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Method of obtaining improved geophysical information about earth formations

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ABSTRACT

METHOD OF OBTAINING IMPROVED GEOPHYSICAL INFORMATION ABOUT EARTH FORMATIONS

The present invention provides a method for forming wellbores. In one method, one or more wellbores (10) are drilled along preplanned paths based in part upon seismic surveys performed from the surface. An acoustic transmitter conveyed in such wellbores (10) transmits acoustic signals at one or more frequencies within a range of frequencies at a plurality of spaced locations. A plurality of substantially serially spaced receivers (12a) in the wellbores (10) and/or at surface receive signals reflected by the subsurface formations. The sensors (14a) may be permanently installed in the boreholes and could be fiber optic devices. The receiver signals are processed by conventional geophysical processing methods to obtain information about the subsurface formations. This information is utilized to update any prior seismographs to obtain higher resolution seismographs. The improved seismographs are then used to determine the profiles of the production wellbores to be drilled. Borehole seismic imaging may then be used to further improve the seismographs and to plan future wellbores. Cross-well tomography may be utilized to further update the seismographs to manage the reservoirs. The permanently installed sensors (14a) may also be used to monitor the progress of fracturing in nearby wells and thereby provide the necessary information for controlling fracturing operations.

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COMPLETE SPECIFICATION

FOR A STANDARD PATENT

ORIGINAL

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Invention Title:	Method of Obtaining Improved Geophysical Information about Earth Formations

The following statement is a full description of this invention, including the best method of performing it known to me/us:-

TITLE: METHOD OF OBTAINING IMPROVED GEOPHYSICAL INFORMATION ABOUT EARTH FORMATIONS

Field of the Invention

This invention relates generally to the placement of wellbores and management of the corresponding reservoirs and more particularly to selectively drilling one or more wellbores for conducting seismic surveys therefrom to improve the seismographs and utilizing the improved seismographs to determine the type and course of wellbores for developing a field. The method of the present invention further relates to obtaining seismic information during drilling of the wellbores and during production of hydrocarbons for improving hydrocarbon production from the reservoirs. The method of the present invention further relates to using the derived seismic information for automatically controlling petroleum production wells using downhole computerized control systems.

Background of the Invention

Seismic surveys are performed from surface locations to obtain maps of the structure of subsurface formations. These surveys are in the form of maps (referred herein as seismographs") depicting cross-section of the earth below the surveyed region or area. Three dimensional ("3D") surveys have become common over the last decade and provide significantly better information of the subsurface formations compared to the previously available two-dimension ("2D") surveys. The 3D surveys have significantly reduced the number of dry wellbores. Still, since such seismic surveys are performed from the surface, they lose resolution due to the distance between the surface and the desired hydrocarbon-bearing formations, dips in and around the subsurface formations, bed boundary delineations, which is typically several thousand feet.

Surface seismic surveys utilize relatively low frequency acoustic signals to perform such surveys because such signals penetrate to greater depths. However, low frequency signals provide lower resolution, which provides low resolution seismographs. High frequency signals provide relatively high resolution boundary delineations, but attenuate relatively quickly and are, thus, not used for performing seismic surveys from the surface.

Only rarely would an oil company drill a wellbore without first studying the seismographs for the area. The number of wellbores and the path of each wellbore is typically planned based on the seismographs of the area. Due to the relatively low resolution of such seismographs, wellbores are frequently not drilled along the most effective wellpaths. It is therefore desirable to obtain improved seismographs prior to drilling production wellbores. Additionally, more and more complex wellbores are now being drilled, the placement of which can be improved with high definition seismographs. Furthermore, relatively recently, it has been proposed to drill wellbores along contoured paths through and/or around subsurface formations to increase potential recovery or to improve production rates of hydrocarbons. In such cases, it is even more critical to have seismographs that relatively accurately depict the delineation of subsurface formations.

Conventionally, seismographs have been updated by (a) performing borehole imaging, which is typically conducted while drilling a wellbore and (b) by cross-well tomography, which is conducted while between a number of producing wells in a region. In the case of borehole imaging, a seismic source seismic source generates acoustic signals during drilling of the wellbore. A number of receivers placed on the surface receive acoustic reflections from subsurface formation boundaries, which signals are processed to obtain more accurate bed boundary information about the borehole. This technique helps improve the surface seismographs in piecemeal basis. Data from each such well being drilled is utilized to continually update the seismographs. However, such wellbores are neither planned nor optimally placed for the purpose of conducting subsurface seismic surveys. Their wellpaths and sizes are determined based upon potential recovery of hydrocarbons. In the case of cross-well tomography, acoustic signals are transmitted between various transmitters and receivers placed in producing wellbores. The effectiveness of such techniques are reduced if the wellbores are not optimally placed in the field. Such techniques would benefit from wellbores which are planned based on improved seismographs.

In the control of producing reservoirs, it would be useful to have information about the condition of the reservoir away from the borehole. Crosswell techniques are available to give this kind of information. In seismic tomography, a series of 3-D images of the reservoir is developed to give a 4-D model or the reservoir. Such data has usually been obtained using wireline methods in which seismic sensors are lowered into a borehole devoted solely for monitoring purposes. To use such data on a large scale would require a large number of wells devoted solely to monitoring purposes. Furthermore, seismic data acquired in different wireline runs commonly suffers from a data mismatch problem where, due to differences in the coupling of the sensors to the formation, data do not match.

The present invention addresses the above-noted problems and provides a method of conducting subsurface seismic surveys from one or more wellbores. These wellbores may be drilled for the purpose of conducting such surveys. Alternatively, permanently implanted sensors in a borehole that could even be a production well could be used to gather such data. The data from such subsurface surveys is utilized to improve the previously available seismographs. The improved seismographs are then utilized to plan the production wellbores. Borehole seismic imaging and cross-well tomography can be utilized to further improve the seismographs for reservoir management and control.

Summary of the Invention

According to one aspect of the present invention there is provided a method of obtaining geophysical information about subsurface formations, comprising:

(a) forming a survey wellbore along a predetermined wellpath, a portion of said survey wellbore in proximity to and substantially parallel to a producing reservoir and distant from the surface of the earth;

(b) placing a first plurality of spaced seismic receivers in the survey wellbore;

(c) generating seismic pulses into the earth's subsurface formations;

(d) detecting by the plurality of seismic receivers seismic waves reflected by earth's formations in response to the generated seismic pulses and generating signals responsive to such detected seismic waves; and

(e) processing the generated signals to obtain geophysical information about the subsurface formations.

