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(54) METHOD OF USING PRESSURE SIGNATURES TO PREDICT INJECTION WELL ANOMALIES

VERFAHREN ZUM EINSATZ VON DRUCKSIGNATUREN ZUR VORHERSAGE VON VERPRESSBOHRUNGSANOMALIEN

PROCÉDÉ D'UTILISATION DE SIGNATURES DE PRESSION POUR PRÉDIRE DES ANOMALIES DE PUITS D'INJECTION

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- **GEEHAN THOMAS ET AL.: 'The cutting edge in drilling-waste management' OILFIELD REVIEW pages 54 - 67, XP003026540**
- **WISHART,DEBONNE ET AL.: 'Hydraulic anisotropy chracterization of pneumatic-fractured sediments using azimuthal self potential gradient' JOURNAL OF CONTAMINANT HYDROLOGY vol. 103, 2009, pages 134 - 144, XP025865712**

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EP 2 198 115 B1

Description

Field of the Invention

[0001] Embodiments disclosed herein generally relate to methods of determining the fracture behavior of a disposal formation during a CRI (cuttings re-injection) operation.

Background Art

[0002] In the drilling of wells, a drill bit is used to dig many thousands of feet into the earth's crust. Oil rigs typically employ a derrick that extends above the well drilling platform. The derrick supports joint after joint of drill pipe connected end-to- end during the drilling operation. As the drill bit is pushed further into the earth, additional pipe joints are added to the ever lengthening "string" or "drill string". Therefore, the drill string includes a plurality of joints of pipe.

[0003] Fluid "drilling mud" is pumped from the well drilling platform, through the drill string, and to a drill bit supported at the lower or distal end of the drill string. The drilling mud lubricates the drill bit and carries away well cuttings generated by the drill bit as it digs deeper. The cuttings are carried in a return flow stream of drilling mud through the well annulus and back to the well drilling platform at the earth's surface. When the drilling mud reaches the platform, it is contaminated with small pieces of shale and rock that are known in the industry as well cuttings or drill cuttings. Once the drill cuttings, drilling mud, and other waste reach the platform, a "shale shaker" is typically used to remove the drilling mud from the drill cuttings so that the drilling mud may be reused. The remaining drill cuttings, waste, and residual drilling mud are then transferred to a holding trough for disposal. In some situations, for example with specific types of drilling mud, the drilling mud may not be reused and it must be disposed. Typically, the non-recycled drilling mud is disposed of separate from the drill cuttings and other waste by transporting the drilling mud via a vessel to a disposal site.

[0004] The disposal of the drill cuttings and drilling mud is a complex environmental problem. Drill cuttings contain not only the residual drilling mud product that would contaminate the surrounding environment, but may also contain oil and other waste that is particularly hazardous to the environment, especially when drilling in a marine environment.

[0005] One method of disposing of oily-contaminated cuttings is to re-inject the cuttings into the formation using a cuttings re-injection (CRI) operation. The basic steps in the process include the identification of an appropriate stratum or formation for the injection; preparing an appropriate injection well; formulation of the slurry, which includes considering such factors as weight, solids content, pH, gels, etc.; performing the injection operations, which includes determining and monitoring pump rates such as volume per unit time and pressure; and capping the well.

[0006] Accordingly, there exists a need for methods of determining the fracture behavior of a disposal formation during a CRI operation. GEEHAN THOMAS ET AL, "The cutting edge in drilling-waste management", OILFIELD REVIEW, ELSEVIER, AMSTERDAM, NL, (20020101), vol. 14, no. 3, ISSN 0923-1730, pages 54 - 67, and US 2005/203723 concern simulation of CRI operations according to the preamble of claim 1.

SUMMARY OF INVENTION

[0007] It is an object of the present invention to provide a method of designing a response to a fracture behavior of a formation during re-injection of cuttings into the formation. This object can be achieved by the features as defined by the independent claims. Further enhancements are characterised by the dependent claims. In one aspect, embodiments disclosed herein relate to a method of designing a response to a fracture behavior of a formation during re-injection of cuttings into a formation, the method including obtaining a pressure signature for a time period, interpreting the pressure signature for the time period to determine a fracture behavior of the formation, determining a solution based on the fracture behavior of the formation, and implementing the solution.

[0008] In another aspect, embodiments disclosed herein relate to a method of assessing a subsurface risk of a cuttings re-injection operation, the method including obtaining a pressure signature for a time period, interpreting the pressure signature to determine a fracture behavior of the formation, characterizing a risk associated with the determined fracture behavior of the formation, and implementing a solution based on the characterized risk.

[0009] Other aspects and advantages of the invention will be apparent from the following description and the appended claims.

BRIEF DESCRIPTION OF DRAWINGS

[0010]

Figure 1 shows a method of pressure signature interpretation and anomaly identification.

Figure 2 shows a normal pressure signature for a CRI operation immediately after shut-in.

Figure 3 shows a pressure signature representing a wellbore storage pressure decline behavior,

Figure 4 shows a pressure signature representing a fracture storage pressure decline behavior.

Figure 5 shows a pressure signature representing a decline pressure rebound.

Figure 6 shows a pressure signature on a log plot representing injection above overburden.

DETAILED DESCRIPTION

[0011] In one aspect, embodiments disclosed herein relate to interpreting pressure behavior of CRI operations. In another aspect, embodiments disclosed herein relate to assessing potential risk and impact on a subsurface drilling system and surrounding formation.

[0012] Batch processing of slurry (i.e., injecting conditioned slurry into the disposal formation and then waiting for a period of time after the injection) allows fractures to mechanically close and, to a certain extent, dissipates the build-up of pressure in the disposal formation. However, the pressure in the disposal formation typically increases due to the presence of the injected solids (i.e., the solids present in the drill cuttings slurry).

[0013] The slurry to be injected should be maintained within calculated parameters to reduce the chances of fracture plugging. To monitor the slurry, rheological parameters are often checked on a periodic basis to ensure that the slurry exhibits predetermined characteristics. For example, some systems incorporate a continual measurement of slurry viscosity and density prior to injection.

[0014] Release of hazardous waste into the environment must be avoided and waste containment must be assured to satisfy stringent governmental regulations. Important containment factors considered during the course of the operations include the following: the location of the injected waste and the mechanisms for storage; the capacity of an injection wellbore or annulus; whether injection should continue in the current zone or in a different zone; whether another disposal wellbore should be drilled; the required operating parameters necessary for proper waste containment; and the operational slurry design parameters necessary for solids suspension during slurry transport.

[0015] Modeling of CRI operations and prediction of disposed waste extent are beneficial to address these containment factors and to ensure the safe and lawful containment of the disposed waste. Modeling and prediction of fracturing is also beneficial to study CRI operation impact on future drilling, such as the required well spacing, formation pressure increase, etc. A thorough understanding of storage mechanisms in CRI operations is key for predicting the possible extent of the injected conditioned slurry and for predicting the disposal capacity of an injection well. As used herein, storage mechanisms may refer to modes or methods in which slurry is stored in a formation, including, for example, methods of injection into a formation, methods of injection into a fracture, fracture growth, and changes in fracture geometry.

