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(54) **Method, system and tool for reservoir evaluation and well testing during drilling operations**

Verfahren und System und Werkzeug zur Reservoirbeurteilung und Bohrlochprüfung während Bohrungen

Procédé, système et outil pour évaluation de réservoir et test réussi au cours d'opérations de forage

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Description

Reference to Related Patent Applications

[0001] This application claims priority from U.S. provisional application serial no. 60/233,847 filed September 20, 2000.

Field of The Invention

[0002] The present invention relates generally to testing and evaluating a section of reservoir intersected during the well construction process. More particularly, the present invention relates to methods, systems and tools used in testing and evaluation of a subsurface well formation during drilling of the wellbore.

Setting of the Invention

[0003] A reservoir is formed of one or more subsurface rock formations containing a liquid and/or gaseous hydrocarbon. The reservoir rock is porous and permeable. The degree of porosity relates to the volume of liquid contained within the reservoir. The permeability relates to the reservoir fluids' ability to move through the rock and be recovered for sale. A reservoir is an invisible, complex physical system that must be understood in order to determine the value of the contained hydrocarbons.

[0004] The characteristics of a reservoir are extrapolated from the small portion of a formation exposed during the well drilling and construction process. It is particularly important to obtain an evaluation of the quality of rock (formation) intersected during well construction. Even though a large body of data may have been compiled regarding the characteristics of a specific reservoir, it is important to understand the characteristics of the rock intersected by a specific wellbore and to recognize, as soon as possible during the process of well construction, the effective permeability and permeability differences of the formation intersected during well construction.

[0005] The present invention is primarily directed to wellbore and formation evaluation while drilling "underbalanced." Underbalanced drilling is a well construction process defined as a state in which the pressure induced by the weight of the drilling fluid (hydrostatic pressure) is less than the actual pressure within the pore spaces of the reservoir rock (formation pressure). In a more conventional process, the well is typically drilled "overbalanced." In an overbalanced drilling process, the pressure induced by the weight of the drilling fluid (hydrostatic pressure) is greater than the actual pore pressure of the reservoir rock.

[0006] During underbalanced well construction, the fluids within the pore spaces of the reservoir rock flow into the wellbore. Because flow is allowed to enter the wellbore, the fluid flow characteristics of the formation are more easily observed and measured. During over-

balanced drilling, the drilling fluid may enter the formation from the wellbore. While this overbalanced flow may be evaluated to assess formation properties, it is more difficult to quantify fluid losses to the formation than it is to quantify fluid gains from the formation.

[0007] There are significant benefits obtained from the application of underbalanced well construction techniques. The rate of penetration or speed of well construction is increased. The incidence of drill pipe sticking is decreased. Underbalanced operations prevent the loss of expensive drilling fluids.

[0008] An understanding of the reservoir being penetrated during the well construction process requires direct and indirect analysis of the information obtained in and from the well. Core analysis and pressure, volume, temperature (PVT) analyses of the reservoir fluids are measurements and testing performed in a laboratory after the wellbore has been drilled. This process of formation evaluating is both costly and time-consuming. Also, it is not practical to perform core analysis and PVT studies on every well constructed within a reservoir.

[0009] During drilling of a wellbore, important information can be determined by evaluating the fluids flowing to the well surface from the formation penetrated by the wellbore. The amount of gas included in the surface flow is particularly important in evaluating the formation producing the gas. The volume of gas per unit of time, or flow rate, is a critical parameter. The rate of gas flow from the formation is affected by the back-pressure exerted through the wellbore. The information desired for a particular formation or layer is the flow rate capacity during expected flowing production pressure. The best measure of this flow rate occurs at the flowing production pressure, however, conventional gas flow measuring instruments require flow restricting orifices in performing flow measurements. Instruments using differential orifices as the basis for flow management are accurate only within a relatively narrow range of flow. Sporadic flow changes associated with penetration of different pressured or flowing formations can produce flow rates outside the accuracy limits of the measuring instrument. Surface measurements of gas flow are, consequently, performed at pressures that are different from normal flowing pressures and the results do not accurately indicate the gas flow potential of the formation. The procedures commonly employed to measure surface flow during drilling or constructing a well that restrict the flow as a part of the gas flow rate measurement reduce the accuracy of evaluations of formation capacity based upon such measurements. Conventional instruments that measure flow without restricting the flow are typically incapable of making precise measurements. These instruments, which generally use a Venturi tube in the flow line, produce unduly broad indications of flow rates.

[0010] Indirect analysis of information requires reference to well logs that are recorded during well construction. A well log is a recording, usually continuous, of a characteristic of a formation intersected by a borehole

during the well construction process. Generally, well logs are utilized to distinguish lithology, porosity, and saturations of water oil and gas within the formation. Permeability values for the formation are not obtained in typical indirect analysis. An instrument for repeated formation tests (RFT) also exists. The RFT instrument can indicate potentially provided permeability within an order of magnitude of correctness. Well logging can account for as much as 5 to 15 percent of the total well construction cost.

[0011] Another means of formation testing and evaluation is the process of drill stem testing. Drill stem testing requires the stopping of the drilling process, logging to identify possible reservoirs that may have been intersected, isolating each formation of each intersected reservoir with packers and flowing each formation in an effort to determine the flow potential of the individual formation. Drill stem testing can be very time consuming and the analysis is often indeterminate or incomplete. Generally, during drill string testing, the packers are set and reset to isolate each reservoir intersected. This may lead to equipment failures or a failure to accurately obtain information about a specific formation.

[0012] Because each formation is tested as a whole, the values or data obtained provide an average formation value. Discrete characteristics within the formation must be obtained in another manner. The discrete characteristics within a layer of the formation are generally inferred from traditional well logging techniques and/or from core analysis. Well logging and core analyses are expensive and time-consuming. The extensive time involved in determining the permeability (productability) of each intersected reservoir layer in a wellbore through multiple packer movements and multiple flow and pressure buildup measurements required during a drill stem test make the process expensive and undesirable.

[0013] WO 99/49172, HYDRIL COMPANY, 26.03.99, describes a system for drilling a subsea well comprising, amongst other things, a subsea blowout preventer stack and a subsea diverter.

