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(54) FLUID DISTRIBUTION DETERMINATION AND OPTIMIZATION WITH REAL TIME TEMPERATURE MEASUREMENT

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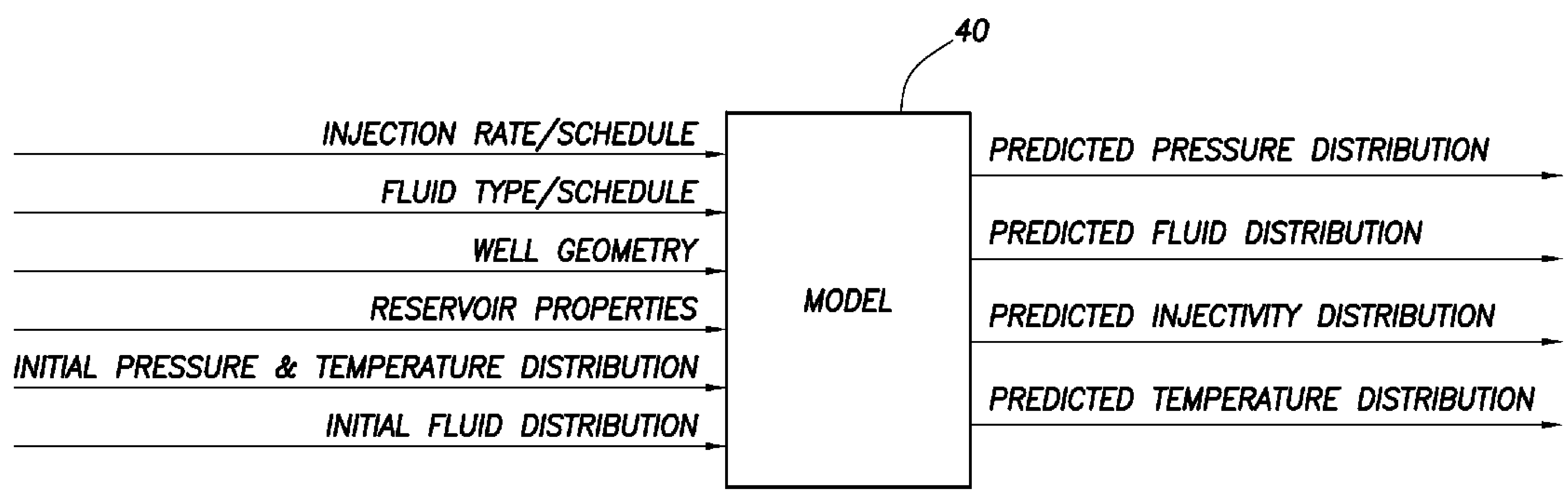
USPC **166/250.15**; 73/152.55

(57) **ABSTRACT**

Fluid distribution determination and optimization using real time temperature measurements. A method of determining fluid or flow rate distribution along a wellbore includes the steps of: monitoring a temperature distribution along the wellbore in real time; and determining in real time the fluid or flow rate distribution along the wellbore using the temperature distribution. A method of optimizing fluid or flow rate distribution includes the steps of: predicting in real time the fluid or flow rate distribution along the wellbore; comparing the predicted fluid or flow rate distribution to a desired fluid or flow rate distribution; and modifying aspects of a wellbore operation in real time as needed to minimize any deviations between the predicted and desired fluid or flow rate distributions.