[0016] Once the required shut-in time for fracture closure is computed from the fracturing simulation, a subsequent batch injection may cause reopening of an existing fracture and may create a secondary branched fracture away from the near-wellbore area. This situation may be determined from local stress, pore pressure changes from previous injections, and formation characteristics. The location and orientation of the branched fracture may also depend on stress anisotropy. For example, if a strong stress anisotropy is present, then the fractures are closely spaced, however if no stress anisotropy exits, the fractures are widespread. How these fractures are spaced and the changes in shape and extent during the injection history may be an important factor in determining the disposal capacity of a disposal well.

[0017] Modeling and simulating CRI operations and fracturing of the formation typically do not provide instantaneous or real-time results during the CRI operations. Further, models and simulations of the CRI operation do not reveal causes for the fracture behavior of the formation. Embodiments disclosed herein, however, provide a method of observing, identifying, and interpreting common pressure signatures observed during CRI operations. Further, embodiments disclosed herein may provide a method for designing a response to a fracture behavior of a formation during CRI operations.

[0018] To increase safety during CRI operations, the pressure response during injection and post shut-in pressure decline periods may be continuously monitored. Readily implemented injection pressure monitoring coupled with in-depth pressure analysis may assist in diagnosing the fracture behavior during the pumping and shut-in periods, and in estimating key fracture and formation parameters. In addition, continuous fracture diagnostics may assist in tracking long-term progression of mechanical parameters, for example, fracture length, width, and direction, and assessing an overall impact posed by injected waste on the disposal and surrounding formations.

[0019] A primary objective of CRI is attaining an environmentally safe and trouble-free subsurface disposal of the drilling waste by means of intermitted batch injections. Accordingly, the importance of pressure analysis as an effective tool for subsurface risks identification and characterization is essential. In-depth interpretation of varied pressure signatures repeatedly observed during cycle injections may be used to reveal and understand the nature of the subsurface risks, characterize possible causes, and comprehensively assess future impact on the subsurface system. Proper and timely pressure signature interpretation may help in securing seamless CRI operation, extend the life of the injection well, and maximize well disposal capacity. Conversely, a lack of subsurface waste injection experience combined with neglect of distinct pressure signatures may potentially lead to unexpected loss of injectivity, which may increase the cost of well re-completion or result in extra injection well drilling.

[0020] Methods of interpreting pressure signatures are presented below. Interpretations of the five most common pressure signatures frequently observed and identified during injection from globally varied CRI projects are presented below. The use of pressure signature in-

terpretation may provide a better understanding of non-ideal pressure behavior observed in CRI operations, may assess potential risk and impact on the subsurface system, and may provide a solution or action based on the determined fracture behavior of the formation.

Method of Interpreting Pressure Signatures

[0021] Pressure signatures from CRJ operations may be interpreted to better understand and address non-ideal pressure behavior observed in CRI operations. Additionally, the operator may be able to assess potential risk and impact on the subsurface system caused by the CRI operations. In one embodiment, pressure signatures may include a graphical representation of a plurality of pressure measurements taken over a period of time. Such graphical representations of pressure signatures are shown in Figures 2-6. In other embodiments, pressure signatures may include a plurality of pressure measurements taken over a period of time and displayed in tabular form. One of ordinary skill in the art will appreciate that a pressure signature may include any output known in the art for conveying a plurality of pressure measurements taken over a period of time.

[0022] Referring to Figure 1, in one embodiment, a pressure signature may be determined for a pre-selected time period of CRI operation, shown at 120. The pressure signature may be determined by any means known in the art and may be taken at varying intervals during, for example, injection, post shut-in, fracture closure, or continuously during CRI operations.

[0023] The pressure signatures obtained may then be interpreted for each time period to determine a fracture behavior of the formation, shown at 122. In one embodiment, the pressure signatures may be compared to pressure signatures identified as representing a subsurface condition or fracture behavior of the formation, as described below. For example, a pressure signature obtained immediately after shut-in may include a substantially straight line on a pressure decline. Upon comparing the obtained pressure signature to an identified pressure signature, the operator may determine that the wellbore storage pressure decline indicates that fluid communication between the wellbore and fracture has been restricted (discussed in more detail below with respect to Figure 3).

[0024] Based on the fracture behavior or subsurface behavior interpreted from the pressure signature 122, a solution may be determined 124 and subsequently implemented 126. For example, if the operator determines that a restriction between the wellbore and the formation has occurred, seawater may be injected downhole to prevent solid settling and/or to relieve stress in the formation, thereby reducing or removing the restriction.

[0025] In one embodiment, the subsurface risk associated with the fracture behavior may be characterized in a range of low to high risk or on a number scale representing a low to high range of risk. For example, in one embodiment, a pressure signature may be interpreted and a fracture behavior of the formation determined. The operator may then classify or characterize the risk of such fracture behavior. For example, if the operator determines that a fracture includes a horizontal component, the operator may assess the risk of the horizontal component of the fracture intersecting a trajectory of a planned well. In this example, the operator may characterize the fracture behavior as a high risk, because it may frustrate drilling of a planned well. In other embodiments, the pressure signature may be interpreted as representing a normal pressure decline. As such, the operator may characterize the fracture behavior as a low risk. Thus, the solution determined based on the fracture behavior of the formation may include taking no action, such as for example continuing the CRI operation. In other embodiments, the subsurface risk associated with the fracture behavior may include determining, for example, the well disposal capacity associated with the fracture behavior, expected pressure changes due to the fracture behavior, and expected geometry changes of the fracture.

Normal Pressure Decline

[0026] Normal pressure (or conventional pressure decline) is frequently observed during post shut-in periods. Figure 2 shows a pressure signature that represents an example of a normal pressure decline. A normal pressure is determined by the fracture closure and formation transient response, and indicates open (or unrestricted) communication between the fracture and the wellbore. Generally, two distinct periods are distinguished during the pressure decline: fracture closure period and transient formation period.

[0027] Fracture behavior during the fracture closure period is governed by fluid-loss characteristics (i.e., fluid volume lost from the fracture to the formation) and the material balance relation. The pressure decline during fracture closure period reflects both fracture length and height change. The fracture penetration initially increases before eventually receding back toward the wellbore. Initial fracture extension generally occurs because of redistribution of stored slurry volume from a large width of the fracture near the wellbore to a fracture tip region. Simultaneously, the height recedes from any higher stress barriers because of pressure reduction in the fracture (i.e., net pressure). By looking at the shape of the pressure decline of the pressure signature, a fracture height growth into higher stress barriers (e.g., containment zone) may be identified. For example, a concave downward pressure decline signature indicates the fracture height growth does not reach a higher stress fracture containment zone. In contrast, a concave upward pressure decline signature indicates significant fracture height growth into the higher stress barrier zones.

[0028] In accordance with embodiments of the present disclosure, a subsurface event may be determined from

such pressure decline signatures, For example, a concave upward pressure decline signature may signify a fluid redistribution in a fracture from higher stress zones (due to height recession) into a main fracture body. A redistribution of fluid in a fracture from a higher stress zone into a main fracture body typically occurs when the net pressure becomes equal to approximately 0.4 times a stress difference between injection and a higher stress barrier zone. Fluid efficiency and a fluid leak-off coefficient may be estimated from the pressure decline signature by utilizing a specialized G-function of time, commonly referred as the G-plot. (See, for example, U.S. Patent No. 6,076,046, issued to Vasudevan.) However, the G-slope application has the same uncertainties as those observed with the interpretation of conventional well test data.

