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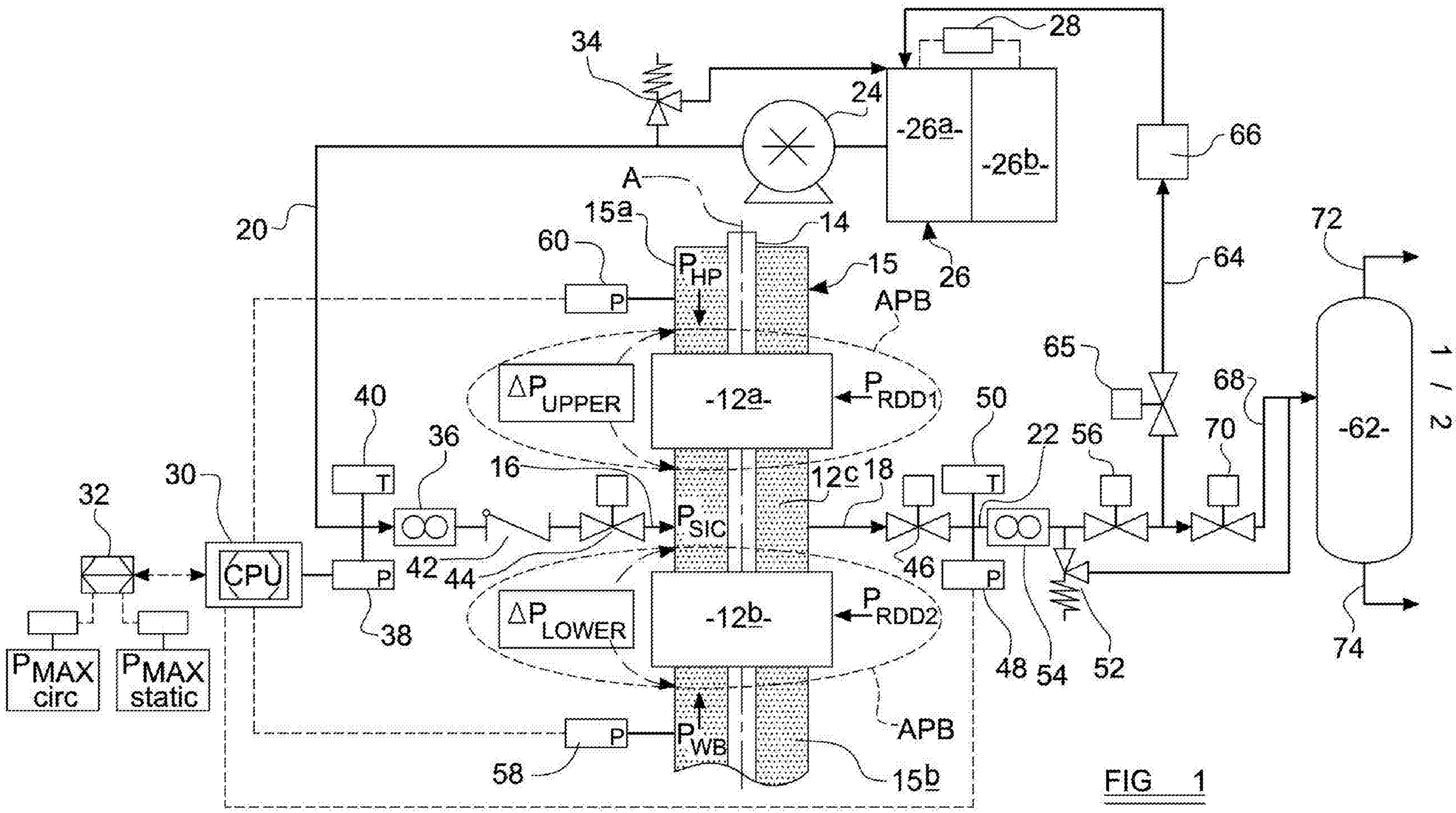
1 / 2
34
28
24
-26a-
-26b-
66
A
72
20
15a
14
26
64
60
P
P_HP
15
APB
65
68
ΔP_UPPER
-12a-
P_RDD1
50
40
36
16
12c
18
22
56
70
-62-
32
30
T
P_SIC
T
CPU
P
42
44
46
P
ΔP_LOWER
-12b-
P_RDD2
38
48
54
52
74
P_MAX circ
P_MAX static
APB
P
P_WB
58
15b

FIG 1

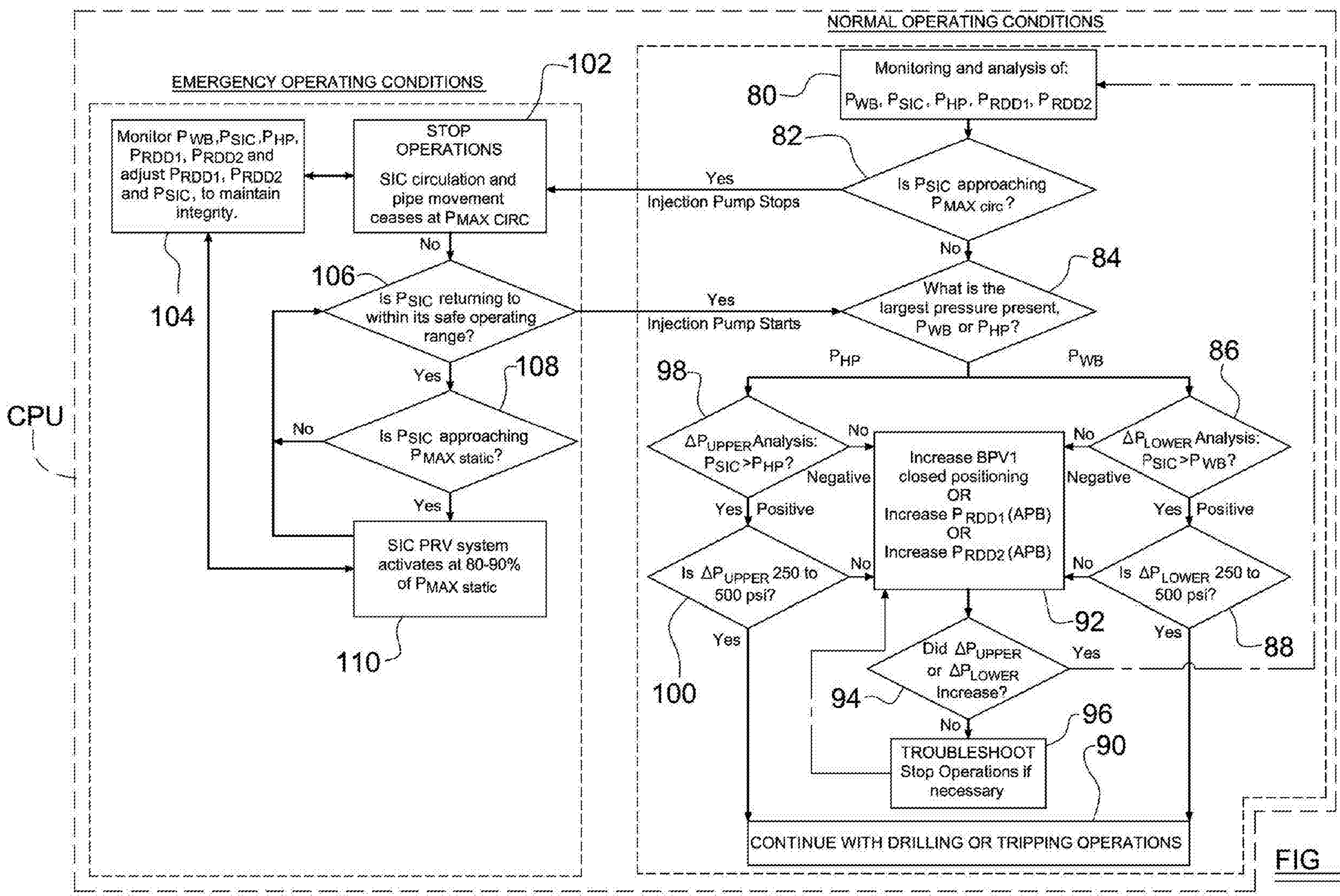
CPU
EMERGENCY OPERATING CONDITIONS
NORMAL OPERATING CONDITIONS
Monitoring and analysis of: P_{WB}, P_{SIC}, P_{HP}, P_{RDD1}, P_{RDD2}
80
82
Is P_{SIC} approaching $P_{MAX\ circ}$?
Yes
Injection Pump Stops
No
84
What is the largest pressure present, P_{WB} or P_{HP}?
Yes
Injection Pump Starts
P_{HP}
P_{WB}
98
ΔP_{UPPER} Analysis: $P_{SIC} > P_{HP}$?
86
ΔP_{LOWER} Analysis: $P_{SIC} > P_{WB}$?
No
Negative
Yes
Positive
Increase BPV1 closed positioning OR Increase P_{RDD1} (APB) OR Increase P_{RDD2} (APB)
92
Is ΔP_{UPPER} 250 to 500 psi?
Is ΔP_{LOWER} 250 to 500 psi?
100
88
Did ΔP_{UPPER} or ΔP_{LOWER} Increase?
94
TROUBLESHOOT Stop Operations if necessary
96
90
CONTINUE WITH DRILLING OR TRIPPING OPERATIONS
102
STOP OPERATIONS
SIC circulation and pipe movement ceases at $P_{MAX\ CIRC}$
Monitor P_{WB}, P_{SIC}, P_{HP}, P_{RDD1}, P_{RDD2} and adjust P_{RDD1}, P_{RDD2} and P_{SIC}, to maintain integrity.
104
106
Is P_{SIC} returning to within its safe operating range?
108
Is P_{SIC} approaching $P_{MAX\ static}$?
SIC PRV system activates at 80-90% of $P_{MAX\ static}$
110