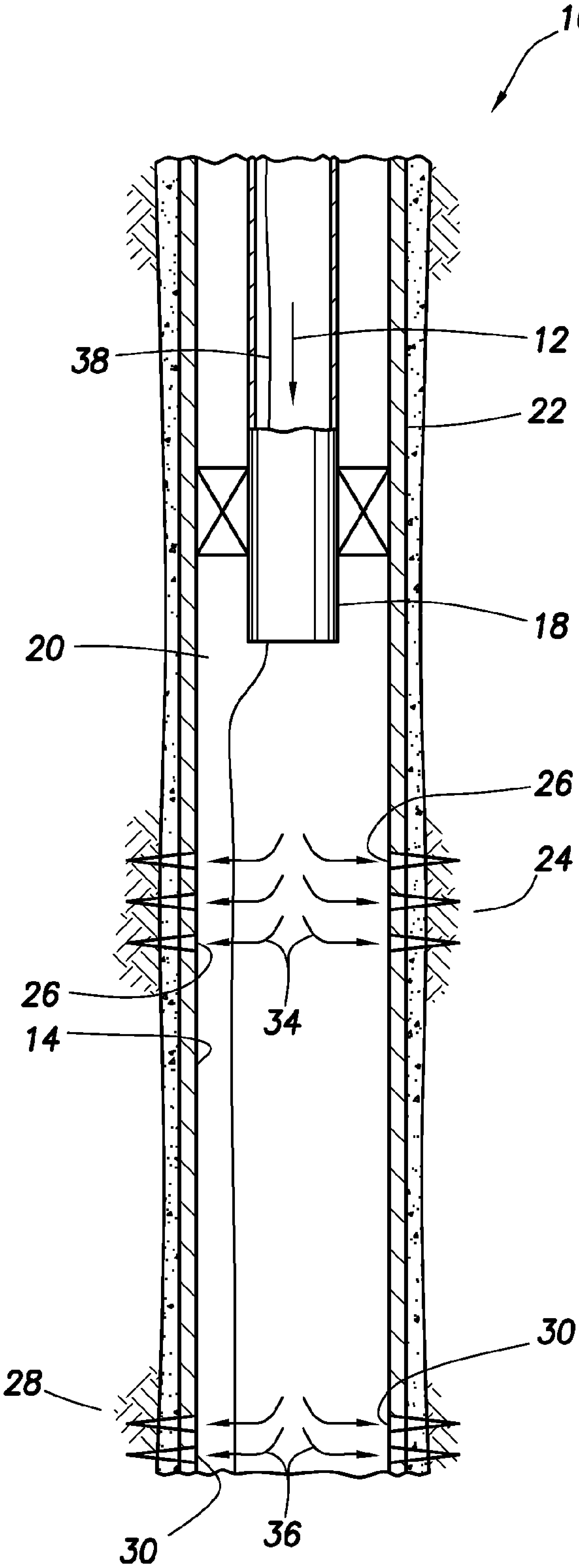


FIG. 1

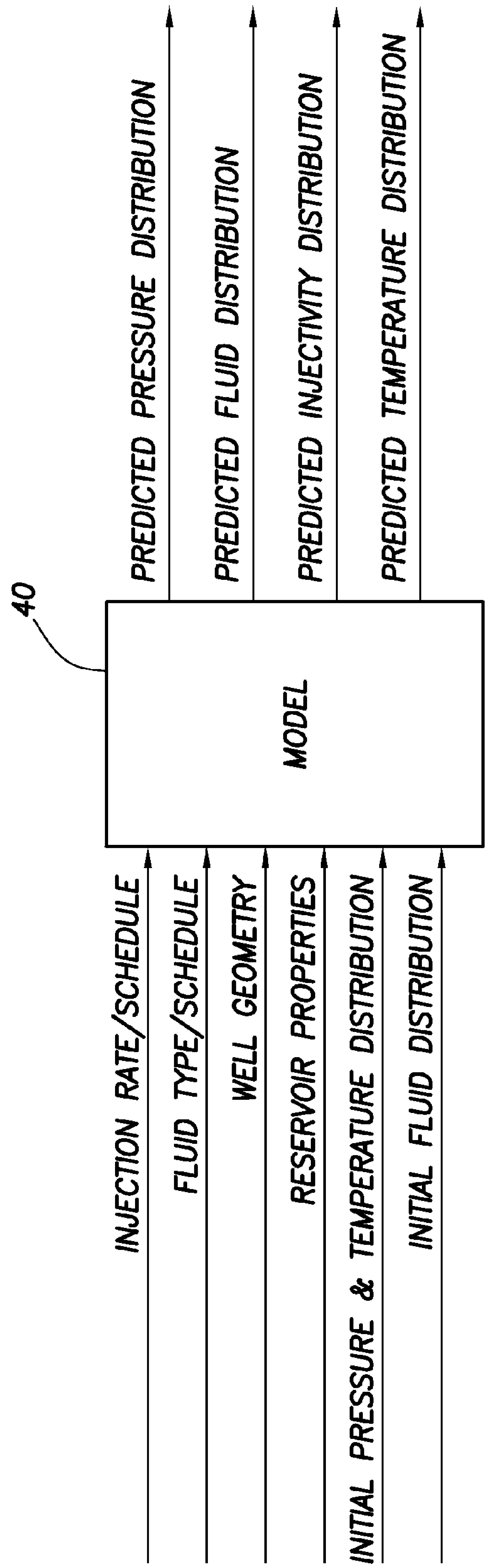
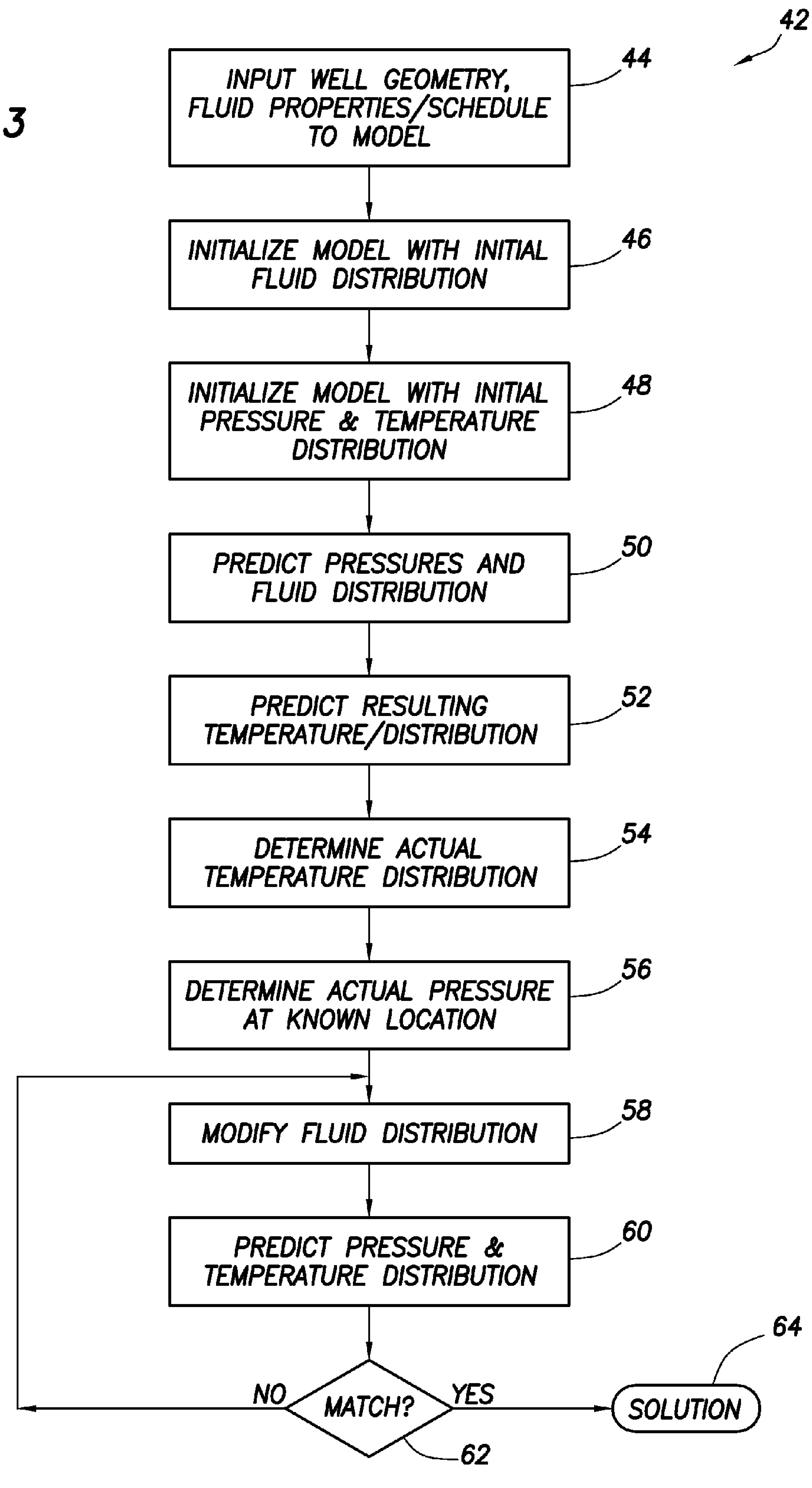
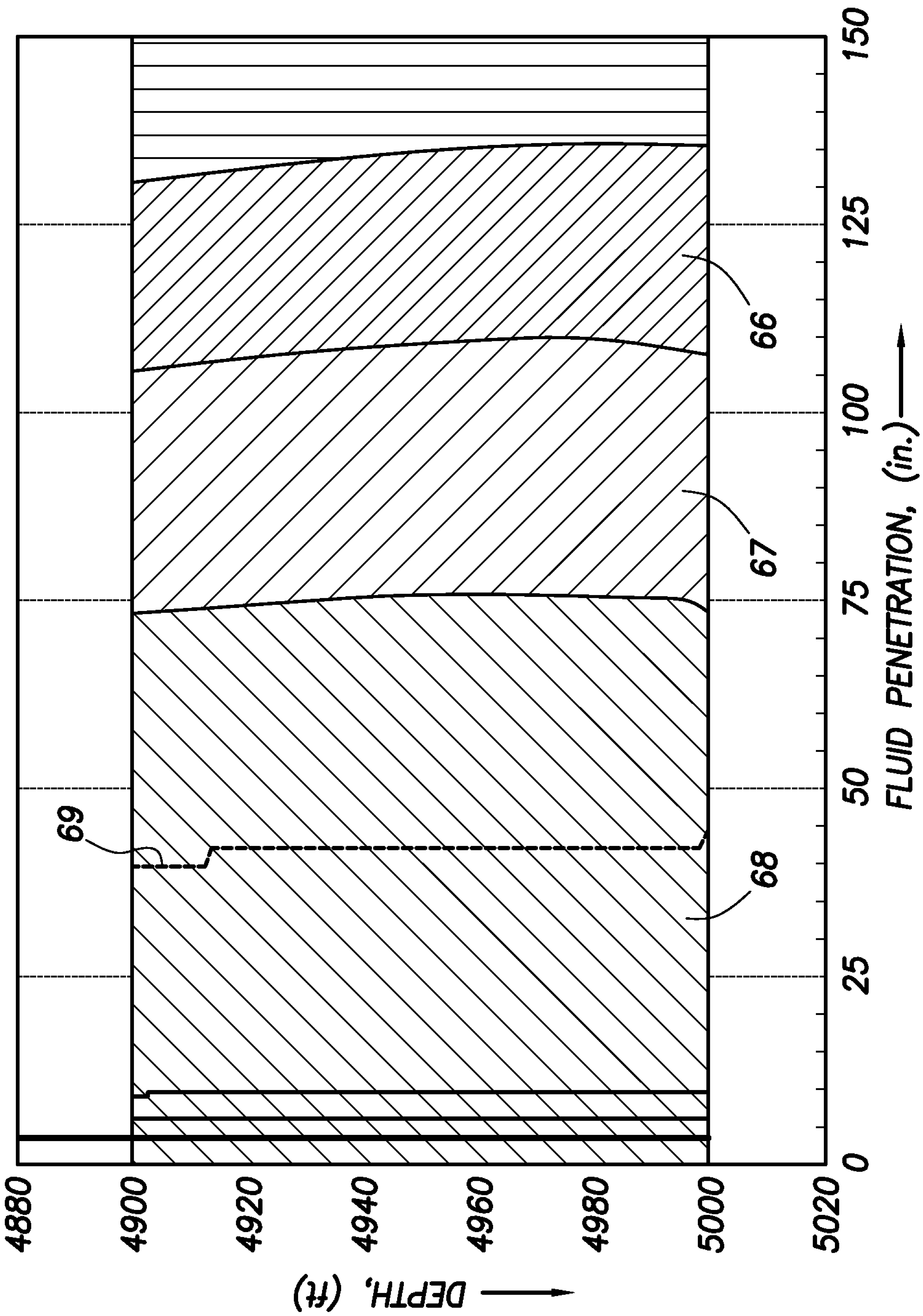

40
MODEL
PREDICTED PRESSURE DISTRIBUTION
PREDICTED FLUID DISTRIBUTION
PREDICTED INJECTIVITY DISTRIBUTION
PREDICTED TEMPERATURE DISTRIBUTION
INJECTION RATE/SCHEDULE
FLUID TYPE/SCHEDULE
WELL GEOMETRY
RESERVOIR PROPERTIES
INITIAL PRESSURE & TEMPERATURE DISTRIBUTION
INITIAL FLUID DISTRIBUTION

FIG.2

FIG.3


42
INPUT WELL GEOMETRY, FLUID PROPERTIES/SCHEDULE TO MODEL
44
INITIALIZE MODEL WITH INITIAL FLUID DISTRIBUTION
46
INITIALIZE MODEL WITH INITIAL PRESSURE & TEMPERATURE DISTRIBUTION
48
PREDICT PRESSURES AND FLUID DISTRIBUTION
50
PREDICT RESULTING TEMPERATURE/DISTRIBUTION
52
DETERMINE ACTUAL TEMPERATURE DISTRIBUTION
54
DETERMINE ACTUAL PRESSURE AT KNOWN LOCATION
56
MODIFY FLUID DISTRIBUTION
58
PREDICT PRESSURE & TEMPERATURE DISTRIBUTION
60
NO
MATCH?
YES
62
SOLUTION
64