According to another aspect of the present invention there is provided a method of managing a hydrocarbon-bearing field comprising:

(a) permanently installing a plurality of acoustic sensors in a survey wellbore;

(b) injecting a fluid at high pressure into a formation at an injection wellbore so as to stimulate a fracture in the formation and generate acoustic pulses thereby;

(c) detecting said acoustic signals in the survey wellbore;

(d) processing the detected signals to determine a location of the stimulated fracture; and

(e) operating a downhole tool in the injection well in response to the determined location of the stimulated fracture to control the fracturing of the formation.

According to still another aspect of the present invention there is provided a method of recovering hydrocarbons from a production wellbore producing hydrocarbons from a formation comprising:

(a) injecting a fluid in an injection wellbore spaced apart from the production wellbore to make a fluid/hydrocarbon interface in the formation;

(b) permanently installing a plurality of seismic sensors in a survey wellbore;

(c) transmitting seismic signals into the formation from a plurality of source locations;

(d) detecting said seismic signals by the seismic sensors in the survey wellbore;

(e) determining a parameter of interest relating to the fluid/hydrocarbon interface from the detected seismic signals; and

(f) operating a downhole tool at least one location selected from (i) the production wellbore, and, (ii) the injection well, in response to the determined parameter of interest to control the flow of hydrocarbons into the production wellbore.

According to still another aspect of the present invention there is provided a method of obtaining geophysical information about subsurface formations, comprising:

(a) permanently deploying a plurality of fiber optic sensors in a survey wellbore, each said sensor having a fiber optic element detecting a seismic wave;

(b) using said fiber optic sensors for detecting seismic waves travelling through the subsurface formations; and

(c) processing the detected seismic waves to obtain geophysical information about the subsurface formation.

According to still another aspect of the present invention there is provided a method of obtaining geophysical information about subsurface formations, comprising:

(a) deploying a plurality of fiber optic sensors in a first survey wellbore, each said sensor having a fiber optic element for detecting a seismic wave;

(b) generating seismic waves in the subsurface using at least one transmitter in a second survey wellbore and using said fiber optic sensors for detecting said generated seismic waves travelling through the subsurface formations; and

(c) processing the detected seismic waves to obtain geophysical information about the subsurface formation.

BRIEF DESCRIPTION OF THE DRAWINGS

For detailed understanding of the present invention, references should be made to the following detailed description of the preferred embodiment, taken in conjunction with the accompanying drawings, in which like elements have been given like numerals, wherein:

FIG. 1 shows a schematic illustration of the placement of a wellbore and corresponding transmitters and receivers for conducting subsurface seismic surveys according to an embodiment of the present invention.

FIG. 1a shows a receiver grid for use at the surface according to an embodiment of the present invention.

FIG. 2 shows a schematic illustration of the placement of a plurality of wellbores and corresponding transmitter and receivers for conducting subsurface seismic survey according to an embodiment of the present invention.

FIG. 3 shows a schematic illustration of multiple production wellbores formed for producing hydrocarbons utilizing the information obtained from surveys performed according to the present invention.

FIG. 4 shows a schematic illustration of multiple production wellbores formed for producing hydrocarbons utilizing the information obtained from surveys performed according to the present invention, wherein at least one of the production wellbores is formed from the wellbore formed for performing subsurface seismic survey.

FIG. 5 is a diagrammatic view of an acoustic seismic monitoring system in accordance with the present invention.

DETAILED DESCRIPTION OF THE PREFERRED EMBODIMENTS

In general, the present invention provides methods for obtaining improved seismic models prior to drilling production wellbores, drilling wellbores based at least partially on the improved seismic models and method for improving reservoir modeling by continued seismic survey during the life of the production wellbores.

FIG. 1 shows a schematic illustration of an example of the placement of a survey wellbore and receivers and the source points for conducting subsurface seismic surveys according to the present invention. For the purposes of illustration and ease of understanding, the methods of the present invention are described by way of examples and, thus, such examples shall not be construed as limitations. Further, the methods are described in reference to drilling wellbores offshore but are equally applicable to drilling of wellbores from onshore locations. In this configuration, a survey wellbore **10** is planned based on any preexisting information about the subsurface formation structure. Such information typically includes seismic surveys performed at the surface and may include information from wellbores previously formed in the same or nearby fields. As an example, **FIG. 1** shows non-hydrocarbon bearing formations **Ia** and **Ib** separated by hydrocarbon bearing formations **IIa** and **IIb** (also referred to herein as the "production zones" or "reservoirs"). After the wellpath for the survey wellbore **10** has been determined, it is drilled by any conventional manner. Typically, reservoirs are found several thousand feet deep from the earth's surface and in many instances oil and gas is trapped in multiple zones separated by non-hydrocarbon bearing zones. It is preferred that the hydrocarbon bearing formations be not invaded by drilling fluids and other drilling activity except as may be necessary to drill wellbores for recovering hydrocarbons from such formations. Therefore, it is generally preferred that the survey wellbore **10** be placed in a non-hydrocarbon bearing formation, such as formation **Ia**. Additionally, it is preferred that the survey wellbore be placed relatively close to and along the reservoirs.

Typically, production wellbores are relatively large in diameter, generally greater than seven inches (7") in diameter. Such large diameter wellbores are expensive to drill. Survey wellbores, such as exemplary wellbore **10**, however, need only be large enough to accommodate acoustic receivers, such as hydrophones, fiber optic sensors, and an acoustic source moved within the wellbore as more fully explained later. Such small diameter wellbores can be drilled relatively inexpensively in non-producing zones without concerning invading formations near the borehole. Additionally, relatively inexpensive fluids may be utilized to drill such wellbores. As noted earlier, reservoirs typically lie several thousand feet below the earth's surface and thus the survey wellbore, such as wellbore **10**, may be placed several thousand feet below the earth's surface. Additionally, if the survey wellbore is not eventually going to be utilized for purposes that would require casing or otherwise completing the wellbore, such wellbore may be filled with a heavy fluid (called the "kill-weight" fluid) to prevent collapse of the wellbore.