Summary of the Invention

Aspects of the invention are described in the claims.

[0014] It is the primary object of the present invention to provide a method, system and tool for obtaining information about a formation while constructing a wellbore designed to intersect the formation. One characteristic of the formation that determines the productability of the well is permeability. During production, the fluid flows through the medium of the reservoir rock pores with greater or lesser difficulty, depending on the characteristics of the porous medium. The parameter of "permeability" is a manager used to describe the ability of the rock to allow a fluid to flow through its pores.

[0015] Permeability is expressed as an area. However, the customary unit of permeability is the millidarcy, $1 \text{ mD} = 0.987 \times 10^{-15} \text{ m}^2$. Permeability is related to geometric

shape of flow passages, flow rate, differential pressure, and fluid viscosity.

[0016] Parameters such as bottomhole temperature and pressure are acquired through a bottomhole assembly during actual drilling operations and the acquired values are transmitted to the surface.

[0017] The drilling assembly may drill the wellbore to a point above the formation of interest. The measuring instruments in subsurface instruments carried by the drilling assembly may be calibrated with surface measuring instruments at the well surface. The calibration is performed by evaluating injected and return fluids circulated through the closed flow system provided by the drill string assembly and the wellbore annulus. Precise qualitative and quantitative measuring instruments are provided in the calibrated system to produce accurate measurements of fluid composition, flow rates, volumes and condition of fluids injected into the drill string from the surface and fluids returning in the annulus from both the drill string and the formation.

[0018] The method may comprise the use of an ultrasonic gas flow meter in the surface measurements of gas being produced from the formation to permit unrestricted flow measurements that accurately reflect the formation's flow characteristics. A chromatograph may be used in the surface measurements of annular fluid flow to precisely identify constituents of the flow. The results of the measurement assist in making well construction decisions as the well is being drilled.

[0019] The method may utilise a downhole device to obtain downhole flow rates. These downhole flow rates can be compared to the flow rates determined from well surface operations. The direct measurement of downhole flow permits a more accurate permeability calculation on a foot-by-foot basis of the wellbore penetration through the formation. The need for a complex mathematical model to convert surface rates and flow properties to downhole conditions is eliminated when accurate bottomhole flow rates are obtained with a directly measuring tool.

[0020] The bottomhole temperature and pressure may be used to determine density and/or viscosity of the produced fluids. To determine initial reservoir pressure, the drilling operation may be stopped and the well shut in to allow the pressure to buildup. Additionally, a series of flows at different differential pressure may be used to extrapolate to the initial reservoir pressure. Using these parameters, an effective permeability can be calculated for the section of formation contributing to the flow.

[0021] The measured parameters at the bit are transmitted to the well surface using fluid pulse telemetry or other suitable means. Generally, the downhole data transmission rate, relative to the rate of penetration in a reservoir, is such that the data acquisition at the bit downhole or at the surface is considered to be "real-time" data.

[0022] Another means of obtaining the necessary data for these novel methods of formation evaluation is to have the downhole measurements taken and stored in a sub-

surface memory device during actual well construction operations. After the data is acquired and stored in the memory device, it may be retrieved at a later time such as during the replacement of a worn out drill bit. This recorded data is considered "near real-time" because it is not transmitted to the surface from downhole. This near real-time data from downhole is synchronized and merged with either surface measurements of hydrocarbon production or downhole measurements from the subsurface measurement instrument and used to compute the permeability and productivity of the formation intersected during the well construction process. Near real-time methods are utilized when the added expense of real-time is not warranted.

[0023] The choice is usually based upon required placement accuracy of the wellbore, or when the real-time transmission is technically not feasible, or when the general economics of the reservoir prohibit use of real-time methodology

Brief Description of Drawings

[0024]

Figure 1 is a schematic illustration of a system of the present invention used to evaluate a subsurface formation being intersected by a wellbore during well construction;

Figure 2 is an elevation of an integral blade stabilizer body having energy measurement transducers used for subsurface measurements while drilling;

Figure 3 is a partial cross section taken along the line 2-2 of figure 1 illustrating the placement of the three different types of energy transducers or sensors integrated into the drilling stabilizer of Figure 1: Figure 3A is an enlarged view of a focusing notch employed with the induction transmitters of the present invention; and

Figure 3B is an enlarged view of illustrating details in the construction of the capacitance transducers of the present invention.

Detailed Description of the Illustrated Embodiments

[0025] Figure 1 illustrates a system of the present invention indicated generally at 10. The system 10 is employed to determine the permeability of a formation F that is to be penetrated by a wellbore B. A drilling assembly comprising a bit 11, drilling stabilizer 12, subsurface measuring and recording instrument 13 and drill string 14 extend from the wellbore B to the wellbore surface T. Only a portion of the bottomhole assembly is illustrated in Figure 1. The projected wellbore trajectory is indicated by a dotted line section 15.

[0026] A measuring system 20 used in the evaluation of a formation F is equipped with an inlet fluid measuring section 21, an outlet measurement section 22 and a calibrated instrument analysis section 23. The measuring

system 20 measures and evaluates the fluids flowing into the wellbore B through the drill string 94 and measures and evaluates the fluids returning to the top or surface of the wellbore T through an annulus A formed between the drill string and the wellbore. As used herein, reference to measuring or evaluating "flow" of a fluid is intended to include measurement or evaluation of characteristics of the fluid such as temperature, pressure, resistivity, density, composition, volume, rate of flow and other variable characteristics or parameters of the fluid.

[0027] The calibrated analysis section 23 may be supplemented with subsurface parameter values obtained from a subsurface values section 24. The data from the section 24 are delivered from either a data resource 25 or from an actual downhole measurements section 26. Data provided by the data resource section 25 may be data taken from historical data sources 25a, such as analogous or similar wells or the data may be derived from a computer data model 25b that performs mathematical calculations, or determines data from other inferential processes. The actual downhole measurements are provided through a real-time system section 27 or a near real-time system section 28.

[0028] In applying the method of the present invention to a system in which subsurface flow values are to be inferred or deduced from measurements or assumed values of related parameters, the system 20 is calibrated and checked before the wellbore B is extended into the formation F. This step in the procedure assists in determining systems noise and in determining circulating system responses to changes in the back-pressure in the annulus A.