0
25
50
75
100
125
150
FLUID PENETRATION, (in.)
4880
4900
4920
4940
4960
4980
5000
5020
DEPTH, (ft)
66
67
68
69

FIG. 4

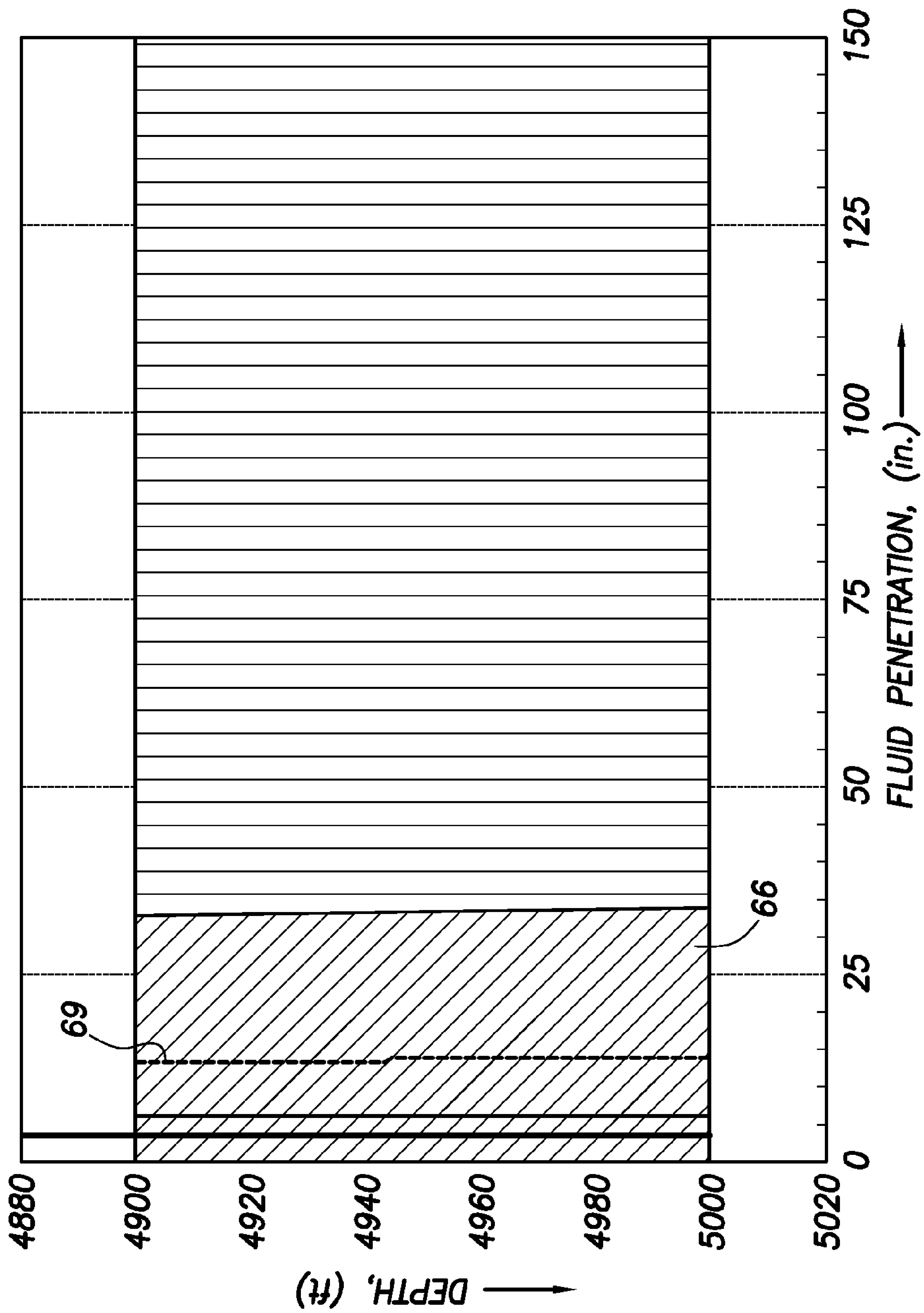
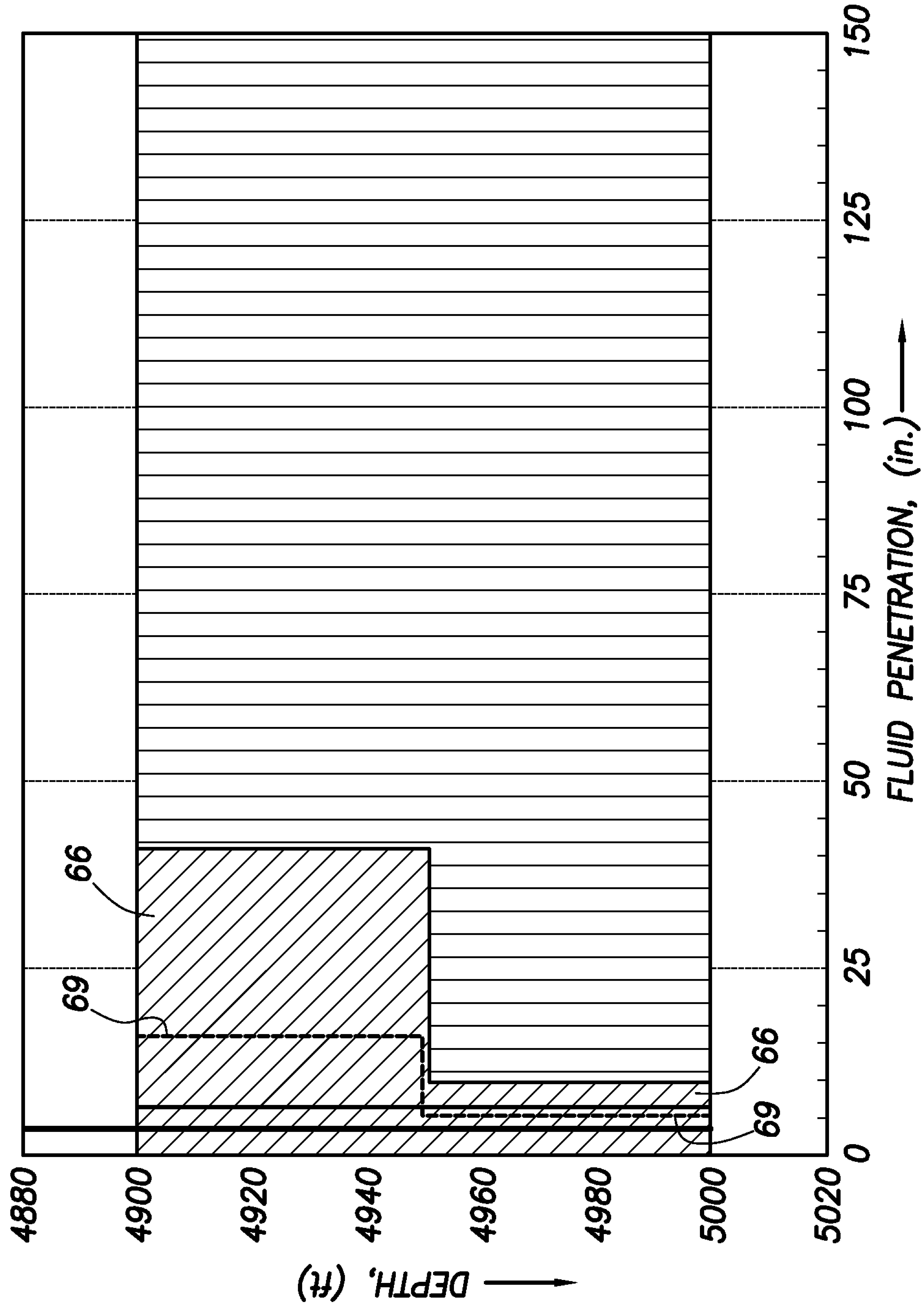
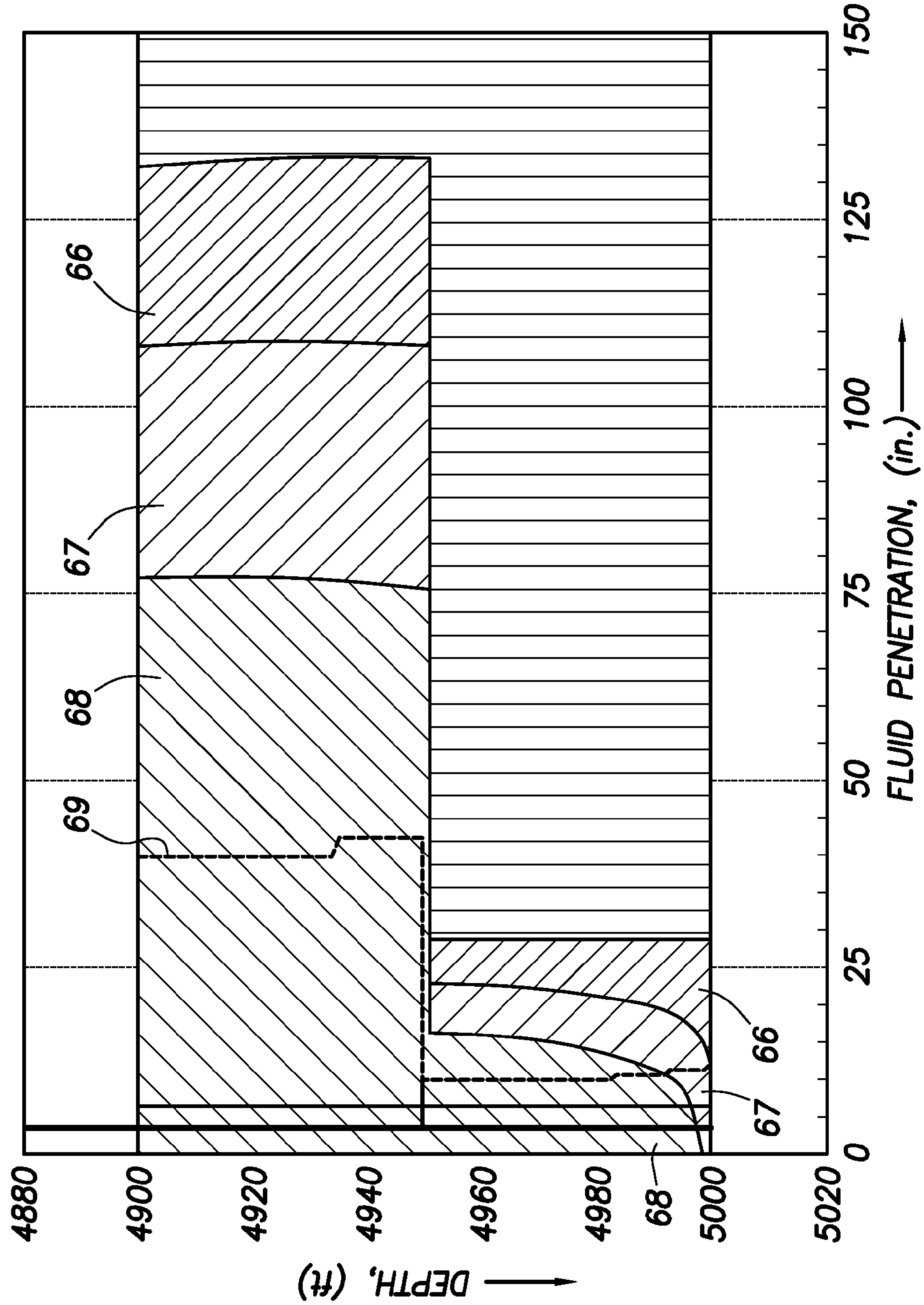

