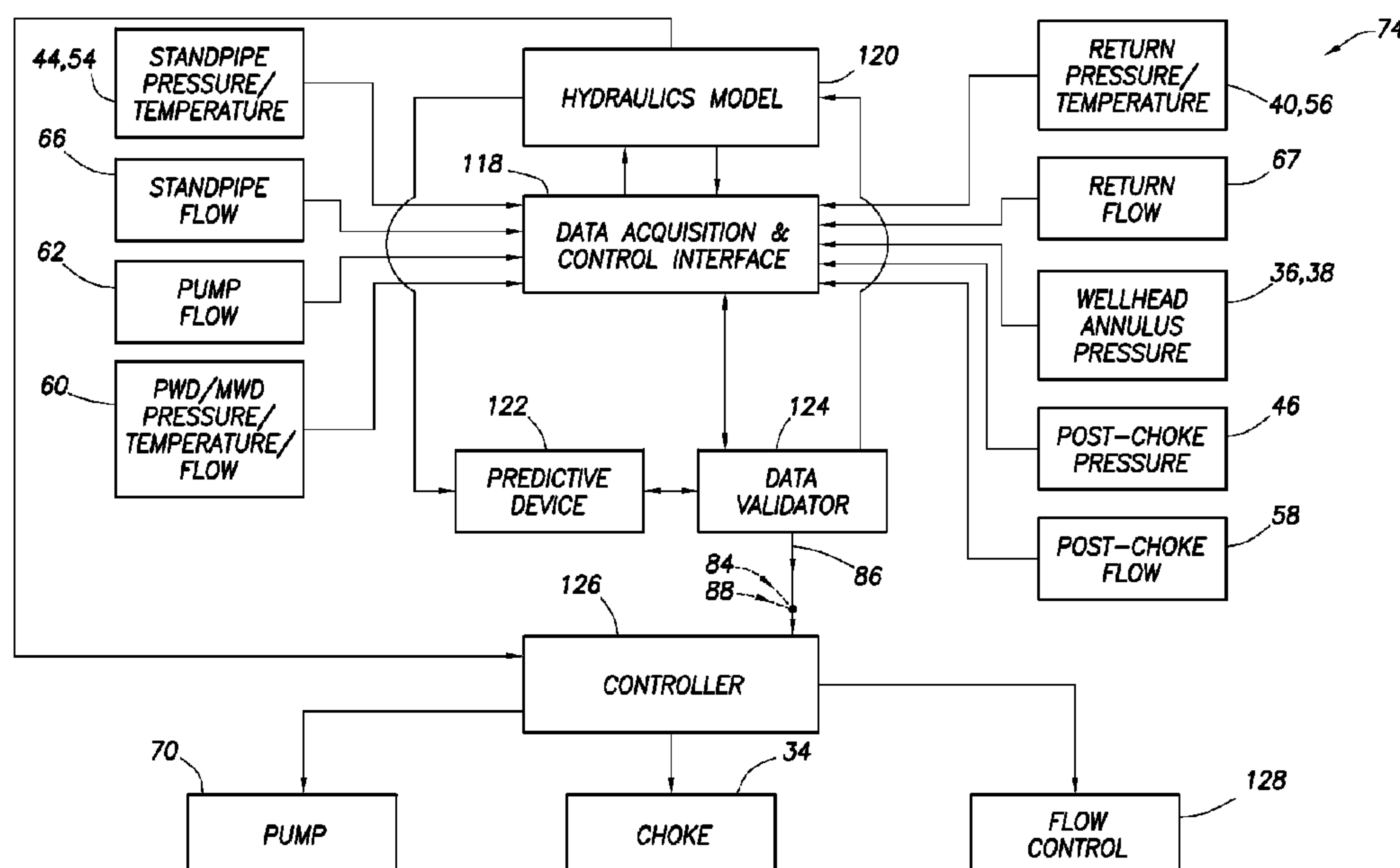




(86) **Date de dépôt PCT/PCT Filing Date:** 2011/04/08
(87) **Date publication PCT/PCT Publication Date:** 2012/10/11
(45) **Date de délivrance/Issue Date:** 2015/11/17
(85) **Entrée phase nationale/National Entry:** 2013/08/21
(86) **N° demande PCT/PCT Application No.:** US 2011/031767
(87) **N° publication PCT/PCT Publication No.:** 2012/138349

(51) **Cl.Int./Int.Cl.** *E21B 21/08* (2006.01),
E21B 47/00 (2012.01), *E21B 47/06* (2012.01)
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(54) **Titre : COMMANDE DE PRESSION AUTOMATIQUE DE COLONNE MONTANTE DANS UN FORAGE**
(54) **Title: AUTOMATIC STANDPIPE PRESSURE CONTROL IN DRILLING**

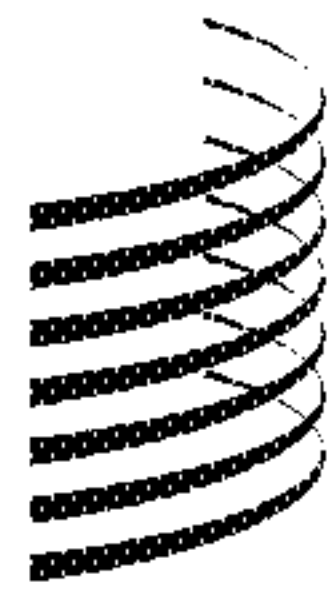


(57) **Abrégé/Abstract:**

A method of controlling standpipe pressure in a drilling operation can include comparing a measured standpipe pressure to a desired standpipe pressure, and automatically adjusting a choke in response to the comparing, thereby reducing a difference between the measured standpipe pressure and the desired standpipe pressure. A standpipe pressure control system for use in a drilling operation can include a controller which outputs an annulus pressure setpoint based on a comparison of a measured standpipe pressure to a desired standpipe pressure, and a choke which is automatically adjusted in response to the annulus pressure setpoint. A well system can include a standpipe line connected to a drill string in a wellbore, a sensor which measures pressure in the standpipe line, and a controller which outputs an annulus pressure setpoint based at least in part on a difference between the measured pressure and a desired standpipe pressure.

