves a much faster computation time (when using a bidiagonalization procedure) compared to PCR. PLS regression shares many PCR characteristics—for example, PLS regression finds factors analogous to PCR's principal components. However, because these factors contain information about the correlations, they often yield more parsimonious and, in some situations, more reliable models than PCR.

Although PLS regression is preferred, other regression techniques could also be utilized, such as classical least squares, or inverse least squares in addition to any of the other techniques discussed above. For example, neural net regression techniques could also be used, especially if the regression model were nonlinear. A number of regression techniques suitable for use in practicing the current invention are described more fully in R. Kramer, "Chemometric Techniques For Quantitative Analysis," ISB 0-824-0198-4, Marcel Dekker (1998), incorporated by reference herein.

Regardless of the regression technique utilized, a separate regression is performed for each constituent so that a weighting factors β_i is obtained for each of the selected wavelengths to be used in the algorithm for each constituent.

D. Determination of the Wavelengths to be Used in the Algorithm

As previously discussed, in performing the calibration and constructing the algorithm, component intensities are preferably measured at each wavelength within a preselected range of wavelengths—for example, in the experiments discussed above, algorithms were constructed using the normalized intensity for each wavelength within the 1100 to 1520 nm range for oil using the near-IR absorption method, within the 18 to 770 pixels range for oil using the fluorescence method, and within the 1100 to 1300 nm range for gas using the near-IR absorption method. The weighting factor associated with many of these wavelengths (i.e., those whose intensities can not be readily relied upon to determine concentration of the constituent of interest), however, will be very close to zero. Therefore, if desired in order to simply the computations, the algorithm can be constructed by selecting only key wavelengths within the range—specifically, those wavelengths whose intensities contain the maximum amount of information concerning the concentration of the constituents of interest.

According to the current invention, a variety of methods may be used to select the key wavelengths to be included in the algorithm, such as by inspection of the weighting factors in the algorithm. As previously discussed, the larger the variation in the intensity of the component of the emerging light at a given wavelength as the concentration of a particular constituent varies, relative to the intensity variation at that wavelength as the concentration of other constituents varies, the larger the weighting factor β_{ki} for that particular constituent at that wavelength. A large weighting factor means that the value of the intensity of the light at that wavelength will carry significant information about the concentration of interest.

Preferably, the wavelengths to be used in the algorithm are determined using a "leave one out" validation technique. This is accomplished by performing the calibration calculations discussed above using all but one of the mixtures for which data is available but so as to develop an algorithm containing only one wavelength—the wavelength having the highest weighting factor β . This algorithm is then used to predict the concentration for the mixture excluded from the calibration and the resulting error determined. The

calibration calculations are then re-run but this time including the mixture previously excluded but leaving out a different mixture so as to develop another single-wavelength algorithm. Again the error associated with the predicted concentration for the new excluded mixture is determined. This process is repeated until each of the mixtures in the calibration have been left out. The predicted residual error sum of the squares (PRESS) associated with this one wavelength algorithm is then calculated.

The calculations above are then repeated using an algorithm containing the wavelengths having the two highest weighting factors, and the PRESS associated with these algorithms is calculated. The calculations are then repeated adding one additional wavelength to the algorithm each time until an algorithm containing all of the wavelengths has been constructed. The algorithm that results in the lowest value for PRESS contains the optimum number of wavelengths.

E. Multiple Algorithms for Different Concentration Ranges

Calibration results can be improved if the algorithms are limited to certain concentration ranges. This can be accomplished by performing separate regression analyses for mixtures in concentrations within predetermined ranges—for example, mixtures ranging between 0% to 50% oil are used in one regression to arrive at one algorithm and mixtures ranging between 50% to 100% oil are used in another regression to arrive at another algorithm—rather than using all of the mixtures from 0% to 100% in a single regression. For example, the near-IR calibration data shown in FIGS. 6 and 7 were re-analyzed using the same partial least squares regression technique but, this time, the analysis was performed separately for the 0% to 50% oil concentration range and the 50% to 100% oil concentration range so as to develop two different algorithms, one for each range. This reduced the 2.9% standard error that resulted from the use of a single algorithm, previously discussed, to a 1.6% for the 0% to 50% range and to 1.4% for the 50% to 100% range. Similarly, re-analyzing the near-IR fluorescence calibration data shown in FIGS. 11 and 12 separately for the 0% to 50% and 50% to 100% ranges reduced the standard error from 5.6% to 3.1% for the 0% to 50% range and to 2.1% for the 50% to 100% range.