4880
4900
4920
4940
4960
4980
5000
5020
DEPTH, (ft)
0
25
50
75
100
125
150
FLUID PENETRATION, (in.)
66
69

FIG.5



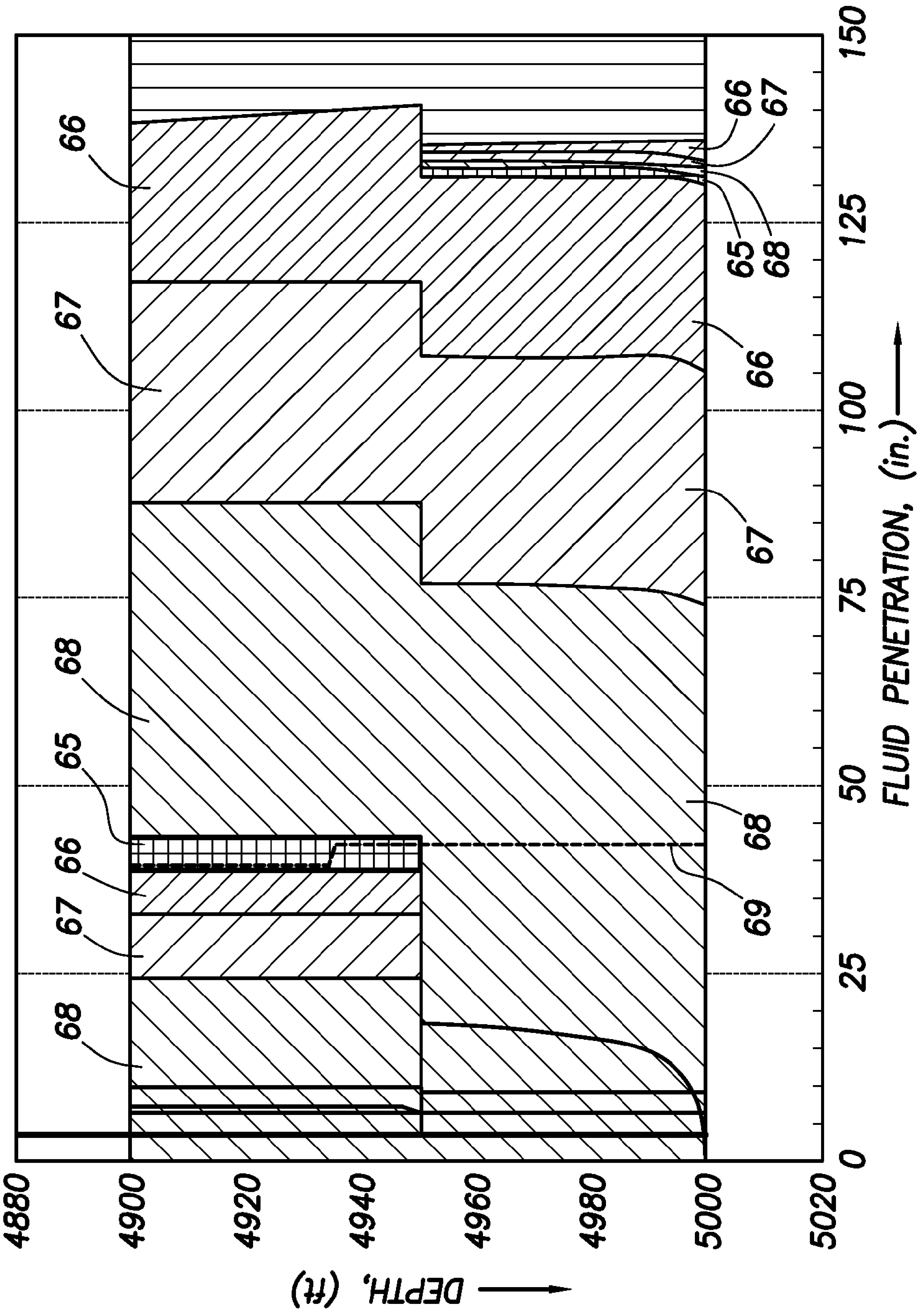
DEPTH, (ft)
4880
4900
4920
4940
4960
4980
5000
5020
FLUID PENETRATION, (in.)
0
25
50
75
100
125
150
66
69
66
69

FIG.6



66
67
68
69
66
67
68
4880
4900
4920
4940
4960
4980
5000
5020
DEPTH, (ft)
0
25
50
75
100
125
150
FLUID PENETRATION, (in.)