(12) INTERNATIONAL APPLICATION PUBLISHED UNDER THE PATENT COOPERATION TREATY (PCT)

(19) World Intellectual Property
Organization
International Bureau



(43) International Publication Date
11 October 2012 (11.10.2012)

WIPO | PCT

(10) International Publication Number
WO 2012/138349 A1

(51) International Patent Classification:

E21B 21/08 (2006.01) *E21B 47/06* (2006.01)
E21B 47/00 (2006.01)

(21) International Application Number:

PCT/US2011/031767

(22) International Filing Date:

8 April 2011 (08.04.2011)

(25) Filing Language:

English

(26) Publication Language:

English

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(81) Designated States (unless otherwise indicated, for every
kind of national protection available): AE, AG, AL, AM,
AO, AT, AU, AZ, BA, BB, BG, BH, BR, BW, BY, BZ,

CA, CH, CL, CN, CO, CR, CU, CZ, DE, DK, DM, DO,
DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, GT, HN,
HR, HU, ID, IL, IN, IS, JP, KE, KG, KM, KN, KP, KR,
KZ, LA, LC, LK, LR, LS, LT, LU, LY, MA, MD, ME,
MG, MK, MN, MW, MX, MY, MZ, NA, NG, NI, NO, NZ,
OM, PE, PG, PH, PL, PT, RO, RS, RU, SC, SD, SE, SG,
SK, SL, SM, ST, SV, SY, TH, TJ, TM, TN, TR, TT, TZ,
UA, UG, US, UZ, VC, VN, ZA, ZM, ZW.

(84) Designated States (unless otherwise indicated, for every
kind of regional protection available): ARIPO (BW, GH,
GM, KE, LR, LS, MW, MZ, NA, SD, SL, SZ, TZ, UG,
ZM, ZW), Eurasian (AM, AZ, BY, KG, KZ, MD, RU, TJ,
TM), European (AL, AT, BE, BG, CH, CY, CZ, DE, DK,
EE, ES, FI, FR, GB, GR, HR, HU, IE, IS, IT, LT, LU, LV,
MC, MK, MT, NL, NO, PL, PT, RO, RS, SE, SI, SK, SM,
TR), OAPI (BF, BJ, CF, CG, CI, CM, GA, GN, GQ, GW,
ML, MR, NE, SN, TD, TG).

Declarations under Rule 4.17:

- as to applicant's entitlement to apply for and be granted a patent (Rule 4.17(ii))
- of inventorship (Rule 4.17(iv))

Published:

- with international search report (Art. 21(3))

(54) Title: AUTOMATIC STANDPIPE PRESSURE CONTROL IN DRILLING

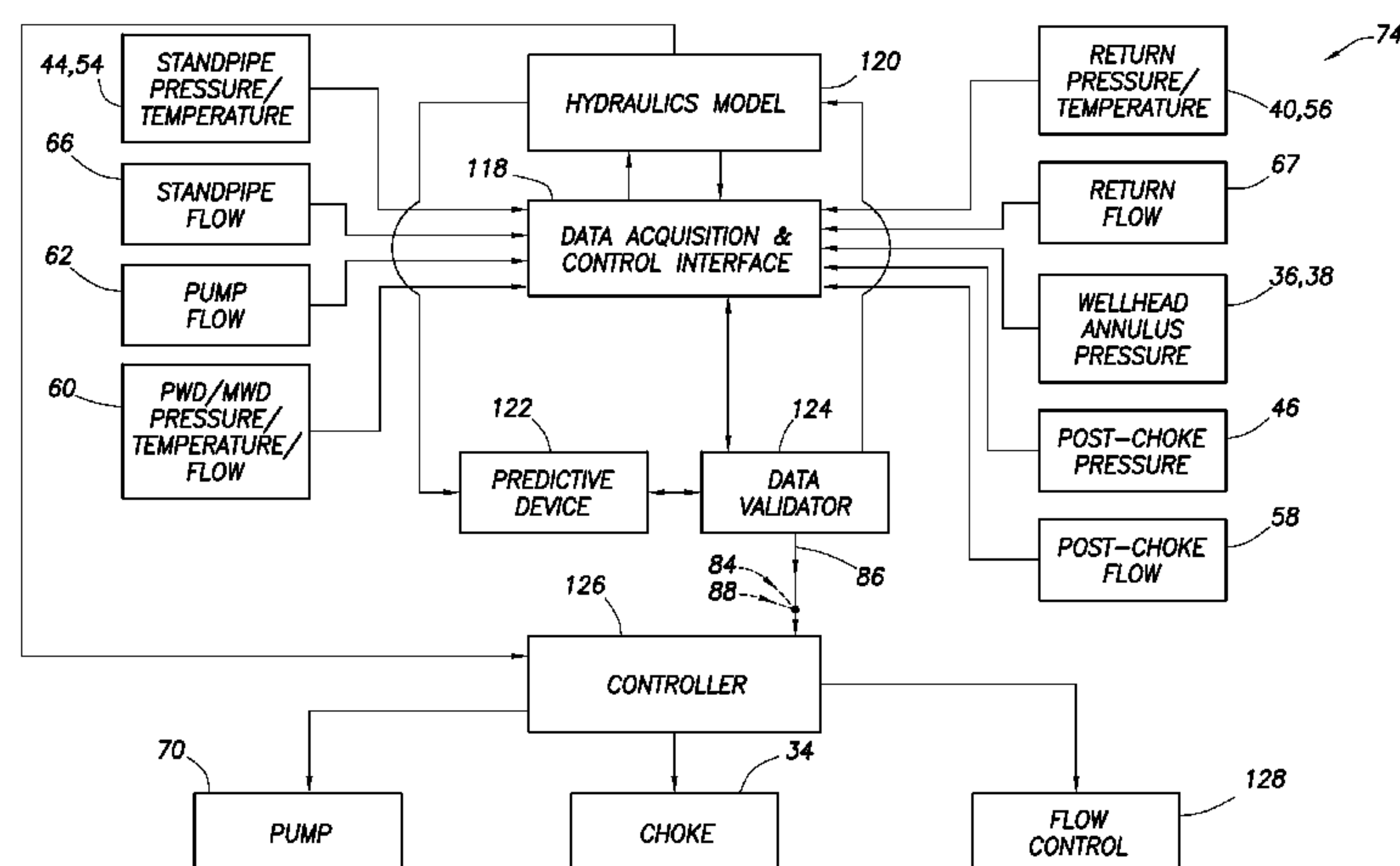


FIG.2

(57) Abstract: A method of controlling standpipe pressure in a drilling operation can include comparing a measured standpipe pressure to a desired standpipe pressure, and automatically adjusting a choke in response to the comparing, thereby reducing a difference between the measured standpipe pressure and the desired standpipe pressure. A standpipe pressure control system for use in a drilling operation can include a controller which outputs an annulus pressure setpoint based on a comparison of a measured standpipe pressure to a desired standpipe pressure, and a choke which is automatically adjusted in response to the annulus pressure setpoint. A well system can include a standpipe line connected to a drill string in a wellbore, a sensor which measures pressure in the standpipe line, and a controller which outputs an annulus pressure setpoint based at least in part on a difference between the measured pressure and a desired standpipe pressure.