Once the survey wellbore **10** has been drilled, a receiver string or line **12** with a plurality of serially spaced receivers **12a** is placed along the wellbore. The receiver locations **12a** are preferably equi-spaced and each receiver location **12a** may include one or more receivers, such as hydrophones, seismometers or accelerometers. The receivers could also be single or a plurality of fiber optic strings or segment, each such segment containing a plurality of spaced apart fiber optic sensors: in such a case, a light source and detector (not shown) are disposed used in the wellbore to transmit light energy to the sensors and receiver the reflected light energy from the sensors and a suitably placed data acquisition and processing unit is used for processing the light signals. The use of such receiver lines is known in the art and is not described in detail herein. Alternatively or in addition to the receiver string **12**, one or more receiver lines, such as lines **14**, each having a plurality of serially spaced acoustic sensors **14a** may be placed on the ocean bottom **16** for relatively shallow water applications. For relatively deep water applications, one or more receiver lines may be placed a relatively short distance below the water surface **22**. Receiver lines **22** are made buoyant so that they remain at a desired distance below the water surface. **FIG. 1a** shows a plan view of an exemplary configuration of a plurality of receiver lines **R1-Rn** that may be placed on the earth's surface. The receivers in each line designated by r_{ij}, where **i** represents the line and **j** represents the sequential position in the line **i**. The receivers in adjacent lines are shown staggered one half the distance between adjacent receivers.

The same fiber-optic sensor could be used as an acoustic sensor and to determine other downhole conditions, such as the temperature, pressure and fluid flow. The use of fiber optic sensors in downhole tools is fully described in Provisional Application Serial No. 60/045,354, incorporated herein by reference.

Referring back to **FIG. 1**, to perform a seismic survey from the survey wellbore **10**, a seismic source (acoustic transmitter) is energized at a first location, such as location **12s**$_1$. The acoustic signals travel around the survey wellbore **10** and are reflected and refracted by the bed boundaries between the various formations. The reflected waves, such as waves **30** are detected by the receivers **12s** in the survey wellbore **12**. The detected signals are transmitted to a surface control unit **70**, which processes the detected signals according to known seismic processing methods. Desired information relating to the survey activity is displayed on the display and any desired information is recorded by the recorder. The control unit preferably includes a computer with a seismic data processing programs for performing processing receiver data and for controlling the operation of the source **15**.

The source **15** is then moved to the next location in the wellbore **10** and the above process is repeated. When receiver lines, such as lines **14** are deployed on the sea bottom **16**, then the signals **32** reflected from the subsurface formations are detected by the receivers **14a**. The signals detected by the sensors **14a** are then collected and processed by the control unit **70** in the manner described earlier. When receiver lines **18** are suspended in the ocean water **20** then reflected signals as shown by lines **34** are detected by the receivers **18a** in lines **18**. The signals received by the lines **18** are then processed by the control unit **70** in the manner described earlier. It should be noted that for the purpose of this embodiment of the invention any combination of the receiver lines may be utilized. Additionally, the source may be activated at surface locations.

In the first embodiment of the invention, the source **15** is preferably conveyed into the survey wellbores **10** and moved to each of the source points **15**s_i. This allows utilizing only one source for performing the survey. The source **15** preferably is adapted to transmit acoustic signals at any frequency within a range of frequencies. The control unit **70** is used to alter the amplitude and frequency of the acoustic signals transmitted by the source **15**. Since the survey wellbore is strategically placed from relatively short distance from some or all of the producing formations, a relatively high frequency signals may be utilized to obtain high resolution seismic maps for short distances, which is nor feasible from any seismic surveys performed from the surface. Additionally, the source **15** may be oriented in any direction to transmit acoustic signals in a particular direction (herein referred to as the focused signals). This can allow obtaining true three dimensional bed boundary information respecting formations surrounding the survey wellbore **10**. During drilling of the wellbore, core cuttings from known depths provide information about the rock structure, which in turn can be used to determine relatively accurately the acoustic velocities of some of the formations surrounding the survey wellbore **10**. These velocities are utilized in processing the signals detected by the receiver lines, such as lines, such as line **12**, **14** and **18**. This provides more accurate delineation of bed boundaries compared to surface seismic surveys which typically use estimated values of acoustic velocities for subsurface formations.

The information obtained from the survey as described above is used to update preexisting seismic models. This may be done by combining the data obtained from the survey performed from the survey wellbore **10** or by any other known method. Additionally actual acoustic velocities of the subsurface formations obtained herein can be utilized to update the seismic models of the area.

Now referring to **FIG 1a**, the source line defined by s_1 -s_p is shown to be symmetrically placed in relation to the surface seismic lines $\mathbf{R_1}$ -$\mathbf{R_n}$. It is preferred to utilize symmetrical receiver and transmitter configurations because it simplifies processing of data.

FIG. 2 shows a schematic illustration of the placement of a plurality of wellbores and corresponding transmitter and receiver lines for conducting subsurface seismic survey according to one method of one embodiment of the invention. In this configuration, a survey wellbore **100** is formed along a wellpath based on the prior seismic and other subsurface formation information available. The wellbore **100** has a first branch wellbore **100a** placed above the first reservoir **IIa** and a second branch wellbore **100b** placed above and along a second reservoir **IIb**. Other configurations for multiple survey wellbores may be adopted based upon the location of reservoirs to be developed. For example, separate wellbores may be drilled from different surface locations. A survey wellbore may be drilled along a dip to more precisely map the dipping formation utilizing relatively high frequency acoustic signals.

Each of the survey wellbores, such as wellbores **100a** and **100b** are lined with a receiver line **102** and **104** respectively. To conduct seismic survey from wellbore **100a**, a transmitter is activated from each of the source points **s**. The reflected signals **106** are detected by the receivers **r** in the line **102**, receivers in any other survey wellbore and by any other receivers placed on the surface. The data from the receivers is then processed by the control unit in the manner described earlier with respect to **FIG. 1** to obtain information about the subsurface formations. Seismic data may be obtained at different frequencies and by utilizing focused signals in the manner described earlier with respect to **FIG. 1**.

FIG. 3 shows a schematic illustration of multiple production wellbores formed for producing hydrocarbons utilizing the information obtained from surveys performed according to one embodiment of the invention. Once the subsurface geological information has been updated, the size and the placement of production wellbores, such as wellbores **100, 100a** and **100b** for developing a region are determined based upon the updated seismographs or subsurface models. The desired production wellbores are drilled and completed to produce hydrocarbons. It is desirable to place a plurality of receivers, such as receivers **202** in wellbore **200a** and receivers **206** in wellbore **200b**. In some cases it may be desirable to leave the receiver line **12** in the survey wellbore **10**. During the life of the wellbores **200a** and **200b**, acoustic sources may be activated at selective locations in any of the production wellbores and in the survey wellbore **10**. The receivers in the various wellbores detect signals corresponding to the transmitted signals. The detected signals are then processed to determine the condition of the various reservoirs over time.