FIG 2

Title: Method of Operating a Drilling System

Description of Invention

The present invention relates to an improved method of operating a drilling system for drilling a subsea or subterranean well bore for oil and/or gas production.

Subterranean drilling typically involves rotating a drill bit from surface or on a downhole motor at the remote end of a tubular drill string. It involves pumping a fluid down the inside of the tubular drill string, through the drill bit, and circulating this fluid continuously back to surface via the drilled space between the hole/tubular, referred to as the annulus. For a subsea well bore, a tubular, known as a riser extends from the rig to the top of the wellbore which exists at subsea level on the ocean floor. It provides a continuous pathway for the drill string and the fluids emanating from the well bore. In effect, the riser extends the wellbore from the sea bed to the rig, and the annulus also comprises the annular space between the outer diameter of the drill string and the riser.

As drilling progresses pipe has to be connected to the existing drillstring to drill deeper. Conventionally, this involves shutting down fluid circulation completely so the pipe can be connected into place as the top drive has to be disengaged.

The large diameter sections that exist at the end of each section of drillpipe are referred to as tool joints. During a connection, these areas provide a low stress area where the rig pipe tongs or Iron Roughneck can be placed to grip the pipe and apply torque to either make or break a connection.

Conventionally, the well bore is open to atmospheric pressure and there is no surface applied pressure or other pressure existing in the system. The drillpipe rotates freely without any sealing elements imposed or acting on the drill pipe at the surface, and there is no requirement to divert the return fluid flow or exert pressure on the system during these standard operations.

Managed pressure drilling and/or underbalanced drilling utilizes additional special equipment that has been developed to keep the well closed at all times, and the wellhead pressures in these cases are non-atmospheric as in the traditional art of the conventional overbalanced drilling method. In such drilling systems, drilling fluid is circulated within a closed loop system. The closed loop is generated by a seal around the drillpipe at surface or subsea using a pressure containment device, diverting all returned flow from the wellbore annulus to a flow line connected to the annulus below the sealing point. The function of the pressure containment device is to allow the drill string and its tool joints to pass through with reciprocation/stripping or rotation with wellbore pressure below while maintaining the seal integrity.

With drilling activity in progress and the device closed a back pressure is created on the annulus. The drill string is stripped or rotated through the sealing element(s) pressure containment device which isolates the pressurized annulus from the external atmosphere while maintaining a pressure seal around the drillpipe. A typical sealing element in existing pressure containment designs includes an elastomer or rubber packing/sealing element and a bearing assembly that allows the sealing element to rotate along with the drillstring. There is no rotational movement between the drillstring and the sealing element, and only the bearing assembly exhibits the rotational movement during drilling. Rotating pressure containment devices are well known in the art of pressurized drilling, referred to as Rotating Control Head (RCD), Rotating Blow Out Preventer (RBOP), or Pressure Control While Drilling (PCWD), and are described in detail in patents US7699109B2, US7926560, and US6129152.

Drillpipe rotation and vertical movement wears out the sealing elements, and the passage of tool joints and larger OD tubulars causes the sealing element to expand and contract multiple times with the diametrical changes in the drill string. With wellbore pressure present below the sealing element and atmospheric or near atmospheric pressure above, a large differential pressure is produced across the sealing face, with the highest magnitude of differential pressure existing in the bottom sealing area of the element where it contacts the tubular. As a result, the lower sealing area between the tubular and the element generally exhibits the highest wear rate, and as the pressure differential decreases closer to the top of the sealing element so does the degree of wear within the sealing face. Therefore, a higher wellbore pressure below the sealing point creates a higher differential pressure across the sealing face, and ultimately, higher wear rates in the lower area of the element result.

Typically, in the prior art, a dual sealing arrangement for an RCD or other rotating pressure control device is a common configuration used for pressurized drilling. The operational history of the dual sealing arrangement for any rotating pressure control device reveals that the lower sealing element is consistently the first failure mechanism for the assembly because of the magnitude of the differential pressure across the lowest element. The pressure between the elements is continuously monitored with these systems, and when the pressure starts to increase this is a positive indicator that the lower sealing element is, or has, failed.

Furthermore, the frictional coefficients existing between the steel tubulars and the elastomeric sealing material of the rotating pressure control devices are quite high resulting in a high wear rate occurring within the sealing face. Most designs on the market to date lack the capability to lubricate or self-lubricate the sealing face between the element and the tubular. During drilling and tripping under pressure, the degree of heat generated from the friction between the tubular and the element through the vertical movement and rotational motion of the tubular within the element is substantial without a friction reducing fluid to lubricate and cool the sealing interface. Thus, the wear rates for conventional sealing devices increases drastically in addition to the effects of differential pressure.

An alternative apparatus to the rotating control device technology, utilizing a non-rotating sealing device is described in patent applications WO2012127227 and WO2011128690. This device eliminates the requirement for a bearing assembly, and includes a single or dual seal sleeve assembly installed within a specified housing within the riser system and secured in place with hydraulically locking dogs/pistons. Rotation of the seal sleeve assembly with the drill pipe is prevented through the frictional forces of an adjacent annular packer assembly within the housing which applies pressure to the external surface of the seal sleeve when it is in position in the housing. The seal sleeve's mechanical structure and composite materials result in a high wear resistant low friction coefficient sealing face on the drill pipe. This system does not use the conventional bearing systems described in the prior art.

In one embodiment described in WO2011128690, a lubricating circuit is utilized to circulate a fluid such as water or oil based fluids between two sealing elements of an annular stripping sleeve, or alternately referred to as a seal sleeve assembly, with the intent of providing a constant fluid pressure between the two seals. The fluid is metered in and out of the annular volume between the sealing elements to account for any fluid loss within the circulating system and any gain through the ingress of wellbore fluids. Maintaining a constant fluid pressure between the sealing elements decreases the pressure differential across the assembly and enhances the longevity of the sealing assembly. With this circuit, a negative differential pressure is created across the lower sealing element utilizing circulation pressure through this annular volume. For example, if the wellbore pressure below the lowest element is 6.9 MPa (1,000 psi), the circuit volume is pressurized to 3.4 MPa (500 psi). The magnitude of the differential across the sealing assembly is decreased, and a negative differential of 3.4 MPa (500 psi) would result across the lower sealing element.

The circuit described in patent applications WO2012127227 and WO2011128690 is now referred to as the Seal Integrity Circuit (SIC), and the inventive system and method introduces further aspects of such a system which may enhance the efficiency and safety of its operation.

There is provided a method of operating a drilling system for drilling a subterranean bore hole, the drilling system including a drill string and two sealing devices which are operable to provide a substantially fluid tight seal around the drill string whilst the drill string is rotating during drilling, wherein one of the or both sealing devices is configured such that the sealing pressure it exerts on the drill string when operated to seal against the drill string can be varied, wherein the method includes the steps of:

a) injecting fluid into the annular volume around the drill string between the two sealing devices,

b) controlling the fluid pressure in the annular volume around the drill string between the two sealing devices so that this pressure is greater than the fluid pressure in the annular volume around the drill string directly below the lowermost sealing device, and

c) varying the sealing pressure exerted by one of the or both sealing devices to establish a desired rate of leakage of injected fluid between one of the or both the sealing devices and the drill string.

