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ABSTRACT

A method of producing gas through liquid level detection in an oil or gas well uses various types of artificial lift systems (10) that include subsurface gas lift, beam pumps, progressive cavity pump and submersible pumps. The artificial lift systems (10) are controlled in response to a known liquid level (34) within the wellbore to prevent the well from pumping off and damaging the artificial lift system (10) or from reducing the liquid level (34) in the wellbore to an unnecessarily low level to thereby increase the energy required by the artificial lift system (10) to remove the liquid (32) from the wellbore. The liquid level detection method includes the detection of at least the pressure on a side string tube in the wellbore to determine the level of liquid in the wellbore for automated control of liquid removal from the wellbore to be removed to the surface through a production tube to allow improved gas or oil production, increase artificial lift efficiency and to allow for control of the artificial lift system to prevent damage to the system. Another method measures production from the well in conjunction with automated liquid level control to maximise liquid level in the wellbore without interfering with production. A timing method allows for control of the quantity of gas injected during the gas injection cycle of a subsurface gas lift artificial lift system.

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Invention Title:

PRODUCING WELL ARTIFICIAL LIFT SYSTEM CONTROL

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

PRODUCING WELL ARTIFICIAL LIFT SYSTEM CONTROL

This invention relates to producing wells having an artificial lift system for removing liquid from an underground formation. In one of its aspects, the invention relates to improved methods of and systems for control of artificial lift systems utilizing pressure measurements and pressure manipulation to detect the liquid level in the well bore to thereby increase the efficiency, operational predictability and to automate the artificial lift systems. In another of its aspects, the invention relates to the monitoring of production gas from a gas producing well and detection of the liquid level in the well bore to thereby control the artificial lift system to maximize gas production from the well while simultaneously maximizing artificial lift system performance and efficiency.

There is a need to provide a method and system to conserve energy and increase longevity of well bore equipment by precise control of the liquid level within the well bore to avoid pump off in artificial lift systems. A systemic method of control of the liquid level will improve the efficiency of a well pump while further reducing the manpower requirements to operate the system by reducing the need for operator intervention with the artificial lift system to control liquid level to optimize well production and to prevent the system from damaging itself. There is further a need to have cost effective oil or gas well artificial lift systems that are relatively environmentally and operationally safe, low maintenance, operationally predictable, easy to use, have an acceptable level of efficiency and have the ability to automatically compensate to meet the variable conditions of a dynamic well bore.

SUMMARY OF INVENTION

The invention relates to a method and system of producing gas and liquid from a gas and liquid-containing underground stratum comprising a well bore extending between the surface of the ground to the stratum, the well bore having a casing and a production tube defining an annulus through which gas from the stratum passes and is collected at the surface of the ground through a production line. The production tube extends from the surface of the ground and is in fluid communication with the gas and liquid-containing stratum through which the liquid is collected from the well and removed to the surface by artificially raising the liquid in the production tube to the surface to thereby release gas from the formation to the well bore and production line. A side string tube extends from the surface of the ground through the annulus and is in fluid communication with the gas and liquid-containing stratum. An artificial lift system is provided for artificially raising the liquid in the production tube to the surface to thereby release gas from the formation to the well bore and production line.

According to the invention, the level of liquid in the well bore is reiteratively measured by reiteratively detecting at least the pressure in the side string tube, comparing the measured level of liquid with a predetermined value representative of a desired level of liquid in the well bore and controlling the artificial raising of the liquid in the production tube in accordance with the measured level and predetermined value so that the measured level reaches the predetermined value.

In one embodiment of the invention, the artificial raising of the liquid in the production tube is accomplished by injecting a volume of gas into a bottom portion of the production tube through the side string tube when the measured level of liquid (as detected by pressure) reaches the predetermined value.

According to a further embodiment of the invention, a relatively small amount of gas is injected into the side string tube to clear any liquid that may be present in the side string tube, just prior to or during the detection of the pressure in the side string tube.

According to an even further embodiment of the invention, the pressure in the production tube is detected, and the differential pressure between the detected side string pressure and the production tube pressure is calculated and compared to the predetermined value.

According to a further embodiment of the invention, the rate of gas production in the production line is monitored and the predetermined value representative of the desired level of liquid in the well bore is adjusted to maximize gas production and liquid level. Preferably, the adjustment of the predetermined value is performed over a plurality of gas lift injection cycles or otherwise over a period of time for artificial lift systems incorporating a pump.

Still further according to the invention in a SSGL system, the time required to artificially raise the liquid in the production tube to the surface of the ground is measured and compared with a predetermined and desired time of liquid rise. The volume of gas injected into the production tube during the injection step is adjusted until the measured time of liquid rise to surface is substantially equal to the predetermined and desired time of liquid rise to surface.

According to another embodiment of the invention, a pump is operatively associated with the production tube for artificially raising the liquid in the production tube. Depending on the well conditions, the pump can be started, stopped, sped up or slowed down to control the level of liquid in the well bore.

According to an even further embodiment of the invention, the time is monitored at which the level of liquid in the well bore is measured and the predetermined set point representative of desired liquid level is altered when the time substantially equals a first predetermined time, such as the time just before a peak power draw from a power company, to thereby artificially raise the liquid in the production tube when the level of liquid in the well bore is different from the desired level. Preferably, the predetermined set point is lowered to a lower set point to thereby lower the level of liquid in the well bore to a reduced level, such that artificially raising the liquid in the production tube can be omitted during peak hours without interference with well production.

In a system for producing gas according to the invention, a first pressure sensor detects the pressure in the side string tube at surface and generates a first pressure signal representative of the detected pressure in the side string tube. A controller is operably connected to the first pressure sensor for reiteratively computing the level of liquid in the production tube or well bore in response at least in part to the first pressure signal. The computed level of liquid in the production tube or well bore is compared to a predetermined value representative of the desired level of liquid in the well bore and the artificial lift system is controlled to allow the level of liquid in the well bore to reach the desired level of liquid in the well bore.

In the embodiment of the invention wherein the artificial lift system comprises a gas injection system with an injection valve for periodically injecting a blast of gas into a lower portion of the production tube through the side string tube, the controller is operably connected to the injection valve and is adapted to control the initiation of the blast of gas into the production tube to artificially lift the liquid in the production tube to the surface of the ground. The controller actuates the injection valve to initiate the injection of gas into the side string tube when the measured level of liquid in the production tube reaches a predetermined value representative of the desired level of liquid in the production tube and well bore. Preferably, the controller is adapted to compute the level of liquid in the production tube in response to the first pressure signal after liquid has been substantially cleared from the side string tube by the injection of a minuscule volume of gas.

In a preferred embodiment of the invention wherein the artificial lift system comprises a gas injection system, a second pressure sensor is fluidly attached to the production tube to sense the pressure therein and to generate a second pressure signal representative of the pressure in the production tube. A controller is operably coupled to the second pressure sensor and is adapted to compute the level of liquid in the production tube in response at least in part to the first and second pressure signals. In a preferred embodiment of the invention, the controller is adapted to compute the level of liquid in the production tube in response to the difference between the first and second pressure signals.

In another embodiment of the invention, the artificial lift system comprises a beam pump. In still another embodiment of the invention, the artificial gas lift system comprises a progressive cavity pump. In still another embodiment of the invention, the artificial lift system is an electrically driven submersible pump.

In a preferred embodiment of the invention wherein the artificial lift system incorporates a pump, a second pressure sensor is fluidly attached to the annulus to sense the pressure therein and to generate a second pressure signal representative of the pressure in the annulus. A controller is operably coupled to the second pressure sensor and is adapted to compute the level of liquid in the well bore in response at least in part to the first and second pressure signals.

According to one aspect of the invention, the controller is adapted to compute the level of liquid in the well bore in response to the difference between the first and second pressure signals. Preferably the controller is adapted to generate an output signal for controlling the initiation of the artificial lift system when the liquid level in the well bore as detected by pressure reaches a predetermined value.

According to another embodiment of the invention in an SSGL artificial lift system, an arrival detector is mounted at an upper portion of the production tube or on the lubricator to detect the arrival of the ejected liquid or plunger from the lower portion of the production tube and to generate an arrival signal representative thereof. The controller is operably coupled to the arrival detector and is adapted to compute the time required to artificially lift the liquid or plunger from the lower portion of the production tube to the arrival detector, to compare the computed trip time of the liquid or plunger to a predetermined and desired trip time, and to control the operation of the injection valve to adjust the volume of gas injected into the side string tube during subsequent injection cycles until the computed trip time of the lifted liquid or plunger substantially equals the predetermined and desired trip time.

In yet another embodiment of the invention, a production detector in the production line measures the rate of gas production and generates a production signal responsive thereto. The controller is further operably coupled to the production detector and is adapted to compute the rate of gas production responsive to the production signal and to adjust the predetermined value representative of the desired liquid level in the production tube or well bore to maximize the gas production in the production line.

The invention can be applied to a single producing well with the controller physically at the wellhead. Alternatively, a controller can be used to control a plurality of wells. The controller can be located geographically remote from each of the wells and in communication with the sensors and control valves at the well head through electrical communication lines or through telemetry.

BRIEF DESCRIPTION OF THE DRAWINGS

The invention will now be described with reference to the drawings in which:

FIG. 1 is a schematic cross sectional view of a bore hole with a subsurface gas lift artificial lift system incorporating a control system according to the invention;

FIG. 2 is a schematic cross sectional view of an alternate bore hole which can be used with an SSGL artificial lift system according to the invention;

FIG. 3 is a schematic cross sectional view of an alternate bore hole which can be used with an SSGL artificial lift system according to the invention;

FIG. 4 is a schematic representation of an alternate well head assembly which can be used with an SSGL artificial lift system incorporating a control system according to the invention;

FIG. 5 is a schematic representation of a second alternate well head assembly which can be used with an SSGL artificial lift system incorporating a control system according to the invention;

FIG. 6 is a block diagram illustrating a method according to the invention for controlling a gas injection cycle in an oil or gas well having an SSGL artificial gas lift system;

FIG. 7 is a block diagram illustrating yet another method according to the invention for controlling a gas injection cycle in an oil or gas well having an SSGL artificial gas lift system;

FIG. 8 is a block diagram illustrating still another method according to the invention for controlling a gas injection cycle in an oil or gas well having an SSGL artificial gas lift system;

FIG. 9 is a block diagram illustrating still another method according to the invention for controlling a gas injection cycle in an oil or gas well having an SSGL artificial gas lift system;

FIG. 10 is a block diagram illustrating a method according to the invention for dynamically adjusting a predetermined artificial lift liquid level set point in an oil or gas well having an artificial lift system;

FIG. 11 is a block diagram illustrating a method according to the invention for dynamically controlling the necessary volume of gas injected during a gas injection cycle in an oil or gas well having an SSGL artificial gas lift system;

FIG. 12 is a block diagram illustrating another method according to the invention for dynamically controlling the necessary volume of gas injected during a gas injection cycle in an oil or gas well having an SSGL artificial gas lift system;

FIG. 13 is an enlarged cross sectional view of a modified lubricator for detecting liquid arrival according to the invention;

FIG. 14 is a diagrammatic representation of a plurality of well systems arranged for telemetric communication between a remote computer which can be used for control in any of the methods or systems according to the invention;

FIG. 15 is a schematic cross sectional view of a beam pump artificial lift system and bore hole with a control system according to the invention;

FIG. 16 is a schematic cross sectional view of a progressive cavity pump artificial lift system and bore hole with a control system according to the invention;

FIG. 17 is a schematic cross sectional view of an alternate bore hole which can be used with a beam pump or progressive cavity pump artificial lift system according to the invention;

FIG. 18 is a schematic cross sectional view of an alternate bore hole which can be used with a beam pump or progressive cavity pump artificial lift system according to the invention;

FIG. 19 is a schematic representation of an alternate well head assembly which can be used with a beam pump or progressive cavity pump artificial lift system incorporating a control system according to the invention;

FIG. 20 is a schematic cross sectional view of a submersible pump artificial lift system and bore hole with a control system according to the invention;

FIG. 21 is a schematic cross sectional view of an alternate bore hole which can be used with a submersible pump artificial lift system according to the invention;

FIG. 22 is a schematic cross sectional view of an alternate bore hole which can be used with a submersible pump artificial lift system according to the invention;

FIG. 23 is a schematic representation of an alternate well head assembly which can be used with a submersible pump artificial lift system incorporating a control system according to the invention;

FIG. 24 is a block diagram illustrating a method according to the invention for controlling a pump in an oil or gas well having an artificial lift system;

FIG. 25 is a block diagram illustrating yet another method according to the invention for controlling a pump in an oil or gas well having an artificial lift system;

FIG. 26 is a block diagram illustrating still another method according to the invention for controlling a pump in an oil or gas well having an artificial lift system;

FIG. 27 is a block diagram illustrating and still another method according to the invention for controlling a pump in an oil or gas well having an artificial lift system; and

FIG. 28 is a block diagram illustrating a method according the invention for dynamically adjusting a predetermined set point to reduce energy drawn by the artificial lift system during peak load hours and optimize production.

DESCRIPTION OF THE PREFERRED EMBODIMENTS

To avoid an unreasonable amount of redundance. the invention will be described in two parts.

In part one, as the invention applies to an artificial lift system incorporating sub surface gas lift SSGL (FIGS. 1 through 14). and in part two, as the invention applies to artificial lift systems incorporating the use of a pump (FIGS. 10, and 15 through 28). In each of these artificial lift systems the invention will be describe from its most simple form using only one sensor 92 to a complete system that is both dynamic and interactive using multiple sensors 91, 92, 93, 94 and in the case of the SSGL system including the use of a magnetic sensor 95.

In part one, FIG. 1 illustrates a well assembly having an artificial lift system 10 that incorporates a subsurface gas lift system (SSGL) and an electronic controller 90 in conjunction with electronic sensors 91, 92, 93, 94, and 95. The controller 90 can be one of any well known micro controllers having a central processing unit, arithmetic logic unit, memory locations, input/output ports, timer(s), etc, or can be an electronic circuit having a comparator depending on the particular well assembly complexity. The comparator can also be associated with a display, such as a monitor or printer for displaying well conditions. The system is closed to atmosphere, creating a closed artificial lift system.

As illustrated, the formation contains two types of fluid, natural gas 30 and water 32 in the liquid state. However, other types of liquid such as liquid hydrocarbons can be in the formation 51. The natural gas 30 and liquid 32 are typically separated because of their different densities. The liquid 32 can have some natural gas in solution. The formation 51 can also hold substantial quantities of natural gas that is retained within the formation 51. The natural gas 30 and liquid 32 are usually under pressure in the formation 51. The pressure of the fluids in the formation can be caused by the weight of overburden 50 acting on the formation and the pressure of the liquids in the formation 51. This internal pressure of the formation is known as the head pressure. The natural gas 30 and liquid 32 are at static equilibrium within the formation 51. To deplete the natural gas from the formation 51, it is necessary to remove the liquid from the formation 51 so that the head pressure is reduced to release the natural gas 30 from the formation 51 and so the natural gas 30 in the formation 51 can fill the well bore in the area vacated by the removed liquid 32.

The well assembly 60 comprises a casing 42 disposed from the surface and extending into the bore hole 43 and into the formation 51. Preferably, the casing 42 extends substantially to the bottom of the overburden 50 and to the formation 51 and is open at the lower end or has suitable perforations through which the gas 30 and liquids 32 can pass. However, a rat hole portion 45 of the bore hole, shown in FIGS. 2 and 3, can be drilled below the bottom of the formation 51 and into the substrata 52 and the casing 42 can extend into the rat hole 45.

The casing 42 is sealed with respect to the atmosphere at its upper end by a wellhead 60. A production tube 41 extends through the wellhead 60 and extends substantially near the bottom of the bore hole 43. The casing 42 may or may not extend to the bottom of the formation, depending on the application. Although the casing 42 is illustrated as extending the entire length of the bore hole, (FIGS. 2 and 3), the casing 42 typically extends only to a depth dictated by engineering preference or completion technique because of the relatively high cost of installing and perforating the casing 42. However, the casing 42 is present at the surface of the bore hole and cooperates with the wellhead 60 to seal the bore hole with respect to the atmosphere.

An annulus 46 is formed by the inner diameter of the casing 42 or bore hole 43 and the outer diameter of the production tube 41. The lower end of the production tube 41 has an injection mandrel 80 in which is mounted a one-way standing valve 81. A high pressure side string injection line 24 extends from a high pressure gas source 20 through the well head 60 to a high pressure side string injection tube 40 and to the injection mandrel 80. Preferably, the side string injection tube 40 is fluidly connected with the I.D. of injection mandrel 80 above the standing valve 81. When high pressure gas is directed from the high pressure gas source 20 through the side string injection tube 40 and into the production tube 41, the standing valve 81 prohibits the high pressure gas from escaping from the production tube 41 and keeps the high pressure gas out of the annulus 46. A plunger 82 can be disposed in the production tube 41 above the inlet for the side string injection tube 40 and is sized to fit within close tolerance of the inner diameter of the production tube 41. In some SSGL systems, the plunger is eliminated.

An open hole or uncased section of the bore hole 43 (FIG. 1) or a series of perforations 44 (FIGS. 2 and 3) are formed in the casing so that the fluids, such as the natural gas and liquid, can enter the annulus 46. The casing 42 also has a production line 77 positioned at the surface, and extending to a collector 100 which separates liquid from gas, so that the natural gas entering the annulus 46 through the perforations 44 or open hole 43 can be directed to the collector 100. A valve 70 and a check valve 71 are disposed within the production line 77 between the casing 42 and the collector 100. The valve 70 and the check valve 71 control the flow of natural gas 30 from the annulus 46 to the collector 100. Preferably, the valve 70 is a manually operated valve to close the production line 77, whereas the check valve 71 is a one-way valve that permits the flow of the natural gas 30 from the annulus 46 to the collector 100 but prohibits flow from the collector 100 into the annulus 46. The production line 77 further has in it a measurement orifice 76 and pressure sensors and transmitters 93 and 94. The measurement orifice 76 is operably connected to the differential pressure transmitter 93 and pressure transmitter 94 is operably connected to the production line 77. (While only a single method of gas measurement is presented herein it is to be understood that any method of gas measurement such as a turbine meter or vortex meter, etc. may be used as long as an output signal is generated representative of the flow in the production line 77.) The collector 100 is further connected to the production tube 41 through master valve 61, lubricator 62, ejection line 74 and commingling line 75. The ejection line 74 has a pressure sensor and transmitter 91, and isolation valve 72 and a check valve 73.

A motor valve 21, pressure sensor and transmitter 92 and a valve 22 are positioned in the side string injection line 24. The valve 22 is preferably a manually operated valve for opening and closing the side string injection tube 40 when desired. The motor valve 21 is connected to a controller 90 having a timer. A small branch line 36 extends from the high pressure source 20 to the side string injection line 24 between the motor valve 21 and the pressure sensor and transmitter 92. The branch line 36 has a regulator 23 to control the pressure and volume flowing therethrough. The controller 90 can be programmable and opens and closes the motor valve 21 so that the high pressure gas from the high pressure gas source 20 can be injected through the side string tube 40 and into the production tube 41 at either predetermined or dynamic intervals according to the invention. The controller 90 can be any suitable controller which is programmable to make the computations from the pressure signals from the sensors 91, 92, 93, 94 and 95, compare the resultant signals to predetermined set points, and open the valve 21 for a predetermined length of time during the SSGL cycle. The controller 90 is further programmable to make the computations described hereinafter for adjusting the time of the gas injection cycle and to adjust the predetermined set points on the controller as described hereinafter. A suitable controller for this purpose is a Pumpmate Control, sold by OKC Products of Longmont, Colorado. Further the controller 90 can be a simple monitoring device incorporating a timer and a telemetry unit 290 (FIG. 14) that transmits the value from the sensors 91, 92, 93, 94 and 95 to a remote data receiver 292 and computer 294 which completes the logic functions and then transmits the control parameters according to the invention back to the telemetry unit 292 and to the timer 90 for control of the artificial lift system 10.

A lubricator 62 is mounted to the wellhead 60 above the production tube 41 and is fluidly connected to the production tube 41. The lubricator 62 is an extension of the production tube 41. The lubricator preferably has a cushioning device, such as a spring, positioned at the upper end of the lubricator 62 when a plunger 82 is disposed in the production tube 41. The spring functions to cushion or arrest the upward movement of the plunger 82. The lubricator 62 can consist of any device with an outlet to the ejection line 74 if a plunger 82 is not disposed in the production tube 41. A valve 61 is connected to the production tube 41 at an upper portion thereof and is preferably manually operated to open and close the flow from the production tube 41 and through the lubricator 62 when desired.

An ejection line 74 extends from the lubricator 62, preferably above the valve 61, and is connected to the production line 77. Alternately, according to FIGS. 4 and 5, the ejection line 74 can be isolated from the production line 77 or intermittently equalized with the production line 77. Preferably a valve 72 and a check valve 73 are connected in the ejection line 74. The pressure sensor and transmitter 91 is also mounted in the ejection line 74 to detect the pressure in the production tube 41 at the surface of the ground. The valve 72 is a manually operated valve to open and close the ejection line 74, whereas the check valve 73 is preferably a one-way valve for controlling the flow from the lubricator 62 to the production line 77, but preventing flow from the production line 77 to the ejection line 74 and into the production tube 41. The check valves 71 and 73 keep fluids from back flowing from the commingling line 75 into the production tube 41 or the annulus 46.

