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(54) Title: METHOD OF ACOUSTIC SURVEYING

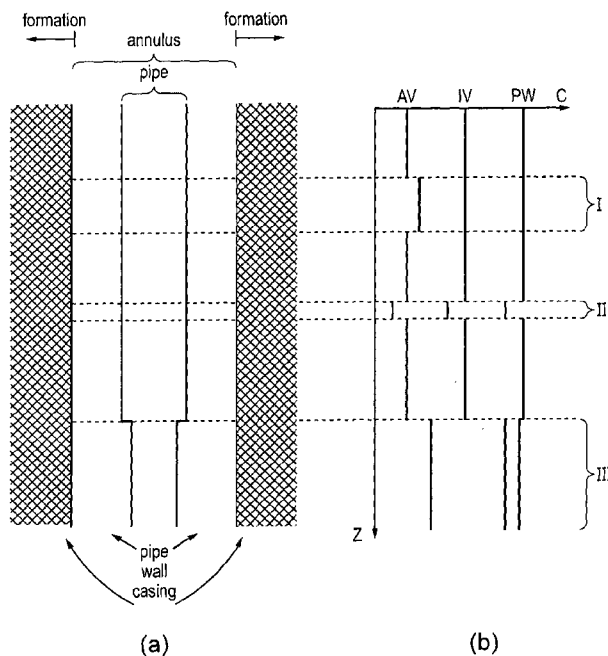


FIG. 10

(57) Abstract: The invention relates to the use of distributed optical fibre sensors for distributed acoustic sensing, and in particular, modal analysis of distributed acoustic data obtained in-well to monitoring well integrity. By determining one or more acoustic modes corresponding to distributed speed of sound measurements within the wellbore, and analysing variations in the distributed speed of sound measurement it is possible to derive information relating to a formation and/or fluid in the wellbore.

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1 Method of acoustic surveying

2

3 The present invention relates to distributed optical fibre sensors for distributed acoustic
4 sensing, methods of use in acoustic surveying and applications thereof. In particular,
5 modal analysis of distributed acoustic data obtained in-well provides a means for
6 monitoring well integrity.

7

8 Background to the invention

9

10 Flow metering is a key measurement when attempting to optimise production from a well.
11 However, current technologies are limited to flow measurements at a limited number of
12 discrete locations, for example by permanent installation of optical flow meters at a
13 number of spaced locations along a length of production tubing.

14

15 Well integrity is also a key concern. However, using such a flow metering system again
16 only allows measurements to be made at discrete points – although by measuring the
17 speed of sound in the tubing the contents of the tubing can be determined, albeit only at
18 those discrete points.

19

1 Noise logging can also be employed to determine in-well fluid flow and composition.
2 Again, such measurements can only be made at discrete points, unless they are made
3 while lowering a hydrophone into the well. Such a measurement requires an intervention,
4 and so is generally undesirable.

5

6 Downhole optical fibres are used in a number of different applications as a replacement for
7 conventional technologies that cannot withstand the pressures and temperatures that fibre
8 based sensors can withstand. Furthermore, distributed optical fibre sensors may allow
9 simultaneous measurements at a significantly greater number of measurement points –
10 not limited by individual physical sensors.

11

12 It is proposed by the Applicant to employ optical fibre based sensors, such as their
13 proprietary Intelligent Distributed Acoustic Sensor (iDAS), for the purposes of wellbore
14 surveying and in particular downhole flow metering to obtain a distributed measurement of
15 in-well fluid flow. However, it is not obvious how the skilled person could employ the iDAS
16 technology to produce meaningful survey data or useful distributed flow data.

17

18 It is anticipated that the solution will be applicable to many different applications and to
19 data obtained from a variety of different measurements (i.e. not just iDAS).

20

21 It is therefore an object of at least one embodiment of the present invention to provide a
22 method of surveying a wellbore based on obtaining a distributed acoustic measurement of
23 the wellbore.

24

25 It is also an object of at least one embodiment of the present invention to provide
26 corresponding methods of monitoring a formation and of monitoring fluid flow within a
27 wellbore.

1 Summary of the invention

2

3 According to a first aspect of the invention, there is provided a method of surveying a
4 wellbore comprising: obtaining a distributed acoustic measurement within and
5 corresponding to at least a portion of the wellbore; processing the distributed acoustic
6 signal to obtain a distributed speed of sound measurement within the wellbore; and
7 analysing variations in the distributed speed of sound measurement to derive information
8 relating to a formation and/or fluid in the wellbore; the method further comprising
9 determining an acoustic mode corresponding to the, each, or a distributed speed of sound
10 measurement within the wellbore.

11

12 A measured acoustic signal is likely to comprise contributions from several spatially
13 simultaneous acoustic modes within the wellbore, each having a corresponding speed of
14 sound. The present invention makes use of a distributed speed of sound measurement
15 (i.e. speed of sound determined as a function of position) and, by looking at absolute
16 values of and changes in the speeds of sound as measured, derive information about a
17 formation and/or fluid within the wellbore.

18

19 Preferably, the analysis comprises analysing variations in the distributed speed of sound
20 measurement as a function of position. Additionally, or alternatively, the analysis
21 comprises analysing variations in the distributed speed of sound measurement as a
22 function of time.

23

24 Analysing variations as a function of position allows, for example, the location of defects or
25 changes to be determined. Analysing variations as a function of time allows, for example,
26 real time monitoring of the occurrence and developments of defects or changes. A
27 combination of both position- and time-based analysis provides a means to monitor where
28 and when defects or developments occur, and track them.

29

30 Preferably, processing the distributed acoustic signal comprises determining a plurality of
31 distributed speed of sound measurements within the wellbore as a function of position.

32

33 By way of example, an installation comprising a cased wellbore and a recovery pipeline
34 disposed therethrough will result in the presence of at least three acoustic modes (as
35 described in the following description of the figures). Determining speed of sound for a
36 particular acoustic mode (whose position is known) provides a mechanism for tracking the

1 behaviour of that acoustic mode by virtue of the distributed nature of the speed of sound
2 measurement.

3

4 It is therefore preferable that processing the distributed acoustic signal comprises
5 obtaining a plurality of distributed speed of sound measurements.

6

7 Preferably, the analysis comprises determining an acoustic amplitude corresponding to
8 the, each or a distributed speed of sound measurement. Alternatively, or additionally, the
9 analysis comprises determining relative amplitudes corresponding to different acoustic
10 modes. Alternatively, or additionally, the analysis comprises determining dispersion
11 characteristics of the, each, or an acoustic mode. Alternatively, or additionally, the
12 analysis comprises determining an upper-frequency cut-off for the presence of modal
13 phenomena.

14

15 Most preferably, the analysis comprises inverting a wellbore model against the distributed
16 speed of sound measurement in order to determine a value of one or more unknown
17 parameters in the wellbore model. Optionally, the wellbore model is configured to receive
18 as an input one or more speed of sound measurements and output one or more
19 corresponding wellbore parameters.

20

21 As described in more detail below, acoustic propagation within a wellbore can be modelled
22 using (for example) full 3-D elastodynamic equations and parameters of the well. Such
23 parameters might include the hardness of the formation. Such a wellbore model can
24 therefore be modified to treat speed of sound as a known parameter and other model
25 parameters as unknowns.

26

27 Preferably, the analysis comprises identifying one or more features in the, each or a
28 distributed speed of sound measurement and attributing the one or more features to one
29 or more corresponding events.

30

31 Features in, say, a trace of speed of sound versus position for a particular acoustic mode
32 may reveal the presence (and, of course, location) of a gas bubble or a hydrate clump, a
33 change in pipe diameter, a leak in the casing or some undesirable downhole activity.