[0029] The pressure decline during a transient formation period, or the pressure following fracture closure, relates to an injection formation response. The pressure response during this transient formation period becomes less dependent on the mechanical response of an open fracture and more dependent on the transient pressure response within the injection formation. The character of the transient formation period pressure decline is determined primarily, if not entirely, by the response of the injection formation disturbed by the fluid leak-off process (migration of the fluid into the fracture face). During this transient formation period, the reservoir may initially exhibit formation linear flow followed by transitional behavior and finally long-term pseudo -radial flow. The pressure decline during the transient formation period provides information that is traditionally determined by a standard well test (i.e., transmissibility and formation pressure), and it completes a chain of fracture pressure analyses that provides a complete set of data required for developing a unique characterization of an effect from the fracturing process.

[0030] A normal pressure signature for a CRI operation typically does not represent any potential risks for the subsurface system and may be considered as a safe pressure signature. A normal pressure signature may be used to evaluate the fracture behavior during closure and to estimate main fracture and formation parameters. Thus, in accordance with embodiments of the present disclosure, a pressure signature during a CRI operation that, similar to Figure 2, represents a normal pressure decline may indicate to an operator that the fracture behavior of the formation does not suggest a risk for the subsurface system. Therefore, the operator may continue the CRI operation without taking any further action.

Wellbore Storage Pressure Decline

[0031] Figure 3 shows a pressure signature for a CRI operation immediately after shut-in. A wellbore storage pressure decline signature indicates a restriction between the wellbore and formation, The restriction may be caused by sealing between the wellbore and formation by, for example, viscous fluid from a previous injection or from solids fall-off and settling. The restriction may also be caused by a mechanical restriction accidentally induced in the injection point by, for example, cement. The wellbore storage pressure response may also be a result of fluid compression or expansion in a confined volume. The formation sealing prevents adequate fluid communication between the fracture and the wellbore, and creates confined volume within the wellbore. As shown in Figure 3, the duration of the wellbore storage pressure decline period depends on the severity of artificial restriction as well as wellbore fluid compressibility, and may be clearly characterized by the straight line, indicated at 302, on the pressure decline occurring immediately after shut-in. The pressure decline during this period no longer represents fracture response and fracture parameters cannot be determined.

[0032] In most cases, a wellbore storage pressure signature revealed immediately after shut-in, represents a warning signal of an artificially induced restriction in the injection point. Due to potential sealing of the injection interval, the wellbore storage pressure behavior observed immediately after shut-in represents a higher risk for potential well plugging. The risks for potential well plugging worsens when particle settling is experienced during an injection suspension period. Considering that well plugging causes most failures in CRI projects, any wellbore storage pressure behavior, as well as a root cause for the partial sealing of the injection interval, observed immediately after shut-in must be closely monitored, evaluated, and thoroughly investigated.

[0033] Referring still to Figure 3, a wellbore storage pressure response observed immediately after shut-in during a CRI project annular injection while cementing a 9 5/8-inch (24.45 centimetres) casing is shown. In this example, the actual cement level was higher than initially designed. Consequently, the cement bridged part of an open-hole injection interval and induced artificial restriction in the injection point. This is reflected immediately in the pressure signature by the wellbore storage pressure behavior (i.e., straight line portion indicated at 302) after shut-in and later confirmed by a cement evaluation log.

[0034] Thus, in accordance with embodiments of the present disclosure, a pressure signature during a CRI operation that, similar to Figure 3, represents a wellbore storage post shut-in pressure decline may indicate to the operator that fluid communication between the wellbore and the fracture has been restricted. In one embodiment, the operator may, therefore, perform seawater injection to prevent solid settling and/or to relieve stress in the formation. Alternatively, acid may be pumped downhole to dissolve the mechanical restriction and restore normal communication between the wellbore and the fracture. Overall, this type of the pressure signature, as shown in Figure 3, represents a high risk of the well or fracture plugging; hence, the pressure signatures need to be closely monitored and corrective action promptly implemented.

Fracture Storage Pressure Decline

[0035] Referring now to Figure 4, a pressure signature representing a fracture storage pressure decline is shown. A fracture storage pressure signature generally exhibits a linear relation between pressure and time (i. e. , a straight line portion on the pressure decline indicated at 404) during a post fracture closure period. Fracture storage pressure decline typically results from the pressure bouncing, shown at 406, within the confined fracture boundary after closure. The fracture boundary confinement may result from a filter cake at the fracture face created by previous injections (e.g., residual polymers and solid particles) or damage to the fracture face. Similar fracture confinement may also be observed during tip screen-out (TSO) (i.e., when high concentrations of sand or proppant reach the tip of the fracture and halt further fracture extension), when fluid-loss induces insufficient fracture width, or when dehydration causes the solids slurry to bridge at the tip of the fracture.

[0036] During the fracture storage period, the pressure behavior is dominated by the fluid storage in the fracture, assuming that the welibore storage has a minor effect on overall storage response. The fracture storage pressure mainly occurs due to fluid compression or expansion in confined fracture volume, where the fracture may effectively transmit the pressure and has higher permeability in comparison to the injected formation. The fracture storage pressure is usually observed after the fracture mechanically closes on the cutting solids, thereby allowing fluid and pressure to redistribute inside the fracture. Factors affecting fracture storage duration may include permeability and pressure contrast between the fracture and injected formation, and severity of the damage originated at the fracture face.

[0037] In accordance with embodiments of the present disclosure, a pressure signature during a CRI operation that, similar to Figure 4, represents a fracture storage pressure decline may indicate to the operator that the fracture face may be damaged, thereby causing fracture confinement. In one embodiment, the operator may, therefore, re-assess the fluid leak-off from the fracture to the formation using a G- function plot, and evaluate the fracture confinement by performing additional fracture simulation with updated fluid leak-off and main fracture parameters (e.g., fracture closure pressure).

Decline Pressure Rebound

[0038] Referring now to Figure 5, a pressure signature representing a decline pressure rebound is shown. In the embodiment shown, a surface pressure re-bound, indicated at 508, has been observed during post shut-in pressure decline, when injections were suspended for a long period. Simultaneously drilling or production activity in the injection well during a CRI operation may increase the amplitude of a pressure rebound. The pressure decline initially drops below the fracture closure pressure and continues declining until welibore fluid starts to heat up, thereby affecting the hydrostatic pressure in the wellbore. The wellbore fluid may heat up due to heat generated during drilling and/or oil production. As the temperature of wellbore fluid increases, the hydrostatic head decreases, thereby causing an increase in surface pressure (i.e., a pressure re-bound effect).

