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(54) Wellbore real-time monitoring and analysis of fracture contribution

(57) Methods and apparatus are provided for calculating production of each of a plurality of fractured intervals (or fractures) and monitoring changes in the fracture contribution with time. Such real-time monitoring and analysis may be performed by combining temperature distribution (and pressure) measurements, a real-time surface multiphase flow measurement, and an inflow model for each fractured interval (or fracture). In this manner, the industry may be able to understand the behavior of fractures and, in turn, optimize the number of stages (*i.e.,* fractured intervals), the number of fractures, and the spacing between fractures and stages.

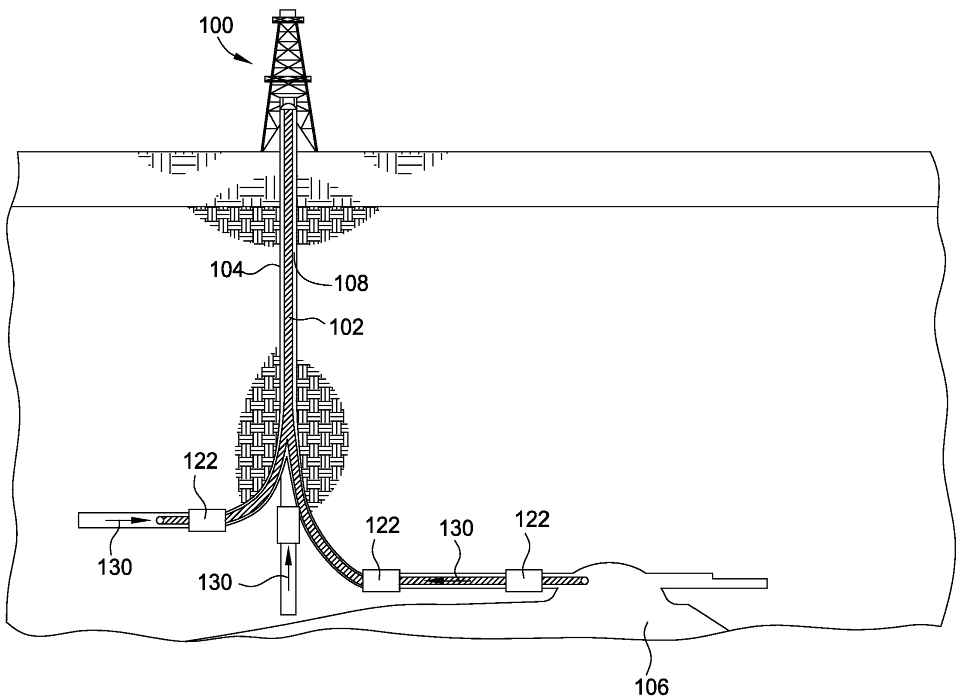

FIG. 1

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Description

[0001] The present application claims benefit of U.S. Provisional Patent Application No. 61/611,924, filed March 16, 2012, which is herein incorporated by reference in its entirety.

BACKGROUND OF THE INVENTION

Field of the Invention

[0002] Embodiments of the present invention generally relate to hydrocarbon production and, more particularly, to determining the individual contribution of fractured intervals (or fractures) in time.

Description of the Related Art

[0003] Various tools may be used in order to measure the contribution of the fractures within wellbores. Different services companies may run production logging tools, and chemical tracers may also be used to determine the fracture contribution. However, these measurements may only provide a snapshot of what is happening at the moment the measurements are performed, and may change with time because conditions within the wellbore are transient.

SUMMARY OF THE INVENTION

[0004] Embodiments of the invention generally relate to allocating production of each of a plurality of fractured intervals (or fractures). This allocation may be performed by combining temperature distribution (and pressure) measurements, a real-time surface multiphase flow measurement, and an inflow model for each fractured interval (or fracture).

[0005] One embodiment of the invention is a method for determining production of hydrocarbons. The method generally includes determining a temperature distribution associated with a plurality of fractured intervals or fractures disposed along a well; measuring a total flow rate for the well; modeling an inflow rate for each of the plurality of fractured intervals or fractures; and allocating production of each of the plurality of fractured intervals or fractures based on the temperature distribution, the total flow rate, and the inflow rates.

[0006] Another embodiment of the invention provides a system for determining production of hydrocarbons. The system generally includes a temperature sensing device configured to determine a temperature distribution associated with a plurality of fractured intervals or fractures disposed along a well, a flowmeter configured to measure a total flow rate for the well, and a processing unit. The processing unit is typically configured to model an inflow rate for each of the plurality of fractured intervals or fractures and to allocate production of each of the plurality of fractured intervals or fractures based on the temperature distribution, the total flow rate, and the inflow rates.

[0007] Yet another embodiment of the invention provides a system for determining production hydrocarbons. The system generally includes means for determining a temperature distribution associated with a plurality of fractured intervals or fractures disposed along a well; means for measuring a total flow rate for the well; means for modeling an inflow rate for each of the plurality of fractured intervals or fractures; and means for allocating production of each of the plurality of fractured intervals or fractures based on the temperature distribution, the total flow rate, and the inflow rates.

BRIEF DESCRIPTION OF THE DRAWINGS

[0008] So that the manner in which the above recited features of the present invention can be understood in detail, a more particular description of the invention, briefly summarized above, may be had by reference to embodiments, some of which are illustrated in the appended drawings. It is to be noted, however, that the appended drawings illustrate only typical embodiments of this invention and are therefore not to be considered limiting of its scope, for the invention may admit to other equally effective embodiments.

[0009] FIG. 1 is a conceptual diagram of a system for producing hydrocarbons, the system having a pipe inside a casing and downhole tools positioned at various locations along the pipe, in accordance with an embodiment of the invention.

[0010] FIG. 2 illustrates an ideal reservoir model with multiple fractures, in accordance with an embodiment of the invention.

[0011] FIG. 3 illustrates hydrocarbon production allocation from multiple wells, in accordance with an embodiment of the invention.

[0012] FIG. 4 illustrates hydrocarbon production allocation from a horizontal well with multiple fractured intervals, in accordance with an embodiment of the invention.

[0013] FIG. 5 is a flow diagram of example operations for allocating hydrocarbon production to multiple fractured intervals (or fractures), in accordance with an embodiment of the invention.

[0014] FIG. 6 illustrates a workflow for identifying and calculating the contribution of each fractured interval (or fracture), in accordance with an embodiment of the invention.

[0015] FIG. 7 illustrates an example plot of gas production versus number of contributing fractures, in accordance with an embodiment of the invention.

DETAILED DESCRIPTION

[0016] Embodiments of the invention provide techniques and apparatus for calculating production of each of a plurality of fractured intervals (or fractures) and monitoring changes in the fracture contribution with time.

Such real-time monitoring and analysis may be based on a combination of different measurements in the wellbore, on the surface, and from a mathematical model, as described below. In this manner, the industry may be able to understand the behavior of fractures and, in turn, optimize the number of stages (*i.e.*, fractured intervals), the number of fractures, and the spacing between fractures and stages.