Particularly in the case of oil wells, those skilled in the art will realize that both the near-IR attenuation data and the near-IR fluorescence data may be significantly dependent on the pressure and temperature of the fluid stream being analyzed, which may be at pressures and temperatures as high as 400° F. and 20,000 psig. Thus, in some applications, it may be desirable to compensate for pressure and temperature effects by performing the calibration on mixtures at the pressures and temperatures expected to be encountered in actual service, or on mixtures of varying pressures and temperatures so as to arrive at a set of algorithms, each of which is applicable to a different ranges of pressures and/or temperatures. In this case, classification models can be constructed using mixtures compositions of varying pressure and temperature so that the light component data from the flowing fluid can be assigned to a concentration algorithm that has been optimized for the pressures and temperatures having ranges that encompass those of the flowing fluid.

V. Use of Downhole Fluid Analysis in an Oil Well

By way of example only, the invention will be described in connection with the analysis of the fluid flowing from a multilateral well into which production strings have been incorporated. It will be understood by those skilled in the art that the invention is equally applicable to other environ-

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ments in which it is desirable to remotely sense the presence of a substance that fluoresces or absorbs radiation, such as oil, in a flowing fluid.

As depicted in FIG. 16, a multilateral well 4 has three zones extending into the formation 2. A section of a production string 8 is located in each zone so that all three zones produce fluids simultaneously. Each section of the production string 8 includes a valve 70 for regulating the flow of fluid from its zone. The fluid 25 flowing from the well 4 typically may comprise one or more of oil, water, natural gas, and solids, such as sand. As is conventional, the fluid 25', 25" and 25''' from all three zones are combined into a common flow line 25 before reaching the surface. As a result, an analysis of the fluid at the surface according to a conventional approach will not enable the operator to assess the production of the individual zones of the well.

A system for analyzing fluid according to the current invention is shown incorporated into each zone of the well 4. Specifically, an instrumented section 10 of the type shown in FIG. 1 have been incorporated into the branches of the production piping that extend into each zone of the well, along with a mixer 60 and diverter 62. As shown in FIG. 16, fiber optic cables 14, which may be several kilometers long, connect each of the instrumented sections 10 to the light source 16 and fluid analyzer 6 at the surface.

As previously discussed, the computer 20 of the fluid analyzer 6 is programed with an appropriate algorithm for calculating the concentrations of oil and water, each of which is preferably in the form of equation [5] so that it employs weighting factors for selected wavelengths, which are preferably determined based on a calibration of the oil from the well.

As shown in FIGS. 1 and 15, during production, the light source 16 periodically or continuously transmits light to each of the sensors 12 in the instrumented sections 10 via the optical fibers 14'. The intensity of the components of the collected light returned from each of the sensors 12 by the optical fibers 14" over a predetermined range of wavelengths is measured using the spectrographic detector 18. The computer 20 periodically or continuously calculates the concentrations of oil and water flowing through each of the zones of the well, using software that allows it to calculate the normalized intensity of the measured light components, preferably using one of the normalization techniques previously discussed, and then apply those normalized intensities to the aforementioned algorithms. The calculated concentrations of oil and water are then displayed by the indicator 24.

Incorporating instrumented sections 10 in each zone of the well 4 allows the operator to determine the percentage of oil and/or water in the fluid flowing downhole through each zone on a nearly real-time basis. This information can, in turn, be used to regulate the flow from each zone so as to optimize production, for example, by operating the valve 70 to reduce the flow from a zone producing a low percentage of crude oil, or excessive water.

Although the present invention has been discussed in connection with the determination of the concentration of crude oil or gas in an oil well producing an oil/water/gas mixture, the invention can be used to determine the concentration, or merely detect the presence, of oil or gas in other applications, such as when contamination of water by oil is suspected. Alternatively, the invention can be used to determine the concentration or detect the presence of other substances that fluoresce or absorb radiation in flowing streams that have scattering characteristics.

Moreover, although the mixer and diverter have been discussed in connection with the sensor of a fluid analyzer,

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these components could also be used in connection with other types of sensors used in the well piping.

Accordingly, the present invention may be embodied in other specific forms without departing from the spirit or essential attributes thereof and, accordingly, reference should be made to the appended claims, rather than to the foregoing specification, as indicating the scope of the invention.