34 These features may be identified by manual inspection, neural network processing, pattern
35 recognition or, in light of the teachings of the present application, one of a variety of

1 suitable feature identification methods that will be apparent to the skilled person. In
2 addition, if multiple acoustic modes are present, identification of which modes exhibit the
3 features, relative strengths therebetween, etc. all provide diagnostic information regarding
4 the wellbore and/or the formation.

5

6 Optionally, identifying one or more features comprises determining the presence and/or
7 location of one or more discontinuities; variations; and/or relative variations between
8 modes, in relation to speed of sound and/or amplitude corresponding to an acoustic signal.

9

10 Optionally, the analysis comprises averaging the, each, or a distributed speed of sound
11 measurement along at least a portion of the wellbore.

12

13 This provides an indication of peak quality and, in the presence of multiple acoustic
14 modes, a comparative measure of signal strengths and profiles.

15

16 According to a second aspect of the invention, there is provided a method of monitoring a
17 formation, comprising the method of the first aspect.

18

19 Preferably, the method comprises identifying the or each distributed speed of sound
20 measurement that corresponds to an acoustic mode which penetrates the formation.

21

22 Optionally, the method comprises determining hardness of the formation. The method
23 may be affected by the development of a Mach Cone resulting from a higher speed of
24 propagation within the steel than can be sustained by the formation.

25

26 Embodiments of the second aspect of the invention may include one or more features
27 corresponding to features of the first aspect of the invention or its embodiments, or vice
28 versa.

29

30 According to a third aspect of the invention, there is provided a method of monitoring fluid
31 flow within a wellbore, comprising the method of the first aspect.

32

33 Optionally, the method comprises tracking eddies, detecting outgassing events, and/or
34 detecting the presence and position of solids or particulate material in the wellbore.

35

- 1 Embodiments of the third aspect of the invention may include one or more features
- 2 corresponding to features of the first or second aspects of the invention or their
- 3 embodiments, or vice versa.

1 Brief description of the drawings

2

3 There will now be described, by way of example only, various embodiments of the
4 invention with reference to the drawings, of which:

5

6 Figure 1 illustrates in schematic form a distributed fibre optic system for measuring the
7 optical amplitude, phase and frequency of an optical signal from which the acoustic
8 amplitude, phase and frequency may be derived, and which may be comprised in a
9 detection means or distributed acoustic sensor in accordance with an embodiment of the
10 present invention;

11

12 Figure 2 illustrates in schematic form how the speed of sound within a tubular, such as a
13 downhole section of pipe, varies dependent on the composition of the fluid within,
14 providing a basis for distributed flow monitoring;

15

16 Figure 3 illustrates in schematic form how the speed of sound within a tubular, such as a
17 downhole section of pipe, varies dependent on the speed and direction of fluid flow within
18 the tubular, providing a further or alternative basis for distributed flow monitoring and eddy
19 tracking;

20

21 Figure 4 illustrates, as a function of depth, the speed of sound waves travelling within a
22 well in (top) an upwards direction and (bottom) a downwards direction, from which
23 information about the well can be determined;

24

25 Figure 5 illustrates in schematic form a cross section through a pipe and casing-lined well,
26 corresponding to the well to which Figure 4 relates;

27

28 Figure 6 illustrates the mode shapes for the well to which Figure 4 relates, in the vicinity of
29 a change in pipe cross-section

30

31 Figure 7 illustrates the detected speeds of sound, as a function of depth, for four separate
32 wells exhibiting different behaviour relating to different conditions and parameters in each
33 well;

34

1 Figure 8 illustrates the peak quality as a function of speed of sound, averaged along the
2 entire depth of the wells to which Figure 7 relates;

3

4 Figure 9 illustrates the flow as a function of depth of the wells to which Figure 7 relates, as
5 calculated from the speeds of sound detected and the different modes detected; and

6

7 Figure 10 illustrates in schematic form an example of the correlation between changes in
8 acoustic mode data and changes in wellbore conditions.

1 Detailed description of preferred embodiments

2

3 In a particular embodiment of the invention, described here in order to provide an example
4 of a preferred implementation of the present invention, a plurality of acoustic sensors is
5 provided in a distributed optical fibre sensor which comprises a length of optical fibre –
6 located in a location or environment to be monitored as illustrated in Figure 1. Examples
7 of such distributed sensor arrangements are described in Silixa Limited's international
8 patent application publication numbers WO2010/136809A2 and WO2010/136810A2 and in
9 further detail below. Using such interferometers as an optical sensor, it is possible to
10 make measurements of acoustic phase, frequency and amplitude from an optical sensor
11 with high sensitivity, high speed of measurement and a large dynamic range.

12

13 With reference to Figure 1, light emitted by a laser (21) is modulated by a pulse signal
14 (22). An optical amplifier (25) is used to boost the pulsed laser light, and this is followed
15 by a band-pass filter (26) to filter out the Amplified Spontaneous Emission noise (ASE) of
16 the amplifier. The optical signal is then sent to an optical circulator (27). An additional
17 optical filter (28) may be used at one port of the circulator (27). The light is sent to sensing
18 fibre (32), which is for example a single mode fibre or a multimode fibre. A length of the
19 fibre may be isolated and used as a reference section (30), for example in a "quiet"
20 location or with a controlled reference signal. The reference section (30) may be formed
21 between reflectors or a combination of beam splitters and reflectors (29) and (31). The
22 reflected and the backscattered light generated along the sensing fibre (32) is directed
23 through the circulator (27) and into the interferometer (33).

24

25 Within the interferometer, the incoming light is amplified in an optical amplifier (1), and
26 transmitted to the optical filter (2). The filter (2) filters the out of band ASE noise of the
27 amplifier (1). The light then enters into an optical circulator (3) which is connected to a 3x3
28 optical coupler (4). A portion of the light is directed to the photodetector (12) to monitor the
29 light intensity of the input light. The other portions of light are directed along first and
30 second optical paths (5) and (6), with a path length difference between the two paths.
31 Faraday-rotator mirrors (FRMs) (7) and (8) reflect the light back through the first and
32 second paths (5) and (6), respectively. The Faraday rotator mirrors provide self-
33 polarisation compensation along optical paths (5) and (6) such that the two portions of light
34 efficiently interfere at each of the 3x3 coupler (4) ports. The optical coupler (4) introduces
35 relative phase shifts of 0 degrees, +120 degrees and -120 degrees to the interference

1 signal, such that first, second and third interference signal components are produced, each
2 at a different relative phase.

3

4 First and second interference signal components are directed by the optical coupler (4) to
5 photodetectors (13) and (14), and the third interference signal component incident on the
6 optical circulator (3) is directed towards photodetector (15).

7

8 The photodetectors (12), (13), (14) and (15) convert the light into electrical signals. The
9 electrical signals are digitised and then the relative optical phase modulation along the
10 reference fibre (30) and the sensing fibre (32) is computed using a fast processor unit (34).
11 The processor unit is time synchronised with the pulse signal (22). The path length
12 difference between path (5) and path (6) defines the spatial resolution, and the origin of
13 the backscattered light (i.e. the position of the measured condition) is derived from the
14 timing of the measurement signal. Rapid measurement is made possible by measuring
15 light intensity only.

16

17 Methods for calculating the relative phase and amplitude from three phase shifted
18 components of an interference signal are known from the literature. For example,
19 Zhiqiang Zhao et al. ("Improved Demodulation Scheme for Fiber Optic Interferometers
20 Using an Asymmetric 3x3 Coupler", J. Lightwave Technology, Vol.13, No.11, November
21 1997, pp. 2059 – 2068) and Huang et al (US 5,946,429) describe techniques for
22 demodulating the outputs of 3x3 couplers in continuous wave multiplexing applications.