FIG.7



DEPTH, (ft)
4880
4900
4920
4940
4960
4980
5000
5020
FLUID PENETRATION, (in.)
0
25
50
75
100
125
150
65
66
67
68
69

FIG.8

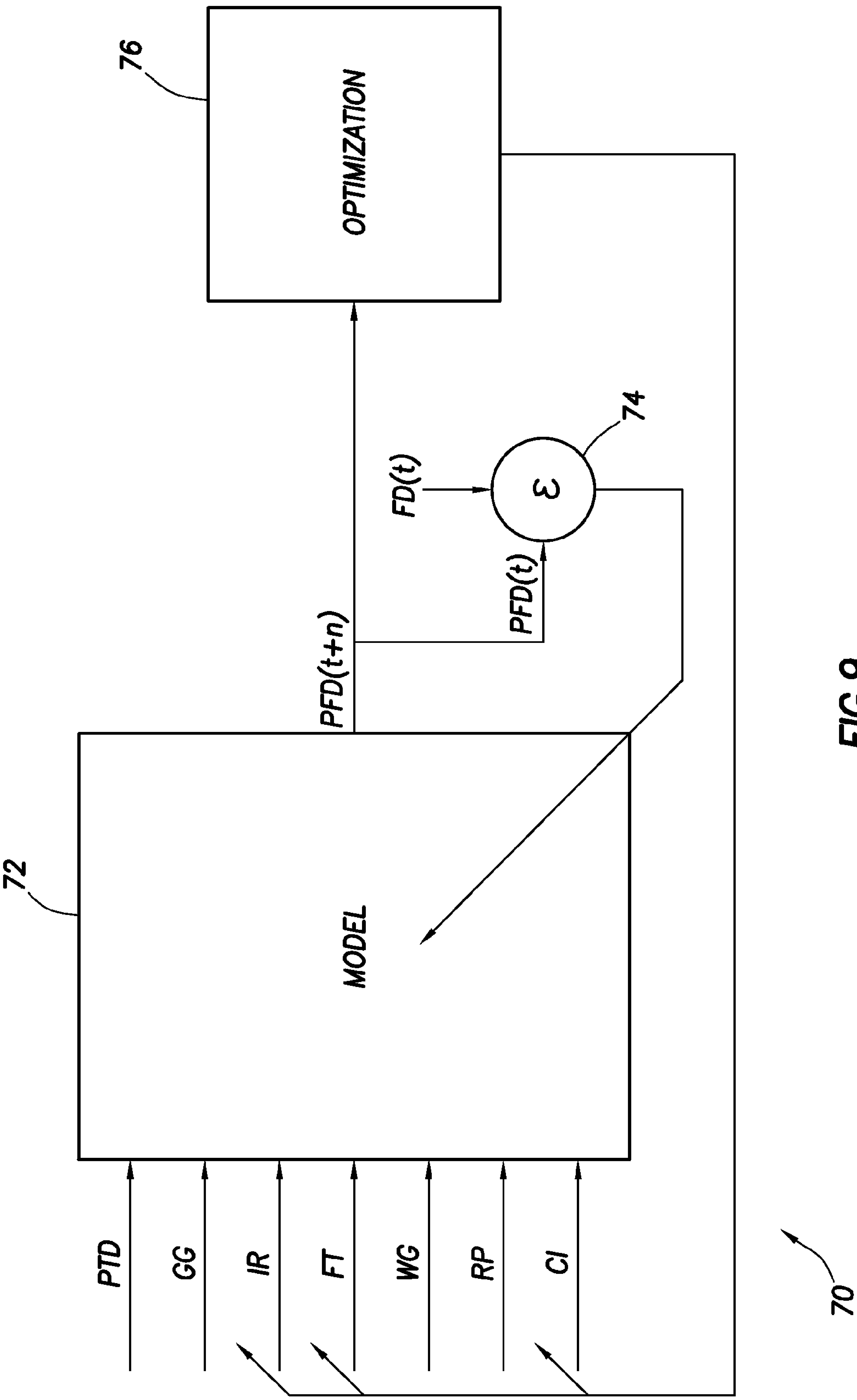

76
OPTIMIZATION
74
FD(t)
ε
PFD(t)
PFD(t+n)
72
MODEL
PTD
GG
IR
FT
WG
RP
CI
70

FIG.9

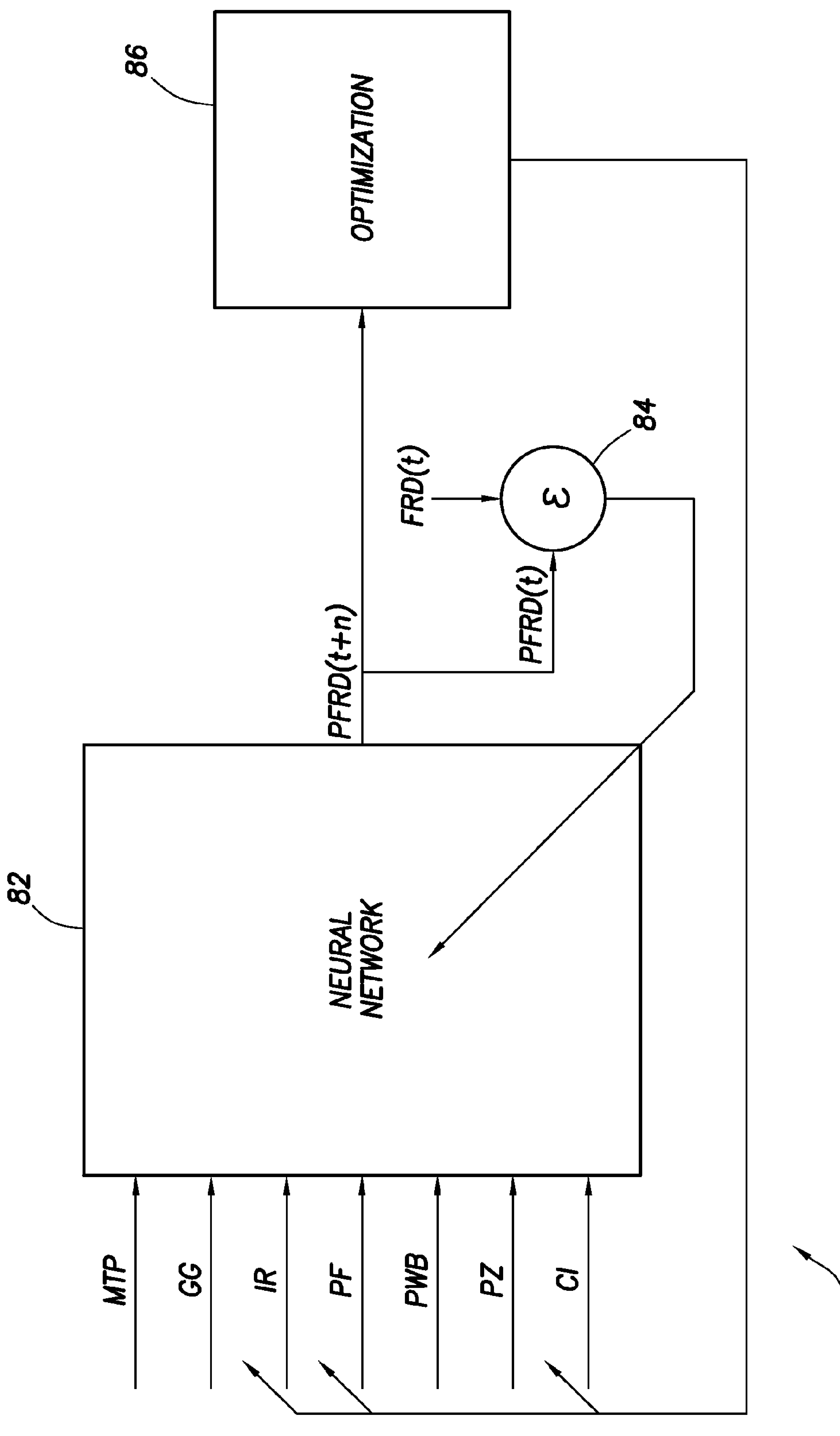

86
OPTIMIZATION
84
FRD(t)
ε
PFRD(t+n)
PFRD(t)
82
NEURAL
NETWORK
MTP
GG
IR
PF
PWB
PZ
CI
80

FIG. 10

FLUID DISTRIBUTION DETERMINATION AND OPTIMIZATION WITH REAL TIME TEMPERATURE MEASUREMENT

BACKGROUND

[0001] The present invention relates generally to equipment utilized and operations performed in conjunction with subterranean wells and, in an embodiment described herein, more particularly provides a method for fluid distribution determination and optimization using real time temperature measurements.

[0002] Several methods have been used in the past for determining fluid distribution along a wellbore. Among these are flowmeter logging, evaluation of pressure response, qualitative evaluation of temperature profile or distribution and evaluation of temperature profile after shut-in.

[0003] Unfortunately, each of these methods has its shortcomings. Flowmeter logging only provides an indication of flow rate at a single point in the wellbore. Multiple logging runs may be made, but each logging run still produces only an indication of flow rate at a single point. Pressure measurements at surface and/or at downhole locations also provide indications of flow rate at only discrete points in the wellbore.

[0004] Past evaluations of temperature profiles have only been qualitative, that is, a determination may be made as to whether or not fluid flows into certain intervals, but quantitative measurements of flow rate distribution along the interval are not provided. Evaluations of temperature profiles after shut-in do not provide real time determinations of fluid distribution, and therefore cannot be used to modify or optimize an operation as it progresses.

[0005] Thus, it will be appreciated that improvements are needed in the art of fluid distribution determination and optimization. It is among the objects of the present invention to provide such improvements.

