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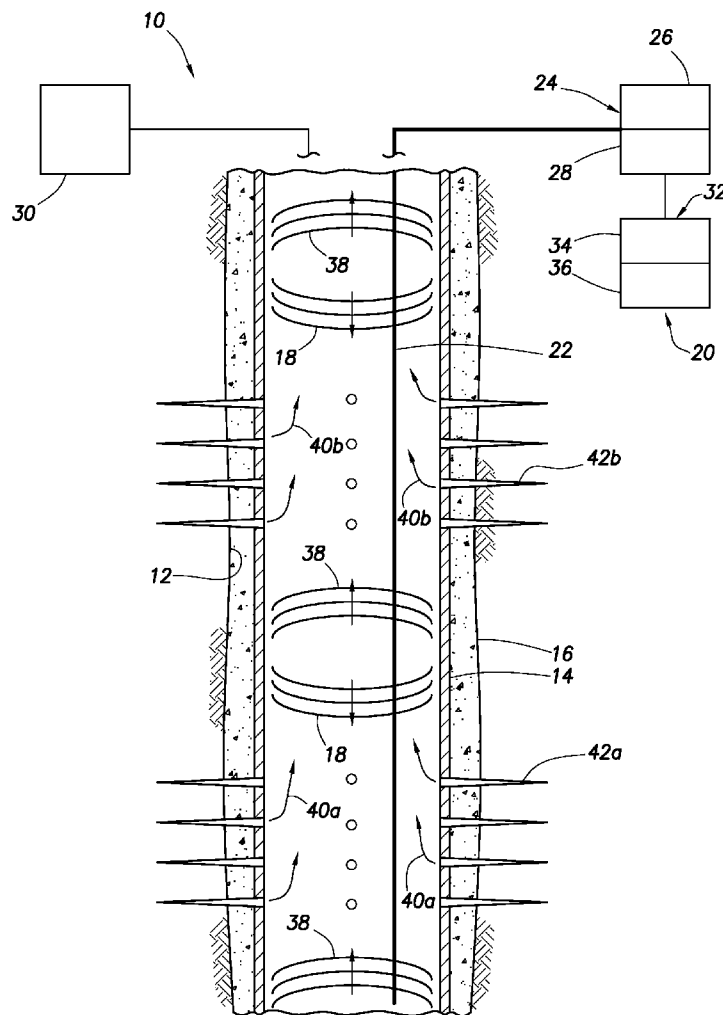
(57) **ABSTRACT**

A well flow velocity measurement method can include transmitting an acoustic signal through at least one fluid composition in a well, detecting velocities of the acoustic signal in both opposite directions along an optical waveguide in the well, the optical waveguide being included in a distributed acoustic sensing system, and determining an acoustic velocity in the fluid composition based on the velocities of the acoustic signal. Another well flow velocity measurement method can include propagating at least one pressure pulse through at least one fluid composition in a well, detecting a velocity of the pressure pulse along an optical waveguide in the well, the optical waveguide being included in a distributed acoustic sensing system, and determining an acoustic velocity in the fluid composition based on the velocity of the pressure pulse.