What is claimed:

1. A method of determining the concentration of at least one predetermined constituent in a fluid flowing through a downhole portion a well, comprising the steps of:

- a) generating a beam of light;
- b) directing said beam of light into said fluid flowing through said downhole portion of said well so as to cause one portion of said light to be absorbed by said fluid and another portion of said light to travel through said fluid and emerge from said fluid, said emerging light having been scattered by said fluid and comprised of a plurality components each of which has a different wavelength;
- c) transmitting at least a portion of said light that traveled through said fluid and emerged therefrom to a location proximate to the surface of the earth;
- d) measuring the intensity of each of at least a portion of said components of said transmitted light, each of said light components in said portion of light components having a wavelength falling within a predetermined range of wavelengths, said light component intensity measurements being conducted at said location proximate said surface;
- e) normalizing at least those of said measured light component intensities having selected wavelengths by dividing said intensities by a characteristic derived from said measured component intensities so as to reduce the effect of said scattering of said light components;
- f) raising each of said normalized light component intensities at said selected wavelengths by a respective exponent, said exponents being any non-zero numbers;
- g) multiplying each of said exponentially raised normalized light component intensities at said selected wavelengths by a predetermined weighting factor based upon its respective wavelength so as to obtain a weighted and normalized light component intensity at each of said selected wavelengths; and
- h) combining said weighted and normalized light component intensities at said selected wavelengths so as to calculate said concentration of said constituent.

2. The method according to claim 1, wherein said characteristic by which said measured components intensities are normalized is derived from all of said measured component intensities at all wavelengths at which said component intensities are measured.

3. The method according to claim 2, wherein the step of normalizing said component intensities comprises dividing each of said component intensities at said selected wavelengths by the vector length of said measured component intensities.

4. The method according to claim 3, wherein said vector length is calculated from the equation:

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$$f = \sqrt{\sum_{i=1}^m I_i^2}$$

where:

f=the vector length,

i=represents the wavelength of each of said light components whose intensity is measured,

I_i =the measured intensity of the light component having wavelength

m=the total number of components whose intensities are measured.

5. The method according to claim 2, wherein the step of normalizing said component intensities comprises dividing each of said component intensities at said selected wavelengths by f, where:

$$f = \sum_{i=1}^m |I_i|$$

where:

i=represents the wavelength of each of said light components whose intensity is measured,

I_i =the measured intensity of the light component having wavelength i,

m=the total number of components whose intensities are measured.

6. The method according to claim 2, wherein the step of normalizing said component intensities comprises dividing each of said component intensities at said selected wavelengths by the maximum measured intensity of said light components.

7. The method according to claim 1, wherein said constituent has at least one wavelength at which the absorption of light contacting said constituent peaks, and wherein said predetermined range of wavelengths within which the wavelengths of said measured components fall encompasses said absorption peak.

8. The method according to claim 1, wherein the step of transmitting at least a portion of said emerging light to said remote location comprises directing said portion of said emerging light through a fiber optic cable extending from said downhole location to said location proximate the surface of the earth.

9. The method according to claim 1, wherein the step of measuring said intensity of each of at least a portion of said components of said transmitted light is performed so that all of said intensities are measured simultaneously.

10. The method according to claim 1, wherein said selected wavelengths for which said component intensities are normalized in step (e) comprise a plurality of wavelengths selected based upon the extent to which the intensities of light components at said wavelengths are effected by variations in said concentration of said constituent.

11. The method according to claim 1, wherein said selected wavelengths for which said component intensities are normalized in step (e) comprise a plurality of wavelengths, and further comprising the step of selecting said plurality of wavelengths based upon the extent to which the intensities of light components at said wavelengths contribute to the prediction of said concentration of said constituent.

12. The method according to claim 11, wherein the step of selecting said plurality of wavelengths based upon the extent

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to which the intensities of light components at said wavelengths contribute to the prediction of said concentration of said constituent comprises the steps of:

i) directing a calibration beam of light into a plurality of fluid calibration mixtures so as to cause light to emerge from each of said calibration mixtures, each of said calibration mixtures containing predetermined varying concentrations of said constituent, said light emerging from said calibration mixtures comprised of components each of which has a different wavelength;

j) measuring the intensity of each of said components of said light emerging from said calibration mixtures having a wavelength falling within said predetermined range of wavelengths;

k) normalizing said measured intensities of said light components emerging from said calibration mixtures;

l) performing a regression analysis on said normalized intensities of said calibration mixtures.