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AUTOMATIC STANDPIPE PRESSURE CONTROL IN DRILLING

TECHNICAL FIELD

10 The present disclosure relates generally to equipment utilized and operations performed in conjunction with a subterranean well and, in an embodiment described herein, more particularly provides for automatic standpipe pressure control in drilling.

15

BACKGROUND

 In managed pressure drilling and underbalanced drilling, pressure in a wellbore is precisely controlled by, for example, controlling pressure in an annulus at or near
20 the earth's surface. However, in some circumstances (such as in well control situations, etc.) it may be desirable to control wellbore pressure by controlling pressure in a standpipe connected to a drill string.

 Therefore, it will be appreciated that advancements are
25 needed in the art of wellbore pressure control.

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BRIEF DESCRIPTION OF THE DRAWINGS

FIG. 1 is a representative partially cross-sectional view of a well system and associated method which can embody
5 principles of the present disclosure.

FIG. 2 is a representative illustration of a process control system which may be used with the well system and method of FIG. 1.

FIG. 3 is a representative illustration of a standpipe pressure control system which may be used with the well
10 system, method and process control system.

FIG. 4 is a representative illustration of a portion of the standpipe pressure control system.

15 **DETAILED DESCRIPTION**

Representatively and schematically illustrated in FIG. 1 is a well system 10 and associated method which can embody principles of the present disclosure. In the system 10, a wellbore 12 is drilled by rotating a drill bit 14 on an end
20 of a tubular drill string 16.

Drilling fluid 18, commonly known as mud, is circulated downward through the drill string 16, out the drill bit 14 and upward through an annulus 20 formed between the drill string and the wellbore 12, in order to cool the drill bit, lubricate the drill string, remove cuttings and provide a
25 measure of bottom hole pressure control. A non-return valve 21 (typically a flapper-type check valve) prevents flow of the drilling fluid 18 upward through the drill string 16 (for example, when connections are being made in the drill
30 string).

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Control of bottom hole pressure is very important in managed pressure and underbalanced drilling, and in other types of well operations. Preferably, the bottom hole pressure is accurately controlled to prevent excessive loss of fluid into an earth formation 64 surrounding the wellbore 12, undesired fracturing of the formation, undesired influx of formation fluids into the wellbore, etc.

In typical managed pressure drilling, it is desired to maintain the bottom hole pressure just greater than a pore pressure of the formation 64, without exceeding a fracture pressure of the formation. In typical underbalanced drilling, it is desired to maintain the bottom hole pressure somewhat less than the pore pressure, thereby obtaining a controlled influx of fluid from the formation 64.

Nitrogen or another gas, or another lighter weight fluid, may be added to the drilling fluid 18 for pressure control. This technique is especially useful, for example, in underbalanced drilling operations.

In the system 10, additional control over the bottom hole pressure is obtained by closing off the annulus 20 (e.g., isolating it from communication with the atmosphere and enabling the annulus to be pressurized at or near the surface) using a rotating control device 22 (RCD). The RCD 22 seals about the drill string 16 above a wellhead 24. Although not shown in FIG. 1, the drill string 16 would extend upwardly through the RCD 22 for connection to, for example, a rotary table (not shown), a standpipe line 26, a kelly (not shown), a top drive and/or other conventional drilling equipment.

The drilling fluid 18 exits the wellhead 24 via a wing valve 28 in communication with the annulus 20 below the RCD 22. The fluid 18 then flows through fluid return line 30 to

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a choke manifold 32, which includes redundant chokes 34. Backpressure is applied to the annulus 20 by variably restricting flow of the fluid 18 through the operative choke(s) 34.

5 The greater the restriction to flow through the choke 34, the greater the backpressure applied to the annulus 20. Thus, bottom hole pressure can be conveniently regulated by varying the backpressure applied to the annulus 20. A hydraulics model can be used, as described more fully below,
10 to determine a pressure applied to the annulus 20 at or near the surface which will result in a desired bottom hole pressure, so that an operator (or an automated control system) can readily determine how to regulate the pressure applied to the annulus at or near the surface (which can be
15 conveniently measured) in order to obtain the desired bottom hole pressure.

It can also be desirable to control pressure at other locations along the wellbore 12. For example, the pressure at a casing shoe, at a heel of a lateral wellbore, in
20 generally vertical or horizontal portions of the wellbore 12, or at any other location can be controlled using the principles of this disclosure.

Pressure applied to the annulus 20 can be measured at or near the surface via a variety of pressure sensors 36,
25 38, 40, each of which is in communication with the annulus. Pressure sensor 36 senses pressure below the RCD 22, but above a blowout preventer (BOP) stack 42. Pressure sensor 38 senses pressure in the wellhead below the BOP stack 42. Pressure sensor 40 senses pressure in the fluid return line
30 30 upstream of the choke manifold 32.

Another pressure sensor 44 senses pressure in the standpipe line 26. Yet another pressure sensor 46 senses

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pressure downstream of the choke manifold 32, but upstream of a separator 48, shaker 50 and mud pit 52. Additional sensors include temperature sensors 54, 56, Coriolis flowmeter 58, and flowmeters 62, 66.

5 Not all of these sensors are necessary. For example, the system 10 could include only one of the flowmeters 62, 66. However, input from the sensors is useful to the hydraulics model in determining what the pressure applied to the annulus 20 should be during the drilling operation.

10 In addition, the drill string 16 may include its own sensors 60, for example, to directly measure bottom hole pressure. Such sensors 60 may be of the type known to those skilled in the art as pressure while drilling (PWD), measurement while drilling (MWD) and/or logging while
15 drilling (LWD) sensor systems. These drill string sensor systems generally provide at least pressure measurement, and may also provide temperature measurement, detection of drill string characteristics (such as vibration, weight on bit, stick-slip, etc.), formation characteristics (such as
20 resistivity, density, etc.) and/or other measurements. Various forms of telemetry (acoustic, pressure pulse, electromagnetic, optical, wired, etc.) may be used to transmit the downhole sensor measurements to the surface. The drill string 16 could be provided with conductors,
25 optical waveguides, etc., for transmission of data and/or commands between the sensors 60 and the process control system 74 described below (and illustrated in FIG. 2).