In this case, preferably the fluid pressure in the annular volume around the drill string between the two sealing devices is also controlled so that this pressure is greater than the fluid pressure in the annular volume around the drill string directly above the uppermost sealing device.

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The drilling system may be provided with an injection line which connects the annular volume around the drill string between the two sealing devices, with an injection pump which is operable to pump fluid from a fluid reservoir into the annular volume around the drill string between the two sealing devices.

The drilling system may be provided with a return line which connects the annular volume around the drill string between the two sealing devices, with a fluid reservoir, there being a back pressure valve provided in the return line, the back pressure valve being adjustable to restrict the flow of fluid along the return line to a greater or lesser extent. In this case, the method may further include the step of controlling the fluid pressure in the annular volume around the drill string between the two sealing devices by controlling the back pressure valve to vary to the extent to which it restricts flow of fluid along the return line.

Preferably, the return line is connected to the same fluid reservoir as the injection pump.

In one embodiment, an injection pressure sensor is provided to measure the fluid pressure in the injection line.

In one embodiment, a return pressure sensor is provided to measure the fluid pressure in the return line. In this case, the return pressure sensor is preferably located upstream of the back pressure valve.

The pressure measured by a pressure sensor located in one or both of the injection line and/or return line may be used in controlling the fluid pressure in the annular volume around the drill string between the two sealing devices.

The method may further include the step of controlling the fluid pressure in the annular volume around the drill string between the two sealing devices by controlling the sealing pressure of one of the or both sealing devices.

A flow meter may be provided in the return line upstream of the back pressure valve, and a flow meter may be provided in the injection line. In this case, the method may further include monitoring the inflow rate of flow of fluid into the annular volume around the drill string between the two sealing devices, and the outflow rate of flow of fluid out of the annular volume around the drill string between the two sealing devices, comparing the inflow rate and outflow rate, and using this comparison to detect a loss of sealing integrity of one or both of the sealing devices.

Preferably the injection flow meter and return flow meter are both mass flow meters, and the method further includes the step of comparing the inflow rate and outflow rate, and using this comparison to detect an influx of gas into the injected fluid.

The drilling system further includes a mud gas separator, and the method further includes directing fluid from the return line to the mud gas separator is gas is detected in the injected fluid, and returning degasified liquid from the mud gas separator to the fluid reservoir. In this case, the return line preferably includes a main returns flow line which extends directly to the fluid reservoir and an emergency returns flow line which extends to the mud gas separator, and a valve assembly which is operable to control flow of fluid along the main returns flow line and emergency returns flow line. In this case, the method may include the step of operating the valve assembly to close the main returns flow line and open the emergency returns flow line if gas is detected in the injected fluid.

The drilling system may further include a pressure relief system which is operable to direct fluid from the annular volume around the drill string between the two sealing devices to the fluid reservoir if the pressure in the annular volume around the drill string between the two sealing devices exceeds a predetermined level. The pressure relief system may include a pressure relief valve which is located in a pressure relief line between the return line and the fluid reservoir, and is configured to allow flow of fluid along the pressure relief line if the pressure in the annular volume around the drill string between the two sealing devices exceeds a predetermined level. The pressure relief line may extend from the pressure relief valve to the fluid reservoir via the mud gas separator.

The drilling systems may be configured to switch off the injection pump automatically if the pressure in the annular volume around the drill string between the two sealing devices, exceeds a predetermined level. In this case, the method may further include adjusting the sealing pressure of one of the or both sealing devices to reduce the pressure in the annular volume around the drill string between the two sealing devices to below the predetermined level.

The pressure relief system may include a pressure relief valve which is located in a pressure relief line between the injection line and the fluid reservoir, and is configured to allow flow of fluid along the pressure relief line if the pressure in the annular volume around the drill string between the two sealing devices exceeds a predetermined level.

One or both of the sealing devices preferably includes a tubular seal which is mounted around the drill string.

One or both of the sealing devices may further include a housing with a main passage, and an actuator which is operable to urge the seal into sealing engagement with the drill string. The actuator may comprise a piston which is movable generally parallel to the longitudinal axis of the main passage in the housing. One or both of the sealing devices may further include an annular packer which has a central aperture in which the seal is mounted, the actuator being operable to act on the packer so that the packer pushes the seal into engagement with a drill string extending along the main passage of the housing.

There is also provided a tangible computer readable medium having installed thereon instructions which when executed by a processing device cause the processing device to implement the method described above.

An embodiment of the invention will now be described, by way of example only, with reference to the following figures of which,

FIGURE 1 shows a schematic illustration of a drilling system according to the first aspect of the invention,

FIGURE 2 shows a flow chart illustrating a method of using the drilling system shown in Figure 1, and according to the second aspect of the invention.

Referring now to Figure 1, there is shown a drilling system 10 including two sealing devices 12a, 12b, and a drill string 14, the sealing devices 12a, 12b being operable to seal around drill string 14 to contain fluid pressure in the annular space around the drill string 14, whilst allowing the drill string 14 to rotate about its longitudinal axis A.

In this example, the drilling system is an offshore system which includes an offshore marine riser 15, with a section of riser 15a above and a section of riser 15b below the sealing devices 12a, 12b. The drill string 14 extends from the surface, down the riser 15, through the sealing devices 12a, 12b, and into the wellbore below. The annular space around the drill string 14 below the lowest sealing device 12b contains the returned fluid stream from the wellbore being drilled at pressure P_{WB}, and may contain fluids, solids, and entrained gas. The annular space around the drill string 14 above the upper sealing device 12a contains a column of drilling fluid at atmospheric pressure with a hydrostatic pressure P_{HP} acting downwards on the sealing device 12a at the bottom of the fluid column. The magnitude of P_{HP} is determined by the mud weight and the setting depth of the sealing devices 12a, 12b within the riser configuration.

It should be appreciated, however, that the invention may equally be employed in a land based drilling system, in which case the sealing devices could be installed on the top of a land based blowout preventer (BOP).

Examples of suitable sealing devices are shown in WO2012127227 and WO2011128690, the contents of which are incorporated herein by reference. To summarise, however, each sealing device comprises a flexible tubular sealing element which has a main passage, along which, the drill string extends, so that the sealing element can be urged into sealing engagement with the drill string.

In these embodiments, the sealing device also includes an annular packer which is made from an elastomeric material such as rubber, and which is mounted in a tubular housing which encloses a main passage. The sealing element is located in the central aperture of the annular packer, so that, in use, the drill string 14 extends along the main passage of the housing, and through the central aperture in the annular packer. Also contained in the housing is an actuator which is operable to act on the annular packer to urge it into engagement with the sealing element, so that the sealing element is, in turn, forced into sealing engagement with the drill string 14. In a preferred embodiment, the actuator is a piston which is movable generally parallel to the longitudinal axis A of the drill string 14. Preferably the actuator is fluid pressure operated, for example the supply of pressurised fluid to a close chamber provided in the housing causing the piston to move to force the packer against the housing, thus causing the packer to constrict, so that the diameter of its central aperture reduces, and to urge the sealing element into sealing engagement with the drill string 14. The closing pressure applied to the upper and lower sealing elements of the upper and lower sealing devices 12a, 12b through this fluid pressure control system will be referred P_{RDD1} and P_{RDD2} respectively.

The sealing element is preferably retained in the desired position within the packer by means of two sets of locking dogs which are movable between a retracted position in which they are contained within the housing, and an extended position in which they extend from the housing into its main passage. The locking dogs are also preferably fluid pressure operated, and the two sets are spaced along the housing so that the sealing element is captured between the two sets when it is in the desired position, and when the or each locking dog in each set is in its extended position.

In this case, as mentioned above, two sealing devices 12a, 12b are provided, the sealing devices being spaced along the longitudinal axis A of the drill string 14. The housings of the two sealing devices 12a, 12b may be integrated to form a single housing, and the sealing elements may be joined end to end to form a dual seal sealing sleeve. In the latter case, there is no need to provide two sets of locking dogs for each sealing element – one pair will suffice to retain the sealing sleeve within the housing so that each sealing element is located in the central aperture of the associated packer.