13. The method according to claim 1, wherein at least a portion of said respective exponents by which said normalized light component intensities are raised in step (f) have a value that is not equal to 1.

14. The method according to claim 1, wherein each of said respective exponents by which said normalized light component intensities are raised in step (f) has a value equal to 1.

15. The method according to claim 1, wherein at least a portion of said of said weighting factors are negative.

16. The method according to claim 1, wherein said wavelengths at which said component intensities are measured in step (d) comprises each of said wavelengths within said predetermined range of wavelengths.

17. The method according to claim 16, wherein said predetermined range of wavelengths encompasses at least a portion of the near infrared range.

18. The method according to claim 17, wherein said selected wavelengths for which said component intensities are normalized in step (e) comprise every wavelength at which said component intensity is measured.

19. The method according to claim 17, wherein said selected wavelengths for which said component intensities are normalized in step (e) comprise less than every wavelength at which said component intensity is measured.

20. The method according to claim 18, wherein said selected wavelengths for which said component intensities are normalized in step (e) comprise at least two wavelengths.

21. The method according to claim 1, wherein said selected wavelengths for which said component intensities are normalized in step (e) comprise each wavelength at which said component intensity is measured.

22. The method according to claim 1, wherein said selected wavelengths for which said component intensities are normalized in step (e) comprise less than every wavelength at which said component intensity is measured.

23. The method according to claim 1, wherein said selected wavelengths for which said component intensities are normalized in step (e) comprise at least two wavelengths.

24. The method according to claim 1, further comprising the step of determining said weighting factors by:

i) directing a calibration beam of light into a plurality of fluid calibration mixtures so as to cause light to emerge from each of said calibration mixtures, each of said calibration mixtures containing predetermined varying concentrations of said constituent, said light emerging from said calibration mixtures comprised of components each of which has a different wavelength;

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- j) measuring the intensity of each of said components of said light emerging from said calibration mixtures having a wavelength falling within said predetermined range of wavelengths;
- k) normalizing at least a selected portion of said measured intensities of said light components emerging from said calibration mixtures;
- l) performing a regression analysis on said normalized intensities of said calibration mixtures so as to determine said weighting factors.

25. The method according to claim 1, wherein said constituent is oil.

26. The method according to claim 1, wherein said constituent is natural gas.

27. The method according to claim 1, wherein said constituent is water.

28. The method according to claim 1, wherein said beam of light directed into said fluid is comprised of at least one component having a wavelength in the near infrared range.

29. The method according to claim 1, wherein said beam of light directed into said fluid is comprised of components having wavelengths that encompass at least a portion of the near infrared range.

30. The method according to claim 1, wherein said predetermined range of wavelengths within which the wavelengths of said measured components fall comprises at least a portion of the near-infrared range.

31. The method according to claim 1, wherein the step of combining said weighted and normalized light component intensities at said selected wavelengths so as to calculate said concentration of said constituent comprises summing each of said weighted and normalized light component intensities at said selected wavelengths.

32. A method of determining at a first location the concentration C of at least one predetermined constituent k in a fluid n located at a second location remote from the first location, comprising the steps of:

- a) generating a beam of light proximate said first location;
- b) transmitting said beam of light to said second location;
- c) directing said beam of light into said fluid n at said second location so as to cause light to emerge from said fluid, said emerging light comprised of a plurality of components each of which has a different wavelength;
- d) transmitting at least a portion of said emerging light to said first location;
- e) measuring the intensity I of each of at least a portion of said components of said transmitted light at said first location, each of said light components having a wavelength falling within a predetermined range of wavelengths;
- d) normalizing at least m measured light component intensities having selected wavelengths i so as to determine normalized light component intensities IN_{mi} ;
- e) calculating said concentration C of said constituent k by inputting said normalized light component intensities into an equation of the form:

$$C_{kn} = \sum_{i=1}^m \beta_{ki} IN_{mi}^{\alpha_{ki}} + b_k$$

where:

β_{ki} =Weighting factors for constituent k at wavelengths i

α_{ki} =Exponents for constituent k at wavelengths i, at least a portion of said exponents being not equal to one, whereby said equation is non-linear

b_k =A constant for constituent k.

