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(54) METHOD FOR EVALUATING A WELLBORE PARAMETER IN A DRILLING OPERATION AND RELATED ASSEMBLY

(57) The method comprises:
- injecting a tracer gas at an injection point (152) in a drilling fluid intended to circulate in the wellbore;
- circulating the drilling fluid containing the tracer gas from the injection point (152) to an exit of the wellbore;
- extracting gas from the drilling fluid, the extraction being configured so that hydrocarbons and the tracer gas are extracted if present in the drilling fluid,
- transporting the extracted gas to a measuring device (57) intended for detecting hydrocarbons;
-detecting the tracer gas at the measuring device (57);
-calculating the wellbore parameter based at least on a time of detection of the tracer gas.

The tracer gas comprises at least a perfluorocarbon and/or a hydrofluorocarbon.

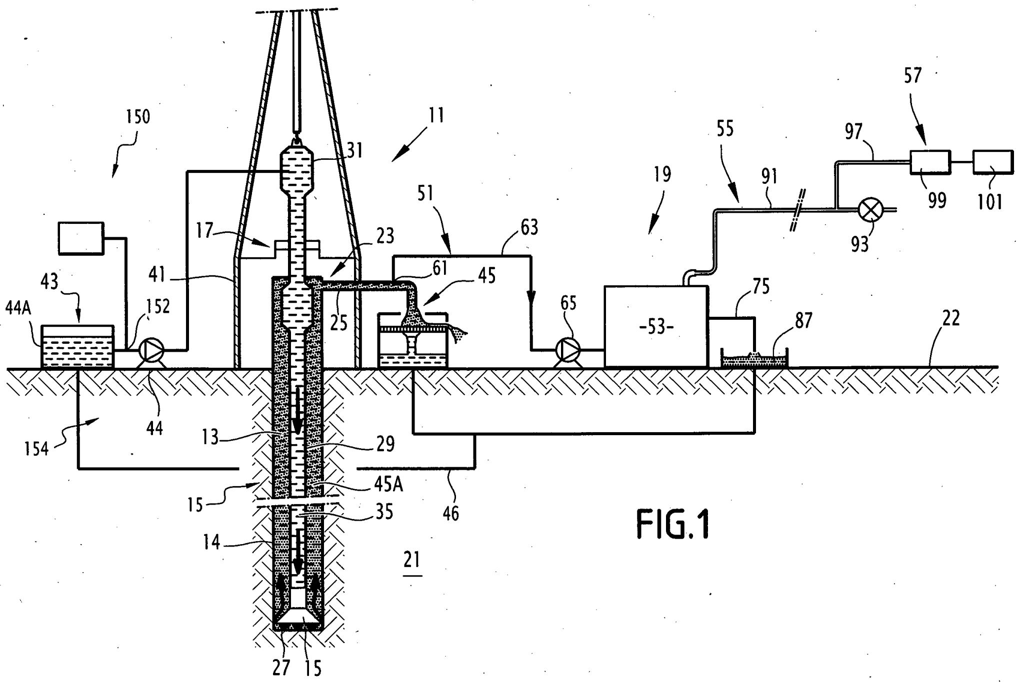

FIG.1

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Description

[0001] The present disclosure concerns a method for evaluating a wellbore parameter in a drilling operation

[0002] The method is adapted in particular for determining a lag time for gases to rise from the bottom of a hole to the surface in a wellbore, the gases being contained in a drilling fluid circulating in the wellbore being drilled.

[0003] When an oil and gas well is being drilled, rock cuttings and formation fluids (especially gaseous and liquid hydrocarbons) are released from the formation, mixed with the drilling fluid, and are carried to the surface. Mud gas logging (or fluid logging) and cuttings analysis are carried out to continuously monitor the drilling process for safety reasons and for evaluating the type of fluids encountered in the drilled formations.

[0004] Thus, for precisely correlating hydrocarbon fluids and cuttings to the formations and depths from which they originate, it is critical to know the exact amount of time the hydrocarbon fluids and cuttings take to travel from the drilling bit to the surface.

[0005] Such a determination is done by carrying out a lag time determination. The lag time is physically measured at regular intervals, for example every twelve hours and/or every 150 meters of drilling. A tracer gas is injected in the drilling fluid, for example when the circulation of the drilling fluid is stopped for connecting a new drilling string tube. Then, the drilling fluid containing the tracer gas circulates down the hole to the drilling bit, and rises to the surface where the tracer gas is detected by a gas analyzer.

[0006] In order to avoid stopping the circulation of a fluid, WO 93/21420 discloses a method in which a tracer gas is introduced at the top of a drilling string, directly in a pipe supplying the drilling string with drilling fluid.

[0007] The use of a tracer gas does not damage downhole tools, it is ideal to tag gaseous hydrocarbons from the formation, and it is generally applicable to any kind of mud.

[0008] In WO 93/21420, the tracer gas is acetylene. Acetylene has nevertheless several drawbacks in gas detection. First of all, acetylene is a very flammable gas, and special precautions must be taken at the injection point of the tracer gas. Moreover, acetylene is quite toxic, which requires additional precautions to avoid risks to the site operators.

[0009] Acetylene is also quite reactive due to the triple bounds between carbon atoms. There is therefore a risk of decomposition/degradation of the acetylene, which may affect the mud properties, especially in the harsh environment of a well.

[0010] Additionally, acetylene is soluble in water. The solubility of acetylene is therefore different from the solubility of the hydrocarbons which are to be detected at the outlet of the well. The difference in solubility may affect the results which are obtained when detecting acetylene.

[0011] The disclosure provides a reliable method for evaluating a wellbore parameter in a drilling operation.