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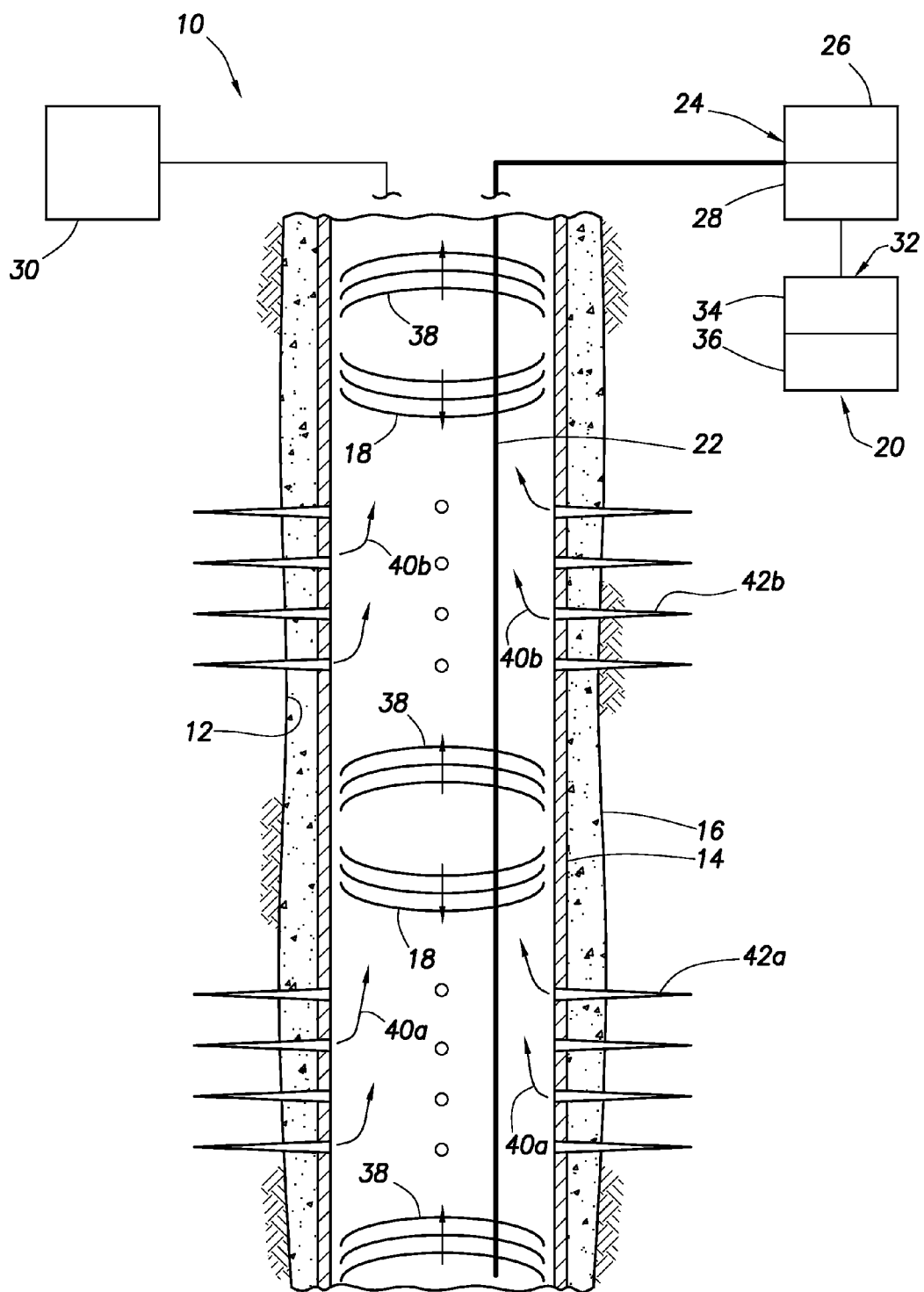
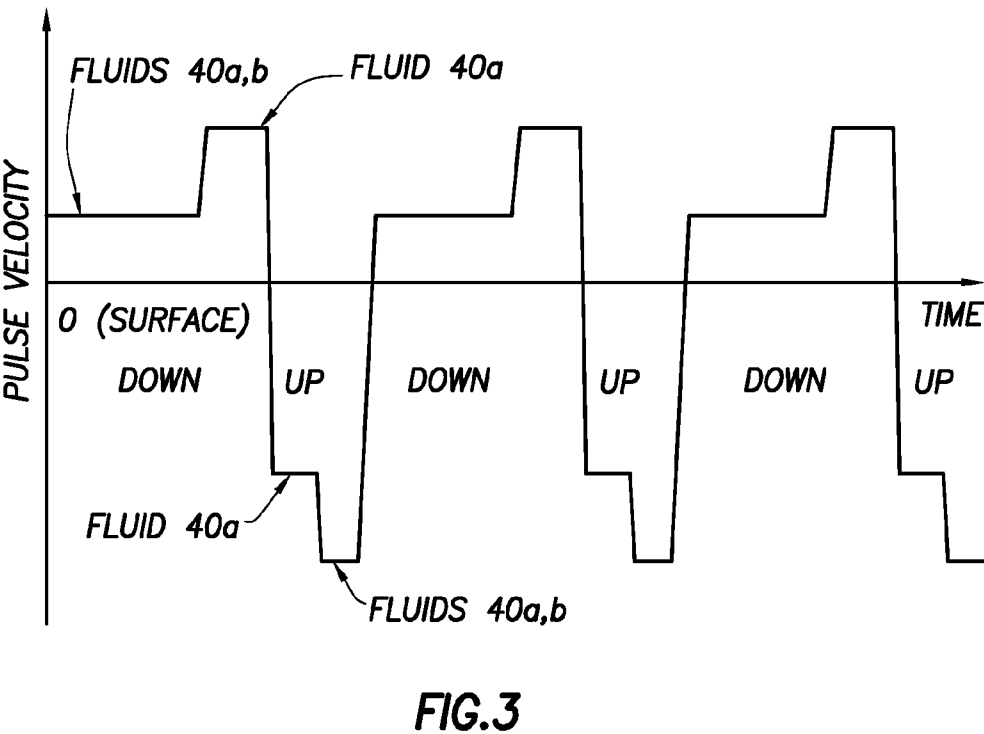
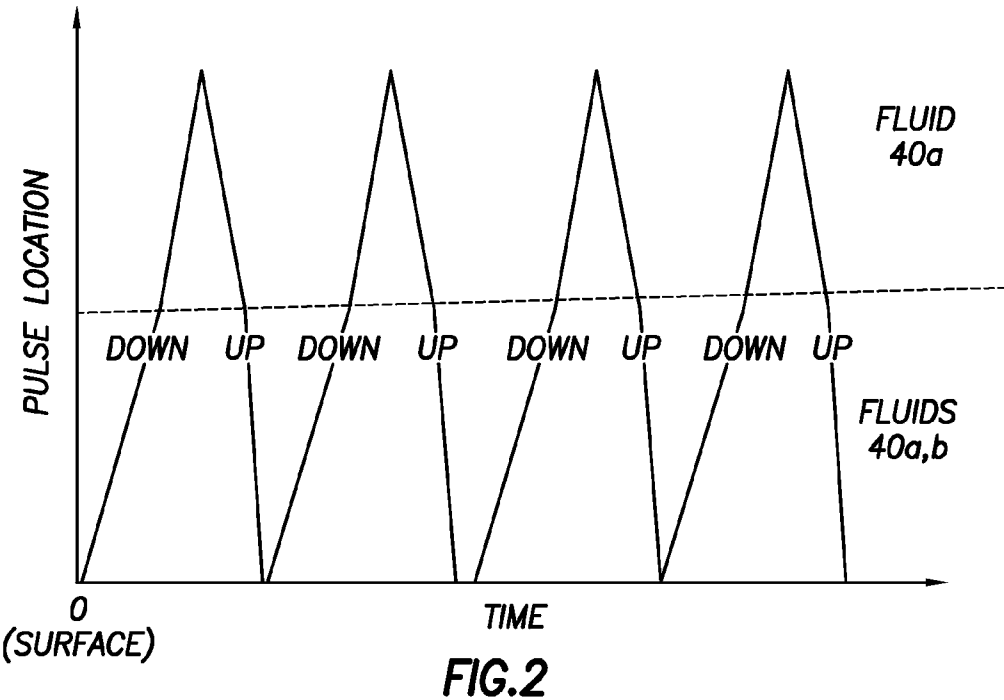


