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(54) DISTRIBUTED SENSOR NETWORK

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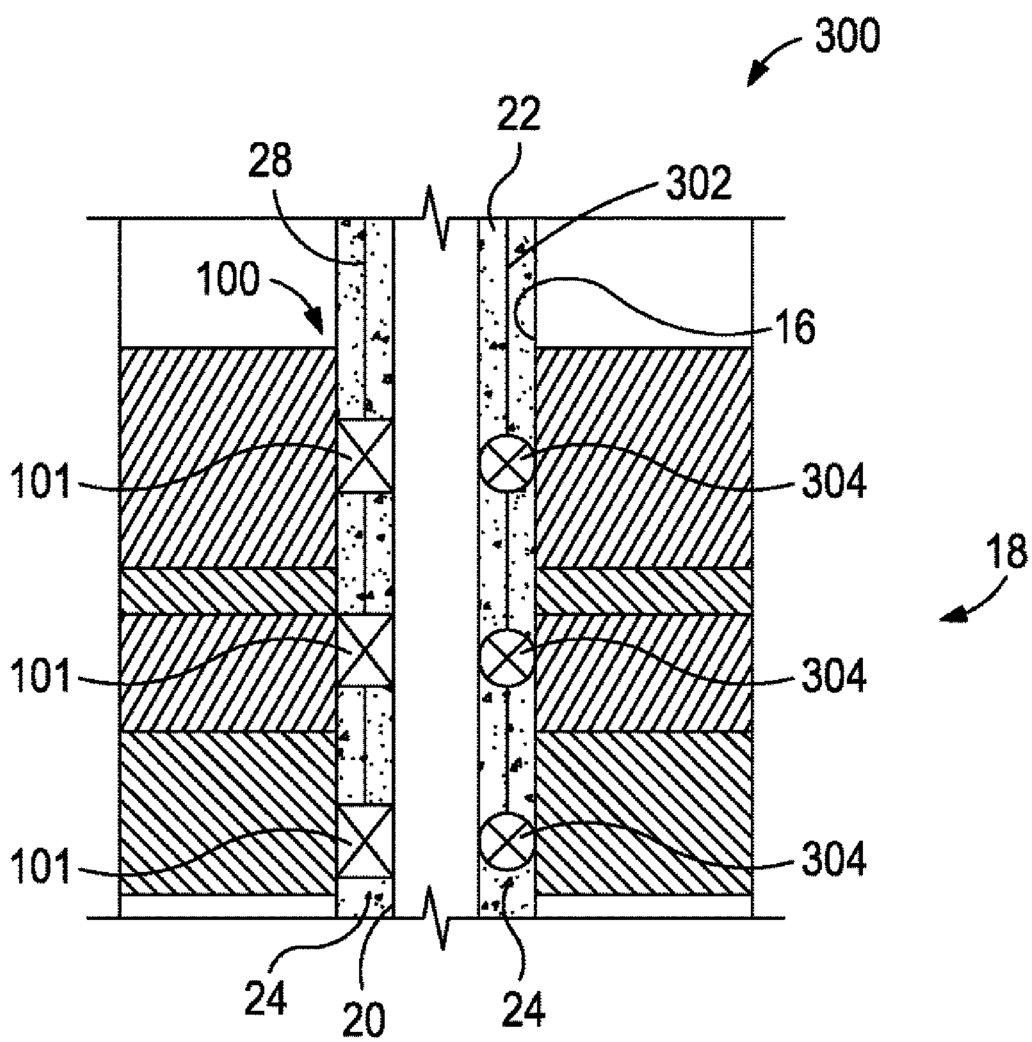
(57) **ABSTRACT**

A system may include a sensor to detect a characteristic of a fluid and output an electrical signal proportional to the characteristic, an acoustic signal generator to output an acoustic signal proportional to the electrical signal, and a signal detection apparatus to generate a signal proportional to the acoustic signal and transmit the signal to a remote location.



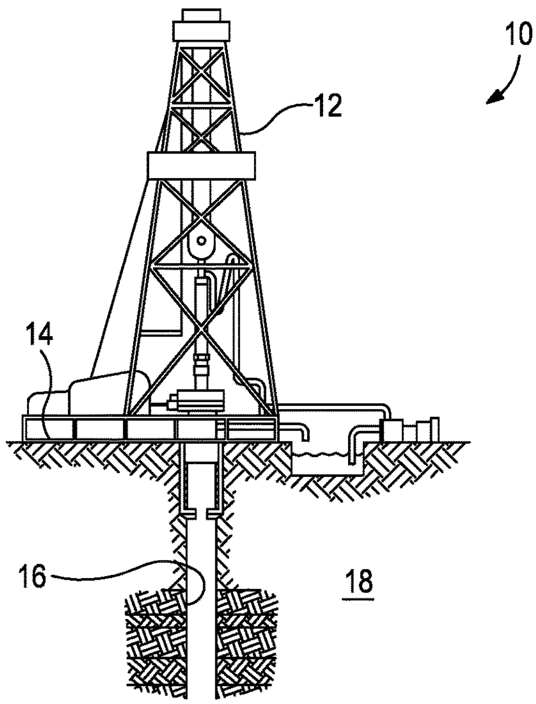


FIG. 1A

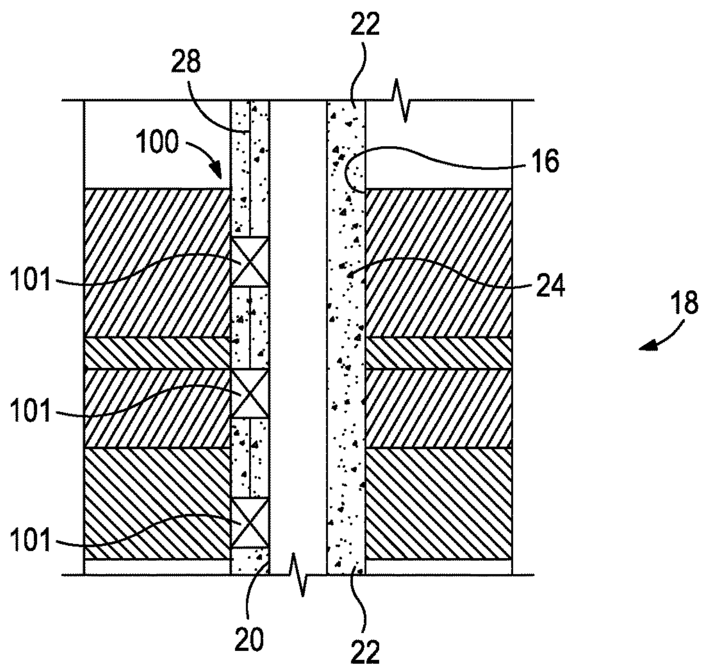


FIG. 1B

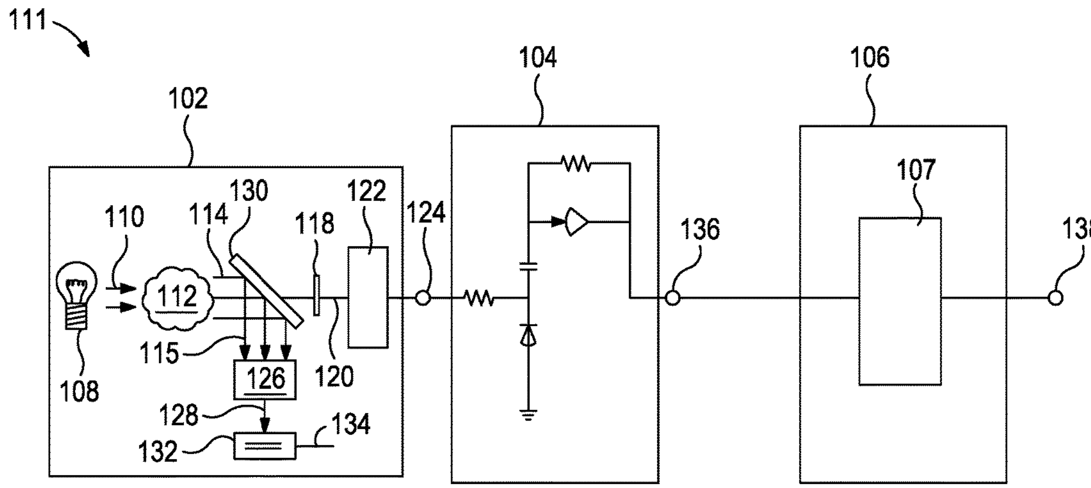

111
102
104
106
107
108
110
112
114
115
118
120
122
124
126
128
130
132
134
136
138

