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SOLICITUD

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71. **SOLICITANTE** 1. BP Exploration operating company Limited.
2. BP Corporation North. America Inc.

DOMICILIO 1. Middlesex, TW, Gran Bretaña
2. Illinois, estados Unidos

74. **APODERADO** Dilia María Rodríguez D' Alemán

22. **BOGOTÁ, D. C.,** Enero 24/2006.

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ENTRADA EN FASE NACIONAL 2006-02-25

1) SOLICITUD DE:

☒ Patente de invención ☐ Patente de Modelo de Utilidad

☐ Capitulo I. ☒ Capitulo II.

2) S LICITANTE (71)	**Nombre: 1. BP EXPLORATION OPERATING COMPANY LIMITED 2. BP CORPORATION NORTH AMERICA INC.** **Dirección: 1. Chetsey Road, Sunbury on Thames, Middlesex TW 16 7 BP, Gran Bretaña 2. 4101 Winfield Road, Warrenville, IL., 60555, Estados Unidos** **Nacionalidad o domicilio: 1. Middlesex TW, Gran Bretaña 2. Illinois, Estados Unidos** **Lugar de constitución: 1. Gran Bretaña 2. Illinois, Estados Unidos**	**IDENTIFICACIÓN** **C.C.** ☐ **NIT:** ☐ **C.E.** ☐ **OTRO** ☐ **Cual** _____ **NÚMERO** _____
	Teléfono: Fax: **E. Mail:**	
3) REPRESENTANTE APODERADO	Nombre: DILIA MARÍA RODRÍGUEZ D´ALEMAN Dirección: Carrera 11 N°. 86-53 Piso 6 Bogotá D.C. Teléfono: 6181088 Fax: 6350824 E. Mail: info@clarkemodet.com.co	**IDENTIFICACIÓN** **C.C.** ☒ **NIT:** ☐ **C.E.** ☐ **OTRO** ☐ **NÚMERO:** 41.654.882 **TP:** 20824 CSJ
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Instrucciones para el diligenciamiento del presente formulario. Ver reverso de esta pagina

AA
2

10) ANEX S

- ☒ Comprobante de pago de la tasa de presentación de la solicitud
- ☐ Comprobante de pago por reivindicación de prioridad
- ☐ Documento que acredita la existencia y representación legal cuando el solicitante sea persona Jurídica - BP EXPLORATION OPERATING COMPANY LIMITED
- ☒ Poderes, si fuera el caso – BP EXPLORATION OPERATING COMPANY LIMITED
- ☐ Documento de cesión del inventor al solicitante o a su causante
- ☐ Declaraciones
- ☒ Copia de la solicitud Internacional. (Resumen, descripción, reivindicación, Dibujos).
- ☒ Traducción de la solicitud internacional al castellano. (Resumen, descripción, reivindicación, Dibujos)
- ☒ Copia del examen preliminar efectuado por la IPEA
- ☐ De ser el caso, copia del contrato de acceso
- ☐ De ser el caso, documento que acredite la licencia o autorización de uso de conocimientos tradicionales de las comunidades indígenas
- ☐ De ser el caso, certificado de depósito del material biológico
- ☐ Arte final 12 x 12 y 6 x 6 cm
- ☐ De ser el caso, información sobre otras solicitudes de patente o títulos obtenidos en el extranjero por el mismo titular o su causante, relacionados parcial o totalmente con la invención de esta solicitud.
- ☒ Otros:
  1. Repuesta a Opinión escrita
  2. Notificación de la transmisión del reporte de búsqueda
  3. Solicitud PCT
  4. Pct Capítulo II

11) FIGURA CARACTERÍSTICA:

12) Solicitud concesión de la patente,

NOMBRE: DILIA RODRÍGUEZ D´ALEMAN

FIRMA:

C.C. 41.654.882 de Bogota TP 20824 CSJ

Instrucciones para el diligenciamiento del presente formulario. Ver reverso de esta pagina

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CANT.	RENTISTICO	CONCEPTO	TOTAL CONCEPTO
1	50005-01-01 SOLICITUDES	1 TRAMITES DE SOL. DE PATENTE DE IN	463,000.00
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SON: CUATROCIENTOS SESENTA Y TRES MIL PESOS

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PATENT COOPERATION TREATY

From the INTERNATIONAL BUREAU

PCT

NOTIFICATION CONCERNING TRANSMITTAL OF COPY OF INTERNATIONAL APPLICATION AS PUBLISHED OR REPUBLISHED

To:

COLLINS, Frances, Mary
BP International Limited
Patents & Agreements
Chertsey Road
Sunbury on Thames
Middlesex TW16 7LN
ROYAUME-UNI

Date of mailing *(day/month/year)* 10 February 2005 (10.02.2005)	
Applicant's or agent's file reference 10061	**IMPORTANT NOTICE**

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Applicant
BP EXPLORATION OPERATING COMPANY LIMITED et al

The International Bureau transmits herewith the following documents:

☑ copy of the international application as published by the International Bureau on 10 February 2005 (10.02.2005) under No. WO 2005/012687

☐ copy of international application as republished by the International Bureau on under No. WO
For an explanation as to the reason for this republication of the international application, reference is made to INID codes (15), (48) or (88) (*as the case may be*) on the front page of the attached document.

The International Bureau of WIPO 34, chemin des Colombettes 1211 Geneva 20, Switzerland	Authorized officer Nora Lindner
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(74) Agents: COLLINS, Frances, Mary et al.; BP International Limited, Patents & Agreements, Chertsey Road, Sunbury on Thames, Middlesex TW16 7LN (GB).

(81) Designated States *(unless otherwise indicated, for every kind of national protection available)*: AE, AG, AL, AM, AT, AU, AZ, BA, BB, BG, BR, BW, BY, BZ, CA, CH, CN, CO, CR, CU, CZ, DE, DK, DM, DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, HR, HU, ID, IL, IN, IS, JP, KE, KG, KP, KR, KZ, LC, LK, LR, LS, LT, LU, LV, MA, MD, MG, MK, MN, MW, MX, MZ, NA, NI, NO, NZ, OM, PG, PH, PL, PT, RO, RU, SC, SD, SE, SG, SK, SL, SY, TJ, TM, TN, TR, TT, TZ, UA, UG, US, UZ, VC, VN, YU, ZA, ZM, ZW.

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— *as to the applicant's entitlement to claim the priority of the earlier application (Rule 4.17(iii)) for all designations*

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Published:

— *with international search report*

— *before the expiration of the time limit for amending the claims and to be republished in the event of receipt of amendments*

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(54) Title: DRILLING METHOD

(57) Abstract: A method of reducing formation breakdown during the drilling of a wellbore which method comprises: (a) circulating a drilling mud in the wellbore comprising (i) an aqueous or oil based fluid, (ii) at least one fluid loss additive at a concentration effective to achieve a high temperature high pressure (HTHP) fluid loss from the drilling mud of less than 2 ml/30 minutes and (iii) a solid particulate bridging material having an average particle diameter of 25 to 2000 microns and a concentration of at least 0.5 pounds per barrel: (b) increasing the pressure in the wellbore to above the initial fracture pressure of the formation such that fractures are induced in the formation and a substantially fluid impermeable bridge comprising the solid particulate bridging material and the fluid loss additive(s) is formed at or near the mouth of the fractures thereby strengthening the formation: (c) thereafter continuing to drill the wellbore with the pressure in the wellbore maintained at above the initial fracture pressure of the formation and below the breakdown pressure of the strengthened formation.

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DRILLING METHOD

The present invention relates to drilling of wells through a subterranean formation, and more particularly to a method of increasing the resistance of the wellbore wall to fracturing during drilling operations.

Conventionally, the drilling of a well into the earth by rotary drilling techniques, involves the circulation of a drilling fluid from the surface of the earth down a drill string having a drill bit on the lower end thereof and through ports provided in the drill bit to the well bottom and thence back to the surface through the annulus formed about the drill string. Commonly, drilling fluids are employed that are either oil or water based. These fluids are treated to provide desired rheological properties which make the fluids particularly useful in the drilling of wells.

A problem often encountered in the drilling of a well is the loss of unacceptably large amounts of drilling fluid into subterranean formations penetrated by the well. This problem is often referred to generally as "lost circulation," and the formations into which the drilling fluid is lost are often referred to as "lost circulation zones" or "thief zones". Various causes may be responsible for the lost circulation encountered in the drilling of a well. For example, a formation penetrated by the well may exhibit unusually high permeability or may contain fractures or crevices therein. In addition, a formation may simply not be sufficiently competent to support the pressure applied by the drilling fluid and may break down under this pressure and allow the drilling fluid to flow thereinto.

It is this latter situation where the formation is broken down by the pressure of the drilling fluid to which the present invention is addressed. One of the limiting factors in drilling a particular portion of a well is the mud weight (density of the drilling fluid)

that can be used. If too high a mud weight is used, fractures are created in the wall of the borehole with resulting loss of drilling fluid and other operating problems. On the other hand, if too low a mud weight is used, encroachment of formation fluids can occur, borehole collapse may occur due to insufficient support from the fluid pressure in the wellbore, and in extreme cases safety can be compromised due to the possibility of a well blowout. In many cases, wells are drilled through weak or lost-circulation-prone zones prior to reaching a potential producing zone, requiring use of a low mud weight and installation of sequential casing strings to protect weaker zones above a potential producing zone. If a higher weight mud could be used in drilling through weaker or depleted zones, then there is a potential for eliminating one or more casing strings in the well. Elimination of even one casing string from a well provides important savings in time, material and costs of drilling the well. Thus, there is a need for a method of drilling boreholes using a higher mud weight than could normally be used without encountering formation breakdown problems.

Surprisingly, it has now been found that formation breakdown during drilling can be controlled by drilling the borehole using an ultra-low fluid loss mud with the pressure of the drilling mud maintained at above the initial fracture pressure of the formation wherein the fractures that are induced in the wellbore wall are bridged at or near the mouth thereof by a solid particulate material that is added to the drilling mud and the bridge is sealed by the accumulation of fluid loss additives in the voids between the bridging particles and/or the precipitation of fluid loss additives onto the bridging particles. The presence of the fluid impermeable bridge at or near the mouth of the fracture strengthens the near wellbore region of the formation by generating a stress cage. Thereafter, the drilling of the wellbore is continued with the pressure of the drilling mud maintained at below the breakdown pressure of the strengthened formation.

Thus, according to a first aspect of the present invention there is provided a method of reducing formation breakdown during the drilling of a wellbore which method comprises:

(a) circulating a drilling mud in the wellbore comprising (i) an aqueous or oil based fluid, (ii) at least one fluid loss additive at a concentration effective to achieve a high temperature high pressure (HTHP) fluid loss from the drilling mud of less than 2 ml/30 minutes and (iii) a solid particulate bridging material having an average particle diameter of 25 to 2000 microns and a concentration of at least 0.5 pounds per barrel;

(b) increasing the pressure in the wellbore to above the initial fracture pressure of the formation such that fractures are induced in the formation and a substantially fluid impermeable bridge comprising the solid particulate material and the fluid loss additive(s) is formed at or near the mouth of the fractures thereby strengthening the formation;

(c) thereafter continuing to drill the wellbore with the pressure in the wellbore maintained at above the initial fracture pressure of the formation and below the breakdown pressure of the strengthened formation.

For avoidance of doubt, the strengthened formation may be a permeable or non-permeable formation.

Without wishing to be bound by any theory, the mechanism by which the method of the present invention strengthens the wall of the wellbore and hence reduces formation breakdown is that as a fracture is deliberately induced in the wellbore wall, the solid particulate material enters and bridges the fracture at or near the mouth of the fracture. Additives which are conventionally included in the drilling mud to reduce loss of fluid from the drilling mud into the formation subsequently either precipitate on the solid particulate material that bridges the fracture or fill the voids between the solid particulate material thereby establishing a fluid impermeable immobile mass or bridge at or near the mouth of the fracture. Accordingly, fluid from the drilling mud can no longer pass into the fracture and the pressure within the fracture may begin to dissipate until it is substantially the same as the pressure of the surrounding formation. The rate of reduction in pressure within the fracture beyond the bridge will depend on the rock permeability and other factors such as the supporting action of the bridge which maintains the rock displacement caused by the fracture and the sealing action of the bridge which prevents fluid loss from the drilling mud into the fracture. The rock displacement caused by the fracture places the rock in the near wellbore region of the formation (for example, within a radial distance of up to 5 feet from the wellbore wall) in a state of compression, thereby increasing the "hoop stress" and generating a "stress cage". If there is a reduction in pressure in the fracture beyond the bridge, the fracture will attempt to close and this will impart stress on the fluid impermeable immobile mass or bridge which, in turn, leads to additional compressive stress being imparted to the rock in the near wellbore region of the formation. The increased compressive stress in the near wellbore region of the formation results in the wall of the wellbore having a

greater resistance to further fracturing. The method of the present invention therefore allows a drilling mud of higher density to be employed in drilling the wellbore than could be used in the absence of strengthening of the formation. The method also has a further beneficial effect of reducing loss of fluid from the drilling mud into the formation owing to the sealing of the fractures with the fluid impermeable immobile mass.

The method of the first aspect of the present invention differs from a conventional "tip screen out" in that a "tip screen out" requires the use of a high fluid loss drilling mud so that particulate material accumulates rapidly at the fracture tip thereby sealing the fracture and preventing further propagation of the fracture. The person skilled in the art would therefore have concerns that the use of an ultra-low fluid loss drilling mud would slow down deposition of particulate material at the fracture tip. Furthermore, there was no understanding that it may be preferable to bridge at or near the mouth of a fracture. Thus, conventional drilling muds employed in a "tip screen out" are designed so that the particulate material readily penetrates into the fracture to deposit at the fracture tip. Also, a "tip screen out" does not create an effective near wellbore "stress cage". Although the rock at the fracture tip would be under increased compressive stress (owing to the accumulation of particulate material at the fracture tip), this would not apply to the rock between the fracture tip and the mouth of the fracture. Finally, there was a prejudice against using a low fluid loss drilling mud owing to a belief that a low fluid loss mud would slow down the "rate of penetration" while drilling. It was therefore surprising that an ultra-low fluid loss mud does not significantly reduce the "rate of penetration".

The fluid loss value for the drilling mud is determined using a standard high temperature high pressure (HTHP) fluid loss test, according to the specifications of the American Petroleum Institute (API), as described in "Recommended Practice Standard Procedure for Field Testing Oil-Based Drilling Fluids", API Recommended Practice 13B-2 Third Edition, February 1998, Section 5.2.1 to 5.2.3; and "Recommended Practice Standard Procedure for Field Testing Water-Based Drilling Fluids", API Recommended Practice 13B-1 Second Edition, September 1997, Section 5.3.1 to 5.3.2. The test employs a pressurized cell fitted with a standard hardened filter paper as a filtration medium. The filtration behaviour of the drilling mud is determined with a standard pressure differential across the filter paper of 500 psi. A filter cake is allowed

to build up on the filter paper for 30 minutes and the volume of filtrate collected after this 30 minute period is then recorded. Because the filtration area (3.5 square inches) of the pressurized cell is half the filtration area of a standard API low temperature low pressure (LTLP) fluid loss test (7 square inches), the filtrate volume after 30 minutes is doubled to give a corrected API fluid loss value. Suitably, the temperature at which the high temperature high pressure (HTHP) fluid loss test is carried out corresponds to the temperature in the borehole. Generally, the test temperature is in the range 50 to 150°C.

By "fracture pressure" is meant the minimum fluid pressure in the wellbore at which a fracture is created in the wellbore wall. As would be evident to the person skilled in the art, creation of a near wellbore "stress cage" will increase the fracture pressure of the strengthened formation. Accordingly, by "initial fracture pressure" of a formation is meant the fracture pressure of the formation prior to creation of the "stress cage". The initial fracture pressure of a formation may be readily determined, for example, from historical data.