SUMMARY

[0006] In carrying out the principles of the present invention, methods are provided which solve at least one problem in the art. One example is described below in which fluid and flow rate distribution along a wellbore are determined in real time. Another example is described below in which fluid and flow rate distribution are optimized in real time during an operation.

[0007] In one aspect of the invention, a method of determining fluid or flow rate distribution along a wellbore is provided. The method includes the steps of: monitoring a temperature distribution along the wellbore in real time; and determining in real time the fluid or flow rate distribution along the wellbore using the temperature distribution.

[0008] In another aspect of the invention, a method of optimizing fluid or flow rate distribution along a wellbore includes the steps of: predicting in real time the fluid or flow rate distribution along the wellbore; comparing the predicted distribution to a desired fluid or flow rate distribution; and modifying aspects of a wellbore operation in real time as needed to minimize any deviations between the predicted and desired fluid or flow rate distributions.

[0009] In another aspect of the invention, a method of determining fluid or flow rate distribution along a wellbore includes the steps of: inputting a fluid or flow rate distribution to a model; predicting temperature distribution along the wellbore using the model; monitoring temperature distribution along the wellbore in real time; and modifying the fluid or flow rate distribution based on a comparison between the predicted temperature distribution and the monitored temperature distribution.

[0010] Among the benefits of the methods described below is the ability to determine in real time the fluid and flow rate distributions along a wellbore, so that an evaluation of a wellbore operation may be conducted as the operation progresses. Another benefit is that the fluid and flow rate distributions may be optimized in real time, so that desired fluid and flow rate distributions may be achieved during the operation.

[0011] These and other features, advantages, benefits and objects of the present invention will become apparent to one of ordinary skill in the art upon careful consideration of the detailed description of representative embodiments of the invention hereinbelow and the accompanying drawings, in which similar elements are indicated in the various figures using the same reference numbers.

BRIEF DESCRIPTION OF THE DRAWINGS

[0012] FIG. **1** is a partially cross-sectional schematic view of a method embodying principles of the present invention;

[0013] FIG. **2** is a schematic view of a model which may be used in the method of FIG. **1**;

[0014] FIG. **3** is a flowchart of steps in a technique suited for use in the method of FIG. **1**;

[0015] FIGS. **4-8** are exemplary graphs of desired, predicted and actual fluid distributions during an injection operation in the method of FIG. **1**;

[0016] FIG. **9** is a schematic view of a fluid distribution determination and optimization technique for use in the method of FIG. **1**; and

[0017] FIG. **10** is a schematic view of a flow rate distribution determination and optimization technique for use in the method of FIG. **1**.

DETAILED DESCRIPTION

[0018] It is to be understood that the various embodiments of the present invention 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 invention. The embodiments are described merely as examples of useful applications of the principles of the invention, which is not limited to any specific details of these embodiments.

[0019] In the following description of the representative embodiments of the invention, directional terms, such as "above", "below", "upper", "lower", etc., are used for convenience in referring to the accompanying drawings. In general, "above", "upper", "upward" and similar terms refer to a direction toward the earth's surface along a wellbore, and "below", "lower", "downward" and similar terms refer to a direction away from the earth's surface along the wellbore.

[0020] Representatively illustrated in FIG. **1** is a method **10** which embodies principles of the present invention. As depicted in FIG. **1**, fluid **12** is injected into a wellbore **14** via a production tubing string **18**, and then into an area **20** of the wellbore below a packer set in a casing string **22**. Although the area **20** is depicted as being cased, in other embodiments of the invention the area could be uncased.

[0021] Eventually, the fluid **12** flows into a formation, strata or zone **24** via perforations **26**. If desired, the fluid **12** may also be flowed into another formation, strata or zone **28** via separate perforations **30**. The zones **24**, **28** could be isolated from each other in the wellbore **14** by a packer set in the casing string **22**, if desired.

[0022] In this manner, a portion **34** of the fluid **12** flows into the upper zone **24**, and another portion **36** flows into the lower zone **28**. One problem solved by the method **10**, as described more fully below, is how to determine in real time the flow rate of the fluid **12** as it flows through the wellbore **14** and into each of the zones **24**, **28**.

[0023] Another problem solved by the method **10** and described more fully below is how to optimize the distribution of the fluid **12** in the zones **24**, **28** in real time during the operation. Fluid distribution is the extent to which fluid penetrates a formation or zone versus depth along a wellbore. Graphic examples of desired, predicted and actual fluid distributions are depicted in FIGS. **4-8**, and are described more fully below.

[0024] In the past, DTS systems utilizing an optical conductor **38** (such as an optical fiber in a small diameter tube, or incorporated into a cable, etc.) have been used to produce a temperature profile along the wellbore **14**. After the injection operation, the temperature profile from before the operation would be compared to the temperature profile from during the operation, in order to determine where the fluid **12** entered the various zones **24**, **28** and how much of the fluid entered each zone. However, these past methods do not allow the distribution of the fluid **12** to be determined in real time, so that the injection operation can be evaluated and optimized during the operation.

[0025] At this point it should be pointed out that the invention is not limited in any way by the details of the method **10** described herein or the configuration of the well as illustrated in FIG. **1**. For example, the invention is not necessarily used only in injection operations, since it may also be used in other types of operations (such as production, stimulation, completion, conformance, etc. operations).

[0026] The invention may be used to monitor conditions in a wellbore prior to a treatment, for example, to determine where water is being produced and where a treatment gel should be placed. The invention may be used to place resins for sand control, to repair gravel packing screens, etc.

[0027] The invention is not necessarily used only in cased wellbores, since it may also be used in uncased wellbores. The invention is not necessarily used only where multiple zones have fluid transfer with a wellbore. A coiled tubing string could be used to transfer fluid to or from a wellbore. It is not necessary for an optical conductor to be used to monitor temperature along a wellbore.

[0028] Therefore, it should be clearly understood that the method **10** is described and illustrated herein as merely one example of an application of the principles of the invention, which is not limited at all to the details of the described method.

[0029] Referring additionally now to FIG. **2**, a wellbore model **40** which may be used in the method **10** is representatively illustrated. The model **40** is used to design stimulation treatments or more general fluid placement/injection. The model **40** predicts pressure, fluid, injectivity and temperature distribution versus time.

[0030] Actual treatment parameters, such as injection rate, fluid type and schedules for these, well geometry, reservoir properties, etc. may be input to the model **40**, so that the predicted pressure, fluid, injectivity and temperature distributions are based on the actual parameters. Initial fluid distribution (and reaction parameters, if desired) and pressure and temperature distributions input to the model **40** may be manually adjusted to obtain a match between measured and predicted responses versus time. Examples of models are described in "Field Validation of Acidizing Wormhole Models," SPE 94695 (2005), the entire disclosure of which is incorporated herein by this reference.

[0031] Calibration of the model can be conducted based on measured temperature distribution and one or more measured pressures by adjusting the reservoir or other relevant properties. This may require several iterations, and can be automated.

[0032] The downhole pressures may be measured using any type of pressure sensor, such as optical pressure sensors coupled to the optical conductor **38**. The sensors may be temporary sensors (e.g., installed only for the term of the operation) or permanent sensors (e.g., installed for long term use over the life of the well).

[0033] Note that the optical conductor **38** may be retrievably deployed, for example, in fracturing or injection operations, without strapping the optical conductor to the tubing string **18**. However, the optical conductor **38** could be permanently deployed or strapped to the tubing string **18**, if desired.

[0034] Periodically (for example, approximately each minute), a current measured temperature distribution is available from the DTS system using the optical conductor **38**. An acceptable DTS system for use in providing the measured temperature distribution is the OPTOLOG® DTS system available from Halliburton Energy Services of Houston, Tex. USA.

[0035] Referring additionally now to FIG. **3**, a technique **42** which may be used in the method **10** is representatively illustrated in flowchart form. Of course, the technique **42** may be used in other methods without departing from the principles of the invention.

[0036] In an initial step **44**, the well geometry and planned treatment schedule with fluid types/properties and other data are input to the model **40**. Possible inputs include reservoir properties, such as permeability, porosity, mineralogy, acid reactivity, skin damage, and permeability contrast. Well geometry may include height of the layers, wellbore tubulars, friction pressures, etc.

[0037] In step **46**, the model **40** is initialized with an initial fluid distribution versus depth. This initial fluid distribution may be based on well logs and/or core data or other relevant data.

[0038] In step **48**, the model **40** is initialized with initial data, such as pressure and temperature versus depth. The DTS system may be used to supply this data.

[0039] In step **50**, the model **40** is used to predict pressure and fluid distribution versus time. Alternatively, these parameters may be predicted for a certain future time.

[0040] In step **52**, the resulting temperature distribution is predicted. In step **54**, the actual temperature distribution is determined in real time, for example, using the DTS system.