FIG. 2A

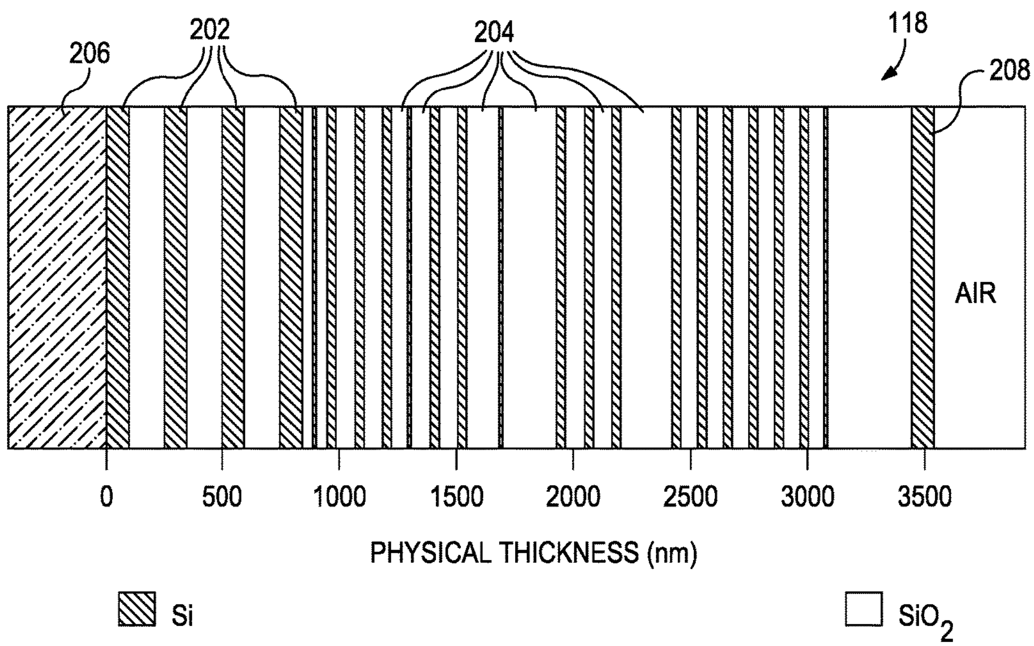

206
202
204
118
208
AIR
0
500
1000
1500
2000
2500
3000
3500
PHYSICAL THICKNESS (nm)
Si
SiO2

FIG. 2B

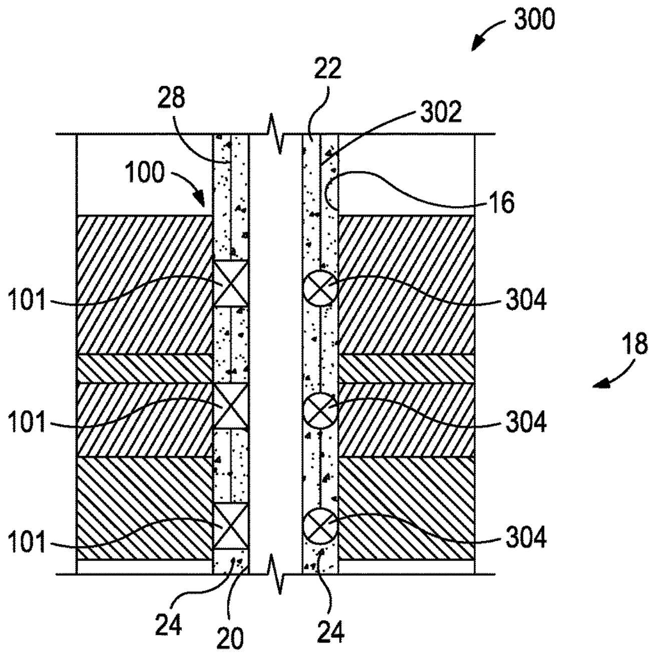

300
22
28
302
100
16
101
304
18
101
304
101
304
24
20
24

FIG. 3

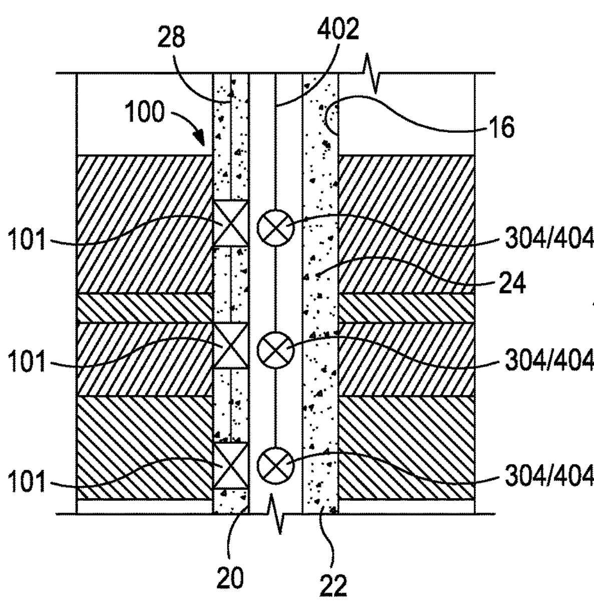

28
402
100
16
101
304/404
24
18
101
304/404
101
304/404
20
22

FIG. 4

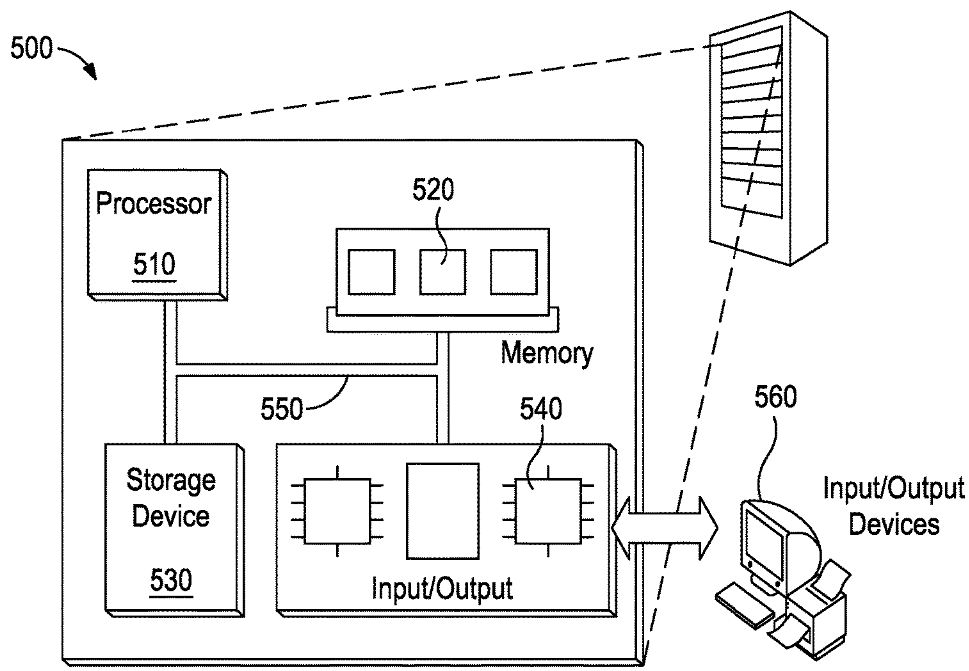

500
Processor
510
520
Memory
550
540
Storage Device
530
Input/Output
560
Input/Output Devices

FIG. 5

DISTRIBUTED SENSOR NETWORK

BACKGROUND

[0001] In the oil and gas industry, it can be required to measure the characteristics and/or compositions of substances located at remote subterranean locations and convey the results to the earth's surface for processing and analysis. For instance, it may be required to measure chemical and/or physical properties of substances located in subterranean hydrocarbon-bearing formations and convey the results of the measurement over long distances to the earth's surface. The measurements may be carried out using electrical devices; however, there is a limited amount of electrical power available to operate such electrical devices and transmit the measurements over long distances to the surface using electrical signals with a high signal-to-noise ratio (SNR).

BRIEF DESCRIPTION OF THE DRAWINGS

[0002] The following figures are included to illustrate certain aspects of the present disclosure, and should not be viewed as exclusive embodiments. The subject matter disclosed is capable of considerable modifications, alterations, combinations, and equivalents in form and function, without departing from the scope of this disclosure.

[0003] FIG. **1**A illustrates an exemplary well system that may embody or otherwise employ one or more principles of the present disclosure.

[0004] FIG. **1**B illustrates an enlarged cross-sectional view of the wellbore shown in FIG. **1**A.

[0005] FIG. **2**A illustrates an exemplary sensor included in a sensor system of FIG. **1**B.

[0006] FIG. **2**B illustrates a cross-sectional side view of an exemplary integrated computation element (ICE) included in the sensor of FIG. **2**A.

[0007] FIG. **3** illustrates an exemplary fiber optic based Distributed Acoustic Sensing (DAS) network.

[0008] FIG. **4** illustrates another exemplary fiber optic based Distributed Acoustic Sensing (DAS) network.

[0009] FIG. **5** illustrates an exemplary processing system for configuring and/or controlling the sensor system of FIG. **1**A and the DAS networks of FIGS. **3** and **4**.

DETAILED DESCRIPTION

[0010] Embodiments described herein relate to a distributed network of sensors for measuring physical and/or chemical properties of substances located in deep subterranean hydrocarbon reservoirs. The distributed network can include a variety of sensors that are located downhole for sensing chemical or physical properties of substances located in the hydrocarbon reservoirs. Embodiments may be directed to systems and methods for converting the electrical signals obtained from the sensors to acoustic signals, converting the acoustic signals to optical signals, and subsequently transmitting the optical signals to the surface via fiber optics.

[0011] Converting the electrical signals to acoustic signals may permit deployment of sensors over long downhole distances without the need for deploying long electrical conductors to the surface or deploying power consuming processing units to convert and convey a high SNR electrical signal to the surface.

[0012] As used herein, the term "fluid" refers to any substance that is capable of flowing, including particulate solids, liquids, gases, slurries, emulsions, powders, muds, glasses, combinations thereof, and the like. In some embodiments, the fluid can be an aqueous fluid, including water or the like. In some embodiments, the fluid can be a non-aqueous fluid, including organic compounds, more specifically, hydrocarbons, oil, a refined component of oil, petrochemical products, and the like. In some embodiments, the fluid can be a treatment fluid or a formation fluid as found in the oil and gas industry. Fluids can include various flowable mixtures of solids, liquids and/or gases. Illustrative gases that can be considered fluids according to the present embodiments include, for example, air, nitrogen, carbon dioxide, argon, helium, methane, ethane, butane, and other hydrocarbon gases, combinations thereof and/or the like.