The check valves 71 and 73 isolate the annulus 46 and the production tube 41 from back flowing into each other at the surface but allow them to equalize in pressure with respect to the commingling line 75. Because the production tube 41 and the annulus 46 are fluidly connected to commingling line 75, they are equalized in pressure at surface and the liquid can reach a static equilibrium with similar levels in the production tube 41 and the annulus 46. Alternately, the ejection line 74 and the production line 77 can be isolated to their respective collectors (FIG. 4), and, therefore, static equilibrium can be achieved with dissimilar liquid levels in the production tube 41 and the annulus 46. During the injection of high pressure gas from the high-pressure gas source 20 through the side string injection line 24 down the side string injection tube 40 and the ejection of liquids up the production tube 41 through the ejection line 74 and into the commingling line 75, the check valve 71 directs the liquid flow to the collector 100 rather than allowing the liquid to reenter the annulus 46.

Although only one plumbing arrangement is shown in FIG. 1, there are many possible variations. It should be understood that the well assembly 60 and the SSGL 10 can be reconfigured so as to eliminate or include various components as long as sensors 91 and 92 are mounted in the injection line 24 and the ejection line 74, respectively, to gather pressure information to determine the static liquid level 34 within the production tube 41. Sensors 93 and 94 are mounted in gas production line 77 to gather pressure information to determine production through the production line 77 and sensor 95 is mounted to the lubricator 62 or to the upper portion of the production tube 41 to detect the plunger 82 or liquid 32 travel time to surface. Further, even though the pressure sensors and transmitters 91, 92, 93, 94 are shown in only one configuration, various arrangements can be used. For example in FIG. 1, pressure sensor 94 could serve the dual purpose of pressure measurement of the production line 77 and ejection line 74 because these lines are substantially equalized. Therefore many possible plumbing and electronic arrangements exist within the scope of the invention without departing from the spirit of the invention.

There are several pressure measurements relevant to determining the bottom hole or head pressure in the artificial lift system 10 and the location of the liquid level 34 in the production tube 41 and therefore the annulus 46. Besides the pressure of the side string injection line 24 at surface and the production tube 41 at surface, the pressures in the length of bore hole 43 and the production tube 41 must also be considered. The pressures in the length of bore hole 43 and the production tube 41 are commonly referred to in the terms of pressure gradients. "Gradient" is defined as pounds of pressure per square inch (psi) per vertical foot in the bore hole. For example, fresh water will have gradient of .433 psi per vertical foot, whereas an unpressurized gas gradient may be as low as .002 psi per vertical foot. In effect, a 1000-foot column of fresh water will have a bottom hole or head pressure of 433 psi whereas a 1000-foot column of unpressurized gas would have a bottom hole or head pressure of 2 psi.

Most artificial lift systems discharge their liquids or gas into a pressurized production line 77, such as a pipeline system that directs the liquids or gas to a collector, such as collector 100 at a production facility. This gathering system pressure promotes flow from the well head to the production facility and also aids in the separation of the gas and liquid in that the collector 100 may require pressure to discharge the liquid from the collector 100 to a tank. Also, the compressors used to compress the gas up to sales line pressure, except in rare configurations, require a positive inlet pressure to perform efficiently. Variations in this pipeline pressure and, therefore, the production line 77 pressure will cause the SSGL artificial lift system 10 to perform erratically in that higher pressures often cause the static liquid level 31 in the annulus 46 to decrease. Decreasing the liquid level in the annulus 46 will decrease the liquid level in the production tube 41. Without a corresponding decrease in the volume of injection gas 20 injected into the production tube 41, the plunger 82 will rise in the production tube 41 with ever increasing velocity. If this condition is unchecked, damage may result. On the other hand, a decreasing pressure on the pipeline system and, therefore, in the production line 77 will cause the static liquid level 31 in the annulus 46 to rise. A rising static liquid level 31 in the annulus 46 will cause the liquid level 34 in the production tube 41 to rise. An increase in the liquid level in the production tube 41 without a corresponding increase in the volume of injection gas 20 injected into the production tube 41 under the plunger 82 will cause the plunger to fail to rise to surface and eject the liquid. If this condition is unchecked, the well will load up with liquid and gas production 30 into the annulus 46 will become suppressed. Therefore, a method of detecting the static liquid level 31 in the well bore to initiate the artificial lift 10 cycle and automatically adjusting the injection gas 20 volumes injected into the production tube 41 to sustain a consistent production gas 30 volume in a system with ever changing pressures and liquid level is of great importance.

Referring to FIG. 1, the operation of the SSGL artificial lift system 10 begins with the opening of valves 22, 61, 70, and 72. Valves 22, 61, 70, and 72 are normally open during normal production operations. The liquid 32 in the formation 51 can then more fully enter the production tube 41 through the standing valve 81 attached to the injection mandrel 80 to reach a point of static equilibrium with the liquid level 31 in the formation 51 because the production tube 41 is fluidly equalized at the surface with the annulus 46 via the production line 77, the ejection line 74 and the commingling line 75. The controller 90 initiates the injection of gas into the side string 40 and into the mandrel 80 under the plunger 82 by opening the motor valve 21 to physically raise the liquid 32 in the production tube 41 to the surface and remove the liquid 32 through the lubricator 62 into the ejection line 74 and to the collector 100. After a predetermined and arbitrary period of injection into the side string tube 40, the controller 90 will close the motor valve 21 until the next injection cycle is to begin. The blast of injection gas from source 20 is prohibited from exiting the bottom of the production tube 41 by the one way standing valve 81 which allows the liquid 32 to enter the production tube 41 but prohibits the liquid 32 and the injection gas in the production tube 41 from escaping into the annulus 46. Further, the check valve 71 on the production line 77 directs the flow of liquid 32 and injection gas from the ejection line 74 down the commingling line 75 to the collector 100 and prohibits the back flow of liquid 32 or injection gas 20 into the annulus 46.

A pressure sensor 92 is fluidly connected to the side string injection line 24 to detect the pressure caused by the influx of liquid 32 into the production tube 41. The liquid 32 entering the production tube 41 will rise to a point 34 where the combined head pressure of the gas and liquid in the production tube 41 will be equal to the combined head pressure of the gas and liquid in the annulus 46 at the injection mandrel 80. As the liquid 32 enters the production tube 41, it will also enter the side string tube 40 through the side string tube 40 attachment port on the mandrel 80. However, the side string tube 40 influx liquid 33 entering into the side string tube 40 will achieve only a portion of the liquid level 34 in the production tube 41 because the side string injection line 24 motor valve 21 is shut and the side string tube 40 is not equalized with the production line 77 or ejection line 74 at surface. This influx of liquid 33 will cause the pressure of the side string injection line 24 at surface to rise until the combined head pressures of the gas in the side string tube 40 and the liquid level 33 in the side string tube 40 are equal to the combined head pressure of the gas and liquid in the production tube 41 at the side string tube 40 attachment point on the mandrel 80. At this point, the difference between the side string injection line 24 pressure at surface and the production tube 41 pressure at surface multiplied by the appropriate liquid gradient pressure factor will give an approximate liquid level 34 in the production tube 41. It is important to understand, however, that the liquid level is approximate due to the fact that liquid has entered the side string tube

40 to compress the gas in the upper portion thereof which results in two different gradients in the side string tube 40, one for gas and one for influx liquid 33, the level of which is unknown. This side string injection line 24 pressure detected by pressure sensor 92 can be used to determine an estimated pressure set point to be programmed into the controller 90 to initiate the SSGL injection cycle based on an estimated liquid level. To this end, the pressure sensor 92 is electrically connected to the controller 90 so that a signal representative of the pressure in the side string line 24 as detected by the pressure sensor 92 is input into the controller 90. The controller is programmed with a predetermined set point representative of the desired liquid level in the production tube 41 for initiation of the SSGL injection cycle.

The basic method of controlling the SSGL cycle, as shown in FIG. 6, includes reiteratively monitoring the production tube liquid level throughout the SSGL non-injection or off cycle by detecting the side string tube (sst) pressure with pressure sensor 92 as represented in block 210. The controller 90 then compares the detected side string pressure to the predetermined set point as represented at block 212. If the side string pressure is less than the predetermined set point, the side string pressure is again detected. When the production tube 41 liquid level 34 (as indicated by pressure) substantially equals the predetermined set point in the controller 90, controller 90 will initiate the SSGL injection cycle as represented at block 214. In this step, the controller 90 will open control valve 21 for a predetermined period of time to deliver a high-pressure blast of gas to the bottom of the production tube 41. During initiation of the SSGL injection cycle, a time delay as represented at block 216 is activated. This time delay allows the liquid column and/or plunger 82 to reach the surface and also allows the plunger 82 to return under gravity to its position proximal to the side string injection tube 40 inlet to the injection mandrel 80 before commencing another reiterative monitoring of the production tube 41 liquid level 34.

This method will require the greatest amount of operator intervention to work with nominal efficiency. This method will only give a rough estimate of the liquid level 34 in the production tube 41 due to the fact that there will be an influx of liquid 32 into the side string 40 the level 33 of which unknown. This method is also prone to error in that the predetermined SSGL artificial lift 10 injection initiation pressure set point programmed into the controller 90 is subject to errors that can be induced by fluctuations in production line 77 or ejection line 74 pressures (FIG. 4) due to the fact the operator must assume an average production line 77 or ejection line 74 pressure when programming the predetermined set point in controller 90. Therefore, this method will perform best on wells with substantial rat hole 45 (FIGS. 2 and 3) or with very high liquid levels 31 where side string injection line 24 pressure will become noticeably elevated due to the production tube 41 liquid gradient.

The second embodiment of a method according to the invention, as schematically represented in FIG. 7, incorporates all the steps of the first embodiment illustrated in FIG. 6 plus the improvement step of injecting a relatively small or minuscule volume of injection gas from source 20 through a regulator 23 into the side string injection line 24 to remove the influx liquid level 33 in the side string tube 40 down to the level of the side string tube 40 connection on the injection mandrel 80 so that the pressure in the side string injection line 24 more accurately represents the head pressure in the production tube 41. This method of controlling the SSGL injection cycle includes injecting a minuscule volume of gas into the side string at block 220 during the SSGL non-injection or off cycle. Simultaneously, the side string pressure is detected by pressure sensor 92 as a measure of the level of liquid 34 in the production tube 41 as represented at block 210. When the minuscule volume of gas is injected, the pressure at surface in the side string injection line 24 will rise until all of the liquid is expelled from the side string injection tube 40, at which time the pressure in the side string injection line at surface will stabilize. The volume of injected gas can be monitored or can be estimated during this step. The removal of all the influx liquid 33 (with its accompanying unknown level) in the side string tube 40 causes only a gas gradient to be present in the side string tube 40 and thus leads to a more precise liquid level computation in the production tube 41 and therefore the annulus 46. The operator can then use this more precise liquid level detection method to enter a predetermined value representative of the desired liquid level in the well bore. This predetermined value is referenced by the controller 90 at block 212 and subsequently the SSGL injection cycle is automatically initiated for an arbitrary period of time by the controller 90 by opening valve 21 at block 214 when the monitored liquid level as determined by pressure is substantially equal to the predetermined set point in the controller 90 as represented at block 212. As in the method of FIG. 6, a time delay represented at block 216 can be provided to allow the liquid column and/or plunger 82 to reach the surface and also allow the plunger 82 to return under gravity to its position proximal to the side string injection tube 40 inlet to the injection mandrel 80 before commencing another reiterative monitoring of the production tube 41 liquid level 34.

While this method is more accurate than the method of FIG. 6, it is still prone to the same weakness as the first method in that fluctuations in production line 77 or ejection line 74 pressures are not compensated for and it may be necessary for the operator to assume an average production line 77 or ejection line 74 pressure when programming the predetermined set point into the controller 90 to initiate the SSGL 10 injection cycle. Therefore, this method will perform best on wells with substantial rat hole 45 (FIGS. 2 and 3) or with a high annulus 46 and production tube 41 liquid levels where side string injection line 24 pressure will become noticeably elevated due to production tube 41 liquid gradient during the injection of the minuscule quantity of gas into the side string injection line 24.

The third embodiment of the invention is shown most clearly in FIGS 1, 4, 5 and 8. The pressure sensor 92 senses the side string injection line 24 pressure increase caused by the influx of liquid 34 into the production tube 41 and a pressure sensor 91 fluidly connected to the ejection line 74 senses the pressure of the production tube 41. The pressure sensors 91 and 92 are connected to the controller 90 by wires or through a transmitter to input a signal from the sensors 91 and 92 representative of the pressure in the ejection line 74 and the side string injection line 24. Alternatively, sensors 91 and 92 can be replaced by a single transducer (not shown) that directly measures the difference between the line pressures. While pressure sensor 91 is shown attached to the ejection line 74 it may be attached to the well head or associated plumbing in any position that is equalized is such a way that the sensor 91 can correctly detect the pressure in the production tube 41 at surface. The liquid 32 entering the production tube 41 will rise until the combined head pressure of the liquid 32 and gas 30 in the production tube 41 will be equal to the combined head pressure of the liquid 32 and gas 30 in the annulus 46 at the injection mandrel 80. However, the influx of liquid 33 into the side string tube 40 will only be a portion of the level of the liquid 34 in the production tube 41 because the motor valve 21 is shut and the side string tube 40 is not equalized with the production line 77 or ejection line 74 at the surface. This influx of liquid 33 will cause the pressure of the side string injection line 24 to rise until the combined head pressures of the gas in the side string tube 40 and the liquid in the side string tube 40 are equal to the combined head pressure of the gas and liquid in the production tube 41 at the side string tube 40 attachment port on the mandrel 80. At this point, the difference between the side string injection line 24 pressure at surface and the production tube 41 pressure at surface multiplied by the appropriate liquid gradient pressure factor will give an approximate liquid level 34 in the production tube 41. The reason the liquid level is only approximate is due to the fact that liquid has entered the side string tube 40 to compress the gas in the upper portion of the side string tube 40 which results in two different gradients in the side string tube 40, one for gas and one for influx liquid 33, the level of which is unknown. These pressure measurements are used in this embodiment of the invention by the controller 90 to compute a value representative of the liquid level 34 in the production tube 41. This computed value is then compared to the predetermined set point in the controller 90 to determine when the level of liquid 34 in the production tube 41 reaches the desired level, at which time, the controller 90 will initiate the SSGL artificial lift 10 injection cycle. Thus, the pressure monitoring method of control of the SSGL cycle of this embodiment includes the steps of: one, reiteratively detecting both the side string injection line pressure and the production tube pressure at surface throughout the SSGL non-injection or off cycle as represented in blocks 210 and 234 and generating signals representative thereof; two, calculating a differential pressure between the side string pressure and production tube pressure as represented in block 251 based on the pressure signals, which is approximately representative of the level of liquid in the production tube; three, comparing the calculated differential pressure to a predetermined differential pressure representative of the desired level of liquid in the production tube as represented in block 230 and; four, initiating the SSGL gas injection cycle represented in block 214 when the measured pressure is substantially equal to the predetermined value. As in the first and second embodiments of the invention, a time delay represented in block 216 can be provided.

The improvement of this embodiment over the first two embodiments is that the system now compensates for fluctuations in production line 77 or ejection line 74 (FIG. 4) pressure. In this method, while the exact level of liquid 34 in the production tube 41 is not known, the pressure differential between the pressure in side string injection line 24 (as detected by pressure sensor 92) and the pressure in the ejection line 74 (as detected by pressure sensor 91) will represent a liquid head pressure constant, regardless of the fluctuations in production line 77 or ejection line 74 pressure. The difference between the side string injection line 24 pressure detected by pressure sensor 92 and the ejection line 74 pressure detected by pressure sensor 91 is then used by the controller to reiteratively monitor the level 34 of liquid 32 in the production tube 41 as represented by the pressure differential to determine when the liquid level 34 reaches the predetermined and desired level. The controller 90 then initiates the SSGL 10 injection cycle when the detected liquid level reaches the predetermined and desired liquid level (as detected by pressure) regardless of whether the exact production tube 41 liquid level 34 and annular liquid level 31 are known.

Referring now to FIG. 9, the fourth embodiment of the invention for control of the SSGL cycle includes the steps of: one, injecting a minuscule volume of gas into the side string as represented in block 220 throughout the SSGL non-injection or off cycle; two, simultaneously detecting the side string pressure by pressure sensor 92 at block 210 and production tube pressure by pressure sensor 91 as represented in block 234 and generating pressure signals representative thereof; three, calculating a differential pressure between the production tube pressure and side string pressure based on the pressure signals as represented in block 251, the differential pressure being representative of the level of liquid in the production tube; four, comparing the measured differential pressure to a predetermined differential pressure representative of the desired level of liquid in the production tube as represented in block 230 and; five, initiating the SSGL gas injection cycle as represented in block 214 when the calculated differential pressure is substantially equal to the predetermined differential pressure value. As in the first three embodiments, a time delay as represented in block 216 is desirably provided.

This embodiment, like the previous embodiment, uses the pressure sensor 92 fluidly connected to the side string injection line 24 to sense the pressure increase caused by the influx of liquid 32 into the production tube 41 and the pressure sensor 91 fluidly connected to the ejection line 74 to sense the pressure of the production tube 41. The improvement over the previous embodiment is the injection of a minuscule volume of injection gas from source 20 through the regulator 23 into the side string injection line 24 to reduce the liquid level 33 in the side string tube 40 down to the level of the side string tube 40 connection on the injection mandrel 80 thereby producing a single gradient pressure in the side string tube 40, i.e., gas only. Thus, the differential pressure calculated will be an accurate representation of the liquid head pressure in the production tube 41. The removal of all the influx liquid column 33 in the side string tube 40 results in only a gas gradient in the side string tube 40. At this point, the difference between the side string injection line pressure 24 at surface and the production tube 41 pressure at surface multiplied by the appropriate liquid gradient pressure factor will give a very precise production tube liquid level 34. The difference between the side string injection line 24 pressure detected by pressure sensor 92 and the ejection line 74 pressure detected by pressure sensor 91 can then be used by the controller 90 to compute the liquid level in the production tube 41 and initiate the SSGL 10 injection cycle when the computed liquid level substantially equals the predetermined and desired liquid level as represented by the predetermined set point in the controller.

Referring now to FIGS. 1, 4, 5 and 10, yet another method according to the invention can be used with any of the four embodiments disclosed above. This fifth embodiment of the invention dynamically sets and resets the predetermined artificial lift initiation set point using values from the side string pressure sensor 92, production tube pressure sensor 91, differential pressure sensor 93 and production line pressure sensor 94. The differential pressure sensor 93 is fluidly connected to a measurement orifice or other industry standard gas measurement device in the production line 77 and the pressure sensor 94 is fluidly connected to the production line 77. The pressure sensor 93 and the pressure sensor 94 are electrically connected to the controller to input to the controller signals representative of the pressures sensed by the pressure sensors 93 and 94. The pressure values from sensors 93 and 94 are used to determine the production gas 30 flow rate from the annulus 46 into the production line 77. According to this embodiment of the invention, the predetermined pressure set point (PSI) for the first two embodiments, or differential pressure set point (DP) as used in the third and fourth embodiments to initiate the SSGL injection cycle, is automatically adjusted upwardly as represented in block 260 by the controller 90 to raise the liquid level 31 in the annulus 46. This adjustment, in effect, increases the liquid level DP or PSI value necessary to initiate the injection cycle of the SSGL artificial lift system 10 and thus results in an increased liquid level 31 in the annulus so that the liquid level in the production tube 41 rises farther before initiating the SSGL injection cycle. As the liquid level rises, there will come a time when the gas production will decline within a specified time weighted average, as represented in block 262. The time weighted average is determined through well known statistical analysis for the amount of production over a specified time period or number of SSGL cycles. At that point, controller 90 automatically begins the reduction of the predetermined PSI or DP value set point at block 264 to reduce the liquid level 31 in the annulus 46 by reducing the liquid level PSI or DP value necessary to initiate the SSGL injection cycle. The well bore response in the form of increased volumetric production is then monitored by the controller 90 as represented in block 266. As the production increases within the specified time and volume parameters, the predetermined set point for the desired liquid level will continue to decrease until no more increase in production volume 266 is determined by controller 90 within the specified time or cycle parameters. At this stable production period, the PSI or DP values in the controller 90 enter a dormant or nonadjustment state at block 268 for an arbitrary period before the controller 90 will initiate another change to the predetermined set point.

In this dynamic and interactive method, maximum production down the production line 77 is balanced with optimum liquid level 31 in the annulus 46 to best automatically economize the volume of injection gas from source 20 necessary to sustain production. At the end of the specified non-management period, the liquid level management procedure described above will be repeated until the next dormant period. It is to be understood that the automated liquid level management method will be done with adjustments taking place over the course of many hours and possibly days, the end result being the maximum liquid level sustainable within a given well bore with minimal interference with production and a reduced need of injection gas.