[0012] Accordingly, the disclosure relates to a method for evaluating a wellbore parameter in a drilling operation, comprising:

- injecting a tracer gas comprising a perfluorocarbon or a hydrofluorocarbon at an injection point in a drilling fluid;
- circulating the drilling fluid containing the tracer gas from the injection point to an exit of the wellbore;
- extracting gas from the drilling fluid, so that hydrocarbons and the tracer gas are extracted if present in the drilling fluid,
- transporting the extracted gas to a measuring device detecting hydrocarbons;
- detecting the tracer gas at the measuring device;
- calculating the wellbore parameter based on a time of detection of the tracer gas. ,

[0013] The method according to the disclosure may comprise one or more of the following features, taken solely or according to any relevant technical combination:

- the perfluorocarbon is a perfluoroalkane and/or the hydrofluorocarbon is a hydrofluoroalkane;
- the perfluoroalkane is a perfluoroalkane having less than 6 atoms of carbon and/or the hydrofluoroalkane is a hydrofluoroalkane having less than 6 atoms of carbon;
- the perfluoroalkane or the hydrofluoroalkane is a fluorinated form of ethane or of propane;
- the method comprises carrying out the detection of the tracer gas at the gas analyzer simultaneously with the detection of hydrocarbons arising from the wellbore at the gas analyzer;
- transporting the extracted gas to the measuring device comprises passing the tracer gas in a chromatograph.;
- the tracer gas is chosen so as to have an elution time in the gas chromatograph comprised between 0% and 200% of the elution time of at least one of the alkanes having less than 6 carbon atoms in the same gas chromatograph;
- injecting the tracer gas at the injection point comprises automatically introducing a predetermined quantity of tracer gas in the drilling fluid;
- injecting the tracer gas comprises injecting the tracer gas according to a predetermined injection pattern;
- the injection pattern comprises at least one injection pulse, injected during an injection time of less than 30 seconds, and in particular a series of periodic pulses;

- injecting the tracer gas is carried out:

  * upstream of an injection head for injecting a drilling fluid in a drill string, or/and
  * in a return line, after the drilling fluid has already exited the wellbore, or/and
  * in a downhole assembly, close to a drilling head for carrying out the drilling operation;

- injecting the tracer gas is carried out while circulating the drilling fluid in the wellbore.
- the wellbore parameter is chosen among a lag time, a short cycle, or a long cycle time.

[0014] The disclosure also relates to an assembly for evaluating a wellbore parameter in a drilling operation, comprising:

- a tracer gas injector for injecting a tracer gas at an injection point in a drilling fluid;
- a measuring device detecting hydrocarbons in the drilling fluid;
- a circulation assembly for circulating the drilling fluid containing the tracer gas from the injection point to an exit of the wellbore;
- an extractor extracting hydrocarbons and the tracer gas are extracted from the drilling fluid if present,
- a transport device for transporting the extracted gases to the measuring device;
- a calculator for calculating the wellbore parameter based on a time of detection of the tracer gas at the measuring device;

[0015] The tracer gas injector comprises a tracer gas source containing a perfluorocarbon or a hydrofluorocarbon and is detected by the measuring device.
[0016] The method according to the disclosure may comprise one or more of the following features, taken solely or according to any relevant technical combination:

- the measuring device comprises one detector for detecting the tracer gas and the hydrocarbons.

[0017] The disclosure will be better understood, upon reading of the following description, given solely as an example, and made in reference to the following drawings, in which:

- Fig. 1 is a schematic vertical sectional view of a drilling installation comprising an assembly for evaluating a wellbore parameter in a drilling operation according to the disclosure;
- Fig. 2 is an example of a tracer gas injector in the evaluating assembly, for injecting a tracer gas at an injection point in a drilling fluid;
- Fig. 3 is a schematic view of a variant of the injector;
- Fig. 4 is another example of gas chromatography separation in which two different tracer gases according to the disclosure are detected.

[0018] One or more specific embodiments of the present disclosure will be described below. These described embodiments are examples of the presently disclosed techniques. Additionally, in an effort to provide a concise description of these embodiments, a complete listing of features of an actual implementation may not be described in the specification. It should be appreciated that in the development of any such actual implementation, as in any engineering or design project, numerous implementation-specific decisions are made to achieve the developers' specific goals, such as compliance with system-related and business-related constraints, which may vary from one implementation to another. Moreover, it should be appreciated that such a development effort might be complex and time-consuming, but would still be a routine undertaking of design, fabrication, and manufacture for those of ordinary skill having the benefit of this disclosure.
[0019] When introducing elements of various embodiments of the present disclosure, the articles "a," "an," and "the"' are intended to mean that there are one or more of the elements. The terms "comprising," "including," and "having" are intended to be inclusive and mean that there may be additional elements other than the listed elements.
[0020] Additionally, it should be understood that references to "one embodiment" or "an embodiment" of the present disclosure are not intended to be interpreted as excluding the existence of additional embodiments that also incorporate the recited features.
[0021] In all the following, the terms "upstream" and "downstream" are also to be understood relatively to the normal direction of circulation of a fluid in a conduit.
[0022] With reference to Fig. 1, a drilling installation 11 is described.
[0023] The drilling installation 11 is for drilling a well for producing fluid, notably hydrocarbons, such as an oil well.
[0024] This installation 11 comprises a drilling conduit 13 positioned in a cavity 14 or wellbore pierced by a rotary

drilling tool 15 in a subsoil 21, a surface installation 17, and an analyzer 19 for analyzing the gases contained in the drilling fluid exiting the well. According to the disclosure, the installation 11 further comprises an assembly for evaluating a wellbore parameter in a drilling operation.

[0025] At the surface 22, the drilling conduit 13 includes a wellhead 23 provided with a conduit 25 for discharging the drilling fluid exiting the well.

[0026] The drilling tool 15 comprises, from bottom to top in Fig. 1, a drilling head 27, a drilling string 29, and a head 31 for injecting drilling fluid. The drilling tool 15 is driven into rotation by the surface installation 17.

[0027] The drilling head 27 is mounted on the lower portion of the drilling string 29 and is positioned in the bottom of the cavity 14.

[0028] The drilling string 29 comprises a set of hollow drilling tubes. These tubes delimit an inner space 35 which allows the drilling fluid injected through the head 31 from the surface 22 to be brought as far down as the drilling head 27.

[0029] The drilling fluid, commonly designated with the term « drilling mud », is essentially liquid.

[0030] The surface installation 17 comprises a system 41 for supporting and driving in rotation the drilling tool 15, and a system 43 for injecting the drilling fluid and a vibrating sieve 45.