Additional sensors could be included in the system 10, if desired. For example, another flowmeter 67 could be used
30 to measure the rate of flow of the fluid 18 exiting the wellhead 24, another Coriolis flowmeter (not shown) could be

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interconnected directly upstream or downstream of a rig mud pump 68, etc.

Fewer sensors could be included in the system 10, if desired. For example, the output of the rig mud pump 68
5 could be determined by counting pump strokes, instead of by using flowmeter 62 or any other flowmeters.

Note that the separator 48 could be a 3 or 4 phase separator, or a mud gas separator (sometimes referred to as a "poor boy degasser"). However, the separator 48 is not
10 necessarily used in the system 10.

The drilling fluid 18 is pumped through the standpipe line 26 and into the interior of the drill string 16 by the rig mud pump 68. The pump 68 receives the fluid 18 from the mud pit 52 and flows it via a standpipe manifold (not shown)
15 to the standpipe line 26. The fluid 18 then circulates downward through the drill string 16, upward through the annulus 20, through the mud return line 30, through the choke manifold 32, and then via the separator 48 and shaker 50 to the mud pit 52 for conditioning and recirculation.

Note that, in the system 10 as so far described above, the choke 34 cannot be used to control backpressure applied to the annulus 20 for control of the bottom hole pressure, unless the fluid 18 is flowing through the choke. In conventional overbalanced drilling operations, a lack of
25 circulation can occur whenever a connection is made in the drill string 16 (e.g., to add another length of drill pipe to the drill string as the wellbore 12 is drilled deeper), and the lack of circulation will require that bottom hole pressure be regulated solely by the density of the fluid 18.

In the system 10, however, flow of the fluid 18 through the choke 34 can be maintained, even though the fluid does not circulate through the drill string 16 and annulus 20.
30

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Thus, pressure can still be applied to the annulus 20 by restricting flow of the fluid 18 through the choke 34.

In the system 10 as depicted in FIG. 1, a backpressure pump 70 can be used to supply a flow of fluid to the return line 30 upstream of the choke manifold 32 by pumping fluid into the annulus 20 when needed (such as, when connections are being made in the drill string 16). As depicted in FIG. 1, the pump 70 is connected to the annulus 20 via the BOP stack 42, but in other examples the pump 70 could be connected to the return line 30, or to the choke manifold 32.

Alternatively, or in addition, fluid could be diverted from the standpipe manifold (or otherwise from the rig pump 68) to the return line 30 when needed, as described in International Application Serial No. PCT/US08/87686, as described in US Application Serial No. 13/022,964, or using other techniques.

Restriction by the choke 34 of such fluid flow from the rig pump 68 and/or the backpressure pump 70 will thereby cause pressure to be applied to the annulus 20. If the backpressure pump 70 is implemented, a flowmeter 72 can be used to measure the output of the pump.

The choke 34 and backpressure pump 70 are examples of pressure control devices which can be used to control pressure in the annulus 20 near the surface. Other types of pressure control devices (such as those described in International Application Serial No. PCT/US08/87686, and in US Application Serial No. 13/022,964, etc.) may be used, if desired.

Referring additionally now to FIG. 2, a block diagram of one example of a process control system 74 is representatively illustrated. In other examples, the process

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control system 74 could include other numbers, types, combinations, etc., of elements, and any of the elements could be positioned at different locations or integrated with another element, in keeping with the scope of this disclosure.

As depicted in FIG. 2, the process control system 74 includes a data acquisition and control interface 118, a hydraulics model 120, a predictive device 122, a data validator 124 and a controller 126. These elements may be similar to those described in International Application Serial No. PCT/US10/56433 filed on 12 November 2010.

The hydraulics model 120 is used to determine a desired pressure in the annulus 20 to thereby achieve a desired pressure in the wellbore 12. The hydraulics model 120, using data such as wellbore depth, drill string rpm, running speed, mud type, etc., models the wellbore 12, the drill string 16, flow of the fluid through the drill string and annulus 20 (including equivalent circulating density due to such flow), etc.

The data acquisition and control interface 118 receives data from the various sensors 36, 38, 40, 44, 46, 54, 56, 58, 60, 62, 66, 67, 72, together with rig and downhole data, and relays this data to the hydraulics model 120 and the data validator 124. In addition, the interface 118 relays the desired annulus pressure from the hydraulics model 120 to the data validator 124.

The predictive device 122 can be included in this example to determine, based on past data, what sensor data should currently be received and what the desired annulus pressure should be. The predictive device 122 could comprise a neural network, a genetic algorithm, fuzzy logic, etc., or

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any combination of predictive elements to produce predictions of the sensor data and desired annulus pressure.

The data validator 124 uses these predictions to determine whether any particular sensor data is valid, whether the desired annulus pressure output by the hydraulics model 120 is appropriate, etc. If it is appropriate, the data validator 124 transmits the desired annulus pressure to the controller 126 (such as a programmable logic controller, which may include a proportional integral derivative (PID) controller), which controls operation of the choke 34, the pump 70 and the various flow control devices 128 (such as valves, etc.).

In this manner, the choke 60, pump 70 and flow control devices 128 can be automatically controlled to achieve and maintain the desired pressure in the annulus 20. Actual pressure in the annulus 20 is typically measured at or near the wellhead 24 (for example, using sensors 36, 38, 40), which may be at a land or subsea location.

Referring additionally now to FIG. 3, representatively illustrated in schematic form is a standpipe pressure control system 80 which may be used with the well system 10 and/or process control system 74. Of course, the standpipe pressure control system 80 may be used with other well systems and other process control systems, in keeping with the principles of this disclosure.

In the example depicted in FIG. 3, the controller 126 can be used to control operation of the choke 34 based on a selected one of three possible annulus pressure setpoint sources. The selection of the annulus pressure setpoint source is performed by an operator using a human-machine interface (HMI) 82, such as an appropriately configured computer, monitor, etc., and/or event detection software.

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The annulus pressure setpoint source can be selected via the HMI 82, or can be selected automatically by control logic.

Annulus pressure is sometimes referred to as wellhead pressure, since it is commonly measured at or near the wellhead 24. However, in some situations (such as subsea drilling operations, etc.), pressure in the annulus 20 may not be measured at the wellhead 24, or at least pressure in the annulus 20 measured at the wellhead may not be used for controlling pressure in the wellbore 12. For example, pressure in the annulus 20 measured at a surface location, floating or semi-submersible rig, etc., may possibly be used for controlling pressure in the wellbore 12. In this description, wellhead pressure is assumed to be synonymous with annulus pressure, but it should be clearly understood that in other examples, the annulus pressure may not be measured at the wellhead, or such a wellhead pressure measurement may not be used for controlling wellbore pressure.