A sixth embodiment of the invention will now be described with reference to FIGS. 1 and 11. A magnetic sensor (MSO) 95 is attached to the production tube 41 or lubricator 62 to detect the arrival of the plunger 82 at surface subsequent to the injection of a blast of injection gas from source 20 down the side string tube 40 during the injection cycle of the SSGL artificial lift system 10 to control the ejection of the liquid 32 in the production tube 41 into the ejection line 74. The magnetic sensor 95 is electrically connected to the controller 90 to input to the controller a signal representative of the magnetic flux sensed by the magnetic sensor 95. The plunger 82 travel time from the initiation of the SSGL injection cycle to surface is calculated by the controller 90 and used by the controller 90 to adjust the SSGL artificial lift system 10 injection gas volumes from source 20 to accommodate a varying liquid level 34 in the production tube 41, thereby controlling the average velocity of the plunger 82 in the production tube 41 and the impact of the plunger into the lubricator 62 as the liquid 32 in the production tube 41 is being ejected into the ejection line 74. The magnetic sensor detects the arrival of the plunger as represented in block 350 and transmits a signal representative of the plunger arrival to the controller 90. The controller 90 in turn calculates the trip time for the plunger 82 and compares the detected plunger trip time over a time weighted average (which is determined through well known statistical methods for a number of detected plunger trip times over a predetermined number of cycles) with a predetermined plunger trip time set point and adjusts the volume of gas injected during the subsequent SSGL injection cycles so that the detected trip time matches the predetermined trip time set point. For example, if the calculated average trip time of the plunger at block 352 does not equal the predetermined set point as represented in block 354 and is longer than the predetermined set point as represented in block 356, the gas volume in the subsequent SSGL injection cycles is increased as represented in block 360. If the detected plunger trip time is less than the predetermined trip time set point represented at block 356, the gas volume during the subsequent SSGL injection cycles is decreased as represented in block 358. The predetermined plunger trip time set point is determined by dividing the distance between the bottom of the production tube and the surface of the ground by the desired average rate of travel for the plunger 82 from the bottom of the production tube 41 to the surface. This value is then used by the controller 90 to adjust the SSGL artificial lift system 10 injection cycle so as to either increase or decrease the plunger 82 trip time to allow the plunger 82 reach the sensor 95 at the desired time. The sensor 95 can be any suitable magnetic sensor which measures a change in magnetic flux. An example of a suitable sensor is an Omni sensor manufactured by OKC Products Company. This method and apparatus of this embodiment can be used with any of the five embodiments discussed above.

Referring now to FIG. 12 and 13, an alternate arrangement for use with the sixth embodiment is shown. Although the system as illustrated in FIGS. 1-3 show a plunger 82 for removing liquid from the production tube, it is not always necessary nor desirable to use a plunger. Plungers are most commonly used in production tubes with little or no rat hole and relatively short liquid columns to be ejected from the production tube. The use of a plunger in this instance significantly reduces the percentage of liquid loss. However, in production tubes having rat holes and large columns of liquid, gas can be injected directly into the production tube without a plunger from the side string without a significant percentage of liquid loss. Common production tubes may contain as much or even more than 150 feet of liquid. In the event that a plunger is not used, it is still desirable to adjust the volume of gas injected into the side string to control the average liquid ejection velocity in the most efficient manner. For this purpose, a donut-shaped lubricator plunger 280, preferably constructed of ferromagnetic material, is supported on a flange 282 within lubricator 62 or production tube 41. A magnetic sensor (MSO) 95 is attached to the lubricator 62 or production tube 41 to detect movement of the lubricator plunger 280. When gas is injected from source 20 down the side string tube 40 during the injection cycle of the SSGL artificial lift system 10 to eject the column of liquid 32 from the production tube 41 into the ejection line 74, an upper portion of the liquid column will contact the lubricator plunger 280 when it arrives at surface. The force of the liquid displacing upward will move the lubricator plunger 280 in the direction of arrow 284 until lubricator plunger 280 contacts compression spring 286 and trips MSO 95. Thereafter, the lubricator plunger 280 will fall under gravity and rest on flange 282 until the next SSGL injection cycle. The signal from MSO 95 is transmitted to the controller 90 and can be manipulated in the same way as the method of the sixth embodiment for adjusting the SSGL injection cycle.

In embodiments one through six, the injection of gas from the source 20 through the injection valve 21 and down the side string tube 40 is commonly described as a blast of gas which infers that the injection valve 21 is fully open from the source 20 to the side string tube 40. However, under certain conditions such as a well having a deep rat hole, as shown in FIGS. 2 and 3, or in a well that may have a high bottom hole or head pressure in the formation 51, it may be desirable to inject a sustained and controlled volume from the source 20 through the injection valve 21 and side string tube 40 and into the production tube 41 to the surface. To this end, the controller 90 may be operably adapted to position the injection valve 21 in a partially open position to constantly inject gas from the source 20 through the side string tube 40 to constantly lift liquid 32 to the surface. The injection valve 21 may be adjusted to a more open or restricted position to maintain the side string tube 40 pressure or differential pressure within the desired parameters according to any of the pressure monitoring methods previously described. This sustained and controlled volume is to be differentiated from the relatively small or minuscule volume of gas injected into the side string tube 40 for clearing any liquid from the side string tube. The minuscule volume of gas is insufficient to raise the liquid in the production tube to the surface.

In part 2, as shown in FIGS. 15 and 16, bore holes using a beam pump 300 and a progressive cavity pump 307 are employed for raising the liquid 32 in the production tube 41 to the surface of the ground. FIG 20 shows a submersible pump system for raising the liquid 32 in the production tube 41 to the surface of the ground. While each of these pump artificial lift systems 10 incorporate the side string tube 40 method of liquid level 31 detection, they vary from the SSGL method of artificial lift in that the side string tube 40 termination point 48 is in the annulus 46 because in these lift systems the production tube 41 will be completely full of liquid 32 to surface when the artificial lift system 10 is in operation. Therefore, the side string tube 40 termination point 48 is in the annulus 46 to detect the level of liquid 31 in the bore hole to provide for control of the artificial lift system 10. Also, while the termination point 48 of the side string tube 40 is demonstrated as being substantially equal with the position of the pumps 310, 315 and 320 (FIGS. 15, 16 and 20) in the well bore it is to be understood that the termination point 48 of the side string tube 40 may be lower or higher than the pump as long as the side string tube 40 termination point 48 is below the lowest point in the well bore that the operator desires to control liquid level 31. Further, in FIGS. 15, 16, 19, 20 and 23 pressure sensor and transmitter 91 is illustrated as being fluidly attached to the annulus to detect the differential pressure between the side string tube 40 and the annulus 46 to detect the liquid level in the bore hole 43. Alternatively, pressure sensor 94 could serve the dual purpose of production line pressure 77 and annulus 46 pressure detection because the annulus 46 and the production line 77 are substantially equalized or alternatively, sensors 91 and 92 can be replaced by a single transducer (not shown) that directly measures the difference between the line pressures..

Thus, the invention can be used to control the operation of a beam pump 300, a progressive cavity pump 307 and a submersible pump 320.

Referring to FIGS. 15 and 16, sucker rod 304 is connected to the pumps 315 or 310 at a lower portion of the production tube 41 and to a beam pump head 300 or progressive cavity (PC) pump head 307 at an upper portion to drive the pump in a conventional manner. The barrel pump 315 or PC pump stator 310 is positioned at the lower portion of the well bore and is adapted to pump liquid 32 from the bottom of the bore hole to the surface of the ground. A side string tube 40 extends down along the outside of the production tube 41 in the annulus 46 and is open at a bottom portion thereof to be fluidly connected with and terminated in the annulus 46. Electric or hydraulic lines 418 are connected to the prime mover 412 to drive the beam pump 300 or PC pump head 307 to operate the pumps 315 or 310 respectively. The prime mover 412 is connected to a controller 414 which is connected to the controller 90 and controller 90 is use to control controller 414 to maintain the level of liquid 31 in the bore hole above a predetermined minimum and preferable also below a predetermined maximum as measured by any of the pressure measurement techniques disclosed herein. FIGS. 17, 18 and 19 are alternate well bore and well head configurations that can be used with the beam pump 300 or PC pump 307 artificial lift systems.

Referring to the submersible pump artificial lift system 10 in FIG. 20 the submersible pump 320 is located at the lower portion of the production tube 41. In this arrangement the submersible pump 320 is attached to the production tube 41 and an electrical cord 322 passes through the well head 60 and is operably attached to the submersible pump 320 to lift the liquid 32 from the bottom of the bore hole to the surface of the ground and a side string tube 40 has a termination point 48 in the annulus 46 to allow for the detection of liquid level 31 in the annulus 46. A prime mover control 414 is connected to the electrical cord 322 and to the controller 90 to allow controller 90 to control the submersible pump 320 to maintain the liquid level 31 in the bore hole above a predetermined minimum and preferable also below a predetermined maximum as measured by any of the pressure measurement techniques disclosed herein. FIGS. 21, 22 and 23 are alternate bore hole and wellhead assemblies that can be used with the submersible pump artificial lift system 10.

In the embodiments of the invention as applied to the beam pump 300, progressive cavity pump 307 and the submersible pump 320 artificial lift systems 10, the pressure sensor and transmitter 91 is operably connected to the well casing 42 to detect the pressure in the annulus 46 and the side string tube 40 termination point 48 is in the annulus to allow for detection of the liquid level 31 in the well bore. The embodiments that will now be described can be used with, but are not limited to, the pump systems herein disclosed. Like numerals in the previous embodiments have been used to described like parts.

A method according to a seventh embodiment of the invention includes the operation and control of a pump associated with artificial lift systems. This method is similar to the first embodiment with the exception that a pump is controlled for removing liquid from the well bore instead of the gas injection. The basic method of controlling the pumping cycle as shown in FIG. 24, includes reiteratively monitoring the annulus 46 liquid level 31 by detecting the side string (sst) pressure with pressure sensor 92 as represented in block 210. The controller 90 then compares the detected side string pressure to the predetermined set point as represented at block 215. If the side string pressure substantially equals the predetermined set point, the side string pressure is again detected. When the well bore liquid level (as indicated by pressure) no longer equals the predetermined set point in the controller 90, controller 90 will alter pump operations at block 240. Altering of pump operations at block 240 can include but is not limited to increasing or decreasing pump speed and starting the pump or stopping the pump by use of controller 90 to control the prime mover control 414 as shown in FIGS. 15, 16 and 20. After the altering the pump operations at block 240 a time delay as represented at block 218 is activated. This time delay allows for a period of stable pump operation to determine the effect of the altered pump operation on the liquid level 31 in the well bore.

As with the first embodiment, this method will require the greatest amount of operator intervention to work with nominal efficiency. This method will only give a rough estimate of the liquid level 31 in the annulus 46 due to the fact that there will be an influx of liquid 32 into the side string tube 40 the level of which is unknown. This method is also prone to error in that the predetermined "alter pump operation" pressure set point programmed into the controller 90 is subject to errors that can be induced by fluctuations in production line 77 pressures (FIGS. 15, 16, 19, 20 and 23) due to the fact the operator must assume an average production line 77 pressure when programming the predetermined set point into controller 90. Therefore, this method will perform best on wells with substantial rat hole 45 (FIGS. 17, 18, 21 and 22) or with very high liquid levels 31 where side string tube 40 pressure will become noticeably elevated due to the annulus 46 liquid gradient. Further, this method is susceptible to errors that may be induced by any leak in the side string injection line 24 at surface causing a reduced side string tube 40 pressure and therefore an inability to detect the annulus 46 liquid level 31.

An eighth embodiment according to the invention is similar to the second embodiment with the exception that a pump is used for fluid removal from the well bore, as represented in FIG. 25. This embodiment incorporates all the steps of the seventh embodiment illustrated in FIG. 24 with the added improvement step of injecting a minuscule volume of injection gas from source 20 through a regulator 23 into the side string injection line 24 to remove the influx liquid level 33 in the side string tube 40 down to the level of termination point 48 of the side string tube 40 in the annulus 46 so that the pressure in the side string injection line 24 more accurately represents the liquid head pressure in the annulus 46. This method for controlling the artificial lift system includes injecting a minuscule volume of gas into the side string at block 220 while simultaneously detecting the side string pressure by pressure sensor 92 as a measure of the level of liquid in the annulus represented at block 210. When the gas is injected, the pressure at surface in the side string injection line 24 will rise until all of the liquid is expelled from the side string injection tube 40, at which time the pressure in the side string injection line at surface 24 will stabilize. The volume of injected gas can be monitored or can be estimated during this step. The removal of all the influx liquid 33 (with its accompanying unknown level) in the side string tube 40 causes only a gas gradient to be present in the side string tube 40 and thus leads to a more precise liquid level computation in the annulus 46. The operator can then use this more precise liquid level to enter a predetermined liquid level value into the controller 90 to be referenced by the controller 90 at block 215. If the detected value is no longer equal to the predetermined value at 215 the pump operation is then altered at block 240 based on the pressure criteria. The altering of pump operation is automatically initiated by the controller 90 controlling the prime mover control 414 (FIGS. 15, 16 and 20) when the detected pressure is no longer equal to the predetermined set point in the controller 90 as represented at blocks 210 and 215. As in the method of FIG. 24, a time delay represented at block 218 can be provided to allow for a period of stable pump operation to determine the effect the altered pump operation has on the liquid level 31 in the bore hole.

While this method is more accurate than the method of FIG. 24, it is still prone to the same weakness as the first and seventh methods in that fluctuations in production line 77 pressures are not compensated for and it may be necessary for the operator to assume an average production line 77 pressure when programming the controller 90 to alter pump operation 240. Therefore, this method will perform best on wells with substantial rat hole 45 (FIGS. 17, 18, 21 and 22) or with a high liquid level 31 where side string injection line 24 pressure will become noticeably elevated due to annulus 46 liquid gradient during the injection of the minuscule quantity of gas into the side string injection line 24.

The ninth embodiment of a method according to the invention is shown most clearly in FIGS. 15, 16, 19, 20, 23 and 26, and is similar to the third method, with the exception of the operation of a pump for artificially lifting the liquid from the bore hole. The pressure sensor 92 senses the side string injection line 24 pressure increase caused by the influx of liquid 33 into the side string tube 40 and a pressure sensor 91 fluidly connected to the annulus 46 senses the pressure of the annulus 46. The pressure sensors 91 and 92 are connected to the controller 90 by wires or through a transmitter to input a signal from the sensors 91 and 92 representative of the pressure in the annulus 46 and the side string injection line 24. The liquid 32 in the annulus 46 will rise and enter the side string tube 40. However, the influx of liquid 33 into the side string tube 40 will only be a portion of the level of the liquid in the annulus 46 because the side string 40 is not equalized with the production line 77 at the surface. This influx of liquid 33 will cause the pressure of the side string injection line 24 to rise until the combined head pressures of the gas in the side string tube 40 and the liquid in the side string tube 40 are equal to the combined head pressure of the gas and liquid in the annulus 46 at the termination point 48 of the side string tube 40. At this point, the difference between the side string injection line 24 pressure at surface and the annulus 46 pressure at surface multiplied by the appropriate liquid gradient pressure factor will give an approximate liquid level 31 in the annulus 46. The reason the liquid level is only approximate is due to the fact that liquid has entered the side string tube 40 to compress the gas in the upper portion of the side string tube 40 which results in two different gradients in the side string tube 40, one for gas and one for influx liquid 33, the level of which is unknown. These pressure measurements are used in this embodiment of the invention by the controller 90 to compute a value representative of the liquid level in the annulus 46. This computed value is then compared to the predetermined set point in the controller 90 to determine when the level of liquid 31 in the annulus 46 reaches a point either greater or less than the desired level, at which time, the controller 90 will alter pump operation. Thus, referring to FIG. 26, the pressure monitoring method of control of artificial lift systems incorporating a pump includes the steps of: one, reiteratively detecting both the side string injection line 24 pressure and the annulus pressure 46 at surface as represented in blocks 210 and 236 and generating signals representative thereof; two, calculating a differential pressure between the side string pressure and annulus pressure as represented in block 250 based on the pressure signals, which is approximately representative of the level of liquid in the annulus 46; three, comparing the calculated differential pressure to a predetermined differential pressure representative of the desired level of liquid in the annulus 46 as represented in block 235 and; four, altering pump operation in block 240 when the measured pressure is no longer substantially equal to the predetermined value. As in the previous embodiment of the invention, a time delay represented in block 218 can be provided to allow for a period of stable pump operation to determine the effect the altered pump operation has on the liquid level 31 in the well bore.

The improvement of this embodiment over the seventh and eighth embodiments is that the system now compensates for fluctuations in production line 77 pressure. In this method, while the exact level of liquid 31 in the annulus 46 is not known, the pressure differential between the pressure in side string injection line 24 (as detected by pressure sensor 92) and the pressure in annulus 46 at surface (as detected by pressure sensor 91) will represent a liquid head pressure constant, regardless of the fluctuations in production line 77 pressure. The difference between the side string injection line 24 pressure detected by pressure sensor 92 and the ejection line 74 pressure detected by pressure sensor 91 is then used by the controller to reiteratively monitor the level 31 of liquid 32 in the annulus 46 as represented by the pressure differential to determine when the liquid level 31 reaches the predetermined value. The controller 90 then alters the pump operation when the detected liquid level pressure differential value no longer equals the predetermined set point regardless of whether the exact annulus 46 liquid level 31 is known. Again, alteration of pump operation can include but is not limited to increasing or decreasing pump speed and starting or stopping the pump system.

Referring now to FIGS. 15, 16, 20 and 27, the tenth embodiment of the invention for control of artificial lift systems incorporating a pump is similar to the fourth embodiment, and includes the steps of: one, injecting a minuscule volume of gas into the side string line 24 as represented in block 220; two, simultaneously detecting the side string pressure 24 by pressure sensor 92 at block 210 and annulus 46 pressure by pressure sensor 91 as represented in block 236 and generating pressure signals representative thereof; three, calculating a differential pressure between the annulus 46 pressure and side string line 24 pressure based on the pressure signals as represented in block 250, the differential pressure being representative of the level of liquid in the annulus 46; four, comparing the measured differential pressure to a predetermined differential pressure representative of the desired level of liquid in the annulus 46 as represented in block 235 and; five, altering pump operation represented in block 240 when the calculated differential pressure is no longer substantially equal to the predetermined differential pressure value. As in the previous three embodiments, a time delay as represented in block 218 is desirably provided.

This embodiment, like the previous embodiment, uses the pressure sensor 92 fluidly connected to the side string injection line 24 to sense the pressure increase caused by the influx of liquid 32 into the side string tube 40 and the pressure sensor 91 fluidly connected to sense the annulus 46 pressure. The improvement over the previous embodiment is the injection of a minuscule volume of injection gas from source 20 through the regulator 23 into the side string injection line 24 to reduce or eliminate the liquid level 33 in the side string tube 40 down to the level of the side string tube termination point 48 thereby producing a single gradient pressure in the side string tube 40, i.e., gas only. Thus, the differential pressure calculated will be a very precise representation of the liquid head pressure in the annulus 46. The removal of all the influx liquid column 33 in the side string tube 40 results in only a gas gradient in the side string tube 40. At this point, the difference between the side string injection line pressure 24 at surface and the annulus pressure 46 at surface multiplied by the appropriate liquid gradient pressure factor will give a very precise annulus 46 liquid level 31. The difference between the side string injection line 24 pressure detected by pressure sensor 92 and annulus pressure sensor 91 can then be used by the controller 90 to compute the liquid level in the annulus 46 and alter pump operation when the computed liquid level no longer substantially equals the predetermined level as represented by the predetermined set point in the controller.

Referring now to FIGS. 10, 15, 16 and 20 yet another method according to the invention can be used with any of the embodiments seven through ten disclosed above. This eleventh embodiment of the invention is similar to the fifth embodiment and dynamically sets and resets the predetermined set point for altering pump operation using values from the side string pressure sensor 92, annulus pressure sensor 91, the differential pressure sensor 93 and production line pressure sensor 94. The differential pressure sensor 93 is fluidly connected to a measurement orifice, or other industry standard gas measurement device capable of outputting a signal representative of gas volume, in the production line 77 and the pressure sensor 94 is fluidly connected to the production line 77. The pressure sensor 93 and the pressure sensor 94 are electrically connected to the controller to input to the controller signals representative of the pressures sensed by the pressure sensors 93 and 94. The pressure values from sensors 93 and 94 are used to determine the production gas 30 flow rate from the annulus 46 into the production line 77. According to this embodiment of the invention, the predetermined pressure set point (PSI) for the embodiments seven and eight, or differential pressure set point (DP) as used in embodiments nine and ten to alter pump operation, is automatically adjusted upwardly as represented in block 260 by the controller 90 to raise the liquid level 31 in the annulus 46. This adjustment, in effect, increases the liquid level DP or PSI value necessary to alter pump control and thus results in an increased liquid level 31 in the annulus so that the liquid level in the annulus will be maintained at a greater level than before altering pump operations. As the liquid level rises, there will come a time when the gas production will decline within a specified time weighted average, as represented in block 262. The time weighted average is determined through well known statistical analysis for the amount of production over a specified time period. At that point, controller 90 automatically begins the reduction of the predetermined PSI or DP value set point at block 264 to reduce the liquid level 31 in the annulus 46 by reducing the liquid level PSI or DP value necessary to alter pump operation. The well bore response in the form of increased volumetric production is then monitored by the controller 90 as represented in block 266. As the production increases within the specified time and volume parameters, the predetermined set point for the desired liquid level will continue to be reduced until no more increase in production volume 266 is determined by controller 90 within the specified time period. At this stable production period, the PSI or DP values in the controller 90 enter a dormant or nonadjustment state at block 268 for an arbitrary period before it will initiate another change to the predetermined set point.

In this dynamic and interactive method, maximum production down the production line 77 is balanced with optimum liquid level 31 in the annulus 46 to best automatically economize the energy required by the pump to lift the liquid to the surface of the ground and sustain production. At the end of the specified non-management period, the liquid level management procedure described above will be repeated until the next dormant period. It is to be understood that the automated liquid level management method will be done with adjustments taking place over the course of many hours and possibly days, the end result being the maximum liquid level sustainable within a given well bore with minimal interference with production and a reduced need of energy for the prime mover 412.

A twelfth embodiment of a method according to the invention in an artificial lift system (FIGS. 15, 16 and 20), to reduce or control the power requirements of a pump system during peak load hours, as shown in FIG. 28.