[0041] As described in the copending patent application entitled TRACKING FLUID DISPLACEMENT ALONG A WELLBORE USING REAL TIME TEMPERATURE MEASUREMENTS, attorney docket no. 2005-IP-019088 U1 USA, the fluid properties and injection rate may be modified and/or chemical reactions may be initiated to enhance detection of temperature gradient differences in the wellbore **14**. This technique can enable more accurate determinations of fluid distribution along the wellbore. The entire disclosure of this copending patent application is incorporated herein by this reference.

[0042] In step **56**, the actual pressure at one or more known locations is determined. An optical conductor with optical sensors, or any other type of pressure sensors may be used in this step for measuring the actual pressure(s) in real time, either as part of the DTS system or separate therefrom.

[0043] In step **58**, the fluid distribution input to the model **40** is modified, based on the actual temperature and pressure distributions from steps **54** & **56**.

[0044] In step **60**, the pressure distribution and temperature distribution versus time are again predicted using the model **40**. In step **62**, the predicted pressure and temperature distribution are compared to the actual pressure and temperature distribution to determine whether a match is obtained.

[0045] If a match is obtained, then a solution is indicated in step **64**, i.e., the fluid distribution input to the model **40** is correct. If a match is not obtained in step **62**, then steps **58** & **60** are repeated until a match is obtained.

[0046] When additional data becomes available (such as when updated temperature distribution data is provided by the DTS system and/or when pressure measurements become available), this process is performed again. In this manner, the fluid distribution predicted by the model **40** is periodically updated or "calibrated" as the additional data becomes available. In order to optimize the fluid distribution, the planned treatment schedule may be modified based on the calibrated fluid distribution predicted by the model **40**.

[0047] It should be clearly understood that, although certain inputs have been described above for the model **40**, the invention is not limited to only these inputs. Other inputs, and other combinations of inputs, could be used for the model in keeping with the principles of the invention. Thus, it will be appreciated that the model **40** and technique **42** described above may be modified in any manner without departing from the principles of the invention.

[0048] Furthermore, although fluid distribution is described above as being predicted and optimized using the model **40** and technique **42**, it is not necessary for fluids to be injected, for example, the fluids could instead be produced. Flow rate or injectivity distribution integrated over time yields fluid distribution, and so the above described steps wherein fluid distribution is predicted, determined, etc. may be considered to include prediction, determination, etc. of flow rate or injectivity distribution, as well.

[0049] Referring additionally now to FIGS. **4-8**, an example of how the principles of the invention may be beneficially used to optimize fluid distribution in an acidizing operation is representatively illustrated. FIGS. **4-8** are schematic graphs of fluid penetration (on the horizontal scale in units of inches radially outward from the wellbore) vs. depth (on the vertical scale in units of feet along the wellbore).

[0050] FIG. **4** depicts a desired final fluid distribution at the end of the operation. The desired fluid distribution is preferably planned by experienced professionals to achieve optimum results (e.g., an acceptable level of stimulation, economy, etc.). Alternatively, or in addition, the desired fluid distribution could be planned using computational techniques, expert systems, etc.

[0051] In the depicted example, the operation is planned to include injection of 10,000 gallons of preflush **66**, 10,000 gallons of mainflush **67** and 10,000 gallons of overflush **68**. This schedule should result in a fluid front of the preflush **66** at approximately 135 inches penetration, a fluid front of the mainflush **67** at approximately 110 inches penetration, a fluid front of the overflush **68** at approximately 75 inches penetration and a live acid edge **69** at approximately 45 inches penetration. These should be fairly consistent along the wellbore between 4900 and 5000 feet as illustrated in FIG. **4**.

[0052] FIG. **5** depicts the predicted fluid distribution after an initial 2000 gallons of preflush **66** are injected. Note that the fluid front of the preflush **66** should be at approximately 35 inches penetration, and the live acid edge **69** should be at approximately 15 inches penetration, and these should be very consistent between the depths of 4900 and 5000 feet.

[0053] FIG. **6** depicts the actual fluid distribution after 2000 gallons of preflush **66** have been injected. This actual fluid distribution may be determined using the technique **42** described above. Note that, between the depths of 4900 and 4950 feet, the fluid front of the preflush **66** is at approximately 40 inches penetration (greater than the predicted 35 inches penetration), and between the depths of 4950 and 5000 feet the fluid front of the preflush is at approximately 10 inches penetration (less than the predicted 35 inches penetration).

[0054] Thus, a comparison between the predicted fluid distribution (as depicted in FIG. **5**) and the actual fluid distribution (as depicted in FIG. **6**) indicates that remedial action will need to be taken in order to achieve the optimal fluid distribution of FIG. **4**. Among the many beneficial features of the methods and techniques described herein are that the need for remedial action can be quickly identified and accurately quantified in real time as the operation progresses, and the remedial action can be taken in a timely manner so that the optimal fluid distribution can be achieved.

[0055] Another beneficial feature of the methods and techniques described herein is that the model used to predict fluid distribution may be modified as the operation progresses, so that the model will more accurately predict fluid distribution during the operation. Thus, in the present example, a comparison between the actual fluid distribution as depicted in FIG. **6** and the predicted fluid distribution as depicted in FIG. **5** indicates that the model should be modified (for example, by adjusting properties of the reservoir between the depths of 4950 and 5000 feet, etc.), and the modification can be accomplished so that subsequent predictions of fluid distribution during the operation will be more accurate. In this sense, it may be considered that the model is "calibrated" as the operation progresses.

[0056] In the present example, the remedial action to be taken includes injection of a diverter midway between two halves of the originally planned schedule. FIG. **7** depicts the fluid distribution after 5000 gallons of preflush, 5000 gallons of mainflush and 5000 gallons of overflush have been injected (i.e., one half of the originally planned schedule).

[0057] FIG. **8** depicts the fluid distribution after injection of a diverter **65**, followed by an additional 5000 gallons of preflush, 5000 gallons of mainflush and 5000 gallons of overflush (i.e., the remaining half of the originally planned schedule). Note that the fluid distribution as depicted in FIG. **8** closely approximates the desired fluid distribution as depicted in FIG. **4**. This result was achieved by modifying the operation as it progressed, and without the need to inject fluids in addition to those originally scheduled, other than the diverter **65**.

[0058] In the past, the original schedule of fluids would have been injected and then, after an analysis of temperature distribution and other data, it may have been determined that remedial action including injection of a diverter should be taken. The diverter and an additional schedule of treatment fluids would have then been injected in an attempt to achieved the desired fluid distribution. It will be readily appreciated by those skilled in the art that the new methods and techniques described herein result in a far more timely, economical and accurate operation being performed.

[0059] Referring additionally now to FIG. **9**, a technique **70** is representatively illustrated for predicting and optimizing fluid distribution in the method **10**. The technique **70** utilizes a model **72** which may be similar to the model **40**, but it should be understood that any other type of model and any combination of models may be used in place of the model **72**, if desired.

[0060] Inputs to the model **72** include (but are not limited to) pressure and temperature distributions PTD (these may be the same as or similar to the pressure and temperature distributions described above as being input in the technique **42** in steps **48** and **54**), geothermal gradient GG (this is similar to the initial temperature distribution described above as being input in the technique **42** in step **48**), injection rate IR, fluid type FT (including density, specific heat, etc. of the fluid; these may be the same as or similar to the fluid properties/schedule described above as being input in the technique **42** in step **44**), well geometry WG (such as diameters and lengths of tubular strings, deviation, etc.; these may be the same as or similar to the well geometry parameters described above as being input in the technique **42** in step **44**), reservoir properties RP (such as rock properties, porosity, permeability, intrinsic fluids, etc.; these may be the same as or similar to the reservoir properties described above as being input in the technique **42** in step **44**), and control inputs CI (such as surface pressure, choke position, etc.). The model **72** outputs a predicted fluid distribution PFD along the wellbore **14** at an incremental future time (t+n).

[0061] An error evaluation **74** compares the predicted fluid distribution PFD to the current fluid distribution at present time (t). Note that the current fluid distribution FD(t) may be provided by the technique **42** described above and depicted in FIG. **3**.

[0062] Any error determined in the error evaluation **74** is used to modify the model **72**, so that future predictions of fluid distribution FD are more accurate. It will be appreciated that this technique **70** of continuously predicting the fluid distribution FD, comparing the predicted fluid distribution PFD to the fluid distribution determined using the real time temperature and pressure measurements in the technique **42**, and modifying the model **72** to minimize errors in the predictions enables highly accurate determinations of the fluid distribution in the wellbore **14** to be available in real time during the course of the operation.

[0063] In another feature of the technique **70**, the predicted fluid distribution PFD(t+n) is input to an optimization device **76** for a determination of how various aspects of the operations should be modified to achieve a desired fluid distribution. The desired fluid distribution is determined prior to the operation, for example, to deliver certain volumes of stimulation fluid to particular zones or intervals, etc.