This information is then used to update reservoir models. The updated reservoir models are subsequently utilized to manage production from the various wellbores in the field. The updated models may be used to selectively alter production rates from any of the production wellbores in the field, to shut in a particular well, to workover a particular production wellbore, etc. The permanent availability of receiver lines in the survey wellbore **10**, relatively close to the production wellbores **200a** and **200b**, provides more accurate information about the subsurface formations than surveys conducted from the surface. However, surface seismic surveys, if performed after the wellbores have been producing, may still be updated with information obtained from surveys performed using survey wellbore **10**.

FIG. 4 shows a schematic illustration of multiple production wellbores formed for producing hydrocarbons utilizing the information obtained from surveys performed according to one embodiment of the invention, wherein at least one of the production wellbores is formed from the wellbore formed for performing subsurface seismic survey. In some cases it may be desirable to drill a survey wellbore which can later be utilized to form production branch wellbores therefrom. **FIG. 4** shows the formation of a survey wellbore **300a** from a common vertical well section **300**. The wellbore **300** is first used to perform seismic surveys in the manner described herein and then one or more production wellbores, such as wellbores **300b** and **300c**, are formed from the survey wellbore **300a**. Additional production wellbores, such as wellbore **310** may be formed from the common wellbore section **300** or from other surface locations (not shown) as desired. Receivers **302a** and **312a** respectively shown in the wellbores **300a** and **310** perform the same functions as explained earlier with respect to **FIGS. 1-3**.

Another aspect of the invention is the use of permanently installed downhole acoustic sensors. **FIG. 5** depicts a schematic representation of the acoustic seismic monitoring system as described immediately above. **FIG. 5** more particularly depicts a production well **410** for producing oil, gas or the like. Well **410** is defined by well casing **412** which is cemented or otherwise permanently positioned in earth **414** using an appropriate cement **416.** Well **410** has been completed in a known manner using production tubing with an upper section of production tubing being shown at **416A** and a lower section of production tubing being shown at **416B**. Attached between production tubing **416A** and **416B**, at an appropriate location, is the permanent acoustic seismic sensor in accordance with the present invention which is shown generally at **418.** Acoustic seismic sensor **418** comprises a housing **420** having a primary flow passageway **422** which communicates with and is generally in alignment with production tubing **416A** and **416B**. Housing **420** also includes a side passageway **424** which is laterally displaced from primary flow passageway **422.** Side passageway **424** is defined by a laterally extending section **426** of housing **420** and an interior dividing wall **428.** Positioned within side passageway **424** is a downhole electronics and control module **430** which is connected in series to a plurality of permanent acoustic receivers **432** (e.g., hydrophones, seismometers and accelerometers). The acoustic receivers **432** are placed longitudinally along production tubing **416** (and therefore longitudinally along the wall of the borehole) in a region of the geological formation which is of interest in terms of sensing and recording seismic changes with respect to time. At the surface **434** is a surface control system **436** which controls an acoustic transmitter **438.** As discussed, transmitter **438** may also be located beneath the surface **434.** Transmitter **438** will periodically transmit acoustic signals into the geological formation which are then sensed by the array of acoustic receivers 432 with the resultant sensed data being processed using known analysis techniques.

A more complete description of wellbores containing permanent downhole formation evaluation sensors can be found in U.S. Pat. Nos. 5,662,165 all of the contents of which are incorporated herein by reference.

As discussed in trade journals such as in the articles entitled "4D Seismic Helps Track Drainage, Pressure Compartmentalization," Oil and Gas Journal, Mar. 27, 1995, pp 55-58, and "Method Described for Using 4D Seismic to Track Reservoir Fluid Movement," Oil and Gas Journal, Apr. 3, 1995, pp. 70-74 (both articles being fully incorporated herein by reference), seismic monitoring of wells over time is becoming an important tool in analyzing and predicting well production and performance. Prior to the present invention, such seismic monitoring could only be done in near real time using known wire-line techniques; or on sensors mounted on the outside of tubing of various sorts for shallow applications (never in producing wells). Examples of such seismic monitoring are described in U.S. Pat. No. 5,194,590; the article "Time-lapse crosswell seismic tomogram Interpretation: Implications for heavy oil reservoir characterization, thermal recovery process monitoring and tomographic imaging technology" Geophysics v. 60, No. 3, (May-June), p 631-650; and the article "Crosswell seismic radial survey tomograms and the 3-D interpretation of a heavy oil steamflood." Geophysics v. 60, no. 3, (May-June) p

651-659 all of the contents of which are incorporated herein by reference. However, in accordance with the present invention, a significant advance in seismic monitoring is accomplished by installing the seismic (e.g., acoustic) sensors as a permanent downhole installation in a well. A plurality of seismic transmitters, as described in U.S. Patent 5,662,165 are used as sources of seismic energy at boreholes at known locations. The seismic waves detected at receivers in other boreholes, upon proper analysis, provide a detailed three-dimensional picture of a formation and fluids in the formation with respect to time. Thus, in accordance with this invention, a well operator has a continuous real time three dimensional image of the borehole and surrounding formation and is able to compare that real time image with prior images to ascertain changes in the formation; and as discussed in detail above, this constant monitoring can be done from a remote location.

Such an imaging of fluid conditions is used to control production operations in the reservoir. For example, an image of the gas-water contact in a producing gas reservoir makes it possible to take remedial action before water is produced in a well by selectively closing sleeves, packers, safety valves, plugs and any other fluid control device downhole where it is feared that water might be produced without remedial action. In a steam-flood or CO_2 flood operation for secondary recovery of hydrocarbons, steam or CO_2 are injected into the reservoir at selected injection wells. The steam or CO_2 drive the oil in the pore spaces of the reservoir towards the producing wells. In secondary recovery operations, it is critical that the steam or CO_2 not enter the producing wells: if a direct flow path for steam or CO_2 is established between the injection well and the recovery well (called a breakthrough), further "flushing" operations to recover oil are ineffective. Monitoring of the position of the steam/oil or CO_2/oil interface is therefore important and by closing sleeves, packers, safety valves, plugs and any other fluid control device in a producing well where breakthrough is imminent, the flow patterns can be altered sufficiently to avoid a breakthrough. In addition, sleeves and fluid pressure control devices can be operated in the injection wells to affect the overall flow of fluids in the reservoir. The downhole seismic data for performing the tomographic analysis is transmitted uphole using methods described in U.S. Patent 5,662,165, gathered by the control center and transmitted to a remote site where a powerful digital computer is used to perform the tomographic analysis in accordance with methods described in the patent and references above.