[0039] The amplitude of the pressure increase during a re -bound period is proportional to the increase of fluid temperature in the wellbore. Although the pressure increases during the re-bound period, the fracture may not be re-initiated, because of the thermo -elastic impact on the formation. In other words, the temperature variation in the wellbore changes the state of stress, especially in a near- wellbore area. Typically, formation heat-up during a suspended period induces an additional stress component in the horizontal plane, while formation heat-up in the near- wellbore area increases the normal stress. Thus, wellbore fluid heat-up may lead to a higher breakdown pressure required to overcome additional thermal stress in the near wellbore area to initiate the fracture,

[0040] The risk associated with excessive wellbore fluid heat-up is primarily related to higher injection pressure on surface and inability to inject within pre-defined surface pressure limits. Thus, in one embodiment, the near-wellbore thermo-elastic stress component may be reduced by maintaining regular seawater injections during extended suspension periods, which effectively cools the static wellbore fluid. As a result, less pressure is required to initiate the fracture after a suspended period and the surface injection pressure may be maintained below maximum limits.

Injection Above Overburden

[0041] Referring now to Figure 6, a pressure signature representing injection above overburden is shown on a log plot. As used herein, overburden refers to the formation or rock overlying an area or point of interest in the subsurface. If the injection pressure is less than the overburden stress, a fracture may propagate only in the vertical plane. However, in a situation when injection occurs in conditions of shallow depth or in formations in tectonically active thrusting environments, the overburden stress may be a minimum principal stress. In such shallow depth conditions, the fracture may propagate in both the vertical and horizontal planes. This geometry is called a T-shape fracture and occurs when an injection pressure is slightly larger than the overburden stress.

[0042] The pressure response during such a period where the injection pressure is slightly larger than the overburden stress provides a diagnostic basis for determining whether the fracture plane is entirely vertical or includes a horizontal component as well. The horizontal component (propagation in a horizontal direction) occurs when the fracture pressure is substantially constant and approximately equal to or above the overburden stress of the formation, as shown in Figure 6. After the injection

pressure exceeds overburden, the penetration of the vertical component becomes less efficient, because the propagating horizontal component prevails.

[0043] The horizontal fracture component increases the area available for fluid loss, decreases fluid efficiency, and limits the fracture width. Excessive fluid loss in the horizontal component and limited fracture width may lead to premature screen-out or fracture plugging during injection. Horizontal fractures may provide extended coverage area with larger disposal capacity. However, due to the risk associated with a horizontal fracture intersecting trajectories of planned offset drilling wells, such horizontal fractures may need to be thoroughly evaluated. The magnitude of the overburden stress may be estimated from density logs and compared with the magnitude of the injection pressure as part of the pressure analysis.

[0044] In accordance with embodiments of the present disclosure, a pressure signature during a CRI operation that, similar to Figure 6, represents injection above overburden may be used to determine the geometry of the fracture in the formation. The operator may determine a solution to reduce excessive fluid loss and/or increase fracture width to prevent premature screen-out or fracture plugging during injection. If the pressure signature indicates that the fracture may include a horizontal component, then the operator may, for example, re-design trajectories of future wells to avoid intersecting the horizontal component of the fracture. Additionally, the operator may perform detail pressure signature interpretation on a regular basis to avoid premature screen-out, particularly in the near-wellbore area or at an intersection between vertical and horizontal components of the fracture.

[0045] Advantageously, embodiments disclosed herein provide a method of determining a fracture behavior of a formation during a CRI operation. Further, embodiments disclosed herein may provide a method of optimizing well disposal capacity by allowing an operator to determine fracture behavior or formation and subsurface events during CRI operations. In yet other embodiments disclosed herein, a method for determining a solution and implementing a solution based on a fracture behavior determined by interpreting a pressure signature is provided.

[0046] Advantageously, embodiments disclosed herein may provide operators a method of addressing non-ideal pressure behavior during CRI operations and a method of assessing potential risks and impacts of the CRI operation on subsurface systems and formation,

[0047] While the invention has been described with respect to a limited number of embodiments, those skilled in the art, having benefit of this disclosure, will appreciate that other embodiments can be devised which do not depart from the scope of the invention as disclosed herein. Accordingly, the scope of the invention should be limited only by the attached claims.

Claims

1. A method of designing a response to a fracture behavior of a formation during re-injection of cuttings into the formation, the method **characterized by** obtaining a pressure signature for a time period, the pressure signature being a plurality of pressure measurements taken over the time period;
   interpreting the pressure signature for the time period to determine a fracture behavior of the formation, wherein
   interpreting the pressure signature comprises determining the pressure signature to be one of the group consisting of normal pressure decline, wellbore storage pressure decline, fracture storage pressure decline, decline pressure rebound, and injection above overburden;
   determining a solution based on the fracture behavior of the formation; implementing the solution; and
   obtaining a second pressure signature from a time period after implementing the solution and determining if the solution affected the fracture behavior.

2. The method of claim 1, further comprising characterizing a subsurface risk of the fracture behavior.

3. The method of claim 1, wherein the determining the solution comprises determining a cause of the fracture behavior.

4. The method of claim 1, further comprising generating a visual representation of the pressure signature.

5. The method of claim 1, wherein the interpreting the pressure signature comprises comparing the pressure signature to a known pressure signature.

6. The method of claim 5, wherein the known pressure signature comprises at least one of a group consisting of normal pressure decline, wellbore storage pressure decline, fracture storage pressure decline, decline pressure rebound, and injection above overburden.

7. The method of claim 1, wherein the time period comprises a fracture closure period.

8. The method of claim 1, wherein the time period comprises a post shut-in interval.

9. The method of claim 1, wherein the solution comprises injecting sea water downhole.

10. The method of claim 1, wherein the solution comprises continuing the cuttings re-injection operation.

11. The method of claims 1, 5, 6, 9 or 10, wherein determining a solution comprises characterizing a risk

associated with the determined fracture behavior of the formation.

12. The method of claim 11, wherein the characterizing a risk associated with the determined fracture behavior of the formation comprises determining the possibility of the determined fracture behavior affecting a planned well.

13. The method of claim 11, wherein the characterizing a risk associated with the determined fracture behavior of the formation comprises determining the well disposal capacity based on the fracture behavior.

Patentansprüche

1. Ein Verfahren zum Entwickeln einer Reaktion auf ein Bruchverhalten einer Formation während der Wiedereinpressung von Bohrgut in die Formation, wobei das Verfahren durch Folgendes gekennzeichnet ist:

Erhalten einer Drucksignatur für einen Zeitraum, wobei es sich bei der Drucksignatur um eine Vielzahl von über den Zeitraum vorgenommenen Druckmessungen handelt;
Interpretieren der Drucksignatur für den Zeitraum zum Bestimmen eines Bruchverhaltens der Formation, wobei
das Interpretieren der Drucksignatur das Bestimmen der Drucksignatur als eine aus der Gruppe, bestehend aus normalem Druckabfall, Bohrlochspeicher-Druckabfall, Bruchspeicher-Druckabfall, erneutem Druckanstieg nach Abfall und Einpressung über Deckschicht, beinhaltet;
Bestimmen einer Lösung auf der Basis des Bruchverhaltens der Formation; Implementieren der Lösung; und
Erhalten einer zweiten Drucksignatur von einem Zeitraum nach dem Implementieren der Lösung und Bestimmen, ob die Lösung das Bruchverhalten beeinflusst hat.