The drilling system 10 is also provided with an injection port 16 which is located between two sealing devices 12a, 12b. Where the two sealing devices 12a, 12b are integrated in a single housing as described above, the injection port 16 preferably extends through the housing into the main passage of the housing between the upper and lower sealing elements of the seal sleeve assembly. Thus, fluid being injected into injection port 16 enters a confined annular volume 12c between the upper and lower sealing devices 12a, 12b, which forms an internal cavity and part of a circulating system, once hydraulic closing pressure P_{RDD1} has been applied to the upper sealing element and P_{RDD2} to the lower sealing element.

The injection port 16 is connected to an injection line 20 which is equipped with an injection pump 24 which is operable to draw fluid from a storage reservoir 26, and inject the fluid under pressure into the injection port 16.

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In this embodiment, the storage reservoir is divided into two volumes – an active tank 26a and a mixing tank 26b. A water or oil based low solids drilling fluid, compatible with the drilling fluid system used in the drilling operation, is mixed in the mixing tank 26b. The mixing tank 26b contains a simplified and easy to access mixing system (not shown) which provides the necessary shear force to mix lubricants or other friction reducing additives into the base fluid, and also providing constant agitation and the necessary shear force in the storage tanks 26a, 26b to ensure effective mixing and prevention of settled/separated fluids. The active tank 26a provides the sufficient volume required for the injection circuit, and supplies the necessary feed rate of fluid to the injection pump 24 through a single or series of charge pumps (not shown). The injection pump 24 is operable to supply the required fluid rate from the active tank 26a and delivers it at the required injection pressure, referred to as P_{SIC}, to the circuit given the wellbore pressure P_{WB} present.

Each tank 26a, 26b within the storage reservoir 26 is equipped with a level sensor and alarm system 28, which transmits data representing the liquid level in each tank 26a, 26b to a central processing unit (CPU) 30 for processing. These values are used in part to determine any volume anomalies occurring within the circulating volume of the injection circuit, while ensuring that the volume of fluid in the active tank 26a remains above the required operating level. The data analysis results are transmitted to the human machine interface (HMI) display 32, which is the main user interface and control for the drilling system. It is appreciated the total system volume capacity of the tanks 26a, 26b will vary, and may be determined by the space available on the offshore installation where it is used.

The HMI 12 allows a user to input operational safety set points which govern the functioning of the system. For example, this may be upper and lower limits on pressures, temperatures, and flow rates. When these set points are reached, the data is processed within the CPU 11 and alarms are triggered through the HMI 12 display. Thus, the HMI provides the user with a central control and data monitoring point for the SIC.

The injection line 20 is fitted with a pressure relief system 34 with an outlet connected to the active tank 26a of the storage reservoir 26, a flow meter 36, preferably a highly accurate mass flow meter referred to as a Coriolis meter, a pressure sensor 38, a temperature sensor 40, a check valve 42 to prevent back flow into the circuit, and an isolation valve 44. It should be appreciated that more than one isolation valves may be provided. The flow meter 36, pressure sensor 38 and temperature sensor 40, and valves 42 and 44 are all connected to the CPU 30 so that the flow, temperature, pressure, and valve status data may be processed within the CPU 30 and transmitted to the HMI display 32.

Preferably, the injection line diameter is such that large pressure losses are not incurred in the circuit at its maximum circulating rate with a specific fluid in circulation. In one embodiment, the injection line has a 51 mm (2 inch) internal diameter.

The drilling system 10 is also provided with a return port 18 located opposite the injection port 16, located between the upper and lower sealing devices 12a, 12b. A return line 22 is connected to the return port 18, and the return line 22 and injection line 20 create a closed loop circulation system with the confined annular volume 12c between the upper and lower sealing devices 12a, 12b. This closed loop is hereinafter referred to as the seal integrity circuit or SIC.

The return line 22 connects the return port 18 to the storage reservoir 26, and is equipped with a choke valve or back pressure valve 56 and two alternate flow paths. The flow path depends on the operating conditions present, for example, if there is entrained gas within the return flow stream.

In one embodiment, the return line 22 is fitted with an isolation valve 46, a pressure sensor 48, a temperature sensor 50, pressure relief system 52, a flow meter 54 which, in this embodiment, is a highly accurate mass Coriolis meter, all of which are located upstream of the back pressure valve 56. It should be appreciated that one or more isolation valves may be provided in the return line 22. As with the injection line 20, the flow meter 54, pressure sensor 48, temperature sensor 50, and valves 46 and 56 are all connected to the CPU 30 so that the flow, temperature, pressure, and valve status data may be processed within the CPU 30 and transmitted to the HMI display 32.

In a preferred embodiment, the return line diameter is such that large pressure losses are not incurred in the circuit at its maximum circulating rate with the fluid type in circulation. For example, the return line 22 may be, but is not limited to, a 51 mm (2 inch) in internal diameter.

The isolation valves 44, 46 and choke valve 56 are “fail close” valves to prevent the escape of fluid from the confined annular volume between the two sealing devices 12a, 12b, such that pressure is maintained within the circuit if a return line rupture or leak occurs.

The pressure sensors 38, 48 in the injection line 20 and return line 22 thus monitor the SIC pressure P_{SIC} upstream and downstream of the confined annular volume 12c between the two sealing devices 12a, 12b. This is the measurement of the pressure contained within the confined annular volume 12c between the upper and lower sealing devices 12a, 12b, the injection line 20, and the return line 22 up to the back pressure valve 56.

In one embodiment, the drilling system 10 includes a further pressure sensor 58, hereinafter referred to as the lower annulus pressure sensor 58, which is located in the annular space around the drill string 14 below the lowermost sealing device 12b, and, as such, monitors the wellbore pressure P_{WB} in the riser or wellbore annulus below the lowest sealing device 12b. A further pressure sensor 60, hereinafter referred to as the upper annulus pressure sensor 60, is located in the annular space around the drill string 14 above the uppermost sealing device 12b. This pressure sensor 60 thus monitors the hydrostatic pressure acting downwards on the upper sealing device 12a from the height of the fluid column in the annulus above the sealing devices 12a, 12b, and its value depends on the mud weight and setting depth of the sealing devices 12a, 12b within the riser. Again, these pressure sensors 58, 60 are connected to the central CPU 30 so that data signals representative of the pressure measured by each sensor 58, 60 can be transmitted to and processed by the CPU 30 and transmitted to the HMI display 32.

As mentioned above, the return line 22 includes two alternate flow paths. An emergency flow path allows the SIC return flow stream to be diverted to a mud-gas separator (MGS) 62, whilst the main flow path allows the SIC return stream to return to the storage reservoir 26. The main flow path comprises a main return flow line 64 which extends from the return line 22 downstream of the back pressure valve 56 to the active tank 26c of the storage reservoir 26 via a return valve 65 and solids filtering device 66 used to process the returned fluid and remove entrained solids before it is returned to the storage reservoir 26. The emergency flow path comprises an emergency flow line 68 which extends from the return line 22 downstream of the back pressure valve 56 to the MGS 62 via an MGS inlet valve 70.

The MGS has a gas outlet 72 which vents to a safe area away from the rig, and a liquid outlet 74 which is connected to the rig's conventional fluid treatment system.

An outlet of the pressure relief system 52 in the return line 22 is also connected to the MGS 62.

In a preferred embodiment, the injection pump 24, valves 44, 46, 56, 65, and 70, pressure relief systems 34, 52, and the hydraulic control valves for closing or opening the two sealing devices 12a, 12b are all connected to the central CPU 11, so that operation of these may be controlled by the CPU 30 through programmable logic controllers (PLC) is as well known in the art.

The pressure relief systems 34, 52 included in the injection line 20 and return line 22 are configured to activate when the SIC pressure approaches a maximum static operating pressure $P_{MAX\ static}$. As mentioned above, on the injection line 20 the relief system 34 relieves fluid pressure to the active tank 26a, whilst in the return line 22, the pressure relief system 52 relieves pressure to the MGS 62 to mitigate any gas that may be present in the fluid stream when $P_{MAX\ static}$ is reached. The setpoint for the pressure relief systems 34, 52 is a user input within the HMI 32, and the central CPU 30 processes data from the pressure sensors 38 (i.e. measuring upstream pressure) and 48 (i.e. measuring downstream pressure) to determine if the maximum allowable static pressure $P_{MAX\ static}$ of the circuit is being approached. The pressure relief systems 34, 52 relieve the pressure within the SIC once the safety set point is reached. Check valve 42 in the injection line 20 prevents reverse flow from occurring back through the injection line as the injection line pressure relief system 34 relieves pressure to the active tank 26a. The safety setpoint may be, but is not limited to, 80% to 90% of the maximum allowable circulating pressure $P_{MAX\ static}$.