The method entails the responsible use of electrical energy by reducing the power requirement of the artificial lift system 10 during certain periods of the day with minimal well production interference by altering the artificial lift system 10 operation to reduce or increase the liquid level 31 in the annulus 46. To this end, the liquid level 31 in the annulus 46 is detected from the side string pressure or from the differential pressure as described in embodiments seven through ten and as represented in block 390. Real time is monitored by the control 90 at block 391 and compared to the relevant specified time period in blocks 392 or 400. Subsequently, the predetermined pressure set point for altering pump operation is adjusted in blocks 393 or 401 or the pump is shut down in block 405. The predetermined PSI or DP set point in block 393 or 401 is compared in block 394 to the detected side string or differential pressure in block 390. Subsequently if the detected pressure in block 390 is determined in block 394 to be greater than the appropriate predetermined PSI or DP set point in block 393 or 401 the state of pump operation will be monitored in block 397 to determine if the pump needs to be started in block 398 or if the pump speed should be increased in block 399 if a variable speed drive is available on the particular artificial lift system. Further, if at block 394 it is determined that the side string pressure or differential pressure value detected at block 390 is not greater than the predetermined value set in block 393 or 401 the pressure as detected in block 390 will then be compared in block 395 to the predetermined value set forth in block 393 or 401 to determine if the detected pressure represents a liquid level value that is less than the optimum level of liquid in the well bore. Next, the detected pressure in block 390 is compared in block 402 to a predetermined minimum PSI or DP as provided at block 402. This predetermined minimum can be the reduction value set in block 401 or the normal operational value set in block 393, or any other value that prevents pump damage. If the measured pressure is not less than the predetermined value, the pump speed can be reduced at block 403 in wells using an artificial lift system incorporating a variable speed drive. Alternatively, the pump can be shut down at block 405 if the side string pressure or differential pressure has declined below the predetermined minimum value set forth in block 402 to keep the artificial lift system from pumping off and damaging itself. A delay time is provided in block 396 to allow for a period of stable pump operation to determine the effect the altered pump operation has on the liquid level 31 in the bore hole.

Thus, a very desirable method of energy efficiency based on liquid level detection in a bore hole to control the artificial lift system by the above method is demonstrated. As is commonly known, peak load hours require utility companies to invest large sums to meet the high demand caused by residential use for a short period in the morning and evening. Often oil and gas wells are drilled in great numbers in small geographical areas and use electrical power from the same power grid as supplies the surrounding residences. If the power requirements for the oil or gas well artificial lift systems can be reduced or eliminated during the peak residential load hours a benefit will be realized by all the parties involved in electricity production and usage. In this method time is monitored relative to the peak load time established by the electrical utility company and pump operations are altered to balance the liquid removal requirements of the well bore and reduce energy consumption at an appropriate time. The pump artificial lift system can be shut down to prevent the system from drawing power during peak hours but this shut down may cause the liquid level to rise in the well bore and reduce production down the gas production line. In this new and unique method the controller detects a time prior to peak load hours and adjusts the predetermined set point of liquid level in the well bore to a minimum value. Subsequently the pump operation is altered to reduce the liquid level in the well bore to substantially equal the predetermined value then during the peak load hours the pump system can be shut down or operated at a reduced speed to either eliminate or reduce the artificial lift system power draw from the electrical grid. Further, because the liquid level has been reduced to a minimum level the empty rat hole in the well becomes storage for liquid entering the well bore to minimized the effect of liquid level on production volumes due to the fact the liquid must first fill the rat hole before it can begin to cover the productive formation and interfere with production. In this method, while the pump will require increased amounts of energy to reduce the liquid level into the rat hole below the productive formation, the energy will be required at an off peak load time when the electrical grid has power to spare. In this embodiment the prudent and timely use of electrical energy will benefit all parties involved with the electrical grid while allowing the operator minimize impact on production.

Referring now to FIG. 14, a plurality of artificial lift systems 10 having a respective local controller 90 can be arranged at a number of well sites. Each controller 90 includes a telemetry unit 290 that receives signals from pressure sensors 91, 92, 93, 94 and MSO 95, and any other system parameters and then transmits them to data receiver and control transmitter unit 292 in a well known manner. These signals are then transferred to a central controller 294 that can include a computer. The controller computer 294 separates, processes and performs the logic functions on the data for each well. The updated information is then transmitted back to the respective controller 90 through control transmitter unit 292 and the respective telemetry unit 290 to operate each well following any of the embodiments previously described, depending on each well's particular needs and the operator's preferences. In place of the telemetry unit 290, conventional electrical lines can be used. Although a separate local controller 90 and remote central controller 294 have been described, it is to be understood that a single controller could be located at the remote location. Signals are directly transferred from the well and processed in the central controller 294.

While particular embodiments of the invention have been shown, it will be understood, of course, that the invention is not limited thereto since modifications may be made by those skilled in the art, particularly in light of the foregoing teachings. For example, each method presented is capable of functioning as a stand alone improvement or being combined with any other of the methods presented to create either a partially dynamic or fully dynamic and interactive artificial lift control methods that can be used with the SSGL or pump artificial lift systems.

Throughout the specification and claims, the words "comprise", "comprises" and "comprising" are used in a non-exclusive sense.

THE CLAIMS DEFINING THE INVENTION ARE AS FOLLOWS:

1. In a method of producing gas from a gas and liquid containing underground stratum in which a well bore extends between a ground surface and the underground stratum and the well bore has a casing, and a production tube defining an annulus through which the gas from the underground stratum passes and is collected at the ground surface through a production line connected to the annulus, the production tube extending from the ground surface and into fluid communication with the gas and liquid containing stratum and through which the liquid is collected from the well bore and removed to the ground surface by the injection of gas at a predetermined rate down a side string tube which extends down through the annulus from the ground surface and is connected to a lower portion of the production tube to thereby release the gas from the gas and liquid containing underground stratum to the casing and production line, the improvement comprising the steps of:

monitoring the rate of gas production in the production line and adjusting the predetermined rate at which gas is injected into the side string tube to maximise gas production in the production line.

2. In a method of producing gas from a gas and liquid containing underground stratum in which a well bore extends between a ground surface and the underground stratum and the well bore has a casing and a production tube defining an annulus through which the gas from the underground stratum passes and is collected at the ground surface through a production line connected to the annulus, the production tube extending from the ground surface and into fluid communication with the gas and liquid containing stratum and through which the liquid is collected from the well bore and removed to the ground surface by the injection of a volume of gas down a side string tube which extends through the annulus from the ground surface and is connected to a lower portion of the production tube to

thereby release the gas from the gas and liquid containing underground stratum to the casing and production line, the improvement comprising the steps of:

measuring the time during which the liquid in the production tube is artificially raised to the ground surface;

comparing the measured liquid rise time with a predetermined liquid rise time; and

adjusting the volume of gas injected into the production tube during a subsequent injection step until the measured liquid rise time is substantially equal to the predetermined liquid rise time.

3. A method of producing gas according to claim 2 wherein a plunger is provided in the production tube and is adapted for travel in the production tube between lower and upper portions of the production tube, and wherein the step of measuring the time at which the liquid in the production tube is artificially raised includes computing the time for the plunger to arrive at the ground surface from the initiation of the injection of the volume of gas;

and wherein the step of comparing the measured time includes comparing the plunger arrival time with a predetermined arrival time;

and wherein the step of adjusting the volume of injected gas includes the steps of:

decreasing the volume of gas injected during a subsequent gas lift injection cycle if the plunger arrival time is less than the predetermined arrival time; and

increasing the volume of gas injected during a subsequent gas lift injection cycle if the plunger arrival time is greater than the predetermined arrival time.

4. A method of producing gas according to claim 3 wherein the step of comparing the plunger arrival time is performed for an average plunger arrival time taken over a plurality of gas injection steps.

5. A method of producing gas according to claim 2 wherein the step of measuring the time at which the liquid

in the production tube is artificially raised includes the step of measuring the time for a column of liquid in the production tube to arrive at the ground surface from initiation of the injection of the volume of gas;

and wherein the step of comparing the measured time includes comparing the liquid column arrival time with a predetermined arrival time;

and wherein the step of adjusting the volume of injected gas includes the steps of:

decreasing the volume of gas injected during a subsequent gas lift injection cycle if the liquid column arrival time is less than the predetermined arrival time; and

increasing the volume of gas injected during a subsequent gas lift injection cycle if the liquid column arrival time is greater than the predetermined arrival time.

6. A method of producing gas according to claim 5 wherein the step of comparing the liquid column arrival time is performed for an average liquid column arrival time taken over a plurality of gas injection steps.

Dated this 20th day of March 2000

~~MICHAEL D HERSHBERGER~~ John E. McChanny

By their Patent Attorneys

GRIFFITH HACK

Fellows Institute of Patent and

Trade Mark Attorneys of Australia

AUSTRALIAN PATENT OFFICE SEC 113

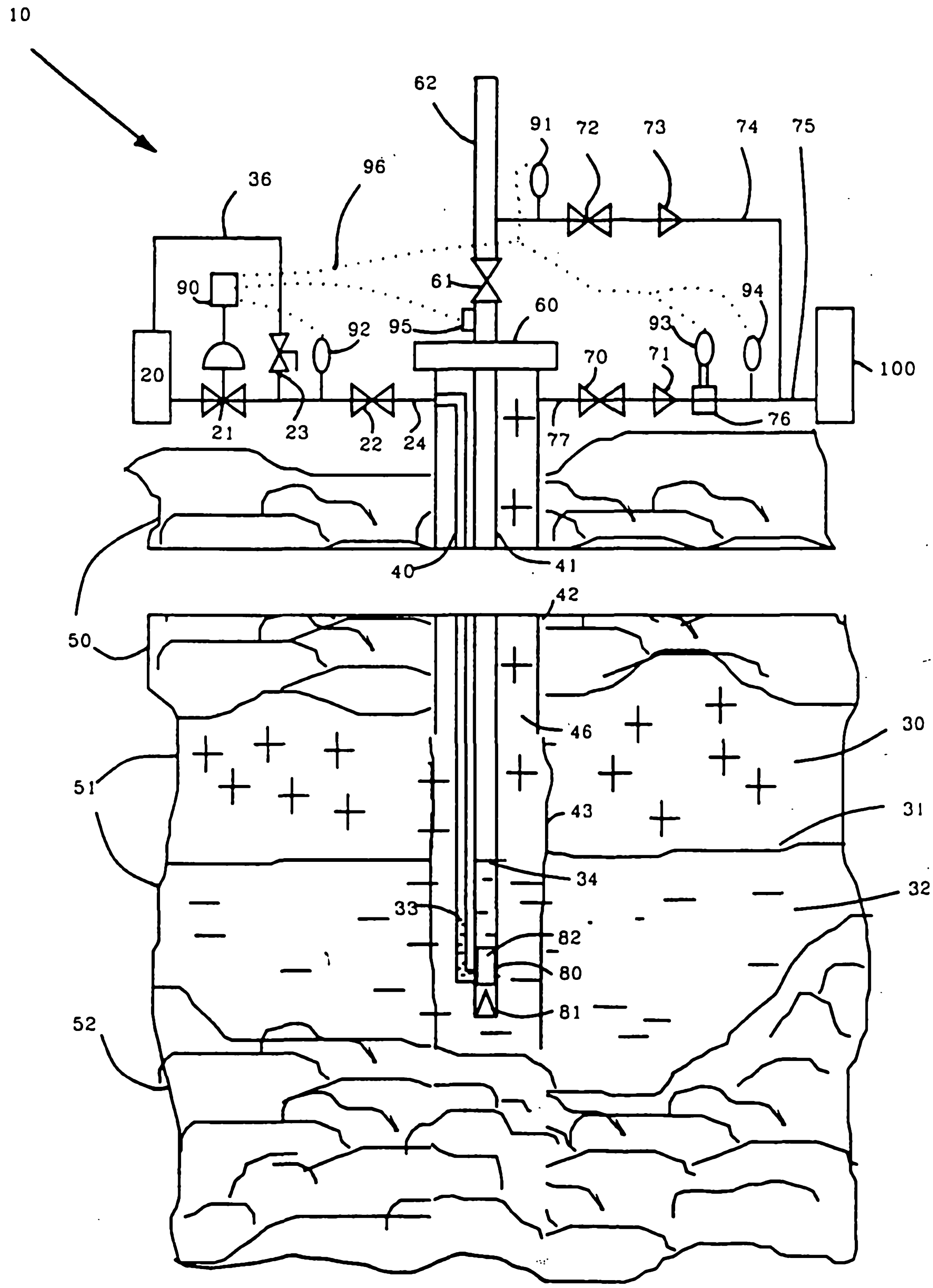
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Fig. 1

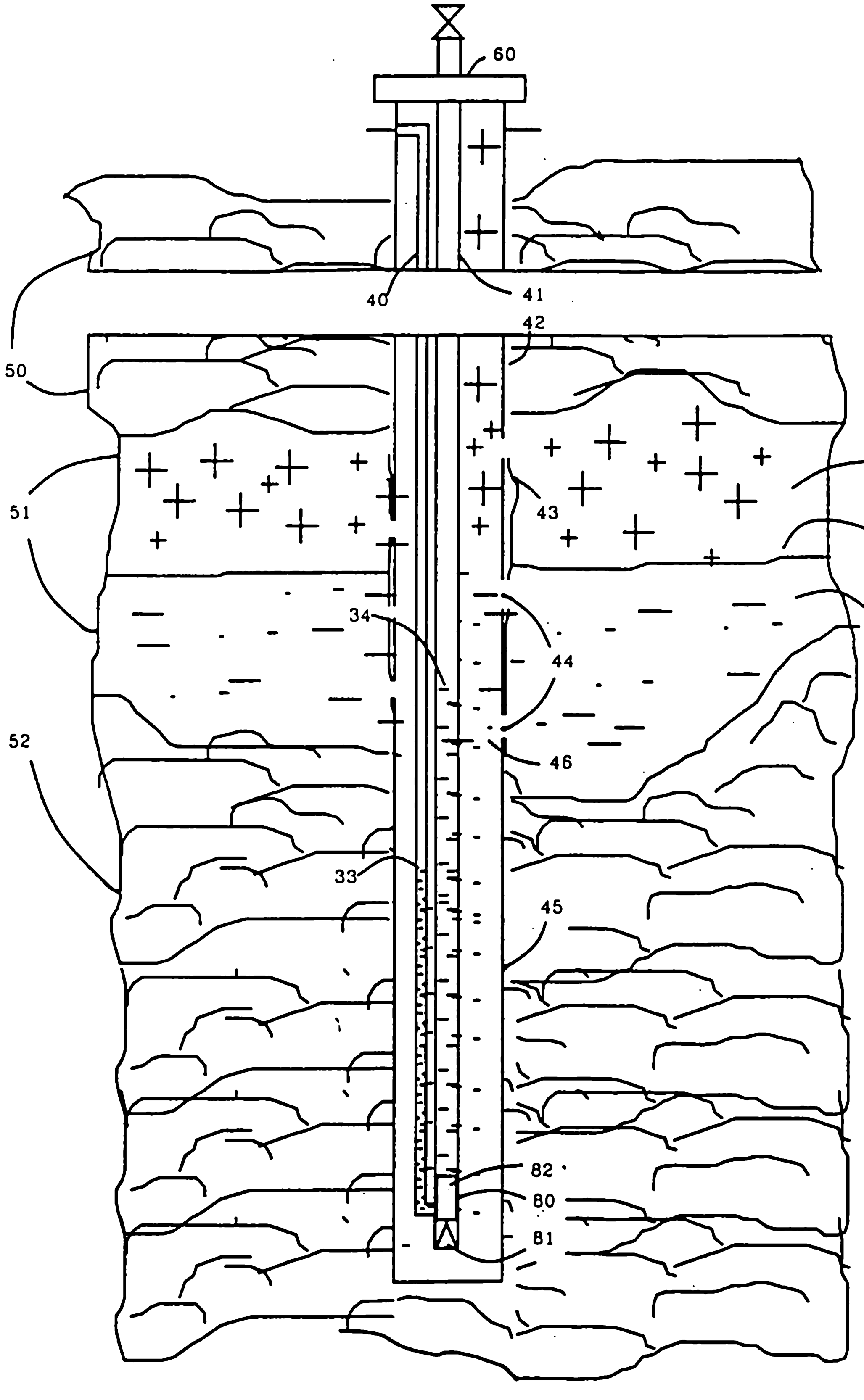

Fig. 2

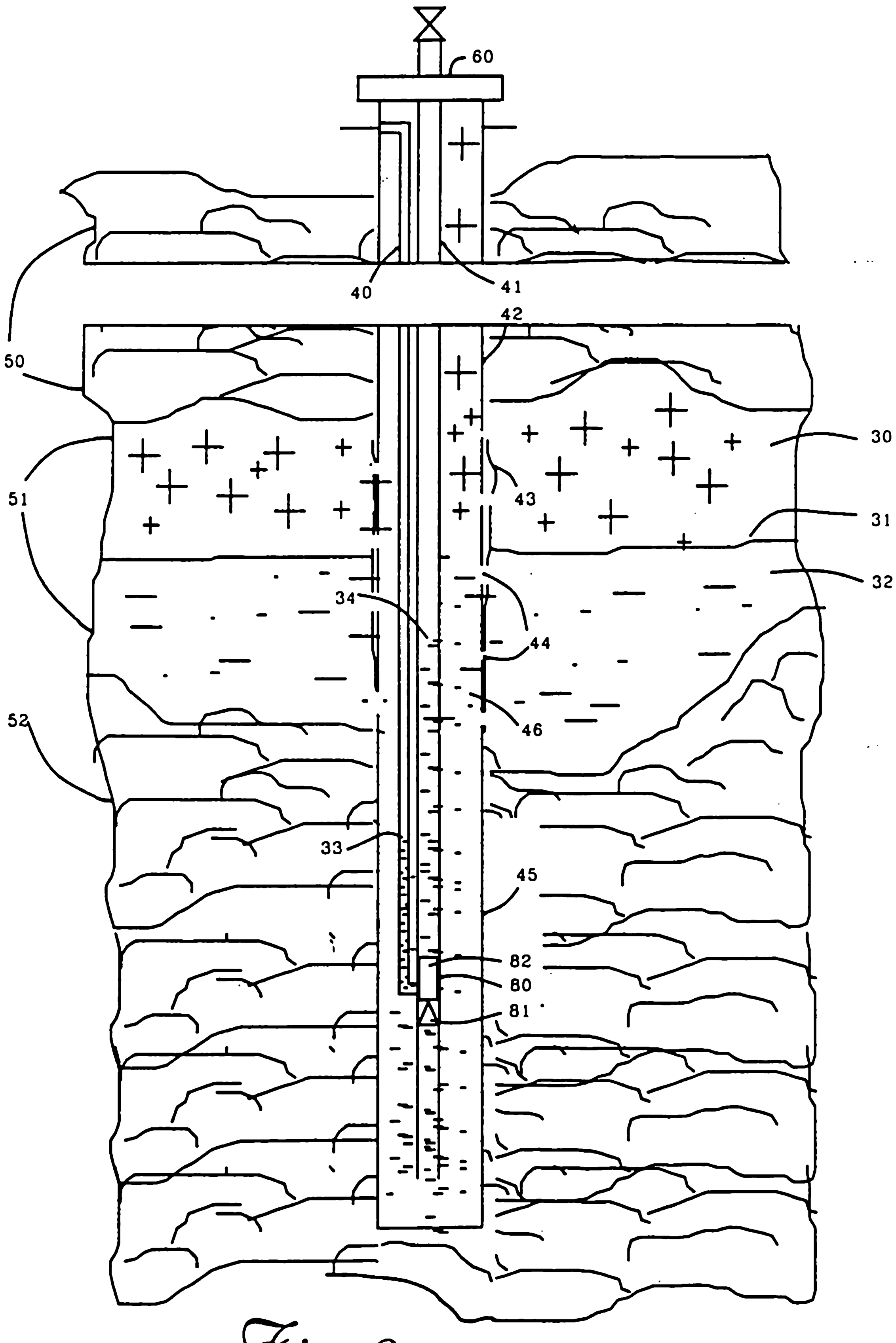

Fig. 3

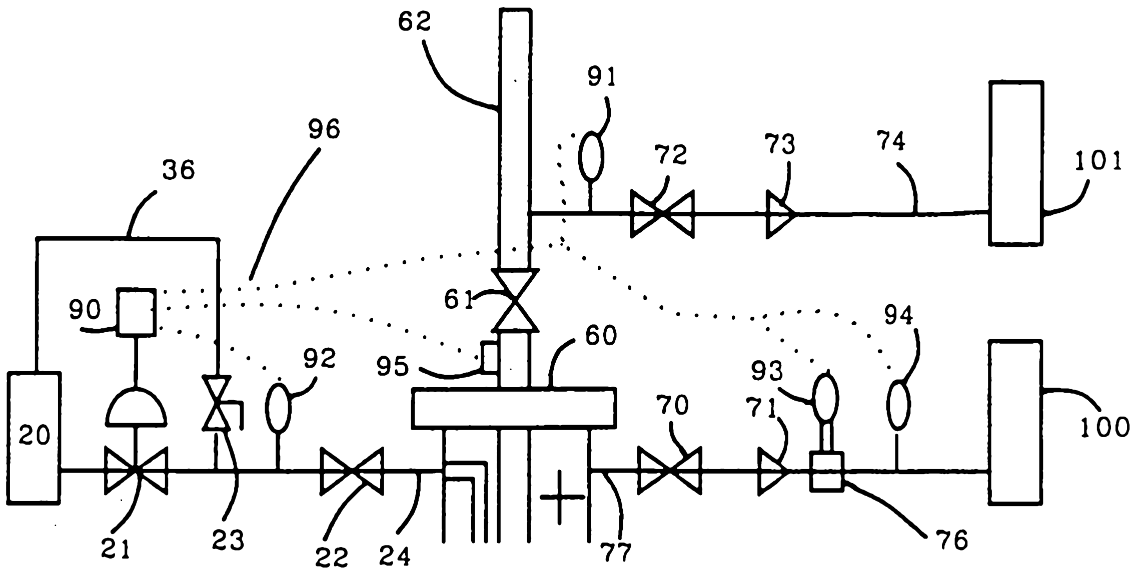
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Fig. 4