[0013] As used herein, the term "characteristic" or "characteristic of interest" refers to a chemical, mechanical, or physical property of the fluid or a sample of the fluid, also referred to herein as the substance or a sample of the substance. The characteristic of the fluid may include a quantitative or qualitative value of one or more chemical constituents or compounds present therein or any physical property associated therewith. Such chemical constituents and compounds may be referred to herein as "analytes." Illustrative characteristics of the fluid that can be detected with the sensors described herein can include, for example, chemical composition (e.g., identity and concentration in total or of individual components), phase presence (e.g., gas, oil, water, etc.), impurity content, pH, alkalinity, viscosity, density, ionic strength, total dissolved solids, salt content (e.g., salinity), porosity, opacity, bacteria content, total hardness, transmittance, combinations thereof, state of matter (solid, liquid, gas, emulsion, mixtures thereof, etc.), and the like.

[0014] As used herein, the term "component," or variations thereof, refers to at least a portion of a substance or material of interest in the fluid to be evaluated using the sensors disclosed herein. In some embodiments, the component is the characteristic of interest, as defined above, and may include any integral constituent of the fluid flowing within the flow path.

[0015] For example, the component may include compounds containing elements such as barium, calcium (e.g., calcium carbonate), carbon (e.g., graphitic resilient carbon), chlorine (e.g., chlorides), manganese, sulfur, iron, strontium, chlorine, etc., and any chemical substance that may lead to precipitation within a flow path. The component may also refer to paraffins, waxes, asphaltenes, clays (e.g., smectite, illite, kaolins, etc.), aromatics, saturates, foams, salts, particulates, hydrates, sand or other solid particles (e.g., low and high gravity solids), combinations thereof, and the like. In yet other embodiments, in terms of quantifying ionic strength, the component may include various ions, such as, but not limited to, Ba2+, Sr2+, Fe+, Fe2+(or total Fe), Mn2+, SO4 2−, CO32−, Ca2+, Mg2 30+, Na+, K+, Cl−.

[0016] In other aspects, the component may refer to any substance or material added to the fluid as an additive or in order to treat the fluid or the flow path. For instance, the component may include, but is not limited to, acids, acid-generating compounds, bases, base-generating compounds, biocides, surfactants, scale inhibitors, corrosion inhibitors, gelling agents, crosslinking agents, anti-sludging agents, foaming agents, defoaming agents, antifoam agents, emulsifying agents and emulsifiers, de-emulsifying agents, iron control agents, proppants or other particulates, gravel, particulate diverters, salts, fluid loss control additives, gases, catalysts, clay control agents, clay stabilizers, clay inhibitors, chelating agents, corrosion inhibitors, dispersants, flocculants, base fluids (e.g., water, brines, oils), scavengers (e.g., H2S scavengers, CO2 scavengers or O2 scavengers), lubricants, breakers, delayed release breakers, friction reducers, bridging agents, viscosifiers, thinners, high-heat polymers, tar treatments, weighting agents or materials (e.g., barite, etc.), solubilizers, rheology control agents, viscosity modifiers, pH control agents (e.g., buffers), hydrate inhibitors, relative permeability modifiers, diverting agents, consolidating agents, fibrous materials, bactericides, tracers, probes, nanoparticles, and the like. Combinations of these substances can be referred to as a substance as well.

[0017] As used herein, the term "flow path" refers to a route through which a fluid is capable of being transported between two points. Exemplary flow paths include, but are not limited to, a flowline, a pipeline, a hose, a process facility, a storage vessel, a tanker, a railway tank car, a transport ship or vessel, a trough, a stream, a sewer, a subterranean formation, etc., combinations thereof, or the like.