[0017] Referring to FIG. 1, there is shown a hydrocarbon production system 100 containing one or more production pipes 102 (also known as production tubing) that may extend downward through a casing 104 to one or more hydrocarbon sources 106 (*e.g.*, reservoirs). An annulus 108 may exist between the pipe 102 and the casing 104. Each production pipe 102 may include one or more lateral sections (*e.g.*, created by horizontal drilling) that branch off to access different hydrocarbon sources 106 or different areas of the same hydrocarbon source 106. The fluid mixture may flow from sources 106 to the well completion through the production pipes 102, as indicated by fluid flow 130. The production pipe 102 may include one or more tools 122 for performing various tasks (*e.g.*, sensing parameters such as pressure or temperature) in, on, or adjacent a pipe or other conduit as the fluid mixtures flow through the production pipes 102. The tools 122 may be any type of downhole device, such as a flow control device (*e.g.*, a valve), a sensor (*e.g.*, a pressure, temperature or fluid flow sensor) or other instrument, an actuator (*e.g.*, a solenoid), a data storage device (*e.g.*, a programmable memory), a communication device (*e.g.*, a transmitter or a receiver), etc.

[0018] Each tool 122 may be incorporated into an existing section of production pipe 102 or may be incorporated into a specific pipe section that is inserted in line with the production pipe 102. The distributed scheme of tools 122 shown in FIG. 1 may permit an operator of the system 100 to determine, for example, the level of depletion of the hydrocarbon reservoir. This information may permit the operator to monitor and intelligently control production of the hydrocarbon reservoir.

[0019] Advances in directional drilling (*e.g.*, horizontal drilling as shown in FIG. 1) and reservoir stimulation techniques have dramatically increased gas production from wells drilled in shale reservoirs that were considered uneconomical not too long ago. In spite of many advances in understanding the behavior of the production of this type of reservoir, many unknowns remain, such as determining the optimal length of horizontal sections, how many stages, and determining how many fractures are optimal. Particularly, it is difficult to predict productivity from cores, logs, drillstem tests (DSTs), or early well-production performance. Drainage volumes are uncertain, and well spacing is based on trial and error methods.

[0020] The use of microseismic and production logs has helped in the fracture evaluation to determine the drainage volume and fracture inflow. Microseismic can provide useful information on the development of fracture symmetry, half-length, azimuth, width and height, and their dependence on the treatment parameters and reservoir characteristics. Additionally, these fracture geometries in conjunction with other measured or calculated parameters (*e.g.*, rates, inflow models, etc.) can be used to better understand fracture modeling and production characteristics.

[0021] Review of production logs have indicated that only a percentage of the fractures are contributing to the production, and until now, only snapshots of the fracture contributions have been made. However, considering that this is a transient system (where fracture contributions typically change with time, typically for the first 15 to 20 months of production), a snapshot measurement is not sufficient to understand the behavior of the fractures and their contribution over time.

[0022] Accordingly, what is needed are techniques and apparatus for establishing which fractures (or at least which fractured intervals) are contributing and how much.

[0023] Due to the transient behavior, an ideal system would offer continuous, permanent, and real-time monitoring on key variables like production rates, pressure and temperature in an effort to determine the fracture contributions. Procedures that integrate different types of measurements and calculations in "real time" may help to find and understand the behavior of the fractures and to optimize the number of stages, fractures, and spacing.

[0024] Embodiments of the invention provide methods and apparatus to optimize, or at least increase, the production of horizontal fractured wells in shale reservoirs, for example. By integrating different types of real-time measurements, methods described herein enable the optimization of the number of fractures, the spacing of fractures, and the length of the horizontal section by determining the contribution of the fracture stages (or the fractures) over time.

[0025] One way to solve this problem might be the installation of downhole flowmeters in each fracture stage. However, this can be a challenge operationally and may also be very costly and risky.

[0026] Instead, considering the very low permeability of shale reservoirs (on the order of nanodarcys) , it can be established that a reservoir is created only after fracturing. If the spacing between fractures is correct (such that the fractures do not interfere with one another) , the production allocation of each fracture stage (or fracture) may be calculated in an analogous way to that performed in a traditional field, where the total production rates are allocated to each production well using well testing measurements, done periodically with daily measurement information like wellhead pressure. In this particular case, by combining permanent downhole measurement of temperature (and one or more pressure measurements at the heel and the toe of the wellbore, for example) , permanent wellhead flow measurement of the different phases, and a mathematical transient model of the production rates of each fracture, an acceptable production allocation can be made as a function of time. Because the system is transient, such allocation may be performed on a real- time basis.

[0027] In scenarios where the number of fractures is large, the idealized system 200 shown in FIG. 2 may be used to model the reservoir. In FIG. 2, multiple fractures 204, 206 are represented as spaced along and transverse to the horizontal well trajectory 202. Assuming fracturing conditions were the same, the length and width of each fracture in the fracture stage may be considered equal. These parallel fractures are formed in an area (*e.g.*, a shale reservoir) with essentially zero permeability (as illustrated in the region 212 unshaded in FIG. 2), thereby forming a region 214 of modified permeability (shaded in FIG. 2), essentially creating a reservoir where none existed before. Although any number of fractures (N_{frac}) may be formed with any spacing therebetween, five fractures are illustrated in the fracture stage of FIG. 2 (two external fractures 204 and three internal fractures 206) with equal fracture spacing. The fracture stage is defined by confining external boundaries 210. FIG. 2 shows that external fractures 204 are confined by virtual no-flow boundaries 208, which force the external fractures to have the same behavior as the internal fractures 206, and pure linear flow initially occurs. In shale gas reservoirs of nanodarcy permeability, pure linear flow opposite the fracture faces occurs for very long times.

[0028] The concept of Stimulated Reservoir Volume (SRV) is based on the premise that negligible flow occurs from beyond the fracture tips. The reservoir is created by the fracturing, and the reservoir size is limited by the length of the main fracture. Production performance from the fractured reservoir may be based on the SRV, the fracture spacing, and the fracture conductivity.

[0029] The near-wellbore temperature distribution yielded by distributed temperature sensing (DTS) or multi-point or array temperature sensing (ATS) may be used to determine the relative amount of fluid that each perforation interval contributes. If this information is combined with one or more pressure measurements and a real-time surface multiphase flow measurement in conjunction with an inflow model for each fractured interval, a production allocation may be calculated for each fracture. This approach is analogous to a traditional well allocation where a daily aggregated measurement at the production plant is back-allocated to each well based on wellhead measurements like pressure, temperature, and well performance. The description below provides details on the use of these technologies to analyze the fracture behavior in horizontal wells in shale reservoirs, for example.

[0030] FIG. 3 illustrates a multi-well system 300 in an oil/gas production field, in which hydrocarbon production may be allocated to each of the wells. In this allocation process, periodical (*e.g.*, 15 days to weeks or months) production well tests are performed on each individual well, and daily (or in some cases, every few hours) pressure (P) and/or temperature (T) measurements at or near the wellhead 302 of each well are registered. The produced fluids from each well may be collected at a manifold and then separated by a separator 310 into oil, gas, and water. Daily (or in some cases, every few hours or minutes) total flow rates of oil (Qo), gas (Qg), and water (Qw) may be measured. With the production well tests, using nodal analysis techniques, the well performance (P vs. Q relation) for each well at the wellhead 302 is calculated. The use of this wellhead performance with frequent wellhead pressure measurements allows the flow rates of each individual well to be determined.

[0031] Ideally, the addition of all these individual well flow rates is the total production of the field, but for various reasons (*e.g.*, well performance of each well can change over time) , there is a difference between these values. To eliminate this difference, an allocation factor (K) is found using the relationship between the total flow rate (Qt) measured and the sum of the individual well flow rates (ΣQi) and may be subsequently used.