Another aspect of the invention is the ability to control a fracturing operation. In a "frac job", fluid at a high pressure is injected into a geologic formation that lacks adequate permeability for the flow of hydrocarbons. The injection of high pressure fluid into a formation at a well has the effect of fracturing the formation. These fractures generally propagate away from the well in directions determined by the properties of the rock and the underground stress conditions. As discussed by P.B. Wills et al in an article entitled "Active and Passive Imaging of Hydraulic fractures" *Geophysics, the Leading Edge of Exploration*, July, p 15-22, (incorporated herein by reference), the use of downhole geophones in one well (a monitor well) makes it possible to monitor the propagation of fractures from another well in which fracturing is being induced. The propagating fracture in the formation acts as a series of small seismic sources that emit seismic waves. These waves can be recorded in the sensors in the monitor well and based upon the recorded signals in a number of monitor wells, the active edge of the fracture can be mapped. Having such real-time observations makes it possible to control the fracturing operation itself using the methods of this invention..

While the foregoing disclosure is directed to the preferred embodiments of the invention various modifications will be apparent to those skilled in the art. It is intended that all variations within the scope and spirit of the appended claims be embraced by the foregoing disclosure. Examples of the more important features of the invention have been summarized rather broadly in order that the detailed description thereof that follows may be better understood, and in order that the contributions to the art may be appreciated. There are, of course, additional features of the invention that will be described hereinafter and which will form the subject of the claims appended hereto.

The claims defining the invention are as follows:

1. A method of managing a hydrocarbon-bearing field comprising:

(a) permanently installing a plurality of acoustic sensors in a survey wellbore;

(b) injecting a fluid at high pressure into a formation at an injection wellbore so as to stimulate a fracture in the formation and generate acoustic pulses thereby;

(c) detecting said acoustic signals in the survey wellbore;

(d) processing the detected signals to determine a location of the stimulated fracture; and

(e) operating a downhole tool in the injection well in response to the determined location of the stimulated fracture to control the fracturing of the formation.

2. The method of claim 1, wherein the downhole tool is selected from the group consisting of flow control devices and formation isolation tools.

3. The method of claim 2,wherein the acoustic sensor is selected from the group consisting of geophone, accelerometer, hydrophone and fiber optic sensor.

4. A method of managing a hydrocarbon-bearing field, substantially as herein defined with reference to any one of the embodiments as illustrated in Figs. 1 to 5.

DATED this Ninth Day of December 2000

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Patent Attorneys for the Applicant

SPRUSON & FERGUSON

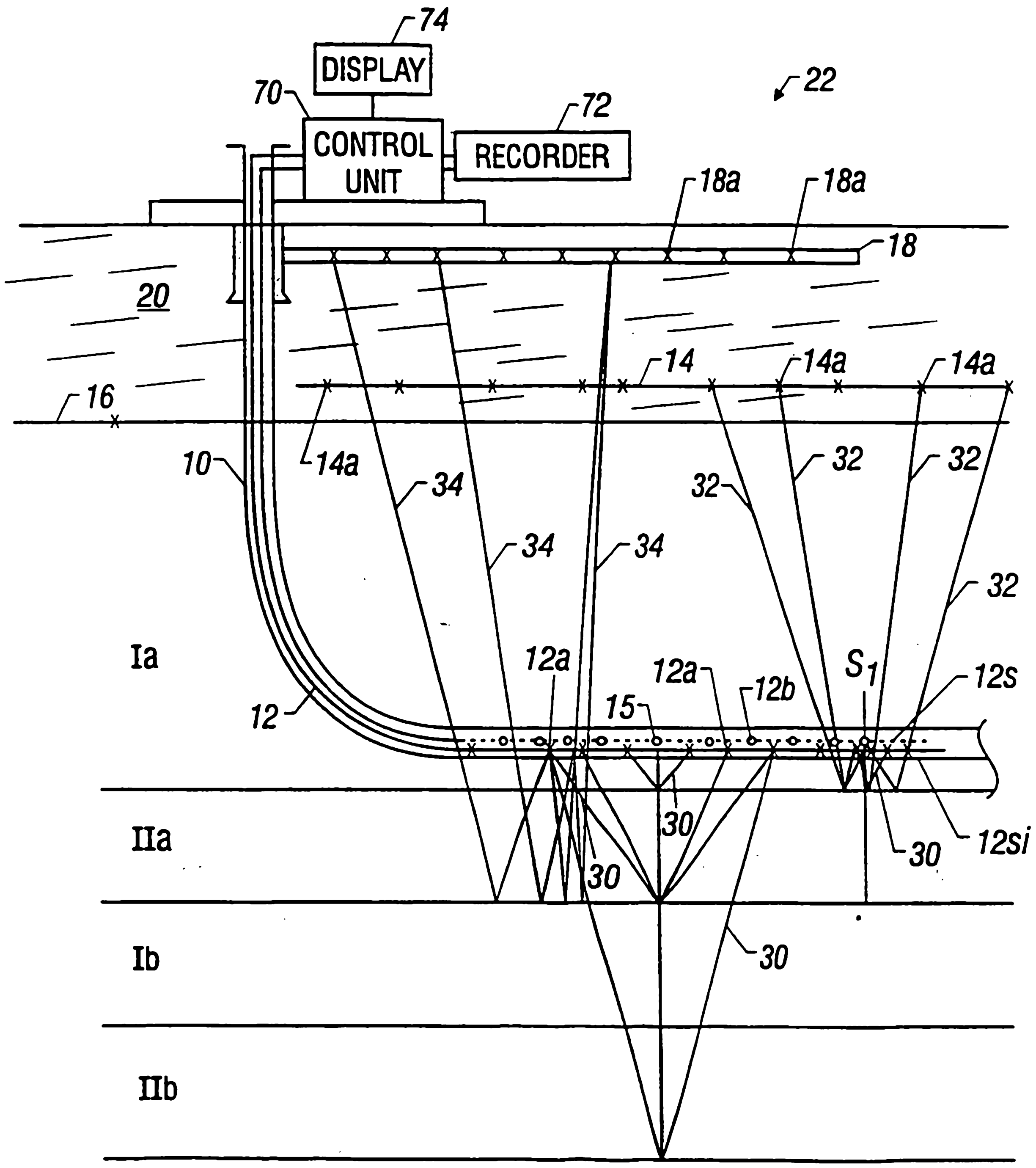
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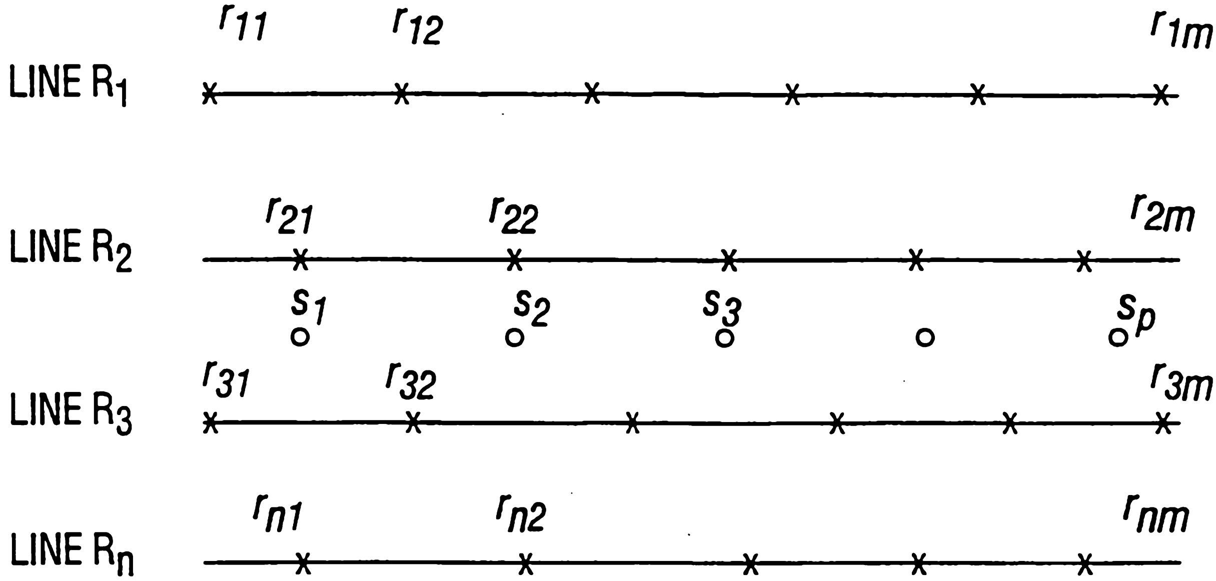
Figure 1