23

24 The phase angle data (or relative phase) is sensitive to acoustic perturbations experienced
25 by the sensing fibre. As an acoustic wave passes through the optical fibre, it causes the
26 glass structure to contract and expand. This varies the optical path length between the
27 backscattered light reflected from two locations in the fibre (i.e. the light propagating down
28 the two paths in the interferometer), which is measured in the interferometer as a relative
29 phase change. In this way, the optical phase angle data can be processed to measure the
30 acoustic signal at the point at which the light is reflected or backscattered. The result is
31 that the true acoustic field can be measured at any and/or all points along the fibre.

32

33 It is a key benefit of this "iDAS" system that, in comparison to previous technologies which
34 consist of distributed point sensors or require special components such as fibre gratings, it
35 is possible to obtain a continuum of acoustic signal measurements along a length of

1 optical fibre. However, in practical terms, measurements will typically be performed at a
2 spacing (i.e. resolution) of 1 metre over several thousand metres of optical fibre. A key
3 application is in the monitoring of in-well (and out-of-well) acoustic signals, where an
4 optical fibre is deployed within a well and iDAS employed to measure, in real-time, sound
5 as a function of depth. Note that fibres can be deployed retrospectively for this purpose,
6 although it is common for fibre optic cables to have already be deployed in permanent
7 installations which iDAS can simply be coupled to.

8

9 From iDAS measurements taken over a period of time, it is possible to derive a measure of
10 the speed of sound corresponding to a particular acoustic signal at a particular position
11 along the fibre (and hence at a particular depth in a well).

12

13 It will of course be understood that the concepts and applications presented in the
14 following description in the context of upstream measurements (e.g. within production and
15 injection wells), will apply equally to midstream (e.g. within flowlines and pipelines) and
16 downstream (e.g. within refineries and petrochemical plants) measurements, as well as a
17 host of other applications, in the energy field and other fields, that will be readily apparent
18 to the skilled reader. Furthermore, while iDAS is the preferred measurement system for
19 obtaining acoustic measurements, it will be understood that the concepts will apply equally
20 to other distributed acoustic measurement systems.

21

22 As described briefly above, Figure 2 illustrates how the speed of sound within a tubular is
23 affected by the composition of the fluid within the tubular. It is evident from the trace below
24 the tubular that the presence of a gas (e.g. in air bubbles as illustrated or in the event of
25 outgassing) will result in a localised reduction in the speed of sound, and that in contrast
26 the presence of a dense or particulate material (e.g. a hydrate clump) will result in a
27 localised increase in the speed of sound. Importantly, it should be realised that
28 conventional acoustic detection techniques, such as the use of hydrophones or fibre
29 gratings, may be useful for implementing this technology but may not provide sufficient
30 spatial resolution or be adequately positioned to identify highly localised occurrences such
31 as these that might relate to unfavourable (or perhaps favourable) developments within the
32 well. On this basis, iDAS provides a sensitive means of performing distributed flow
33 monitoring including fluid composition monitoring such as determining liquid to gas ratio
34 (as described in Silixa Limited's international patent application publication numbers
35 WO2010/136809A2 and WO2010/136810A2).

1

2 Figure 3 illustrates how the speed of sound within a tubular is also affected by the direction
3 of propagation of the sound wave or, to put it another way, the relative direction of the fluid
4 flow within the tubular. Also illustrated, schematically, are eddies which in addition to
5 contributing to localised variations in the speed of sound will generally move in the
6 direction of fluid flow. Using iDAS, these eddies can be tracked in real-time. Accordingly,
7 further or alternative bases for distributed flow monitoring are provided.

8

9 Figure 4 shows as schematic data to enhance features (top) the speed of upward-
10 travelling sound waves within a well as a function of depth and (bottom) the speed of
11 downward-travelling soundwaves within a well as a function of depth. For actual
12 calculations a colour map provides additional information of intensity (i.e. amplitude), with
13 red indicating strongest signal power and blue indicating weakest signal power. From
14 these graphs, it is possible to determine characteristics and/or diagnostic information
15 about the well. These characteristics have been determined for actual wells with greater
16 detail than shown here.

17

18 For example, it can be observed from Figure 4 that (aside from the discontinuities) the
19 sound speed varies generally linearly with depth, which is consistent with the expected
20 variations in speed of sound in deep waters. In the deep isothermal layer, temperature
21 and salinity are substantially uniform and as such the speed of sound varies only with
22 pressure.

23

24 However, as noted above there are several discontinuities in the plots. In the upward-
25 travelling sound waves plot there is a discontinuity at position X above which the velocity is
26 $\sim 1500 \text{ m.s}^{-1}$ and below which the velocity is $\sim 1300 \text{ m.s}^{-1}$. Furthermore, there is a
27 significant discontinuity at position Y. This discontinuity has been found to correspond to a
28 change in casing cross-section.

29

30

31 The discontinuity corresponds to a change between a larger (7") diameter inner pipe and a
32 smaller (5.5") diameter pipe. Accordingly, the speed of sound measurement provides a
33 mechanism for measuring said pipe diameter, or at least for detecting changes in pipe
34 diameter.

35

1 It is noted that in some regions, multiple coincident sound speeds are visible. Lea and
2 Kyllingstad ("Propagation of Coupled Pressure Waves in Borehole with Drillstring",
3 International Conference on Horizontal Well Technology, SPE37156 pp. 963-970, 1996)
4 describe the physics of a coupled system in which waves within the drill string
5 communicate within the annulus as a result of the annular flexibility of the drill string and of
6 the formation. In cross-section, this is analogous to the pipe within a cased borehole (as
7 illustrated in cross-section in Figure 5). Accordingly, it is possible to derive the equations
8 of motion for the inner fluid volume (i.e. the fluid within the pipe), the pipe itself, and the
9 outer fluid volume (i.e. the fluid in the annulus between the pipe and the casing).

10

11 The skilled person will readily appreciate that equivalent equations of motion may be
12 derived for any multi degree of freedom oscillating system and therefore that the invention
13 is applicable to systems other than systems comprised of a pipe within cased borehole.
14 However the invention will be further described in the context of such a system in order to
15 provide an illustrative example with real data obtained through experiment.

16

17 In this example, analysis has shown that the fluid pressure communication between the
18 inner fluid volume, the pipe, and the outer fluid volume leads to the presence of a coupled
19 mode system containing three modes, each of which consists of three waves. The first
20 wave is predominantly within the inner fluid volume, the second wave is predominantly
21 within the walls of the pipe, and the third wave is predominantly in the outer fluid volume.
22 Based on the well geometries in the vicinity of the change in cross-section at position Y the
23 mode shapes and velocities can be determined and are illustrated in Figure 6.

24

25 Figure 6 demonstrates the presence of said three mode shapes each consisting of three
26 different waves. The first (Mode 1 – top) consists of a pressure wave with a dominant
27 presence in the inner fluid volume. The second (Mode 2 – middle) consists of a strain
28 wave in the wall of the pipe itself. The third (Mode 3 – bottom) consists of another
29 pressure wave with a dominant presence in the annular fluid volume.

30

31 Based on this information, it is possible to determine the root of the coincident sound
32 speeds evident in Figure 4. In region Z, the slower-propagating wave is a pressure wave
33 predominantly in the annular fluid volume and the faster-propagating wave is a pressure
34 wave predominantly in the inner fluid volume.