2. Verfahren gemäß Anspruch 1, das ferner das Charakterisieren eines Untergrundrisikos des Bruchverhaltens beinhaltet.

3. Verfahren gemäß Anspruch 1, wobei das Bestimmen der Lösung das Bestimmen einer Ursache des Bruchverhaltens beinhaltet.

4. Verfahren gemäß Anspruch 1, das ferner das Erzeugen einer visuellen Darstellung der Drucksignatur beinhaltet.

5. Verfahren gemäß Anspruch 1, wobei das Interpretieren der Drucksignatur das Vergleichen der Drucksignatur mit einer bekannten Drucksignatur beinhaltet.

6. Verfahren gemäß Anspruch 5, wobei die bekannte Drucksignatur mindestens eine aus einer Gruppe, bestehend aus normalem Druckabfall, Bohrlochspeicher-Druckabfall, Bruchspeicher-Druckabfall, erneutem Druckanstieg nach Abfall und Einpressung über Deckschicht, beinhaltet.

7. Verfahren gemäß Anspruch 1, wobei der Zeitraum eine Bruchverschließungsperiode beinhaltet.

8. Verfahren gemäß Anspruch 1, wobei der Zeitraum ein Nach-Einschluss-Intervall beinhaltet.

9. Verfahren gemäß Anspruch 1, wobei die Lösung das Einpressen von Meerwasser in den Untergrund beinhaltet.

10. Verfahren gemäß Anspruch 1, wobei die Lösung das Fortführen des Wiedereinpressvorgangs des Bohrguts beinhaltet.

11. Verfahren gemäß den Ansprüchen 1, 5, 6, 9 oder 10, wobei das Bestimmen einer Lösung das Charakterisieren eines mit dem bestimmten Bruchverhalten der Formation assoziierten Risikos beinhaltet.

12. Verfahren gemäß Anspruch 11, wobei das Charakterisieren eines mit dem bestimmten Bruchverhalten der Formation assoziierten Risikos das Bestimmen der Möglichkeit der Beeinflussung einer geplanten Bohrung durch das bestimmte Bruchverhalten beinhaltet.

13. Verfahren gemäß Anspruch 11, wobei das Charakterisieren eines mit dem bestimmten Bruchverhalten der Formation assoziierten Risikos das Bestimmen der Bohrungsentsorgungskapazität auf der Basis des Bruchverhaltens beinhaltet.

Revendications

1. Une méthode de conception d'une réponse à un comportement de fracture d'une formation durant la réinjection de débris de forage dans cette formation, la méthode étant **caractérisée par**
le fait d'obtenir une signature de pression pour une période de temps, la signature de pression étant une pluralité de mesures de pression relevées tout au long de la période de temps ;
le fait d'interpréter la signature de pression pour la période de temps afin de déterminer un comportement de fracture de la formation, où
le fait d'interpréter la signature de pression comprend le fait de déterminer que la signature de pres-

sion est une signature du groupe constitué du déclin d'une pression normale, du déclin d'une pression de stockage dans le puits de forage, du déclin d'une pression de stockage dans la fracture, du rebond d'une pression en déclin et de l'injection au-dessus de la couverture (« injection above overburden ») ;
le fait de déterminer une solution sur la base du comportement de fracture de la formation ;
le fait de mettre la solution en application ; et
le fait d'obtenir une deuxième signature de pression provenant d'une période de temps postérieure à la mise en application de la solution et de déterminer si la solution a affecté le comportement de la fracture.

2. La méthode de la revendication 1, comprenant en sus le fait de caractériser un risque en subsurface du comportement de la fracture.

3. La méthode de la revendication 1, dans laquelle le fait de déterminer la solution comprend le fait de déterminer une cause du comportement de la fracture.

4. La méthode de la revendication 1, comprenant en sus le fait de générer une représentation visuelle de la signature de pression.

5. La méthode de la revendication 1, dans laquelle le fait d'interpréter la signature de pression comprend le fait de comparer la signature de pression à une signature de pression connue.

6. La méthode de la revendication 5, dans laquelle la signature de pression connue comprend au moins une signature d'un groupe constitué du déclin d'une pression normale, du déclin d'une pression de stockage dans le puits de forage, du déclin d'une pression de stockage dans la fracture, du rebond d'une pression en déclin et de l'injection au-dessus de la couverture.

7. La méthode de la revendication 1, dans laquelle la période de temps comprend une période de fermeture de fracture.

8. La méthode de la revendication 1, dans laquelle la période de temps comprend un intervalle après arrêt provisoire du puits (« post shut-in »).

9. La méthode de la revendication 1, dans laquelle la solution comprend le fait d'injecter de l'eau de mer en fond de trou.

10. La méthode de la revendication 1, dans laquelle la solution comprend le fait de continuer l'opération de réinjection de débris de forage.

11. La méthode des revendications 1, 5, 6, 9 ou 10, dans laquelle le fait de déterminer une solution comprend le fait de caractériser un risque associé au comportement de fracture déterminé de la formation.

12. La méthode de la revendication 11, dans laquelle le fait de caractériser un risque associé au comportement de fracture déterminé de la formation comprend le fait de déterminer la possibilité que le comportement de fracture déterminé n'affecte un puits prévu.

13. La méthode de la revendication 11, dans laquelle le fait de caractériser un risque associé au comportement de fracture déterminé de la formation comprend le fait de déterminer la capacité d'élimination du puits sur la base du comportement de la fracture.

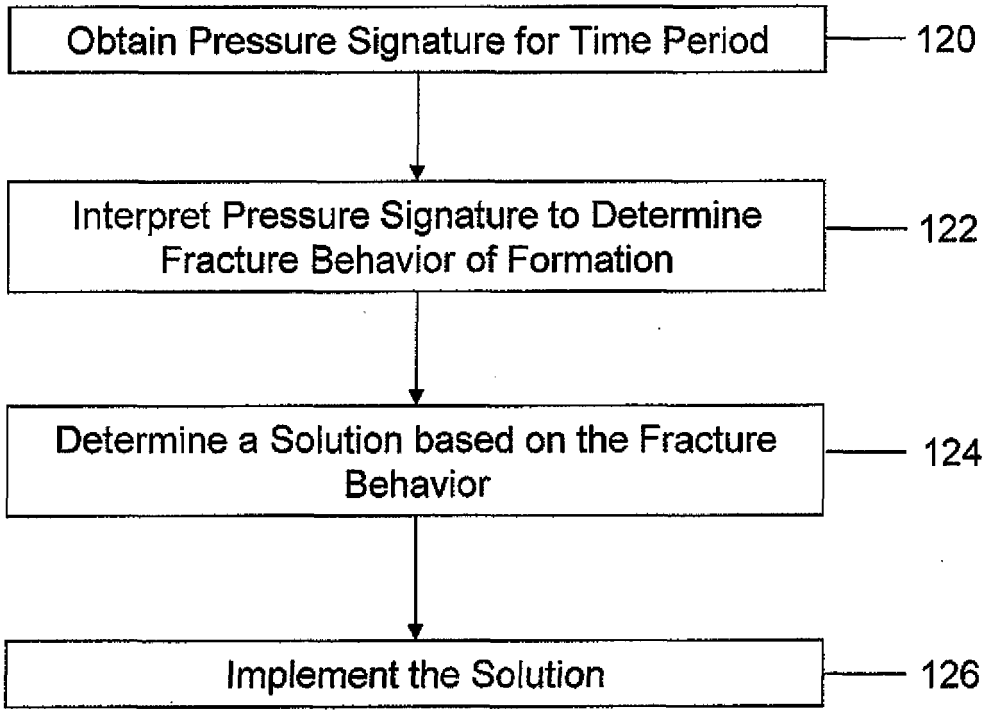

Obtain Pressure Signature for Time Period
120
Interpret Pressure Signature to Determine Fracture Behavior of Formation
122
Determine a Solution based on the Fracture Behavior
124
Implement the Solution
126