[0018] FIG. **1**A illustrates an exemplary well system **10** that may embody or otherwise employ one or more principles of the present disclosure, according to one or more embodiments. As illustrated, the well system **10** may include a service rig **12** that is positioned on the earth's surface **14** and extends over and around a wellbore **16** that penetrates one or more subterranean formations **18**. The service rig **12** may be a drilling rig, a completion rig, a workover rig, or the like. In some embodiments, the service rig **12** may be omitted and replaced with a standard surface wellhead completion or installation. Moreover, while the well system **10** is depicted as a land-based operation, it will be appreciated that the principles of the present disclosure could equally be applied in any sea-based or sub-sea application where the service rig **12** may be a floating platform or sub-surface wellhead installation, as generally known in the art.

[0019] The wellbore **16** may be drilled into the subterranean formation **18** using any suitable drilling technique and may extend in a substantially vertical direction away from the earth's surface **14**. Although not illustrated, at some point the wellbore **16** may deviate from vertical relative to the earth's surface **14** and transition from the substantially vertical direction into a substantially horizontal direction.

[0020] FIG. **1**B illustrates an enlarged cross-sectional view of the wellbore **16** in the formation **18**. As illustrated, the wellbore **16** may be at least partially lined with casing **20**, which may comprises a string of metal tubulars connected end to end and secured within the wellbore **16** to provide a protective wellbore lining. The casing **20** can alternatively be replaced with liner or other metallic or non-metallic tubing. Thus, the scope of this disclosure is not limited to use of any particular type of casing. An annulus **22** is defined between the casing **20** and the wellbore **16**, and the casing **20** may be secured within the wellbore **16** using cement **24** positioned in the annulus **22**, which seals the annulus **22**.

[0021] As illustrated, a sensor system **100** may be positioned in the annulus **22**, for instance, during the construction of the wellbore **16**. As illustrated, the sensor system **100** may include a plurality of sensors **101** communicably coupled to a control line **28** that may supply power to the sensors **101** from a source located on the surface **14** or a location downhole. The control line **28** and the sensor system **100** may be secured within the annulus **22** with the cement **24**. The sensors **101** may be deployed as a function of depth during the deployment of the casing **20**.

[0022] The control line **28** may also facilitate communication to remote locations, such as the surface **14** (FIG. **1**A). Accordingly, the control line **28** may be or otherwise include one or more transmission media such as, but not limited to, optical fibers, electrical wires, or the like, via which the output of the sensors **101** may transmitted to the surface **14** for processing and/or control signals from the surface **14** may be transmitted to the sensor system **100** for controlling operation thereof.

[0023] The sensors **101** of the sensor system **100** may comprise a variety of sensors capable of sensing chemical or physical properties associated with the subterranean formations **18**. In one embodiments, for instance, one or more of the sensors **101** may include chemical sensors that function based on electromagnetic radiation (commonly referred to as "opticoanalytical devices"), quasi-distributed chemical sensors, electrochemical sensors (e.g., pH sensors), or the like. In other embodiments, or in addition thereto, one of more of the sensors **101** may include optical sensors, physical property sensors, density sensors, viscosity sensors, temperature sensors, pressure sensors (e.g., microphone based sensors), and electrical sensors, for example, a thermopile optoelectronic transducer. The sensors **101** can be configured to detect not only the composition and concentrations of a fluid or a component therein, but they also can be configured to determine physical properties and other characteristics of the fluid and/or components present within the fluid.

[0024] In at least one embodiment, one or more of the sensors **101** may comprise an optical computing device. As used herein, the term "optical computing device" refers to an optical device that is configured to receive an input of electromagnetic radiation from a fluid, or a substance within the fluid, and produce an output of electromagnetic radiation from a processing element arranged within the optical computing device. The processing element may be, for example, an integrated computational element (ICE) used in the optical computing device. As discussed in greater detail below, the electromagnetic radiation that optically interacts with the processing element is changed so as to be readable by a detector, such that an output of the detector can be correlated to at least one substance measured or monitored within the fluid. The output of electromagnetic radiation from the processing element can be reflected electromagnetic radiation, transmitted electromagnetic radiation, and/or dispersed electromagnetic radiation. Whether reflected, transmitted, or dispersed electromagnetic radiation is eventually analyzed by the detector may be dictated by the structural parameters of the optical computing device as well as other considerations known to those skilled in the art. In addition, emission and/or scattering of the substance, for example via fluorescence, luminescence, Raman scattering, and/or Raleigh scattering, can also be monitored by the optical computing devices. Optical computing devices, however, are merely one example of a sensor **101** that may be included in the sensor system **100**, which may include (alternatively or in addition thereto) any type of electrical, chemical, and/or mechanical sensors, without departing from the scope of the disclosure.

[0025] FIG. **2**A illustrates an exemplary sensor **111** that may be included in the sensor system **100** of FIG. **1**B, according to one or more embodiments. The sensor **111** may be the same as or similar to any of the sensors **101** depicted in FIG. **1**B. As illustrated, the sensor **111** may include an optical sensor **102**, a voltage-to-frequency convertor **104**, and an acoustic signal generator **106**. The optical sensor **102** may be configured specifically detect and/or measure a particular component or characteristic of interest of a fluid present within the annulus **22** or any flow lines or pipelines extending to/from the wellbore **16**.

[0026] In some embodiments, the optical sensor **102** may include an electromagnetic radiation source **108** configured to emit or otherwise generate electromagnetic radiation **110**. The electromagnetic radiation **110** may refer to radio waves, microwave radiation, infrared and near-infrared radiation, visible light, ultraviolet light, X-ray radiation, and gamma ray radiation. The electromagnetic radiation source **108** may be any device capable of emitting or generating electromagnetic radiation. For example, the electromagnetic radiation source **108** may be a light bulb, a light emitting diode (LED), a laser, a blackbody, a photonic crystal, an X-Ray source, combinations thereof, or the like. In some embodiments, a lens (not illustrated) may be configured to collect or otherwise receive the electromagnetic radiation **110** and direct a beam of the electromagnetic radiation **110** toward the fluid **112**.

[0027] The electromagnetic radiation **110** impinges upon and optically interacts with a fluid, generally indicated as **112**, and any components present within the fluid **112**. Herein, "optically interact" or variations thereof may refer to the reflection, transmission, scattering, diffraction, or absorption of electromagnetic radiation. As a result, optically interacted radiation **114** is generated by the fluid **112**. The optically interacted radiation **114** may be directed to or otherwise be received by an ICE **118** arranged within the optical sensor **102**. In operation, the ICE **118** may be configured to receive the optically interacted radiation **114** and produce modified electromagnetic radiation **120** corresponding to a particular characteristic of the fluid **112**. In particular, the modified electromagnetic radiation **120** is electromagnetic radiation that has optically interacted with the ICE **118**, which is programmed to have an optical profile that mimics a regression vector corresponding to the characteristic of the fluid **112**.

[0028] Referring briefly to FIG. **2**B, illustrated a cross-sectional side view of the ICE **118** suitable for use in the optical sensor **102** of FIG. **2**A. As illustrated, ICE **118** may include a plurality of alternating layers **202** and **204**, such as silicon (Si) and SiO_2 (quartz), respectively. In general, these layers **202**, **204** consist of materials whose index of refraction is high and low, respectively. Other examples might include niobia and niobium, germanium and germania, MgF, SiO_x, and other high and low index materials known in the art. An optical substrate **206** provides support to layers **202**, **204**, according to some embodiments. In some embodiments, optical substrate **206** is BK-7 optical glass. In other embodiments, optical substrate **206** may be another type of optical substrate, such as quartz, sapphire, silicon, germanium, zinc selenide, zinc sulfide, or various plastics such as polycarbonate, polymethylmethacrylate (PMMA), polyvinylchloride (PVC), diamond, ceramics, combinations thereof, and the like.