[0029] The system calibration process and checking are preferably performed between 5 and 25 meters above the anticipated top of the formation F. The top of the formation F may be determined using a geological marker from an offset well, seismic data on reservoir contour mapping. During the calibration process, a closed fluid flow system is established by the drilling assembly in the wellbore B such that fluids introduced into the drill string 14 travel through the drilling assembly 14, 13, 12, 11, and exit the drilling assembly through the bit 11 where they are returned to the well surface T through the annulus A. Only fluids introduced into the drill string 14 flow through the closed system during the calibration and checking process.

[0030] The calibration performed by circulating a known quantity and density of a known fluid (gases included) while the drilling assembly and any downhole sensing equipment carried in the drilling assembly are deployed within the wellbore B. A material balance relating the injected fluids to the returned fluids is preferably employed in the calibration process. The calibration process is employed to establish a standard or control to detect or determine changes in measurements that result from encountering a productive formation environment.

[0031] In a preferred method of calibration, the following parameters are measured for a minimum of three

different back-pressure values obtained at the annulus A while fluids are circulating through the system:

- I) Injection: pressures, temperatures and rates;
- II) bottomhole: annulus pressures and temperatures;
- III) return: pressures, temperatures and rates; and
- IV) C1 to C6 hydrocarbon percentage over a period of 1.1 to 15 wellbore circulation volumes.

[0032] The time required for the fluid to complete circulation through the drilling assembly and return to the surface through the annulus is monitored and recorded. In a preferred method, a circulation time measurement is performed with the assistance of a tracer added to the injection fluid stream entering the drill pipe 11 at the well surface T. The elapsed time from injection of the tracer until reappearance of the tracer in the fluid returns at the well surface annulus indicates the circulation time. The tracer material may be a carbide, or an inert substance such as neon gas, or a short half-life radioactive material or other suitable material.

[0033] After calibration and system checking are performed, the drilling operation is resumed and the drilling assembly is used to extend the wellbore into the formation F. During extension of the wellbore, the rate of penetration is preferably maintained at a rate below 25 meters per hour. The weight on bit and rotary or bit motor speeds are maintained as constant as possible to enhance the accuracy of the results of the system measurement.

[0034] In performing the method of the present invention during underbalanced drilling conditions, it is preferable to maintain an underbalanced bottomhole pressure between 100 and 2000 psi below the anticipated pressure of the formation F. The bottomhole pressure can be adjusted by manipulation of the drilling fluid densities, pump rates and annular back-pressures.

[0035] The point at which the drill bit 11 encounters the top of the formation F may be determined by closely monitoring the system 20 for any significant change in the bottomhole pressure, bottomhole temperature, C1 or surface flow rates. Once the top of the formation F has been traversed, an additional 1 to 5 meters of wellbore depth is drilled into the formation and the drilling is stopped as fluid circulation is maintained.

[0036] In an underbalanced condition, reservoir flow and pressure response are established while injecting fluid into the drill string 14 from the surface and combining the injected fluids with fluids flowing from the reservoir F into the wellbore B. The combined injection and formation fluids flow through the annulus A to the well surface T. During this step, the following sensor point measurements are performed:

- I) injection: pressures, temperatures and rates;
- II) bottomhole: annulus pressures and temperatures;
- III) return: pressures, temperatures and rates; and
- IV) C1 to C6 hydrocarbon percentage over a period

of 1.1 to 15 wellbore circulation volumes.

[0037] The measurements I)-IV) are made and recorded for a preferred period of time equivalent to 1.5 to 15 times the "bottoms up" time. "Bottoms up" time is the time required to flow fluid at the bottom of the well bore to the well surface. Once a stabilized annular flow through the annulus A has been established, the back-pressure in the annulus is increased to achieve a second underbalanced flowing condition. If the annular flow does not stabilize at this increased back-pressure; the back-pressure is reduced by 25 percent and the annular flow is maintained for 1.5 to 15 times the bottoms up time to test for stabilization of the annular flow.

[0038] The next step in the method is to reduce the circulating back-pressure or bottomhole pressure by 30 to 40 percent, preferably not to exceed 35 percent of the draw down on the bottomhole pressure (BHP) for a period of time of from 1.5 to 15 times the bottoms up time, depending on the annular flow conditions. The time of each back-pressure change is recorded, to be correlated with the flow measurements. The back-pressure is increased, using either a surface choke or by increasing the bottomhole pressure, to a safe drilling level and then stabilized over a period of from 1.5 to 15 times the bottoms up time.

[0039] Drilling is resumed and the borehole B is extended to the formation F at a steady drilling rate of preferably 10-20 meters per hour. During the resumption of drilling, the sensor points variable measurements I)-IV) are continuously monitored and recorded. Drilling is continued until the formation F has been fully traversed. Once the wellbore extends below the bottom of the formation by 2 to 10 meters, drilling is stopped. Fluid flow through the annulus is continued for a time of from 2 to 15 times the bottoms up time. If the back-pressure in the annulus A cannot be increased without killing the well, the annulus back-pressure is decreased by 15-20 percent from the initial pressure value occurring following initial penetration of the formation bottom. If the back-pressure in the annulus A is still high enough to kill the well, the annulus back-pressure is decreased 30-40 percent from the initial pressure value.

[0040] Once the measurements have been completed following the application of the different back-pressures in the annulus A, the original back-pressure existing at the penetration of formation bottom is restored and the well bore drilling is continued, or the drilling assembly is pulled from the well if the total well depth has been reached.

[0041] The flow rates and corresponding bottomhole pressures obtained from the foregoing process are plotted to form Inflow Production (IPR) curves. The IPR curves are extrapolated to determine the virgin reservoir pressure P^* of the formation F or a specific portion of the formation or layer of interest. This method is an alternative technique for determining the formation pressure P^* without using direct measurement process of stopping circulating through the well shutting in the well and then

allowing the pressure from the formation to build up to a stabilized level indicative of P^*

[0042] With the collected data, Darcy's Radial Flow equation is used to solve for matrix permeability "k," or fracture transmissibility "kh." Skin effect S is assumed to be zero where underbalanced drilling conditions are used since the absence of drilling fluid flow into the formation exerts minimal skin damage to the formation. P^* is taken from the IPR curves or shut in pressure buildup determination. These calculations can conveniently be used to provide a graphical presentation of flow rate versus drilling depth.