[0031] The injection system 43 is hydraulically connected to the injection head 31 for introducing and circulating the drilling fluid in the internal space 35 of the drilling string 29. It comprises at least a drilling fluid pump 44 to pump drilling fluid from a mud pit 44A to the bottom of the cavity 14 through the inner space 35.

[0032] The drilling fluid is introduced into the inner space 35 of the drilling string 29 through the injection system 43. The drilling fluid flows downwards to the drilling head 27 and passes into the drilling conduit 13 through the drilling head 27. It cools and lubricates a drilling head 27 comprising a drill bit. The drilling fluid collects the solid debris resulting from the drilling and flows upwards through the annular space 45A defined between the drilling string 29 and the walls of the drilling conduit 13, and is then discharged through the discharge conduit 25.

[0033] The discharge conduit 25 is hydraulically connected to the cavity 14, through the wellhead 23 in order to collect the drilling fluid from the cavity 14. It is for example formed by an open mud conduit or by a closed tubular conduit.

[0034] The vibrating sieve 45 collects the fluid loaded with drilling residues which flow out of the discharge conduit 25, and separates the liquid from the solid drilling residues.

[0035] A return line 46, for instance equipped with a pump connects the vibrating sieve 45 to the mud pit 44A to return the drilling fluid collected in the vibrating sieve 45 to the mud pit 44A.

[0036] The gas analyzer 19 comprises a device 51 for sampling drilling fluid in the conduit 25, an extraction system 53 for extracting gases contained in the drilling fluid, a transport device 55 for transporting the extracted gases, a measuring device 57, and a calculator 101 for determining the content of at least one gas extracted from the drilling fluid from the measurement.

[0037] The sampling device 51 comprises a sampling head 61 immersed in the circulation conduit 25, and a sampling conduit 63 connected upstream to the sampling head 61.

[0038] With reference to Fig. 2, the extraction system 53 may comprise a pump 65 downstream of the sampling conduit 63, an extraction device (not shown) for performing a gas extraction in the drilling fluid, and a mud discharge conduit 75.

[0039] The pump 65 is for example a peristaltic pump capable of conveying the drilling fluid sampled by the head 61 towards the extraction device 53 with a controlled mud volume flow rate Q_m.

[0040] The extraction device comprises an enclosure and a rotary stirrer mounted in the enclosure for churning the drilling fluid and extracting gases contained in it. The extraction device may comprise a flow meter and a mud heater hydraulically connected in series between the pump 65 and the enclosure.

[0041] The enclosure has a mud inlet for receiving a first flow of drilling fluid from the sampling device 51, and a mud outlet for delivering a second flow of drilling fluid to the discharge conduit 75.

[0042] The enclosure also has a gas inlet for injecting a carrier gas, and a gas outlet for recovering an extracted gas mixture.

[0043] The enclosure has an inner volume for example comprised between 0.04L and 3L. It defines a lower portion containing the drilling fluid stemming from the sampling conduit 63 and an upper portion defining a gas head space above the drilling fluid.

[0044] The volume of mud V_m is kept constant in the inner volume by controlling the flow of drilling fluid Q_m and the volume of the upper portion $V_{g,}$, corresponding to the volume of the enclosure minus the volume of the mud V_m is therefore kept constant as well.

[0045] The gas outlet is connected to the transport device 55.

[0046] The stirrer is immersed into the drilling fluid present in the lower portion of the enclosure. It is capable of vigorously stirring the drilling fluid in order to extract at least a hydrocarbon gas to be analyzed and/or a tracer gas.

[0047] In the example shown, the carrier gas is formed by the surrounding air around the installation, at atmospheric pressure. Alternatively, this carrier gas is another gas such as nitrogen or helium.

[0048] The discharge conduit 75 is connected to a retention tank 87 intended to receive the drilling fluid discharged out of the extraction system 53. The retention tank 87 is connected to the return line 46.

[0049] Alternatively, any extraction device may be used for extracting the gas from the drilling mud, for instance a standard gas trap.

[0050] The transport device 55 comprises a line 91 for transporting the extracted gases towards the measuring device 57, and a suction system 93 for conveying the extracted gases through the transport line 91.

[0051] The measuring device 57 comprises a sampling conduit 97 tapped on the transport line 91 upstream from the suction system 93, and an instrumentation 99.

[0052] The instrumentation 99 is capable of detecting and quantifying gas fractions in the extracted gas which are transported through the transport line 91.

[0053] This instrumentation 99 for example comprises at least a detector such as an infrared detection apparatus, a flame ionisation detectors (FID) for detecting hydrocarbons or a thermal conductivity detectors (TCD) or a mass spectrometer. Any of the detectors may be used for determining an hydrocarbon content such as a total amount of gas, such as hydrocarbons or alkanes, or carbon dioxide (that may result from a combustion of alkane in an oven), etc.

[0054] The detector may be coupled with a separator upstream of the detector, the separator being for instance a gas chromatograph. More generally, any separator may be appropriate. The detector may then be used to detect a content of each hydrocarbon to be detected or even of different isotopes of a same hydrocarbon. The compounds of a gas mix enter the column simultaneously, but exit the column each at a different specific elution time due to the properties of the column, which enables to obtain a specific measurement for each of the compounds.

[0055] The instrumentation may comprise one detection apparatus coupled to several extraction devices or several detection apparatuses, such as each detection apparatus is couples to an extraction device.

[0056] The separation columns of the chromatography system can be conventional columns, capillary columns, MEMS-based columns having a stationary phase including gas-liquid such as wall coated open tubular columns and gas-solid chromatographic column, , such as packed columns, porous layer open tubular columns. Any other type of separation columns may also be used.

[0057] Online simultaneous detection and quantifiication of a plurality of hydrocarbon gases contained in the fluid, without any manual sampling by an operator, is therefore possible within time intervals of less than 1 minute.

[0058] The drilling fluid for example is formed by oil-based mud (having oil as a main component) or water-based mud (having water as a main component). In general, drilling fluid compounds contain at least hydrocarbons with C_n with n<20 (n being the number of carbon atoms in the gaseous compounds). The hydrocarbon gases which are analyzed are usually up to C8, in particular from C1 to C5 hydrocarbons, however higher Cn compounds may be analyzed if needed.