A further return port (not shown) may also be provided directly above the uppermost sealing device 12a. This further return port could be connected to the main return flow line 64, the or to a further return line which extends to the storage reservoir 26. In this case, advantageously, a further flow meter is provided to measure the rate of flow of fluid through the further return port.

A method of operating the drilling system 10 is illustrated in Figure 2, and will be described further below.

With the drill string 14 present as described above, the injection pump 24 is operated to establish an injection rate through the injection port 16 and into the volume between the upper and lower sealing devices 12a, 12b. The injected fluid therefore displaces the fluid present in the confined annular volume 12c between the two sealing devices 12a, 12b, and exits through the return port 18. The sealing devices 12a, 12b, are, at this stage, still open, sothe fluid displaced by the injected fluid, and then the injected fluid itself, also flows upwards and downwards through the riser. This displaces the drilling fluid below the sealing devices to create a fluid buffer below the sealing devices 12a, 12b. Once this displacement of drilling fluid is completed, the injection of fluid through the injection port 16 is momentarily stopped, whilstthe sealing devices 12a, 12b are closed by energising both sealing elements of the seal sleeve so that they enter into sealing engagement with the drill string 14.

Injection of fluid through the injection port 16 is then resumed. At this stage, substantially all of the injected fluid exits the confined annular volume 12c between the two sealing devices 12a, 12b via the return port 18, and so the flow rate through the injection port 16 (measured using flow meter 36) is substantially equal to the flow rate through the return port 18 (measured using flow meter 54). The closing pressure of the lowest sealing device 12b is then reduced until a reduction in the return flow rate is detected, indicating there is fluid flowing across the lower sealing face

The same may be performed for the upper sealing device 12a, with a further decrease in the return line rate indicating that there is fluid flowing across the upper sealing face. In this case, where there is a further return port provided above the upper sealing device 12a, this fluid is returned to the storage reservoir via the further return port. Alternatively, if no such further return port is provided, because the riser volume above the sealing devices 12a, 12b will be full of fluid anyway, this fluid returns to rig's fluid treatment system via the conventional diverter system.

The injected fluid thus provides lubrication and cooling within the sealing faces of the sealing devices to minimize heat generation, friction, and wear rates of the sealing elements. Furthermore, the fluid creates a fluid buffer zone directly beneath the lowest sealing device which displaces the drilling fluid, drilling solids, and gasified fluid away from the confined annular volume 12c such that the likelihood of invasion of gas and fluid upwards through the sealing faces of the sealing devices 12a, 12b is reduced. As such, the injected fluid is preferably a fluid with low friction coefficients and relatively high heat transfer coefficients. Additives may be added to the fluid to further alter friction and heat transfer properties.

At this point, the MGS inlet valve 70 is closed, and the return flow valve 65 is open, so the return flow stream flows along the main return flow line 64 and is diverted through the solids filtering device 66 and back to the storage reservoir 26, maintaining the SIC circulating volume. The flow of injected fluid across the sealing faces of the sealing devices 12a, 12b ensures that lubrication of the sealing devices 12a, 12b is achieved and so drilling can commence, with any changes to the injection and return rates and pressures signifying changes in the integrity of the seal sleeve. Monitoring the temperature of the return stream will indicate the degree of friction present with the associated closing pressures, wellbore pressure, and drillpipe speed through the seal sleeve. Automatic adjustment of the closing pressures on the sealing devices can be used to achieve an optimal fluid injection rate across the sealing faces which results in a maximum reduction in friction, heat generation, and wear rate for any wellbore pressure that is present.

The SIC operating pressure may also be automatically maintained at a safe level above the existing wellbore pressure, whilst ensuring a positive differential pressure exists across the sealing devices 12a, 12b, and alarms raised when SIC pressure values decrease to user input set points within the CPU 30. A positive differential pressure assists in maintaining seal integrity when larger diameter tubulars or diametrical changes pass through the seal sleeve assembly. Furthermore, over pressuring of the SIC is prevented through the pressure relief valve systems 34, 52 in both the injection line 20 and return line 22.

The desired operating SIC pressure P_{SIC} is defined by the largest magnitude of pressure the sealing devices 12a, 12b are exposed to. Hence, the greater of the wellbore pressure P_{WB} and the upper riser annulus hydrostatic pressure P_{HP} is determined, and the 1.7 MPa (250 psi) to 3.4 MPa (500 psi) positive differential is applied to the greater of these two pressures. The hydrostatic pressure P_{HP} effects becomes more prominent at deeper subsea setting depths for the RDD, but at shallow or surface set depths the largest pressure differential is always created by the wellbore pressure P_{WB} across the lower sealing device 12b.

The positive differential ΔP_{LOWER} across the lower sealing device 12b is achieved through the continuous data analysis within the algorithms of the CPU 30 from pressure PT1 measured by the injection line pressure sensor 38, the pressure PT4 measured by the return line pressure sensor 48 and the pressure PT2 measured by the lower annulus pressure sensor 58, and is represented by the relationships

$$PT4 - PT2 = \Delta P_{LOWER}$$

$$PT1 - PT2 = \Delta P_{LOWER}$$

Or alternately

$$P_{SIC} - P_{WB} = \Delta P_{LOWER}$$

Where the pressure values measured by the injection pressure sensor 38 and return line pressure sensor 48 are the SIC circulating pressure P_{SIC} upstream and downstream of the confined annular volume 12c. The relationships described herein represent the same parameter (ΔP_{LOWER}), with PT4 and PT1 providing qualitative data checks on P_{SIC} through an upstream PT1 and downstream PT4 pressure measurement. ΔP_{LOWER} should be a positive value, representing a positive pressure differential ΔP_{LOWER} across the lower sealing element when the sealing devices 12a, 12b are installed near the surface of a marine riser or on top of a land based BOP. However, at deeper subsea setting depths in a marine riser these conditions change, which is discussed later. A positive differential pressure ΔP_{LOWER} may reduce the likelihood of the ingress of wellbore fluid from the annulus below the sealing devices 12a, 12b at the current wellbore pressure P_{WB} through the lower sealing device 12b, which is undesired as it may contain solids and entrained gas.

Furthermore, by applying the SIC pressure P_{SIC} through the confined annular volume 12c, the magnitude of the differential pressure ΔP_{LOWER} across the lowest sealing device 12b is decreased. Lower wear rates in the sealing element of any BOP or pressure containment device are observed at lower wellbore pressures P_{WB}. Without applying the SIC pressure P_{SIC}, the largest differential pressure ΔP_{LOWER} exists within the sealing face in the lower area of the lowermost sealing device 12b and results in a tendency to wear at a higher rate during drill string 14 movement. By increasing P_{SIC} within a range of 1.7 MPa (250 psi) to 3.4 MPa (500 psi) above the wellbore pressure P_{WB}, the differential pressure ΔP_{LOWER} across the lower sealing device 12b and within the lower area of the seal is greatly decreased. Thus the operational longevity of the seal sleeve assembly may be enhanced.

For example, if the wellbore pressure P_{WB} is 5.2 MPa (750 psi), the SIC pressure P_{SIC} is increased to 6.9 MPa (1,000 psi), and both injection pressure sensor 38 and return pressure sensor 48 measure a circuit pressure of 6.9 MPa (1,000 psi), the following relationships hold true

$$PT4 - PT2 = 6.9 \text{ MPa } (1000 \text{ psi}) - 5.2 \text{ MPa } (750 \text{ psi}) = 1.7 \text{ MPa } (250 \text{ psi}) = \Delta P_{LOWER}$$

$PT1 - PT2 = 6.9$ MPa (1000 psi) – 5.2 MPa (750 psi) = 1.7 MPa (250 psi) = ΔP_{LOWER}

$P_{SIC} - P_{WB} = 6.9$ MPa (1000 psi) – 5.2 MPa (750 psi) = 1.7 MPa (250 psi) = ΔP_{LOWER}

Hence, a positive differential pressure ΔP_{LOWER} of 1.7 MPa (250 psi) exists across the lower sealing device 12b.