[0064] The optimization device **76** compares the predicted fluid distribution PFD(t+n) to the desired fluid distribution and determines whether certain aspects of the operation should be modified in order to achieve the desired fluid distribution. Of course, if the predicted fluid distribution is the same as the desired fluid distribution, then no modifications will be needed.

[0065] As depicted in FIG. **9**, the optimization device **76** may be used to modify the injection rate IR, fluid types FT and control inputs CI. These modified inputs are used by the model **72** to again predict the fluid distribution PFD(t+n), which is then input again to the optimization device **76** for evaluation. In this manner, the predicted fluid distribution PFD(t+n) is continuously evaluated, and aspects of the operation (such as injection rate IR, fluid types FT and control inputs CI) may be continuously modified to obtain and maintain the desired fluid distribution (e.g., to minimize any deviation between the predicted fluid distribution and the desired fluid distribution) in real time, as the operation progresses.

[0066] Referring additionally now to FIG. **10**, a technique **80** is representatively illustrated for predicting and optimizing flow rate distribution in the method **10**. The technique **80** utilizes a predictive device **82** in the form of a neural network, but it should be understood that any other type of predictive device and any combination of predictive devices may be used in place of the neural network, if desired.

[0067] For example, the predictive device **82** may include a neural network, an artificial intelligence device, a floating point processing device, an adaptive model, a nonlinear function which generalizes for real systems and/or a genetic algorithm. The predictive device **82** may perform a regression analysis, perform regression on a nonlinear function and may utilize granular computing. An output of a first principle model may be input to the predictive device **82** and/or a first principle model may be included in the predictive device.

[0068] Inputs to the neural network **82** include (but are not limited to) measured temperature distribution or profile MTP (this may be the same as or similar to the temperature distribution described above), geothermal gradient GG (this is similar to the initial temperature distribution described above as being input in the technique **42** in step **48**), injection rate IR, properties of the fluids PF (such as density, specific heat, etc.; these may be the same as or similar to the fluid types/schedule described above), properties of the wellbore PWB (such as diameters and lengths of tubular strings, deviation, etc.; these may be the same as or similar to the well geometry parameters described above), properties of the intersected zones PZ (such as rock properties, porosity, permeability, intrinsic fluids, etc.; these may be the same or similar to the reservoir properties described above as being input in the technique **42** in step **44**), and control inputs CI (such as surface pressure, choke position, etc.). Any of these inputs may be the same as or similar to the corresponding inputs described above for the technique **70**.

[0069] The neural network **82** outputs a predicted injectivity or flow rate distribution PFRD along the wellbore **14** at an incremental future time (t+n). As discussed above, flow rate or injectivity distribution integrated over time yields fluid distribution, and so it should be understood that prediction or determination of flow rate or injectivity distribution over time also provides predicted or determined fluid distribution, as well.

[0070] An error evaluation **84** compares the predicted flow rate distribution PFRD to the current flow rate distribution at present time (t). Note that the current flow rate distribution FRD(t) may be provided by the technique **42** described above and depicted in FIG. **3**.

[0071] Any error determined in the error evaluation **84** is used to modify the neural network **82**, so that future predictions of flow rate distribution PFRD are more accurate. It will be appreciated that this technique **80** of continuously predicting the flow rate distribution FRD, comparing the predicted flow rate distribution PFRD to the flow rate distribution determined using the real time temperature measurements in the technique **42**, and modifying the neural network **82** to minimize errors in the predictions enables highly accurate determinations of the flow rate distribution in the wellbore **14** to be available in real time during the course of the operation.

[0072] In another feature of the technique **80**, the predicted flow rate distribution PFRD(t+n) is input to an optimization device **86** for a determination of how various aspects of the operations should be modified to achieve a desired flow rate distribution. The desired flow rate distribution is determined prior to the operation, for example, to deliver certain volumes of stimulation fluid to particular zones or intervals over a certain time, etc.

[0073] The optimization device **86** compares the predicted flow rate distribution PFRD(t+n) to the desired flow rate distribution and determines whether certain aspects of the operation should be modified in order to achieve the desired flow rate distribution. Of course, if the predicted flow rate distribution is the same as the desired flow rate distribution, then no modifications will be needed.

[0074] As depicted in FIG. **10**, the optimization device **86** may be used to modify the injection rate IR, properties of the fluids PF and control inputs CI. These modified inputs are used by the neural network **82** to again predict the flow rate distribution PFRD(t+n), which is then input again to the optimization device **86** for evaluation. In this manner, the predicted flow rate distribution PFRD(t+n) is continuously evaluated, and aspects of the operation (such as injection rate IR, properties of the fluids PF and control inputs CI) may be continuously modified to obtain and maintain the desired flow rate distribution (e.g., to minimize any deviation between the predicted flow rate distribution and the desired flow rate distribution) in real time, as the operation progresses.

[0075] As discussed above, the principles of the invention are useful in operations other than injection operations. For example, in production operations the input injection rate IR in the techniques **42**, **70**, **80** could be replaced with production rate. Similar modifications may be used for other types of operations, as well.

[0076] Of course, a person skilled in the art would, upon a careful consideration of the above description of representative embodiments of the invention, readily appreciate that many modifications, additions, substitutions, deletions, and other changes may be made to these specific embodiments, and such changes are within the scope of the principles of the present invention. Accordingly, the foregoing detailed description is to be clearly understood as being given by way of illustration and example only, the spirit and scope of the present invention being limited solely by the appended claims and their equivalents.

1-7. (canceled)

8. A method of optimizing fluid distribution along a wellbore, the method comprising the steps of:

predicting in real time the fluid distribution along the wellbore;

comparing the predicted fluid distribution to a desired fluid distribution; and

modifying aspects of a wellbore operation in real time as needed to minimize any deviations between the predicted and desired fluid distributions.

9. The method of claim **8**, further comprising the step of monitoring a temperature distribution along the wellbore in real time, and wherein the predicting step further comprises predicting the fluid distribution along the wellbore using the temperature distribution.

10. The method of claim **8**, further comprising the steps of monitoring a temperature distribution along the wellbore in real time, and determining a current fluid distribution along the wellbore using the temperature distribution.

11. The method of claim **8**, wherein the predicting step further comprises inputting a real time temperature distribution along the wellbore to a predictive device, so that the predictive device predicts the fluid distribution.

12. The method of claim **11**, wherein the predictive device includes a neural network.

13. The method of claim **8**, wherein the comparing step further comprises inputting the predicted fluid distribution to an optimization device.

14. The method of claim **13**, wherein the modifying step further comprises the optimization device modifying inputs to the predictive device, so that the deviation between the predicted and desired fluid distributions is minimized.

15. A method of determining fluid distribution along a wellbore, the method comprising the steps of:

inputting a fluid distribution to a model;

predicting temperature distribution along the wellbore using the model;

monitoring temperature distribution along the wellbore in real time; and

modifying the fluid distribution based on a comparison between the predicted temperature distribution and the monitored temperature distribution.

16. The method of claim **15**, wherein the predicting step further comprises predicting pressure distribution in the wellbore, the monitoring step further comprises monitoring pressure distribution in the wellbore, and wherein the modifying step further comprises modifying the fluid distribution based on a comparison between the predicted pressure distribution and the monitored pressure distribution.

17. The method of claim **15**, wherein the predicting step further comprises inputting at least one parameter to a model, so that the model predicts the temperature distribution.

18. The method of claim **17**, further comprising the step of optimizing the fluid distribution by modifying the parameter input to the model, then predicting the temperature distribution based on the modified parameter, then modifying the fluid distribution based on a comparison between the predicted temperature distribution based on the modified parameter and the monitored temperature distribution.

19. The method of claim **18**, further comprising the step of modifying the parameter based on a comparison between the modified fluid distribution and a desired fluid distribution after the step of modifying the fluid distribution based on the comparison between the predicted temperature distribution based on the modified parameter and the monitored temperature distribution.

20. A method of determining flow rate distribution along a wellbore, the method comprising the steps of:

monitoring a temperature distribution along the wellbore in real time; and determining in real time the flow rate distribution along the wellbore using the temperature distribution.

21. The method of claim **20**, further comprising the step of optimizing the flow rate distribution.

22. The method of claim **21**, wherein the optimizing step further comprises comparing a desired flow rate distribution with the flow rate distribution determined using the temperature distribution.

23. The method of claim **20**, wherein the determining step further comprises inputting the temperature distribution to a predictive device, so that the predictive device predicts the flow rate distribution.

24. The method of claim **23**, wherein the predictive device includes a neural network.

25. The method of claim **23**, further comprising the step of inputting the flow rate distribution to an optimization device.

26. The method of claim **25**, wherein the optimization device modifies inputs to the predictive device, so that a deviation of the flow rate distribution from a desired flow rate distribution is minimized.

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