Figure 1

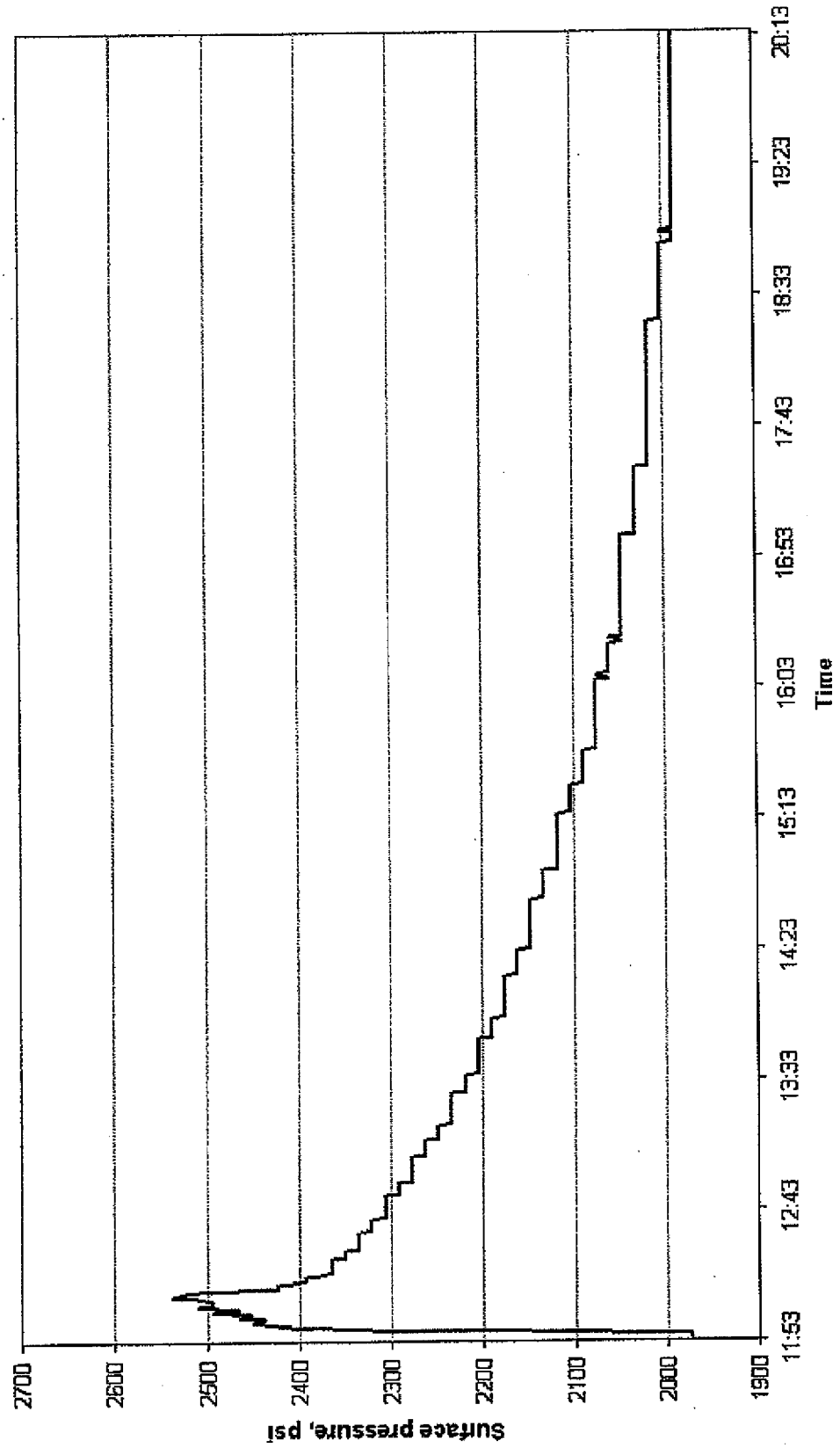

Surface pressure, psi
2700
2600
2500
2400
2300
2200
2100
2000
1900
11:53
12:43
13:33
14:23
15:13
16:03
16:53
17:43
18:33
19:23
20:13
Time