[0029] At the opposite end (e.g., opposite optical substrate **206** in FIG. **2**A), ICE **118** may include a layer **208** that is generally exposed to the environment of the device or installation. The number of layers **202**, **204** and the thickness of each layer **202**, **204** are determined from the spectral attributes acquired from a spectroscopic analysis of a characteristic of interest using a conventional spectroscopic instrument. The spectrum of interest of a given characteristic of interest typically includes any number of different wavelengths. The exemplary ICE **118** in FIG. **2**A does not in fact represent any particular characteristic of interest, but is provided for purposes of illustration only. Consequently, the number of layers **202**, **204** and their relative thicknesses, as shown in FIG. **2**A, bear no correlation to any particular characteristic of interest. Nor are layers **202**, **204** and their relative thicknesses necessarily drawn to scale, and therefore should not be considered limiting of the present disclosure. Moreover, those skilled in the art will readily recognize that the materials that make up each layer **202**, **204** (i.e., Si and SiO_2) may vary, depending on the application, cost of materials, and/or applicability of the materials to the monitored substance.

[0030] In some embodiments, the material of each layer **202**, **204** can be doped or two or more materials can be combined in a manner to achieve the desired optical characteristic. In addition to solids, ICE **118** may also contain liquids and/or gases, optionally in combination with solids, in order to produce a desired optical characteristic. In the case of gases and liquids, ICE **118** can contain a corresponding vessel (not shown), which houses gases or liquids. Exemplary variations of ICE **118** may also include holographic optical elements, gratings, piezoelectric, light pipe, digital light pipe (DLP), variable optical attenuators, and/or acousto-optic elements, for example, that can create transmission, reflection, and/or absorptive properties of interest.

[0031] Layers **202**, **204** exhibit different refractive indices. By properly selecting the materials of layers **202**, **204**, their relative thicknesses and spacing ICE **118** may be configured to selectively pass/reflect/refract predetermined fractions of electromagnetic radiation at different wavelengths. Each wavelength is given a predetermined weighting or loading factor. The thickness and spacing of layers **202**, **204** may be determined using a variety of approximation methods from the spectrograph of the characteristic of interest. These methods may include inverse Fourier transform (IFT) of the optical transmission spectrum and structuring ICE **118** as the physical representation of the IFT. The approximations convert the IFT into a structure based on known materials with constant refractive indices.

[0032] The weightings that layers **202**, **204** of ICE **118** apply at each wavelength are set to the regression weightings described with respect to a known equation, or data, or spectral signature. Briefly, ICE **118** may be configured, in conjunction with the optical transducer or detector **122** described in more detail below, to perform the dot product of the input light beam into ICE **118** and a desired loaded regression vector represented by each layer **202**, **204** for each wavelength. As a result, the output light intensity of ICE **118**, as measured by detector **122**, is related to the characteristic of interest.

[0033] Referring again to FIG. **2**A, the modified electromagnetic radiation **120** generated by the ICE **118** may subsequently be conveyed to a detector **122**. The detector **122** may be any device capable of detecting electromagnetic radiation, and may be generally characterized as an optical transducer. In some embodiments, the detector **122** may be, but is not limited to, a thermal detector such as a thermopile or photoacoustic detector, a semiconductor detector, a piezoelectric detector, a charge coupled device (CCD) detector, a video or array detector, a split detector, a photon detector (such as a photomultiplier tube), photodiodes, combinations thereof, or the like, or other detectors known to those skilled in the art.

[0034] In some embodiments, the detector **122** may be configured to produce an output signal **124** in real-time or near real-time in the form of a voltage (or current) that corresponds to the particular characteristic of interest in the fluid **112**. In at least one embodiment, the output signal **124** produced by the detector **122** may be directly proportional to the characteristic of the fluid **112**, such as the concentration of a particular analyte of interest present therein. In other embodiments, the relationship may be a polynomial function, an exponential function, and/or a logarithmic function.

[0035] In some embodiments, the optical sensor **102** may include a second detector **126**, which may be similar to the first detector **122** in that it may be any device capable of detecting electromagnetic radiation. The second detector **126** can be arranged to detect the reflected optically interacted light **115**. In other embodiments, the second detector **126** may be arranged to detect the electromagnetic radiation **114** derived from the fluid **112** or electromagnetic radiation directed toward or before the fluid **112**. Without limitation, the second detector **126** may be used to detect radiating deviations stemming from the electromagnetic radiation source **108**. For example, radiating deviations can include such things as, but not limited to, intensity fluctuations in the electromagnetic radiation, interferent fluctuations (e.g., dust or other interferents passing in front of the electromagnetic radiation source), coatings on windows included with the optical sensor **102**, combinations thereof, or the like. As illustrated, the second detector **126** may be configured to receive a portion of the optically interacted radiation **114** via a beamsplitter **130** in order to detect the radiating deviations. To compensate for these types of undesirable effects, the second detector **126** may be configured to generate a compensating signal **128** generally indicative of the radiating deviations of the electromagnetic radiation source **108**. The compensating signal **128** may be conveyed to or otherwise received by a signal processor **132** configured to provide an output signal **134**. In an embodiment (not illustrated), the output signal **134** may be provided to the detector **122** in order to normalize the output signal **124** in view of any radiating deviations detected by the second detector **126**.

[0036] As mentioned above, the sensor **111** is simply an example of a variety of sensors that may be used in the sensor system **100**. As such, the optical sensor **102** can be replaced with any other sensor mentioned herein and, thus, the output signal **124** can come from any of those sensors.

[0037] The output signal **124** may be an electrical signal, for instance a voltage signal, and may be provided to the voltage-to-frequency convertor (or, a frequency generator) **104**, which, for instance, may be or include a voltage-controlled oscillator (VCO) or a phase-locked loop (PLL). In an embodiment, the output signal **124** may be a current signal, which may be converted to a voltage signal before being received by the voltage-to-frequency convertor **104**. As mentioned above, the output signal **124** may be proportional to the characteristic of interest of the fluid **112**. Because the output signal **124** may determine or control a frequency (also referred to as the oscillation frequency) of a signal at an output **136** of the voltage-to-frequency convertor **104**, the frequency of the signal at the output **136** may be proportional to the characteristic of interest of the fluid **112**. Accordingly, any variation in the characteristic of interest (e.g., concentration of a particular analyte) of the fluid **112** may proportionally vary the frequency of the signal at the output **136**. Alternatively, the frequency of the signal at the output **136** may be set at a predetermined base frequency, and an amplitude of the signal may be proportionally varied based on the variation in the characteristic of interest in the fluid **112**.

[0038] The output **136** of the voltage-to-frequency convertor **104** may be provided to the acoustic signal generator (e.g., an acoustic transducer) **106**, which, for example, may be or include a piezoelectric device **107**. Alternatively, the acoustic signal generator **106** may include a magnetostriction device, an electrostriction device or an electro-optic device. An acoustic signal (or wave) generated by the acoustic signal generator **106** at the output **138** thereof may be proportional to the frequency of the signal at the output **136** of the voltage-to-frequency convertor **104**. In an embodiment, a frequency of the acoustic signal may be proportionally varied according to the variations in the frequency of the signal at the output **136**. Alternatively, the frequency of the acoustic signal may be set to a desired base frequency and the amplitude of the acoustic signal may be varied (or modulated) according to the variations in the frequency of the signal at the output **136**.