[0059] The evaluating assembly is for evaluating at least a wellbore parameter in a drilling operation carried out in the drilling installation 11.

[0060] The wellbore parameter is for example a specific circulation time of the drilling fluid. The wellbore parameter is for instance a lag time of the drilling fluid. The lag time or "bottoms-up time" is the time taken by a material to circulate in the wellbore from the drilling head 27 situated at the bottom of the well to the surface, during circulation of the drilling fluid, or the time needed to displace the annular volume contained in the annular space 45A.

[0061] Other relevant circulation times which may be determined by the method according to the disclosure are the short cycle and the long cycle. The term "short cycle" refers to sum of surface to drilling head 27 time and drilling head 27 to surface time which is the time needed to displace the internal volume of the drilling string 29 and the annular volume of the annular space 45A. The term "long cycle" is the total time required for a given point in the drilling fluid to pass through the drilling string, the annulus and surface mud drilling fluid volume to return to its starting point.

[0062] The evaluation assembly comprises a tracer gas injector 150, for injecting a tracer gas at an injection point 152 in the drilling fluid, a circulation assembly 154, for circulating the drilling fluid containing tracer gas from the injection point 152 through the cavity 14 to the gas analyzer 19, and at least a detector of the tracer gas, which here consists of a detector in the instrumentation 99 of the gas analyzer 19.

[0063] The evaluating assembly further comprises a calculator, which here consists of the same calculator 101 used in the gas analyzer 19.

[0064] In the example of Fig. 2, the tracer gas injector 150 comprises at least a gas source 160 and a tracer gas injection duct 162 connecting the gas source 160 to a drilling fluid circulation line 164. In the example of Fig.2, the gas source 160 comprises at least a tracer gas container 166 containing tracer gas.

[0065] In a variant or in complement, the gas source 160 comprises a tracer gas generator able to generate tracer gas.

[0066] According to the disclosure, the tracer gas is gaseous at the injection point, in particular at ambient temperature and at the injection pressure.

[0067] The tracer gas comprises at least a halocarbon, such as a fluorocarbon (ie organic compounds containing at least carbon and fluor) and in particular a perfluorocarbon and/or a hydrofluorocarbon, in particular a perfluoroalkane and /or hydrofluoroalkane.

[0068] Perfluorocarbons are compounds of the general formula C_nF_m, n and m being integers equal or greater than 1. They comprise in particular perfluoroalkanes, perfluoroalkenes, perfluoroalkynes and perfluoroaromatic compounds. Perfluorocarbons only contain carbon and fluorine atoms .

[0069] Perfluoroalkanes contained in the tracer gas are for example C1 to C10 perfluoroalkanes, in particular C1 to C5 perfluoroalkanes, more particularly C2 to C3 perfluoroalkanes. Perfluoroalkanes are compounds of the general formula C_nF_m, with m equal to 2n + 2..

[0070] In particular, examples of perfluoroalkanes which can be used as tracer gas are tetrafluoromethane (CF4), hexafluoroethane (C2F6), octafluoropropane (C3F8) perfluoro- n-butane (n-C4F10), perfluoro-iso-butane (i-C4F10). Such perfluoroalkanes are non-flammable.

[0071] Hydrofluorocarbons are compounds of the general formula $C_nH_pF_m$, n, p and m being integers. They comprise in particular hydrofluoroalkanes, hydrofluoroalkenes, hydrofluoroalkynes and hydrofluoroaromatic compounds. Hydrofluorocarbons only contain carbon, hydrogen and fluorine atoms.

[0072] Hydrofluoroalkanes contained in the tracer gas are for example C1 to C10 hydrofluoroalkanes, in particular C1 to C5 hydrofluoroalkanes, more particularly C2 to C3 hydrofluoroalkanes.

[0073] Examples of hydrofluoroalkanes which can be used are 1,1,1,2-tetrafluoroethane (HFC-134a), 1,1,1,2,3,3,3-heptafluoropropane (HFC-227ea) and/or 1,1,1,3,3-pentafluoropropane (HFC-245fa). Such hydrofluoroalkanes are non-flammable.

[0074] The gas source 160 is able to deliver to the gas injection duct 162 a pressurized flow of tracer gas, for example at a pressure comprised between 10,000 Pa and 10,000,000 Pa.

[0075] The gas injection duct 162 runs from the gas source to the injection point 152. It is equipped at least with one controlled automatic gas shut-off valve 170.

[0076] In the example of Fig. 2, the gas injection duct 162 further comprises a pressure regulator 172 including a manometer, a flow control device 174, for example an needle valve or a flow restrictor, both located upstream of the automatic gas shut-off valve 170.

[0077] The gas injection duct 162 comprises a check valve 176 located downstream of the shut-off valve 170 to prevent contamination of the shut-off valve 170 when drilling fluid circulates in the circulation line 164.

[0078] The injection point 152 is here located in a suction line 164 upstream of the mud pump 44, and downstream of the mud pit 44A.

[0079] The automatic shut-off valve 170 is automatically controlled to deliver, punctually or periodically, a quantity of tracer gas from the gas source 160 into the drilling fluid.

[0080] The tracer gas may be injected as a pulse, whose intensity and duration is controlled by the flow rate inside the gas injection duct 162. The initial injection concentration needs to be high enough to induce a significant increase in the total gas output at the detector in the instrumentation 99, and to be above the detector limit of detection.

[0081] Further, the injection time is controlled by the pulse duration, i.e. the duration between the opening and the closing of the shut-off valve 170. This injection time needs to be as short as possible in order to keep a narrow and sharp peak. The injection time may range from 1 seconds to 30 seconds.

[0082] The automatic shut-off valve 170 may be controlled so that the tracer gas is injected to form a pattern of a plurality of periodic pulses (for instance 10 pulses of 10 seconds with 30 seconds between two adjacent pulses).

[0083] In a variant shown in Fig. 3, a gas treater 178 is added to remove some contaminants/impurities which may be contained in the tracer gas. The gas treater 178 is inserted between the pressure regulator 172 and the flow controller 174.