Figure 2

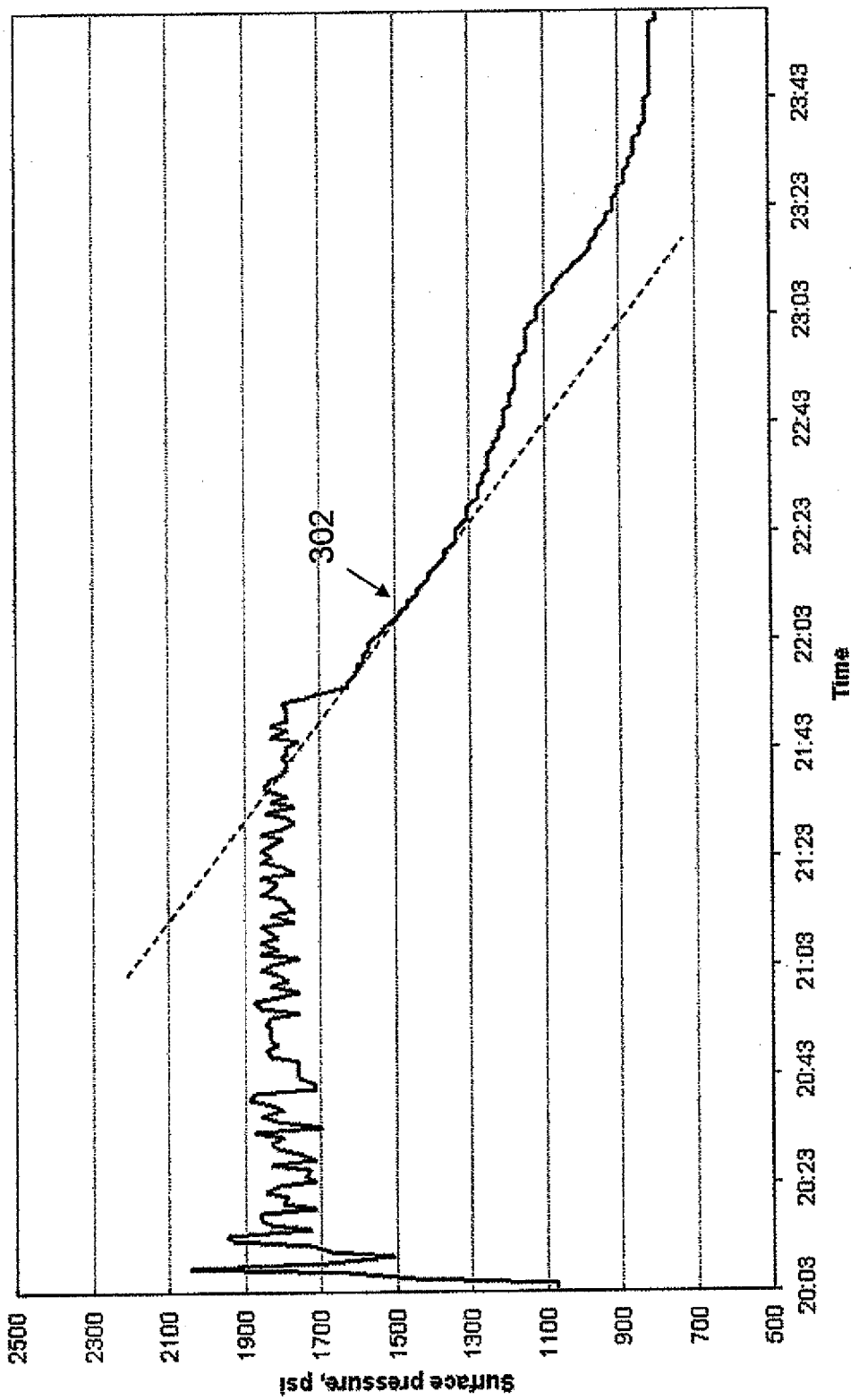

Surface pressure, psi
2500
2300
2100
1900
1700
1500
1300
1100
900
700
500
Time
20:03
20:23
20:43
21:03
21:23
21:43
22:03
22:23
22:43
23:03
23:23
23:43
302

Figure 3

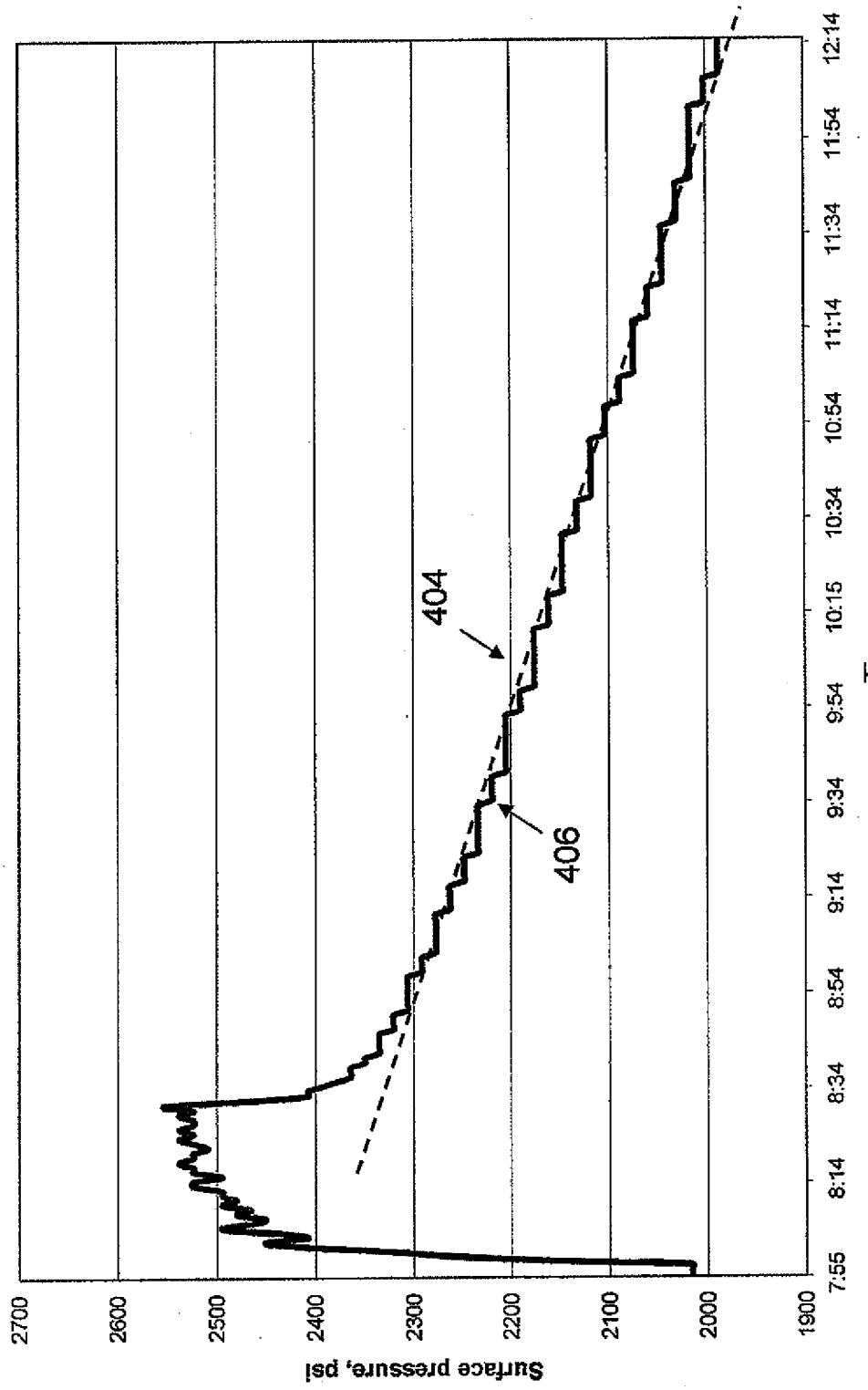

Surface pressure, psi
2700
2600
2500
2400
2300
2200
2100
2000
1900
Time
7:55
8:14
8:34
8:54
9:14
9:34
9:54
10:15
10:34
10:54
11:14
11:34
11:54
12:14
404
406