[0039] In an embodiment, the acoustic transducer **106** may include two (or more) piezoelectric devices, one of which (referred to as a primary piezoelectric device, for instance, piezoelectric device **107**) may be used to generate the acoustic signal and the other (referred to as a secondary piezoelectric device, not illustrated) may generate a reference signal that may be used to cancel background noises. Herein, the second piezoelectric device is not provided the output **136** of the voltage-to-frequency convertor **104**. A detection system (not illustrated) located on the surface **14** (or any other location) measures background vibration and acoustic noise by comparing the output signals of the two collocated piezoelectric devices, the acoustic signal at the output **138** of the primary piezoelectric device **107** and the reference signal generated by the second piezoelectric device. The difference in the output signals will then be the signal of interest that is impressed on the primary piezoelectric device **107**, assuming the background vibrations are very small. In another embodiment, the secondary piezoelectric device may be absent, and the primary piezoelectric device **107** may be switched between receiving the output **136** of the voltage-to-frequency convertor **104** and the reference signal. The reference signal and the signal at the output **138** may then be decoupled by the detection system located on the surface **14** (or any other location).

[0040] The acoustic signal generated by the acoustic signal generator **106** at the output **138** may be provided to and otherwise detected by the control line **28**. For instance, the acoustic signal may be provided to (e.g., impinge on) one or more optical fibers included in the control line **28**. In an embodiment, the optical fiber(s) may be directly coupled (e.g., wrapped around) to the piezoelectric device **107** of the acoustic signal generator **106** to maximize transmission efficiency of the acoustic signal from the acoustic signal generator **106** to the control line **28**.

[0041] In an operation based on interferometric phase modulation techniques, coherent light, e.g., a laser pulse, may be transmitted downhole through the optical fiber from an interrogation unit (not illustrated) located on the surface **14**. Defects in the optical fiber backscatter the pulse (Rayleigh scattering) as it propagates along the optical fiber and the backscattered photons are received in a photodetector located on the surface **14** (FIG. **1**A). The acoustic signal from the acoustic transducer **106** may cause localized changes in the optical fiber and these changes may affect the backscatter of the pulse. As the speed of light is constant, based on the time delay between the moment the pulse is transmitted downhole and the backscattered pulse is received, the distance to the sensor **111** can be determined. This may in turn provide the location of the component present in the fluid **112** or the characteristic of the fluid **112** at that location.

[0042] In another embodiment, the output **136** of the voltage-to-frequency convertor **104** may be provided to an electro-optic modulator (not expressly illustrated). Typically, electro-optic modulators include conductive plates across a preferred crystal axis and may be fabricated using titanium diffusion or proton exchange techniques that create optical index changes along prescribed pathways in a host crystal material of the electro-optic modulator. The crystal material may typically include Lithium Niobate and/or KDP (potassium dihydrogen phosphate). The varying frequency of the signal at the output **136** varies the refractive index of the crystal of the electro-optic modulator. In effect, this modulates either the phase or amplitude of a coherent light beam that is transmitted downhole through the crystal of the electro-optic modulator. The modulated optical signal is sensed at the surface **14** (or any other location) via single or looped optical fiber included in the control line **28**. The electro-optic modulator may be coupled to the optical fiber using known fiber cable termination techniques, such as pigtails and fanout kits or breakout kits.

[0043] FIG. **3** illustrates an exemplary fiber optic based Distributed Acoustic Sensing (DAS) network **300**, according to one or more embodiments. The DAS network **300** may include one or more single mode optical fibers **302** (one shown) positioned in the annulus **22** adjacent the formation **18**. Similar to the embodiment of FIG. **2**A, the sensor system **100**, including the plurality of axially-spaced sensors **101**, may also be positioned in the annulus **22** at a predetermined distance from the optical fiber **302**. The control line **28** may supply electrical power to the sensor systems **100**. However, in this case, the control line **28** may not include fiber optic cables or lines. The optical fiber **302** may be positioned (or embedded) in the wellbore **16** during the construction thereof and may be supported by the cement **24** used to fill the annulus **22**. Although FIG. **3** illustrates the optical fiber **302** located diametrically opposite the sensor system **100**, this is merely for the sake of illustration and the optical fiber **302** may alternatively be positioned at any desired location in the annulus **22**.

[0044] A plurality of Fiber Bragg Gratings (FBG) **304** each corresponding to a circumferentially adjacent sensor **101** may be coupled to the optical fiber **302**. The acoustic signals (or waves) produced by the sensors **101** may traverse the annulus **22** and impinge on the corresponding FBG **304**, resulting in a strain in the corresponding FBG **304**, which may be detected at the surface **14** (FIG. **1**A) using a variety of interferometric phase modulation techniques. The backscattered pulse from the FBGs **304** may have higher amplitude as compared to the backscattered pulse from an optical fiber without FBGs. Thus, sections of optical fiber **302** that contain FBGs **304** may produce higher amplitude signals, thereby improving the spatial resolution. The backscattered signals may be detected over relatively larger distances and in relatively harsh environments (e.g., high noise environments), while requiring no downhole electrical power.

[0045] Using the embedded DAS network **300**, the acoustic signals generated by sensor systems **100** may be converted from an electrical domain to an optical domain and conveyed to the surface **14** (FIG. **1**A). As can be appreciated, the conversion of acoustic signals to the optical domain in the DAS network **300** may be accomplished without directly coupling the optical fiber **302** to the sensor system **100**. The embedded DAS network **300** may provide the additional benefit of being able to triangulate the location of the sensors **101** as a function of depth.

[0046] In an embodiment, each sensor **101** may output a corresponding acoustic signal (or wave) only when the characteristic of interest of the substance or material of interest in the fluid **112** (FIG. **2**A) reaches or exceeds a predetermined level. For instance, the optical sensor **102** of FIG. **2**A may be configured to monitor or measure (either continuously or intermittently) the concentration of a particular analyte of interest present in the fluid **112** and output a voltage proportional to the concentration. The acoustic signal corresponding to the voltage, however, may be produced only when the voltage meets or exceeds a predetermined threshold voltage that may correspond to a desired concentration of the particular analyte of interest. As such, until the predetermined threshold voltage is met or exceeded, the acoustic signal may be OFF and may only be switched ON once the predetermined threshold voltage has been met or exceeded.

[0047] In another embodiment including multiple sensors **101**, each sensor **101** may output an acoustic signal having a base frequency that is different from the base frequencies of acoustic signals output by other sensors **101**. Each sensor **101** may be configured to shift (increase or decrease) its respective base frequency proportional to the property (e.g., a concentration of a particular analyte) being measured by the respective sensor **101**. For instance, an output of a first sensor **101** may have a base frequency 1 kHz, an output of a second sensor **101** may have a base frequency 2 kHz, and so on. The first sensor **101** may be configured to increase its base frequency by 250 Hz or decrease it by 250 Hz proportional to the property being measured. Similarly, the second sensor **101** may be configured to increase its base frequency by 250 Hz or decrease it by 250 Hz proportional to the property being measured, and so on.

[0048] In such embodiments, the output of each sensor **101** may be optically multiplexed (e.g. Sagnac or hybrid combinations of Sagnac, Michelson, Mach-Zehnder, Fabry-Perot distributed fiber interferometers) and transmitted to the surface **14** (FIG. **1**A) where each base frequency and any shift therein may be demodulated and monitored. The base frequency of each sensor system **100** may be a predetermined value (e.g., a value preset by the operator of the wellbore system) that may be configured either during or after the installation of the DAS network **300**. Further, it may be possible to change the base frequency during operation as desired.

[0049] The location of each sensor **101** may be obtained based on the time delay from the time a light pulse is transmitted downhole via the optical fiber **302** and the time it takes for the corresponding backscattered pulse to reach the surface **14** (FIG. **1**A). The DAS network **300** may provide a spatial resolution of 1 meter or less at for a total distance of around 10 km. Alternatively, for spatial location of particular sensors **101**, subcarrier frequency bands or channels may be allocated to convey local sensor information. For instance, each sensor **101** (or sensor system **100**) may be allocated a frequency band or channel having a 1 kHz bandwidth. Multiple sensor channels to be multiplexed onto the same optical fiber.