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33. The method according to claim 32, wherein at least a portion of said weighting factors β_i are equal to zero.

34. The method according to claim 32, wherein at least a portion of said exponents α_i are equal to 1.

35. The method according to claim 32, wherein the step of normalizing said component intensities at said selected wavelengths i comprises dividing each of selected component intensities by the vector length f of said measured component intensities, said vector length being calculated from the equation:

$$f = \sqrt{\sum_{i=1}^m I_i^2}$$

where:

I_i =the intensity of the light component having wavelength i.

36. The method according to claim 32, wherein said constituent has at least one wavelength at which the absorption of light contacting said constituent peaks, and wherein said predetermined range of wavelengths within which the wavelengths of said measured components fall encompasses said absorption peak.

37. The method according to claim 32, wherein at least one of the components of said light directed to said fluid has a wavelength that causes said constituent to emit fluorescent radiation so that at least a portion of said light emerging from said fluid comprises fluorescent radiation emitted by said fluid.

38. The method according to claim 32, wherein said second location is downhole in a well and said first location is proximate the surface of the earth.

39. An apparatus for determining the concentration of a predetermined constituent in a fluid flowing through a downhole portion a well, comprising:

- a) means for generating a beam of light;
- b) a section of pipe for directing the flow of said fluid flowing in said well toward the surface of the earth;
- c) a sensor incorporated in the wall of said section of pipe, said sensor having (i) means for directing said beam of light into said fluid flowing through said downhole portion of said well so as to cause light to emerge from said fluid, said emerging light comprised of a plurality of components each of which having a different wavelength, said light emerging from said fluid having been scattered by said fluid prior to emerging therefrom, and (ii) means for collecting at least a portion of said light emerging from said fluid;
- d) a fiber optic cable for transmitting at least a portion of said light collected by said sensor to a location proximate the surface of the earth;
- e) means for measuring the intensity of each of said components of said transmitted light having a wavelength falling within a predetermined range of wavelengths at said location proximate the surface of the earth;
- f) normalizing means for reducing the effect of said scattering of said light by dividing at least a selected portion of said measured component intensities by a characteristic derived from said measured component intensities;
- g) means for multiplying each of said normalized light component intensities by a predetermined weighting factor based upon the respective wavelength of said

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light component so as to obtain weighted and normalized light component intensities; and

- h) means for determining said concentration of said constituent by combining said weighted and normalized selected light component intensities.

40. The apparatus according to claim 39, further comprising a mixer disposed in said well for mixing said fluid before said beam of light is directed into said fluid by said light beam directing means.

41. The apparatus according to claim 39, further comprising a diverter disposed in said well for diverting at least a portion of said fluid toward said means for measuring said component intensities.

42. The apparatus according to claim 39, further comprising a computer, and wherein said means for normalizing said selected portion of said measured component intensities and said means for determining said concentration of said constituent comprises software program into said computer.

43. The apparatus according to claim 39, wherein said means for multiplying said normalized selected light component intensities by said predetermined weighting factors and said means for determining said concentration of said constituent by combining said weighted and normalized selected light component intensities comprises software programed into a computer.

44. The apparatus according to claim 39, further comprising means for raising each of said normalized light component intensities by a respective exponent, at least a portion of said exponents not being equal to one.

45. A method of determining the concentration of at least one predetermined constituent in a fluid flowing through a downhole portion of a well, comprising the steps of:

- a) generating a beam of light;
- b) directing said beam of light into said fluid flowing through said downhole portion of said well so as to cause light to emerge from said fluid, said light directed into said fluid having at least one component having a wavelength that causes said constituent to emit fluorescent radiation so that at least a portion of said light emerging from said fluid comprises fluorescent radiation emitted by said fluid, said emerging light having been scattered by said fluid and comprised of a plurality of components each of which has a different wavelength;
- c) transmitting at least a portion of said emerging light to a location proximate to the surface of the earth;
- d) measuring the intensity of each of at least a portion of said components of said transmitted light, each of said light components in said portion of light components having a wavelength falling within a predetermined range of wavelengths, said light component intensity measurements being conducted at said location proximate said surface;
- e) normalizing at least those of said measured light component intensities having selected wavelengths by dividing said intensities by a characteristic derived from said measured component intensities, so as to reduce the effect of said scattering of said light components;
- f) raising each of said normalized light component intensities at said selected wavelengths by a respective exponent, said exponents being any non-zero numbers;
- g) multiplying each of said exponentially raised normalized light component intensities at said selected wavelengths by a predetermined weighting factor based

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upon its respective wavelength so as to obtain a weighted and normalized light component intensity at each of said selected wavelengths; and

- h) combining said weighted and normalized light component intensities at said selected wavelengths so as to calculate said concentration of said constituent.