Using the human-machine interface 82, the operator can select to control wellbore pressure using either a wellhead pressure (WHP) setpoint 84 manually input to the human-machine interface, a wellhead pressure setpoint 86 which results from the process control system 74 as described above, or a wellhead pressure setpoint 88 output from a controller 90.

The controller 126 can include a proportional integral differential controller (PID) and can be implemented in a programmable logic controller (PLC) of the types well known to those skilled in the art. The proportional integral differential controller operates based on a difference e between the selected wellhead pressure setpoint 84, 86 or

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88, and the measured wellhead pressure (e.g., using sensors 36, 38 or 40).

The proportional integral differential controller determines if or how the choke 34, pump 70, other flow control devices 128, etc., should be adjusted to minimize the difference e . The programmable logic controller adjusts the choke 34, etc., based on the output of the proportional integral differential controller. Of course, process control devices other than a proportional integral differential controller and/or a programmable logic controller may be used, if desired.

The wellhead pressure setpoint 88 is selected by the operator if the operator desires to control wellbore pressure based on pressure measured in the standpipe line 26 (e.g., measured using sensor 44). One situation in which this may be desired is in a well control procedure, for example, following an influx of fluid into the wellbore 12 from the formation 64.

The controller 90 (which may comprise a proportional integral differential controller) receives a difference e between a desired standpipe pressure (SPP) 92, which may be manually input via the human-machine interface 82, and the measured standpipe pressure 94 (e.g., measured using the pressure sensor 44). The controller 90 determines if or how the wellhead pressure should be adjusted to minimize the difference e , and outputs the appropriate desired wellhead pressure setpoint 88 for selection using the human-machine interface 82.

Preferably, the controllers 90, 126 operate via cascade control, with an outer loop (including the controller 90 and sensor 44) for controlling the standpipe pressure, and an inner loop (including the controller 126, sensor 40, choke

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34, pump 70 and other flow control devices 128) for controlling the wellhead pressure. More preferably, the dynamics of the inner loop (e.g., frequency of comparisons between the measured wellhead pressure 96 and the selected
5 wellhead pressure setpoint 88) is at least four times the dynamics of the outer loop (e.g., frequency of comparisons between the measured standpipe pressure 94 and the desired standpipe pressure 92).

The proportional integral differential controller of
10 the controller 90 may base its calculations on the following equation 1:

$$u_k = u_{k-1} + K_p(e_k - e_{k-1}) + \frac{K_p T_s}{T_i} e_k + \frac{K_p T_d}{T_s} (e_k - 2e_{k-1} + e_{k-2}) \quad (1)$$

in which u is the output wellhead pressure setpoint 88, k is a sequence indicator (with k being a present sample, $k-1$ being a next previous sample, $k-2$ being two samples
15 previous), K_p is a gain for the controller 90, T_s is a sampling interval, T_d is a derivative time, T_i is an integral time, and e is the difference between the desired standpipe pressure 92 and the measured standpipe pressure
20 94.

Referring additionally now to FIG. 4, a schematic view of a portion of the standpipe pressure control system 80 is representatively illustrated. In this view, it may be seen that the controller 90 receives the desired standpipe
25 pressure 92 from an initialization module 98.

The module 98 supplies the controller 90 with initial values for certain variables at startup. The desired standpipe pressure 92 is preferably input via the human-machine interface 82. Alternatively, an initial wellhead
30 pressure setpoint 100 can be supplied to the controller 90 by the module 98. The initial wellhead pressure setpoint 100

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may be based on the last wellhead pressure setpoint 88 supplied to the controller 126 by the controller 90.

Certain configuration data 102 can be input by an operator via the human-machine interface 82 and supplied to the module 98 and controller 90. The data 102 may include maximum and minimum allowable values for the controller 90 output, the controller gain, the integral and derivative times, and the sampling interval. Preferably, all of these variables (with the exception of the sampling interval) can be changed by the operator during the pressure control operation.

The predictive device 122 and data validator 124 can be used to validate the wellhead pressure setpoint 88 output by the controller 90. In this manner, an erroneous or out-of-range wellhead pressure setpoint 88 can be prevented from being input to the controller 126.

The standpipe pressure is actually being controlled when the wellhead pressure setpoint 88 generated by the controller 90 is selected for use by the controller 126 to control wellhead pressure. This is because the wellhead pressure setpoint 88 is adjusted by the controller 90 to minimize the difference e between the desired standpipe pressure 92 and the measured standpipe pressure 94. Thus, the choke 34, pump 70 and/or other flow control devices 128 are controlled by the controller 126, so that the standpipe pressure is maintained at the desired level.

It can now be fully appreciated that this disclosure provides several advancements to the art of controlling wellbore pressure. The standpipe pressure control system 80 described above can be used to regulate operation of a process control system 74, whereby a desired standpipe pressure 92 is maintained.

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The above disclosure provides to the art a method of controlling standpipe pressure in a drilling operation. The method can include comparing a measured standpipe pressure 94 to a desired standpipe pressure 92, and automatically
5 adjusting a choke 34 in response to the comparing, thereby reducing a difference e between the measured standpipe pressure 94 and the desired standpipe pressure 92.

The choke 34 receives fluid 18 while a rig pump 68 pumps the fluid through a drill string 16. Automatically
10 adjusting the choke 34 can include a controller 90 outputting an annulus pressure setpoint 88. The controller 90 may comprise a proportional integral differential controller.

Automatically adjusting the choke 34 can also include
15 comparing a measured annulus pressure 96 to the annulus pressure setpoint 88, and automatically adjusting the choke 34 so that a difference e between the measured annulus pressure 96 and the annulus pressure setpoint 88 is reduced. Comparing the measured annulus pressure 96 to the annulus
20 pressure setpoint 88 may be performed at least four times as frequent as comparing the measured standpipe pressure 94 to the desired standpipe pressure 92.

Also described above is a standpipe pressure control system 80 for use in a drilling operation. The system 80 can
25 include a controller 90 which outputs an annulus pressure setpoint 88 based on a comparison of a measured standpipe pressure 94 to a desired standpipe pressure 92, and a choke 34 which is automatically adjusted in response to the annulus pressure setpoint 88.

30 Automatic adjustment of the choke 34 preferably reduces a difference e between the measured standpipe pressure 94 and the desired standpipe pressure 92.

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Another controller 126 may compare a measured annulus pressure 96 to the annulus pressure setpoint 88. Automatic adjustment of the choke 34 preferably reduces a difference e between the measured annulus pressure 96 and the annulus pressure setpoint 88.