[0032] FIG. 4 illustrates a system 400 for allocating hydrocarbon produced from a horizontal well with multiple fractured intervals 402 along a horizontal well, in accordance with an embodiment of the invention. Although seven fractured intervals 402, each with five fractures 404, are shown in FIG. 4, any number of fractured intervals and any number of fractures per interval may be used. The system 400 also includes a multiphase real-time flowmeter 406 and a DTS cable 408 disposed downhole. The system may also include one or more sensors 410 for measuring pressure (P) and/or temperature (T), which may be disposed anywhere in the wellbore, such as in the vertical section as shown. The multiphase flowmeter 406 may be installed at or adjacent the wellhead or within the wellbore and, for some embodiments, may be an optical flowmeter (*e.g.*, an optical downhole flowmeter). The DTS cable 408 may be installed adjacent the casing 104, as shown in FIG. 4.

[0033] Drawing an analogy to the multi-well system 300 of FIG. 3, each stage (*i.e.*, fractured interval 402) in FIG. 4 is akin to a producing well. With the help of the variation of temperature and a transient inflow model, it is possible to calculate the production of each stage at any time. In fact, if the temperature variation is high enough to distinguish between fractures 404, it may also be possible to allocate the production of each particular fracture.

[0034] The analogy between production allocation for individual wells and stages (or fractures) is possible (*i.e.*, each stage or fracture may be considered as an individual contributor to production) because, due to the low permeability of this type of reservoir (as described above with respect to FIG. 2), the communication between stages, and even between fractures, is negligible. The main characteristics of the fractures (*e.g.*, length and width) may be considered equal in each stage, assuming fracturing conditions were the same. The inflow rate of each fracture will be computed by an analytical transient model and combined with the change in temperature (as determined by the DTS cable 408, for example) at each stage referenced to an initial condition prior to fracturing. In conjunction with the total flow rate (Qt) measured by the multiphase flowmeter 406, a production allocation for each stage (Qsi) (or each fracture) will be performed.

[0035] FIG. 5 is a flow diagram of example operations 500 for determining the contribution to hydrocarbon production of each fractured interval (or each fracture). The operations 500 may begin, at 502, by determining a temperature distribution associated with a plurality of fractured intervals or fractures disposed along a well. The temperature distribution may be determined by performing at least one of distributed temperature sensing (DTS) or array temperature sensing (ATS). The plurality of fractured intervals or fractures may be located in a shale reservoir, for example.

[0036] At 504, a total flow rate of a fluid (or any combination of fluids) produced by the well (*i.e.*, the produced hydrocarbons) is measured. The total flow rate may be a total gas flow rate or a total oil flow rate, for example. For some embodiments, the total flow rate may be measured using a flowmeter disposed at the surface. For example, the flowmeter may be disposed at or adjacent a wellhead of the well.

[0037] An inflow rate is modeled at 506 for each of the plurality of fractured intervals or fractures. The inflow rate may be an inflow gas rate or an inflow oil rate, for example.

[0038] At 508, production of each of the plurality of fractured intervals or fractures is allocated based on the temperature distribution, the total flow rate, and the inflow rates. For some embodiments, allocating the production at 508 may include: (1) determining a first temperature value T_0 at a first time t_0 (*e.g.*, before production starts) for each of the plurality of fractured intervals or fractures; (2) determining a second temperature value T_n at a second time t_n (*e.g.*, subsequent to the first time to) for each of the plurality of fractured intervals or fractures; (3) calculating a delta temperature value ($\Delta T_n = T_n - T_0$) for the second time t_n for each of the plurality of fractured intervals or fractures by determining a difference between the first and second temperature values for each of the plurality of fractured intervals or fractures; (4) calculating a first ratio $(\Delta T/Tg)_n$ of the delta temperature value ΔT_n for the second time t_n for each of the plurality of fractured intervals or fractures to a geothermal temperature (Tg) at the second time t_n (5) comparing the first ratio $(\Delta T/Tg)_n$ for the second time t_n to a maximum value of the first ratio over all previous times for each of the plurality of fractured intervals or fractures (6) for each of the plurality of fractured intervals or fractures, designating the first ratio for the second time t_n as the maximum value of the first ratio over all previous times if the first ratio for the second time t_n is greater than the previously designated maximum value (7) calculating a second ratio $(\Delta T/Tg)$ / $(\Delta T/Tg)$ max of the first ratio for the second time t_n for each of the plurality of fractured intervals or fractures to the currently designated maximum value of the first ratio over all previous times for each of the plurality of fractured intervals or fractures; (8) multiplying the second ratio for the second time t_n with the modeled inflow rate corresponding to the second time t_n for each of the plurality of fractured intervals or fractures; (9) summing results of the multiplication for each of the plurality of fractured intervals or fractures; (10) determining an allocation factor (K) by dividing the measured total flow rate corresponding to the second time t_n by the sum; (11) applying the allocation factor (K) to the modeled inflow rate for each of the plurality of fractured intervals or fractures.

[0039] For some embodiments, the operations 500 may also include repeating the determining at 502, the measuring at 504, and the modeling at 506 within a period short enough to observe transient behavior of the plurality of fractured intervals or fractures. The determining, measuring, and/or modeling described above may be performed and repeated with any desired frequency (at any desired rate or periodicity). For example, the determining, measuring, and/or modeling may be performed continuously, hourly, daily, weekly, or with other frequencies.

[0040] For some embodiments, the operations 500 may also include determining one or more pressure measurements for the well. In this case, allocation of the production at 508 may also be based on the pressure measurements. The pressure measurements may be made by one or more pressure sensors located downhole, along the horizontal or vertical portion of the wellbore. The pressure sensors may be optical-based pressure sensors having one or more fiber Bragg gratings (FBGs) located therein.

[0041] FIG. 6 illustrates a workflow 600 for identifying and calculating the contribution of each fractured interval (or fracture), in accordance with an embodiment of the invention. For simplicity, the description below will focus on production allocation for each fractured interval. The workflow 600 can be easily expanded to production allocation for each fracture, as long as the temperature variation is high enough to distinguish between fractures.

[0042] In the workflow 600, the DTS (or ATS) data 602 is related to the geothermal gradient value for each stage 402. The cable 408 may be sampled with some periodicity to generate the data 602, leading to temperature measurements at certain sampling times (t_n) . For each sampling time (t_n) , the delta temperature (ΔT) between the temperature at the sampling time and at time t_0 is calculated for each stage 402. At 604, the ΔT values for each stage are divided by Tg to normalize the data. For some embodiments, pressure measurements (*e.g.*, taken by the sensors 410) may be used to ensure accuracy of the ΔT values for each stage (*e.g.*, by correlation with the temperature measurements) . At 606, a ratio $((\Delta T/Tg)$ / $(\Delta T/Tg)$ max) for the sampling time (t_n) is calculated for each stage 402. The ratio for each stage is calculated by dividing the Tg- normalized ΔT value for this particular stage by the maximum Tg- normalized ΔT value over all previous times for this stage.

[0043] The ΔT value at time t_0 is initially assumed to be the maximum Tg-normalized ΔT value, so the ratio in this case will be 1. The maximum ΔT value is stored for later validation of this assumption.

[0044] At 608, inflow transient models are run to generate inflow rates for each stage 402 (indexed by "i"). The workflow 600 of FIG. 6 generates inflow gas rates for each stage (Qgfi), but inflow oil rates or both may also be used. The inflow transient models either produce the inflow rates at the sampling time (t_n) as shown at 610, or interpolation or other techniques are used to determine inflow rates at the sampling time based on inflow rates produced for other times. At 612, the ratio at the sampling time (t_n) for each stage calculated at 606 is multiplied with the modeled inflow rate for each stage from 610 corresponding to the sampling time.