FIG. 1



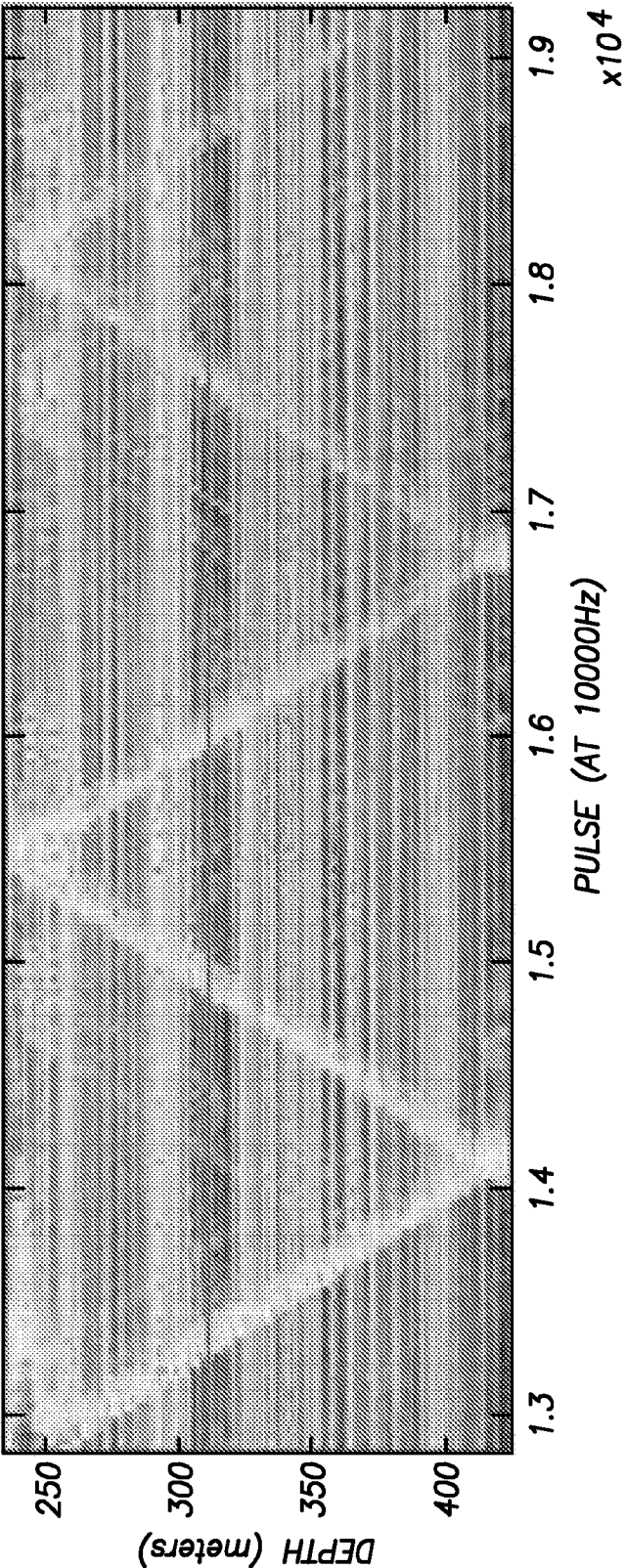


FIG. 4

# **FLOW VELOCITY AND ACOUSTIC VELOCITY MEASUREMENT WITH DISTRIBUTED ACOUSTIC SENSING**

## **BACKGROUND**

[0001] This disclosure relates generally to equipment utilized and operations performed in conjunction with a subterranean well and, in an example described below, more particularly provides for flow velocity and acoustic velocity measurement with distributed acoustic sensing.