[0084] Optionally, the gas injection duct 162 is equipped with a gas/liquid mixer 180 located in the vicinity of the injection point 152. The mixer 180 allows the introduction of micron sized bubbles into a flowing stream of drilling fluid.

[0085] The bubbles yields a large gas-liquid surface contact area per unit volume of gas, which allows high volume gas transport from the gas and more efficient and quicker dissolution of the gas tracer in the drilling fluid.

[0086] The circulator assembly able to circulate the drilling fluid with the tracer gas comprises the mud pump 44. It is able to pump the drilling fluid containing tracer gas into the drilling string 29 downwards to the drilling head 27, and then upwards in the annular space 45A to the discharge conduit 25.

[0087] The injector of the tracer may be disposed at surface, upstream of the injection head 31 (upstream or downstream of the mud pump 44) or in the return line, after the drilling fluid has exited the wellbore. It may also be disposed downhole, close to the drilling head 27.

[0088] According to the disclosure, the same instrumentation 99 is used for analyzing the hydrocarbon gases which are contained in the drilling fluid, and the tracer gas injected in the drilling fluid. The same detector of the instrumentation 99 may be used for detecting a signal arising for the hydrocarbon gases to be analyzed and for detecting a signal of tracer gas at the outlet of a chromatograph.

[0089] In the present case, the same calculator 101 is used to calculate the content in at least one hydrocarbon in the drilling fluid and to determine the wellbore parameter during the drilling operation.

[0090] When the wellbore parameter is a lag time and the injector 150 is disposed at the surface, the calculator is able to evaluate the lag time from the time difference between the detection time of the tracer gas into the detector and the time at which the tracer gas pulse was injected into the drilling fluid. The lag time is determined by the following equation:

Lag time (LT) [min] = (injection to detection time) - (surface to drilling head 27 time) - (gas line transit time) (1), in which the surface to drilling head 27 time is estimated by calculation and in which the gas line transit time is also estimated by calculation. The surface to drilling head 27 time and the gas line transit time can be calculated based on the drilling string internal volume, the mud flow rate, the gas line volume, and the gas line flow rate.

[0091] The gas line transit time is the time needed for the gas sample extracted from the mud to be displaced from the extractor to the analyzer.

[0092] When a duration representative of the travel time of the drilling fluid in the borehole called short cycle is calculated, the following formula is applied :

$$\text{Short Cycle [min]} = \text{(injection to detection time)} - \text{(gas line transit time)}$$

[0093] In a variant, when the tracer gas injector 150 is disposed directly in the drill string, it is considered that the injection point is at the drilling head 27. In this case, the lag time may be calculated as follows :

$$\text{Lag time (LT) [min]} = \text{(injection to detection time)} - \text{(gas line transit time).}$$

[0094] Indeed, the tracer gas in this case does not travels from surface to drilling head 27.

[0095] The short cycle may be calculated from the lag time as mentioned here.

[0096] In a further variant, and in particular when the injection point 152 is located in the return line 46 connecting the vibrating sieve 45 collector to the mud pit 44A., a duration called 'long cycle' and representative of the duration of recirculation of drilling fluid in the wellbore may be calculated. Such duration may however be calculated no matter where the injection point is.

[0097] When the long cycle is calculated, it is obtained by the following equation, a first detection time being determined at a first detection of the tracer gas in the analyzer 19, a second detection time being determined at a second detection of the tracer gas in the analyzer after having recirculated in the well :

$$\text{Long cycle (LC) [min]} = \text{second detection time (t2)} - \text{first detection time (t1).}$$

[0098] The method for evaluating a wellbore parameter of a drilling operation, during the drilling operation will be now described.

[0099] In order to carry out a drilling operation, the drilling tool 15 is rotably driven by the surface installation 17. A drilling fluid is introduced into the internal space of the drilling string 29 through the injection head 31. The drilling fluid descends to the drilling head 27 and passes into the annular space 45A through the drilling head 27. The drilling fluid cools and lubricates the drill bit. The drilling fluid then collects the solid debris resulting from the drilling operation and circulates back up via the annular space 45A defined between the drilling string 29 and the walls of the drilling conduit 13, and is then discharged by way of the conduit 25.

[0100] When circulating in the borehole, the drilling fluid may collect gas (hydrocarbons) coming from the reservoir and that will be used to evaluate the nature of the formation, as well-known in the art.

[0101] The pump 65 is then activated in order to continuously sample a predetermined fraction of the drilling fluid flowing in the pipe 15 and to convey it to the extractor 53.

[0102] In the extractor 53, the drilling fluid is stirred and gases to be analyzed are extracted and conveyed in the transport device 55. The gases to be analyzed are then introduced in the instrumentation 99 for detection.

[0103] Punctually or at regular intervals, the tracer gas injector 150 is activated. A pulse of tracer gas is injected into the drilling fluid and the time at which the injection takes place is recorded by the calculator 101.

[0104] In the example of Fig. 2, the automatic shut-off valve 170 is activated to allow the passage of a short pulse of tracer gas through the pressure regulator 172, the flow control device 174, and the check valve 176 to reach the injection fluid.

[0105] The tracer gas then travels along the drilling string 29 to the drilling head 27 and raises in the annular space 45A to the conduit 25. It is then sampled into the sampling device 51 and reaches the extractor 53. The tracer gas is extracted along with the hydrocarbon gases (when present) into the transport device 55, to reach the measurement device 57.

[0106] The gas mix containing the tracer gas and the hydrocarbon gases collected from the formation (if any) is introduced in the instrumentation 99 to be analyzed.

[0107] In a first embodiment, the gas mixture is brought directly from the extractor 53 to the detector. The detector then measures the total quantity of extracted gas. In this embodiment, the detection of the tracer gas corresponds to an increase of the total quantity of gas. In this embodiment, injecting the tracer gas with a specific injection pattern may enable to detect the tracer gas even when the total quantity of extracted gas suddenly varies due to changes in the composition of the formation.

[0108] In a second embodiment, the gas mixture is eluted on a chromatographic column before traveling to the detector. In this embodiment, the gases are separated in the chromatographic column and the detector measures the quantity of each compound of the gas mix. Generally, each compound is associated to a peak after a specific predetermined elution time (in view of the chromatographic column). The detection of the tracer gas corresponds in this embodiment to a non-zero quantity detected at a predetermined elution time.