[0045] As described above, surface multiphase measurements may be made at 614, for example, by the flowmeter 406, to generate one or more total flow rates (Qg, Qo, and/or Qw) for the well. The total flow rates may either be generated at the sampling time (t_n) as shown at 616, or interpolation or other techniques may be used to determine the total flow rates at sampling time based on measurements taken at other times.

[0046] The results of the multiplications at 612 for each of the stages 402 at the sampling time (t_n) may be summed (ΣQ'gfi). At 618, this sum may be compared to the total gas flow rate (Qg) corresponding to the sampling time (t_n).

[0047] At the first sampling time (t_0), the ratio for each stage 402 calculated at 606 is multiplied by the Qgfi at t_0 for each stage at 612, and the sum of all Qgfi values is compared to the Qg corresponding to to at 618. For this time to, it is being assumed that all fractures are contributing at their 100% capacities, unless the ΔT value is zero, in the case of no contribution. For the next time t_1, the value of ΔT_1 will be compared to the value of ΔT_0. If ΔT_1 is bigger, then a new maximum value is obtained. This new maximum value replaces the previous value, and in this case the contribution of this particular stage will be 100% during this period of time, and the assumption on the previous time step was wrong. A new calculation for t_0 will be performed to correct the first assumption and similarly at any time that a new maximum value is found.

[0048] The workflow 600, operating on a "real-time" basis, will increase well productivity, helping to determine what is the optimal choke size to flow back the well and to have all fractures contributing (or to find out which fractures do not contribute at all). After this procedure is performed on different wells with a different number of stages and/or fractures, a normalized graph of production versus a number of contributing stages and/or fractures can be obtained and, based on these results, an optimal number of stages and/or fractures may be determined. A good relationship is expected of production versus number of contributing fractures, more consistent than the plot 700 of gas production versus number of contributing fractures shown in FIG. 7 (from Modeland N. et al., "Stimulation's Influence on Production in the Haynesville Shale: A Playwide Examination of Fracture-Treatment Variables that Show Effect on Production," SPE 148940 presented at Canadian Unconventional Resources Conference, 15-17 November 2011, Alberta, Canada).

[0049] As described above, the near-wellbore temperature distribution yielded by distributed temperature sensing (DTS) or multi-point or array temperature sensing (ATS) may be used to determine the relative amount of fluid that each perforation interval contributes. If this information is combined with a real-time surface multiphase flow measurement in conjunction with an inflow model for each fractured interval (and one or more pressure measurements), a production allocation may be calculated for each fractured interval or fracture. This approach is analogous to a traditional well allocation where a daily aggregated measurement at the production plant is back-allocated to each well based on wellhead measurements like pressure, temperature, and well performance.

[0050] While the foregoing is directed to embodiments of the present invention, other and further embodiments of the invention may be devised without departing from the basic scope thereof, and the scope thereof is determined by the claims that follow.

Claims

1. A method for determining production of hydrocarbons, comprising:

    determining a temperature distribution associated with a plurality of fractured intervals or fractures disposed along a well;
    measuring a total flow rate for the well;
    modeling an inflow rate for each of the plurality of fractured intervals or fractures; and
    allocating production of each of the plurality of fractured intervals or fractures based on the temperature distribution, the total flow rate, and the inflow rates.

2. The method of claim 1, further comprising repeating the determining, the measuring, and the modeling within a period short enough to observe transient behavior of the plurality of fractured intervals or fractures.

3. The method of claim 1 or 2, wherein the measuring comprises measuring the total flow rate using a multiphase flowmeter.

4. The method of claim 1, 2 or 3, wherein at least one of the determining, the measuring, or the modeling is performed daily.

5. The method of claim 1, 2, 3, or 4, wherein at least one of the determining, the measuring, or the modeling is performed continuously.

6. A system for determining production of hydrocarbons, comprising:

a temperature sensing device configured to determine a temperature distribution associated with a plurality of fractured intervals or fractures disposed along a well;
a flowmeter configured to measure a total flow rate for the well; and
a processing unit configured to:

model an inflow rate for each of the plurality of fractured intervals or fractures; and
allocate production of each of the plurality of fractured intervals or fractures based on the temperature distribution, the total flow rate, and the inflow rates.

7. The method of any of claims 1 to 5, or the system of claim 6, wherein the plurality of fractured intervals or fractures is located in a shale reservoir.

8. The method of any of claims 1 to 5, or claim 7, further comprising determining one or more pressure measurements for the well, wherein allocating the production is further based on the pressure measurements, or the system of claim 6 or 7, further comprising a pressure sensor configured to determine one or more pressure measurements for the well, wherein the processing unit is configured to allocate the production further based on the pressure measurements.

9. The method of any of claims 1 to 5, or claim 7 or 8, wherein allocating the production comprises, or the system of claim 6, 7 or 8, wherein the processing unit is configured to allocate the production by:

determining a first temperature value at a first time for each of the plurality of fractured intervals or fractures;
determining a second temperature value at a second time for each of the plurality of fractured intervals or fractures;
calculating a delta temperature value for the second time for each of the plurality of fractured intervals or fractures by determining a difference between the first and second temperature values for each of the plurality of fractured intervals or fractures;
calculating a first ratio of the delta temperature value for the second time for each of the plurality of fractured intervals or fractures to a geothermal temperature;
comparing the first ratio for the second time to a maximum value of the first ratio over all previous times for each of the plurality of fractured intervals or fractures;
for each of the plurality of fractured intervals or fractures, designating the first ratio for the second time as the maximum value of the first ratio over all previous times if the first ratio for the second time is greater than a previously designated maximum value;
for each of the plurality of fractured intervals or fractures, calculating a second ratio of the first ratio for the second time to a currently designated maximum value of the first ratio over all previous times;
multiplying the second ratio for the second time with the modeled inflow rate corresponding to the second time for each of the plurality of fractured intervals or fractures;
summing results of the multiplication for each of the plurality of fractured intervals or fractures; and
determining an allocation factor by dividing the measured total flow rate corresponding to the second time by the sum.

10. The method of claim 9, wherein the first time occurs before the hydrocarbons are produced.

11. The method of claim 9 or 10, further comprising applying the allocation factor to the modeled inflow rate for each of the plurality of fractured intervals or fractures, or the system of claim 9, wherein the processing unit is further configured to apply the allocation factor to the modeled inflow rate for each of the plurality of fractured intervals or fractures.

12. The method of any of claims 1 to 5, or claims 7 to 11, wherein determining the temperature distribution comprises performing at least one of distributed temperature sensing (DTS) or array temperature sensing (ATS), or the system of any of claims 6 to 9, or claim 11, wherein the temperature sensing device comprises a distributed temperature sensing (DTS) device or an array temperature sensing (ATS) device.

13. The method of any of claims 1 to 5, or claims 7 to 12, or the system of any of claims 6 to 9, or claims 11 or 12, wherein the total flow rate comprises a total gas flow rate and wherein the inflow rates comprise inflow gas rates.