[0043] Evaluation of the formation F using the measurements and data obtained in the described process may be enhanced with the use of a computer model 29 of the reservoir. The computer model can account for variances attributable to multiple formation layers, partial penetration of a zone, dual porosity of the formation and the occurrence of vertical, horizontal or high angle wellbores as well as other variations in parameters. The computer model may be employed to more accurately project well production and reserve estimates. Presentation of the evaluation and activation of alarms is made by an evaluation section 30. A kick alarm 31 provides early warning of an influx of formation fluids into the wellbore.

[0044] The methods of the present invention may also be practiced in a system using data obtained directly with downhole flow measurement instruments that comprise a part of the drilling assembly. In a directly measuring downhole system, the requirement for initial system calibration is reduced or becomes unnecessary. With the exception of the initial calibration step, the steps used in performance of the method when using direct downhole flow measurement instruments are substantially the same as those employed when downhole flow parameter are determined inferentially or are obtained from indirect measurements or a data resource. Using actually determined subsurface flow measurements eliminates the requirement for the computer model 29 or the data model 25b and otherwise reduces the need for extensive mathematical correlations and calculations to obtain accurate formation values. Direct measurements also enable rapid warning of a kick to initiate an alarm from the measuring component 31.

[0045] Figures 2 and 3 illustrate details in a preferred subsurface measurement tool, indicated generally at for assisting in determining permeability of the formation F. The measurement tool 50 is illustrated connected to a drill bit 51 to function as part of a near-bit stabilizer. It will be appreciated that the tool 50 may be employed at other near-bit locations within a bottomhole drilling assembly and need not necessarily be connected immediately to the bit, the objective being to provide a stabilizing relationship between the bit and the tool 50. The instrument tool 50 includes three separate types of detection devices in the vicinity of the drill bit permitting a large number of combinations of signals to be analyzed thereby producing increased flexibility and accuracy in both measure-

ment while drilling (MWD) and formation analysis operations.

[0046] The instrument tool 50 is equipped with an axially extending body 52 having a central, axially developed passage 55 for conveying fluid between a first axial tool end 56 and a second axial tool end 57. Radially and axially extending, circumferentially spaced blades 60, 61 and 62 extend from an external tool surface 65. The instrument tool 50 is connected at its first end 56 to a bit 51 and at its second axial end 57 to a monitoring and recording tool 66 that processes and records the measurements taken by the instrument tool 50. The tool 66 records and/or transmits measurements to the well surface. Recorded measurements are retained in the recorded memory until the drilling assembly is retrieved to the well surface or the measurements may be transmitted to the surface through fluid pulse telemetry or other suitable communication means.

[0047] The tools 50 and 66 are connected with the measuring system 20 for real-time or near real-time measurements that permit formation evaluation. Analog to digital converters in the measuring system 20 process signals detected at the transducer receivers and capacitive energy transducers and supply numerical representations to a microprocessor system within the components 23, 29 and 30. The measuring system 20 of the present invention employs a microprocessor and digital-to-analog converters to enable the production of many different types of signals with the acoustic transducers or electromagnetic antenna systems. Both high and low frequency signals can be created. In addition, fast rise time and slow fall time "saw tooth" signals may be employed to provide specific, more discrete rates of change in electronic signaling as compared to older techniques employing continuous variations of sine waves.

[0048] The output signals from the energy transducers employed in the present invention are calibrated and the programming employed in the measuring system is modified to counter intrinsic tool inductance and capacitance that would normally distort the output signals. Reduction in distortion and the presence of discreetly rising and falling signals contribute to greater accuracy in the measurement of the inductance of the fluids. Broad variations in times of signal changes are employed to cause attenuations or reinforcements of signals depending upon gas bubble sizes or oil droplet diameters and volumes. The combination of frequencies ranging from high to low, and varying rates of change within signals assist in sorting smaller and larger bubbles and globules. The dimensions of water concentrations between other fluid contacts also alters the broad range of signals in different ways. Significant fluid geometry information is extractable from the many signals being altered by the flowing fluids and then detected at the receivers of the present invention.

[0049] As best illustrated in Figure 3, several fluid receiving recesses 70, 71 and 72 are defined between the circumferentially spaced blades in an area intermediate the external surface 65 of the tool body and the wellbore

wall (not illustrated). The recesses 70, 71 and 72 are illustrated in Figure 3 between dotted lines 73, 74 and 75, respectively, and external tool surfaces 76, 77 and 78, respectively, of the tool 50.

[0050] The primary monitored indicator of flow in the recesses 70, 71 and 72 is preferably a marker comprising a bubble of gas or a gaseous cluster entrained within the liquid flowing through the recess being monitored. The electrical sensors, circuitry and analytical process for correlating the measurements taken by the various transducers determine a rate of movement of the bubble marker past the transducers.

[0051] Energy transducers are carried by the blades for evaluating characteristics of fluid contained in the fluid receiving recesses. The measured characteristics are convertible into a measure of the flow rate of the fluid flowing through the recesses. To this end, acoustic transducer receivers 85 and acoustic transducer transmitters 86 are carried in the blades 61 and 60, respectively. Electromagnetic induction transmitting transducers 90 and electromagnetic receiving transducers 91 are carried in the blade 60 and 62, respectively. Electrical capacitance transducers 95, 96 and 97 are carried on the tool body between the blades 62 and 61.