35

1 Note that employing the full 3-D elastodynamic solution for the geometry of a pipe within a
2 borehole taught by Rao and Vandiver (“Acoustics of fluid-filled boreholes with pipe: Guided
3 propagation and radiation”, J. Acoust. Soc. Am. 105(6), pp 3057-3066, 1999) provides
4 more complete information relating to the system, such as the amplitude of the signal in
5 the three regions (inner fluid volume, pipe, and annular fluid volume), the relative
6 amplitudes of signals in different modes, dispersion characteristics and the upper
7 frequency cut-off for the modal phenomena.

8

9 The modal phenomena will occur when the wavelength of the acoustic signal is very long
10 in comparison to the diameter of the borehole. At higher frequencies the speed of the
11 wave will be the same as the thermodynamic speed of propagation for the unbounded fluid
12 – which accounts for the presence of a wave moving at the speed of propagation of sound
13 in water ($\sim 1500 \text{ m.s}^{-1}$).

14

15 The sound-speed effects, i.e. coupled modes, observed in the distributed acoustic
16 measurements described above have, until now, never been observed or investigated in
17 relation to cased production or injection tubes. In observing and analysing these
18 phenomena, the work performed by the Applicant has resulted in a technique whereby
19 modal analysis can be used to determine information concerning the formation or the fluid
20 in the annulus, for example by inverting the model against the actual acoustic data. It also
21 enables real-time monitoring of the formation, particularly where detailed information about
22 the formation is already available, because it will be understood that acoustic energy from
23 the modes propagating within the annulus will also penetrate into the formation.

24

25 By way of explanation, based on Rao & Vandiver’s work, acoustic propagation and
26 radiation in a particular well can be modelled using full 3-D elastodynamic equations and
27 various parameters of the well itself including the hardness of the formation.

28

29 The Applicant has developed such a model of a pipe-in-pipe system, the accuracy of
30 which has been confirmed against independent data on a well-known installation.
31 Specifically, a measure of formation hardness has been obtained by modifying the Rao &
32 Vandiver-based model to treat speed of sound as a known parameter and formation
33 hardness as an unknown parameter. Accordingly, having established a model with known
34 parameters it is in a similar way possible to determine other unknown parameters (or

1 indeed look for discrepancies or changes in said known parameters) based on the
2 measured speed(s) of sound.

3

4 To illustrate the above, Figure 10 provides, in schematic form, (a) an example section of
5 pipe within a wellbore with a number of features (or defects), alongside (b) a
6 corresponding trace of speed of speed of sound versus distance. In this example, three
7 acoustic modes are present, corresponding to a mode within the annular volume (AV), the
8 inner volume (IV) and the pipe wall (PW). In region I, there is a discontinuity that affects
9 substantially only the acoustic mode propagating in the annular volume. In this example
10 this corresponds to a local increase in formation hardness. Similarly, there is a
11 discontinuity in all three acoustic modes in region II, in this example corresponding to
12 some damage to the wall of the pipe. Finally, in region III there is a narrowing of the inner
13 pipe diameter which again affects the local speed of sound of all three modes. It will now
14 be evident that while the model may be used to predict acoustic mode behaviour, the
15 acoustic mode data can in fact be used to determine unknown parameters of the wellbore.

16

17 Note that the above example is described for the purposes of illustration only and the
18 relative speeds and the nature and extent of the acoustic discontinuities are suggested
19 and exaggerated to aid understanding of the invention.

20

21 Figure 7 shows schematically speed of sound as a function of depth (again in both
22 directions supported by the waveguide) for four separate example wells, in a similar
23 manner to the way in which corresponding data was presented in Figure 4 (see above). In
24 these graphs it will be noted (particularly in the cases of (b) Well B and (c) Well C) that
25 there again exist spatially simultaneous different acoustic modes (propagating at different
26 speeds), some of which are associated with discontinuities (e.g. see the top graph of (b)
27 Well B). Note that the thick red lines indicate the pipe diameter as a function of depth and,
28 importantly, changes in pipe diameter which can be seen to correspond with
29 discontinuities and other phenomena in the measured speed of sound. White lines are
30 used to denote the separate modes, which are also identified by labels.

31

32 Figure 8 shows the peak quality of the data presented in Figure 7, in which the speed data
33 has been averaged along the entire depth of each well and subsequently normalised.
34 The presence of the distinct modes (in (b) Well B and (c) Well C), and the relative
35 strengths and profiles therebetween, are evident from these plots.

1

2 As before, these measurements confirm the assertions above that changes in pipe
3 diameter result in changes in modal behaviour which can be observed to glean more
4 information about the behaviour of fluid flow on the region of the pipe diameter change. Of
5 course, modal behaviour may be observed in other situations. It will also be appreciated
6 that changes in the formation will also affect the modes and as such these can be
7 employed to monitor the formation as well as in-well conditions. For example, Figure 9
8 illustrates the flow as a function of depth as calculated from the speeds of sound detected
9 and the different modes detected. From this information, it is possible to determine the
10 speed of sound and other parameters relating to the annular fluid volume as well as the
11 inner fluid volume.

12

13 As can be appreciated, analysis of the various modes found within the acoustic
14 measurements performed with an iDAS (or equivalent) apparatus provides a sensitive and
15 high resolution method for studying or monitoring well integrity. For example, in addition to
16 tracking eddies, observing events such as outgassing or the presence of solids such as
17 sand or other particulate material, it is possible to make a determination of the hardness of
18 the formation itself.

19

20 The invention relates to the use of distributed optical fibre sensors for distributed acoustic
21 sensing, and in particular, modal analysis of distributed acoustic data obtained in-well to
22 monitoring well integrity. By determining one or more acoustic modes corresponding to
23 distributed speed of sound measurements within the wellbore, and analysing variations in
24 the distributed speed of sound measurement it is possible to derive information relating to
25 a formation and/or fluid in the wellbore.

26

27 Throughout the specification, unless the context demands otherwise, the terms 'comprise'
28 or 'include', or variations such as 'comprises' or 'comprising', 'includes' or 'including' will be
29 understood to imply the inclusion of a stated integer or group of integers, but not the
30 exclusion of any other integer or group of integers.

31

32 The foregoing description of the invention has been presented for the purposes of
33 illustration and description and is not intended to be exhaustive or to limit the invention to
34 the precise form disclosed. The described embodiments were chosen and described in
35 order to best explain the principles of the invention and its practical application to thereby

1 enable others skilled in the art to best utilise the invention in various embodiments and
2 with various modifications as are suited to the particular use contemplated. Therefore,
3 further modifications or improvements may be incorporated without departing from the
4 scope of the invention as defined by the appended claims.