[0002] It is beneficial to be able to determine characteristics of fluids entering a wellbore, and flow rates of those fluids, so that decisions relating to production of the fluids can be better informed. For example, if it is known that an unacceptably large flow rate of an undesired fluid is entering the wellbore at a certain location, a decision may be made to restrict or prevent the undesired fluid from entering the wellbore.

[0003] Therefore, it will be appreciated that advancements are continually needed in the arts of determining fluid compositions and flow rates in wells. Such advancements may be used in production, injection, stimulation, conformance, or other types of well operations.

## **BRIEF DESCRIPTION OF THE DRAWINGS**

[0004] FIG. 1 is a representative partially cross-sectional view of a well system and associated method which can embody principles of this disclosure.

[0005] FIG. 2 is a representative plot of pressure pulse location versus time.

[0006] FIG. 3 is a representative plot of pressure pulse velocity versus time.

[0007] FIG. 4 is a representative plot of acoustic pulse location versus time.

## **DETAILED DESCRIPTION**

[0008] Representatively illustrated in FIG. 1 is a well flow velocity measurement system 10 and associated method which can embody principles of this disclosure. However, it should be clearly understood that the system 10 and method are merely one example of an application of the principles of this disclosure in practice, and a wide variety of other examples are possible. Therefore, the scope of this disclosure is not limited at all to the details of the system 10 and method described herein and/or depicted in the drawings.

[0009] This disclosure provides unique techniques for determining velocities of fluid flows in wells, and for determining characteristics of the fluids. These techniques can be used to determine flow rates, acoustic velocities and compositions of the various fluids which flow through a wellbore 12.

[0010] In the FIG. 1 example, the wellbore 12 is generally vertical and is lined with casing 14 and cement 16. However, in other examples, the wellbore 12 may be generally horizontal or inclined, and may be uncased or open hole, at least in an area of interest.

[0011] A pressure pulse 18 is transmitted through the wellbore 12. The pressure pulse 18 may be transmitted from the earth's surface, or from another location in the well. For example, a pressure pulse generator 30 may be used to produce positive and/or negative pressure pulses, which propagate through the fluids in the wellbore 12.

[0012] Pressure pulses can be positive where a compressed air or nitrogen gun is used to dump a pre-charged volume of gas into the wellbore 12. Alternatively, pressurized well fluids

may be dumped into an evacuated chamber to generate a negative pressure pulse. Furthermore, flow exiting a well may be modulated by a choke or valve at the surface to generate either positive or negative pulses, or both.

[0013] Apparatus and methods for transmitting such pressure pulses 18 are described in U.S. Pat. Nos. 5,754,495 and 6,321,838, although other types of pressure pulse generators may be used, if desired. A preferred pressure pulse generator is the HalSonics™ system marketed by Halliburton Energy Services, Inc. of Houston, Tex. USA.

[0014] A pressure pulse can also be generated by striking a structure in the well, such as a tubular string, the casing 14, etc. When the structure is impacted, a pressure wave develops in contents of the structure and propagates away from a location of the impact. A mechanism could, for example, deliver a hammer impact driven by differential pressure, an electromagnetic solenoid, or other mechanical actuator.

[0015] In other examples, the pressure pulses 18 could be generated by detonating a series of explosive or other exothermic devices in the well. Thus, the scope of this disclosure is not limited to any particular manner of generating the pressure pulses 18.

[0016] Note that it is not necessary for the pressure pulses 18 to be generated at or near the earth's surface. In some examples, the pressure pulses 18 could be generated at or near a bottom of the wellbore 12, at some location between the surface and the bottom of the wellbore, etc. If the pressure pulses 18 are generated at a location between the surface and the bottom of the wellbore 12, then the pulses can travel in opposite directions via the wellbore from the location where they were generated.

[0017] The pressure pulses 18 are detected by means of a sensor located in the well. In this example, the sensor comprises an optical waveguide 22 (such as, an optical fiber or ribbon), which may be part of a cable including one or more optical waveguides, electrical conductors, hydraulic conduits, etc. The sensor is preferably part of a distributed acoustic sensing (DAS) system 20, which is capable of detecting acoustic energy as distributed along an optical waveguide 22.

[0018] In the technique known to those skilled in the art as distributed acoustic sensing (DAS), acoustic energy distributed along the optical waveguide 22 can be measured by detecting coherent Rayleigh backscattering in the waveguide. In this manner, the pressure pulses 18 and their reflections can be effectively tracked as they travel along the waveguide 22 in the well.

[0019] The DAS system 20 of FIG. 1 comprises surface optics, electronics and software, commonly known to those skilled in the art as an interrogator 24, and the optical waveguide 22. The optical waveguide 22 may be installed in the wellbore 12, inside or outside of the casing 14 or other tubulars, optionally in the cement 16 surrounding the casing, etc.