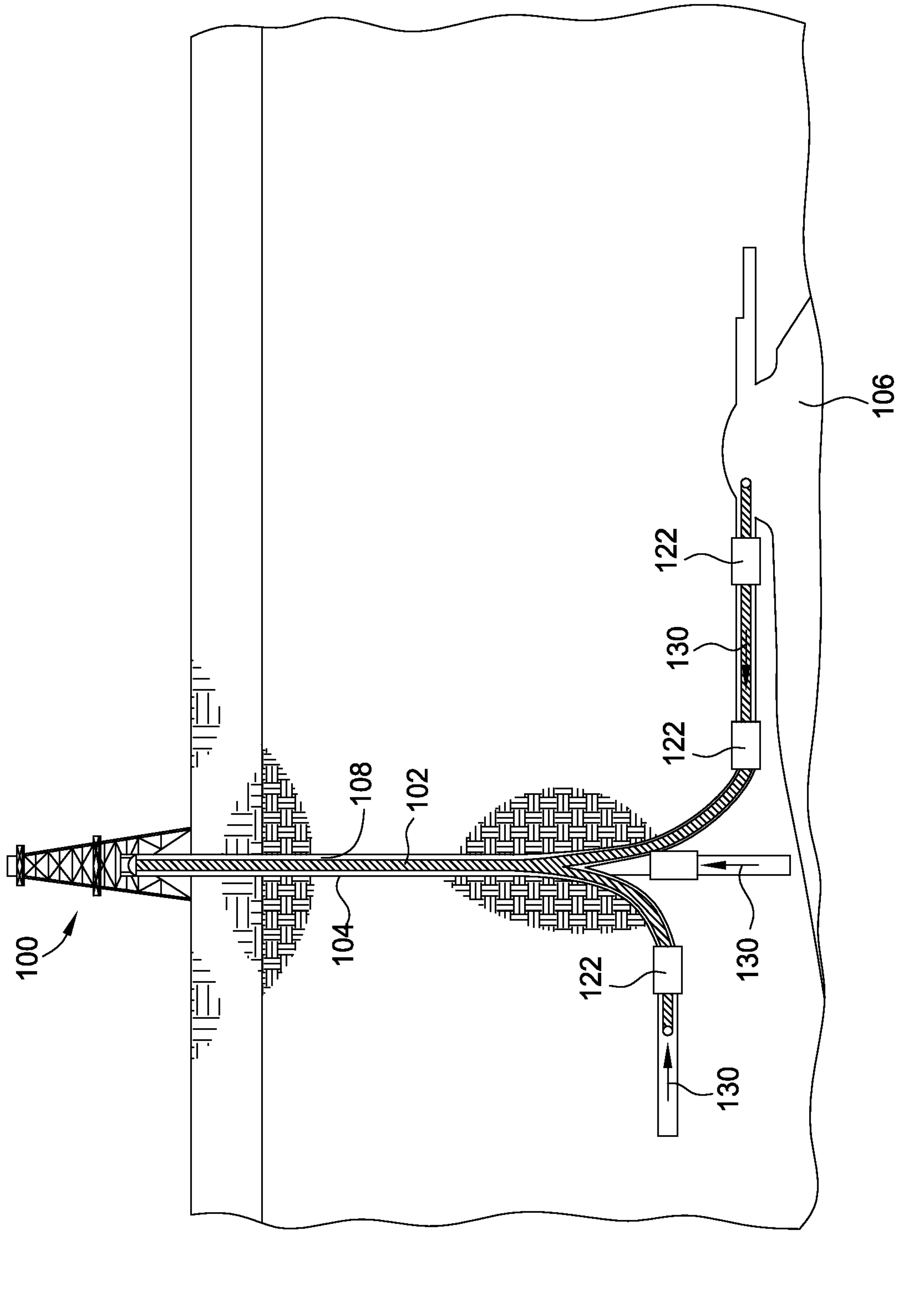
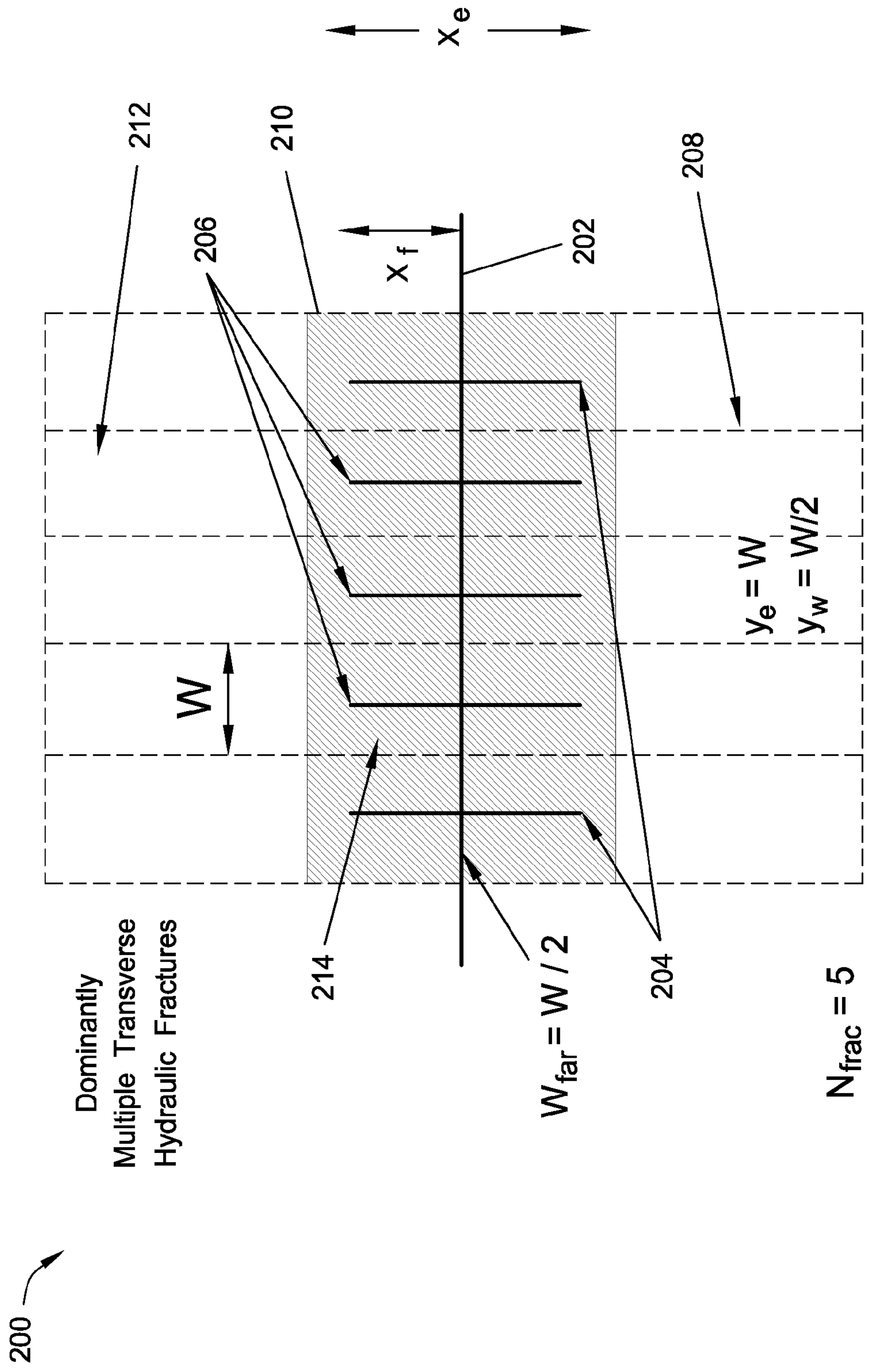