1 Claims:

- 2
- 3 1. A method of surveying a wellbore comprising: obtaining a distributed acoustic
4 measurement within and corresponding to at least a portion of the wellbore,
5 processing the distributed acoustic signal to obtain a distributed speed of sound
6 measurement within the wellbore and analysing variations in the distributed speed of
7 sound measurement to derive information relating to a formation and/or fluid in the
8 wellbore; the method further comprising determining an acoustic mode
9 corresponding to the, each, or a distributed speed of sound measurement within the
10 wellbore.
- 11
- 12 2. The method according to claim 1, wherein the analysis comprises analysing
13 variations in the distributed speed of sound measurement as a function of position.
- 14
- 15 3. The method according to claim 1 or claim 2, wherein the analysis comprises
16 analysing variations in the distributed speed of sound measurement as a function of
17 time.
- 18
- 19 4. The method according to any of claims 1 to 3, wherein processing the distributed
20 acoustic signal comprises determining a plurality of distributed speed of sound
21 measurements within the wellbore as a function of position.
- 22
- 23 5. The method according to any preceding claim, wherein processing the distributed
24 acoustic signal comprises obtaining a plurality of distributed speed of sound
25 measurements.
- 26
- 27 6. The method according to any preceding claim, wherein the analysis comprises
28 determining an acoustic amplitude corresponding to the, each, or a distributed speed
29 of sound measurement.
- 30
- 31 7. The method according to any preceding claim, wherein the analysis comprises
32 determining relative amplitudes corresponding to different acoustic modes.
- 33
- 34 8. The method according to any preceding claim, wherein the analysis comprises
35 determining dispersion characteristics of the, each, or an acoustic mode.
- 36

- 1 9. The method according to any preceding claim, wherein the analysis comprises
2 determining an upper-frequency cut-off for the presence of modal phenomena.
3
- 4 10. The method according to any preceding claim, wherein the analysis comprises
5 inverting a wellbore model against the distributed speed of sound measurement in
6 order to determine a value of one or more unknown parameters in the wellbore
7 model.
8
- 9 11. The method according to claim 10, wherein the wellbore model is configured to
10 receive as an input one or more speed of sound measurements and output one or
11 more corresponding wellbore parameters.
12
- 13 12. The method according to claim 11, wherein the model is based on full 3-D
14 elastodynamic equations and parameters of the well.
15
- 16 13. The method according to claim 11 or claim 12, wherein the one or more parameters
17 comprise the hardness of the formation.
18
- 19 14. The method according to any of claims 10 to 13, wherein the wellbore model is
20 configured to treat speed of sound as a known parameter and other model
21 parameters as unknowns.
22
- 23 15. The method according to any preceding claim, wherein the analysis comprises
24 identifying one or more features in the, each, or a distributed speed of sound
25 measurement and attributing the one or more features to one or more corresponding
26 events.
27
- 28 16. The method according to claim 15, wherein identifying one or more features
29 comprises determining the presence and/or location of one or more discontinuities;
30 variations; and/or relative variations between modes, in relation to speed of sound
31 and/or amplitude corresponding to an acoustic signal.
32
- 33 17. The method according to any preceding claim, wherein the analysis comprises
34 averaging the, each, or a distributed speed of sound measurement along at least a
35 portion of the wellbore.
36

- 1 18. A method of monitoring a formation, comprising the method of any of claims 1 to 17.
2
- 3 19. The method according to claim 18, further comprising identifying the or each
4 distributed speed of sound measurement that corresponds to an acoustic mode
5 which penetrates the formation.
6
- 7 20. The method according to claim 18 or claim 19, wherein the method further comprises
8 determining hardness of the formation.
9
- 10 21. A method of monitoring fluid flow within a wellbore, comprising the method of any of
11 claims 1 to 17.
12
- 13 22. The method according to claim 21, further comprising tracking eddies, detecting
14 outgassing events, and/or detecting the presence and position of solids or particulate
15 material in the wellbore.

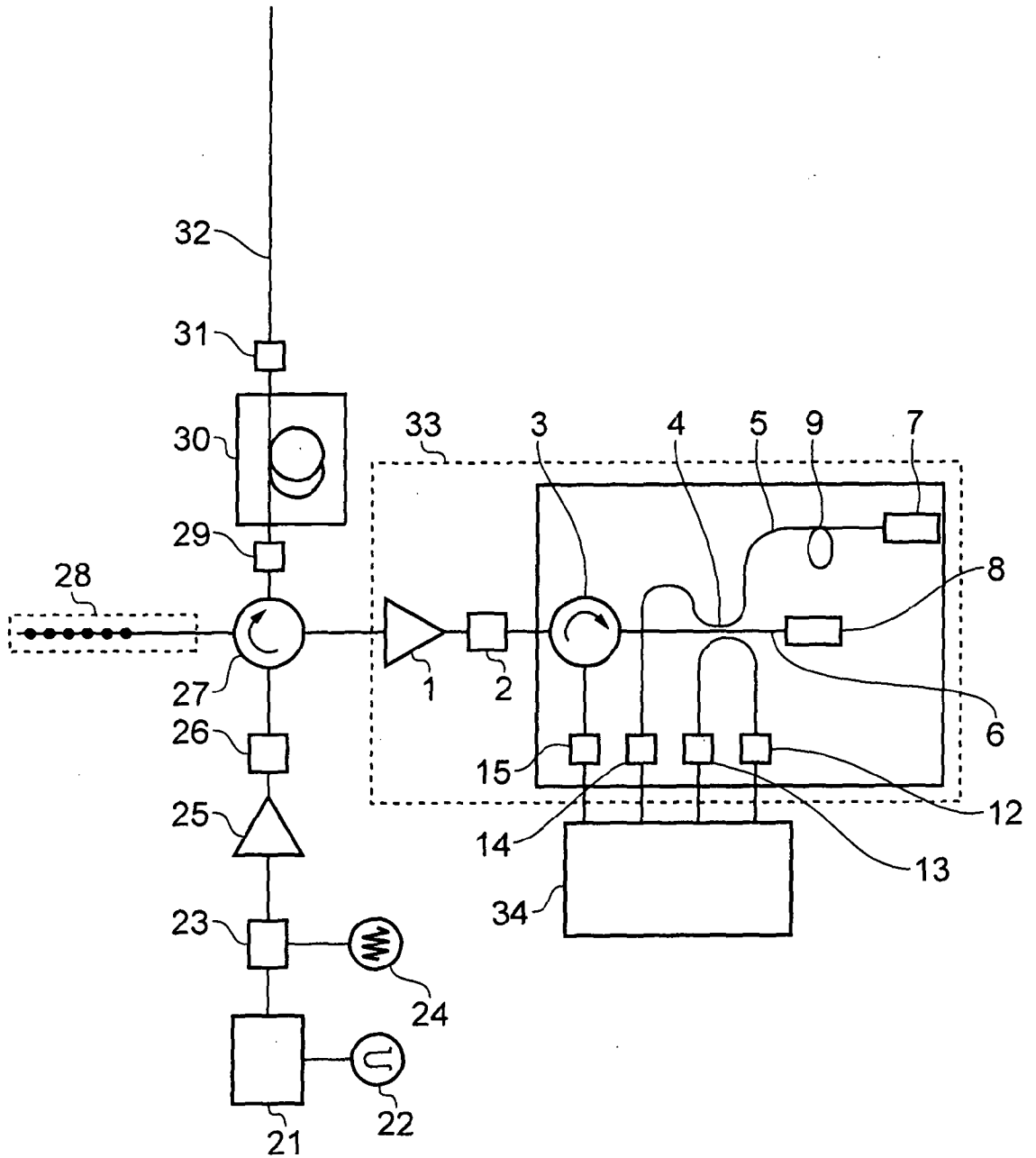


FIG. 1

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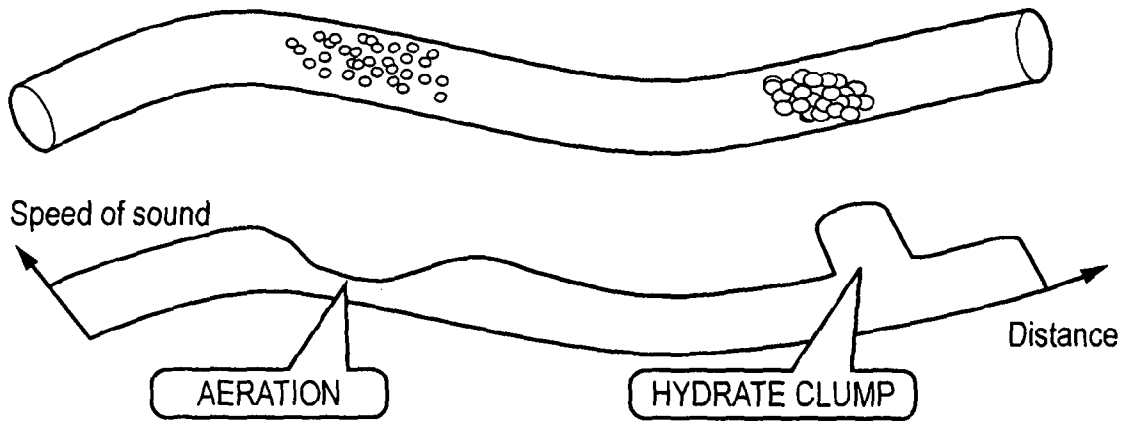