The measured annulus pressure 96 is preferably compared to the wellhead pressure setpoint 88 at least four times as frequent as the measured standpipe pressure 94 is compared to the desired standpipe pressure 92.

The above disclosure also describes a well system 10 which can include a standpipe line 26 connected to a drill string 16 in a wellbore 12, a sensor 44 which measures pressure in the standpipe line 26, and a controller 90 which outputs an annulus pressure setpoint 88 based at least in part on a difference e between the measured pressure 94 and a desired standpipe pressure 92.

It is to be understood that the various embodiments of the present disclosure described herein may be utilized in various orientations, such as inclined, inverted, horizontal, vertical, etc., and in various configurations, without departing from the principles of the present disclosure. The embodiments are described merely as examples of useful applications of the principles of the disclosure, which is not limited to any specific details of these embodiments.

Of course, a person skilled in the art would, upon a careful consideration of the above description of representative embodiments of the disclosure, readily appreciate that many modifications, additions, substitutions, deletions, and other changes may be made to the specific embodiments, and such changes are contemplated by the principles of the present disclosure. Accordingly,

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the foregoing detailed description is to be clearly understood as being given by way of illustration and example only, the scope of the present invention being limited solely by the appended claims.

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CLAIMS:

1. A method of controlling standpipe pressure in a drilling operation, the method comprising:
 - comparing a measured standpipe pressure to a desired standpipe pressure while elongating a wellbore;
 - outputting an annulus pressure set point based on the comparing; and
 - automatically adjusting a choke in response to the outputting, thereby reducing a difference between the measured standpipe pressure and the desired standpipe pressure.
2. The method of claim 1, wherein the choke receives fluid while a rig pump pumps the fluid through a drill string.
3. The method of claim 1, wherein automatically adjusting the choke further comprises a controller outputting an annulus pressure setpoint.
4. The method of claim 3, wherein automatically adjusting the choke further comprises comparing a measured annulus pressure to the annulus pressure setpoint, and automatically adjusting the choke so that a difference between the measured annulus pressure and the annulus pressure setpoint is reduced.
5. The method of claim 4, wherein comparing the measured annulus pressure to the annulus pressure setpoint is performed at least four times as frequent as comparing the measured standpipe pressure to the desired standpipe pressure.
6. The method of claim 3, wherein the controller comprises a proportional integral differential controller.

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7. A standpipe pressure control system for use in a drilling operation, the system comprising:

a first controller which outputs an annulus pressure setpoint based on a comparison of a measured standpipe pressure to a desired standpipe pressure; and

a choke which is automatically adjusted in response to the annulus pressure setpoint, wherein automatic adjustment of the choke reduces a difference between the measured standpipe pressure and the desired standpipe pressure.

8. The system of claim 7, wherein the choke receives fluid while a rig pump pumps the fluid through a drill string.

9. The system of claim 7, wherein a second controller compares a measured annulus pressure to the annulus pressure setpoint.

10. The system of claim 9, wherein automatic adjustment of the choke reduces a difference between the measured annulus pressure and the annulus pressure setpoint.

11. The system of claim 9, wherein the measured annulus pressure is compared to the annulus pressure setpoint at least four times as frequent as the measured standpipe pressure is compared to the desired standpipe pressure.

12. The system of claim 7, wherein the first controller comprises a proportional integral differential controller.

13. A well system, comprising:

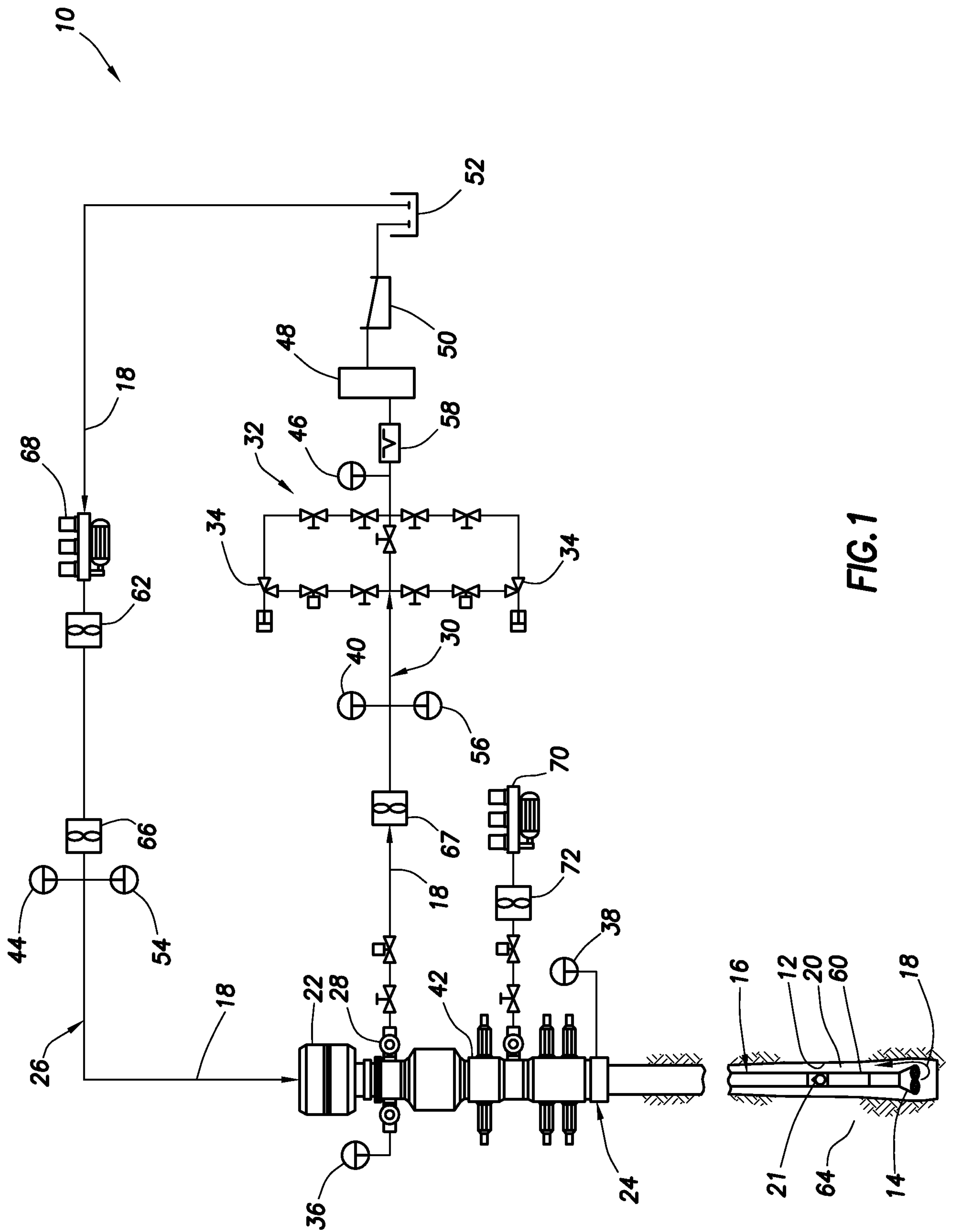
a standpipe line connected to a drill string in a wellbore;