FIG. 1


200
Dominantly
Multiple Transverse
Hydraulic Fractures
212
210
206
202
208
x_e
x_f
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214
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204
$N_{frac} = 5$
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FIG. 2

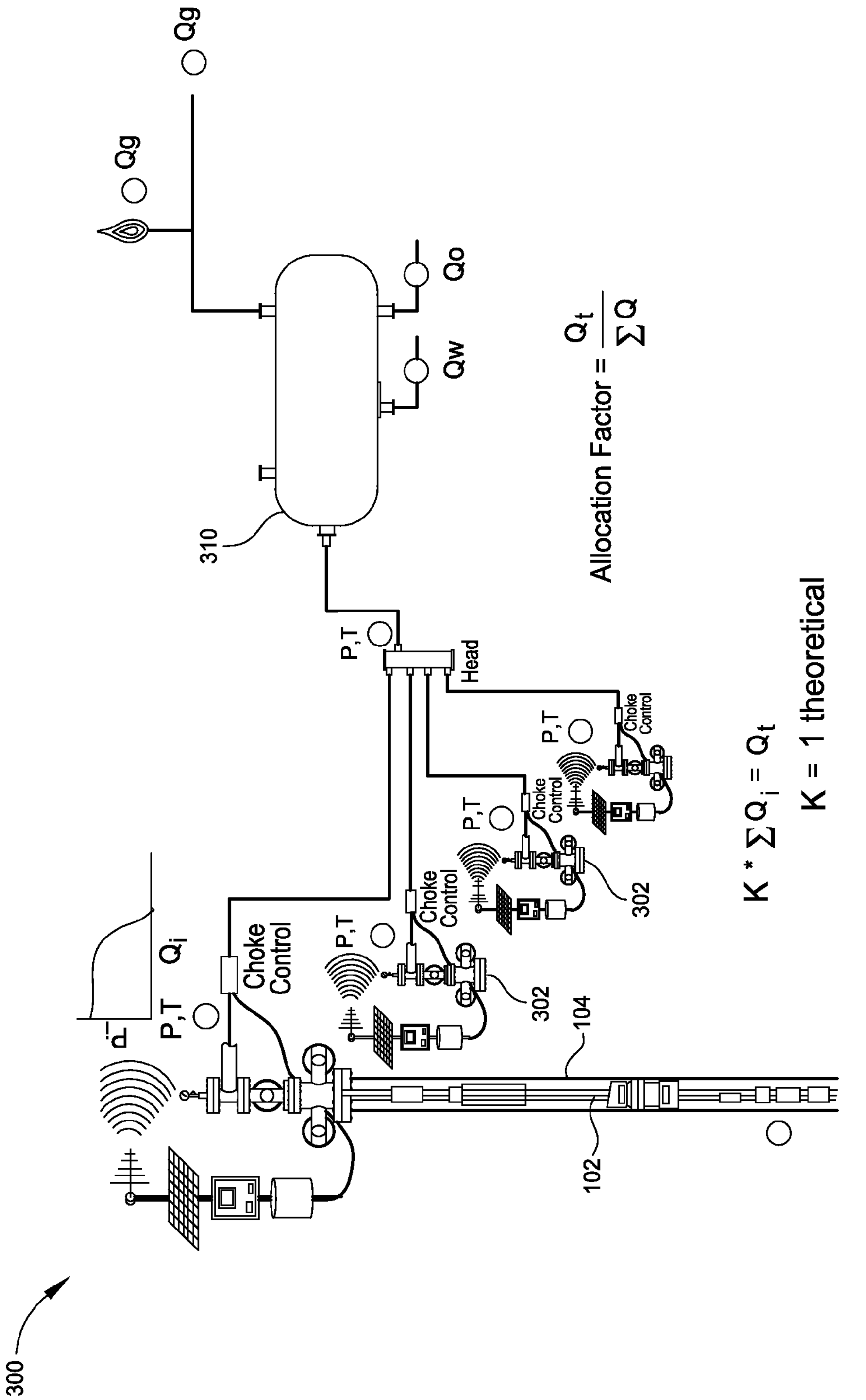
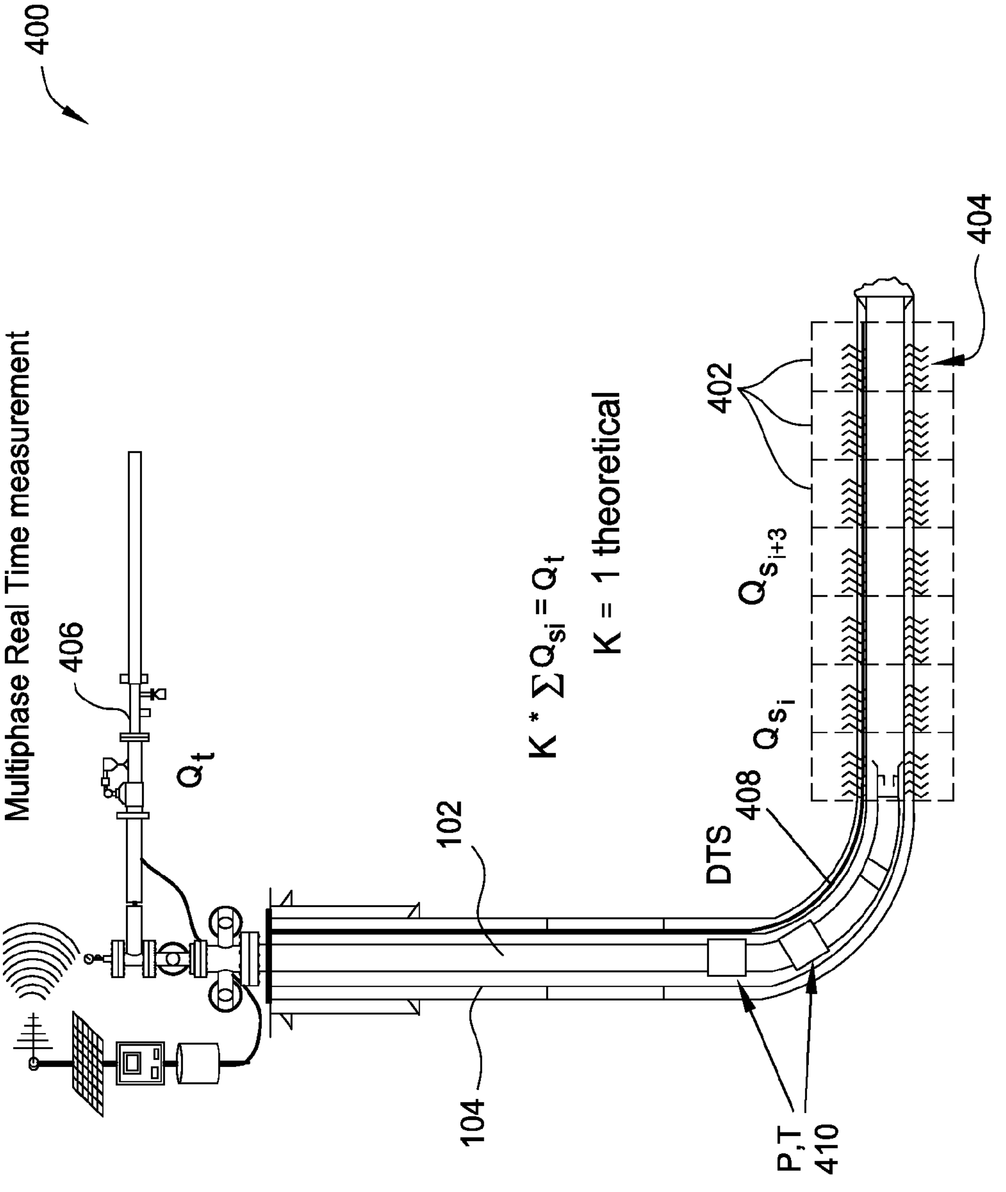