[0052] Referring to Figure 2, the energy transducers carried by the tool 50 are deployed at axially spaced locations along the tool body 65 and blades 60, 61 and 62 to enable the transducers to detect variable parameters associated with axial movement of fluid flowing through the recesses with which the transducers are associated. Accordingly, three acoustic receivers 85a, 85b and 85c are deployed at axially spaced locations along the blade 61 and three acoustic transducer transmitters 86a, 86b and 86c are deployed at axially spaced locations along the blade 60. Similarly, two electromagnetic transmitters 90a and 90b are axially deployed along the blade 60 and three electromagnetic receivers 91 a, 91 b and 91 c are axially deployed along the blade 62. Capacitive transducers are also deployed at circumferentially and axially spaced locations along the body of the tool 50. Capacitive transducers 95, 96 and 97 are displayed in Figure 3 at only one axial location. Similar arrays of capacitive transducers (not illustrated) are deployed at other axially spaced locations between the blades 61 and 62. The various transmitters, receivers and capacitance energy transducers are preferably located high within the protected areas between the stabilizer blades to avoid the mud and rock cuttings that often accumulate in greatest quantities on the lower portions of the blades. The blades function to form fluid channeling recesses to confine the fluid being monitored and also provide protective structure for the energy transmitters.

[0053] With reference to the detail drawing of the transducer 90 in Figure 32A, the induction transmitting antennas of the transducers 90 are positioned within notches in the blade 62 that have curved shapes with sloping surfaces 90b that slightly increase from a parabolic shape to produce an over focusing from a parallel beam to a

concentrated point at the receiving transducers 91. Over focusing of the transmitter signal counteracts dispersion caused by bubbles and rock cuttings in the fluid flowing past the sensors. The angles between the transmitters and receivers are preferably optimized for vector processing relating to typical rotation speeds and expected fluid velocities.

[0054] As illustrated in the detail drawing of transducer 95, illustrated in Figure 3B, the capacitance transducers 95, 96 and 97 are preferably provided with concave surface electrode shapes 95a to improve contact with the convex surfaces of bubbles or rounded oil globules entrained within the fluid flowing past the transducers. Gas bubble shapes change sizes as a function of changing depth and pressure within the wellbore. The capacitance transducers preferably protrude slightly radially from the body of the tool body 50 with the concave surface shapes having an increasing curvature toward the top 95b of the tool 50 to permit better contact of the surface with both small and larger bubbles. The larger curvature at the top of the transducers permits improved matching of shapes of the smaller bubbles or oil globules with the transducers. The smaller curvature at the bottom 95a of the transducers forms a better match with the external surfaces of larger bubbles or globules.

[0055] In operation, the acoustic and electromagnetic transducers in the tool 50 and associated instruments in the recording tool 66 monitor the characteristics of the fluid intercepted in the travel paths of the energy signals traveling between transducers. The capacitive transducers monitor the characteristics of the fluid engaging the reactive surfaces of the transducers. Each of the three acoustic transmitters communicate with each of the three acoustic receivers to produce nine transmission paths. The paths are identified as a function of their physical position within the fluid receiving recess. The electromagnetic transducers function similarly to produce a total of six transmission paths. The radial and axial displacement of transducer paths produces an array of readings that can be correlated both in time and location to provide the rate of flow of fluids flowing through the fluid receiving recesses. The change in capacitance along the axial distribution of the capacitive transducers provides a measure of the flow past the monitoring surfaces.

[0056] The measuring process performed by the tool 50 is preferably done while the tool is rotating with the bit in the wellbore. The rotating motion of the tool homogenizes the liquid and gases into a uniform mixture that enhances the detection capabilities of the sensors. Rotation of the tool 50 also permits each set of three detection systems to provide full borehole coverage. The blades of the tool protect the measuring devices from impact with borehole walls and also afford protection from impact with solids in the returning well fluids.

[0057] Rotation of the tool produces centrifuging of certain fluids that enter the fluid receiving recesses of the tool. Gas, oil and water are inclined to be differentially concentrated by centrifuging. As a result, methane and

other gases may be more easily detected as they are concentrated within the receiving recesses by the spinning motion, pushing denser liquids to the outer edges of the blades. The spinning of the tool also significantly reduces segregation of fluids with respect to the top or bottom side of an inclined wellbore. Mixtures of liquids commonly encountered in well drilling produce complex combinations of signal frequencies and signal wavelet shapes transmitted from acoustic and reactive sources to detectors. Analysis of the transmitted signals provides numerous data sets for physically evaluating a slurry having variations in mixing rules or properties.

[0058] The tool 50 may be used as a kick detector during the construction of the well. The tool's kick detection capability stems from its ability to recognize changes in the subsurface wellbore conditions and fluids associated with a kick. Subsurface detection of increased flow rate or other variables can give an early kick warning. If a wellbore influx or kick occurs during drilling, the presence of oil bubbles in the fluid flowing through the recess 72 will slow acoustic travel times between the acoustic sensors 85a, 85b, 85c and 86a, 86b, 86c. Gas bubbles in the recess 72 will cause far greater increases in acoustic travel time between the energy transducers significant acoustic wave amplitude attenuations will also occur upon the influx of oil or gas into the recess 72. Wave shapes of acoustic signals will be distorted or exhibit complex interference and dielectric measurements will deviate from drilling mud readings. A predetermined combination of the described sensor readings causes the software or firmware in the measurement section 30 to alter mud pulsing priorities and send warnings to the surface kick detection component 31.

[0059] Gas or oil bubbles passing up past the bit during a trip out of the hole are detected by leaving the power on to the induction and acoustic monitoring systems included in the tool 50. Since mud pulses are not being relayed during tripping, a warning system as relayed to the drilling crew by changing acoustic pulses to a gas detection indication sequence. A stethoscope type or amplified sound detection and filtering system in the component 31 enables a crewman to hear a kick warning pulse pattern (e. g., SOS) during a brief quiet period (block lowering time) between pulling each stand.

[0060] The tool 50 may also be used to indicate early wellbore stability problems.

[0061] Faster acoustic travel times, some resistivity changes, and some dielectric changes can indicate increases in quantities of rock cuttings. Mud velocity reductions or other actions may be taken to reduce excessive "washing out" or widening of the borehole after increased cuttings volumes from weaker formations are detected.

[0062] It will be appreciated that various modifications can be made in the design, construction and operation of the present invention without departing from the scope of such invention. Thus, while the principal preferred construction and mode of operation of the invention have

been explained in what is now considered to represent its best embodiments, which have been illustrated and described herein, it will be understood that within the scope of the appended Claims, the invention may be practiced otherwise than as specifically illustrated and described.