[0020] The interrogator 24 launches light into the optical waveguide 22 (e.g., from an infrared laser or other light source 26). A detector 28 detects the light returned via the same optical waveguide 22. The DAS system 20 uses measurement of backscattered light (e.g., coherent Rayleigh backscattering) to detect the acoustic energy along the waveguide 22.

[0021] In another technique, an array of weak fiber Bragg gratings or other artificially introduced reflectors can be used with the optical waveguide 38 to detect acoustic signals along the waveguide.

[0022] The interrogator 24 and/or the pressure pulse generator 30 may be controlled via a control system 32, for example, including at least a processor 34 and memory 36. Signal processing is used to segregate the waveguide 22 into an array of individual “microphones” or acoustic sensors, typically corresponding to 1-10 meter segments of the waveguide.

[0023] The waveguide 22 may be housed in a metal tubing or control line and positioned in the wellbore 12. In some examples, the waveguide 22 may be in cement surrounding the casing 14, in a wall of the casing or other tubular, suspended in the wellbore 12, in or attached to a tubular, etc. The scope of this disclosure is not limited to any particular placement of the waveguide 22.

[0024] The pressure pulse 18 is reflected back through the wellbore 12, and the reflected pressure pulse 38 is also detected by the DAS system 20. Thus, the DAS system 20 detects the propagation of the pressure pulse 18 and the reflected pressure pulse 38 as they displace through the wellbore 12.

[0025] The pressure pulse 18 may be reflected off of a bottom of the well, off of a plug or other obstruction in the wellbore 12, or at a fluid/air or fluid/metal interface at or near the surface. In addition, other changes in acoustic impedance can cause the pressure pulse 18 to be reflected. Such changes in acoustic impedance can include changes in acoustic velocity due to changes in fluid composition in the wellbore 12, changes in casing 14 diameter, etc. The scope of this disclosure is not limited to any particular manner of producing the reflected pressure pulse 38.

[0026] Using the principles of this disclosure, flow velocity,  $V_f$  and acoustic velocity,  $V_a$  of fluid compositions in the wellbore 12 can be readily determined. If flow velocity is known, a volumetric flow rate can be readily calculated by multiplying the flow velocity by flow area.

[0027] The acoustic velocity  $V_a$  in a fluid composition depends on the fluids in the composition and a compliance of a pipe or conduit containing the fluid composition. If one knows the acoustic velocity of the fluid composition, the fluids in the composition (for example, an oil/water ratio) can be readily estimated.

[0028] In the FIG. 1 example, two sets of perforations 42a,b are depicted in the casing 14, so that respective fluid compositions 40a,b are produced into the wellbore 12. Below the bottom perforations 42a, no flow enters the well. Between the perforations 42a,b, only the fluid composition 40a is present in the wellbore 12. Above the upper perforations 42b, the fluid compositions 40a,b are commingled.

[0029] In the FIG. 1 example, the pressure pulse 18 is generated at the surface, which causes an acoustic wave or signal to travel from the surface through the wellbore 12 with velocity  $V_o$  (in this case, opposing the direction of flow of the fluids 40a,b). When the pulse 18 encounters the bottom of the well, it is reflected back toward the surface with velocity  $V_w$  (in this case, with the direction of flow of the fluids 40a,b).

[0030] The reflected pulse 38 may return to the surface and be reflected again through the wellbore 12. With the optical waveguide 22 installed in the well and connected to the DAS interrogator 24, it is possible to observe the propagation of the pulses 18, 38, and it may be possible to observe multiple round trips of a pressure pulse.

[0031] Reflections will occur whenever there is a change in acoustic impedance. For fluids in pipe, such changes occur, for example, when an end of the pipe is blocked by a plug,

when the inner diameter of the pipe changes, or if the pipe terminates inside another pipe with a larger diameter, etc. Amplitudes and signs of reflected pulses are readily calculated, for example, as detailed in Kinsler, L. E., et al., *Fundamentals of Acoustics*, (1982, John Wiley & Sons, Inc.).

[0032] As the pressure pulse or acoustic wave propagates in either direction, it decreases in amplitude due to losses, and spreads out due to dispersion. Although the wave may be detected moving back and forth through the wellbore 12 for an extended period of time, it is advantageous to measure the velocity of wave propagation early on while the wave amplitude is relatively high and its pulse width is relatively narrow. However, the flow property measurement techniques described here depend on pulse velocity, not pulse amplitude.

[0033] Velocities of the pressure pulses 18 and their reflections 38 can be readily determined using the DAS interrogator 24, for example, by dividing displacement of the signals by elapsed time. Using this information, with the system 10 configured as depicted in FIG. 1, an acoustic velocity in the commingled fluids 40a,b can be determined, as well as a velocity of the commingled fluids through the wellbore 12.