[0109] As shown in Fig. 4, the peaks 202, 204 corresponding to the tracer gas have an elution time comprised between 0% and 200% of the maximal elution time of the C1 to C5 compounds extracted from the drilling fluid and coming from the formation. Nevertheless, the peaks 202, 204 corresponding to the tracer gas are significantly different in elution time from the peaks of the C1 to C5 hydrocarbons which are detected by the detector.

[0110] The tracer gas measurement is therefore non disruptive for the normal gas measurement taking place into the analyzer 19 and does not increase significantly the chromatographic cycle.

[0111] Based on the time of detection of the tracer gas, the injection to detection time is calculated by the calculator 101, and the surface to drilling head 27 time and the gas line transit time are subtracted from the injection to detection time, according to Equation (1).

[0112] The lag time is evaluated very precisely, in a continuous basis and under conditions which directly correspond to the conditions of elution of hydrocarbon gases.

[0113] The use of perfluorocarbons, in particular perfluoroalkanes, and/or hydrofluorocarbons, , in particular hydrofluoroalkanes, is very advantageous in that the compounds are non-flammable, present no risk to human health and have a high stability in harsh chemical and thermal environments and remain inert and non-reactive.

[0114] Moreover, these compounds behave similarly to light hydrocarbons such as C1 to C5 hydrocarbons which are traced in a regular evaluation of the hydrocarbon content of a drilling fluid. The fluorinated gases have a low solubility in water, which is similar to the solubility of gaseous hydrocarbons from the formation. Furthermore, such tracer gases do not partition into other mud phases.

[0115] Additionally, perfluoroalkanes and/or hydrofluoroalkanes do not affect the readings of the hydrocarbons in C1 to C5 which are measured. As opposed to a tracer which is a C1 to C5 hydrocarbon, there is no effect on the peaks which are used to evaluate the gas content of the drilling fluid.

[0116] The overall quantity of injected tracer gas can be decreased, since fluorinated gases such as perfluoroalkanes and hydrofluoroalkanes do not require a high quantity of gas to be detected.

[0117] The method and assembly according to the disclosure can be run without stopping the drilling process to introduce the gas tracer. It is not necessary to wait for a drill pipe connection and/or to stop the drilling process to carry out the injection of tracer gas in the drilling fluid. The lag time check can be done more frequently, with a more accurate measurement during all the drilling process.

[0118] No manual operations are needed to introduce the gas tracer in the drilling fluid, since the structure of the injector allows an automatic and reproducible introduction of the gas tracer.

Claims

1. Method for evaluating a wellbore parameter in a drilling operation, comprising:

   - injecting a tracer gas at an injection point (152) in a drilling fluid intended to circulate in the wellbore;
   - circulating the drilling fluid containing the tracer gas from the injection point (152) to an exit of the wellbore;
   - extracting gas from the drilling fluid, the extraction being configured so that hydrocarbons and the tracer gas are extracted if present in the drilling fluid,
   - transporting the extracted gas to a measuring device (57) intended for detecting hydrocarbons;
   - detecting the tracer gas at the measuring device (57);
   - calculating the wellbore parameter based at least on a time of detection of the tracer gas;

   wherein the tracer gas comprises at least a perfluorocarbon and/or a hydrofluorocarbon.

2. Method according to claim 1, wherein the perfluorocarbon is a perfluoroalkane and/or the hydrofluorocarbon is a hydrofluoroalkane.

3. Method according to claim 2, wherein the perfluoroalkane is a perfluoroalkane having less than 6 atoms of carbon and/or the hydrofluoroalkane is a hydrofluoroalkane having less than 6 atoms of carbon.

4. Method according to claim 3, wherein the perfluoroalkane or the hydrofluoroalkane is a fluorinated form of ethane or of propane.

5. Method according to any one of the preceding claims, comprising carrying out the detection of the tracer gas at the gas analyzer (19) simultaneously with the detection of hydrocarbons arising from the wellbore at the gas analyzer (19).

6. Method according to any one of the preceding claims, wherein transporting the extracted gas to the measuring device (57) comprises passing the tracer gas in a chromatograph.

7. Method according to claim 6, wherein the tracer gas is chosen so as to have an elution time in the gas chromatograph comprised between 0% and 200% of the elution time of at least one of the alkanes having less than 6 carbon atoms in the same gas chromatograph.

8. Method according to any one of the preceding claims, wherein injecting the tracer gas at the injection point (152) comprises automatically introducing a predetermined quantity of tracer gas in the drilling fluid.

9. Method according to the preceding claims, wherein injecting the tracer gas comprises injecting the tracer gas according to a predetermined injection pattern.

10. Method according to claim 9, wherein the injection pattern comprises at least one injection pulse, injected during an injection time of less than 30 seconds, and in particular a series of periodic pulses.

11. Method according to claim 8, wherein injecting the tracer gas is carried out :

- upstream of an injection head (31) for injecting a drilling fluid in a drill string, or/and
- in a return line, after the drilling fluid has already exited the wellbore, or/and
- in a downhole assembly, close to a drilling head for carrying out the drilling operation.

12. Method according to any one of the preceding claims, wherein injecting the tracer gas is carried out while circulating the drilling fluid in the wellbore.

13. Method according to any one of the preceding claims, wherein the wellbore parameter is chosen among a lag time, a short cycle, or a long cycle time..

14. Assembly for evaluating a wellbore parameter in a drilling operation, comprising:

- a tracer gas injector (150) for injecting a tracer gas at an injection point (152) in a drilling fluid intended to circulate in the wellbore;
- a measuring device (57) configured to detect hydrocarbons in the drilling fluid
- a circulation assembly (154) for circulating the drilling fluid containing the tracer gas from the injection point (152) to an exit of the wellbore;
- an extractor for extracting gas from the drilling fluid, the extraction being configured so that hydrocarbons and the tracer gas are extracted if present in the drilling fluid,
- a transport device (55) for transporting the extracted gases to the measuring device (57) ;
- a calculator (101) for calculating the wellbore parameter based on a time of detection of the tracer gas at the measuring device (57) ;

wherein the tracer gas injector (150) comprises a tracer gas source (160) containing at least a tracer gas including a perfluorocarbon and/or a hydrofluorocarbon and wherein the measuring device (57) is configured to detect the tracer gas.