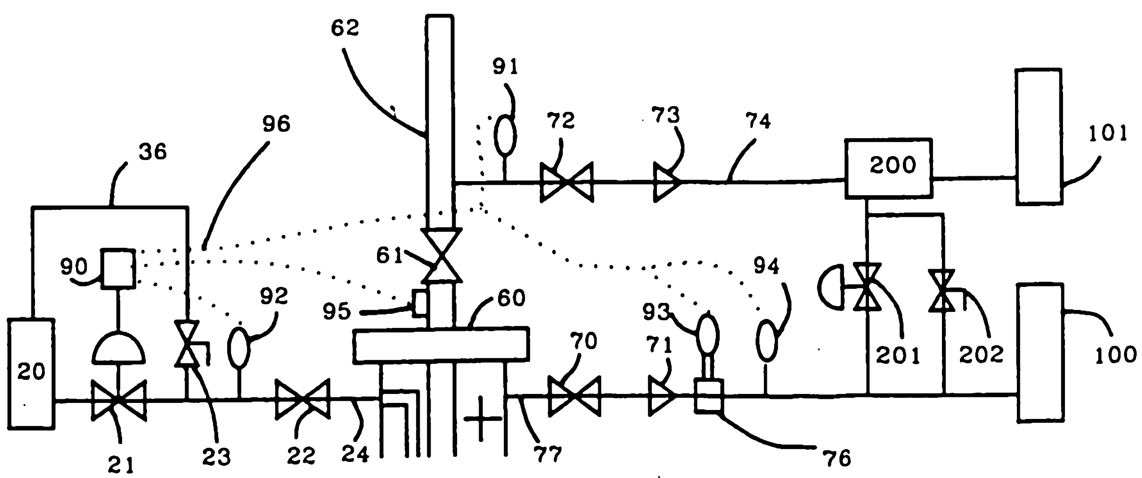
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Fig. 5

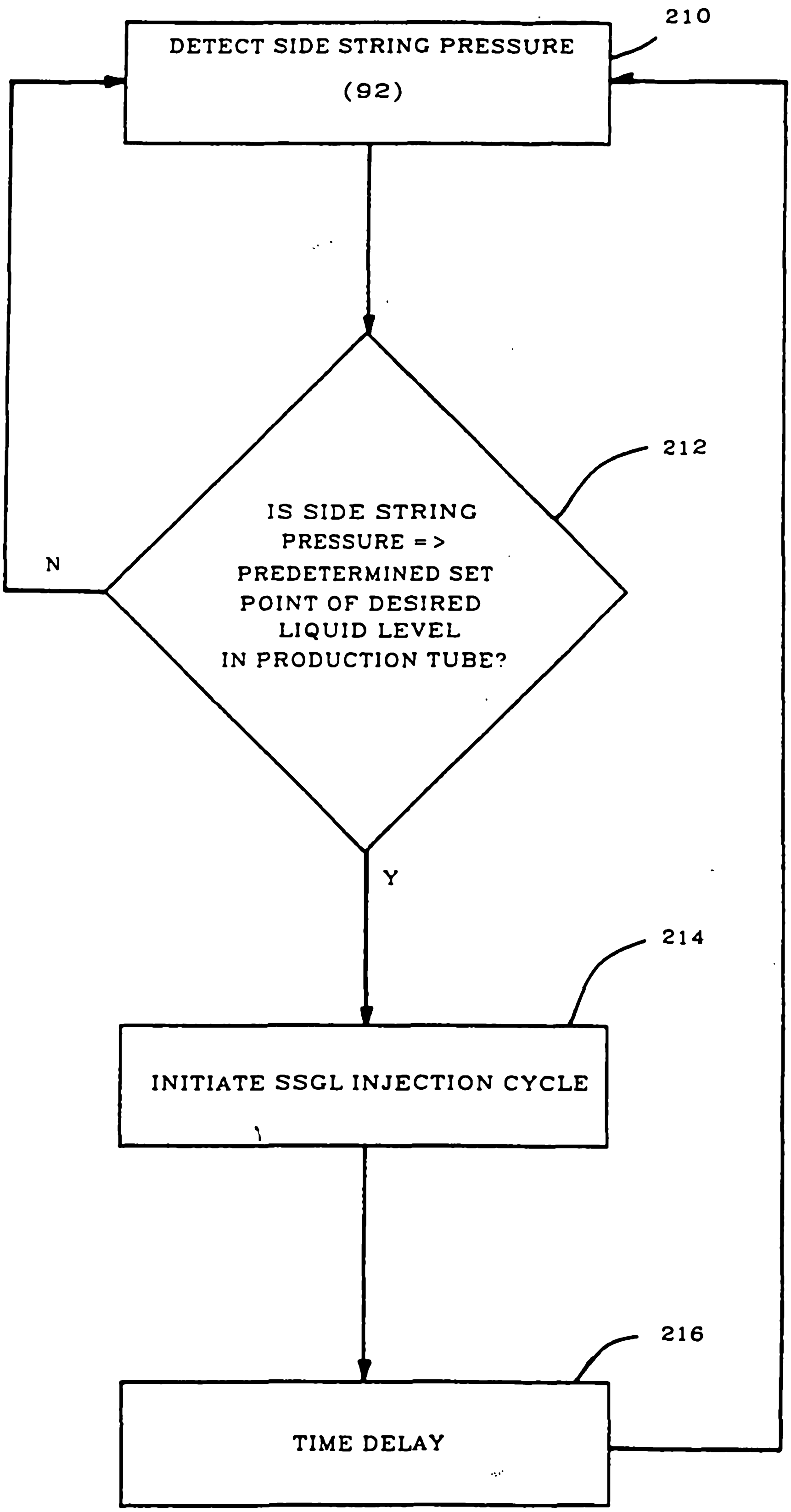

210
DETECT SIDE STRING PRESSURE
(92)
212
IS SIDE STRING
PRESSURE =>
PREDETERMINED SET
POINT OF DESIRED
LIQUID LEVEL
IN PRODUCTION TUBE?
N
Y
214
INITIATE SSGL INJECTION CYCLE
216
TIME DELAY

Fig. 6

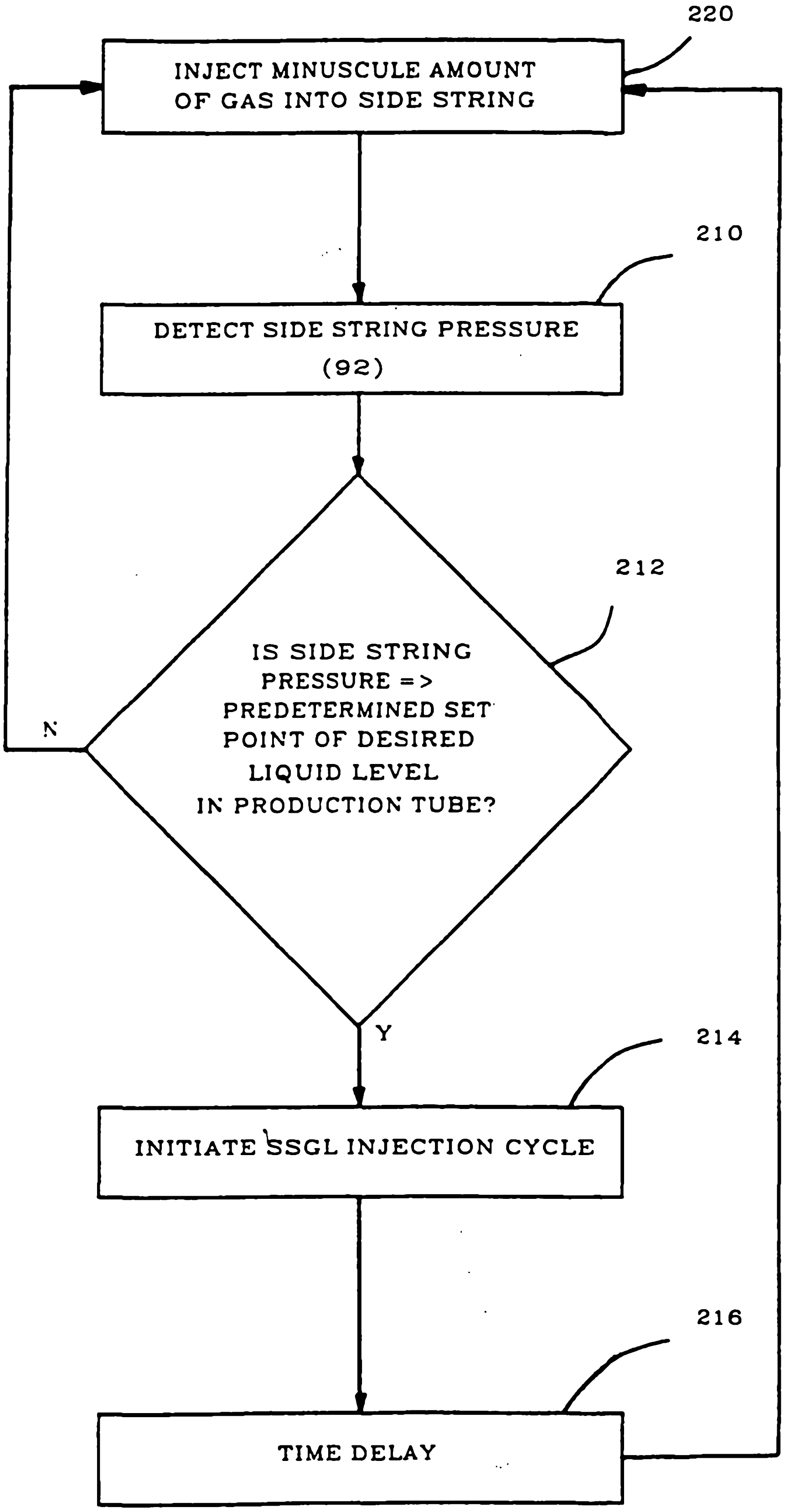

220
INJECT MINUSCULE AMOUNT OF GAS INTO SIDE STRING
210
DETECT SIDE STRING PRESSURE (92)
212
IS SIDE STRING PRESSURE => PREDETERMINED SET POINT OF DESIRED LIQUID LEVEL IN PRODUCTION TUBE?
N
Y
214
INITIATE SSGL INJECTION CYCLE
216
TIME DELAY

Fig. 7

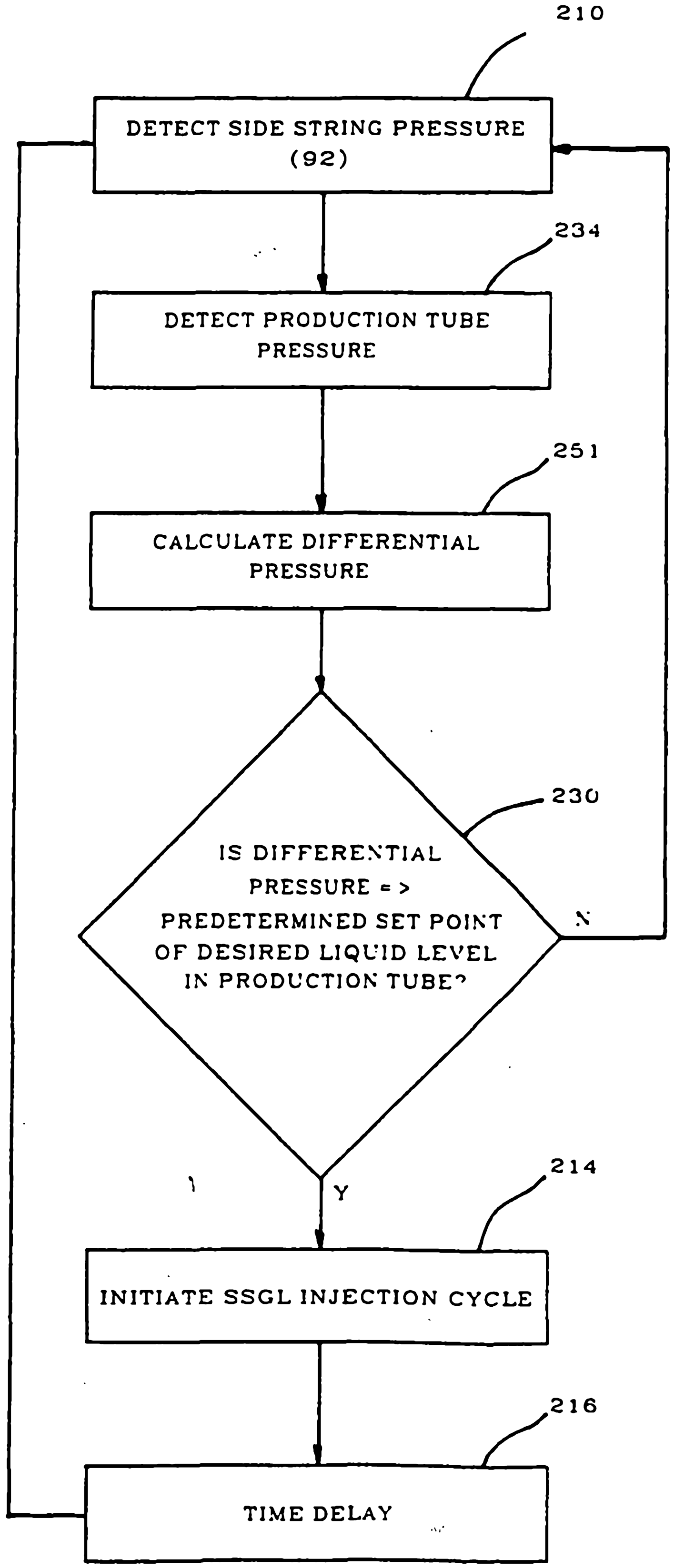
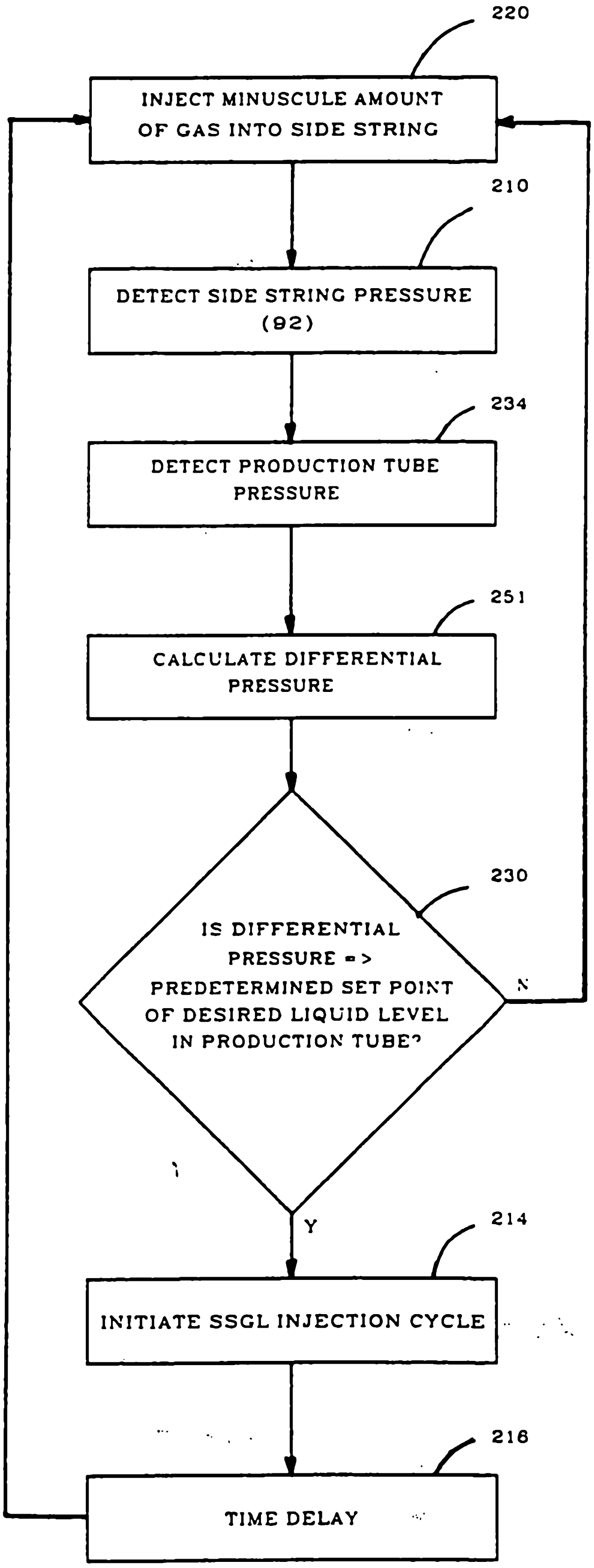

210
DETECT SIDE STRING PRESSURE (92)
234
DETECT PRODUCTION TUBE PRESSURE
251
CALCULATE DIFFERENTIAL PRESSURE
230
IS DIFFERENTIAL PRESSURE => PREDETERMINED SET POINT OF DESIRED LIQUID LEVEL IN PRODUCTION TUBE?
N
Y
214
INITIATE SSGL INJECTION CYCLE
216
TIME DELAY

Fig. 8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INJECT MINUSCULE AMOUNT OF GAS INTO SIDE STRING
210
DETECT SIDE STRING PRESSURE (92)
234
DETECT PRODUCTION TUBE PRESSURE
251
CALCULATE DIFFERENTIAL PRESSURE
230
IS DIFFERENTIAL PRESSURE => PREDETERMINED SET POINT OF DESIRED LIQUID LEVEL IN PRODUCTION TUBE?
N
Y
214
INITIATE SSGL INJECTION CYCLE
216
TIME DELAY

Fig. 9

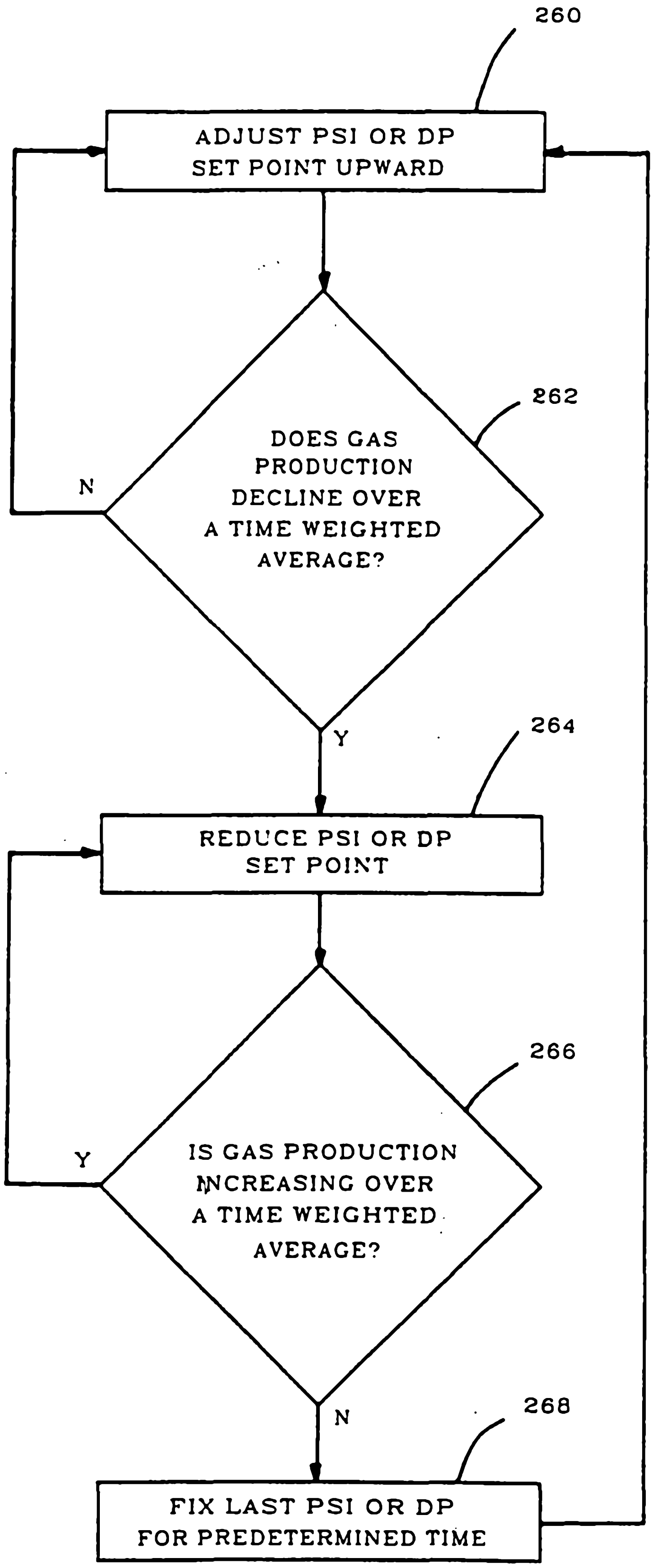
260
ADJUST PSI OR DP SET POINT UPWARD
262
DOES GAS PRODUCTION DECLINE OVER A TIME WEIGHTED AVERAGE?
N
Y
264
REDUCE PSI OR DP SET POINT
266
IS GAS PRODUCTION INCREASING OVER A TIME WEIGHTED AVERAGE?
Y
N
268
FIX LAST PSI OR DP FOR PREDETERMINED TIME