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s_1
s_2
s_3
s_p
r_{31}
r_{32}
r_{3m}
LINE R_3
r_{n1}
r_{n2}
r_{nm}
LINE R_n

Figure 1A

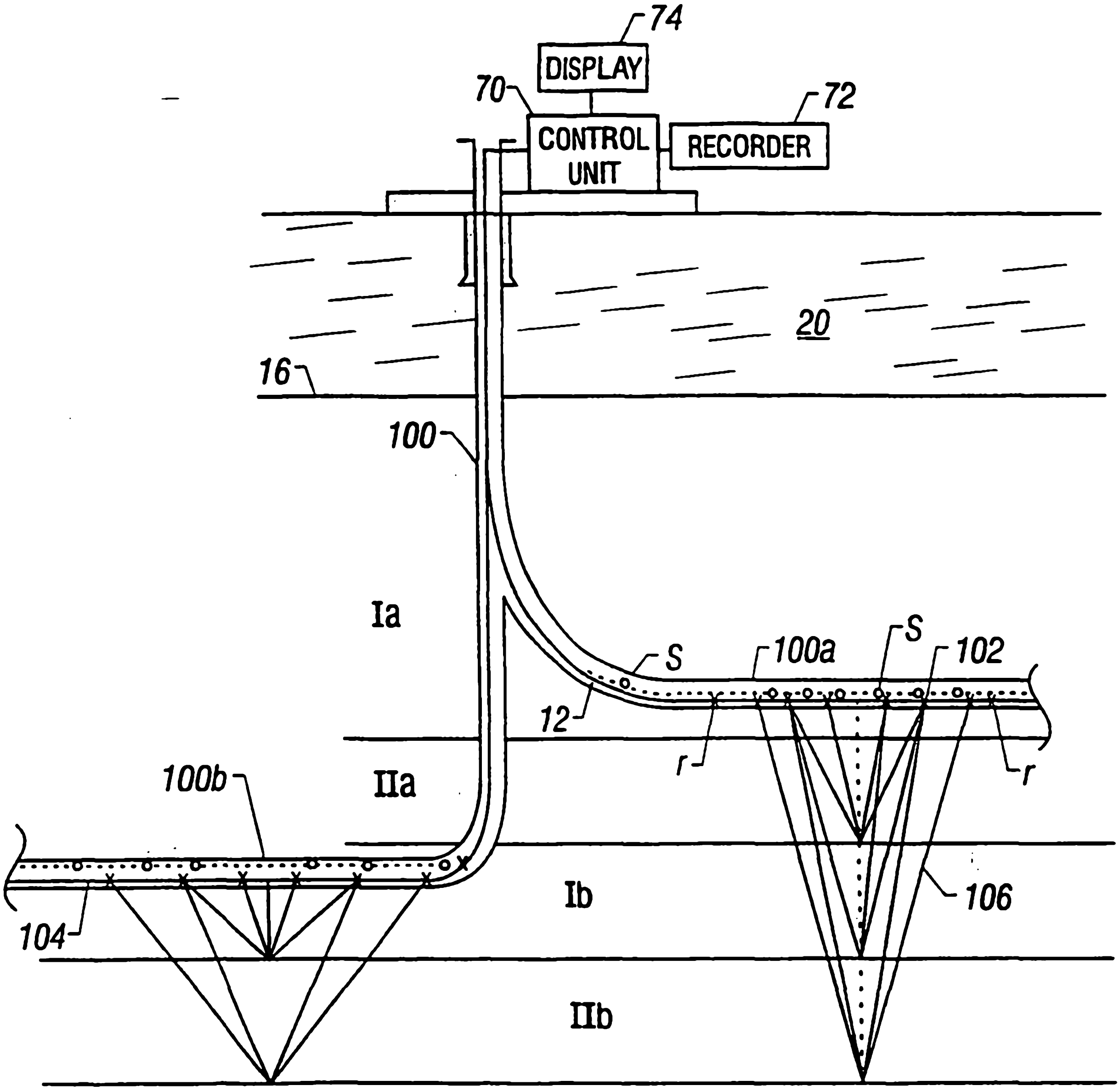
74
DISPLAY
70
CONTROL UNIT
72
RECORDER
20
16
100
Ia
S
100a
S
102
12
r
r
100b
IIa
Ib
106
104
IIb