By "breakdown pressure of the strengthened formation" is meant the maximum fluid pressure that can be sustained within the wellbore without creating a fracture in the strengthened formation and/or without breaking down the fluid impermeable bridge(s) that has been formed at or near the mouth of the fracture(s).

Suitably, the pressure in the wellbore in step (c) of the method of the first aspect of the present invention is at least 50 psi above the initial fracture pressure of the formation, preferably, at least 300 psi above the initial fracture pressure of the formation, for example 300 to 1000 psi above the initial fracture pressure of the formation, with the proviso that the pressure in the wellbore in step (c) is below the breakdown pressure of the strengthened formation.

As is well known to the person skilled in the art, formation pressure generally increases with increasing depth of the wellbore. It is therefore generally necessary to continuously increase the pressure of the drilling mud during the drilling operation, for example, by increasing the density of the drilling mud. A problem arises when the increased pressure of the drilling mud exceeds the initial fracture pressure of a previously drilling formation or exceeds the initial fracture pressure of a formation that is yet to be drilled (hereinafter referred to as "weak formation"). The method of the first aspect of the present invention may therefore be used to strengthen such weak formations thereby allowing the pressure of the drilling mud that is employed for

completing the drilling operation to be increased to above the initial fracture pressure of the weak formation. The method of the first aspect of the present invention is particularly advantageous where the weak formation is a depleted formation i.e. a formation having a decreased pore pressure owing to production of hydrocarbons therefrom. This decrease in pore pressure weakens the depleted formation while neighbouring or inter-bedded low permeability formations may maintain their pore pressure.

Thus, in a specific embodiment of the first aspect present invention there is provided a method of reducing formation breakdown during the drilling of a wellbore through a weak formation with a circulating drilling mud which method comprises:
(a) circulating in a wellbore a drilling mud comprising (i) an aqueous or oil based fluid, and (ii) at least one fluid loss additive at a concentration effective to achieve a high temperature high pressure (HTHP) fluid loss from the drilling mud of less than 2 ml/30 minutes and (iii) a solid particulate bridging material having an average particle diameter of 25 to 2000 microns and a concentration of at least 0.5 pounds per barrel;
(b) increasing the pressure of the drilling mud to above the initial fracture pressure of the weak formation such that fractures are induced in the weak formation and a substantially fluid impermeable bridge comprising the solid particulate material and the fluid loss additive(s) is formed at or near the mouth of the fractures thereby strengthening the weak formation;
(c) thereafter continuing to drill the wellbore with the pressure in the wellbore maintained at above the initial fracture pressure of the weak formation and below the breakdown pressure of the strengthened formation.

It is envisaged that the wellbore may be drilled using a conventional drilling mud until the pressure in the wellbore approaches the initial fracture pressure of the weak formation. The conventional drilling mud is then replaced by (or converted into) the drilling mud employed in step (a) before increasing the pressure in the wellbore to above the initial fracture pressure of the weak formation. The conventional drilling mud may be converted into the drilling mud employed in step (a) by adding at least one fluid loss additive (ii) to the mud until the HTHP fluid loss value of the mud is less than 2 ml/30 minutes and adding the solid particulate bridging material (iii) to the mud in an amount of at least 0.5 pound per barrel. Suitably, the solid particulate bridging material (iii) may be added to a drilling mud comprising components (i) and (ii) immediately

before increasing the pressure of the drilling mud to above the initial fracture pressure of the weak formation. Thus, the drilling mud that is used to drill the wellbore until the pressure in the wellbore approaches the initial fracture pressure of the weak formation may comprise components (i) and (ii) in the absence of component (iii).

The weak formation may lie in a previously drilled section of the wellbore and/or in the rock that is about to be drilled. Where the weak formation is in the rock that is about to be drilled, it is necessary to replace the entire wellbore fluid with the drilling mud employed in step (a). Thus, the weak formation is strengthened as the wellbore is being drilled. Where the weak formation lies in a previously drilled section of the wellbore, it is only necessary to replace the wellbore fluid in the vicinity of the weak formation. Thus, a drilling mud having a high concentration of the particulate solid material may be introduced into the wellbore as a "pill" and may be circulated to the weak formation where the concentrated drilling mud composition is squeezed into the weak formation at a pressure above the initial fracture pressure of the weak formation so that the bridging particulate material bridges the fractures that are induced in the wellbore wall at or near the mouth thereof. Typically, the pill is squeezed into the weak formation by sealing the annulus between a drill string and the wellbore wall, raising the drill string until it lies immediately below the weak formation, and pumping the pill into the wellbore via the drill string until the pressure in the vicinity of the weak formation is greater than the initial fracture pressure. Generally, the well is then shut in for a period of up to 0.5 hour. After strengthening the weak formation, drilling of the wellbore may be continued using a conventional drilling mud with the proviso that the pressure in the wellbore in the vicinity of the strengthened formation is maintained below the breakdown pressure of the strengthened formation. Suitably, the concentration of bridging material in the pill should be at least 50 pounds per barrel, preferably at least 80 lb per barrel. It is also envisaged that the "pill" may be employed as a completion fluid and may be pumped into the wellbore in advance of a cement when casing a wellbore.

In a further aspect of the present invention there is provided a drilling mud composition comprising (a) an aqueous or oil based fluid, (b) at least one fluid loss additive at a concentration effective to achieve a high temperature high pressure (HTHP) fluid loss from the drilling mud of less than 2 ml/30 minutes and (c) a solid particulate bridging material having an average particle diameter of 25 to 2000 microns

and a concentration of at least 0.5 pounds per barrel.

Suitably, the specific gravity of the drilling mud is in the range 0.9 to 2.5, preferably in the range 1.0 to 2.0.

Suitably, the solid particulate bridging material that is included in the drilling mud to bridge the fractures (hereinafter "bridging material") comprises at least one substantially crush resistant particulate solid such that the bridging material props open the fractures (cracks and fissures) that are induced in the wall of the wellbore. By "crush resistant" is meant that the bridging material is physically strong enough to withstand the closure stresses exerted on the fracture bridge. Preferred bridging materials for adding to the drilling mud include graphite, calcium carbonate (preferably, marble), dolomite ($MgCO_3.CaCO_3$), celluloses, micas, proppant materials such as sands or ceramic particles and combinations thereof. These materials are very inert and are environmentally acceptable. It is also envisaged that a portion of the bridging material may comprise drill cuttings having the desired average particle diameter in the range of 25 to 2000 microns.

The concentration of the bridging material may vary with the drilling mud used and the conditions of use. The concentration must be at least great enough for the bridging material to rapidly bridge the fractures (i.e. cracks and fissures) that are induced in the wall of the wellbore but should not be so high as to make circulation of the drilling mud impractical. Suitably, the bridging material should bridge the fractures that are induced in the wellbore wall within less than 10 seconds, preferably less than 5 seconds from when the fracture opens so that the fracture remains short. Thus, rapid sealing of the fracture mitigates the risk of the fracture propagating. Suitably, the concentration of bridging material in the drilling mud is at least 5 pounds per barrel, preferably at least 10 pounds per barrel, more preferably at least 15 pounds per barrel, for example, at least 30 pounds per barrel. However, as discussed above, where the drilling mud is employed in a "pill" treatment, the concentration of the bridging particulate material is suitably at least 50 pounds per barrel, preferably at least 80 pounds per barrel.

Suitably, the bridging material is sized so as not to enter the pores of any permeable rock through which the wellbore is being drilled. Preferably, the bridging material has an average particle diameter in the range 50 to 1500 microns, more preferably 250 to 1000 microns. The bridging material may comprise substantially

spherical particles. However, it is also envisaged that the bridging material may comprise elongate particles, for example, rods or fibres. Where the bridging material comprises elongate particles, the average length of the elongate particles should be such that the elongate particles are capable of bridging the induced fractures at or near the mouth thereof. Typically, the elongate particles will have an average length in the range 25 to 2000 microns, preferably 50 to 1500 microns, more preferably 250 to 1000 microns.

The bridging material is sized so as to readily form a bridge at or near the mouth of the induced fractures. Typically, the fractures that are induced in the wellbore wall have a fracture width at the mouth in the range 0.1 to 5mm. The fracture width is dependent, amongst other factors, upon the strength (stiffness) of the formation rock and the extent to which the pressure in the wellbore is increased to above initial fracture pressure of the formation during the fracture induction step (b) of the method of the present invention (in other words, the fracture width is dependent on the pressure difference between the drilling mud and the initial fracture pressure of the formation during the fracture induction step). It is preferred that at least a portion of the bridging material, preferably, a major portion of the bridging material has a particle diameter approaching the width of the fracture mouth. Preferably, the bridging material has a broad (polydisperse) particle size distribution.

It is necessary to keep the bridging material in suspension in the drilling mud. Generally, a drilling mud is recycled to the wellbore after removal of substantially all of the drill cuttings. The drill cuttings may be removed using screens as would be well known to the person skilled in the art. Typically the drilling mud is filtered using a 200 mesh size screen (US sieve series) that retains particles having a size of greater than 74 microns. However, in the method of the present invention, it is necessary to filter the mud using a coarser screen so as to avoid separation of substantial amounts of the bridging material from the mud. Suitably, the drilling mud is filtered using a 35 mesh screen (US sieve series) that retains particles having a size of greater than 500 microns. However, if the rheology of the mud deteriorates through the accumulation of fine drill cuttings in the mud, it may be necessary to employ finer mesh screens for a short period of time. It is also envisaged that separation methods may be employed which allow the bridging solids to be retained but a major portion of the cuttings, preferably substantially all of the cuttings, to be separated from the drilling mud. In particular, the

cuttings may be separated from the drilling mud by relying on differences in the densities of the cuttings and the bridging particles, for example, using centrifuges or hydrocyclones. In order to maintain the concentration of the bridging material at the desired value in the drilling mud and/or to maintain the fluid loss value of the drilling mud at below 2 ml/30 minutes, it may be necessary to introduce fresh bridging material and/or fresh fluid loss additives respectively into the circulating drilling mud. Alternatively, or in addition, fresh drilling mud may be either continuously or intermittently added to the drilling mud that is being circulated in the wellbore.

The drilling mud has an HTHP fluid loss value of less than 2 ml/30 minutes, preferably, less than 1 ml/30 minutes, more preferably less than 0.5 ml/30 minutes, for example 0.1 to 0.3 ml/30 minutes. As would be well known to the person skilled in the art, such ultra-low fluid loss values may be achieved by incorporating at least one fluid loss additive in the drilling mud. Without wishing to be bound by any theory, it is believed that the fluid loss additive(s) will build up on the solid particulate material that bridges the fractures at or near the mouth thereof thereby forming a fluid impermeable immobile mass. Where the solid particulate bridging material is porous, the fluid loss additives may also enter the pores of the bridging material to seal the pores.

Suitable fluid loss additives that may be incorporated in the drilling mud of the present invention include organic polymers of natural or synthetic origin. Suitable polymers include starch or chemically modified starches; cellulose derivatives such as carboxymethylcellulose and polyanionic cellulose (PAC); guar gum and xanthan gum; homopolymers and copolymers of monomers selected from the group consisting of acrylic acid, acrylamide, acrylamido-2-methyl propane sulfonic acid (AMPS), styrene sulphonic acid, N-vinyl acetamide, N-vinyl pyrrolidone, and N,N-dimethylacrylamide wherein the copolymer has a number average molecular weight of from 100,000 to 1,000,000, and preferably 200,000 to 500,000; asphalts (for example, sulphonated asphalts); gilsonite; lignite and its derivative, humic acid; lignin and its derivatives such as lignin sulfonates or condensed polymeric lignin sulfonates; and combinations thereof. These polymeric additives are particularly suitable for use in oil based drilling muds. As an alternative or, in addition, to employing such polymeric additives, the fluid loss from the drilling mud of the present invention may be reduced by adding finely dispersed particles such as clays (for example, illite, kaolinite, bentonite, or sepiolite) to the drilling mud. Suitably, the finely dispersed particles have an average particle size of

less than 10 microns, preferably, less than 5 microns, for example, about 1 micron. Preferably, the drilling mud contains a smooth/continuous range of particle sizes ranging from about 1 micron for the finely dispersed particulate fluid loss additives to an average particle diameter of the bridging material of up to 2000 microns i.e. has a broad (polydisperse) particle size distribution.

It is envisaged that an oil based drilling mud may contain a significant amount of a discontinuous water phase dispersed in a continuous oil phase by means of at least one emulsifier (a water-in-oil emulsion). The fluid loss value of such drilling muds may vary depending upon the oil to water ratio and the nature of the emulsifier(s) employed to form the water-in-oil emulsion (and hence on the size of the dispersed water droplets). Preferably, the water content of the drilling mud is in the range 80:20 to 50:50, more preferably 70:30 to 55:45. Preferred emulsifiers include imidazolines, fatty acids and combinations thereof.

Particularly preferred ultra-low fluid loss oil based drilling muds are described in SPE 77446, "Towards Zero Fluid Loss Oil Based Muds", M Aston, P Mihalik, J Tunbridge and S Clarke, published 2002, which is herein incorporated by reference.

The effectiveness of the method of the present invention has been demonstrated in both laboratory and field conditions as shown by the following Examples.

Example 1

Oil based mud formulations were evaluated in the laboratory by injecting different drilling muds into a model fracture (as described in SPE/IADC 87130, "Drilling Fluids for Wellbore Strengthening, 2-4 March 2004, M S Aston et al). The model fracture was formed from two rectangular-shaped rock pieces (of 0.3 milliDarcy permeability "Ohio" sandstone). Each rock piece had approximate dimensions of 5cm width x 20cm length x 1cm breadth. The two rock pieces were sandwiched together to create a fracture having a mouth aperture of 1mm with the aperture of the fracture tapering to 0.5mm at the far end thereof (fracture tip). A valve was provided at the exit from the fracture tip such that the fracture tip could be open or sealed. The rock sandwich was placed in a purpose-built holder that was supported in a load frame within a test cell. The fracture width was maintained constant using fixed spacers. The fluid pressure within the fracture was measured just inside the mouth of the fracture using a pressure transducer. Initially, the fracture and the pore spaces in the rock were filled with a clear fluid (water) and the system was heated to a temperature of 60°C. A

pressure of about 100 psi was applied to compress any air in the system. Drilling mud was then injected at a pressure of 400 psi into the mouth of the fracture with the fracture tip open (to give a differential pressure across the fracture of 300 psi). After 3 minutes, the exit from the fracture tip was closed using the valve so that pressure could build up inside the fracture (n.b. the initial driving force for bridge formation at the fracture mouth was fluid leak-off through the fracture tip). The injection pressure was then increased stepwise to 2000 psi. A low pressure measured on the pressure transducer indicated an effective seal at the mouth of the fracture.

The results shown in Table 1 below compare the pressures measured just inside the fracture mouth for different drilling muds employed in the above test procedure. The pressure just inside the fracture mouth was measured after a steady value was reached at each injection pressure.

Table 1 – Effectiveness of drilling muds in sealing a model fracture

Mud System		Pressure just inside fracture mouth, measured after different mud injection pressures (IP) in psi		
		IP 400	IP 1000	IP 2000
Mud 1 (Comparative)	Base mud plus bridging particulate material mix A; API HTHP fluid loss = 3mls/30 minutes at a temperature of 60°C	300	900	1900
Mud 2	As mud 1, but containing 5lb/bbl Pliolite, API HTHP fluid loss = 0.3 mls/30 minutes at a temperature of 60°C	0	30	1900
Mud 3	Base mud plus bridging particulate material mix B plus 5lb/bbl Pliolite, API HTHP fluid loss = 0.1 mls/30 minutes at a temperature of 60°C	0	0	0

Mud 2 forms a more effective seal than Mud 1 (Comparative). This was achieved by reducing the API HTHP fluid loss of the mud system from 3 ml/30 minutes to 0.3 mls/30 minutes. Mud 3 achieved a total seal at the mouth of the fracture by using an improved bridging particulate material mix in a mud having an API HTHP fluid loss of 0.1 mls/30 minutes.