Fig. 10

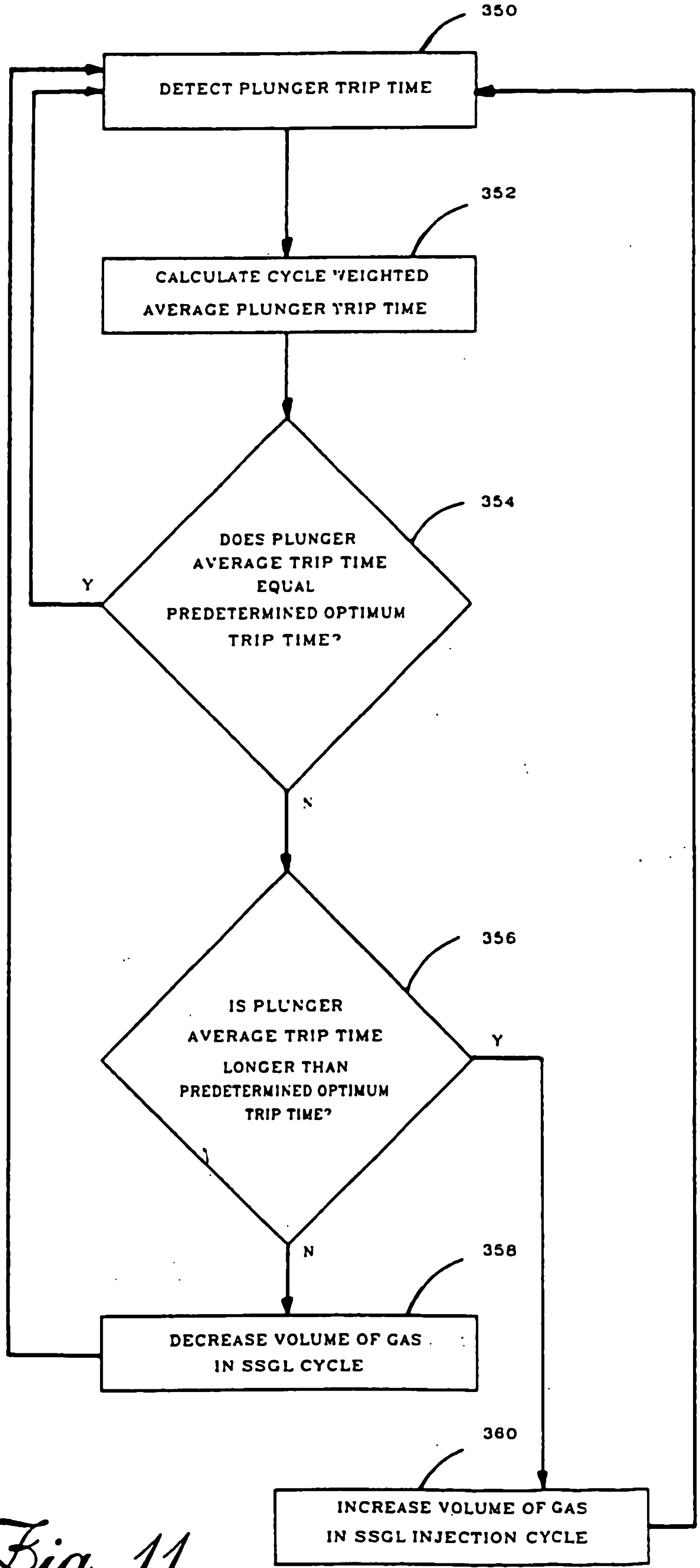
350
DETECT PLUNGER TRIP TIME
352
CALCULATE CYCLE WEIGHTED AVERAGE PLUNGER TRIP TIME
354
DOES PLUNGER AVERAGE TRIP TIME EQUAL PREDETERMINED OPTIMUM TRIP TIME?
Y
N
356
IS PLUNGER AVERAGE TRIP TIME LONGER THAN PREDETERMINED OPTIMUM TRIP TIME?
Y
N
358
DECREASE VOLUME OF GAS IN SSGL CYCLE
360
INCREASE VOLUME OF GAS IN SSGL INJECTION CYCLE

Fig. 11

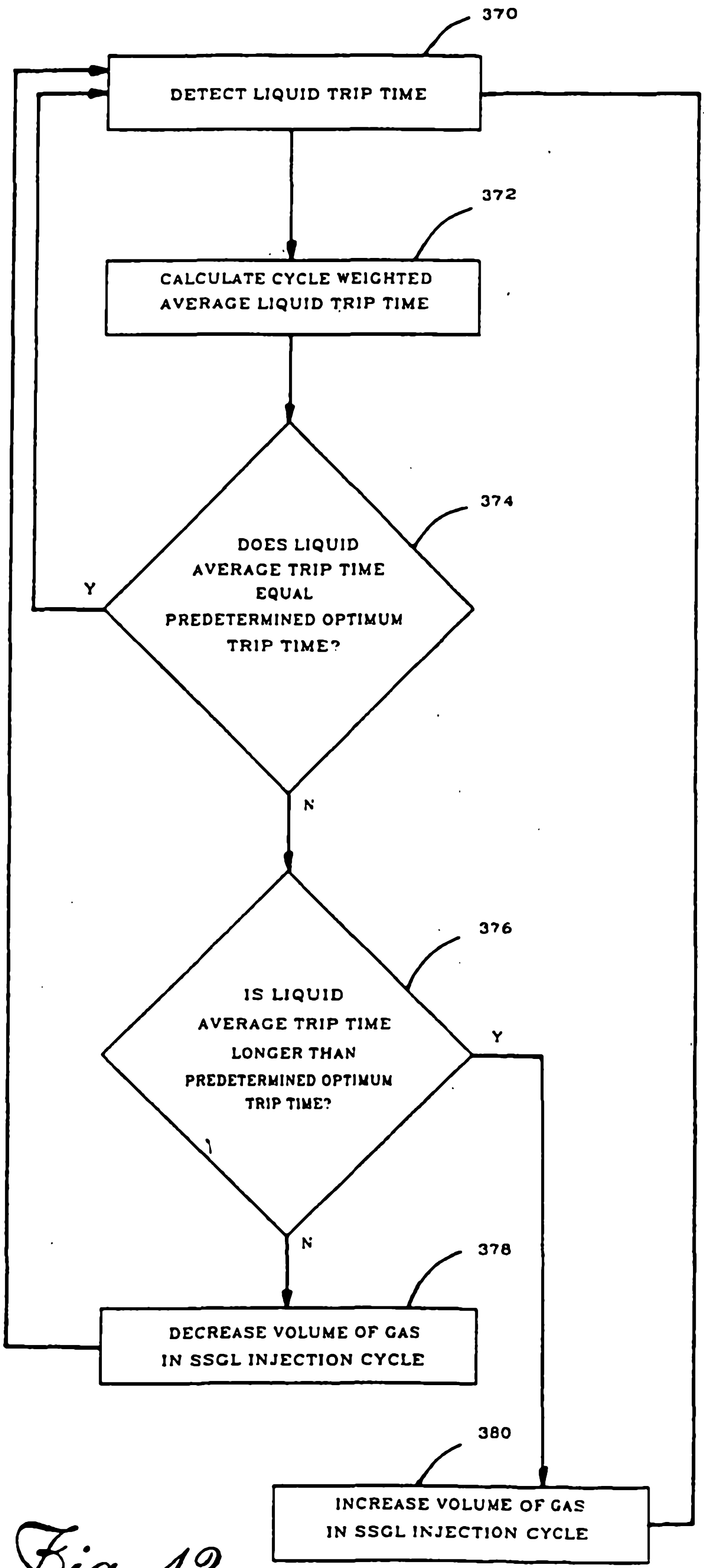
370
DETECT LIQUID TRIP TIME
372
CALCULATE CYCLE WEIGHTED AVERAGE LIQUID TRIP TIME
374
DOES LIQUID AVERAGE TRIP TIME EQUAL PREDETERMINED OPTIMUM TRIP TIME?
Y
N
376
IS LIQUID AVERAGE TRIP TIME LONGER THAN PREDETERMINED OPTIMUM TRIP TIME?
Y
N
378
DECREASE VOLUME OF GAS IN SSGL INJECTION CYCLE
380
INCREASE VOLUME OF GAS IN SSGL INJECTION CYCLE

Fig. 12

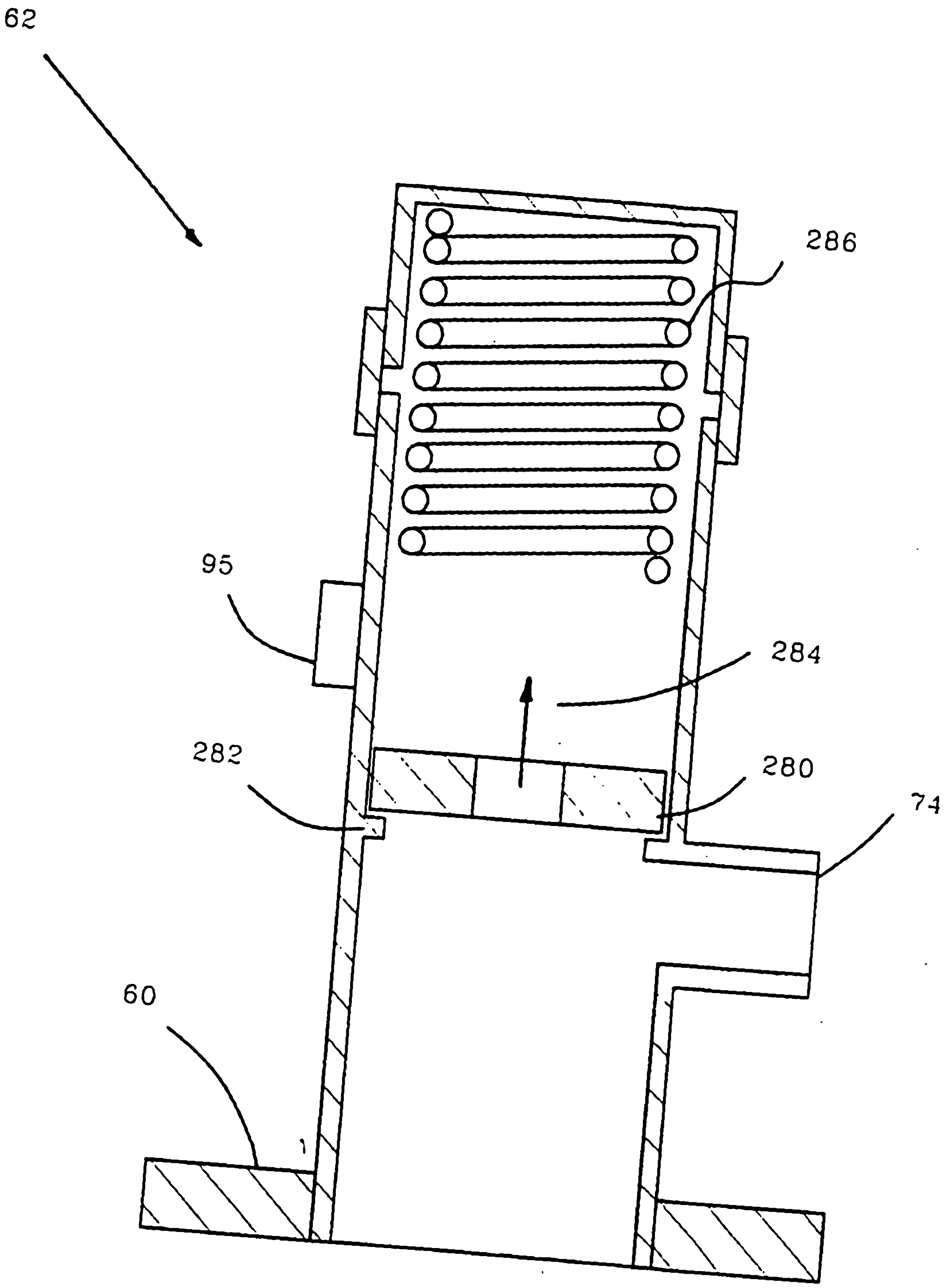

Fig. 13

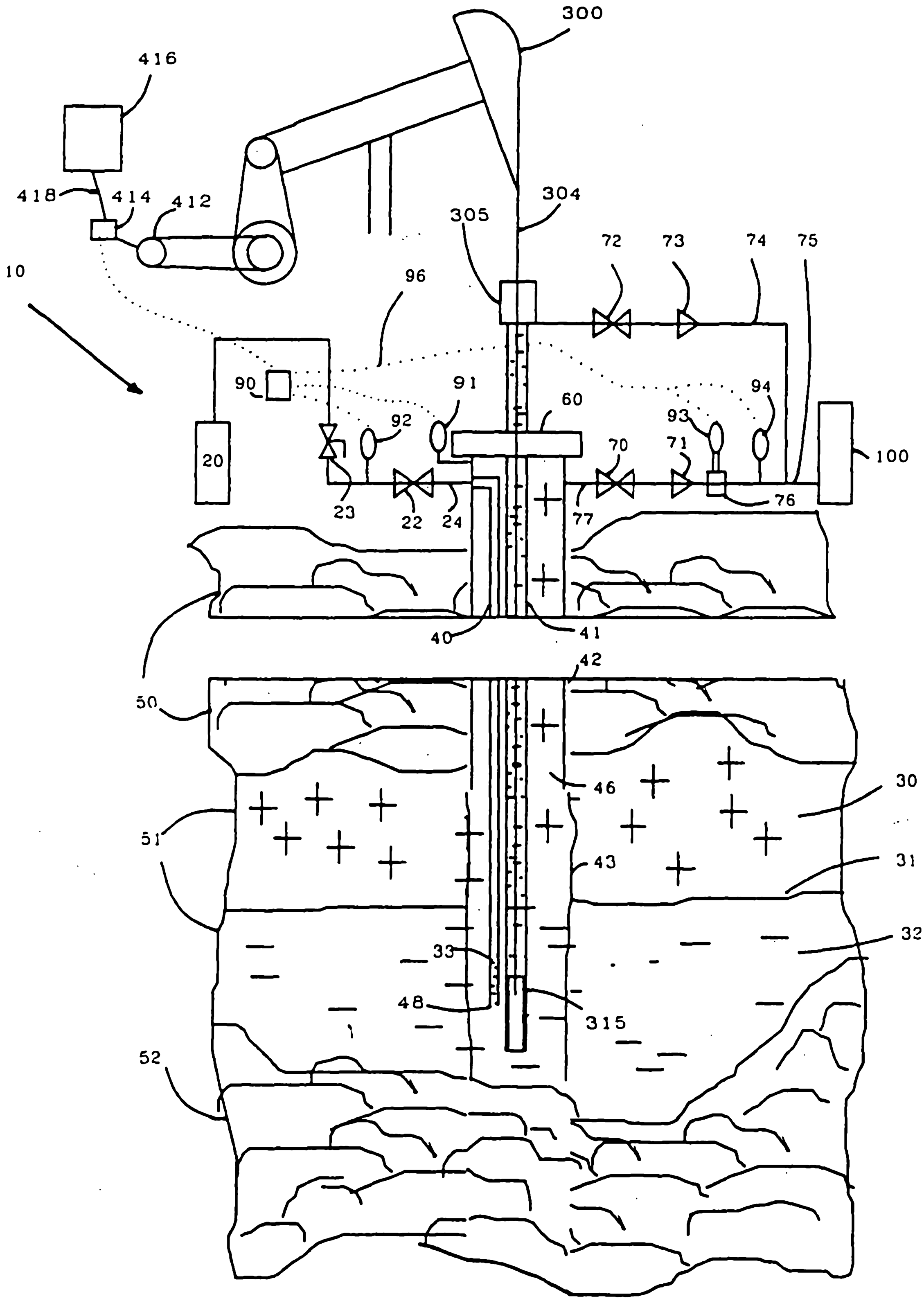
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Fig. 15

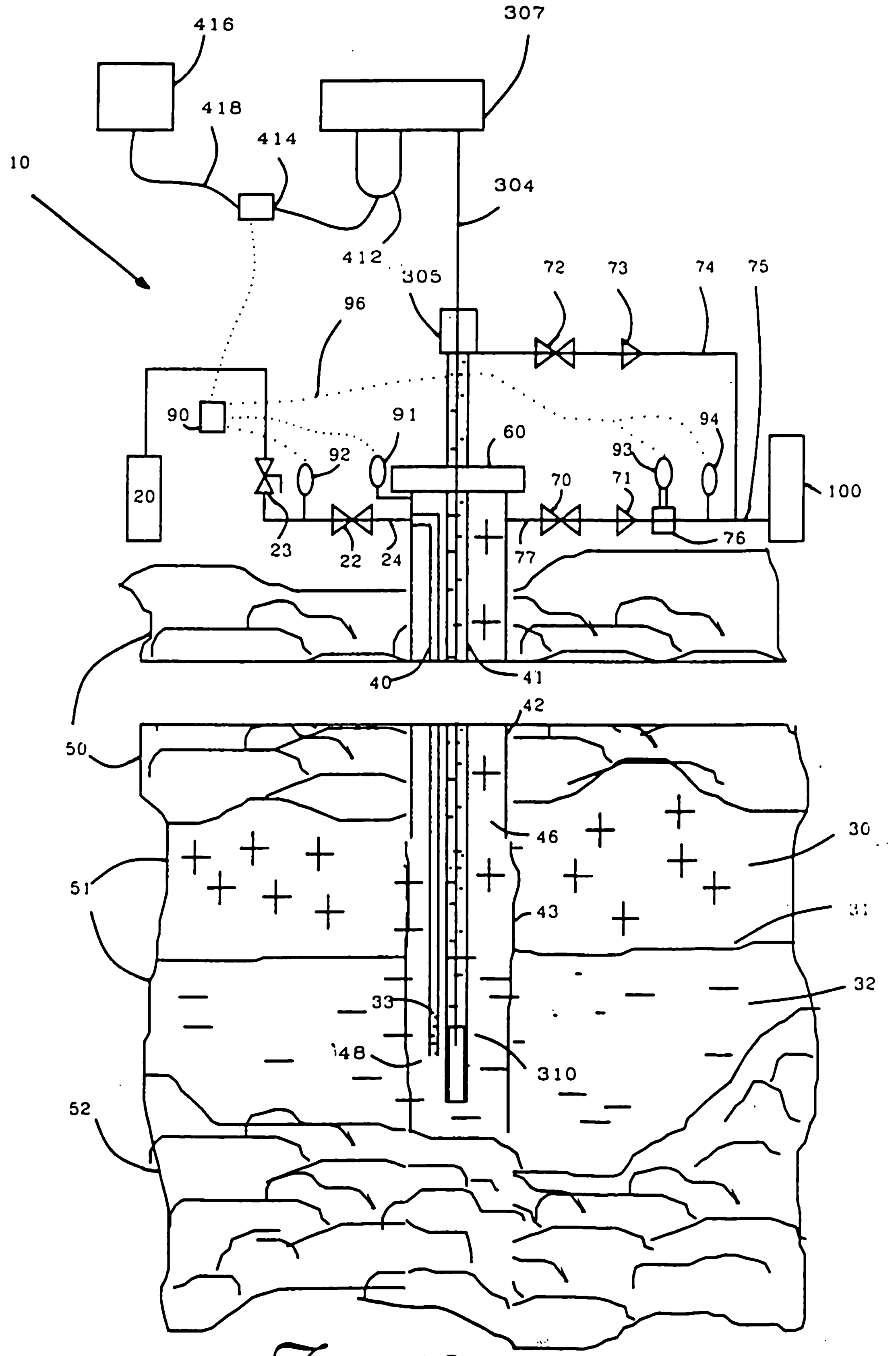
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Fig. 16