It will be appreciated, of course, that these values are used by way of example only, and the SIC pressure P_{SIC} may circulate at any given pressure above the wellbore pressure P_{WB}, as long as a positive pressure differential ΔP_{LOWER} results across the lower sealing device 12b.

It is also desired to maintain a positive differential pressure ΔP_{UPPER} across the upper sealing device 12a. This is to prevent the ingress of drilling fluid from the column of drilling fluid in the riser annulus above the upper sealing device 12a into the SIC. With the sealing devices 12a, 12b installed close to surface in the riser or on top of a land based BOP, this is not an issue as a short column of fluid above results in a very minimal acting hydrostatic pressure P_{HP} given these conditions. A positive differential pressure ΔP_{UPPER} always results as the largest magnitude of pressure is the wellbore pressure P_{WB} given these conditions, and the SIC pressure P_{SIC} adjusts to mitigate this pressure P_{WB}. However, as the subsea setting depth deepens, the hydrostatic pressure P_{HP} becomes more pronounced.

The positive differential ΔP_{UPPER} across the upper sealing element 4A is achieved through the continuous data analysis within the algorithms of the CPU 30 using the pressure PT1 measured by the injection line pressure sensor 38, the pressure PT4 measured by the return line pressure sensor 48 and the pressure PT3 measured by the upper annulus pressure sensor 60, and is represented by the relationships:

$$PT4 - PT3 = \Delta P_{UPPER}$$

$$PT1 - PT3 = \Delta P_{UPPER}$$

Or alternately

$$P_{SIC} - P_{HP} = \Delta P_{UPPER}$$

Where the pressure values measured by the injection pressure sensor 38 and the return pressure sensor 48 are the SIC circulating pressure P_{SIC} upstream and downstream of the confined annular volume 12c. The relationships, described herein, represent the same parameter (ΔP_{UPPER}), with PT4 and PT1 providing qualitative data checks on P_{SIC} through an upstream PT1 and downstream PT4 pressure measurement. ΔP_{UPPER} should be a positive value, representing a positive pressure differential ΔP_{UPPER} across the upper sealing device 12a when the sealing devices 12a, 12b, which is always the case, is installed near or at the surface.

For example, with the setting depth of the sealing devices 12a, 12b set at 91 m (300 ft) and a drilling fluid density of 1200 kgm^{-3} (10 ppg), the resultant hydrostatic pressure P_{HP} acting on the upper sealing device 12a is:

P_{HP} = Height x Mud Weight x 0.052

P_{HP} = 91 m (300 ft) x 1200 kgm^{-3} (10 ppg) x 1.00 x 10^{-5} (0.052) = 1.1 MPa (156 psi)

If the hydrostatic pressure P_{HP} is 1.1 MPa (156 psi) and the current wellbore pressure P_{WB} is 3.4 MPa (500 psi), the wellbore pressure P_{WB} is determined to be the highest degree of pressure present, thus creating the largest negative differential pressure ΔP_{LOWER} across the lower sealing device 12a. Thus a negative differential pressure ΔP_{UPPER} of 1.1 MPa (156 psi) exists across the upper sealing device 12 and a negative differential pressure ΔP_{LOWER} of 3.4 MPa (500 psi) exists across the lower sealing device 12b in absence of SIC pressure P_{SIC}. Therefore, the SIC pressure P_{SIC} is increased to 5.2 MPa (750 psi) to decrease the differential pressure ΔP_{LOWER} across the lower sealing device 12a and impose a 1.7 MPa (250 psi) positive pressure differential ΔP_{LOWER} across the lower sealing device 12b.

The following relationships for the upper sealing device 12a hold true assuming PT4 and PT1 are measuring 5.2 MPa (750 psi) of SIC pressure:

PT4 – PT3 = 5.2 MPa (750 psi) – 1.1 MPa (156 psi) = 4.1 MPa (594 psi) = ΔP_{UPPER}

PT1 – PT3 = 5.2 MPa (750 psi) – 1.1 MPa (156 psi) = 4.1 MPa (594 psi) = ΔP_{UPPER}

P_{SIC} – P_{HP} = 5.2 MPa (750 psi) – 1.1 MPa (156 psi) = 4.1 MPa (594 psi) = ΔP_{UPPER}

Thus, a positive pressure differential ΔP_{UPPER} of 4.1 MPa (594 psi) is also created across the upper sealing element under these conditions.

However, if the subsea setting depth is increased to 610 m (2,000 ft) with a 1200 kgm^{-3} (10 ppg) drilling fluid density, the following hydrostatic pressure results:

610 m (2,000 ft) x 1200 kgm^{-3} (10 ppg) x 1.00 x 10^{-5} (0.052) = 7.2 MPa (1040 psi)

If the current wellbore pressure P_{WB} is 5.2 MPa (750 psi) the algorithms within the CPU 30 determine the hydrostatic pressure P_{HP} is the highest degree of pressure present, thus creating the largest negative differential pressure ΔP_{UPPER} across the upper sealing device 12a. Thus a negative differential pressure ΔP_{UPPER} of 7.2 MPa (1040 psi) exists across the upper sealing device 12a and a negative differential pressure ΔP_{LOWER} of 5.2 MPa (750 psi) exists across the lower sealing device 12b in the absence of SIC pressure P_{SIC}.

Therefore, the SIC pressure P_{SIC} is increased to 8.9 MPa (1,290 psi) to decrease the differential pressure ΔP_{UPPER} across the upper sealing device 12a and impose a 1.7 MPa (250 psi) positive pressure differential ΔP_{UPPER} across the upper sealing device 12a. Subsequently, a positive differential pressure ΔP_{LOWER} of 3.7 MPa (540 psi) is produced across the lower sealing device 12b.

It will be appreciated that the SIC pressure will be determined by the speed of operation of the injection pump 24, the degree of restriction of fluid flow along the return line 22 provided by back pressure valve 56, and the closing pressures P_{RDD1} and P_{RDD2} applied to the two sealing devices 12a, 12b (as this determines the rate of leakage of fluid out of the confined annular volume 12c). As mentioned above, however, automatic adjustment of the closing pressures on the sealing devices 12a, 12b can be used to achieve an optimal fluid injection rate across the sealing faces which results in a maximum reduction in friction, heat generation, and wear rate for any wellbore pressure that is present.

It will therefore be appreciated that, through the process of controlling P_{SIC} to adjust the upper and lower differential pressures ΔP_{UPPER}, ΔP_{LOWER}, the leak rate through the sealing faces of the upper and lower sealing devices 12a, 12b is also affected. The flow paths become more restricted through the sealing face if the closing pressures P_{RDD1}, P_{RDD2} are increased and/or the leak rate through the sealing faces increases if the backpressure valve 56 is closed further. The hydraulic closing pressures P_{RDD1}, P_{RDD2} ultimately affect the differential pressures ΔP_{LOWER}, ΔP_{UPPER} produced across the sealing devices 12a, 12b in addition to the leak rate/lubricating rate occurring across the sealing faces. Thus, these are interrelated functions performed within the CPU 36 between the SIC and the hydraulic controls of the sealing devices 12a, 12b to optimize the leak rate and closing pressures P_{RDD1}, P_{RDD2} while maintaining the pressure integrity of the sealing devices 12a, 12b. The adjustment of the hydraulic closing pressures P_{RDD1} and P_{RDD2} in relation to the leak rate, the differential pressures ΔP_{UPPER} and ΔP_{LOWER}, and maintaining an effective seal on the drill string 14 is referred to as the Activation Pressure Bios (APB). The APB ultimately controls the leak rate through the sealing faces of the seal sleeve assembly for optimal lubrication and cooling of the system. .

The leak rate and fluid buffer methodology utilizes the injection pump 24, the injection and return flow meters 36, 54, and the closing pressures P_{RDD1} P_{RDD2} of the upper and lower sealing devices 12a, 12b. It involves the hydraulic control system of the sealing devices 12a, 12b working in parallel with the SIC for adjusting the closing pressures and leak rates to achieve maximum longevity of the seal sleeve assembly.