The formulation for the base mud employed in the above tests was as follows:

Mineral oil:	0.517 bbls
Versamul™ (emulsifier, ex MI)	4.7 lb/bbl
Versawet™ (wetting agent, ex MI)	7 lb/bbl

15. A drilling mud composition as claimed in any one of Claims 12 to 14 wherein the concentration of the solid particulate bridging material is at least 10 pounds per barrel, preferably at least 15 pounds per barrel.

16. A drilling mud composition as claimed in any one of claims 12 to 15 wherein the solid particulate bridging material has an average particle diameter in the range 50 to 1500 microns.

17. A drilling mud composition as claimed in any one of Claims 12 to 16 having an HTHP fluid loss value of less than 1 ml/30 minutes, preferably less than 0.5 ml/30 minutes.

18. A drilling mud composition as claimed in any one of Claims 12 to 17 wherein the fluid loss additive(s) is selected from organic polymers of natural or synthetic origin and finely dispersed clays.

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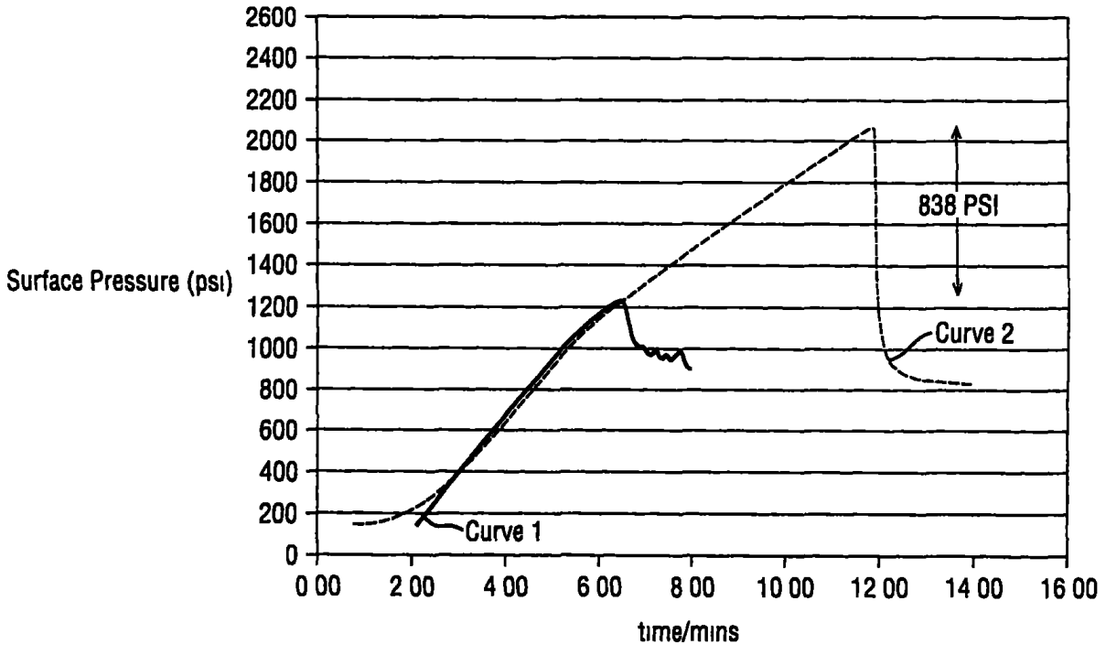
FIG. 1



PCT/GB2004/003154

INTERNATIONAL SEARCH REPORT

PCT/GB2004/003154

A. CLASSIFICATION OF SUBJECT MATTER
IPC 7 E21B33/13

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
IPC 7 C09K E21B

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practical, search terms used)
EPO-Internal

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category *	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
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A	GB 2 351 098 A (SOFITECH NV) 20 December 2000 (2000-12-20) page 6 claims 1-5	1-18
A	US 6 403 537 B1 (PERRICONE CHARLES ET AL) 11 June 2002 (2002-06-11) the whole document	1-18

☐ Further documents are listed in the continuation of box C.

☒ Patent family members are listed in annex.

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"&" document member of the same patent family

Date of the actual completion of the international search	Date of mailing of the international search report
29 November 2004	06/12/2004

Name and mailing address of the ISA	Authorized officer
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INTERNATIONAL SEARCH REPORT

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PCT/GB2004/003154

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METODO DE PERFORACION

La presente invención se refiere a la perforación de pozos a través de una formación subterránea y, más particularmente a un método para aumentar la resistencia a la fractura de la pared del pozo durante las operaciones de perforación.

La perforación de un pozo en la tierra mediante técnicas de perforación rotativa implica convencionalmente la circulación de un fluido de perforación desde la superficie de la tierra, descendentemente por una sarta de perforación que tiene un trépano de perforación en el extremo inferior de la misma, y a través de orificios previstos en el trépano, hasta el fondo del pozo y desde aquí de nuevo hacia la superficie a través de la corona anular formada alrededor de la sarta de perforación. Generalmente se emplean fluidos de perforación que están basados bien en petróleo o bien en agua. Dichos fluidos son tratados para proporcionar propiedades reológicas deseadas que hagan que los fluidos resulten particularmente útiles en la perforación de pozos.

Un problema encontrado frecuentemente en la perforación de un pozo es la pérdida de cantidades inaceptablemente altas de fluido de perforación dentro de las formaciones subterráneas penetradas por el pozo. Este problema suele conocerse generalmente como "pérdida de circulación" y las formaciones en las cuales se pierde el fluido de perforación suelen referirse como "zonas de pérdida de circulación" o "zonas de escape". Varias causas pueden ser las responsables de la pérdida de circulación encontrada en la perforación de un pozo. Por ejemplo, una formación penetrada por el pozo puede exhibir una permeabilidad desusualmente elevada o puede contener fracturas o fisuras en la misma. Además, puede que una formación simplemente no sea lo suficientemente competente para soportar la presión aplicada por el fluido de perforación y puede desplomarse bajo esta presión y

permitir que el fluido de perforación fluya al interior de la misma.

La presente invención está dirigida a esta última situación en donde la formación se desploma por la presión del fluido de perforación. Uno de los factores limitativos en la perforación de una porción particular de un pozo es el peso del lodo de circulación (densidad del fluido de perforación) que puede ser utilizado. Si se emplea un peso de lodo demasiado elevado, se crean fracturas en la pared del pozo con la consecuente pérdida de fluido de perforación y otros problemas operativos. Por otro lado, si se emplea un peso de lodo demasiado bajo, puede presentarse una invasión de fluidos en la formación, puede derrumbarse el pozo como consecuencia del soporte insuficiente frente a la presión de fluido en el pozo y, en casos extremos, la seguridad puede verse comprometida debido a la posibilidad de una erupción del pozo. En muchos casos, los pozos son perforados a través de zonas débiles o expuestas a la pérdida de circulación antes de alcanzar una zona de producción potencial, requiriendo ello el uso de un peso bajo de lodo y la instalación de sartas de entubado para proteger las zonas más débiles situadas por encima de una zona de producción potencial. En el caso de que pudiera emplearse un mayor peso de lodo en la perforación a través de zonas más débiles o agotadas, existe entonces el potencial de eliminar una o más sartas de entubado en el pozo. La eliminación de incluso una sola sarta de entubado de un pozo proporciona ahorros importantes en cuanto a tiempo, material y costes de perforación del pozo. De este modo, existe la necesidad de disponer de un método para la perforación de pozos en donde se utilice un peso de lodo mayor que aquel que podría utilizarse normalmente sin que surjan problemas de desplome de la formación.

De manera sorprendente, se ha comprobado ahora que el desplome de la formación durante la perforación se puede controlar mediante la perforación del pozo

utilizando un lodo de pérdida de fluido ultra-baja y manteniendo la presión del lodo de perforación por encima de la presión de fractura inicial de la formación y en donde las fracturas que son inducidas en la pared del pozo son puenteadas en o cerca de la boca del mismo mediante un material de macropartículas sólidas que se añade al lodo de perforación y en donde el puente es sellado por la acumulación de aditivos para controlar la pérdida de fluido en los vacíos existentes entre las partículas que efectúan el puente y/o la precipitación de aditivos para controlar la pérdida de fluido sobre las partículas que efectúan el puente. La presencia del puente impermeable al fluido en o cerca de la boca de la fractura fortalece la región de la formación próxima al pozo al generar una jaula de tensiones. A continuación, se continúa la perforación del pozo manteniendo la presión del lodo de perforación por debajo de la presión de desplome de la formación así consolidada.

De este modo, de acuerdo con un primer aspecto de la presente invención se proporciona un método para reducir el desplome de una formación durante la perforación de un pozo, cuyo método comprende:

(a) hacer circular por el pozo un lodo de perforación que comprende (i) un fluido a base de agua o petróleo, (ii) al menos un aditivo para controlar la pérdida de fluido en una concentración eficaz para conseguir una pérdida de fluido a elevada temperatura y elevada presión (HTHP) a partir del lodo de perforación menor de 2 ml/30 minutos y (iii) un material de puente en macropartículas sólidas que tiene un diámetro medio de partícula de 25 a 2.000 micrómetros y una concentración de al menos 0,5 libras por barril;

(b) aumentar la presión en el pozo a un valor por encima de la presión de fractura inicial de la formación, de manera que se inducen fracturas en la formación y se forma un puente sustancialmente impermeable al fluido que comprende el material

en macropartículas sólidas y el aditivo o aditivos para controlar la pérdida de fluido en o cerca de la boca de las fracturas, con lo que la formación resulta así fortalecida; (c) continuar entonces la perforación del pozo manteniendo la presión en el mismo por encima de la presión de fractura inicial de la formación y por debajo de la presión de desplome de la formación fortalecida.

Para evitar dudas, la formación fortalecida puede ser una formación permeable o no permeable.

Sin animo de quedar limitados por cualquier teoría en particular, el mecanismo por el cual el método de la presente invención fortalece la pared del pozo y por tanto reduce el desplome de la formación es que, a medida que se induce deliberadamente una fractura en la pared del pozo, el material en macropartículas sólidas entra en la fractura y la puentea en o cerca de la boca de la fractura. Los aditivos que tradicionalmente se incluyen en el lodo de perforación para controlar la pérdida de fluido desde el lodo de perforación al interior de la formación, precipitan posteriormente sobre el material en macropartículas sólidas que puentea la fractura o rellena los vacíos existentes entre el material en macropartículas sólidas, estableciendo con ello una masa o puente inmóvil impermeable al fluido en o cerca de la boca de la fractura. Por tanto, el fluido procedente del lodo de perforación ya no puede pasar al interior de la fractura y la presión dentro de la fractura puede comenzar a disiparse hasta que llega a ser sustancialmente la misma que la presión de la formación circundante. La velocidad de reducción de la presión dentro de la fractura, más allá del puente, dependerá de la permeabilidad de la roca y de otros factores, tales como la acción de soporte del puente que mantiene el desplazamiento de la roca causado por la fractura y la acción de sellado del puente que evita la pérdida de fluido desde el lodo de perforación al interior de la fractura. El

desplazamiento de la roca causado por la fractura hace que la roca en la región de la formación próxima al pozo (por ejemplo, dentro de una distancia radial de hasta 5 pies desde la pared del pozo) se encuentre en un estado de compresión, aumentando con ello la "tensión circunferencial" y generando una "jaula de tensiones". En el caso de que exista una reducción de presión en la fractura más allá del puente, la fractura intentará cerrarse y ello impartirá tensión sobre la masa o puente inmóvil impermeable al fluido lo cual, a su vez, conduce a impartir una tensión de compresión adicional en la roca en la región de la formación próxima al pozo. La mayor tensión de compresión en la región de la formación próxima al pozo hace que la pared del pozo tenga una mayor resistencia frente a una fractura adicional. Por tanto, el método de la presente invención permite utilizar, en la perforación del pozo, un lodo de perforación de mayor densidad que aquel que podría utilizarse en ausencia de fortalecimiento de la formación. El método presenta también el efecto beneficioso adicional de reducir la pérdida de fluido desde el lodo de perforación al interior de la formación debido al sellado de las fracturas con la masa inmóvil impermeable al fluido.

El método del primer aspecto de la presente invención difiere de un "apantallamiento" de la extremidad de la fractura en que dicho "apantallamiento" requiere el uso de un lodo de perforación de alta pérdida de fluido, de manera que el material en macropartículas se acumula rápidamente en la extremidad de la fractura, sellando con ello la fractura y evitando que esta última se propague aún más. Por tanto, el experto en la materia podrá comprender que el uso de un lodo de perforación de pérdida de fluido ultra-baja decelerará la deposición de material en macropartículas en la extremidad de la fractura. Además, no existe conocimiento alguno del por qué puede ser preferible realizar el puente en o cerca de la boca de

una fractura. De este modo, los lodos de perforación convencionales utilizados en un "apantallamiento" de la extremidad de la fractura están diseñados de manera que el material en macropartículas penetra fácilmente en la fractura para depositarse en la extremidad de la misma. Igualmente, un "apantallamiento" de la extremidad de la fractura no crea una "jaula de tensiones" eficaz cerca del pozo. Aunque la roca en la extremidad de la fractura se encontrará bajo una mayor tensión por compresión (debido a la acumulación de material en macropartículas en la extremidad de la fractura), dicha tensión no se aplicará a la roca entre la extremidad de la fractura y la boca de la fractura. Por último, ha existido un prejuicio contra el uso de un lodo de perforación de baja pérdida de fluido debido a la creencia de que un lodo de baja pérdida de fluido desceleraría la "velocidad de penetración" mientras se realiza la operación de perforación. Por tanto, resultó sorprendente que un lodo de pérdida de fluido ultra-baja no reduzca de manera importante la "velocidad de penetración".

El valor de la pérdida de fluido para el lodo de perforación se determina empleando un ensayo normalizado de la pérdida de fluido a elevada temperatura y elevada presión (HTHP) de acuerdo con las especificaciones del American Petroleum Institute (API), como se describe en "Recommended Practice Standard Procedure for Field Testing Oil-Based Drilling Fluids", API Recommended Practice 13B-2 Tercera Edición, Febrero 1998, Sección 5.2.1 a 5.2.3; y "Recommended Practice Standard Procedure for Field Testing Oil-Based Drilling Fluids", API Recommended Practice 13B-1 Segunda Edición, Septiembre 1997, Sección 5.3.1 a 5.3.2. El ensayo utiliza una cuba a presión equipada con un papel de filtro endurecido normalizado como medio de filtración. El comportamiento de filtración del lodo de perforación se determina con un diferencial de presión normalizado de un lado a otro del papel de filtro de 500 psi. Se deja que se forme una torta de filtración sobre el

papel de filtro durante 30 minutos y se anota entonces el volumen de filtrado recogido después de dicho periodo de 30 minutos. Debido a que el área de filtración (3,5 pulgadas cuadradas) de la cuba a presión es la mitad del área de filtración de un ensayo de pérdida de fluido a baja temperatura y baja presión (LTLP) según la norma API (7 pulgadas cuadradas), el volumen de filtrado después de 30 minutos se duplica para proporcionar un valor corregido de la pérdida de fluido API. Convenientemente, la temperatura a la cual se efectúa el ensayo de pérdida de fluido a elevada temperatura y elevada presión (HTHP) corresponde a la temperatura existente en el pozo. Generalmente, la temperatura del ensayo es del orden de 50 a 150° C.

Por el término "presión de fractura" se quiere dar a entender la presión mínima del fluido en el pozo a la cual se crea una fractura en la pared del pozo. Como resultará evidente para el experto en la materia, la creación de una "jaula de tensiones" cerca del pozo aumentará la presión de fractura de la formación fortalecida. En consecuencia, por la expresión "presión de fractura inicial" de una formación se quiere dar a entender la presión de fractura de la formación antes de la creación de la "jaula de tensiones". La presión de fractura inicial de una formación se puede determinar fácilmente, por ejemplo, a partir de datos históricos.