300
102
104
302
302
310
P,T
Q_i
Choke Control
P,T
Choke Control
P,T
Choke Control
P,T
Choke Control
Head
P,T
Qg
Qg
Qo
Qw
Allocation Factor = $\frac{Q_t}{\sum Q}$
$K * \sum Q_i = Q_t$
K = 1 theoretical

FIG. 3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406
Q_t
102
104
K * ΣQ_si = Q_t
K = 1 theoretical
DTS
408
Q_si
Q_si+3
402
404
P,T
410

FIG. 4

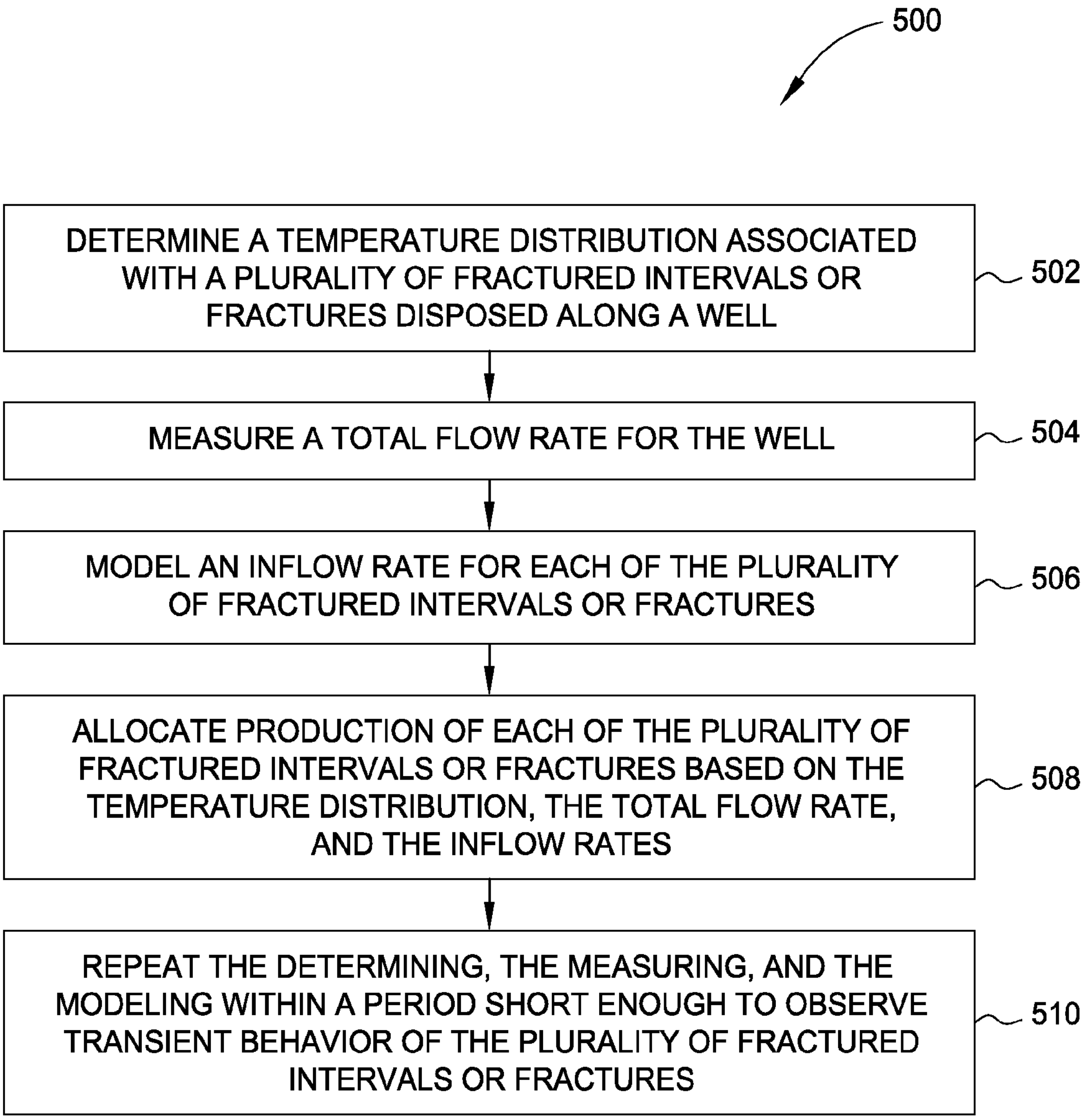
500
DETERMINE A TEMPERATURE DISTRIBUTION ASSOCIATED WITH A PLURALITY OF FRACTURED INTERVALS OR FRACTURES DISPOSED ALONG A WELL
502
MEASURE A TOTAL FLOW RATE FOR THE WELL
504
MODEL AN INFLOW RATE FOR EACH OF THE PLURALITY OF FRACTURED INTERVALS OR FRACTURES
506
ALLOCATE PRODUCTION OF EACH OF THE PLURALITY OF FRACTURED INTERVALS OR FRACTURES BASED ON THE TEMPERATURE DISTRIBUTION, THE TOTAL FLOW RATE, AND THE INFLOW RATES
508
REPEAT THE DETERMINING, THE MEASURING, AND THE MODELING WITHIN A PERIOD SHORT ENOUGH TO OBSERVE TRANSIENT BEHAVIOR OF THE PLURALITY OF FRACTURED INTERVALS OR FRACTURES
510