[0034] In the FIG. 1 example, for a section of the wellbore 12 above the upper perforations 42b:

$$V_w = V_a + V_f \quad (1)$$

and:

$$V_o = V_a - V_f \quad (2)$$

[0035] where  $V_w$  is the velocity of a signal traveling with the flow of fluid (in the FIG. 1 example, the reflected signal 38),  $V_o$  is the velocity of a signal traveling opposite the flow of fluid (in the FIG. 1 example, the generated signal 18),  $V_a$  is the acoustic velocity in the commingled fluids 40a,b, and  $V_f$  is the velocity of the fluids through the wellbore 12. Solving the above linear equations yields:

$$V_a = (V_w + V_o)/2 \quad (3)$$

[0036] and, thus, the acoustic velocity  $V_a$  is simply the average of the velocities of the generated signal 36a and the reflected signal 36b in the FIG. 1 example.

[0037] In addition:

$$V_f = (V_w + V_o)/2 - V_a = V_w - (V_w + V_o)/2 \quad (4)$$

[0038] gives the velocity  $V_f$  of the fluids 40a,b through the wellbore 12. Volumetric flow rate equals fluid velocity times cross-sectional area, so the flow rate of the fluids 40a,b can also be readily determined.

[0039] A similar analysis can be performed for each section of the wellbore 12, enabling a contribution to the flow from each set of perforations 42a,b to be determined. Since the acoustic velocity  $V_a$  in the fluids in the wellbore 12 can be readily determined, a fluid composition contribution of the fluids 40a,b flowing into the individual sections of the wellbore 12 can also be inferred.

[0040] If Equation 4 yields a negative number for the velocity  $V_f$ , this is an indication that the fluid is flowing in an opposite direction to that assumed when applying values to the variables in Equations 1-4. The principles of this disclosure are applicable no matter whether a fluid flows with or in an opposite direction to a signal 36a generated by the signal generator 34, and no matter whether a fluid flows with or in an opposite direction to a reflected signal 36b.

[0041] If, as mentioned above, the pressure pulses 18 are generated between the surface and the bottom of the wellbore

**12**, then the reflected pulses **38** can return to the source location, and flow along the wellbore **12** can be determined as described above. If the reflected pulses **38** do not return to the source location, then flow velocity at the source location can be determined from the velocities of the pressure pulses **18** propagating away from the source location.

**[0042]** FIG. 2 is a representative plot showing a position of a pressure pulse **18** (and its reflections) repeatedly traversing the wellbore **12**. Note that different portions of the plot have respective different slopes, depending on whether the pulse is traveling through only the fluid composition **40a**, or through the commingled fluid compositions **40a,b**. The change in slope is caused by changes in flow velocity from combining two or more flows, as well as changes in the composition of the fluids (e.g., due to mixing multiple flow streams).

**[0043]** Pulse velocity is proportional to the slope or derivative of pulse position with respect to time. FIG. 3 is a representative plot of the pulse velocity as a function of time (the derivative of FIG. 2).

**[0044]** Thus, the pulse velocities in the fluid composition **40a** and in the commingled fluid compositions **40a,b** can be readily determined. Using this data, the acoustic velocity  $V_a$  in each fluid composition **40a,b** can be readily determined from Equation (3), and the velocities  $V_f$  of the fluid composition **40a** and commingled fluid compositions **40a,b** can be readily determined from Equation (4).

**[0045]** Note that the upward and downward velocities are different at any position along the wellbore **12** in which there is flow. This can be explained by examining Equations (1) and (2), and noting a sign difference for  $V_f$  indicating that for a given flow rate and acoustic velocity  $V_a$ , the pulse velocity  $V_w$  of the reflected signal **38** is always greater than the pulse velocity  $V_o$  of the generated signal **18** at any measurement point in the wellbore **12**, for producing wells. For injection wells, this would be reversed.

**[0046]** The acoustic velocity  $V_a$  in a fluid composition depends on the fluids in the composition and the compliance of the pipe walls or conduit walls containing the fluid (such as, the casing **14** in the FIG. 1 example). Because the pipe walls or conduit walls are not infinitely stiff, the speed of sound in the system is reduced in a quantifiable way. (see, e.g., Robert McKee and Eugene "Buddy" Broerman, "Acoustics in Pumping Systems", 25<sup>th</sup> International Pump User Symposium (2009)).

**[0047]** If one knows the acoustic velocity of the fluid composition and the pipe wall compliance(s) (readily calculated from pipe parameters such as the elasticity modulus of the steel pipe, the inside pipe diameter and the pipe wall thickness), the fluids in the composition (for example, an oil/water ratio) can be readily estimated.

**[0048]** In order to infer the composition of the fluid (oil, water, or the fractions of oil and water), the pipe compliance is very important. Pipe compliance can reduce the speed of sound in the pipe by as little as a few percent all the way up to 50 percent or more.

**[0049]** Pipe compliance of a steel pipe is caused by not having infinitely stiff walls. It causes the acoustic wave traveling down the pipe to move slower than it would in a pipe with infinitely stiff walls.