Figure 2

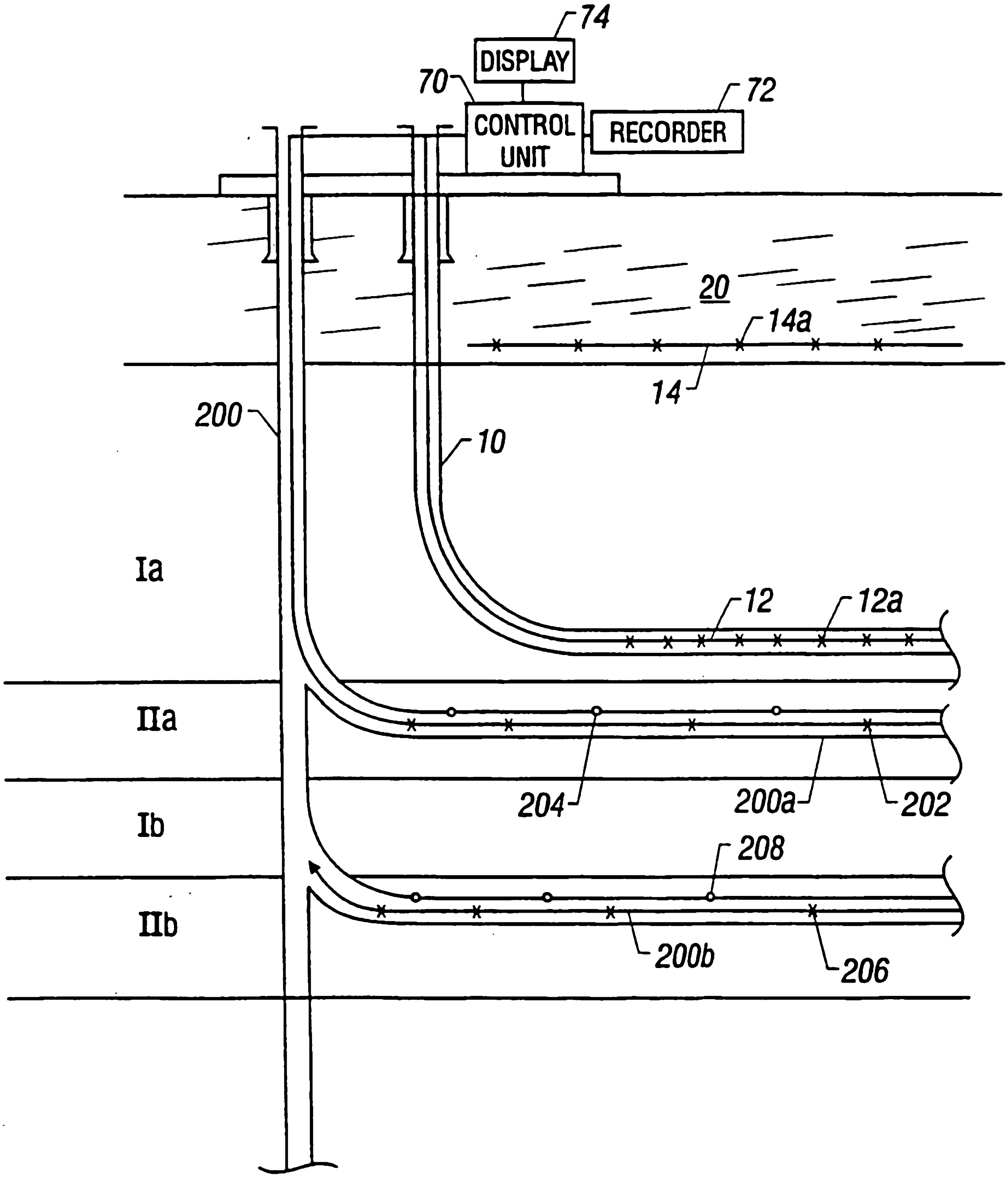
74
DISPLAY
70
CONTROL UNIT
72
RECORDER
20
14a
14
200
10
Ia
12
12a
IIa
204
200a
202
Ib
208
IIb
200b
206