Claims

1. A method for evaluating a formation characteristic in a well having a wellbore (B) for intersecting a sub-surface formation (F) and being drilled from a wellbore surface (T) with a drill bit (11,51) carried at the end of a drill string (14), the method comprising the steps of:

adjusting by a predetermined amount a back-pressure in an annulus (A) formed between the wellbore (B) and the drill string (14) while circulating fluid through the drill string and wellbore (B);
measuring flow rates of the fluid at corresponding different annulus (A) back-pressure during the circulating of the fluid; and
determining a desired value for the annulus (A) back-pressure based on the measured flow rates at different annulus (A) back-pressures.

2. The method of claim 1, wherein the drill string (14) and wellbore (B) are part of a closed fluid flow system.

3. The method of claim 1, further comprising the step of detecting an influx of formation fluids into the wellbore (B) based on the measured flow rates at the different annulus (A) back-pressures.

4. The method of claim 3, further comprising the step of initiating an alarm in response to the detecting of the influx of formation fluids into the wellbore (B).

5. The method of claim 1, further comprising the step of determining a formation parameter based on the measured flow rates at the different annulus back-pressures.

6. The method of claim 1, wherein the formation parameter comprises reservoir pressure.

7. The method of claim 1, wherein the formation parameter comprises formation permeability.

8. The method of claim 1, wherein the step of determining the desired value for the annulus (A) back-pressure further comprises inputting the measured flow rates at the different annulus (A) back-pressure to a computer model of a reservoir.

9. A method for evaluating a formation characteristic in a well having a wellbore (B) for intersecting a sub-surface formation (F) and being drilled from a wellbore surface (T) with a drill bit (11,51) carried at the end of a drill string (14), the method comprising the steps of:

adjusting by a pre-determined amount a back-pressure in an annulus (A) formed between the wellbore (B) and the drill string (14) while circulating fluid through the drill string and wellbore (B);

measuring flow rates of the fluid at corresponding different annulus (A) back-pressure during the circulating of the fluid; and

detecting an influx of formation fluids into the wellbore (B) based on the measured flow rates at the different annulus (A) back-pressure.

10. The method of claim 9, further comprising the step of initiating an alarm in response to the detecting of the influx of formation fluids into the wellbore (B).

11. The method of claim 9, further comprising the step of determining a formation parameter based on the measured flow rates at the different annulus (A) back-pressures.

12. The method of claim 9, wherein the formation parameter comprises reservoir pressure.

13. The method of claim 9, wherein the formation parameter comprises formation permeability.

14. The method of claim 9, wherein the drill string and wellbore are part of a closed fluid flow system.

15. The method of claim 9, further comprising the step of determining a desired value for the annulus back-pressure based on the measured flow rates at the different annulus back-pressures.

16. The method of claim 9, wherein the step of detecting an influx of formation fluids into the wellbore further comprises inputting the measured flow rates at the different annulus back-pressure to a computer model of a reservoir.

Patentansprüche

1. Verfahren zum Beurteilen einer Formations-Charakteristik in einem Bohrloch, welches eine Bohrlochbohrung (B) zum Erbohren einer unterirdischen Formation (F) hat und von einer Bohrloch-Oberfläche (T) mit einer Bohrkronen (11, 51) gebohrt wird, welche am Ende von einer Bohrstange (14) gelagert ist, wobei das Verfahren die Schritte enthält:

Einstellen eines Rückdruckes in einer Ringkammer (A), welche zwischen der Bohrlochbohrung (B) und der Bohrstange (14) ausgebildet ist, während ein Fluid durch die Bohrstange und die Bohrlochbohrung (B) zirkuliert wird, auf eine vorbestimmte Größe;

Messen von Flussraten des Fluides bei einem entsprechend unterschiedlichen Ringkammer (A) Rückdruck während der Zirkulation des Fluides; und

Bestimmen eines gewünschten Wertes für den Ringkammer (A) Rückdruck, basierend auf den gemessenen Flussraten bei unterschiedlichen Ringkammer (A) Rückdrücken.

2. Verfahren nach Anspruch 1, bei welchem die Bohrstange (14) und die Bohrlochbohrung (B) ein Teil eines geschlossenen Fluidflusssystems sind.

3. Verfahren nach Anspruch 1, welches ferner den Schritt des Erfassens eines Zuflusses von Formations-Fluiden in die Bohrlochbohrung (B), basierend auf den gemessenen Flussraten an den unterschiedlichen Ringkammer (A) Rückdrücken, enthält.

4. Verfahren nach Anspruch 3, welches ferner den Schritt einer Alarmauslösung in Ansprechen auf die Erfassung des Zustroms von Formations-Fluiden in die Bohrlochbohrung (B) enthält.

5. Verfahren nach Anspruch 1, welches ferner den Schritt eines Bestimmens eines Formations-Parameters, basierend auf den gemessenen Flussraten bei den unterschiedlichen Ringkammer-Rückdrücken, enthält.

6. Verfahren nach Anspruch 1, bei welchem der Formations-Parameter einen Reservoir-Druck enthält.

7. Verfahren nach Anspruch 1, bei welchem der Formations-Parameter eine Formations-Permeabilität enthält.

8. Verfahren nach Anspruch 1, bei welchem der Schritt des Bestimmens des gewünschten Wertes für den Ringkammer (A) Rückdruck ferner ein Eingeben der gemessenen Flussraten bei dem unterschiedlichen Ringkammer (A) Rückdruck in ein Computermodell eines Reservoirs enthält.