a sensor which measures pressure in the standpipe line;

a first controller which outputs an annulus pressure setpoint based at least in part on a difference between the measured pressure and a desired standpipe pressure; and

a choke which is automatically adjusted in response to the annulus pressure setpoint, wherein automatic adjustment of the choke reduces the difference between the measured pressure and the desired standpipe pressure.

14. The system of claim 13, wherein a second controller compares a measured annulus pressure to the annulus pressure setpoint.
15. The system of claim 14, wherein automatic adjustment of the choke reduces a difference between the measured annulus pressure and the annulus pressure setpoint.
16. The system of claim 14, wherein the measured annulus pressure is compared to the annulus pressure setpoint at least four times as frequent as the measured standpipe is compared the desired standpipe pressure.
17. The system of claim 13, wherein the first controller comprises a proportional integral differential controller.



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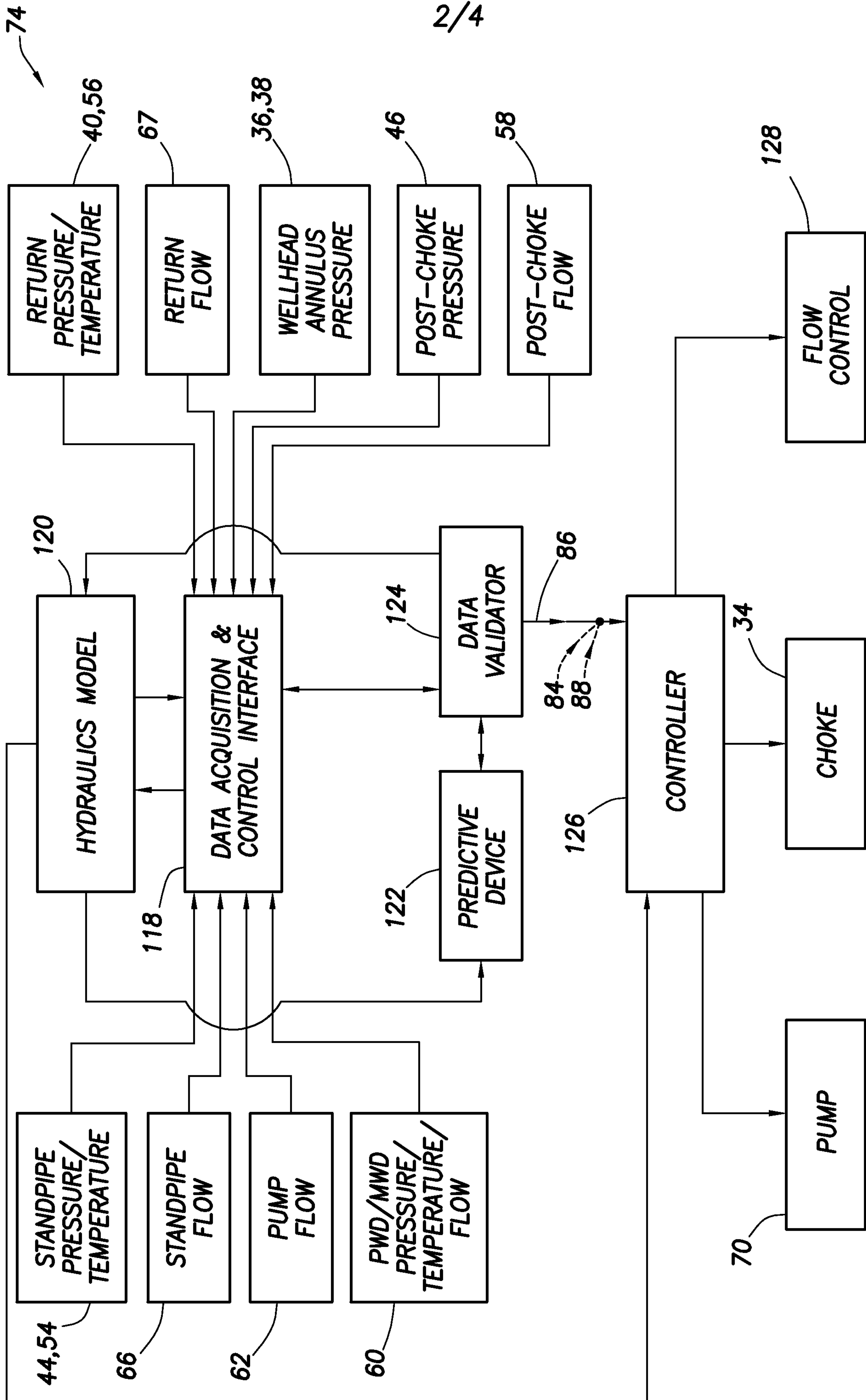