46. The method according to claim 45, wherein said beam of light directed into said fluid is essentially monochromatic, and wherein the step of normalizing said measured component intensities comprises dividing each of said measured component intensities by the intensity of said measured light component having a wavelength equal to that of said essentially monochromatic beam of light.

47. The method according to claim 45, wherein said beam of light directed to said fluid is essentially monochromatic.

48. The method according to claim 47, wherein said monochromatic beam of light directed to said fluid has a wavelength of approximately 852 nm.

49. The method according to claim 45, wherein at least a portion of said respective exponents by which said normalized light component intensities are raised in step (f) have a value that is not equal to one.

50. The method according to claim 45, wherein each of said respective exponents by which said normalized light component intensities are raised in step (f) has a value equal to one.

51. The method according to claim 45, wherein said selected wavelengths for which said component intensities are normalized in step (e) comprise less than every wavelength at which said component intensity is measured.

52. A method of determining the concentration of at least one predetermined constituent in a fluid flowing through a downhole portion of a well, comprising the steps of:

- a) generating a beam of light;
- b) directing said beam of light into said fluid flowing through said downhole portion of said well so as to cause light to emerge from said fluid, said emerging light having been scattered by said fluid and comprised of a plurality of components each of which has a different wavelength;
- c) transmitting at least a portion of said emerging light to a location proximate to the surface of the earth;
- d) measuring the intensity of each of at least a portion of said components of said transmitted light, each of said light components in said portion of light components having a wavelength falling within a predetermined range of wavelengths, said light component intensity measurements being conducted at said location proximate said surface;
- e) normalizing only those of said measured light component intensities that have wavelengths corresponding to a selected predetermined set of wavelengths, so as to produce normalized light component intensities at only said predetermined wavelengths, said predetermined set of wavelengths selected by:
 - (A) directing a calibration beam of light into a plurality of fluid calibration mixtures so as to cause light to emerge from each of said calibration mixtures, each of said calibration mixtures containing predetermined varying concentrations of said constituent, said light emerging from said calibration mixtures comprised of components each of which has a different wavelength;
 - (B) measuring the intensity of at least a portion of said components of said light emerging from said calibration mixtures;

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- (C) normalizing said measured intensities of said light components emerging from said calibration mixtures;
- (D) performing a regression analysis on said normalized intensities of said calibration mixtures;
- f) multiplying by predetermined weighting factors only said normalized light component intensities at said predetermined set of wavelengths, so as to obtain a set of weighted and normalized light component intensity at each of said wavelengths in said predetermined set of wavelengths; and

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- h) combining said weighted and normalized light component intensities at said predetermined set of wavelengths so as to calculate said concentration of said constituent.

5 **53.** The apparatus according to claim **52**, further comprising means for raising each of said normalized light component intensities by a respective exponent, at least a portion of said exponents not being equal to one.

* * * * *

UNITED STATES PATENT AND TRADEMARK OFFICE
CERTIFICATE OF CORRECTION

PATENT NO. : 6,507,401 B1
DATED : January 14, 2003
INVENTOR(S) : Turner et al.

Page 1 of 1

It is certified that error appears in the above-identified patent and that said Letters Patent is hereby corrected as shown below:

Column 14,

Line 12, please delete " $IN_{in}=IN_{in}/fn$ " and insert therefor -- $IN_{in}=I_{in}/fn$ --;

Column 22,

Line 5, please delete " $C=\beta_0+\beta_1 \cdot IN_1+\beta_2 \cdot IN_2+\dots+\beta_{m-1}IN_m+e$ " and insert therefor
-- $C=\beta_0+\beta_1 \cdot IN_1+\beta_2 \cdot IN_2+\dots+\beta_m \cdot IN_m+e$ --;

Signed and Sealed this

Eighteenth Day of November, 2003

A handwritten signature in black ink, appearing to read "James E. Rogan", with a horizontal line drawn underneath it.

JAMES E. ROGAN
Director of the United States Patent and Trademark Office