**[0050]** FIG. 4 is a plot of acoustic pressure along a non-flowing test well taken with an installed optical waveguide connected to a DAS system. Multiple up and down reflections are observed. Slopes of the V-shaped traces depicted in FIG. 4 are indicative of the acoustic velocity  $V_a$  of the well fluid.

The absolute values of the upward and downward velocities should be equal as the well was not flowing.

**[0051]** The FIG. 4 data was generated downhole during a fracturing operation. An acoustic pulse resulted from a pressure differential across a ball (plug) opening a fracturing sleeve. An acoustic wave travels from 250 m to about 400 m and back toward the surface, where it reflects at 250 m.

**[0052]** It may now be fully appreciated that the above disclosure provides significant advancements to the arts of determining fluid compositions and flow rates in wells. Flow rates at multiple different locations in a well can be readily determined. Acoustic velocities in different fluid compositions at different locations in the well can also be determined.

**[0053]** A well flow velocity measurement method is provided to the art by the above disclosure. In one example, the method can comprise: transmitting an acoustic signal (such as the pressure pulse **18**) through at least one fluid composition **40a,b** in a well; detecting velocities  $V_w$ ,  $V_d$  of the acoustic signal in both opposite directions along an optical waveguide **22** in the well, the optical waveguide **22** being included in a distributed acoustic sensing system **20**; and determining an acoustic velocity  $V_a$  in the fluid composition based on the velocities of the acoustic signal.

**[0054]** The distributed acoustic sensing system **20** may detect coherent Rayleigh backscattering along the optical waveguide **22**.

**[0055]** The transmitting step can include propagating at least one pressure pulse **18** through the fluid composition **40a,b**. The detecting step can include detecting at least one reflection of the pressure pulse **18**.

**[0056]** The transmitting step can include transmitting the acoustic signal through multiple fluid compositions **40a,b** in the well. The determining step can include determining the acoustic velocity  $V_a$  in each of the multiple fluid compositions **40a,b**.

**[0057]** Determining the acoustic velocity  $V_a$  in the fluid composition **40a,b** can include compensating for pipe compliance.

**[0058]** The distributed acoustic sensing system **20** can indicate acoustic energy as distributed along the optical waveguide **22**.

**[0059]** The distributed acoustic sensing system **20** may include an interrogator **24** which detects coherent Rayleigh backscattering in the optical waveguide **22**.

**[0060]** Another well flow velocity measurement method described above can comprise: propagating at least one pressure pulse **18** through at least one fluid composition **40a,b** in a well; detecting a velocity of the pressure pulse **18** along an optical waveguide **22** in the well, the optical waveguide being included in a distributed acoustic sensing system **20**; and determining an acoustic velocity  $V_a$  in the fluid composition based on the velocity of the pressure pulse.

**[0061]** The detecting step can include detecting the velocity of the pressure pulse **18** in both opposite directions along the optical waveguide **22**.

**[0062]** The propagating step can include propagating the pressure pulse **18** through multiple fluid compositions **40a,b** in the well.

**[0063]** A well flow velocity measurement system **10** is also described above. In one example, the system **10** can include a pressure pulse generator **30** which propagates at least one pressure pulse **18** through at least one fluid composition **40a,b** in a well, and a distributed acoustic sensing system **20** which detects coherent Rayleigh backscattering along an optical

waveguide **22** in the well, whereby a velocity of the pressure pulse in the well is determined.

**[0064]** The system **10** may include a processor **34** which determines an acoustic velocity  $V_a$  in the fluid composition **40a, b** based on the velocity of the pressure pulse **18**.

**[0065]** Although various examples have been described above, with each example having certain features, it should be understood that it is not necessary for a particular feature of one example to be used exclusively with that example. Instead, any of the features described above and/or depicted in the drawings can be combined with any of the examples, in addition to or in substitution for any of the other features of those examples. One example's features are not mutually exclusive to another example's features. Instead, the scope of this disclosure encompasses any combination of any of the features.

**[0066]** Although each example described above includes a certain combination of features, it should be understood that it is not necessary for all features of an example to be used. Instead, any of the features described above can be used, without any other particular feature or features also being used.

**[0067]** It should be understood that the various embodiments described herein may be utilized in various orientations, such as inclined, inverted, horizontal, vertical, etc., and in various configurations, without departing from the principles of this disclosure. The embodiments are described merely as examples of useful applications of the principles of the disclosure, which is not limited to any specific details of these embodiments.

**[0068]** In the above description of the representative examples, directional terms (such as "above," "below," "upper," "lower," etc.) are used for convenience in referring to the accompanying drawings. However, it should be clearly understood that the scope of this disclosure is not limited to any particular directions described herein.

**[0069]** The terms "including," "includes," "comprising," "comprises," and similar terms are used in a non-limiting sense in this specification. For example, if a system, method, apparatus, device, etc., is described as "including" a certain feature or element, the system, method, apparatus, device, etc., can include that feature or element, and can also include other features or elements. Similarly, the term "comprises" is considered to mean "comprises, but is not limited to."