FIG. 2

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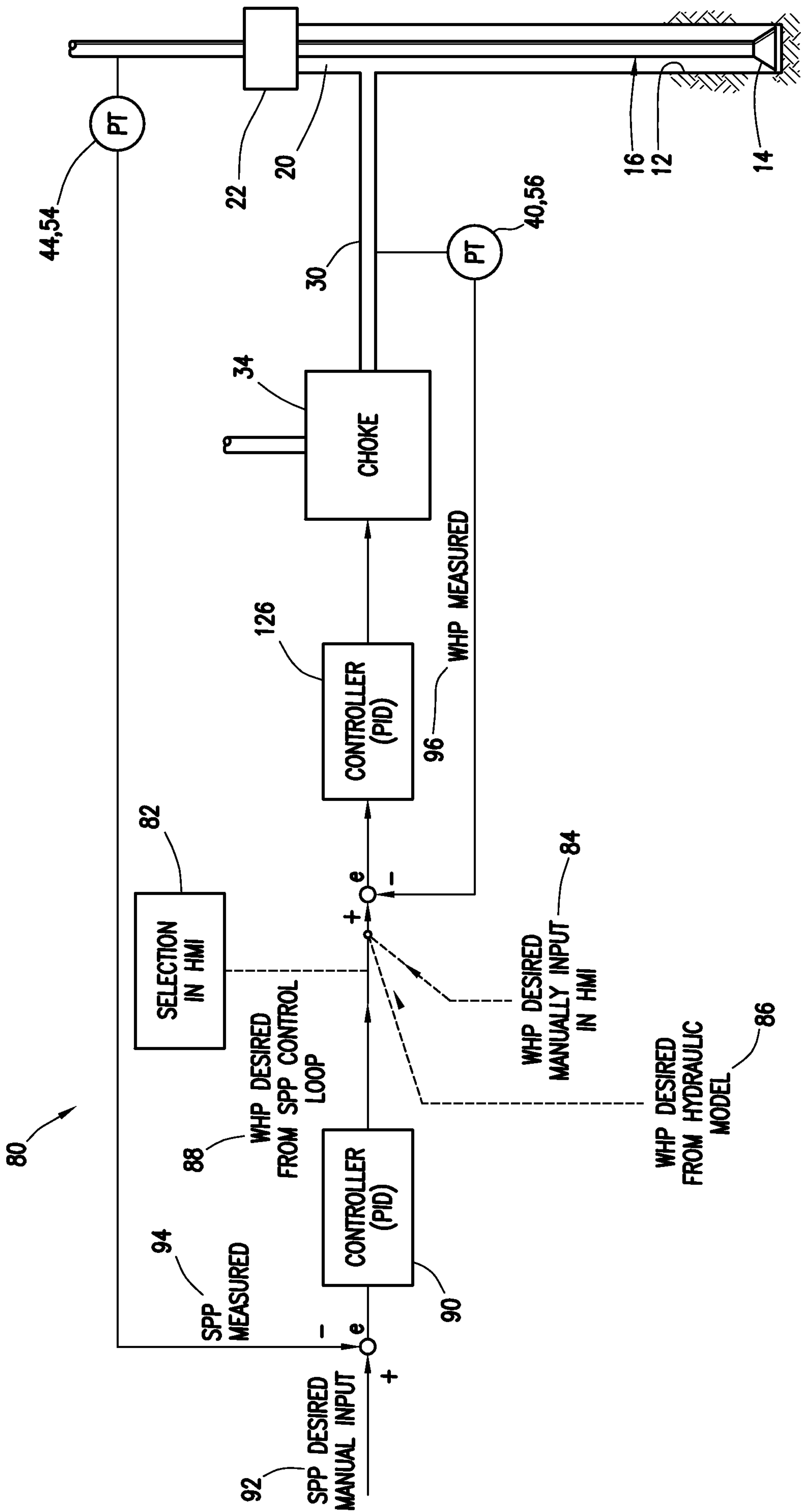


FIG.3

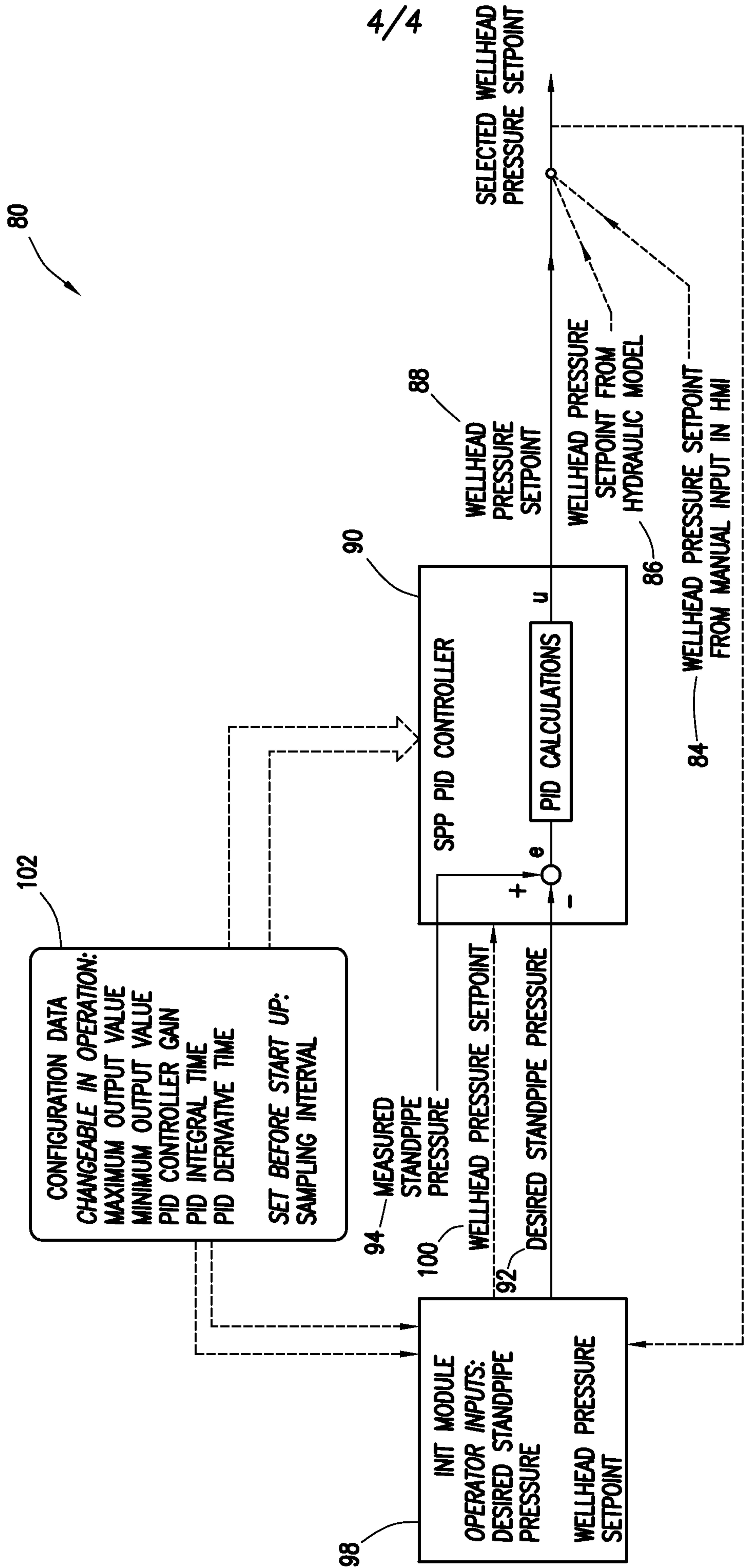


FIG.4