FIG. 5

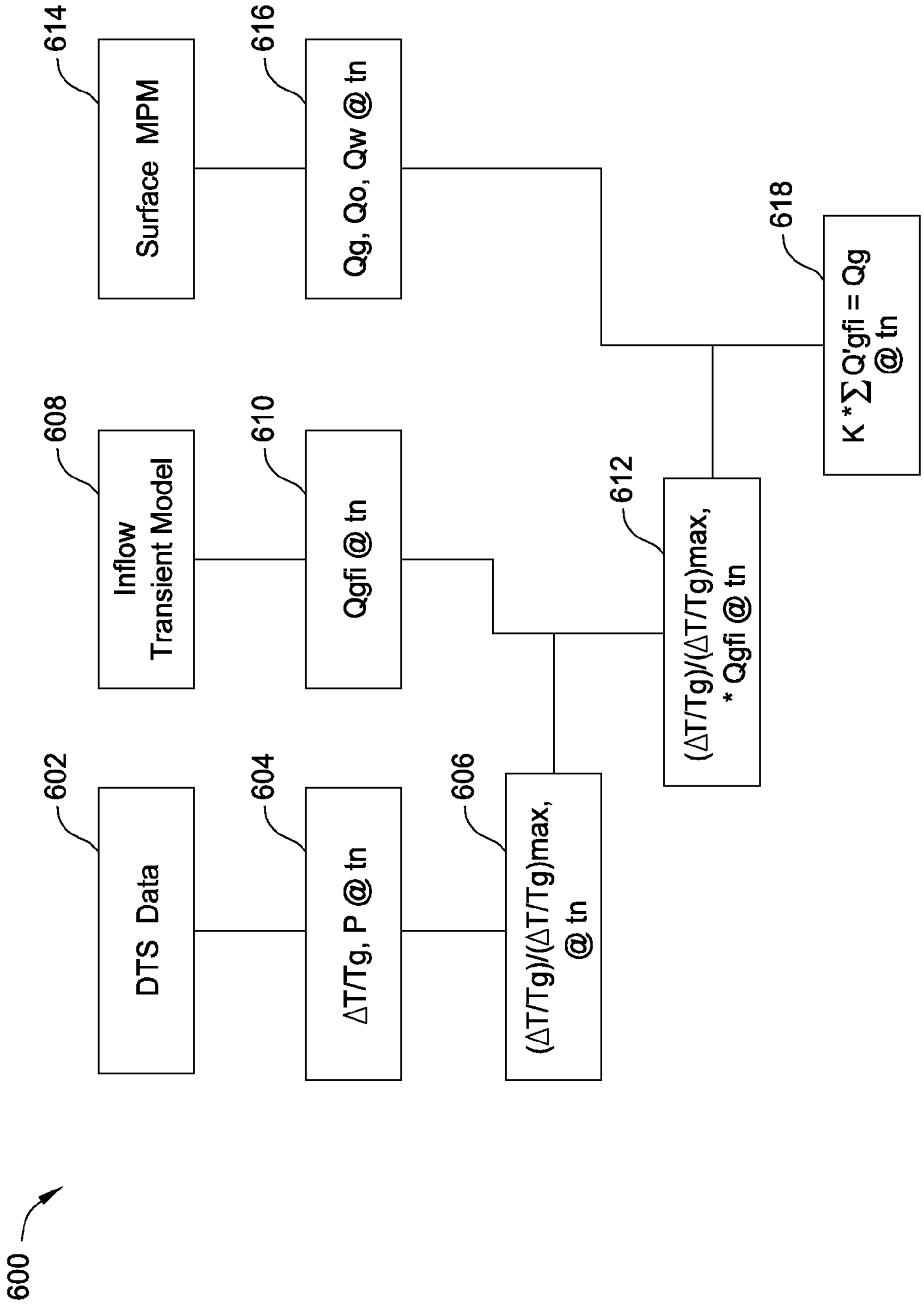
600
602
DTS Data
604
ΔT/Tg, P @ tn
606
(ΔT/Tg)/(ΔT/Tg)max, @ tn
608
Inflow Transient Model
610
Qgfi @ tn
612
(ΔT/Tg)/(ΔT/Tg)max, * Qgfi @ tn
614
Surface MPM
616
Qg, Qo, Qw @ tn
618
K *∑Q'gfi = Qg @ tn

FIG. 6

700

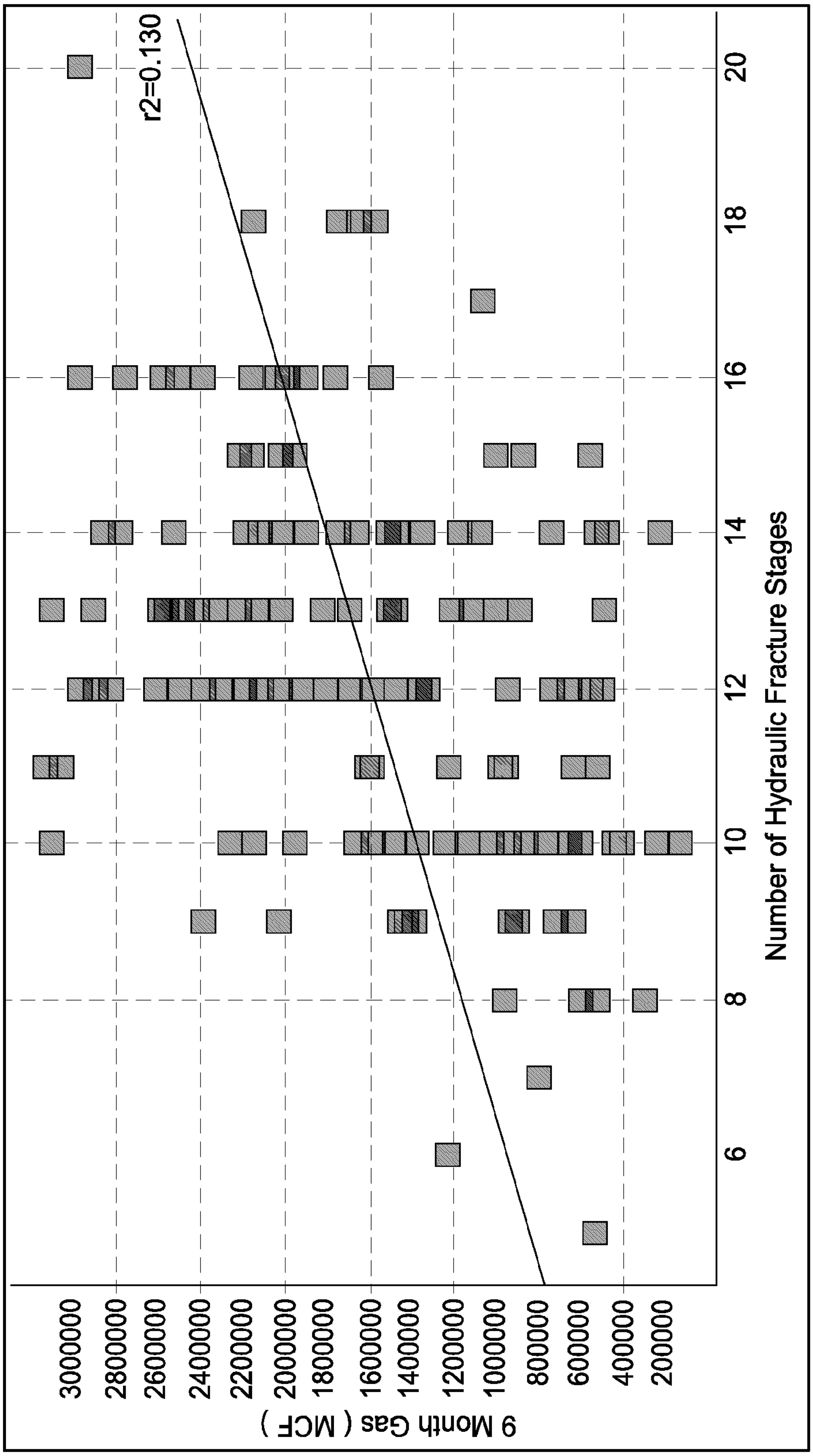
9 Month Gas (MCF)
3000000
2800000
2600000
2400000
2200000
2000000
1800000
1600000
1400000
1200000
1000000
800000
600000
400000
200000
Number of Hydraulic Fracture Stages
6
8
10
12
14
16
18
20
r2=0.130

FIG. 7

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EUROPEAN SEARCH REPORT

Application Number
EP 13 15 9586

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X	US 3 913 398 A (CURTIS M REX) 21 October 1975 (1975-10-21) * column 15, lines 32-46 * * column 16, lines 47-55 * * column 23, lines 36-51; figures 1-4 * -----	1-8	INV. E21B41/00 E21B47/06 E21B49/08
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X	US 2010/299124 A1 (SUN KAI [US] ET AL) 25 November 2010 (2010-11-25) * paragraphs [0018], [0020], [0021]; claims 1, 6; figures 1-5 * -----	1-8	
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The present search report has been drawn up for all claims

1

Place of search	Date of completion of the search	Examiner
Munich	5 June 2013	Manolache, Iustin

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