9. Verfahren zum Beurteilen einer Formations-Charakteristik in einem Bohrloch, welches eine Bohrlochbohrung (B) zum Erbohren einer unterirdischen Formation (F) hat und von einer Bohrloch-Oberfläche (T) mit einer Bohrkronen (11, 51) gebohrt wird, welche am Ende von einer Bohrstange (14) gelagert ist, wobei das Verfahren die Schritte enthält:

- ajuster d'une quantité prédéterminée une contre-pression dans un anneau (A) formé entre le trou de forage (B) et le train de tiges de forage (14) tout en faisant circuler un fluide à travers le train de tiges de forage et le trou de forage (B) ; mesurer les débits du fluide à différentes contre-pressions correspondantes dans l'anneau (A) pendant la circulation du fluide ; et détecter un afflux de fluides de formation dans le trou de forage (B) sur la base des débits mesurés aux différentes contre-pressions dans l'anneau (A). 5 10
- 10.** Procédé selon la revendication 9, comprenant en outre l'étape consistant à lancer une alarme en réponse à la détection de l'afflux de fluides de formation dans le trou de forage (B). 15
- 11.** Procédé selon la revendication 9, comprenant en outre l'étape consistant à déterminer un paramètre de formation sur la base des débits mesurés aux différentes contre-pressions dans l'anneau (A). 20
- 12.** Procédé selon la revendication 9, dans lequel le paramètre de formation comprend une pression de réservoir. 25
- 13.** Procédé selon la revendication 9, dans lequel le paramètre de formation comprend une perméabilité de formation. 30
- 14.** Procédé selon la revendication 9, dans lequel le train de tiges de forage et le trou de forage font partie d'un système de circulation de fluide fermé. 35
- 15.** Procédé selon la revendication 9, comprenant en outre l'étape consistant à déterminer une valeur souhaitée pour la contre-pression dans l'anneau sur la base des débits mesurés aux différentes contre-pressions dans l'anneau. 40
- 16.** Procédé selon la revendication 9, dans lequel l'étape de détection d'un afflux de fluides de formation dans le trou de forage comprend en outre l'entrée des débits mesurés aux différentes contre-pressions dans l'anneau dans un modèle informatique d'un réservoir. 45

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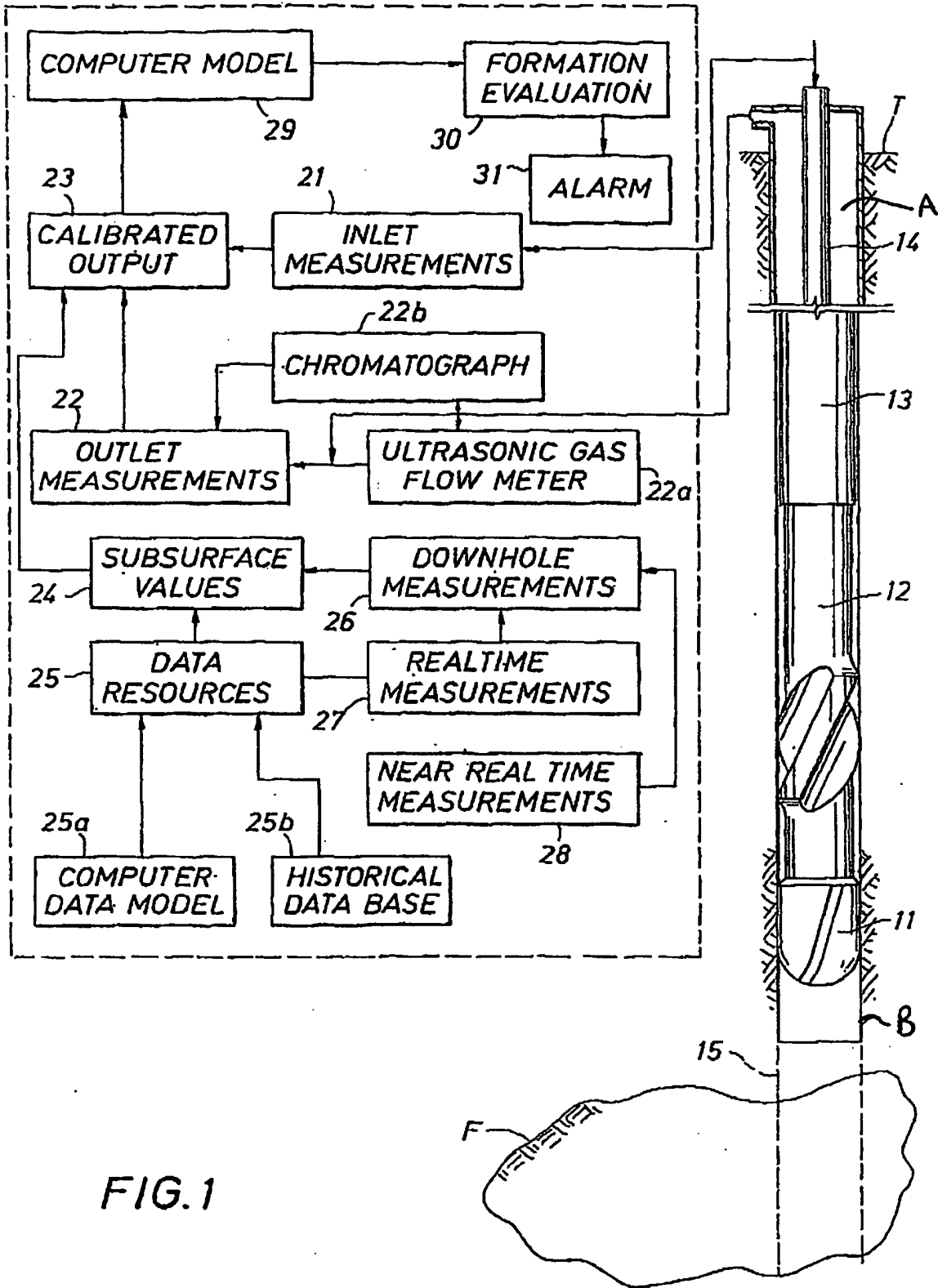