Por la expresión "presión de desplome de la formación fortalecida" se quiere dar a entender la presión máxima del fluido que puede sostenerse dentro del pozo sin crear una fractura en la formación fortalecida y/o sin que se desplome el puente o puentes impermeables al fluido que se han formado en o cerca de la boca de la fractura o fracturas.

Adecuadamente, la presión en el pozo en la etapa (c) del método del primer aspecto de la presente invención es de al menos 50 psi por encima de la presión de fractura inicial de la formación, con preferencia de al menos 300 psi por encima de la

presión de fractura inicial de la formación, por ejemplo de 300 a 1.000 psi por encima de la presión de fractura inicial de la formación, con la condición de que la presión en el pozo en la etapa (c) se encuentre por debajo de la presión de desplome de la formación fortalecida.

Como es bien conocido para el experto en la materia, la presión en la formación aumenta generalmente con el incremento de la profundidad del pozo. Por tanto, generalmente es necesario aumentar de forma continua la presión del lodo de perforación durante la operación de perforación, por ejemplo, aumentando la densidad del lodo de perforación. Surge un problema cuando la presión incrementada del lodo de perforación excede de la presión de fractura inicial de una formación previamente perforada o excede de la presión de fractura inicial de una formación que todavía no ha sido perforada (referida de aquí en adelante como "formación débil"). Por tanto, el método del primer aspecto de la presente invención se puede emplear para fortalecer dichas formaciones débiles, permitiendo con ello que la presión del lodo de perforación que se utiliza para completar la operación de perforación pueda aumentarse a un valor por encima de la presión de fractura inicial de la formación débil. El método del primer aspecto de la presente invención resulta particularmente ventajoso cuando la formación débil es una formación agotada, es decir, una formación que tiene una menor presión en los poros debido a la producción de hidrocarburos a partir de la misma. Este descenso de la presión en los poros debilita la formación agotada, mientras que las formaciones de baja permeabilidad próximas o intercaladas pueden mantener su presión en los poros.

De este modo, en una modalidad específica del primer aspecto de la presente invención, se proporciona un método para reducir el desplome de una formación durante la perforación de un pozo a través de una formación débil con un lodo de

perforación en circulación, cuyo método comprende:

(a) hacer circular por el pozo un lodo de perforación que comprende (i) un fluido a base de agua o petróleo, (ii) al menos un aditivo para controlar la pérdida de fluido en una concentración eficaz para conseguir una pérdida de fluido a elevada temperatura y elevada presión (HTHP) a partir del lodo de perforación menor de 2 ml/30 minutos y (iii) un material de puente en macropartículas sólidas que tiene un diámetro medio de partícula de 25 a 2.000 micrómetros y una concentración de al menos 0,5 libras por barril;

(b) aumentar la presión del lodo de perforación a un valor por encima de la presión de fractura inicial de la formación débil, de manera que se inducen fracturas en la formación débil y se forma un puente sustancialmente impermeable al fluido que comprende el material en macropartículas sólidas y el aditivo o aditivos para controlar la pérdida de fluido en o cerca de la boca de las fracturas, con lo que la formación débil resulta así fortalecida;

(c) continuar entonces la perforación del pozo manteniendo la presión en el mismo por encima de la presión de fractura inicial de la formación débil y por debajo de la presión de desplome de la formación fortalecida.

Queda contemplado que el pozo puede ser perforado empleando un lodo de perforación convencional hasta que la presión en el pozo se aproxime a la presión de fractura inicial de la formación débil. El lodo de perforación convencional se sustituye entonces por (o se convierte en) el lodo de perforación empleado en la etapa (a) antes de aumentar la presión en el pozo a un valor por encima de la presión de fractura inicial de la formación débil. El lodo de perforación convencional se puede convertir en el lodo de perforación empleado en la etapa (a) añadiendo al lodo un aditivo para controlar la pérdida de fluido (ii) hasta que el valor de la pérdida de

fluido HTHP es menor de 2 ml/30 minutos y añadiendo al lodo el material en macropartículas sólidas que efectúa el puente (iii) en una cantidad de al menos 0,5 libras por barril. Convenientemente, el material en macropartículas sólidas que efectúa el puente (iii) se puede añadir a un lodo de perforación que comprende los componentes (i) y (ii) inmediatamente antes de aumentar la presión del lodo de perforación a un valor por encima de la presión de fractura inicial de la formación débil. De este modo, el lodo de perforación que se emplea para perforar el pozo hasta que la presión en el pozo se aproxima a la presión de fractura inicial de la formación débil, puede comprender los componentes (i) y (iii) en ausencia del componente (iii).

La formación débil puede residir en una sección del pozo previamente perforada y/o en la roca que próximamente ha de ser perforada. Cuando la formación débil se encuentra en la roca que ha de ser próximamente perforada, es necesario sustituir todo el fluido del pozo por el fluido de perforación empleado en la etapa (a). De este modo, la formación débil es fortalecida a medida que se perfora el pozo. Cuando la formación débil se encuentra en una sección del pozo previamente perforada, solo es necesario sustituir el fluido del pozo en la proximidad de la formación débil. De este modo, se puede introducir en el pozo, como una "píldora", un lodo de perforación que tiene una alta concentración del material sólido en macropartículas y se puede hacer circular hacia la formación débil en donde la composición concentrada del lodo de perforación es comprimida al interior de la formación débil a una presión por encima de la presión de fractura inicial de la formación débil, de manera que el material en macropartículas puentea las fracturas que son inducidas en la pared del pozo en o cerca de la boca del mismo. Habitualmente, la píldora se comprime al interior de la formación débil sellando la corona anular entre una sarta de perforación y la pared del pozo, subiendo la sarta de

perforación hasta que se encuentra inmediatamente por debajo de la formación débil y bombeando la píldora al interior del pozo por medio de la sarta de perforación hasta que la presión en la proximidad de la formación débil es mayor que la presión de fractura inicial. En general, el pozo se paraliza entonces durante un periodo de hasta 0,5 horas. Después de fortalecer la formación débil, se puede continuar la perforación del pozo empleando un lodo de perforación convencional, siempre que la presión en el pozo, en la proximidad de la formación fortalecida, se mantenga por debajo de la presión de desplome de la formación fortalecida. Adecuadamente, la concentración en la píldora del material que efectúa el puente deberá ser de al menos 50 libras por barril, con preferencia de al menos 80 libras por barril. Queda también contemplado que la "píldora" se puede emplear como un fluido de terminación y puede ser bombeada al interior del pozo con anterioridad a la aplicación de un cemento cuando se entuba el pozo.

En otro aspecto de la presente invención, se proporciona una composición de lodo de perforación que comprende (a) un fluido a base de agua o petróleo, (b) al menos un aditivo para controlar la pérdida de fluido en una concentración eficaz para conseguir una pérdida de fluido a elevada temperatura y elevada presión (HTHP) a partir del lodo de perforación menor de 2 ml/30 minutos y (c) un material de puente en macropartículas sólidas que tiene un diámetro medio de partícula de 25 a 2.000 micrómetros y una concentración de al menos 0,5 libras por barril.

Adecuadamente, la densidad específica del lodo de perforación es del orden de 0,9 a 2,5, con preferencia del orden de 1,0 a 2,0.

Convenientemente, el material sólido en macropartículas que efectúa el puente y que se incluye en el lodo de perforación para puentear las fracturas (de aquí en adelante "material de puente") comprende al menos un sólido en macropartículas

sustancialmente resistente a la trituración, de manera que el material de puente mantiene abiertas las fracturas (grietas y fisuras) que son inducidas en la pared del pozo. Por el término "resistente a la trituración" se quiere dar a entender que el material de puente es físicamente lo suficientemente fuerte para soportar las tensiones de cierre ejercidas sobre el puente de la fractura. Materiales de puente preferidos para añadirse al lodo de perforación incluyen grafito, carbonato cálcico (preferentemente, mármol), dolomita ($MgCO_3 \cdot CaCO_3$), celulosas, micas, materiales consolidantes tales como arenas o partículas cerámicas y combinaciones de los anteriores. Estos materiales son muy inertes y son aceptables desde el punto de vista medioambiental. También queda contemplado que una porción del material de puente puede comprender detritos de perforación que tienen el diámetro medio de partícula deseado del orden de 25 a 2.000 micrómetros.

La concentración del material de puente puede variar con el lodo de perforación empleado y con las condiciones de uso. La concentración ha de ser al menos lo suficientemente grande para que el material de puente puentee rápidamente las fracturas (es decir, grietas y fisuras) que son inducidas en la pared del pozo, pero no deberá ser tan elevada que haga impracticable la circulación del lodo de perforación. Adecuadamente, el material de puente deberá puentear las fracturas que son inducidas en la pared del pozo en un plazo menor de 10 segundos, con preferencia menor de 5 segundos desde que se abre la fractura, de manera que la fractura se mantenga durante un corto periodo. De este modo, el sellado rápido de la fractura mitiga el riesgo de que se propague la fractura. Convenientemente, la concentración del material de puente en el lodo de perforación es de al menos 5 libras por barril, con preferencia de al menos 10 libras por barril, más preferentemente de al menos 15 libras por barril, por ejemplo, al menos 30 libras por

barril. Sin embargo, como se ha indicado anteriormente, cuando el lodo de perforación se emplea en un tratamiento con "píldoras", la concentración del material de puente en macropartículas es adecuadamente de al menos 50 libras por barril, con preferencia de al menos 80 libras por barril.

Adecuadamente, el material de puente presenta unas dimensiones tales que no penetra por los poros de cualquier roca permeable a través de la cual está siendo perforado el pozo. Con preferencia, el material de puente tiene un diámetro medio de partícula del orden de 50 a 1.500 micrómetros, más preferentemente de 250 a 1.000 micrómetros. El material de puente puede comprender partículas sustancialmente esféricas. Sin embargo queda también contemplado que el material de puente puede comprender partículas alargadas, por ejemplo, varillas o fibras. Cuando el material de puente comprende partículas alargadas, la longitud media de las mismas deberá ser tal que las partículas alargadas sean capaces de puentear las fracturas inducidas o cerca de la boca de las mismas. Generalmente, las partículas alargadas tendrán una longitud media del orden de 25 a 2.000 micrómetros, con preferencia de 50 a 1.500 micrómetros y más preferentemente de 250 a 1.000 micrómetros.

El material de puente tiene unas dimensiones tales que forma fácilmente un puente en o cerca de la boca de las fracturas inducidas. Normalmente, las fracturas que son inducidas en la pared del pozo tienen un ancho en la boca del orden de 0,1 a 5 mm. El ancho de la fractura depende, entre otros factores, de la resistencia (rigidez) de la roca de la formación y del grado en el cual se aumenta la presión en el pozo a un valor por encima de la presión de fractura inicial de la formación durante la etapa de inducción de la fractura (b) del método de la presente invención (en otras palabras, el ancho de la fractura depende de la diferencia de presión entre el lodo de perforación y la presión de fractura inicial de la formación durante la etapa de

inducción de las fracturas). Es preferible que al menos una porción del material de puente, preferentemente una porción principal del material de puente, tenga un diámetro de partícula que se aproxime al ancho de la boca de la fractura. Con preferencia, el material de puente tiene una distribución de tamaño de partícula amplia (polidispersa).

Es necesario mantener el material de puente en suspensión en el lodo de perforación. En general, el lodo de perforación es reciclado al pozo después de separar prácticamente la totalidad de los detritos de perforación. Los detritos de perforación pueden ser separados empleando tamices como resulta bien conocido para el experto en la materia. Normalmente, el lodo de perforación se filtra empleando un tamiz de tamaño de malla 200 (serie de tamices US) que retiene partículas que tienen un tamaño mayor de 74 micrómetros. Sin embargo, en el método de la presente invención, es necesario filtrar el lodo empleando un tamiz más basto con el fin de evitar la separación del lodo de cantidades importantes del material de puente. Convenientemente, el lodo de perforación se filtra empleando un tamiz de malla 35 (serie de tamices US) que retiene partículas que tienen un tamaño mayor de 500 micrómetros. Sin embargo, si la reología del lodo se deteriora a través de la acumulación en el lodo de detritos finos de la perforación, puede ser necesario emplear tamices de malla más fina durante un corto periodo de tiempo. También queda contemplado que pueden emplearse métodos de separación que permitan la retención de los sólidos de material de puente pero que puedan separar del lodo de perforación una porción principal de los detritos, con preferencia prácticamente todos los detritos. En particular, los detritos se pueden separar del lodo de perforación en base a diferencias en las densidades de los detritos y de las partículas de puente, por ejemplo, empleando centrífugas o hidrociclones. Con el fin de mantener la

concentración del material de puente en el valor deseado en el lodo de perforación y/o mantener el valor de pérdida de fluido del lodo de perforación por debajo de 2 ml/30 minutos, puede ser necesario introducir material de puente nuevo y/o aditivos nuevos para controlar la pérdida de fluido, respectivamente, en el lodo de perforación en circulación. Alternativa o adicionalmente, se puede añadir lodo de perforación nuevo, bien de forma continua o bien de forma intermitente, al lodo de perforación que está circulando por el pozo.

El lodo de perforación tiene un valor de pérdida de fluido HTHP menor de 2 ml/30 minutos, con preferencia menor de 1 ml/30 minutos, más preferentemente menor de 0,5 ml/30 minutos, por ejemplo de 0,1 a 0,3 ml/30 minutos. Como resultará evidente para el experto en la materia, dichos valores de pérdida de fluido ultra-bajos se pueden conseguir incorporando en el lodo de perforación al menos un aditivo para controlar la pérdida de fluido. Sin que ello suponga una limitación a una teoría en particular, se cree que el aditivo o aditivos para controlar la pérdida de fluido se acumulará sobre el material sólido en macropartículas que puentea las fracturas en o cerca de la boca de las mismas, formando con ello una masa inmóvil impermeable al fluido. Cuando el material sólido en macropartículas que efectúa el puente es poroso, los aditivos para controlar la pérdida de fluido pueden entrar también en los poros del material de puente para sellar los poros.

Aditivos adecuados para controlar la pérdida de fluido que pueden incorporarse en el lodo de perforación de la presente invención incluyen polímeros orgánicos de origen natural o sintético. Polímeros adecuados incluyen almidón o almidones químicamente modificados; derivados de celulosa tales como carboximetilcelulosa y celulosa polianiónica (PAC); goma guar y goma de xantano; homopolímeros y copolímeros de monómeros seleccionados del grupo consistente en

ácido acrílico, acrilamida, ácido archilamido-2-metilpropanosulfónico (AMPS), ácido estirenosulfónico, N-vinilacetamida, N-vinilpirrolidona y N,N-dimetilacrilamida, en donde el copolímero tiene un peso molecular medio en número de 100.000 a 1.000.000 y con preferencia de 200.000 a 500.000; asfaltos (por ejemplo, asfaltos sulfonados); gilsonita; lignito y sus derivados, ácido húmico; lignina y sus derivados tales como ligninsulfonatos o ligninsulfonatos poliméricos condensados; y combinaciones de los anteriores. Estos aditivos poliméricos son particularmente adecuados para utilizarse en lodos de perforación a base de petróleo. Como alternativa o, en adición, al empleo de dichos aditivos poliméricos, la pérdida de fluido del lodo de perforación de la presente invención se puede reducir añadiendo al lodo de perforación partículas finamente dispersas tales como arcillas (por ejemplo, ilita, caolinina, bentonita o sepiolita). Adecuadamente, las partículas finamente dispersas tienen un tamaño medio de partícula menor de 10 micrómetros, con preferencia menor de 5 micrómetros, por ejemplo de 1 micrómetro aproximadamente. Preferentemente, el lodo de perforación contiene un intervalo uniforme/continuo de tamaños de partícula que oscila desde 1 micrómetro aproximadamente para los aditivos reductores de la pérdida de fluido a un diámetro medio de partícula del material de puente de hasta 2.000 micrómetros, es decir, presenta una distribución del tamaño de partícula amplia (polidispersa).