15. Assembly according to the preceding claim, wherein the measuring device (57) comprises one detector for detecting the tracer gas and the hydrocarbons.

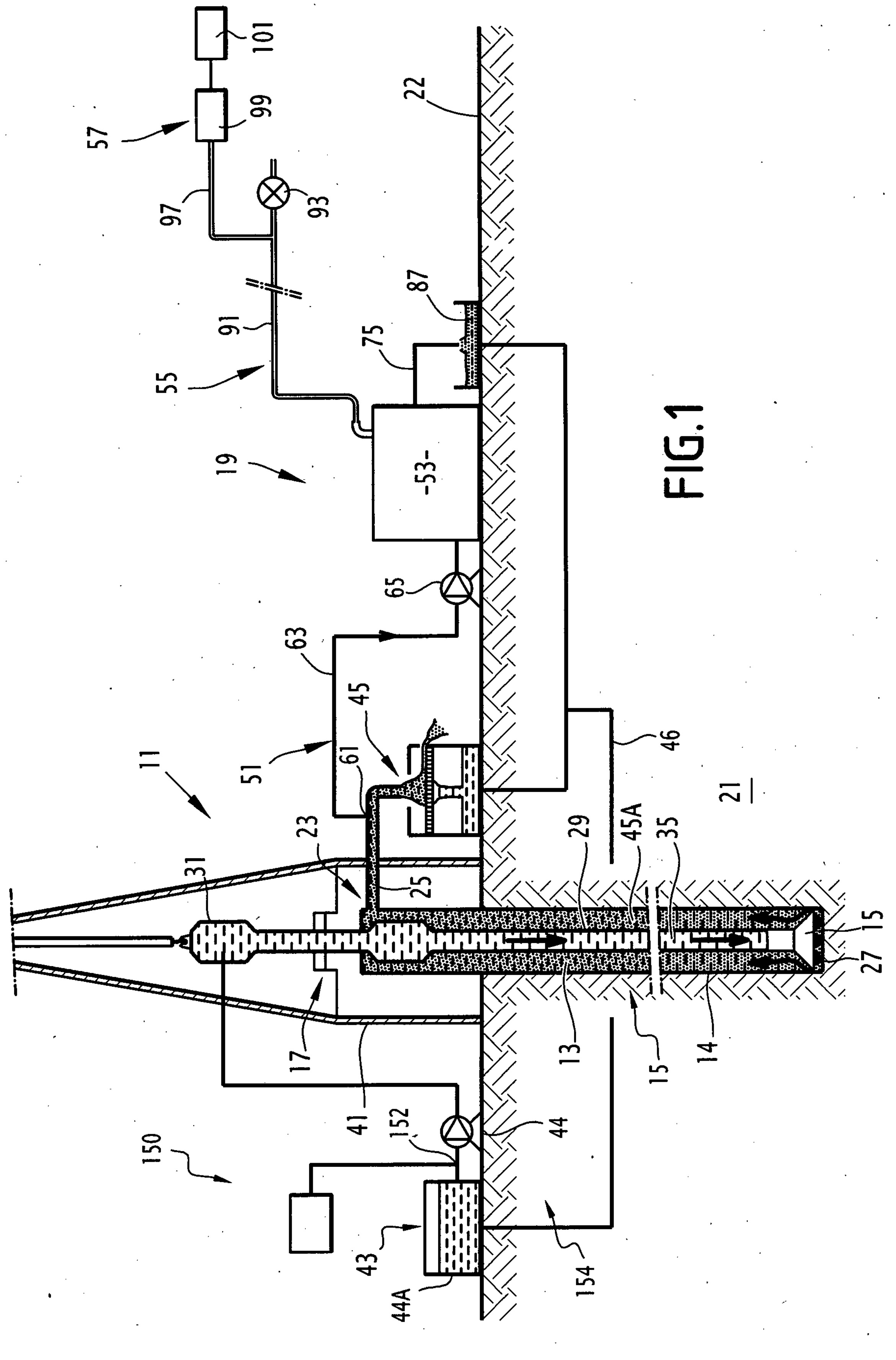
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FIG.1