FIG. 1

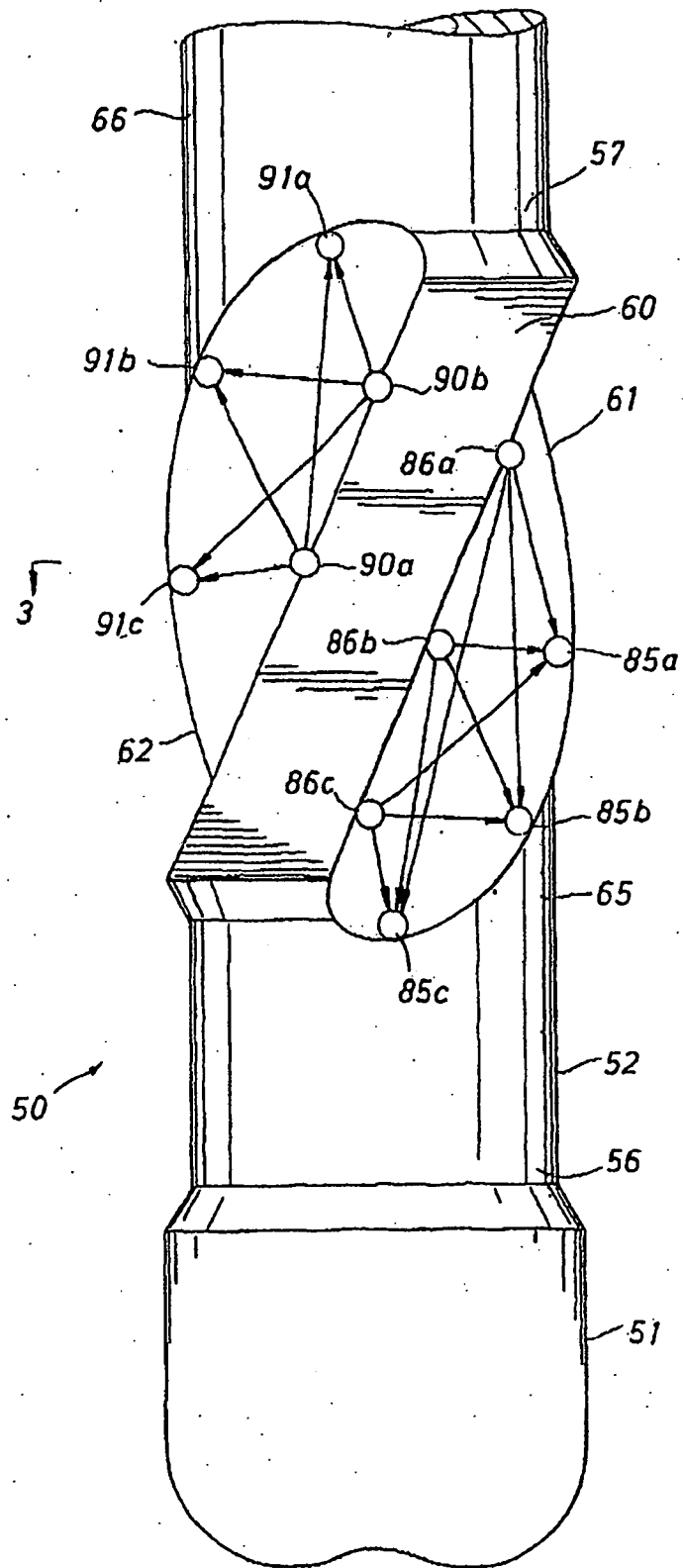


FIG. 2

FIG. 3

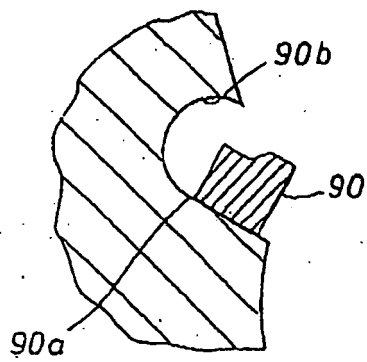
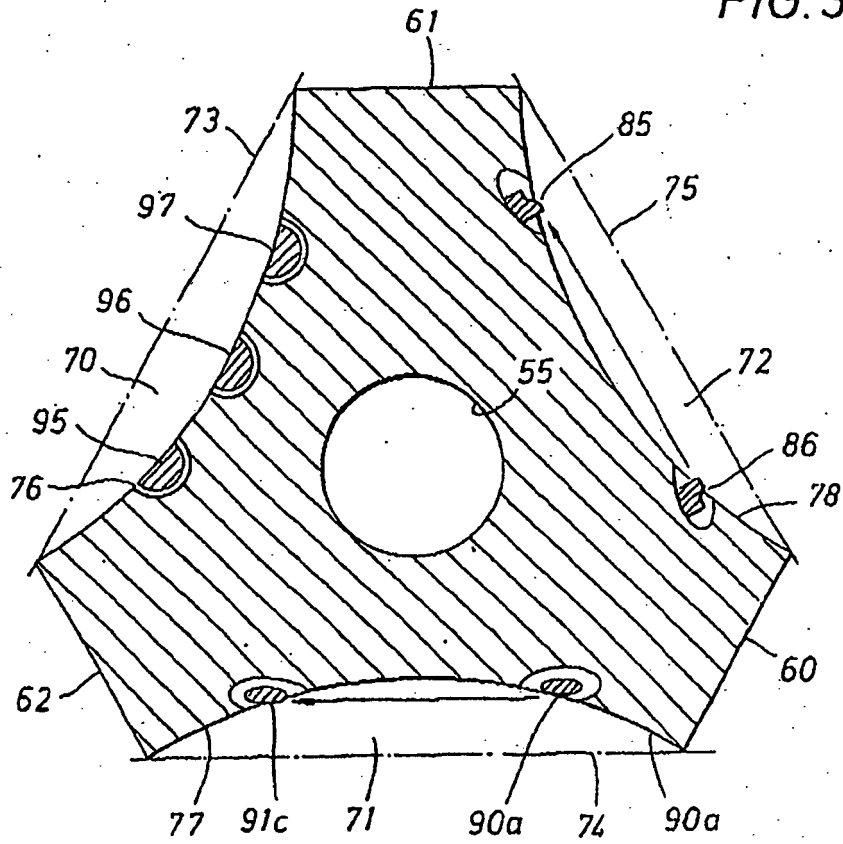


FIG. 3A

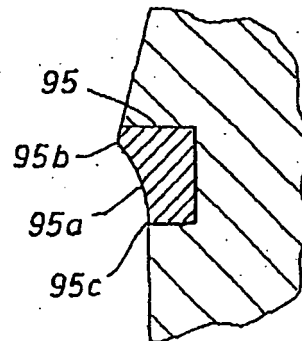


FIG. 3B

REFERENCES CITED IN THE DESCRIPTION

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Patent documents cited in the description

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- WO 9949172 A **[0013]**