FIG. 2

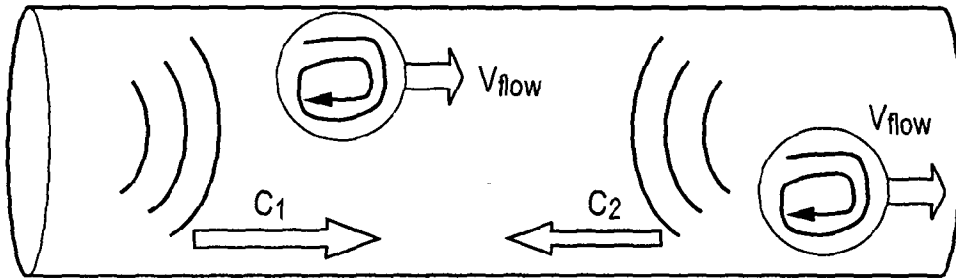


FIG. 3

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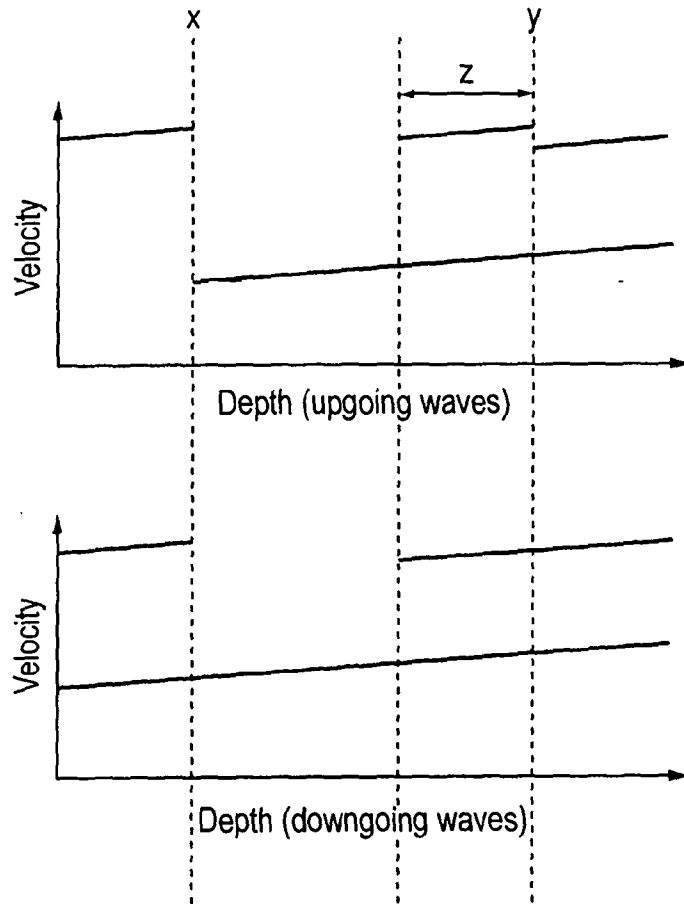


FIG. 4

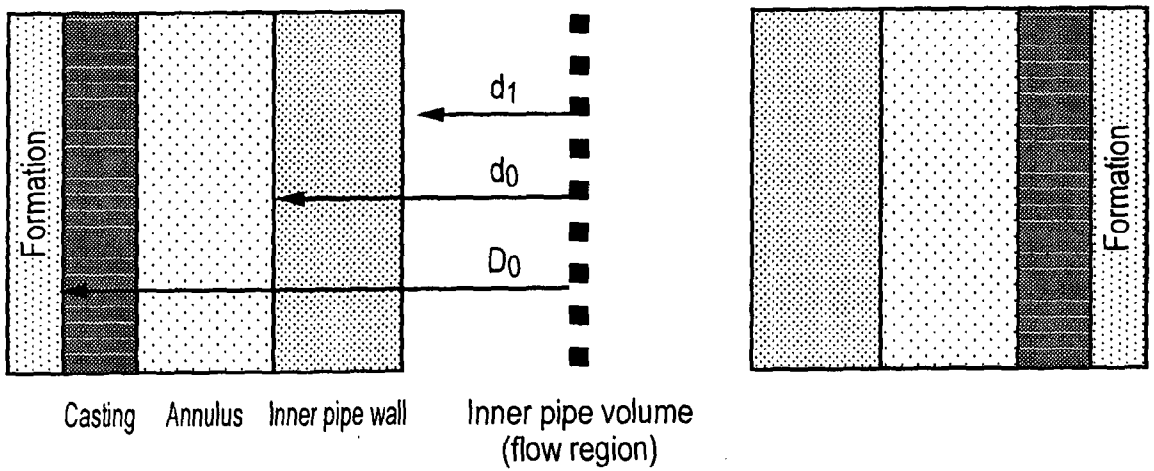
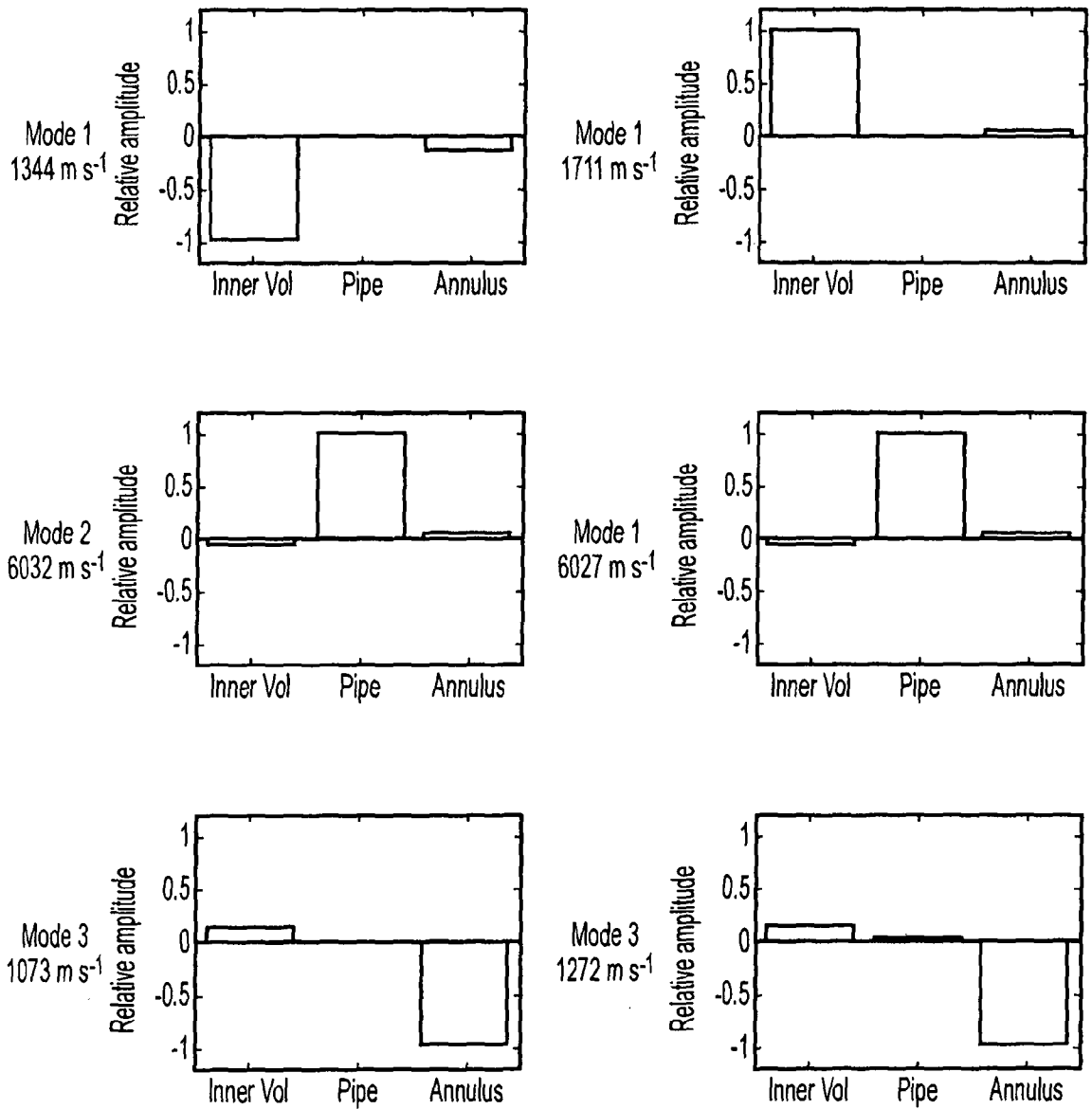