The data analysis carried out by the CPU 30 using data streams from the pressure sensors 38, 48, 58, 60, temperature sensors 40, 50, and flow meters 36, 54 can be used to automate the operation of the injection pump 24, valves 44, 46, 56, 65, and 70, pressure relief systems 34, 52, and the hydraulic closing pressures P_{RDD1}, P_{RDD2} through programmable logic controllers (PLC) well known in the art.

Referring now to Figure 2, this shows a flow diagram illustrating the process logic within the CPU 30 of the drilling system, which governs the pressure feedback loop for the automated adjustment of the SIC pressure.

The algorithms within the CPU 30 continuously monitor and analyse the pressure data for wellbore pressure P_{WB}, the SIC circulating pressure P_{SIC}, the hydrostatic pressure above the upper sealing element P_{HP}, the hydraulic closing pressure of the upper sealing device P_{RDD1}, and the hydraulic closing pressure of the lower sealing device P_{RDD2} 20 (step 80 in Figure 2).

If the SIC pressure P_{SIC} is at or approaching a maximum circulating pressure $P_{MAX\ circ}$ an emergency procedure is followed (82). This will be described further below. Otherwise, the algorithms within the CPU 36 evaluates the wellbore pressure P_{WB} and hydrostatic pressure P_{HP} acting on the sealing elements, and determines which is the greater of the two pressures (step 84).

If it is determined the greater of the two pressures is the wellbore pressure P_{WB}, the lower pressure differential ΔP_{LOWER} analysis is performed on the lower sealing element, examining the pressure data for the current wellbore pressure P_{WB} and the circulating pressure of the SIC P_{SIC} (step 86). If the SIC pressure P_{SIC} is greater than the current wellbore pressure P_{WB} (step 86), the algorithms identify this as a positive lower pressure differential ΔP_{LOWER}, and then analyse the magnitude of the resultant positive pressure differential ΔP_{LOWER} (step 88). If the positive pressure differential is between 1.7 MPa (250 psi) to 3.4 MPa (500 psi), the algorithms deem this safe operating conditions and drilling or tripping operations continue unimpeded (step 90).

If the lower differential pressure ΔP_{LOWER} analysis proves to be less than the existing wellbore pressure P_{WB} (step 86) the algorithms identify this as a negative lower pressure differential ΔP_{LOWER}. The back pressure valve 56 can be further closed or the hydraulic closing pressure for the lower sealing device P_{RDD2} increased to increase the differential pressure ΔP_{LOWER} across the lower sealing device 12b (step 92). Increasing the lower element closing pressure P_{LOWER} is considered the APB, described herein, and restricts the lubrication rate across the lower sealing device 12b which increases the SIC pressure P_{SIC} and ultimately increases the lower differential pressure ΔP_{LOWER}.

Once the back pressure valve 56 or the lower sealing device closing pressure P_{RDD2} has been adjusted, the algorithms within the CPU 30 examine the resultant lower differential pressure ΔP_{LOWER} (94). If it has increased, the pressure feedback loop is repeated from step 80. If the lower differential pressure ΔP_{LOWER} has not increased, a system troubleshooting procedure is implemented (step 96). The backpressure valve 56 or the lower sealing device closing pressure P_{RDD2} may be further adjusted to observe the effects on the lower pressure differential ΔP_{LOWER}. Once a positive lower differential pressure ΔP_{LOWER} has been achieved, the pressure feedback loop is repeated from step 80. If the lower differential pressure ΔP_{LOWER} is still not changing, it may be necessary to stop operations until the problem is resolved.

If it is determined in step 84 that the greater of the two pressures is the hydrostatic pressure P_{HP}, the upper pressure differential ΔP_{UPPER} analysis is performed (step 98). An identical sequence occurs for the upper differential pressure ΔP_{UPPER} analysis, with the algorithms examining the current hydrostatic pressure P_{HP} exerted on the upper sealing device 12a and evaluating if the SIC circulating pressure P_{SIC} is greater than this value.

If the SIC pressure P_{SIC} is greater than the hydrostatic pressure P_{HP}, the algorithms identify this as a positive upper pressure differential ΔP_{UPPER} and then calculates and analyses the magnitude of this value (step 100). If the positive pressure differential is between 1.7 MPa (250 psi) to 3.4 MPa (500 psi), the algorithms deem this as safe operating conditions and drilling or tripping operations continue unimpeded (step 90).

If the upper differential pressure ΔP_{UPPER} analysis (98) proves to be less than the hydrostatic pressure P_{HP}, the algorithms identify this as a negative upper pressure differential ΔP_{UPPER}. The back pressure valve BPV1 can be further closed or the hydraulic closing pressure for the upper sealing element P_{RDD1} increased to increase the differential pressure ΔP_{UPPER} across the upper sealing device 12a (step 92). Increasing the upper element closing pressure P_{UPPER} is considered the APB, described herein, and restricts the lubrication rate across the upper sealing face which increases the SIC pressure P_{SIC} and ultimately increases the upper differential pressure ΔP_{UPPER}.

Once the backpressure valve 56 or the upper sealing device closing pressure P_{RDD1} has been adjusted, the algorithms of the CPU 30 re-examine the upper differential pressure ΔP_{UPPER} (94). If it has increased, the pressure feedback loop is repeated from step 80. If the upper differential pressure ΔP_{UPPER} has not increased, a troubleshooting procedure is implemented (96). The backpressure valve 56 or the upper element hydraulic closing pressure P_{RDD1} may be further adjusted to observe the effects on the upper pressure differential ΔP_{UPPER}. Once a positive upper differential pressure ΔP_{UPPER} has been achieved, the pressure feedback loop is repeated from step 80. If the upper differential pressure ΔP_{UPPER} is still not changing, it may be necessary to stop operations until the problem is resolved.

The algorithms within the CPU 30 also detect when the maximum circulating pressure and the maximum static pressure of the SIC is approached through user input safety set points. In this embodiment, the maximum allowable circulating pressure $P_{MAX\ circ}$ is 13.8 MPa (2,000 psi) and the maximum allowable static pressure is 20.7 MPa (3,000 psi), however, it is appreciated these maximum allowable pressures may vary from system to system. When pressures approach the maximum allowable circulating pressure $P_{MAX\ circ}$ and beyond, it is considered emergency operating conditions for the SIC.

As the CPU 30 processes the data from injection and return pressure sensors 38, 48 it determines if the safety set point for the maximum allowable circulating pressure $P_{MAX\ circ}$ is being approached (step 82). When this condition occurs, the system automatically stops the injection pump 24 (step 102) and maintains the SIC pressure P_{SIC} at its last recorded value using the back pressure valve 56 and/or the hydraulic closing pressures P_{RDD1} and P_{RDD2} for the upper and lower sealing devices 12a, 12b, and pressure data from the injection pressure transducer 38 and return pressure transducer 48 (step 104) – this prevents the circulating pressure capacity $P_{MAX\ circ}$ of the SIC from being exceeded. The safety setpoint may be, but is not limited to, 80% to 90% of the maximum allowable circulating pressure rating $P_{MAX\ circ}$.

If the pressure P_{SIC} starts returning to within its safe operating range, the injection pump 24 is restarted, and normal operations resume (step 106).

On the other hand, if P_{SIC} continues to increase so that the maximum allowable circulating pressure $P_{MAX\ circ}$ is reached, all movement of the drill string 14 through the sealing devices 12a, 12b ceases, and therefore current operations cease. At this stage, the main priority of the SIC is to maintain the seal integrity of the upper and lower sealing devices 12a, 12b, and to continue to provide a positive differential pressure across a single or both sealing devices 12a, 12b. The hydraulic pressure controls apply the optimal closing pressures P_{RDD1} P_{RDD2} on the upper sealing device 12a and lower sealing device 12b during this procedure.

The CPU 30 continues to monitor the wellbore pressure P_{WB} and/or the SIC pressure P_{SIC} to determine if they are continuing to increase or starting to decrease to a safe operating pressure range. Subsequently, if it is then determined that the SIC pressure P_{SIC} is approaching the maximum static pressure capacity of the system $P_{MAX\ static}$ 33, the pressure relief systems 34, 52 operate to vent fluid to the MGS 62 and the active tank 26a of the system (step 110). Typically, the CPU 30 is programmed to activate the pressure relief systems 34, 52 if P_{SIC} reaches 80% to 90% of the maximum static pressure $P_{MAX\ static}$. The algorithms within the CPU 30 continue to analyse the pressure data during such a pressure relief event and adjust the hydraulic closing pressures P_{RDD1} and P_{RDD2} accordingly to maintain the pressure integrity of the seal sleeve assembly during these high pressure conditions.