Figure 4

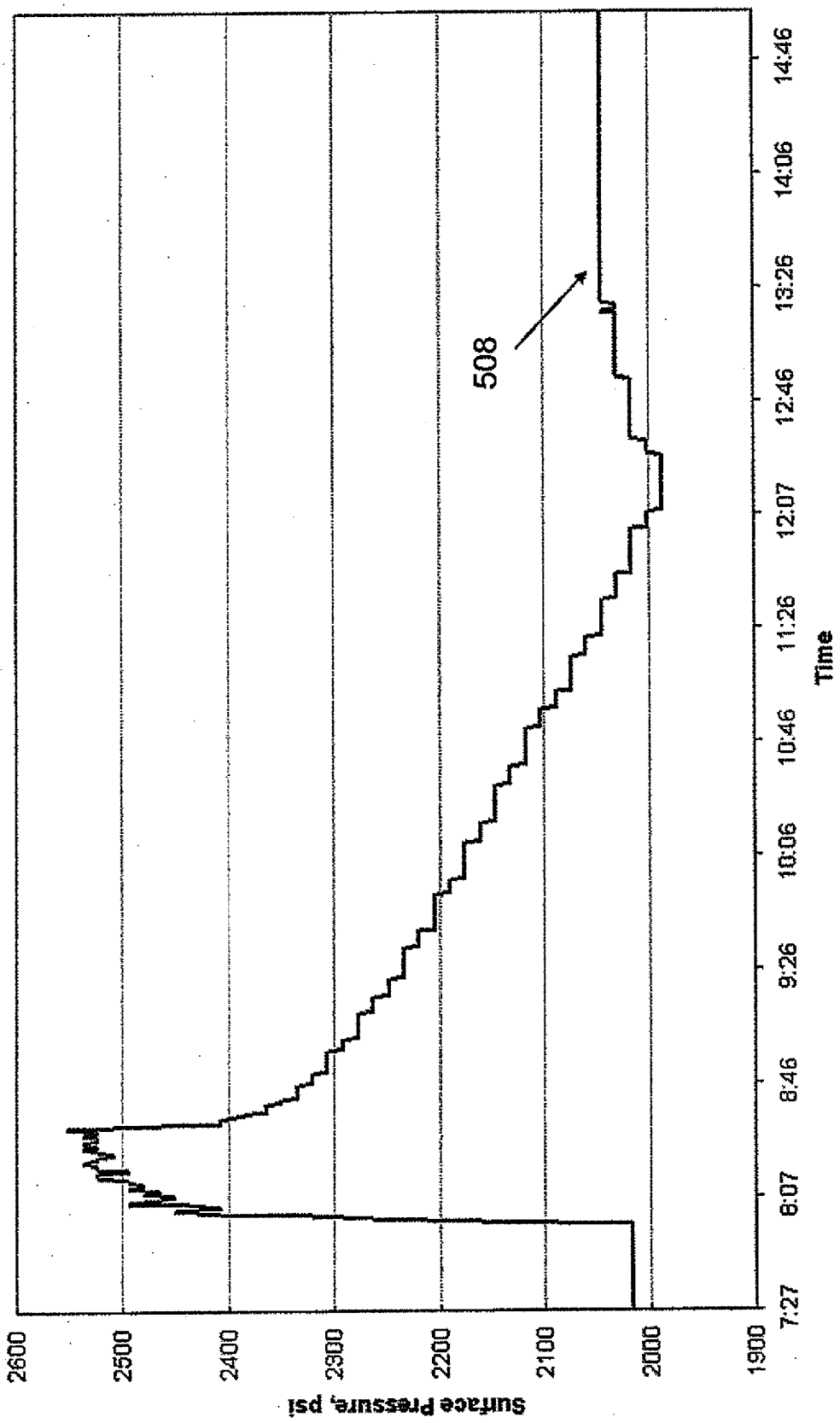

Surface Pressure, psi
2600
2500
2400
2300
2200
2100
2000
1900
Time
7:27
8:07
8:46
9:26
10:06
10:46
11:26
12:07
12:46
13:26
14:06
14:46
508

Figure 5

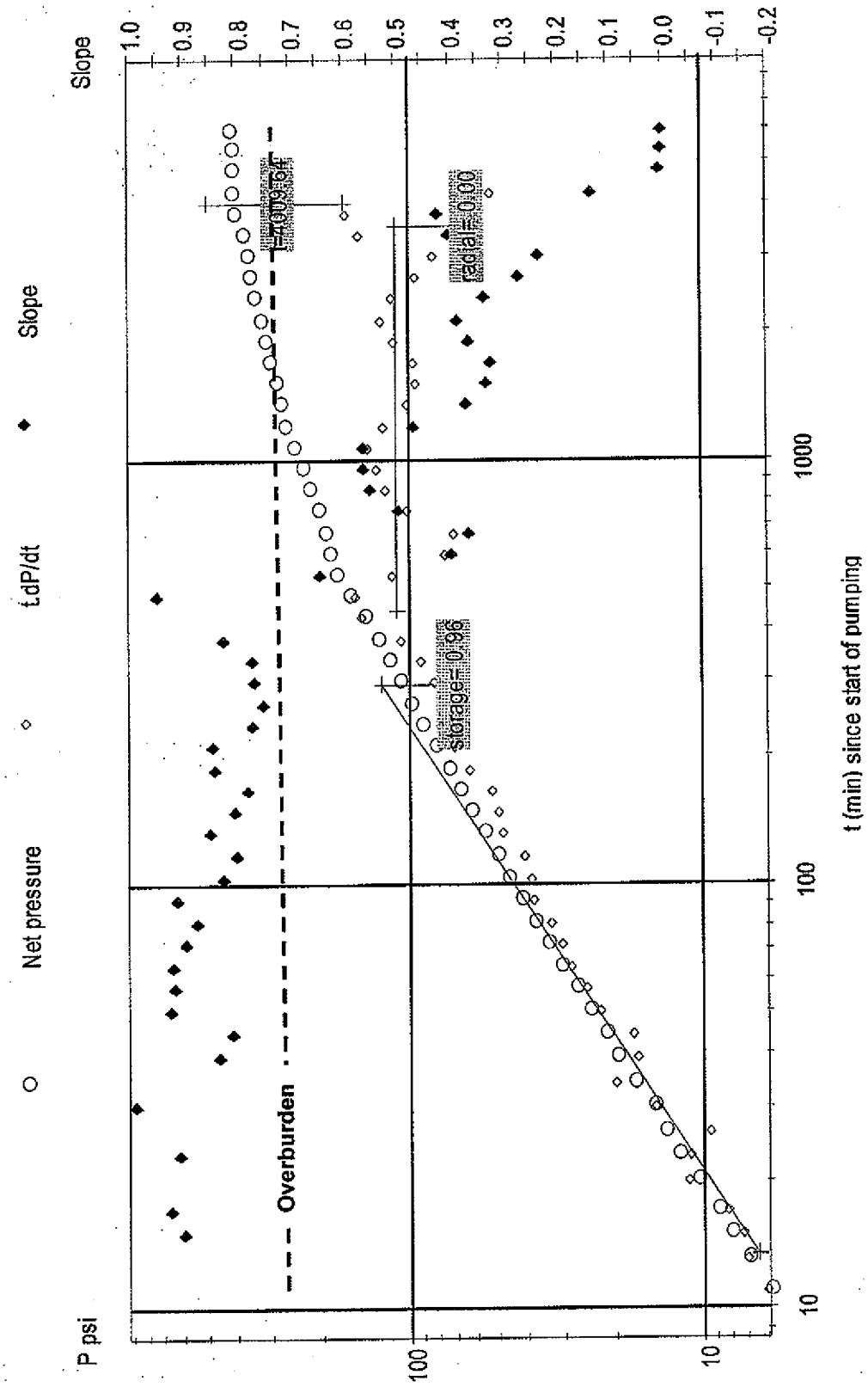

Slope
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
-0.1
-0.2
Net pressure
t.dP/dt
Slope
Overburden
Storage=0.96
radial=0.00
P psi
100
10
1000
100
10
t (min) since start of pumping

Figure 6

REFERENCES CITED IN THE DESCRIPTION

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Patent documents cited in the description

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- US 6076046 A **[0028]**

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