Queda contemplado que un lodo de perforación a base de petróleo puede contener una cantidad importante de una fase acuosa discontinua dispersada en una fase oleosa continua por medio de al menos un emulsionante (una emulsión de agua en aceite). El valor de la pérdida de fluido de dichos lodos de perforación puede variar en función de la relación de petróleo a agua y de la naturaleza del emulsionante o emulsionantes utilizados para formar la emulsión de agua en aceite (y

por tanto del tamaño de las gotitas dispersas de agua). Con preferencia, el contenido en agua del lodo de perforación es del orden de 80:20 a 50:50, más preferentemente de 70:30 a 55:45. Los emulsionantes preferidos incluyen imidazolinas, ácidos grasos y combinaciones de los mismos.

Lodos de perforación a base de petróleo que presentan una pérdida de fluido ultra-baja, particularmente preferidos, se describen en SPE 77446, "Towards Zero Fluid Loss Oil Based Muds", M. Aston, P. Mihalik, J. Tunbridge y S. Clarke, publicado en 2002.

La eficacia del método de la presente invención ha quedado demostrada en condiciones tanto de laboratorio como del campo, como se expone en los siguientes ejemplos.

Ejemplo 1

Se evaluaron en el laboratorio formulaciones de lodos a base de petróleo inyectando diferentes lodos de perforación en una fractura modelo (como se describe en SPE/IADC 87130, "Drilling Fluids for Wellbore Strengthening", 2-4 Marzo 2004, M.S. Aston et al). La fractura modelo se formó a partir de dos piezas de roca de configuración rectangular (de piedra arenisca "Ohio" con una permeabilidad de 0,3 miliDarcy). Cada pieza de roca tenía unas dimensiones aproximadas de 5 cm de ancho x 20 cm de longitud x 1 cm de profundidad. Las dos piezas de roca fueron emparedadas de forma conjunta para crear una fractura que tiene una abertura de boca de 1 mm, conificando la abertura de la fractura a 0,5 mm en el extremo distante de la misma (extremidad de la fractura). Se proporcionó una válvula en la salida de la extremidad de la fractura, de manera que la extremidad de la fractura pudiera ser abierta o sellada. El emparedado de roca se colocó en un apoyo construido para ese fin, el cual se soportó en una estructura de carga dentro de una cuba de ensayo. El

ancho de la fractura se mantuvo constante empleando separadores fijos. Se midió la presión de fluido dentro de la fractura justo en el interior de la boca de la fractura empleando un transductor de presión. Inicialmente, la fractura y los espacios porosos de la roca se llenaron con un fluido limpio (agua) y el sistema se calentó a una temperatura de 60° C. Se aplicó una presión de alrededor de 100 psi para comprimir cualquier aire presente en el sistema. Se inyectó entonces lodo de perforación a una presión de 400 psi al interior de la boca de la fractura manteniendo abierta la extremidad de la fractura (para proporcionar una presión diferencial de un lado a otro de la fractura de 300 psi). Después de 3 minutos, se cerró la salida de la extremidad de la fractura empleando la válvula, de manera que se pudiera acumular presión dentro de la fractura (nota: la fuerza de impulsión inicial para la formación del puente en la boca de la fractura fue para evitar pérdidas de fluido a través de la extremidad de la fractura). Se aumentó entonces la presión de inyección gradualmente a 2.000 psi. Una presión baja medida en el transductor de presión indicó un sellado eficaz en la boca de la fractura.

Los resultados ofrecidos en la siguiente tabla 1 comparan las presiones medidas justo dentro de la boca de la fractura para diferentes lodos de perforación utilizados en el procedimiento de ensayo anterior. La presión justo en el interior de la boca de la fractura se midió después de alcanzarse un valor constante en cada presión de inyección.

Tabla 1 - Eficacia de lodos de perforación en el sellado de una fractura modelo

Sistema de lodo		Presión justo dentro de la boca de la fractura, medida después de diferentes presiones de inyección del lodo (IP) en psi		
		IP 400	IP 1.000	IP 2.000
Lodo 1 (Comparativo)	Mezcla A de lodo base más material de puente en macropartículas; pérdida de fluido HTHP API = 3 ml/30 min a una temperatura de 60° C	300	900	1.900
Lodo 2	Como el lodo 1, pero conteniendo 5 lb/bbl Pliolita, pérdida de fluido HTHP API = 0,3 ml/30 min a una temperatura de 60° C	0	30	1.900
Lodo 3	Mezcla B de lodo base más material de puente en macropartículas más 5 lb/bbl Pliolita (14,3 kg/m^3), pérdida de fluido HTHP API = 0,1 ml/30 min a una temperatura de 60° C	0	0	0

El lodo 2 forma un sellado más eficaz que el lodo 1 (Comparativo). Esto se consiguió reduciendo la pérdida de fluido HTHP API del sistema de lodo desde 3 ml/30 minutos a 0,3 ml/30 minutos. El lodo 3 consiguió un sellado total en la boca de la fractura empleando una mezcla mejorada de material de puente en macropartículas en un lodo que tiene una pérdida de fluido HTHP API de 0,1 ml/30 minutos.

La formulación para el lodo base empleado en los ensayos anteriores fue como sigue:

Aceite mineral:	0,517 bbls
Versamul™ (emulsionante de MI)	4,7 lb/bbl
Versawet™ (agente humectante de MI)	7 lb/bbl
Geltone™ (organoarcilla de Halliburton)	6 lb/bbl

Cal	5,25 lb/bbl
Cloruro cálcico	17,6 lb/bbl
Agua	0,346 lb/bbl
Barita (sulfato de bario)	50 lb/bbl
Hymod Prima Clay (sólidos de perforación simulados)	4,5 lb/bbl

El lodo 1 es el lodo base que contiene los siguientes materiales de puente en macropartículas (mezcla A):

Baracarb™ 150:	46 lb/bbl
Baracarb™ 600:	9,3 lb/bbl

El lodo 2 es como el lodo 1 pero con la adición de 5 lb/bbl Pliolite® DF-01 (aditivo para el control de la pérdida de fluido suministrado por Goodyear).

El lodo 3 es el lodo base conteniendo 5 lb/bbl Pliolite® DF-01 y los siguientes materiales de puente en macropartículas (mezcla B):

Baracarb™ 150:	18lb/bbl
Baracarb™ 600:	18 lb/bbl
Steelseal™:	15 lb/bbl

Baracarb™ 150, Baracarb™ 600 y Steelseal™ se obtuvieron en Halliburton. Baracarb™ 150 y Baracarb™ 600 son carbonatos de calcio con un diámetro medio de partícula de 150 micrómetros y 600 micrómetros, respectivamente. Steelseal™ es un carbón grafítico suministrado por Halliburton, con un intervalo de tamaño medio de aproximadamente 400 micrómetros.

Ejemplo 2

Se llevó a cabo un ensayo práctico en tierra en el estanque de Arkoma, USA, para determinar si el método de la presente invención podía aumentar o no la resistencia de la fractura en una formación de pizarra. El pozo fue un pozo vertical con un entubado de 9 5/8". Se realizó un ensayo de obturación prolongada (tratamiento de la píldora por compresión) en 10 pies de formación de pizarra

expuesta (agujero abierto) justo por debajo de la zapata del entubado de 9 5/8". En este ensayo, se emplearon procedimientos de "obturación" normalizados en donde la corona anular estaba cerrada mientras se bombeaba lodo al interior del pozo. Inicialmente, estaba presente en el pozo un lodo a base de diesel normalizado y este lodo fue bombeado al interior del pozo a una velocidad de 0,25 bbls/minuto hasta que se presentó el desplome de la formación de pizarra expuesta.

La figura 1 ilustra la curva de presión de obturación prolongada para el lodo a base de diesel normalizado (curva 1). La formación de pizarra se fracturó a 1.200 psi aproximadamente, en cuyo momento se detuvo el bombeo del lodo de perforación a base de diesel normalizado. para reducir al mínimo el crecimiento de la fractura. La presión se estabilizó en 800 psi. que es la presión de propagación de las fracturas determinada por el estado de tensión en campo lejano. El exceso de presión en el pozo fue purgado (de nuevo a presión hidrostática), de manera que se cerraron las fracturas y se repitió entonces el procedimiento de obturación bombeando una píldora de un lodo de acuerdo con la presente invención (de aquí en adelante "lodo del inventor") al interior del pozo, también a una velocidad de 0,25 bbls/minuto. La figura 1 ilustra además la curva de obturación prolongada para el lodo del inventor (curva 2). Las fracturas inducidas en la pared del pozo abierto son puenteadas y selladas por las partículas de puente y aditivos reductores de la pérdida de fluido del lodo del inventor y la presión de desplome de la formación fortalecida asciende a un valor por encima de 2.000 psi antes de que se desplome el sellado. Se trata esto de un incremento de alrededor de 850 psi en la presión de desplome de la formación en comparación con el estado original de la formación de pizarra, equivalente a un peso de lodo de 5,4 libras por galón (ppg).

El valor de pérdida de fluido HTHP API para el lodo del inventor empleado

en la prueba práctica fue de 0.45 ml a una temperatura de 115° F (temperatura en el fondo del pozo), mientras que el lodo a base de diesel normalizado tenía una pérdida de fluido HTHP API de 10 ml a una temperatura de 250° F. El lodo del inventor se preparó añadiendo sólidos de puente de carbonato cálcico, sólidos de puente de material grafítico y aditivos reductores de la pérdida de fluido al lodo a base de diesel normalizado de acuerdo con la presente invención. El tamaño de los sólidos de puente osciló entre 10 y 800 micrómetros y dichos sólidos se añadieron en una cantidad de 80 libras por barril . El lodo a base de diesel normalizado original tenía un peso de lodo de 9,0 ppg y estaba libre de sólidos de puente incorporados.

REIVINDICACIONES

1.- Un método para reducir el desplome de una formación durante la perforación de un pozo, caracterizado porque comprende:

(a) hacer circular por el pozo un lodo de perforación que comprende (i) un fluido a base de agua o petróleo, (ii) al menos un aditivo para controlar la pérdida de fluido en una concentración eficaz para conseguir una pérdida de fluido a elevada temperatura y elevada presión (HTHP) a partir del lodo de perforación menor de 2 ml/30 minutos, en donde la pérdida de fluido HTHP se determina empleando un ensayo HTHP de acuerdo con las especificaciones del American Petroleum institute (API), como se describe en API Recommended Practice 13B-2 Tercera Edición, Febrero 1998, Sección 5.2.1 a 5.2.3 o Recommended Practice 13B-1 Segunda Edición, Septiembre 1997, Sección 5.3.1 a 5.3.2, y (iii) un material de puente en macropartículas sólidas que tiene un diámetro medio de partícula de 25 a 2.000 micrómetros y una concentración de al menos 0,5 libras por barril;

(b) aumentar la presión en el pozo a un valor por encima de la presión de fractura inicial de la formación, de manera que se inducen fracturas en la formación y se forma un puente sustancialmente impermeable al fluido que comprende el material en macropartículas sólidas y el aditivo o aditivos para controlar la pérdida de fluido en o cerca de la boca de las fracturas, con lo que la formación resulta así fortalecida;

(c) continuar entonces la perforación del pozo manteniendo la presión en el mismo por encima de la presión de fractura inicial de la formación y por debajo de la presión de desplome de la formación fortalecida.

2.- Un método según la reivindicación 1, caracterizado porque la presión en el pozo en la etapa (c) se mantiene en al menos 300 psi por encima de la presión de fractura inicial de la formación y por debajo de la presión de desplome de la

formación fortalecida.

3.- Un método según la reivindicación 1 o 2, caracterizado porque el material de puente en macropartículas sólidas se añade a un lodo de perforación en circulación que tiene un valor de pérdida de fluido HTHP menor de 2 ml/30 minutos antes de aumentar la presión en el pozo a un valor por encima de la presión de fractura inicial de la formación.

4.- Un método según cualquiera de las reivindicaciones anteriores, caracterizado porque la formación fortalecida es una formación agotada.

5.- Un método según cualquiera de las reivindicaciones 1 a 3, caracterizado porque la formación fortalecida es una formación débil en una sección de pozo previamente perforada.

6.- Un método según cualquiera de las reivindicaciones anteriores, caracterizado porque el lodo de perforación tiene un valor de pérdida de fluido HTHP menor de 1 ml/30 minutos, con preferencia menor de 0,5 ml/30 minutos.

7.- Un método según cualquiera de las reivindicaciones anteriores, caracterizado porque la concentración de material de puente en macropartículas sólidas en el lodo de perforación en circulación es de al menos 10 libras por barril, con preferencia de al menos 15 libras por barril.

8.- Un método según cualquiera de las reivindicaciones anteriores, caracterizado porque el lodo de perforación se recicla al pozo después de separar del mismo el material que tiene un tamaño mayor de 500 micrómetros empleando un tamiz de malla 35 (serie de tamices US).

9.- Un método según la reivindicación 8, caracterizado porque se añade material de puente nuevo en macropartículas sólidas al lodo de perforación antes de reciclar el lodo de perforación al pozo.

10.- Un método según cualquiera de las reivindicaciones 1 a 7, caracterizado porque el lodo de perforación se recicla al pozo después de separar del mismo los detritos de perforación empleando una centrífuga o hidrociclón.

11.- Un método según la reivindicación 5 o 6, caracterizado porque se hace circular por la formación débil una píldora del lodo de perforación que tiene una concentración de material de puente en macropartículas sólidas de al menos 50 libras por barril y se comprime dicha píldora dentro de la formación débil, manteniendo la presión en el pozo en la proximidad de la formación débil en una valor por encima de la presión de fractura inicial de la formación débil.

12.- Una composición de lodo de perforación, caracterizada porque comprende (a) un fluido a base de agua o petróleo, (b) al menos un aditivo para controlar la pérdida de fluido en una concentración eficaz para conseguir una pérdida de fluido a elevada temperatura y elevada presión (HTHP) a partir del lodo de perforación menor de 2 ml/30 minutos. en donde la pérdida de fluido HTHP se determina empleando un ensayo HTHP de acuerdo con las especificaciones del American Petroleum institute (API). como se describe en API Recommended Practice 13B-2 Tercera Edición, Febrero 1998, Sección 5.2.1 a 5.2.3 o Recommended Practice 13B-1 Segunda Edición, Septiembre 1997, Sección 5.3.1 a 5.3.2, y (c) un material de puente en macropartículas sólidas que tiene un diámetro medio de partícula de 50 a 1.500 micrómetros y una concentración de al menos 0,5 libras por barril.

13.- Una composición de lodo de perforación según la reivindicación 12, caracterizada porque tiene una densidad específica del orden de 0,9 a 2,5.

14.- Una composición de lodo de perforación según la reivindicación 12 o 13, caracterizada porque el material de puente en macropartículas sólidas comprende

al menos un sólido en macropartículas sustancialmente resistente a la trituración y seleccionado del grupo consistente en grafito, carbonato cálcico (preferentemente mármol), dolomita, celulosas, micas, arena y partículas cerámicas.

15.- Una composición de lodo de perforación según cualquiera de las reivindicaciones 12 a 14, caracterizada porque la concentración del material de puente en macropartículas sólidas es de al menos 10 libras por barril, con preferencia de al menos 15 libras por barril.

16.- Una composición de lodo de perforación según cualquiera de las reivindicaciones 12 a 15, caracterizada porque el material de puente en macropartículas sólidas tiene un diámetro medio de partícula del orden de 50 a 1.500 micrómetros.

17.- Una composición de lodo de perforación según cualquiera de las reivindicaciones 12 a 16, caracterizada porque tiene un valor de pérdida de fluido HTHP menor de 1 ml/30 minutos, con preferencia menor de 0,5 ml/30 minutos.

18.- Una composición de lodo de perforación según cualquiera de las reivindicaciones 12 a 17, caracterizada porque el aditivo o aditivos para controlar la pérdida de fluido se eligen entre polímeros orgánicos de origen natural o sintético y arcillas finamente dispersas.