Once the SIC pressure P_{SIC} decreases back to within its safe operating range (i.e. less than $P_{MAX\ circ}$) the injection pump automatically starts and circulation recommences. At this point, the SIC returns to normal operating conditions.

When gas is detected in the returning fluid, this is also considered an emergency operating condition and flow is diverted to the MGS 62 to degas the fluid and remove solids from the return stream before returning it to the rig fluid treatment system where it becomes part of the rig's active circulating system.

The presence of gas is detected using the flow meter 54 in the return line. As this is a mass flow meter such as a Coriolis meter, it does not measure the volume per unit time passing through the device (i.e. the volumetric flow rate), but measures the mass per unit time flowing through the device (the mass flow rate). Volumetric flow rate is the mass flow rate divided by the density. The density of the fluid may change with temperature, pressure, or composition, for example, with gas entrained within the SIC fluid. When gas is present in the system, the returning fluid density decreases from the original base fluid density and this is detected by the return line flow meter 54 as a change in mass flow rate. A change in mass flow rate could, of course, be the result of a change in fluid density rather than a change in return volume flow rate (which could, for example, be occurring due to increased leak rate across one of the seals. As such, the Coriolis meter measures actual density, in addition to temperature and flow rate. The Coriolis effect measured by the meter changes with changes in density, and thus it accurately detects density changes with a gas versus a liquid. Algorithms built into the central CPU 30 identify a change in density versus a change in flow rate, which would then trigger a further emergency procedure. When gas is detected in the return stream, the CPU 30 signals an alarm signal to the HMI 32, automatically opens the MGS inlet valve 70 and then closes the main return line valve 65 to divert the returning fluid to the MGS 62 for degassing and phase separation. All separated gas is vented to a safe area away from the rig, with the degassed fluid and/or solids diverted to the rig's fluid treatment system. The returned degassed fluid from the MGS 62 is continually added to the rig's active volume until gas is completely absent from the return stream. This is determined using the output of the return line flow meter 54, and when this indicates that the density of the return flow stream has returned to the density value of the injected fluid, the return line valve 65 is opened and the MGS inlet valve 70 closed again.

When used in this specification and claims, the terms "comprises" and "comprising" and variations thereof mean that the specified features, steps or integers are included. The terms are not to be interpreted to exclude the presence of other features, steps or components.

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CLAIMS

1. A method of operating a drilling system for drilling a subterranean bore hole, the drilling system including a drill string and two sealing devices which are operable to provide a substantially fluid tight seal around the drill string whilst the drill string is rotating during drilling, wherein one of the or both sealing devices is configured such that the sealing pressure it exerts on the drill string when operated to seal against the drill string can be varied,

wherein the method includes the steps of:

a) injecting fluid into the annular volume around the drill string between the two sealing devices,

b) controlling the fluid pressure in the annular volume around the drill string between the two sealing devices so that this pressure is greater than the fluid pressure in the annular volume around the drill string directly below the lowermost sealing device, and

c) varying the sealing pressure exerted by one of the or both sealing devices to establish a desired rate of leakage of injected fluid between one of the or both the sealing devices and the drill string.

2. A method according to claim 1 wherein the fluid pressure in the annular volume around the drill string between the two sealing devices is also controlled so that this pressure is greater than the fluid pressure in the annular volume around the drill string directly above the uppermost sealing device.

3. A method according to claim 1 or 2 wherein the drilling system is provided with an injection line which connects the annular volume around the drill string between the two sealing devices with an injection pump which is operable to pump fluid from a fluid reservoir into the annular volume around the drill string between the two sealing devices.

4. A method according to any preceding claim wherein the drilling system is provided with a return line which connects the annular volume around the drill string between the two sealing devices with a fluid reservoir, there being a back pressure valve provided in the return line, the back pressure valve being adjustable to restrict the flow of fluid along the return line to a greater or lesser extent.

5. A method according to claim 4 wherein the method further includes the step of controlling the fluid pressure in the annular volume around the drill string between the two sealing devices by controlling the back pressure valve to vary to the extent to which it restricts flow of fluid along the return line.

6. A method according to claim 3 and 4 wherein the return line is connected to the same fluid reservoir as the injection pump.

7. A method according to claim 3 wherein an injection pressure sensor is provided to measure the fluid pressure in the injection line.

8. A method according to claim 4, 5 or 6 wherein a return pressure sensor is provided to measure the fluid pressure in the return line.

9. A method according to claim 8 wherein the return pressure sensor is located upstream of the back pressure valve.

10. A method according to claim 3 or 4 wherein the pressure measured by a pressure sensor located in one or both of the injection line and/or return line is used in controlling the fluid pressure in the annular volume around the drill string between the two sealing devices.

11. A method according to any preceding claim wherein the method further includes the step of controlling the fluid pressure in the annular volume around the drill string between the two sealing devices by controlling the sealing pressure of one of the or both sealing devices.

12. A method according to claim 3 wherein a flow meter is provided in the return line upstream of the back pressure valve, and a flow meter is provided in the injection line.

13. A method according to claim 12 wherein the method further includes monitoring the inflow rate of flow of fluid into the annular volume around the drill string between the two sealing devices, and the outflow rate of flow of fluid out of the annular volume around the drill string between the two sealing devices, comparing the inflow rate and outflow rate, and using this comparison to detect a loss of sealing integrity of one or both of the sealing devices.

14. A method according to claims 7 and 8 wherein the injection flow meter and return flow meter are both mass flow meters, and the method further includes the step of comparing the inflow rate and outflow rate, and using this comparison to detect an influx of gas into the injected fluid.

15. A method according to claim 8 wherein the drilling system further includes a mud gas separator, and the method further includes directing fluid from the return line to the mud gas separator if gas is detected in the injected fluid, and returning degasified liquid from the mud gas separator to the fluid reservoir.

16. A method according to claim 15 wherein the return line includes a main returns flow line which extends directly to the fluid reservoir and an emergency returns flow line which extends to the mud gas separator, and a valve assembly which is operable to control flow of fluid along the main returns flow line and emergency returns flow line.

17. A method according to claim 16 wherein the method includes the step of operating the valve assembly to close the main returns flow line and open the emergency returns flow line if gas is detected in the injected fluid.

18. A method according to any preceding claim wherein the drilling system further includes a pressure relief system which is operable to direct fluid from the annular volume around the drill string between the two sealing devices to the fluid reservoir if the pressure in the annular volume around the drill string between the two sealing devices exceeds a predetermined level.

19. A method according to claim 18 wherein the pressure relief system includes a pressure relief valve which is located in a pressure relief line between the return line and the fluid reservoir, and is configured to allow flow of fluid along the pressure relief line if the pressure in the annular volume around the drill string between the two sealing devices exceeds a predetermined level.

20. A method according to claim 19 wherein the pressure relief line extends from the pressure relief valve to the fluid reservoir via the mud gas separator.

21. A method according to any preceding claim wherein the drilling systems is configured to switch off the injection pump automatically if the pressure in the annular volume around the drill string between the two sealing devices exceeds a predetermined level.

22. A method according to any preceding claim wherein the method further includes adjusting the sealing pressure of one of the or both sealing devices to reduce the pressure in the annular volume around the drill string between the two sealing devices to below the predetermined level.

23. A method according to any preceding claim wherein the pressure relief system includes a pressure relief valve which is located in a pressure relief line between the injection line and the fluid reservoir, and is configured to allow flow of fluid along the pressure relief line if the pressure in the annular volume around the drill string between the two sealing devices exceeds a predetermined level.

24. A method according to any preceding claim wherein one or both of the sealing devices includes a tubular seal which is mounted around the drill string.

25. A method according to claim 24 wherein one or both of the sealing devices further includes a housing with a main passage, and an actuator which is operable to urge the seal into sealing engagement with the drill string.

26. A method according to claim 25 wherein the actuator comprises a piston which is movable generally parallel to the longitudinal axis of the main passage in the housing.

27. A method according to any preceding claim wherein one or both of the sealing devices further includes an annular packer which has a central aperture in which the seal is mounted, the actuator being operable to act on the packer so that the packer pushes the seal into engagement with a drill string extending along the main passage of the housing.

28. A tangible computer readable medium having installed thereon instructions which when executed by a processing device cause the processing device to implement the method according to any preceding claim.