**[0070]** Of course, a person skilled in the art would, upon a careful consideration of the above description of representative embodiments of the disclosure, readily appreciate that many modifications, additions, substitutions, deletions, and other changes may be made to the specific embodiments, and such changes are contemplated by the principles of this disclosure. For example, structures disclosed as being separately formed can, in other examples, be integrally formed and vice versa. Accordingly, the foregoing detailed description is to be clearly understood as being given by way of illustration and example only, the spirit and scope of the invention being limited solely by the appended claims and their equivalents.

What is claimed is:

**1.** A well flow velocity measurement method, comprising: transmitting an acoustic signal through at least one fluid composition in a well;

detecting velocities of the acoustic signal in both opposite directions along an optical waveguide in the well, the optical waveguide being included in a distributed acoustic sensing system; and

determining an acoustic velocity in the fluid composition based on the velocities of the acoustic signal.

**2.** The method of claim **1**, wherein the distributed acoustic sensing system detects coherent Rayleigh backscattering along the optical waveguide.

**3.** The method of claim **1**, wherein the transmitting further comprises propagating at least one pressure pulse through the fluid composition.

**4.** The method of claim **3**, wherein the detecting further comprises detecting at least one reflection of the pressure pulse.

**5.** The method of claim **1**, wherein the transmitting further comprises transmitting the acoustic signal through multiple fluid compositions in the well.

**6.** The method of claim **5**, wherein the determining further comprises determining the acoustic velocity in each of the multiple fluid compositions.

**7.** The method of claim **1**, wherein the distributed acoustic sensing system indicates acoustic energy along the optical waveguide.

**8.** The method of claim **1**, wherein the distributed acoustic sensing system includes an interrogator which detects coherent Rayleigh backscattering in the optical waveguide.

**9.** The method of claim **1**, wherein the transmitting further comprises generating the acoustic signal at a location between the earth's surface and a bottom of the well, the acoustic signal propagating in the opposite directions from the location.

**10.** The method of claim **1**, wherein the transmitting further comprises applying an impact to a tubular string.

**11.** The method of claim **1**, wherein determining the acoustic velocity in the fluid composition further comprises compensating for pipe compliance.

**12.** A well flow velocity measurement system, comprising:

a pressure pulse generator which propagates at least one pressure pulse through at least one fluid composition in a well; and

a distributed acoustic sensing system which detects coherent Rayleigh backscattering along an optical waveguide in the well, whereby a velocity of the pressure pulse in the well is determined.

**13.** The system of claim **12**, further comprising a computer which determines an acoustic velocity in the fluid composition based on the velocity of the pressure pulse.

**14.** The system of claim **12**, wherein the velocity of the pressure pulse in both opposite directions along the optical waveguide is determined.

**15.** The system of claim **12**, wherein the distributed acoustic sensing system detects at least one reflection of the pressure pulse.

**16.** The system of claim **12**, wherein the pressure pulse is propagated through multiple fluid compositions in the well.

**17.** The system of claim **16**, wherein an acoustic velocity in each of the multiple fluid compositions is determined.

**18.** The system of claim **12**, wherein the distributed acoustic sensing system indicates acoustic energy along the optical waveguide.

**19.** The system of claim **12**, wherein the pressure pulse generator applies an impact to a tubular string.

**20.** The system of claim **12**, wherein the pressure pulse generator propagates the pressure pulse in opposite directions from a location in the well.

**21.** A well flow velocity measurement method, comprising:

propagating at least one pressure pulse through at least one fluid composition in a well;

detecting a velocity of the pressure pulse along an optical waveguide in the well, the optical waveguide being included in a distributed acoustic sensing system; and

determining an acoustic velocity in the fluid composition based on the velocity of the pressure pulse.

**22.** The method of claim **21**, wherein the detecting further comprises detecting the velocity of the pressure pulse in both opposite directions along the optical waveguide.

**23.** The method of claim **21**, wherein the distributed acoustic sensing system detects coherent Rayleigh backscattering along the optical waveguide.

**24.** The method of claim **21**, wherein the detecting further comprises detecting at least one reflection of the pressure pulse.

**25.** The method of claim **21**, wherein the propagating further comprises propagating the pressure pulse through multiple fluid compositions in the well.

**26.** The method of claim **25**, wherein the determining further comprises determining the acoustic velocity in each of the multiple fluid compositions.

**27.** The method of claim **21**, wherein the distributed acoustic sensing system indicates acoustic energy along the optical waveguide.

**28.** The method of claim **21**, wherein the distributed acoustic sensing system includes an interrogator which detects coherent Rayleigh backscattering in the optical waveguide.

**29.** The method of claim **21**, wherein the propagating further comprises generating the acoustic signal at a location between the earth's surface and a bottom of the well, the acoustic signal propagating in opposite directions from the location.

**30.** The method of claim **21**, wherein the propagating further comprises applying an impact to a tubular string.

**31.** The method of claim **21**, wherein determining the acoustic velocity in the fluid composition further comprises compensating for pipe compliance.

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