RESUMEN

Un método para reducir el desplome de una formación durante la perforación de un pozo, cuyo método comprende: (a) hacer circular por el pozo un lodo de perforación que comprende (i) un fluido a base de agua o petróleo, (ii) al menos un aditivo para controlar la pérdida de fluido en una concentración eficaz para conseguir una pérdida de fluido a elevada temperatura y elevada presión (HTHP) a partir del lodo de perforación menor de 2 ml/30 minutos y (iii) un material de puente en macropartículas sólidas que tiene un diámetro medio de partícula de 25 a 2.000 micrómetros y una concentración de al menos 0,5 libras por barril; (b) aumentar la presión en el pozo a un valor por encima de la presión de fractura inicial de la formación, de manera que se inducen fracturas en la formación y se forma un puente sustancialmente impermeable al fluido que comprende el material en macropartículas sólidas y el aditivo o aditivos para controlar la pérdida de fluido en o cerca de la boca de las fracturas, con lo que la formación resulta así fortalecida; (c) continuar entonces la perforación del pozo manteniendo la presión en el mismo por encima de la presión de fractura inicial de la formación y por debajo de la presión de desplome de la formación fortalecida.

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CONSULADO GENERAL DE COLOMBIA
SUITE 14, 140 PARK LANE, LONDON W1Y 3AA
TELEPHONE 0171-495 4233 • TELEFAX: 0171-495 4441

El suscrito Cónsul General de Colombia en Londres, vistos los documentos presentados ante este Despacho,

CERTIFICA

Que, RICHARD JOHN SAVILLE, Notario Público de Londres, Inglaterra, Gran Bretaña, autenticó la firma del documento precedente y su firma se encuentra registrada en este Consulado General.

Que, BP EXPLORATION OPERATING COMPANY LIMITED, es una Sociedad que se encuentra debidamente establecida en Londres, Inglaterra y cumple con su objeto social de acuerdo con las leyes de este país.

Que MICHAEL JOHN WILSON en su calidad de Apoderado Legal, de la mencionada sociedad, otorga el Poder precedente y su firma se encuentra autenticada por RICHARD JOHN SAVILLE, Notario Público con ejercicio en Londres, Inglaterra, Gran Bretaña.

El Cónsul General no asume responsabilidad por el contenido del mencionado documento.

Dado en Londres, Gran Bretaña, a los Once (11) días del mes de Diciembre de mil novecientos noventa y seis (1996).

Certificación No.12/1314
Derechos: U$ 106,00 CANCELADOS

OSCAR LOPEZ PULECIO
Cónsul General

CONSULADO GENERAL DE COLOMBIA
LONDRES

HUGO NAVARRO ALVAREZ
TRADUCTOR E. INTERPRETE OFICIAL
Res. 1876 Minjusticia 1987

Esta copia coincide con el original que tuve a la vista.
Bogotá, D.C.
12 NOV 2003
AGUSTIN MORALES RIVEIRA
NOTARIO CUARENTA Y UNO

Esta copia coincide con el original que tuve a la vista.
Bogotá, D.C.
12 NOV 2003
AGUSTIN MORALES RIVEIRA
NOTARIO CUARENTA Y UNO

008505
CUYA FIRMA APARECE EN EL DOCUMENTO DESEMPEÑA ... ES INDICADAS

NO SE ASUME RESPONSABILIDAD DEL TEX...
97 JAN 31 AM 10: 40
JEFE DE LEGALIZACIONES
SANTAFE DE BOGOTA D.C.

43

SAVILLE & Co

NOTARIES PUBLIC

2 Throgmorton Avenue
London EC2N 2ER
Telephone: 0171-920 0000
Facsimile: 0171-920 0088
DX 33870 Finsbury Square

Richard Saville

Ian Campbell

Yo el infrascrito RICHARD JOHN SAVILLE Notario Público con vecindad y ejercicio en la Ciudad de Londres, Inglaterra, por Real Autoridad debidamente facultado y jurado CERTIFICO ser auténtica la firma de Don MICHAEL JOHN WILSON, de cuya identidad doy fe, puesta al pie del instrumento anexo por el susodicho Señor Michael John Wilson, apoderado debidamente autorizado de la sociedad denominada BP EXPLORATION OPERATING COMPANY LIMITED de Londres, Inglaterra, según una escritura de poder con fecha 24 de abril de 1996 que ha sido exhibida ante mí el susodicho notario;

Y ADEMÁS CERTIFICO que la sede social de la sociedad está situada en Britannic House, 1 Finsbury Circus, Londres, EC2M 7BA, Inglaterra, y que la sociedad está organizada y se halla existente conforme a las leyes de Inglaterra y Gales.

EN FE Y TESTIMONIO DE LO CUAL expido el presente que firmo y sello con el de mi oficio en Londres antedicho el día diez de diciembre de mil novecientos noventa y seis.

HUGO NAVARRO ALVAREZ
TRADUCTOR E. INTERPRETE OFICIAL
Res. 1876

Esta copia coincide con el original que tuvo a la vista.
Bogotá, D.C.
12 NOV 2003
AGUSTIN MORALES RIVEIRA
NOTARIO CUARENTA Y UNO

8704

Clarke, Modet & Co. Colombia, Ltda.

Carrera 11, Nº 93-53 , Of. 404 - Santa Fé de Bogotá, Colombia

PODER

Yo (nosotros), abajo firmante(s)

en mi (nuestro) caracter de representante(s) legales de

una sociedad organizada y existente de acuerdo con las leyes de

y en actual cumplimiento de su objeto social, con domicilio en

por el presente instrumento confiero (conferimos) poder especial a favor de DILIA MARIA RODRIGUEZ D'ALEMAN, tp. 20824 y CLAUDIA LUCIA CARO RAMIREZ, tp. 38446, con domicilio en Santa Fé de Bogotá, Colombia, para que actuando en su orden en nombre del (de la) otorgante la (la) representen ante cualquier entidad, autoridad y/o persona, especialmente ante las del orden Administrativo, Contencioso Administrativo, Judicial, Tribunales de Arbitramento y/o cualquier otro en lo referente a los siguientes asuntos:

1) Solicitar, tramitar, obtener y/o registrar cualquiera de las modalidades de Propiedad Industrial, tales como: patentes de invención, modelos de utilidad; diseños industriales, variedades vegetales; marcas, lemas, nombres y enseñas comerciales y denominaciones de origen; así como sus renovaciones, prórrogas, transferencias, cambios de nombre y/o domicilio, contratos y licencias.
2) Solicitar, tramitar, obtener y/o registrar derechos de autor, en cualquiera de sus presentaciones así como la protección de secretos industriales y know-how.
3) Solicitar, tramitar, obtener y/o registrar registros sanitarios, permisos y/o licencias de funcionamiento; así como sus renovaciones o prórrogas, transferencias, cambios de nombre y/o domicilio, contratos y licencias.
4) Ejercer acciones de oposición, observación, reclamos, reconsideración, reposición, apelación, cancelación administrativa o judicial, nulidad, protección al consumidor, concesión de licencias, protección de secretos industriales y demás acciones y recursos relacionados con derechos derivados de los asuntos arriba indicados y en contra de la competencia desleal, acciones derivadas de la obtención o explotación de licencias, acciones de indemnización de perjuicios. También podrá(n) intervenir en juicios civiles, comerciales, penales, contencioso-administrativos, tutelas y de policía; en acciones o juicios promovidos por el (la) mandante o en contra el (ella) .
5) En el ejercicio de este mandato los mandatarios arriba mencionados quedan facultados para: conciliar, cancelar, transigir, comprometer en árbitros, desistir, recibir y tomar posesión de la cosa objeto de litigio y renunciar o desistir a derechos concedidos o en curso de concesión, admitir los hechos del proceso.
6) Ratificar o no la agencia oficiosa.
7) Así mismo faculto (facultamos) a los mencionados apoderados para recibir notificaciones y designar apoderados judiciales o extrajudiciales, sustituir el presente poder y revocar las sustituciones que hicieren.

Dado y firmado en

a los días de de

POWER OF ATTORNEY

I (we), the undersigned

Michael John WILSON

legal representative(s) of

BP Exploration Operating Company Limited

an organization existing under the laws of

England

and in present execution of its business activity, domiciled at

Britannic House, 1 Finsbury Circus, London EC2M 7BA, United Kingdom

do hereby grant POWER OF ATTORNEY to DILIA MARIA RODRIGUEZ D'ALEMAN, tp. 20824 and CLAUDIA LUCIA CARO RAMIREZ, tp. 38446, residing in Santa Fé de Bogotá, Colombia, to act in the order of their appointment in behalf of grantor before any entity, authority and/or natural or juridical person, specially before those Administrative, Administrative-Contentious, Judicial, arbitration courts, and/or any other, in all matters concerning the following:

1) To apply, process, obtain and/or register any of the modalities of Industrial Property, such as: Patents of Invention, Utility Models; Designs, vegetal varieties; Marks, Slogans, Trade Names and emblems and appellations of Origin; as well as their renewals, extensions, assignments, changes of name and/or domicile, agreements and licenses.
2) To apply, process, obtain and/or register copyrights of any kind as well as protection of industrial secrets or know-how.
3) To apply, process, obtain and/or register sanitary registrations, operating authorizations and/or licenses; as well as their renewals or extentions, assignments, changes of name and/or domicile, agreements and licenses.
4) To bring actions of opposition, observations, claims, reconsideration, appeal or legal remedies, cancellations, nullity, protection to the consumer, granting of licenses, protection of trade secrets and other actions related with rights derived from the above-mentioned matters and against the unfair competition, actions resulting from the obtention or exploitation of licenses, recovering damages actions. They can also intervene or participate in Civil, Commercial, Criminal or Contentious-Administrative Trials; the actions for writ mandamus, police actions; in actions, lawsuits or litigations instituted by the grantor or against him.
5) To the effect of this mandate the above-named proxy are empowered to: conciliate, cancel, settle, submit to arbitration, withdraw and to receive and take possession of the litigation related objet and waive or renounce the rights granted or in process of granting, admit the facts of the case.
6) To ratify or not the officious agency.
7) I (we) hereby appoint the afore mentioned attorneys with powers to receive notifications and to designate judicial and extrajudicial attorneys, substitute this Power of Attorney and to revoke such sustitutions.

Granted and signed at Sunbury on Thames, United Kingdom on this 6th day of December 1996

for BP Exploration Operating Company Limited

M J Wilson

Michael John WILSON Firma / signature By Power of Attorney

Esta copia coincide con el original
12 NOV 2003
HUGO NAVARRO ALZATE
TRADUCTOR OFICIAL
Res. 1
AGUSTIN MORALES RIVEIRA
NOTARIO CUARENTA Y UNO

CERTIFICADO NOTARIAL (SOCIEDADES)

(Poderes otorgados en: El Salvador, Estados Unidos, Mexico y Venezuela)

A los días del mes de de , el Notario que suscribe DA FE de que:

1. _____
(nombre de la persona que firma el poder)

mayor de edad y domiciliado en_____

_____ firmó de su puño y letra el documento que antecede.

2. Conoce al (a la) otorgante y que este (a) está legalmente capacitado para el otorgamiento.
3. El otorgante ha firmado el referido documento en su

caractar de_____

de la persona jurídica _____

_____

4. La citada persona jurídica con sede en _____

_____

está legalmente constituida, que tiene actualmente existencia legal y que el acto para el cual se ha otorgado este poder está comprendido entre los que constituyen su objeto social.
5. El otorgante tiene efectivamente la representación que obstenta, que esta es legítima y que está facultado para otorgar este poder.
6. las anteriores certificaciones de los puntos 3, 4 y 5, me constan porque he tenido a la vista los siguientes documentos auténticos:

_____
Notario Público

NOTA: A continuación de lo anterior, el Consul de Colombia debe autenticar la firma del Notario Público.

NOTARIAL CERTIFICATE (CORPORATIONS)

(Powers of attorney granted in: El Salvador, Mexico, U.S.A. and Venezuela)

This day of the undersigned Notary CERTIFIES that:

1. _____
(name of the person who signs the power of attorney)

of legal age and domiciled in_____

_____ set his hand on the foregoing document.

2. The grantor is to him personally known and that he/she has legal capacity to execute the document.
3. The grantor has executed the foregoing document in

his capacity of_____

of the juridical person_____

_____

4. The mentioned juridical person with place of business

in_____

is duly organized, has actual legal existence and that the purposes for which the power of attorney is granted are within the scope of its corporate purposes.
5. The grantor has in f act the referred quality and that his/her representation is legal and that he/she is empowered to grant this power of attorney.
6. I have based the above certifications 3, 4 and 5, on the following authentic documents which for such purpose were exhibited to me:

_____
Notary Public

NOTA: Then the Colombian Consul must legalize the signature of the Notary Public.

CERTIFICADO NOTARIAL (INDIVIDUOS)

A los días del mes de de , el Notario que suscribe DA FE de que:

1. _____
(nombre de la persona que firma el poder)

mayor de edad y domiciliado en_____

_____ firmó en su presencia el documento que antecede, conoce al otorgante y que este está legalmente capacitado para el otorgamiento.

_____
Notario Público

NOTA: A continuación de lo anterior, el Consul de Colombia debe autenticar la firma del Notario Público.

Para todos los demás paises el Señor Consul de Colombia debe expedir una certificacion consular dejando constancia 1) de la existencia legal de la sociedad, 2) de que esta ejerce actualmente su objeto social, y 3) de que la persona o personas que otorgan el poder están facultadas para hacerlo, dejando constancia así mismo de que tuvo a la vista las pruebas que acrediten tales circunstancias.

HUGO NAVARRO ALVAREZ
TRADUCTOR E INTERPRETE OFICIAL
Res. 1776 Ministerio de ...

NOTARIAL CERTIFICATE (INDIVIDUALS)

On this day of the undersigned Notary CERTIFIES that:

1. _____
(name of the peson who signs the Power of Attorney)

of legal age and domiciled at_____

_____ signed in his presence the foregoing document, the grantor is to him personally known and that he/she has legal capacity to execute the document.

_____
Notary Public

NOTA: Then the Colombian Consul must legalize the signature of the Notary Public.

For all other countries the Colombian Consul must issue a consular certification stating 1) the legal existence of the corporation, 2) that the corporate purposes are actually being accomplished , 3) that the person or persons who grant this Power of Attorney are empowered to do it. The Consul will certify also that the documents evidencing those circunstances were exhibited to him.

AGUSTIN MORALES RIVERA
NOTARIO CUARENTA Y UNO
2003

TRADUCCION OFICIAL No. 260/97 de las Legalizaciones que se encuentran a continuación de un Poder otorgado por Michael John Wilson, Representante Legal de la sociedad BP Exploration Operating Company Limited, organizada de acuerdo con las leyes de Inglaterra y residente en Londres, Reino Unido, a favor de las doctoras DILIA MARIA RODRIGUEZ D'ALEMAN y CLAUDIA LUCIA CARO RAMIREZ, de Santafé de Bogotá, D.C., Colombia, del Inglés al Español, las cuales para su identificación se sellan con el Sello del Traductor al mismo tiempo que la presente.

ANEXOS. El Poder arriba mencionado, Certificación Notarial, Legalización ante el Consulado de Colombia en Londres, Inglaterra, Autenticación por el Ministerio de Relaciones Exteriores de Colombia .

SAVILLE & Co.
Notarias Públicas

CERTIFICACION EN ESPAÑOL

SELLO EN RELIEVE ADHERIDO

EN ESPAÑOL: La Legalización ante el Consulado de Colombia en Londres, Inglaterra de fecha 11 de Diciembre de 1996; Autenticación hasta por el Ministerio de Relaciones Exteriores de Colombia, bajo el número 088505 de fecha 31 de Enero de 1997.

ES TRADUCCION FIEL Y COMPLETA DE LAS LEGALIZACIONES CONTENIDAS DENTRO DEL DOCUMENTO ANEXO TERMINADA ESTE 5 DE MAYO DE 1997.