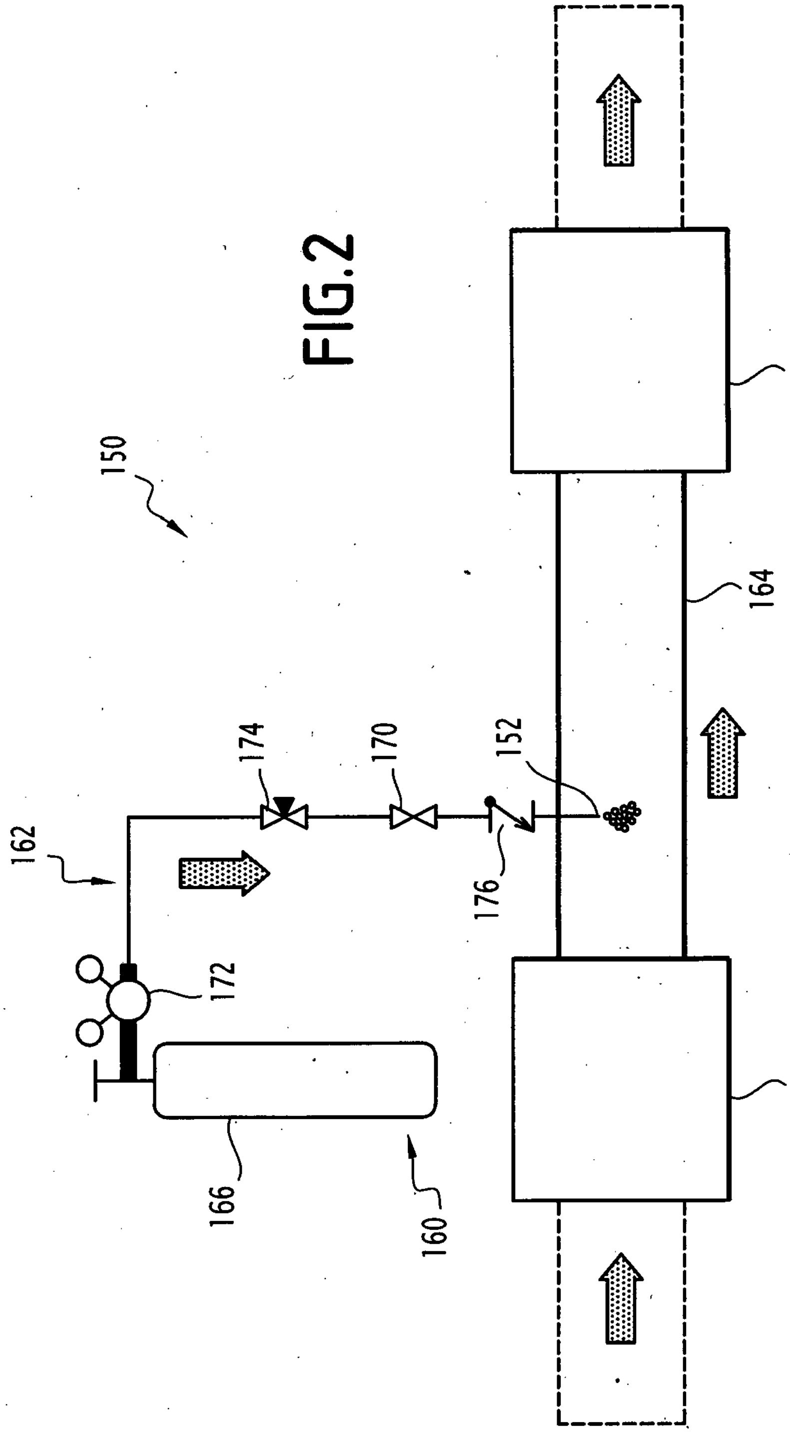
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FIG.2

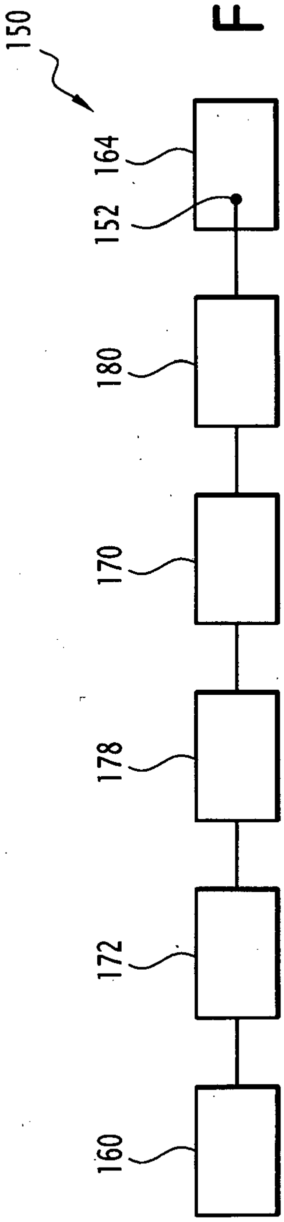
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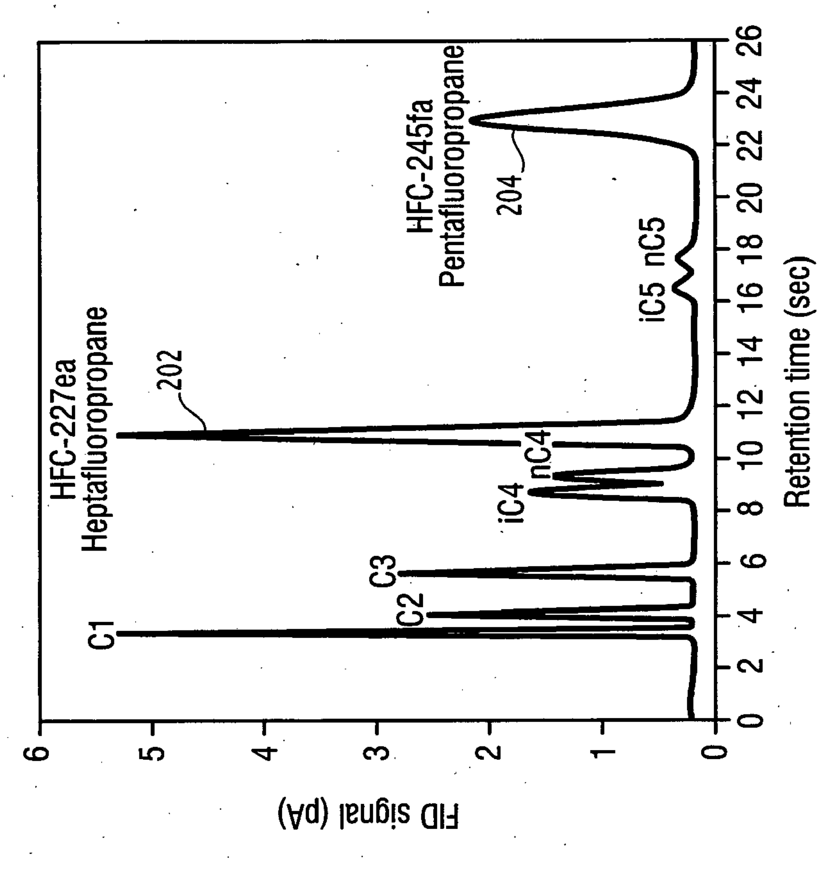
FIG.3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Retention time (sec)
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16
18
20
22
24
26
C1
C2
C3
iC4
nC4
HFC-227ea
Heptafluoropropane
202
iC5 nC5
HFC-245fa
Pentafluoropropane
204

FIG.4

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EUROPEAN SEARCH REPORT

Application Number
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The present search report has been drawn up for all claims

1

Place of search	Date of completion of the search	Examiner
The Hague	14 November 2016	Rampelmann, Klaus

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Application Number
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The present search report has been drawn up for all claims

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Place of search	Date of completion of the search	Examiner
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