[0050] In an embodiment, the DAS network **300** may be positioned in the casing **20** instead of within the annulus **22**. In an another embodiment, the DAS network **300** including the optical fiber **302** may be directly coupled to each sensor **101**, for example, by wrapping the optical fiber **302** around each sensor **101**. Directly coupling the DAS network **300** may reduce the number of networks in the wellbore **16** and may simplify the installation of the network(s) in the wellbore **16**.

[0051] In an embodiment illustrated in FIG. **4**, the DAS network **300** may be lowered in the casing **20** (or in a production tubing disposed within the casing **20**) using tools or systems deployed via a conveyance, such as slickline or wireline **402**. In another embodiment, the DAS network **300** may be replaced by a non-fiber optic based acoustic system including one or more non-fiber optic based acoustic sensors **404** (e.g., hydrophones) and may be introduced into the casing **20** (FIG. **1**A) using the slickline or wireline **402**.

[0052] In both configurations, the DAS **300** and the non-fiber optic based acoustic system may be introduced in the casing **20** and measurements may be carried out on an "as needed" basis. Thus, it may not be required to have a permanently installed DAS network **300** in the wellbore **16**. As will be appreciated, these configurations also permit measuring the acoustic signals without direct contact with the sensor system **100**. Using the non-fiber optic based acoustic system (e.g., hydrophones **404**) may also permit measuring the acoustic signals generated by the sensors **101** in situations where an acoustic sensor that is used in conjunction with the non-fiber optic based acoustic system either has malfunctioned or is absent.

[0053] FIG. **5** shows an illustrative processing system **500** for configuring and/or controlling the sensor system **100** and the DAS network **300** for performing the various tasks as described herein. The processing system **500** may be located at a remote location (e.g., the surface **14**).

[0054] The system **500** may include a processor **510**, a memory **520**, a storage device **530**, and an input/output device **540**. Each of the components **510**, **520**, **530**, and **540** may be interconnected, for example, using a system bus **550**. The processor **510** may be processing instructions for execution within the system **500**. In some embodiments, the processor **510** is a single-threaded processor, a multi-threaded processor, or another type of processor. The processor **510** may be capable of processing instructions stored in the memory **520** or on the storage device **530**. The memory **520** and the storage device **530** can store information within the computer system **500**.

[0055] The input/output device **540** may provide input/output operations for the system **500**. In some embodiments, the input/output device **540** can include one or more network interface devices, e.g., an Ethernet card; a serial communication device, e.g., an RS-232 port; and/or a wireless interface device, e.g., an 802.11 card, a 3G wireless modem, or a 4G wireless modem. In some embodiments, the input/output device can include driver devices configured to receive input data and send output data to other input/output devices, e.g., keyboard, printer and display devices **560**. In some embodiments, mobile computing devices, mobile communication devices, and other devices can be used.

[0056] In accordance with at least some embodiments, the disclosed methods and systems related to scanning and analyzing material may be implemented in digital electronic circuitry, or in computer software, firmware, or hardware, including the structures disclosed in this specification and their structural equivalents, or in combinations of one or more of them. Computer software may include, for example, one or more modules of instructions, encoded on computer-readable storage medium for execution by, or to control the operation of, a data processing apparatus. Examples of a computer-readable storage medium include non-transitory medium such as random access memory (RAM) devices, read only memory (ROM) devices, optical devices (e.g., CDs or DVDs), and disk drives.

[0057] The term "data processing apparatus" encompasses all kinds of apparatus, devices, and machines for processing data, including by way of example a programmable processor, a computer, a system on a chip, or multiple ones, or combinations, of the foregoing. The apparatus can include special purpose logic circuitry, e.g., an FPGA (field programmable gate array) or an ASIC (application specific integrated circuit). The apparatus can also include, in addition to hardware, code that creates an execution environment for the computer program in question, e.g., code that constitutes processor firmware, a protocol stack, a database management system, an operating system, a cross-platform runtime environment, a virtual machine, or a combination of one or more of them. The apparatus and execution environment can realize various different computing model infrastructures, such as web services, distributed computing, and grid computing infrastructures.

[0058] A computer program (also known as a program, software, software application, script, or code) can be written in any form of programming language, including compiled or interpreted languages, declarative, or procedural languages. A computer program may, but need not, correspond to a file in a file system. A program can be stored in a portion of a file that holds other programs or data (e.g., one or more scripts stored in a markup language document), in a single file dedicated to the program in question, or in multiple coordinated files (e.g., files that store one or more modules, sub programs, or portions of code). A computer program may be executed on one computer or on multiple computers that are located at one site or distributed across multiple sites and interconnected by a communication network.

[0059] Some of the processes and logic flows described in this specification may be performed by one or more programmable processors executing one or more computer programs to perform actions by operating on input data and generating output. The processes and logic flows may also be performed by, and apparatus may also be implemented as, special purpose logic circuitry, e.g., an FPGA (field programmable gate array) or an ASIC (application specific integrated circuit).

[0060] Processors suitable for the execution of a computer program include, by way of example, both general and special purpose microprocessors and processors of any kind of digital computer. Generally, a processor will receive instructions and data from a read-only memory or a random access memory or both. A computer includes a processor for performing actions in accordance with instructions and one or more memory devices for storing instructions and data. A computer may also include, or be operatively coupled to receive data from or transfer data to, or both, one or more mass storage devices for storing data, e.g., magnetic, magneto optical disks, or optical disks. However, a computer may not have such devices. Devices suitable for storing computer program instructions and data include all forms of non-volatile memory, media and memory devices, including by way of example semiconductor memory devices (e.g., EPROM, EEPROM, flash memory devices, and others), magnetic disks (e.g., internal hard disks, removable disks, and others), magneto optical disks, and CD-ROM and DVD-ROM disks. The processor and the memory can be supplemented by, or incorporated in, special purpose logic circuitry.

[0061] To provide for interaction with a user, operations may be implemented on a computer having a display device (e.g., a monitor, or another type of display device) for displaying information to the user and a keyboard and a pointing device (e.g., a mouse, a trackball, a tablet, a touch sensitive screen, or another type of pointing device) by which the user can provide input to the computer. Other kinds of devices can be used to provide for interaction with a user as well; for example, feedback provided to the user can be any form of sensory feedback, e.g., visual feedback, auditory feedback, or tactile feedback; and input from the user can be received in any form, including acoustic, speech, or tactile input. In addition, a computer can interact with a user by sending documents to and receiving documents from a device that is used by the user; for example, by sending web pages to a web browser on a user's client device in response to requests received from the web browser.

[0062] A computer system may include a single computing device, or multiple computers that operate in proximity or generally remote from each other and typically interact through a communication network. Examples of communication networks include a local area network ("LAN") and a wide area network ("WAN"), an inter-network (e.g., the Internet), a network comprising a satellite link, and peer-to-peer networks (e.g., ad hoc peer-to-peer networks). A relationship of client and server may arise by virtue of computer programs running on the respective computers and having a client-server relationship to each other.

[0063] Embodiments disclosed herein include:

[0064] A. A system that includes a sensor to detect a characteristic of a fluid and output an electrical signal proportional to the characteristic, an acoustic signal generator to output an acoustic signal proportional to the electrical signal, and a signal detection apparatus to generate a signal proportional to the acoustic signal and transmit the signal to a remote location.

[0065] B. A method that includes monitoring a fluid in a wellbore with a sensor, generating an electrical signal proportional to a characteristic of the fluid with the sensor, generating a control signal proportional to the electrical signal using a frequency generator, generating an acoustic signal proportional to the control signal using an acoustic transducer, detecting the acoustic signal and generating a signal based on the acoustic signal using a signal detection apparatus, and transmitting the signal to a remote location.