SELLO DEL TRADUCTOR

HUGO NAVARRO ALVAREZ
TRADUCTOR E. INTERPRETE OFICIAL
Res. 1878 Minjusticia 1989

Esta copia coincide con el original que tuve a la vista.
Bogotá, D.C.
12 NOV 2003
AGUSTIN MORALES RIVEIRA
NOTARIO CUARENTA Y UNO

TRADUCCION OFICIAL No. 260/97 de las Legalizaciones que se encuentran a continuación de un Poder otorgado por Michael John Wilson, Representante Legal de la sociedad BP Exploration Operating Company Limited, organizada de acuerdo con las leyes de Inglaterra y residente en Londres, Reino Unido, a favor de las doctoras DILIA MARIA RODRIGUEZ D'ALEMAN y CLAUDIA LUCIA CARO RAMIREZ, de Santafé de Bogotá, D.C., Colombia, del Inglés al Español, las cuales para su identificación se sellan con el Sello del Traductor al mismo tiempo que la presente.

ANEXOS. El Poder arriba mencionado, Certificación Notarial, Legalización ante el Consulado de Colombia en Londres, Inglaterra, Autenticación por el Ministerio de Relaciones Exteriores de Colombia .

SAVILLE & Co.
Notarias Públicas

CERTIFICACION EN ESPAÑOL

SELLO EN RELIEVE ADHERIDO

EN ESPAÑOL: La Legalización ante el Consulado de Colombia en Londres, Inglaterra de fecha 11 de Diciembre de 1996; Autenticación hasta por el Ministerio de Relaciones Exteriores de Colombia, bajo el número 088505 de fecha 31 de Enero de 1997.

ES TRADUCCION FIEL Y COMPLETA DE LAS LEGALIZACIONES CONTENIDAS DENTRO DEL DOCUMENTO ANEXO TERMINADA ESTE 5 DE MAYO DE 1997.

SELLO DEL TRADUCTOR

HUGO NAVARRO ALVAREZ
TRADUCTOR E. INTERPRETE OFICIAL
Res. 1876 Minjusticia 1993

Esta copia concuerda con el original que tuvo a la vista.
Bogotá, D.C.
12 NOV 2003
AGUSTIN BORRERO RIVEIRA
NOTARIO CUARENTA Y UNO

PATENT COOPERATION TREATY

PCT

INTERNATIONAL PRELIMINARY REPORT ON PATENTABILITY

(Chapter II of the Patent Cooperation Treaty)

(PCT Article 36 and Rule 70)

Applicant's or agent's file reference 10061	FOR FURTHER ACTION	See Form PCT/IPEA/416
International application No. PCT/GB2004/003154	International filing date *(day/month/year)* 19.07.2004	Priority date *(day/month/year)* 25.07.2003
International Patent Classification (IPC) or national classification and IPC E21B33/13		
Applicant BP EXPLORATION OPERATING COMPANY LIMITED et al.		

1. This report is the international preliminary examination report, established by this International Preliminary Examining Authority under Article 35 and transmitted to the applicant according to Article 36.
2. This REPORT consists of a total of 5 sheets, including this cover sheet.
3. This report is also accompanied by ANNEXES, comprising:
   a. ☒ *sent to the applicant and to the International Bureau)* a total of 18 sheets, as follows:
      ☒ sheets of the description, claims and/or drawings which have been amended and are the basis of this report and/or sheets containing rectifications authorized by this Authority (see Rule 70.16 and Section 607 of the Administrative Instructions).
      ☐ sheets which supersede earlier sheets, but which this Authority considers contain an amendment that goes beyond the disclosure in the international application as filed, as indicated in Item 4 of Box No. I and the Supplemental Box.
   b. ☐ *(sent to the International Bureau only)* a total of (Indicate type and number of electronic carrier(s)) , containing a sequence listing and/or tables related thereto, in computer readable form only, as indicated in the Supplemental Box Relating to Sequence Listing (see Section 802 of the Administrative Instructions).

4. This report contains indications relating to the following items:

☒	Box No. I	Basis of the opinion
☐	Box No. II	Priority
☐	Box No. III	Non-establishment of opinion with regard to novelty, inventive step and industrial applicability
☐	Box No. IV	Lack of unity of invention
☒	Box No. V	Reasoned statement under Article 35(2) with regard to novelty, inventive step or industrial applicability; citations and explanations supporting such statement
☐	Box No. VI	Certain documents cited
☐	Box No. VII	Certain defects in the international application
☐	Box No. VIII	Certain observations on the International application

Date of submission of the demand	Date of completion of this report
21.02.2005	06.06.2005
Name and mailing address of the International preliminary examining authority: European Patent Office D-80298 Munich Tel. +49 89 2399 - 0 Tx: 523656 epmu d Fax: +49 89 2399 - 4465	Authorized Officer Zimpfer, E Telephone No. +49 89 2399-7881

Box No. I Basis of the report

1. With regard to the **language**, this report is based on the international application in the language in which it was filed, unless otherwise indicated under this item.

   ☐ This report is based on translations from the original language into the following language , which is the language of a translation furnished for the purposes of:
   - ☐ international search (under Rules 12.3 and 23.1(b))
   - ☐ publication of the international application (under Rule 12.4)
   - ☐ international preliminary examination (under Rules 55.2 and/or 55.3)

2. With regard to the **elements*** of the international application, this report is based on *(replacement sheets which have been furnished to the receiving Office in response to an invitation under Article 14 are referred to in this report as "originally filed" and are not annexed to this report)*:

Description, Pages	
1-15	received on 06.05.2005 with letter of 04.05.2005
Claims, Numbers	
1-18	received on 06.05.2005 with letter of 04.05.2005
Drawings, Sheets	
1/1	as originally filed

   ☐ a sequence listing and/or any related table(s) - see Supplemental Box Relating to Sequence Listing

3. ☐ The amendments have resulted in the cancellation of:
   - ☐ the description, pages
   - ☐ the claims, Nos.
   - ☐ the drawings, sheets/figs
   - ☐ the sequence listing *(specify)*:
   - ☐ any table(s) related to sequence listing *(specify)*:

4. ☐ This report has been established as if (some of) the amendments annexed to this report and listed below had not been made, since they have been considered to go beyond the disclosure as filed, as indicated in the Supplemental Box (Rule 70.2(c)).
   - ☐ the description, pages
   - ☐ the claims, Nos.
   - ☐ the drawings, sheets/figs
   - ☐ the sequence listing *(specify)*:
   - ☐ any table(s) related to sequence listing *(specify)*:

* *If item 4 applies, some or all of these sheets may be marked "superseded."*

Box No. V Reasoned statement under Article 35(2) with regard to novelty, inventive step or industrial applicability; citations and explanations supporting such statement

1. Statement

Novelty (N)	Yes:	Claims	1-18
	No:	Claims	
Inventive step (IS)	Yes:	Claims	1-18
	No:	Claims	
Industrial applicability (IA)	Yes:	Claims	1-18
	No:	Claims	

2. Citations and explanations (Rule 70.7):

see separate sheet

Re Item V

Reasoned statement with regard to novelty, inventive step or industrial applicability; citations and explanations supporting such statement

The following documents (D) are referred to in this communication; the numbering will be adhered to in the rest of the procedure :

- D1: EP-A-1 074 598 (TEXAS UNITED CHEMICAL CORP) 7 February 2001 (2001-02-07)
- D2: US-B-6 391 8301 (DOBSON JR JAMES W ET AL) 21 May 2002 (2002-05-21)
- D3: GB-A-2 351 098 (SOFITECH NV) 20 December 2000 (2000-12-20)
- D4: US-B-6 403 537 (CHESSER BILLY G. ET AL) 11 June 2002 (2002-06-11)

1. Novelty :

1.1 Since none of the documents cited in the search report disclose all the features of independent claim 1, it is considered that said claim as well as dependent claims 2-11 are novel over said prior art documents.

1.2 Since none of the documents cited in the search report disclose all the features of independent claim 12, it is considered that said claim as well as dependent claims 13-18 are novel over said prior art documents.

2. Inventive step :

2.1 Since none of the prior art document teaches or fairly suggests the specific method of reducing formation breakdown as claimed in claim 1, it appears to be non-obvious to the skilled person.

Hence, **claim 1**, as well as dependent **claims 2-11**, are considered as being inventive.

2.2 **Document D1**, considered as being the closest prior art, discloses a drilling fluid comprising an aqueous base fluid, a bridgingagent and a fluid loss control additive (see [0011]) at concentrations to achieve a fluid loss of less than 10 ml as measured at 180F (85C) and 250 psi differential pressure across a 5 micron disk for 30 minutes.
Example 10 shows values of fluid loss varying between 1.5ml and 4ml in 30 minutes at said HTHP conditions.

Examples of representative bridging material are calcium carbonate or dolomite (see §[0032]-[0033]) at concentrations from 5 ppb to 50 ppb.

The subject-matter of **claim 12** differs from disclosure of **D1**, since it contains the following additionnal features :

- the HTHP fluid loss is less than 2ml/30 minutes and is determined using a test according to the A.P.I. specifications as indicated in claim 12
- the bridging material has an average particle diameter of 50 microns to 1500 microns.

The technical problem solved by the differentiating features is considered as being to improve the sealing of the region at or near the mouth of induced fractures, since the size of the bridging material is larger as the mean pore throat width (less than 0 microns).

Since none of the prior art document teaches or fairly suggests this specific technical features, it appears to be non-obvious to the skilled person.

Hence, **claim 12**, as well as dependent **claims 13-18**, are considered as being inventive.

Case 10061(2)

DRILLING METHOD

The present invention relates to drilling of wells through a subterranean formation, and more particularly to a method of increasing the resistance of the wellbore wall to fracturing during drilling operations.

Conventionally, the drilling of a well into the earth by rotary drilling techniques, involves the circulation of a drilling fluid from the surface of the earth down a drill string having a drill bit on the lower end thereof and through ports provided in the drill bit to the well bottom and thence back to the surface through the annulus formed about the drill string. Commonly, drilling fluids are employed that are either oil or water based. These fluids are treated to provide desired rheological properties which make the fluids particularly useful in the drilling of wells.

A problem often encountered in the drilling of a well is the loss of unacceptably large amounts of drilling fluid into subterranean formations penetrated by the well. This problem is often referred to generally as "lost circulation," and the formations into which the drilling fluid is lost are often referred to as "lost circulation zones" or "thief zones". Various causes may be responsible for the lost circulation encountered in the drilling of a well. For example, a formation penetrated by the well may exhibit unusually high permeability or may contain fractures or crevices therein. In addition, a formation may simply not be sufficiently competent to support the pressure applied by the drilling fluid and may break down under this pressure and allow the drilling fluid to flow thereinto.

It is this latter situation where the formation is broken down by the pressure of the drilling fluid to which the present invention is addressed. One of the limiting factors in drilling a particular portion of a well is the mud weight (density of the drilling fluid)

that can be used. If too high a mud weight is used, fractures are created in the wall of the borehole with resulting loss of drilling fluid and other operating problems. On the other hand, if too low a mud weight is used, encroachment of formation fluids can occur, borehole collapse may occur due to insufficient support from the fluid pressure in the wellbore, and in extreme cases safety can be compromised due to the possibility of a well blowout. In many cases, wells are drilled through weak or lost-circulation-prone zones prior to reaching a potential producing zone, requiring use of a low mud weight and installation of sequential casing strings to protect weaker zones above a potential producing zone. If a higher weight mud could be used in drilling through weaker or depleted zones, then there is a potential for eliminating one or more casing strings in the well. Elimination of even one casing string from a well provides important savings in time, material and costs of drilling the well. Thus, there is a need for a method of drilling boreholes using a higher mud weight than could normally be used without encountering formation breakdown problems.

Surprisingly, it has now been found that formation breakdown during drilling can be controlled by drilling the borehole using an ultra-low fluid loss mud with the pressure of the drilling mud maintained at above the initial fracture pressure of the formation wherein the fractures that are induced in the wellbore wall are bridged at or near the mouth thereof by a solid particulate material that is added to the drilling mud and the bridge is sealed by the accumulation of fluid loss additives in the voids between the bridging particles and/or the precipitation of fluid loss additives onto the bridging particles. The presence of the fluid impermeable bridge at or near the mouth of the fracture strengthens the near wellbore region of the formation by generating a stress cage. Thereafter, the drilling of the wellbore is continued with the pressure of the drilling mud maintained at below the breakdown pressure of the strengthened formation.

Thus, according to a first aspect of the present invention there is provided a method of reducing formation breakdown during the drilling of a wellbore which method comprises:

(a) circulating a drilling mud in the wellbore comprising (i) an aqueous or oil based fluid, (ii) at least one fluid loss additive at a concentration effective to achieve a high temperature high pressure (HTHP) fluid loss from the drilling mud of less than 2 ml/30 minutes and (iii) a solid particulate bridging material having an average particle diameter of 25 to 2000 microns and a concentration of at least 0.5 pounds per barrel

(1.43 kg/m^3);

(b) increasing the pressure in the wellbore to above the initial fracture pressure of the formation such that fractures are induced in the formation and a substantially fluid impermeable bridge comprising the solid particulate material and the fluid loss additive(s) is formed at or near the mouth of the fractures thereby strengthening the formation;

(c) thereafter continuing to drill the wellbore with the pressure in the wellbore maintained at above the initial fracture pressure of the formation and below the breakdown pressure of the strengthened formation.

For avoidance of doubt, the strengthened formation may be a permeable or non-permeable formation.

Without wishing to be bound by any theory, the mechanism by which the method of the present invention strengthens the wall of the wellbore and hence reduces formation breakdown is that as a fracture is deliberately induced in the wellbore wall, the solid particulate material enters and bridges the fracture at or near the mouth of the fracture. Additives which are conventionally included in the drilling mud to reduce loss of fluid from the drilling mud into the formation subsequently either precipitate on the solid particulate material that bridges the fracture or fill the voids between the solid particulate material thereby establishing a fluid impermeable immobile mass or bridge at or near the mouth of the fracture. Accordingly, fluid from the drilling mud can no longer pass into the fracture and the pressure within the fracture may begin to dissipate until it is substantially the same as the pressure of the surrounding formation. The rate of reduction in pressure within the fracture beyond the bridge will depend on the rock permeability and other factors such as the supporting action of the bridge which maintains the rock displacement caused by the fracture and the sealing action of the bridge which prevents fluid loss from the drilling mud into the fracture. The rock displacement caused by the fracture places the rock in the near wellbore region of the formation (for example, within a radial distance of up to 5 feet (1.524 metres) from the wellbore wall) in a state of compression, thereby increasing the "hoop stress" and generating a "stress cage". If there is a reduction in pressure in the fracture beyond the bridge, the fracture will attempt to close and this will impart stress on the fluid impermeable immobile mass or bridge which, in turn, leads to additional compressive stress being imparted to the rock in the near wellbore region of the formation. The

increased compressive stress in the near wellbore region of the formation results in the wall of the wellbore having a greater resistance to further fracturing. The method of the present invention therefore allows a drilling mud of higher density to be employed in drilling the wellbore than could be used in the absence of strengthening of the formation. The method also has a further beneficial effect of reducing loss of fluid from the drilling mud into the formation owing to the sealing of the fractures with the fluid impermeable immobile mass.

The method of the first aspect of the present invention differs from a conventional "tip screen out" in that a "tip screen out" requires the use of a high fluid loss drilling mud so that particulate material accumulates rapidly at the fracture tip thereby sealing the fracture and preventing further propagation of the fracture. The person skilled in the art would therefore have concerns that the use of an ultra-low fluid loss drilling mud would slow down deposition of particulate material at the fracture tip. Furthermore, there was no understanding that it may be preferable to bridge at or near the mouth of a fracture. Thus, conventional drilling muds employed in a "tip screen out" are designed so that the particulate material readily penetrates into the fracture to deposit at the fracture tip. Also, a "tip screen out" does not create an effective near wellbore "stress cage". Although the rock at the fracture tip would be under increased compressive stress (owing to the accumulation of particulate material at the fracture tip), this would not apply to the rock between the fracture tip and the mouth of the fracture. Finally, there was a prejudice against using a low fluid loss drilling mud owing to a belief that a low fluid loss mud would slow down the "rate of penetration" while drilling. It was therefore surprising that an ultra-low fluid loss mud does not significantly reduce the "rate of penetration".