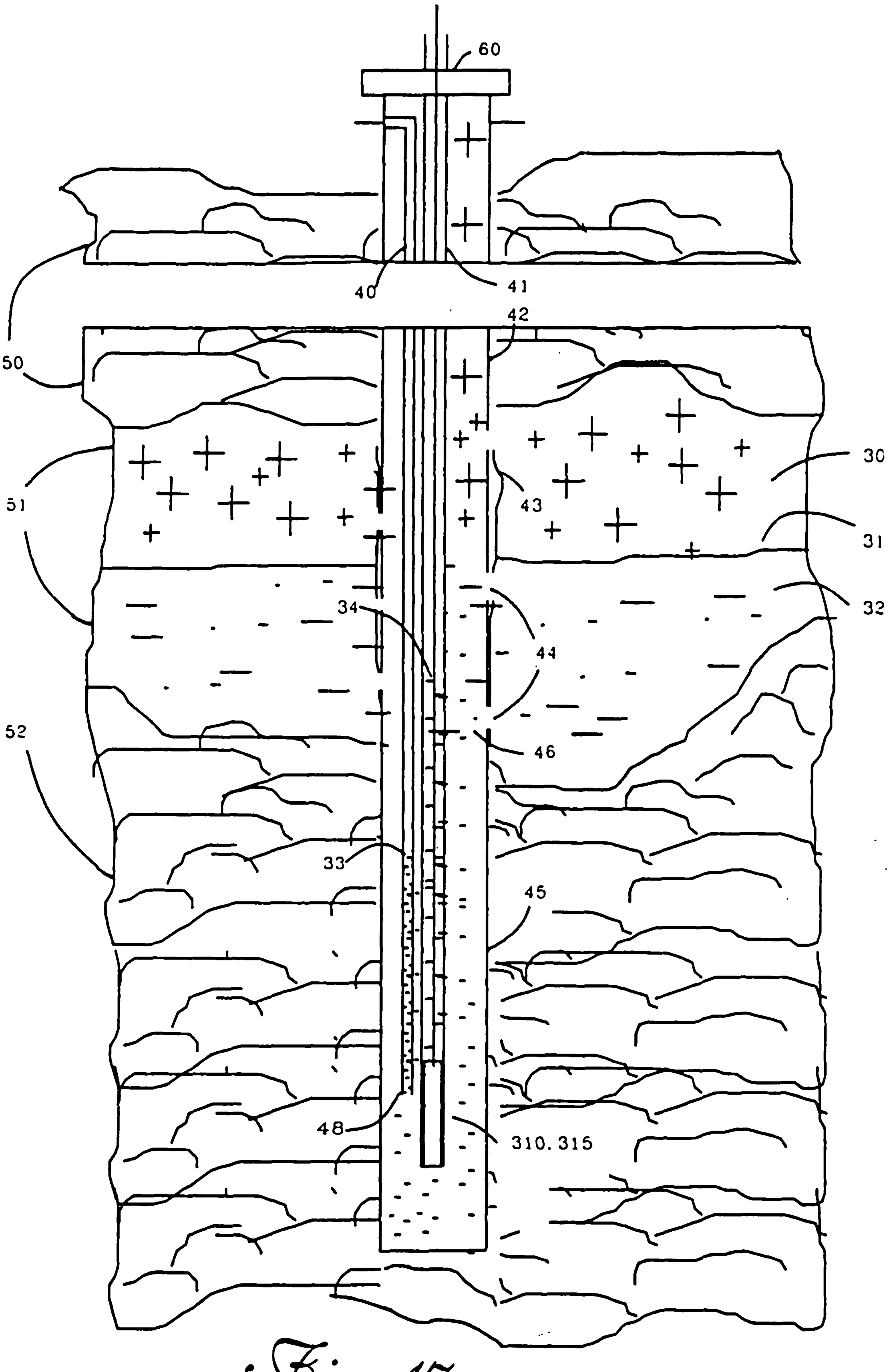

Fig. 17

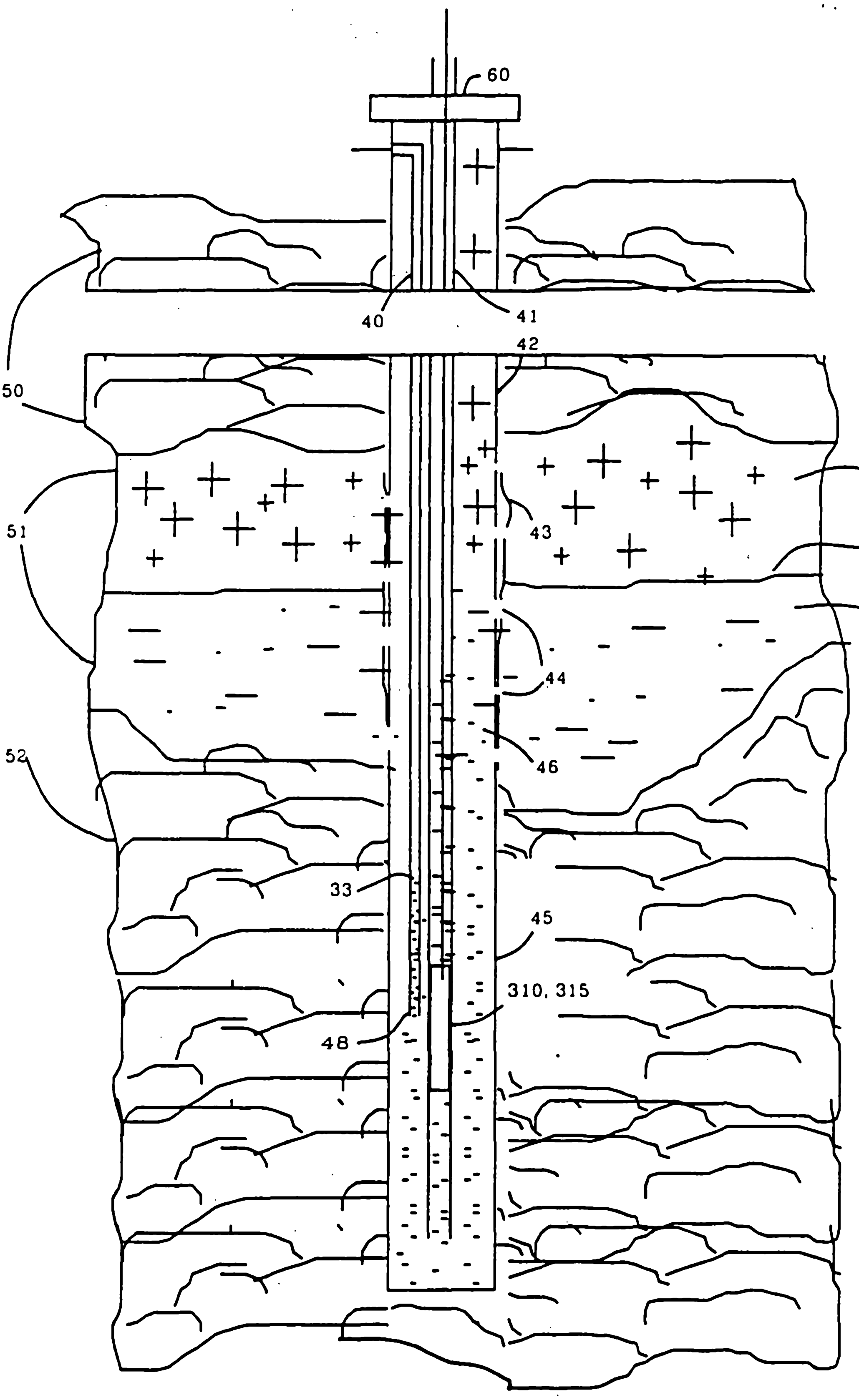

Fig. 18

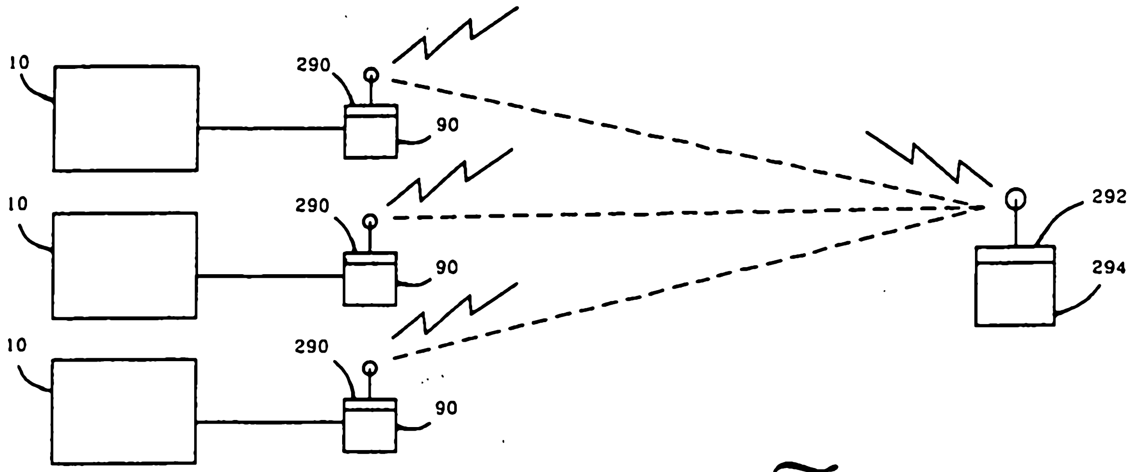

Fig. 14

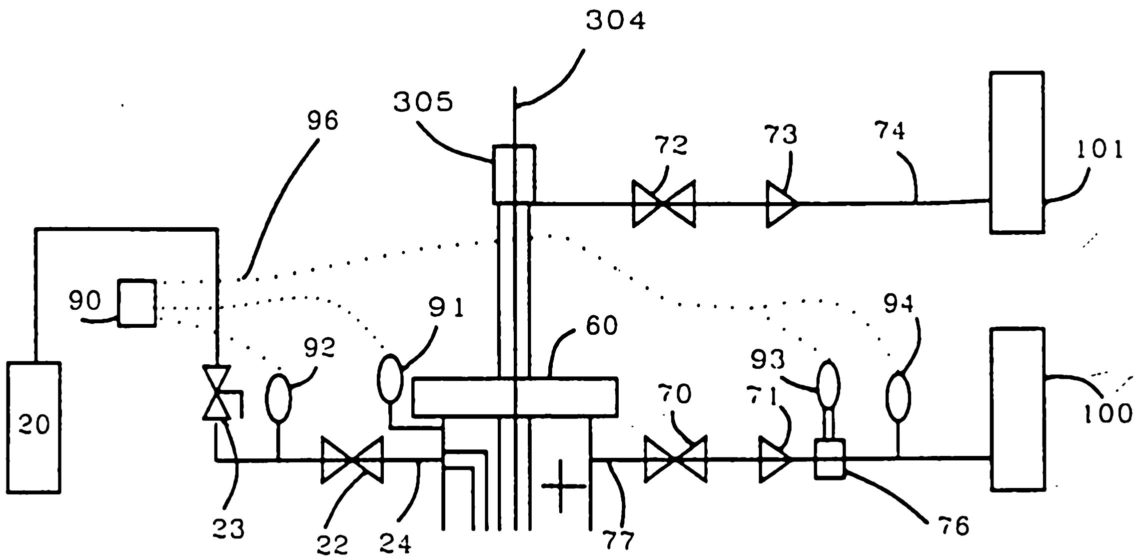

Fig. 19

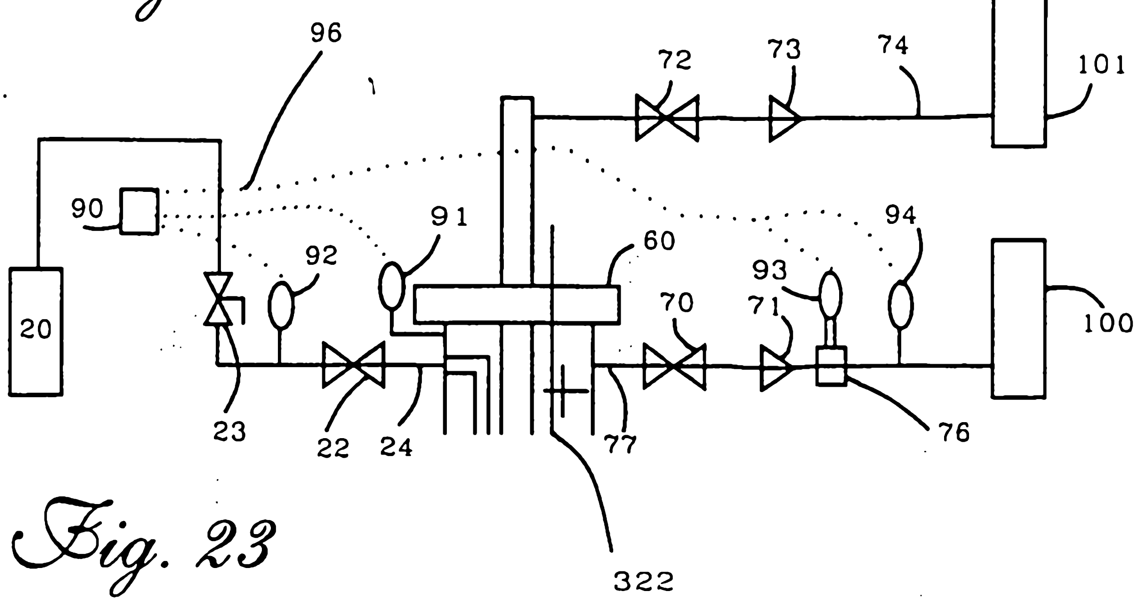

Fig. 23

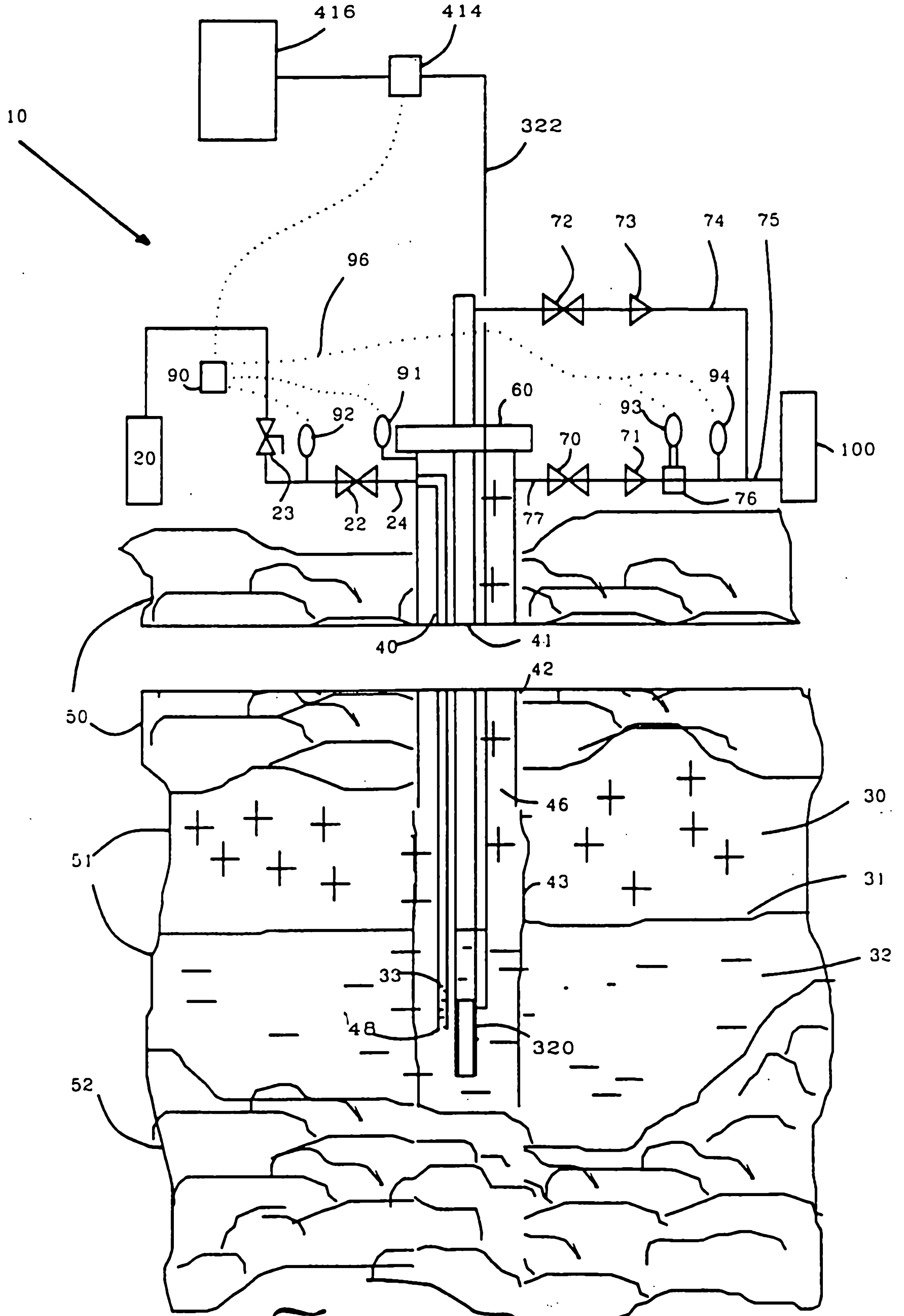
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Fig. 20