FIG. 5

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Upper section

Lower section

FIG. 6

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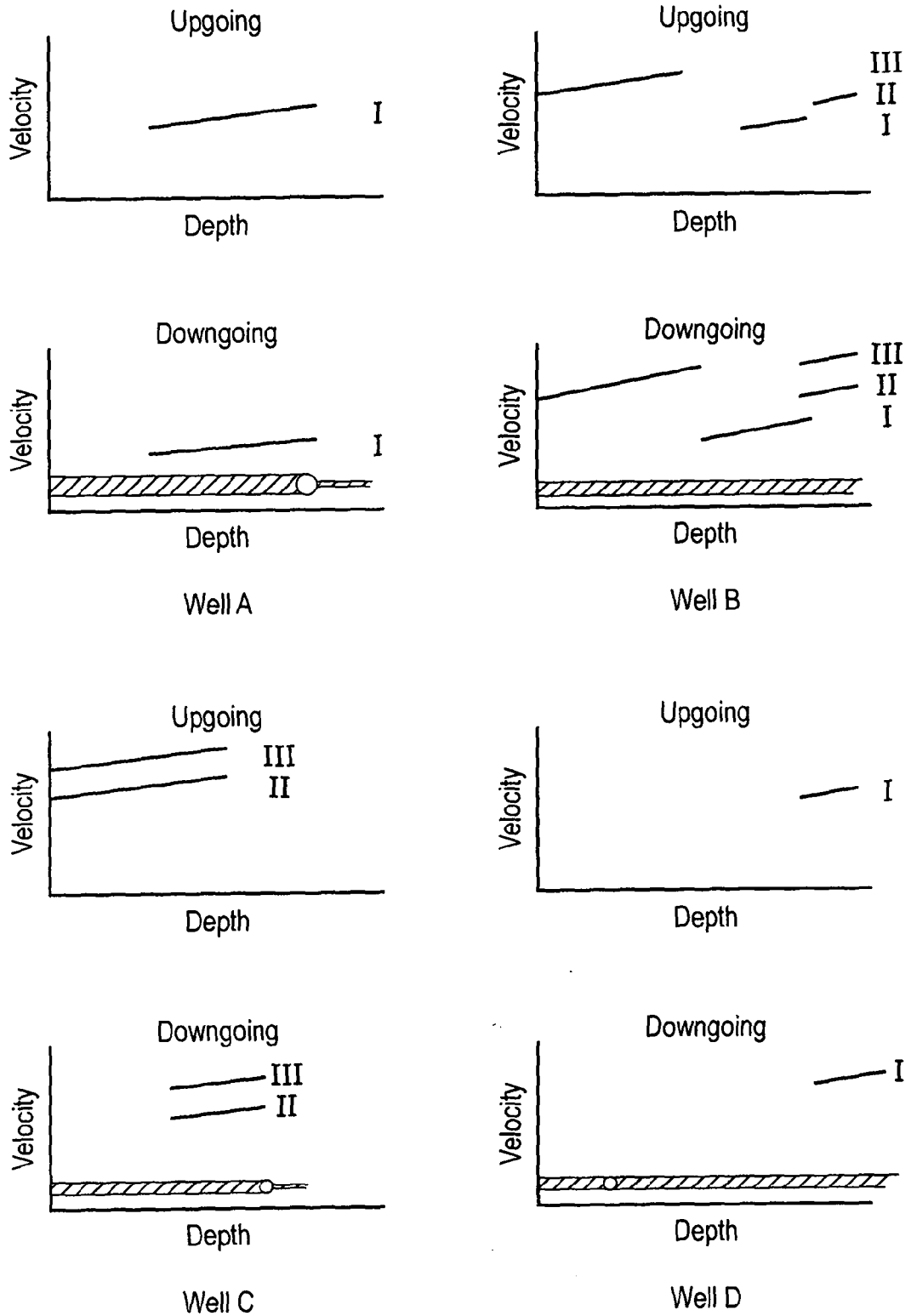


FIG. 7

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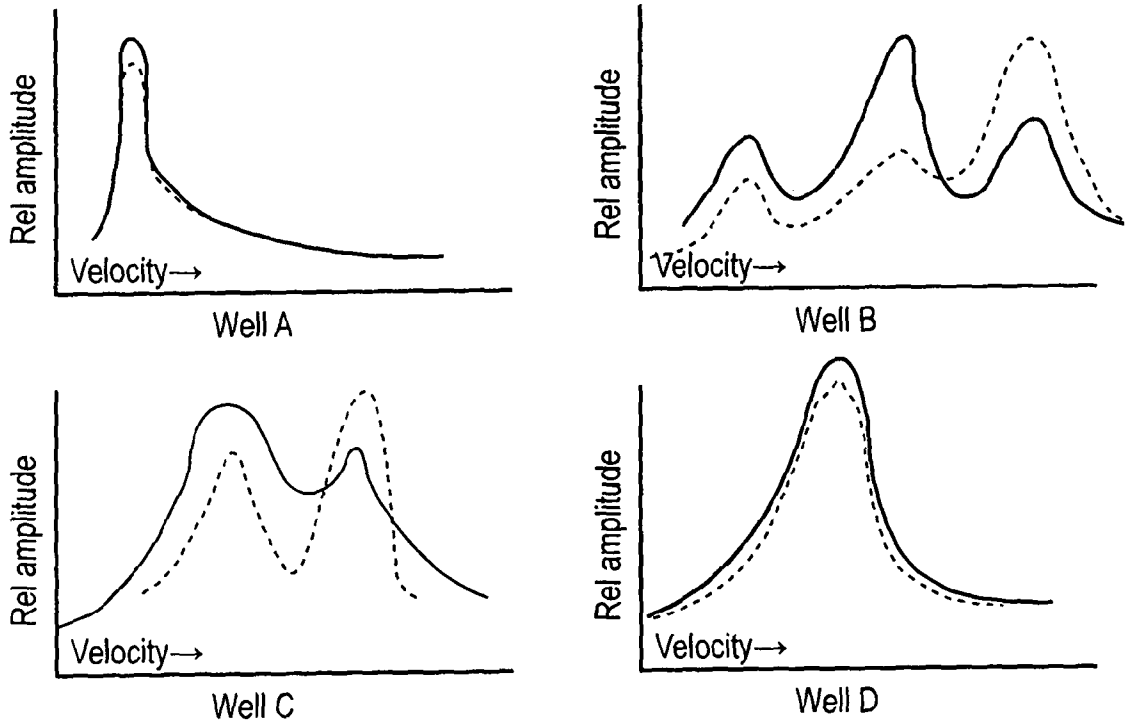