[0066] Each of embodiments A and B may have one or more of the following additional elements in any combination: Element 1: wherein the sensor comprises one of a chemical sensor, an optical sensor, a pH sensor, a density sensor, a viscosity sensor, a thermal sensor, and a pressure sensor.

[0067] Element 2: wherein the acoustic signal generator includes one of a piezoelectric device, a magnetostriction device, an electro-optic device, and an electrostriction device. Element 3: wherein the signal detection apparatus generates an optical signal proportional to the acoustic signal using interferometric phase modulation techniques and transmits the optical signal to the remote location. Element 4: wherein the signal detection apparatus is positioned in an annulus defined between a wellbore and a casing secured within the wellbore. Element 5: wherein the signal detection apparatus is conveyed into a wellbore on slickline or wireline. Element 6: wherein the signal detection apparatus is a non-fiber optic based apparatus that detects the acoustic signal. Element 7: further comprising a frequency generator that receives the electrical signal and generates a control signal proportional to the electrical signal. Element 8: wherein the acoustic signal generator comprises an acoustic transducer to receive the control signal and generate the acoustic signal proportional to the control signal. Element 9: wherein the acoustic signal generator and the signal detection apparatus contact each other. Element 10: wherein the acoustic signal generator and the signal detection apparatus are separated from each other. Element 11: further comprising a processing unit located at the remote location and configured to process the signal from the signal detection apparatus to determine a location of the fluid.

[0068] Element 12: further comprising generating an optical signal proportional to the acoustic signal using the signal detection apparatus, the optical signal being generated by the signal detection apparatus using interferometric phase modulation techniques. Element 13: further comprising generating the acoustic signal when the electrical signal meets or exceeds a predetermined threshold level, the threshold level corresponding to the characteristic of the fluid measured by the sensor. Element 14: further comprising varying a frequency of the control signal proportional to the electrical signal. Element 15: further comprising varying an amplitude of the control signal proportional to the electrical signal. Element 16: further comprising varying a frequency of the acoustic signal proportional to the control signal. Element 17: further comprising varying an amplitude of the acoustic signal proportional to the control signal. Element 18: generating the acoustic signal having a predetermined base frequency, and shifting the base frequency proportional to the characteristic of the fluid measured by the sensor.

[0069] By way of non-limiting example, exemplary combinations applicable to A and B: Element 3 with Element 4; Element 3 with Element 5; and Element 7 with Element 8.

[0070] Therefore, the disclosed systems and methods are well adapted to attain the ends and advantages mentioned as well as those that are inherent therein. The particular embodiments disclosed above are illustrative only, as the teachings of the present disclosure may be modified and practiced in different but equivalent manners apparent to those skilled in the art having the benefit of the teachings herein. Furthermore, no limitations are intended to the details of construction or design herein shown, other than as described in the claims below. It is therefore evident that the particular illustrative embodiments disclosed above may be altered, combined, or modified and all such variations are considered within the scope of the present disclosure. The systems and methods illustratively disclosed herein may suitably be practiced in the absence of any element that is not specifically disclosed herein and/or any optional element disclosed herein. While compositions and methods are described in terms of "comprising," "containing," or "including" various components or steps, the compositions and methods can also "consist essentially of" or "consist of" the various components and steps. All numbers and ranges disclosed above may vary by some amount. Whenever a numerical range with a lower limit and an upper limit is disclosed, any number and any included range falling within the range is specifically disclosed. In particular, every range of values (of the form, "from about a to about b," or, equivalently, "from approximately a to b," or, equivalently, "from approximately a-b") disclosed herein is to be understood to set forth every number and range encompassed within the broader range of values. Also, the terms in the claims have their plain, ordinary meaning unless otherwise explicitly and clearly defined by the patentee. Moreover, the indefinite articles "a" or "an," as used in the claims, are defined herein to mean one or more than one of the elements that it introduces. If there is any conflict in the usages of a word or term in this specification and one or more patent or other documents that may be incorporated herein by reference, the definitions that are consistent with this specification should be adopted.

[0071] As used herein, the phrase "at least one of" preceding a series of items, with the terms "and" or "or" to separate any of the items, modifies the list as a whole, rather than each member of the list (i.e., each item). The phrase "at least one of" allows a meaning that includes at least one of any one of the items, and/or at least one of any combination of the items, and/or at least one of each of the items. By way of example, the phrases "at least one of A, B, and C" or "at least one of A, B, or C" each refer to only A, only B, or only C; any combination of A, B, and C; and/or at least one of each of A, B, and C.

What is claimed is:

1. A system, comprising:

a sensor to detect a characteristic of a fluid and output an electrical signal proportional to the characteristic;

an acoustic signal generator to output an acoustic signal proportional to the electrical signal; and

a signal detection apparatus to generate a signal proportional to the acoustic signal and transmit the signal to a remote location.

2. The system of claim **1**, wherein the sensor comprises one of a chemical sensor, an optical sensor, a pH sensor, a density sensor, a viscosity sensor, a thermal sensor, and a pressure sensor.

3. The system of claim **1**, wherein the acoustic signal generator includes one of a piezoelectric device, a magnetostriction device, an electro-optic device, and an electrostriction device.

4. The system of claim **1**, wherein the signal detection apparatus generates an optical signal proportional to the acoustic signal using interferometric phase modulation techniques and transmits the optical signal to the remote location.

5. The system of claim **4**, wherein the signal detection apparatus is positioned in an annulus defined between a wellbore and a casing secured within the wellbore.

6. The system of claim **4**, wherein the signal detection apparatus is conveyed into a wellbore on slickline or wireline.

7. The system of claim **1**, wherein the signal detection apparatus is a non-fiber optic based apparatus that detects the acoustic signal.

8. The system of claim **1**, further comprising a frequency generator that receives the electrical signal and generates a control signal proportional to the electrical signal.

9. The system of claim **8**, wherein the acoustic signal generator comprises an acoustic transducer to receive the control signal and generate the acoustic signal proportional to the control signal.

10. The system of claim **1**, wherein the acoustic signal generator and the signal detection apparatus contact each other.

11. The system of claim **1**, wherein the acoustic signal generator and the signal detection apparatus are separated from each other.

12. The system of claim **1**, further comprising a processing unit located at the remote location and configured to process the signal from the signal detection apparatus to determine a location of the fluid.

13. A method, comprising:

monitoring a fluid in a wellbore with a sensor;

generating an electrical signal proportional to a characteristic of the fluid with the sensor;

generating a control signal proportional to the electrical signal using a frequency generator;

generating an acoustic signal proportional to the control signal using an acoustic transducer;

detecting the acoustic signal and generating a signal based on the acoustic signal using a signal detection apparatus; and

transmitting the signal to a remote location.

14. The method of claim **13**, further comprising generating an optical signal proportional to the acoustic signal using the signal detection apparatus, the optical signal being generated by the signal detection apparatus using interferometric phase modulation techniques.

15. The method of claim **13**, further comprising generating the acoustic signal when the electrical signal meets or exceeds a predetermined threshold level, the threshold level corresponding to the characteristic of the fluid measured by the sensor.

16. The method of claim **13**, further comprising varying a frequency of the control signal proportional to the electrical signal.

17. The method of claim **13**, further comprising varying an amplitude of the control signal proportional to the electrical signal.

18. The method of claim **13**, further comprising varying a frequency of the acoustic signal proportional to the control signal.

19. The method of claim **13**, further comprising varying an amplitude of the acoustic signal proportional to the control signal.

20. The method of claim **13**, further comprising:

generating the acoustic signal having a predetermined base frequency; and

shifting the base frequency proportional to the characteristic of the fluid measured by the sensor.

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