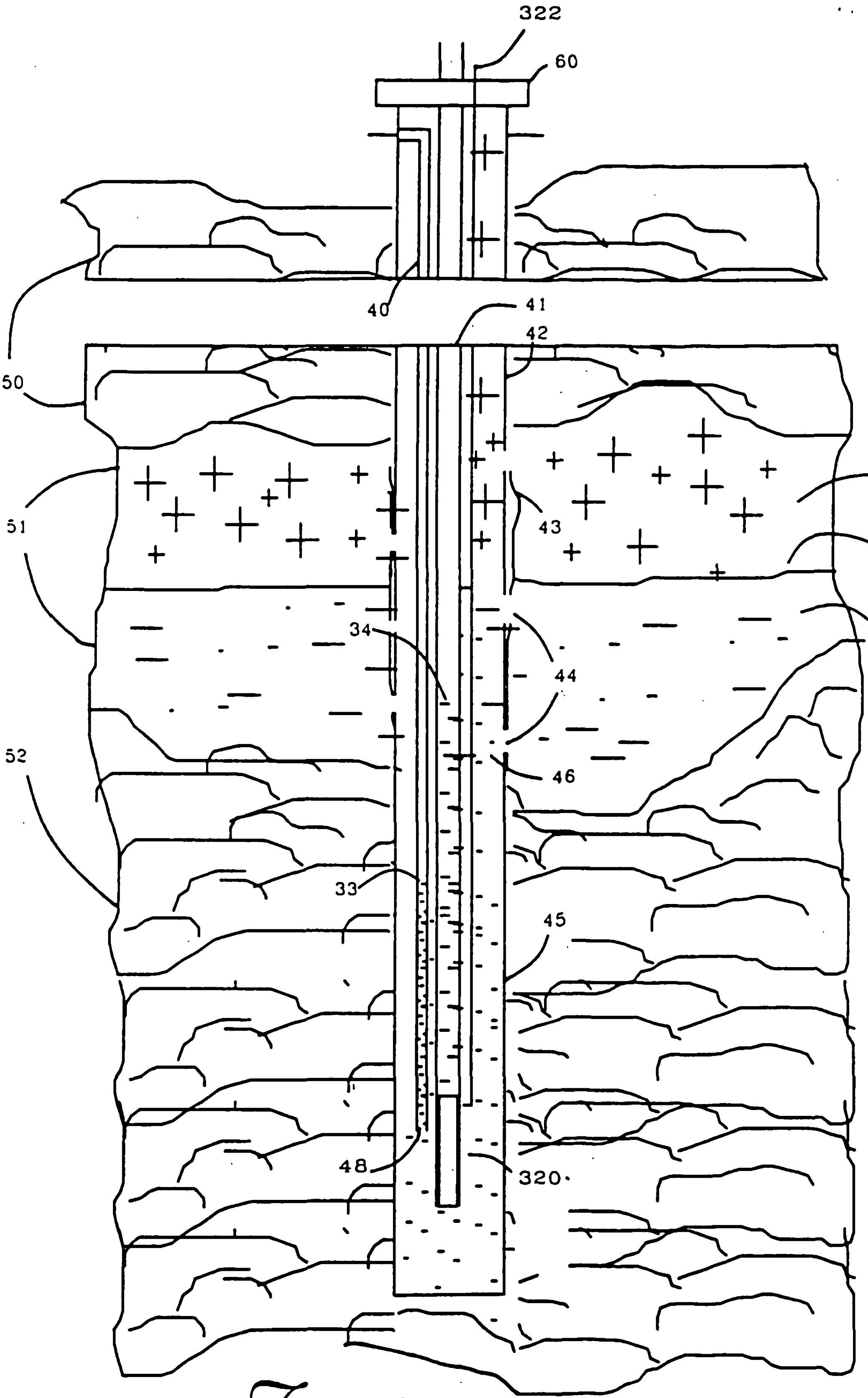


Fig. 21

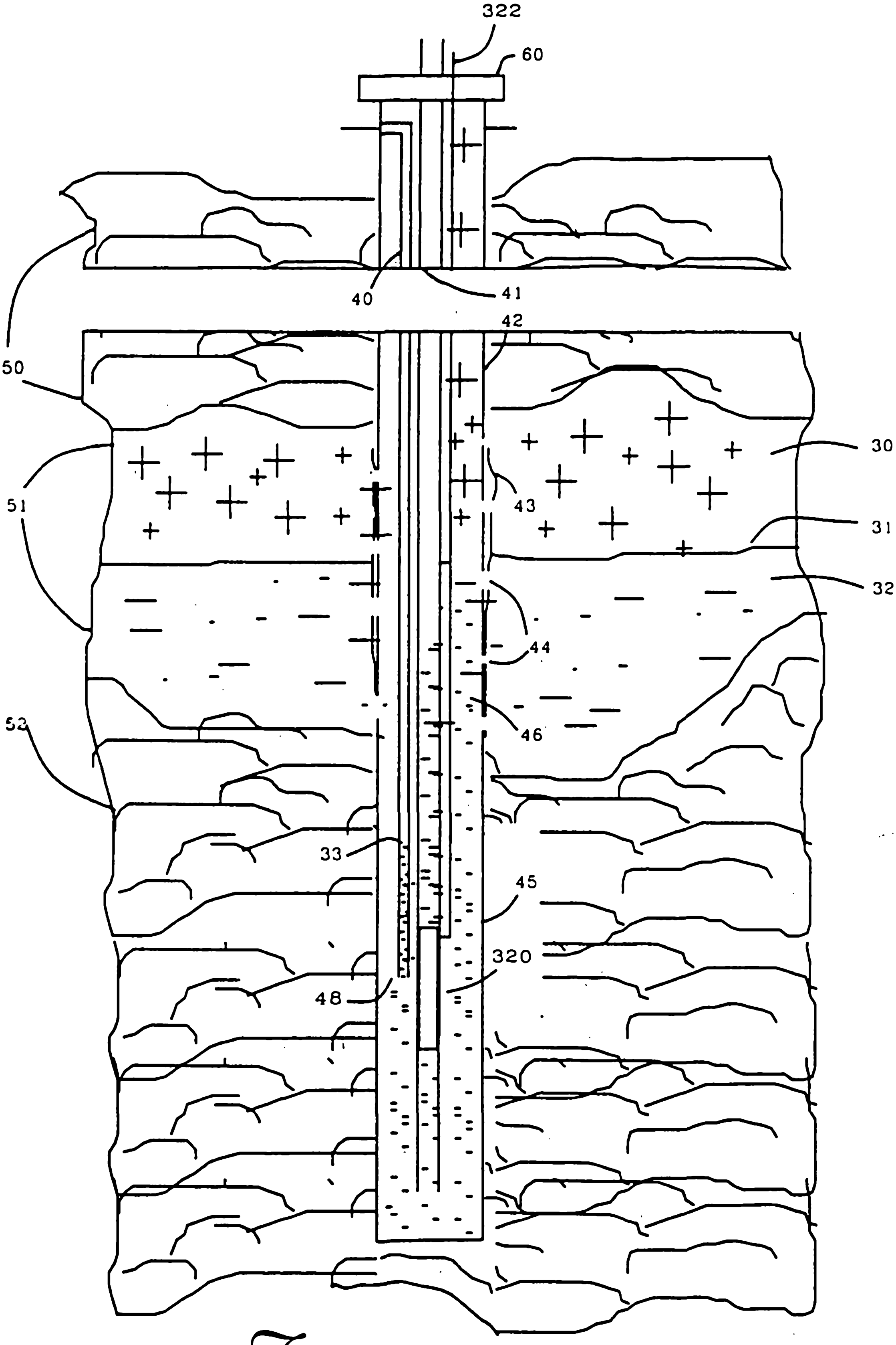
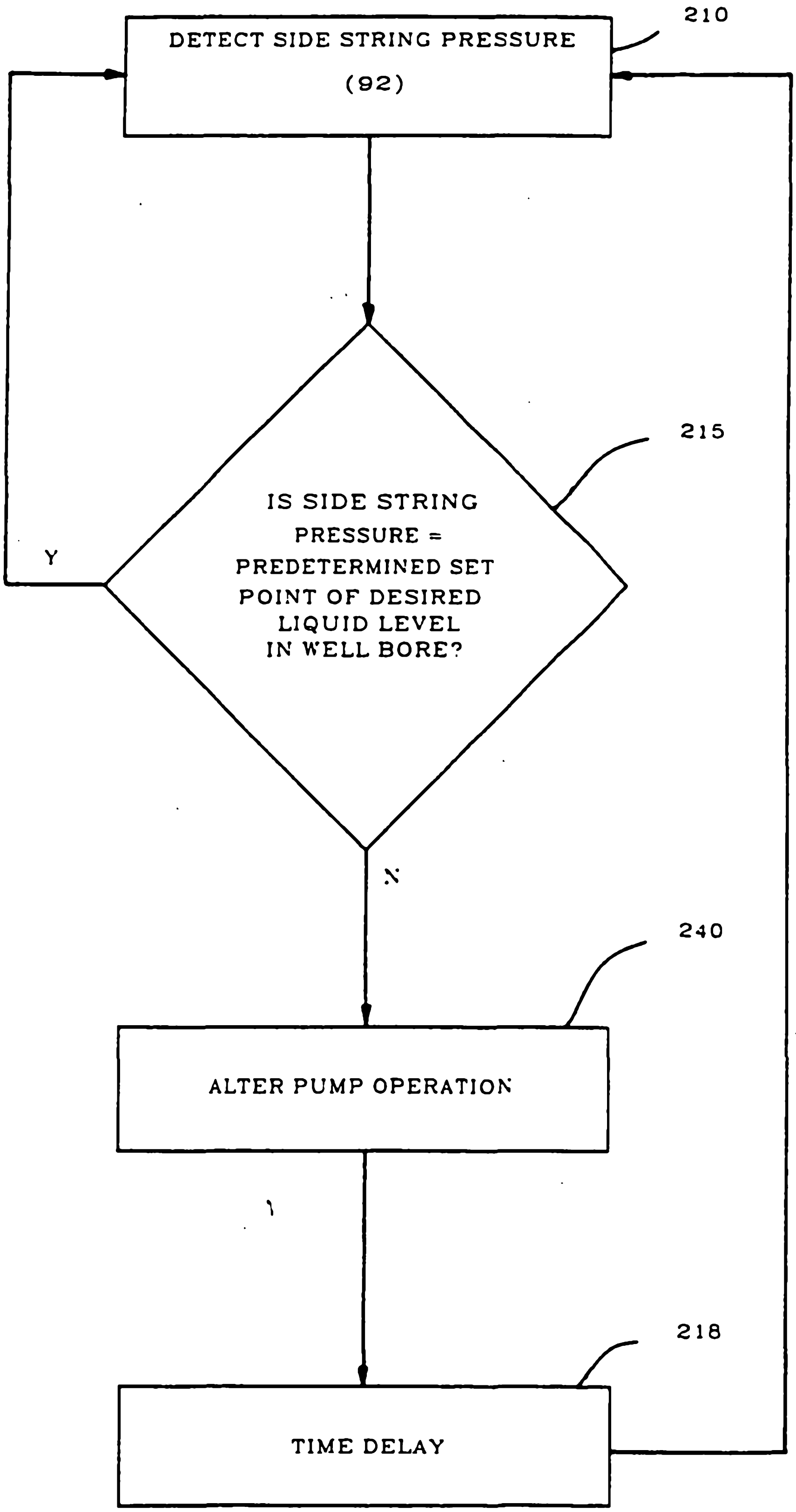


Fig. 22



DETECT SIDE STRING PRESSURE
(92)
210
IS SIDE STRING
PRESSURE =
PREDETERMINED SET
POINT OF DESIRED
LIQUID LEVEL
IN WELL BORE?
215
Y
N
240
ALTER PUMP OPERATION
218
TIME DELAY

Fig. 24

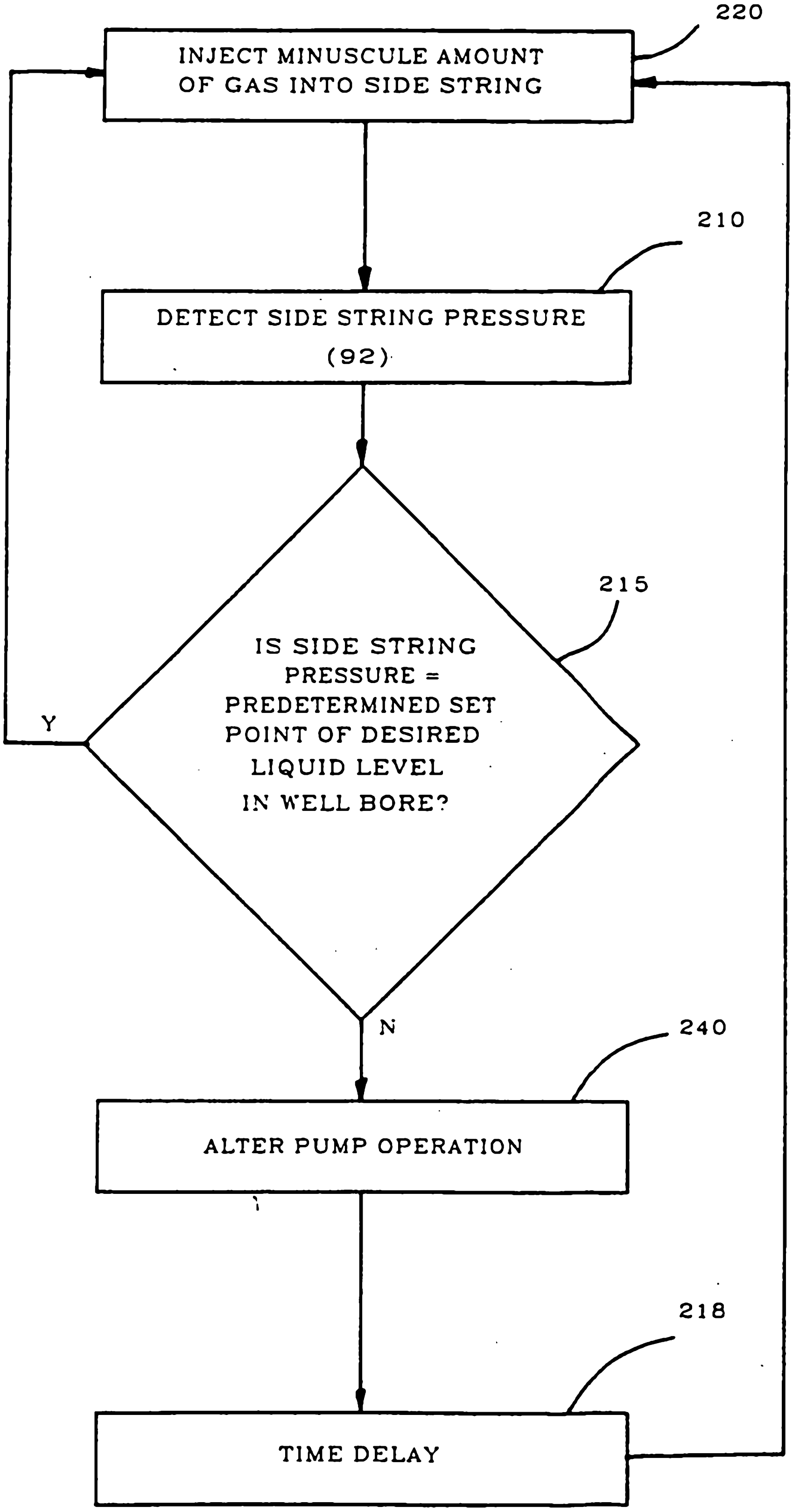

220
INJECT MINUSCULE AMOUNT OF GAS INTO SIDE STRING
210
DETECT SIDE STRING PRESSURE (92)
215
IS SIDE STRING PRESSURE = PREDETERMINED SET POINT OF DESIRED LIQUID LEVEL IN WELL BORE?
Y
N
240
ALTER PUMP OPERATION
218
TIME DELAY

Fig. 25

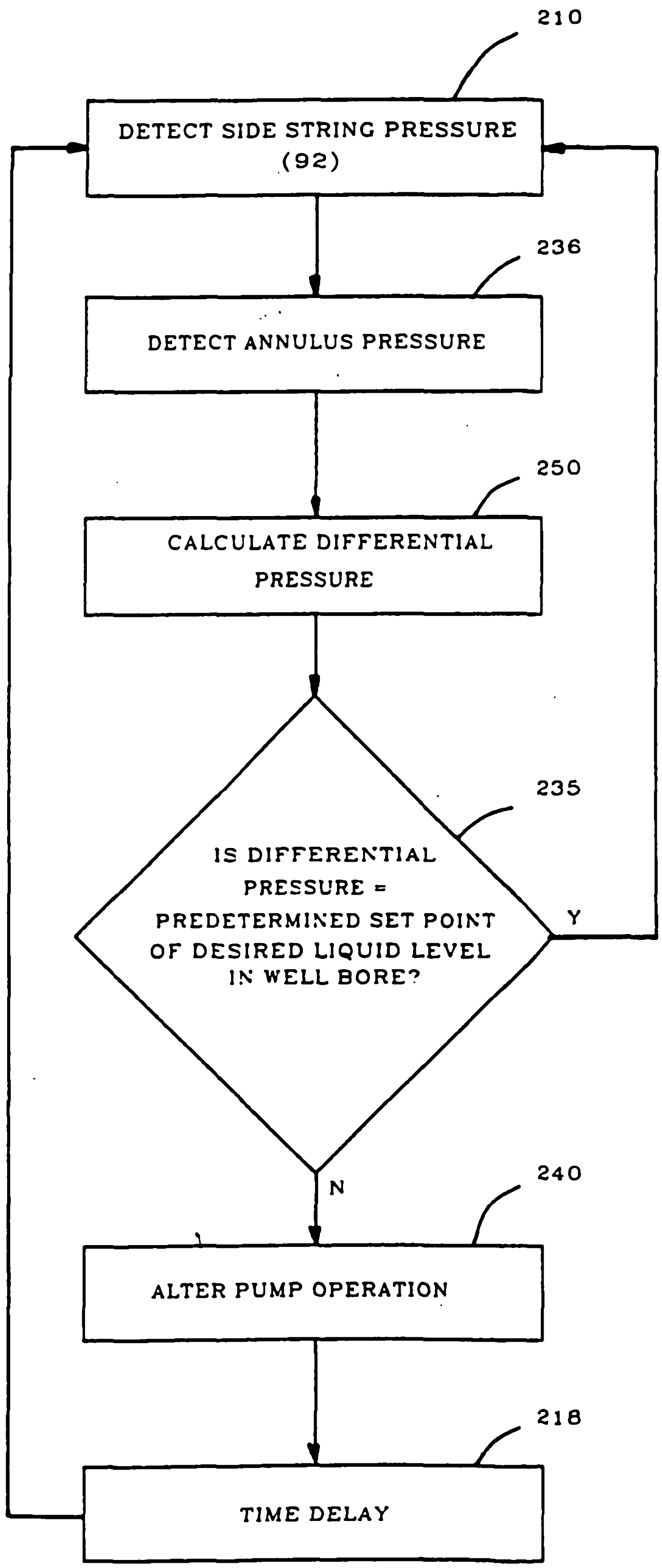

210
DETECT SIDE STRING PRESSURE (92)
236
DETECT ANNULUS PRESSURE
250
CALCULATE DIFFERENTIAL PRESSURE
235
IS DIFFERENTIAL PRESSURE = PREDETERMINED SET POINT OF DESIRED LIQUID LEVEL IN WELL BORE?
Y
N
240
ALTER PUMP OPERATION
218
TIME DELAY

Fig. 26

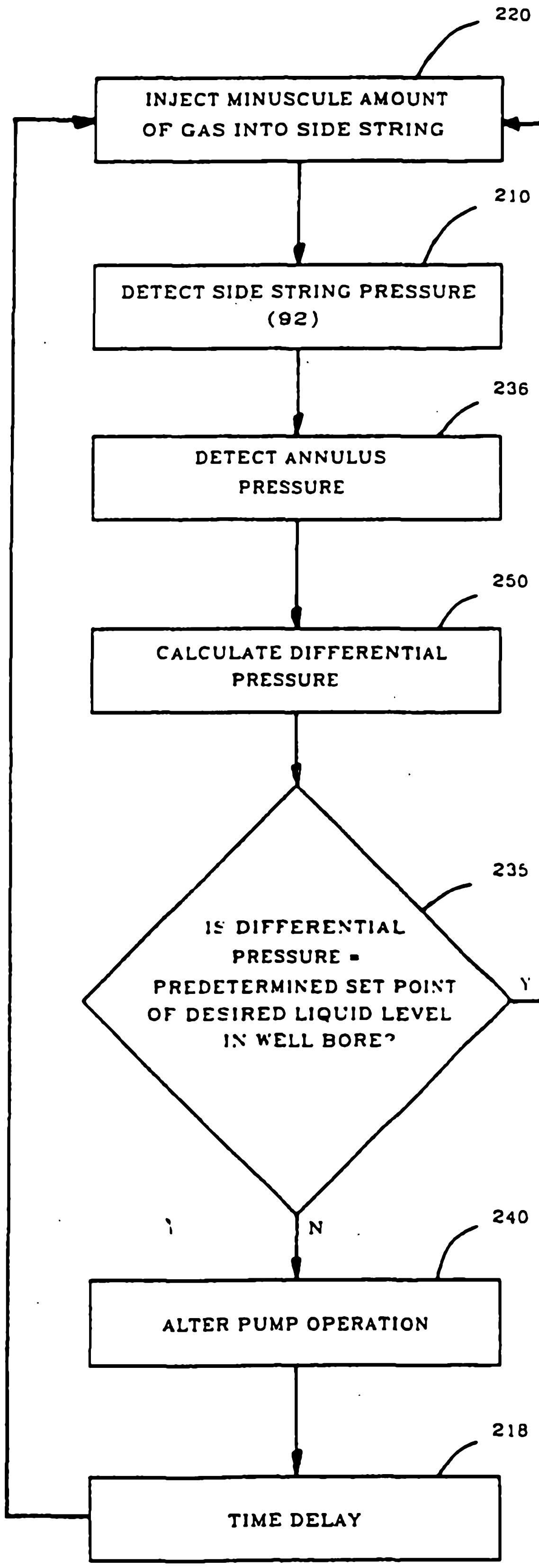

220
INJECT MINUSCULE AMOUNT OF GAS INTO SIDE STRING
210
DETECT SIDE STRING PRESSURE (92)
236
DETECT ANNULUS PRESSURE
250
CALCULATE DIFFERENTIAL PRESSURE
235
IS DIFFERENTIAL PRESSURE = PREDETERMINED SET POINT OF DESIRED LIQUID LEVEL IN WELL BORE?
Y
N
240
ALTER PUMP OPERATION
218
TIME DELAY

Fig. 27

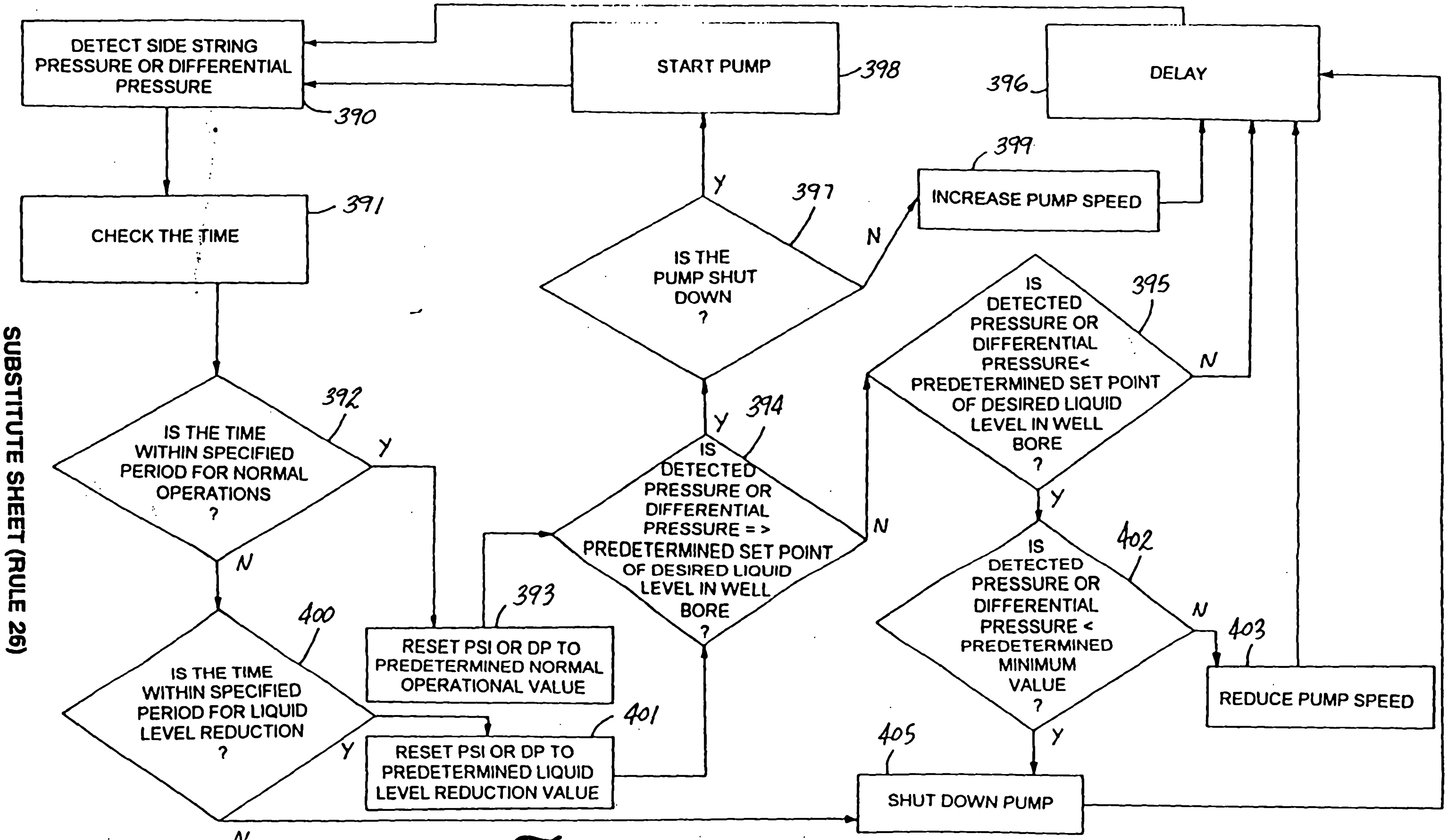

DETECT SIDE STRING PRESSURE OR DIFFERENTIAL PRESSURE
390
CHECK THE TIME
391
IS THE TIME WITHIN SPECIFIED PERIOD FOR NORMAL OPERATIONS ?
392
Y
N
IS THE TIME WITHIN SPECIFIED PERIOD FOR LIQUID LEVEL REDUCTION ?
400
Y
N
RESET PSI OR DP TO PREDETERMINED NORMAL OPERATIONAL VALUE
393
RESET PSI OR DP TO PREDETERMINED LIQUID LEVEL REDUCTION VALUE
401
START PUMP
398
IS THE PUMP SHUT DOWN ?
397
Y
N
IS DETECTED PRESSURE OR DIFFERENTIAL PRESSURE = > PREDETERMINED SET POINT OF DESIRED LIQUID LEVEL IN WELL BORE ?
394
Y
N
INCREASE PUMP SPEED
399
DELAY
396
IS DETECTED PRESSURE OR DIFFERENTIAL PRESSURE< PREDETERMINED SET POINT OF DESIRED LIQUID LEVEL IN WELL BORE ?
395
N
Y
IS DETECTED PRESSURE OR DIFFERENTIAL PRESSURE < PREDETERMINED MINIMUM VALUE ?
402
N
Y
REDUCE PUMP SPEED
403
SHUT DOWN PUMP
405

Fig. 28