FIG. 8

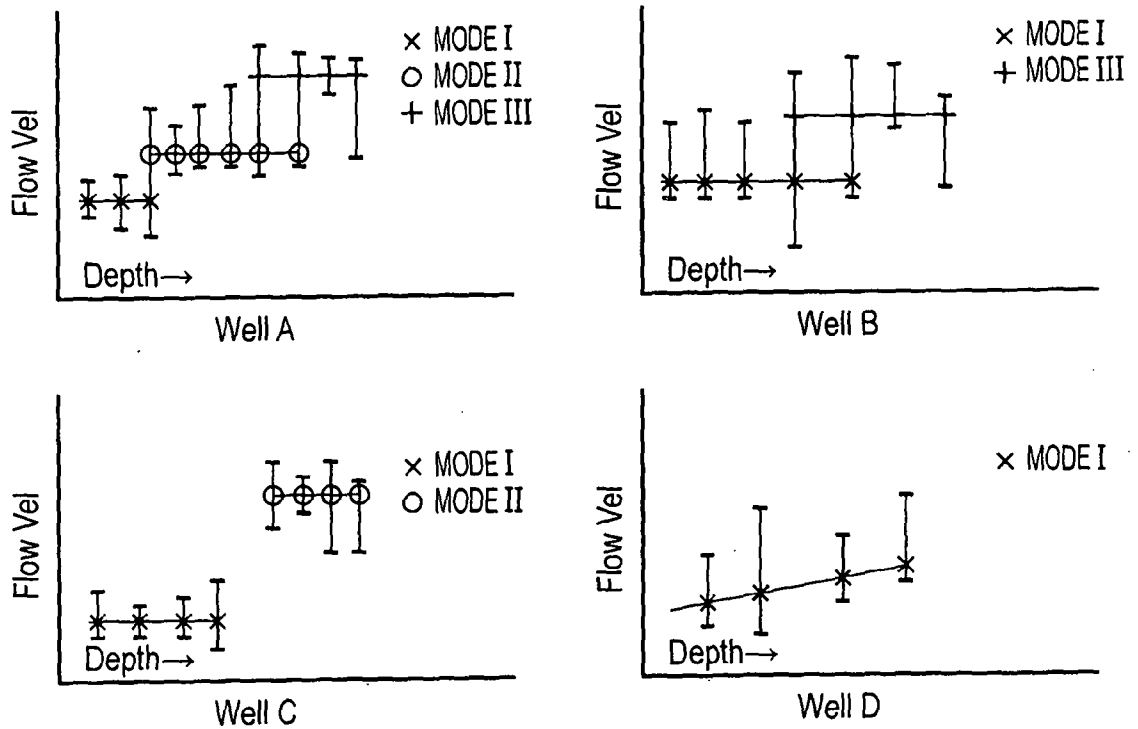


FIG. 9

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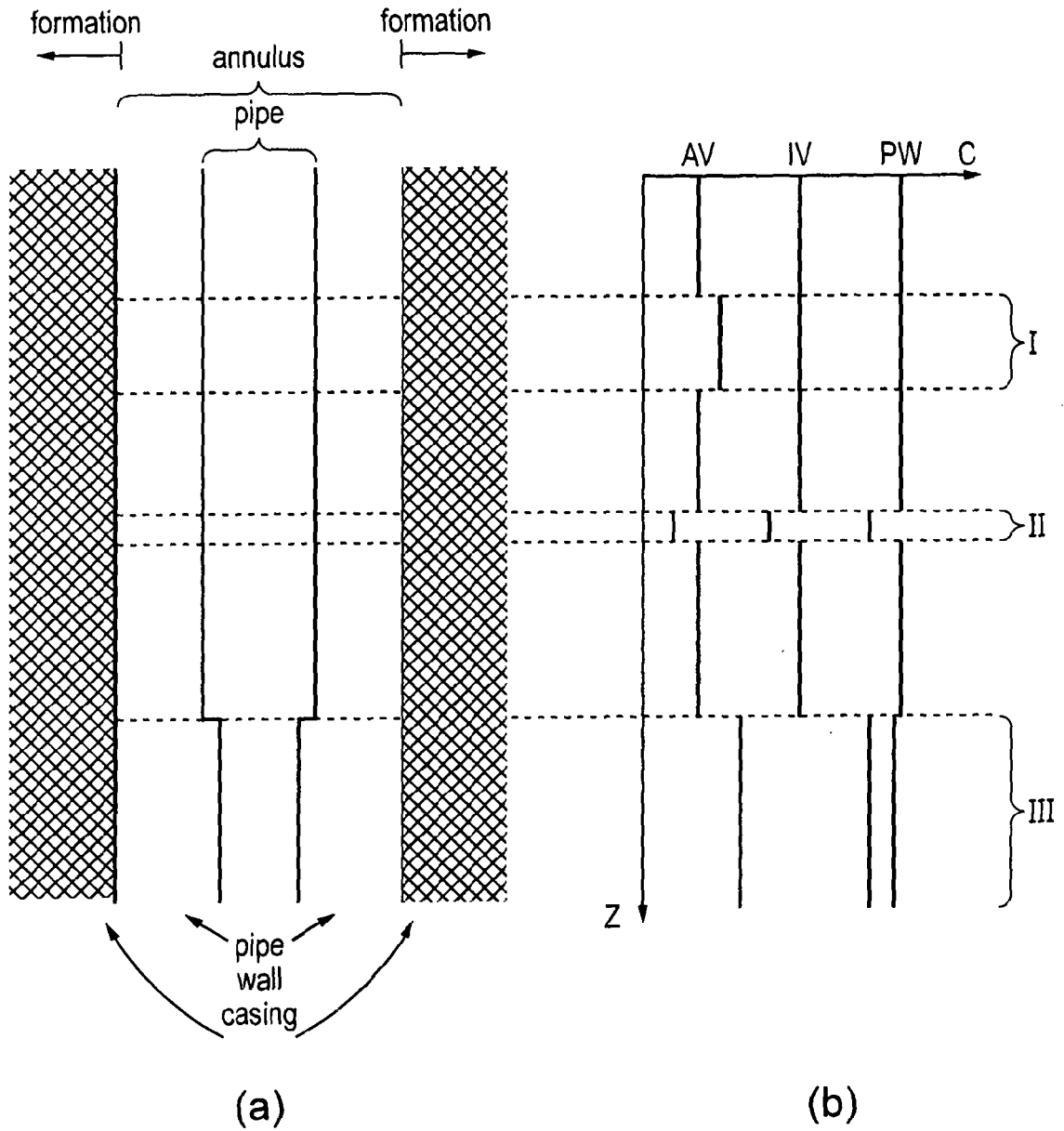


FIG. 10