Figure 3

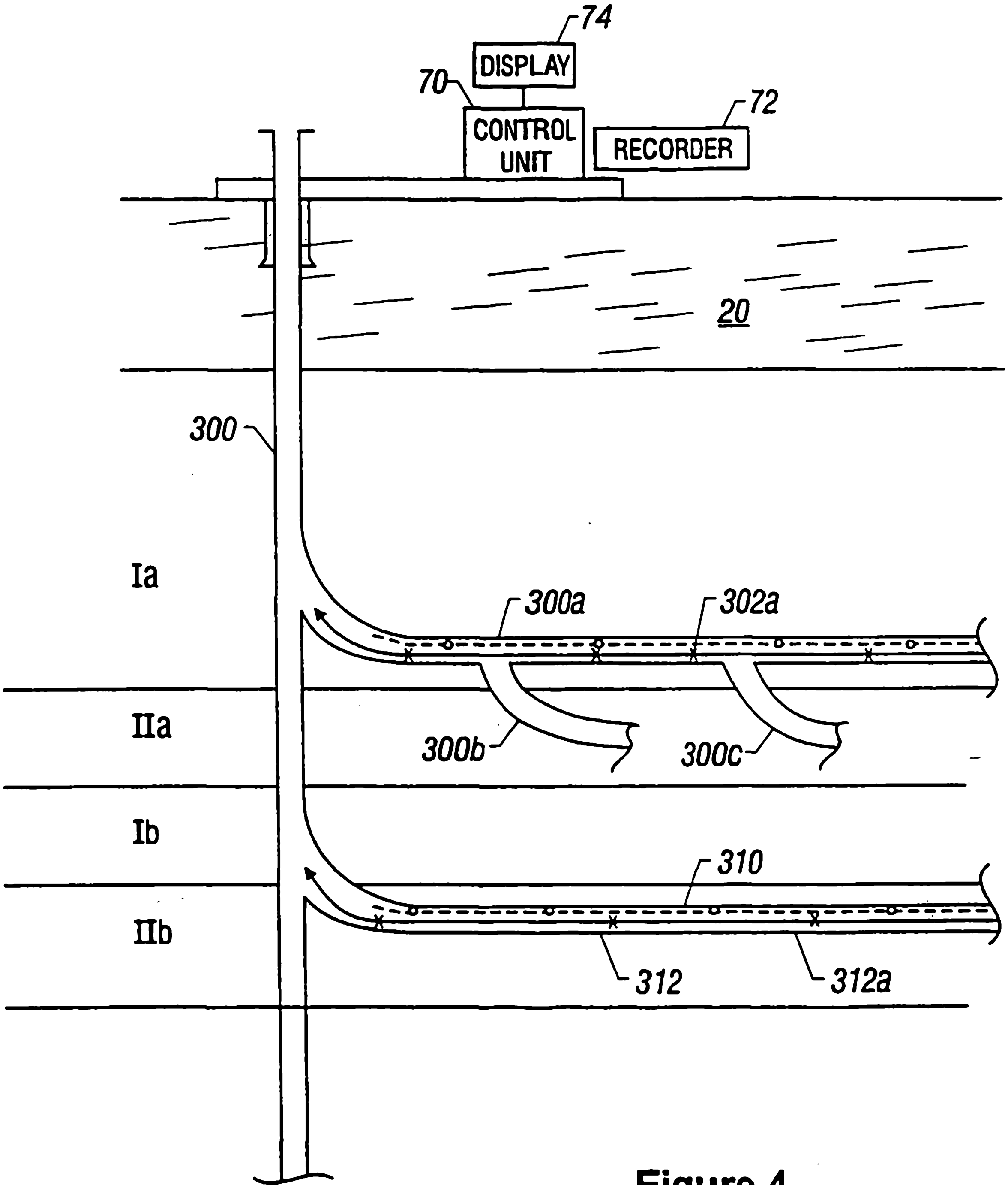
74
DISPLAY
70
CONTROL UNIT
72
RECORDER
20
300
Ia
IIa
Ib
IIb
300a
302a
300b
300c
310
312
312a

Figure 4

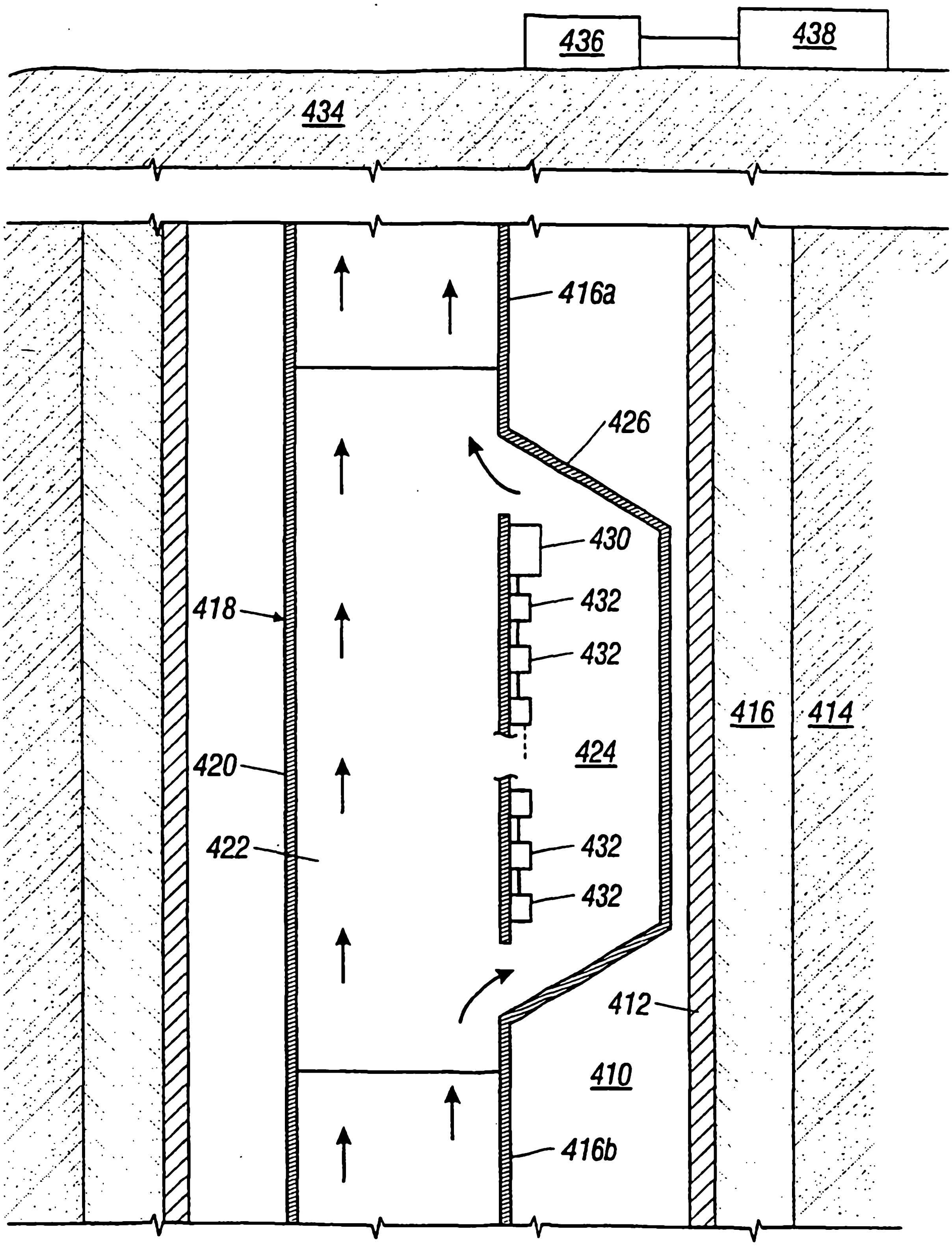
436
438
434
416a
426
430
432
432
418
416
414
424
420
422
432
432
412
410
416b

Figure 5