The fluid loss value for the drilling mud is determined using a standard high temperature high pressure (HTHP) fluid loss test, according to the specifications of the American Petroleum Institute (API), as described in "Recommended Practice Standard Procedure for Field Testing Oil-Based Drilling Fluids", API Recommended Practice 13B-2 Third Edition, February 1998, Section 5.2.1 to 5.2.3; and "Recommended Practice Standard Procedure for Field Testing Water-Based Drilling Fluids", API Recommended Practice 13B-1 Second Edition, September 1997, Section 5.3.1 to 5.3.2. The test employs a pressurized cell fitted with a standard hardened filter paper as a filtration medium. The filtration behaviour of the drilling mud is determined with a

standard pressure differential across the filter paper of 500 psi (3.45 M Pa). A filter cake is allowed to build up on the filter paper for 30 minutes and the volume of filtrate collected after this 30 minute period is then recorded. Because the filtration area (3.5 square inches (2.258×10^{-3} m^2)) of the pressurized cell is half the filtration area of a standard API low temperature low pressure (LTLP) fluid loss test (7 square inches (4.516×10^{-3} m^2)), the filtrate volume after 30 minutes is doubled to give a corrected API fluid loss value. Suitably, the temperature at which the high temperature high pressure (HTHP) fluid loss test is carried out corresponds to the temperature in the borehole. Generally, the test temperature is in the range 50 to 150°C.

By "fracture pressure" is meant the minimum fluid pressure in the wellbore at which a fracture is created in the wellbore wall. As would be evident to the person skilled in the art, creation of a near wellbore "stress cage" will increase the fracture pressure of the strengthened formation. Accordingly, by "initial fracture pressure" of a formation is meant the fracture pressure of the formation prior to creation of the "stress cage". The initial fracture pressure of a formation may be readily determined, for example, from historical data.

By "breakdown pressure of the strengthened formation" is meant the maximum fluid pressure that can be sustained within the wellbore without creating a fracture in the strengthened formation and/or without breaking down the fluid impermeable bridge(s) that has been formed at or near the mouth of the fracture(s).

Suitably, the pressure in the wellbore in step (c) of the method of the first aspect of the present invention is at least 50 psi (0.34 M Pa) above the initial fracture pressure of the formation, preferably, at least 300 psi (2.07 M Pa) above the initial fracture pressure of the formation, for example 300 to 1000 psi (2.07 to 6.90 M Pa) above the initial fracture pressure of the formation, with the proviso that the pressure in the wellbore in step (c) is below the breakdown pressure of the strengthened formation.

As is well known to the person skilled in the art, formation pressure generally increases with increasing depth of the wellbore. It is therefore generally necessary to continuously increase the pressure of the drilling mud during the drilling operation, for example, by increasing the density of the drilling mud. A problem arises when the increased pressure of the drilling mud exceeds the initial fracture pressure of a previously drilling formation or exceeds the initial fracture pressure of a formation that is yet to be drilled (hereinafter referred to as "weak formation"). The method of the first

aspect of the present invention may therefore be used to strengthen such weak formations thereby allowing the pressure of the drilling mud that is employed for completing the drilling operation to be increased to above the initial fracture pressure of the weak formation. The method of the first aspect of the present invention is particularly advantageous where the weak formation is a depleted formation i.e. a formation having a decreased pore pressure owing to production of hydrocarbons therefrom. This decrease in pore pressure weakens the depleted formation while neighbouring or inter-bedded low permeability formations may maintain their pore pressure.

Thus, in a specific embodiment of the first aspect present invention there is provided a method of reducing formation breakdown during the drilling of a wellbore through a weak formation with a circulating drilling mud which method comprises:
(a) circulating in a wellbore a drilling mud comprising (i) an aqueous or oil based fluid, and (ii) at least one fluid loss additive at a concentration effective to achieve a high temperature high pressure (HTHP) fluid loss from the drilling mud of less than 2 ml/30 minutes and (iii) a solid particulate bridging material having an average particle diameter of 25 to 2000 microns and a concentration of at least 0.5 pounds per barrel (1.43 kg/m^3);
(b) increasing the pressure of the drilling mud to above the initial fracture pressure of the weak formation such that fractures are induced in the weak formation and a substantially fluid impermeable bridge comprising the solid particulate material and the fluid loss additive(s) is formed at or near the mouth of the fractures thereby strengthening the weak formation;
(c) thereafter continuing to drill the wellbore with the pressure in the wellbore maintained at above the initial fracture pressure of the weak formation and below the breakdown pressure of the strengthened formation.

It is envisaged that the wellbore may be drilled using a conventional drilling mud until the pressure in the wellbore approaches the initial fracture pressure of the weak formation. The conventional drilling mud is then replaced by (or converted into) the drilling mud employed in step (a) before increasing the pressure in the wellbore to above the initial fracture pressure of the weak formation. The conventional drilling mud may be converted into the drilling mud employed in step (a) by adding at least one fluid loss additive (ii) to the mud until the HTHP fluid loss value of the mud is less than 2

ml/30 minutes and adding the solid particulate bridging material (iii) to the mud in an amount of at least 0.5 pound per barrel (1.43 kg/m^3). Suitably, the solid particulate bridging material (iii) may be added to a drilling mud comprising components (i) and (ii) immediately before increasing the pressure of the drilling mud to above the initial fracture pressure of the weak formation. Thus, the drilling mud that is used to drill the wellbore until the pressure in the wellbore approaches the initial fracture pressure of the weak formation may comprise components (i) and (ii) in the absence of component (iii).

The weak formation may lie in a previously drilled section of the wellbore and/or in the rock that is about to be drilled. Where the weak formation is in the rock that is about to be drilled, it is necessary to replace the entire wellbore fluid with the drilling mud employed in step (a). Thus, the weak formation is strengthened as the wellbore is being drilled. Where the weak formation lies in a previously drilled section of the wellbore, it is only necessary to replace the wellbore fluid in the vicinity of the weak formation. Thus, a drilling mud having a high concentration of the particulate solid material may be introduced into the wellbore as a "pill" and may be circulated to the weak formation where the concentrated drilling mud composition is squeezed into the weak formation at a pressure above the initial fracture pressure of the weak formation so that the bridging particulate material bridges the fractures that are induced in the wellbore wall at or near the mouth thereof. Typically, the pill is squeezed into the weak formation by sealing the annulus between a drill string and the wellbore wall, raising the drill string until it lies immediately below the weak formation, and pumping the pill into the wellbore via the drill string until the pressure in the vicinity of the weak formation is greater than the initial fracture pressure. Generally, the well is then shut in for a period of up to 0.5 hour. After strengthening the weak formation, drilling of the wellbore may be continued using a conventional drilling mud with the proviso that the pressure in the wellbore in the vicinity of the strengthened formation is maintained below the breakdown pressure of the strengthened formation. Suitably, the concentration of bridging material in the pill should be at least 50 pounds per barrel (143 kg/m^3), preferably at least 80 lb per barrel (228.8 kg/m^3). It is also envisaged that the "pill" may be employed as a completion fluid and may be pumped into the wellbore in advance of a cement when casing a wellbore.

In a further aspect of the present invention there is provided a drilling mud composition comprising (a) an aqueous or oil based fluid, (b) at least one fluid loss

additive at a concentration effective to achieve a high temperature high pressure (HTHP) fluid loss from the drilling mud of less than 2 ml/30 minutes and (c) a solid particulate bridging material having an average particle diameter of 25 to 2000 microns and a concentration of at least 0.5 pounds per barrel (1.43 kg/m^3).

Suitably, the specific gravity of the drilling mud is in the range 0.9 to 2.5, preferably in the range 1.0 to 2.0.

Suitably, the solid particulate bridging material that is included in the drilling mud to bridge the fractures (hereinafter "bridging material") comprises at least one substantially crush resistant particulate solid such that the bridging material props open the fractures (cracks and fissures) that are induced in the wall of the wellbore. By "crush resistant" is meant that the bridging material is physically strong enough to withstand the closure stresses exerted on the fracture bridge. Preferred bridging materials for adding to the drilling mud include graphite, calcium carbonate (preferably, marble), dolomite ($MgCO_3.CaCO_3$), celluloses, micas, proppant materials such as sands or ceramic particles and combinations thereof. These materials are very inert and are environmentally acceptable. It is also envisaged that a portion of the bridging material may comprise drill cuttings having the desired average particle diameter in the range of 25 to 2000 microns.

The concentration of the bridging material may vary with the drilling mud used and the conditions of use. The concentration must be at least great enough for the bridging material to rapidly bridge the fractures (i.e. cracks and fissures) that are induced in the wall of the wellbore but should not be so high as to make circulation of the drilling mud impractical. Suitably, the bridging material should bridge the fractures that are induced in the wellbore wall within less than 10 seconds, preferably less than 5 seconds from when the fracture opens so that the fracture remains short. Thus, rapid sealing of the fracture mitigates the risk of the fracture propagating. Suitably, the concentration of bridging material in the drilling mud is at least 5 pounds per barrel (14.3 kg/m^3), preferably at least 10 pounds per barrel (28.6 kg/m^3), more preferably at least 15 pounds per barrel (42.9 kg/m^3), for example, at least 30 pounds per barrel (85.8 kg/m^3). However, as discussed above, where the drilling mud is employed in a "pill" treatment, the concentration of the bridging particulate material is suitably at least 50 pounds per barrel (143 kg/m^3), preferably at least 80 pounds per barrel (228.8 kg/m^3).

Suitably, the bridging material is sized so as not to enter the pores of any

permeable rock through which the wellbore is being drilled. Preferably, the bridging material has an average particle diameter in the range 50 to 1500 microns, more preferably 250 to 1000 microns. The bridging material may comprise substantially spherical particles. However, it is also envisaged that the bridging material may comprise elongate particles, for example, rods or fibres. Where the bridging material comprises elongate particles, the average length of the elongate particles should be such that the elongate particles are capable of bridging the induced fractures at or near the mouth thereof. Typically, the elongate particles will have an average length in the range 25 to 2000 microns, preferably 50 to 1500 microns, more preferably 250 to 1000 microns.

The bridging material is sized so as to readily form a bridge at or near the mouth of the induced fractures. Typically, the fractures that are induced in the wellbore wall have a fracture width at the mouth in the range 0.1 to 5mm. The fracture width is dependent, amongst other factors, upon the strength (stiffness) of the formation rock and the extent to which the pressure in the wellbore is increased to above initial fracture pressure of the formation during the fracture induction step (b) of the method of the present invention (in other words, the fracture width is dependent on the pressure difference between the drilling mud and the initial fracture pressure of the formation during the fracture induction step). It is preferred that at least a portion of the bridging material, preferably, a major portion of the bridging material has a particle diameter approaching the width of the fracture mouth. Preferably, the bridging material has a broad (polydisperse) particle size distribution.

It is necessary to keep the bridging material in suspension in the drilling mud. Generally, a drilling mud is recycled to the wellbore after removal of substantially all of the drill cuttings. The drill cuttings may be removed using screens as would be well known to the person skilled in the art. Typically the drilling mud is filtered using a 200 mesh size screen (US sieve series) that retains particles having a size of greater than 74 microns. However, in the method of the present invention, it is necessary to filter the mud using a coarser screen so as to avoid separation of substantial amounts of the bridging material from the mud. Suitably, the drilling mud is filtered using a 35 mesh screen (US sieve series) that retains particles having a size of greater than 500 microns. However, if the rheology of the mud deteriorates through the accumulation of fine drill cuttings in the mud, it may be necessary to employ finer mesh screens for a short period

of time. It is also envisaged that separation methods may be employed which allow the bridging solids to be retained but a major portion of the cuttings, preferably substantially all of the cuttings, to be separated from the drilling mud. In particular, the cuttings may be separated from the drilling mud by relying on differences in the densities of the cuttings and the bridging particles, for example, using centrifuges or hydrocyclones. In order to maintain the concentration of the bridging material at the desired value in the drilling mud and/or to maintain the fluid loss value of the drilling mud at below 2 ml/30 minutes, it may be necessary to introduce fresh bridging material and/or fresh fluid loss additives respectively into the circulating drilling mud. Alternatively, or in addition, fresh drilling mud may be either continuously or intermittently added to the drilling mud that is being circulated in the wellbore.

The drilling mud has an HTHP fluid loss value of less than 2 ml/30 minutes, preferably, less than 1 ml/30 minutes, more preferably less than 0.5 ml/30 minutes, for example 0.1 to 0.3 ml/30 minutes. As would be well known to the person skilled in the art, such ultra-low fluid loss values may be achieved by incorporating at least one fluid loss additive in the drilling mud. Without wishing to be bound by any theory, it is believed that the fluid loss additive(s) will build up on the solid particulate material that bridges the fractures at or near the mouth thereof thereby forming a fluid impermeable immobile mass. Where the solid particulate bridging material is porous, the fluid loss additives may also enter the pores of the bridging material to seal the pores.

Suitable fluid loss additives that may be incorporated in the drilling mud of the present invention include organic polymers of natural or synthetic origin. Suitable polymers include starch or chemically modified starches; cellulose derivatives such as carboxymethylcellulose and polyanionic cellulose (PAC); guar gum and xanthan gum; homopolymers and copolymers of monomers selected from the group consisting of acrylic acid, acrylamide, acrylamido-2-methyl propane sulfonic acid (AMPS), styrene sulphonic acid, N-vinyl acetamide, N-vinyl pyrrolidone, and N,N-dimethylacrylamide wherein the copolymer has a number average molecular weight of from 100,000 to 1,000,000, and preferably 200,000 to 500,000; asphalts (for example, sulphonated asphalts); gilsonite; lignite and its derivative, humic acid; lignin and its derivatives such as lignin sulfonates or condensed polymeric lignin sulfonates; and combinations thereof. These polymeric additives are particularly suitable for use in oil based drilling muds. As an alternative or, in addition, to employing such polymeric additives, the fluid loss

from the drilling mud of the present invention may be reduced by adding finely dispersed particles such as clays (for example, illite, kaolinite, bentonite, or sepiolite) to the drilling mud. Suitably, the finely dispersed particles have an average particle size of less than 10 microns, preferably, less than 5 microns, for example, about 1 micron. Preferably, the drilling mud contains a smooth/continuous range of particle sizes ranging from about 1 micron for the finely dispersed particulate fluid loss additives to an average particle diameter of the bridging material of up to 2000 microns i.e. has a broad (polydisperse) particle size distribution.

It is envisaged that an oil based drilling mud may contain a significant amount of a discontinuous water phase dispersed in a continuous oil phase by means of at least one emulsifier (a water-in-oil emulsion). The fluid loss value of such drilling muds may vary depending upon the oil to water ratio and the nature of the emulsifier(s) employed to form the water-in-oil emulsion (and hence on the size of the dispersed water droplets). Preferably, the water content of the drilling mud is in the range 80:20 to 50:50, more preferably 70:30 to 55:45. Preferred emulsifiers include imidazolines, fatty acids and combinations thereof.

Particularly preferred ultra-low fluid loss oil based drilling muds are described in SPE 77446, "Towards Zero Fluid Loss Oil Based Muds", M Aston, P Mihalik, J Tunbridge and S Clarke, published 2002.

The effectiveness of the method of the present invention has been demonstrated in both laboratory and field conditions as shown by the following Examples.

Example 1

Oil based mud formulations were evaluated in the laboratory by injecting different drilling muds into a model fracture (as described in SPE/IADC 87130, "Drilling Fluids for Wellbore Strengthening, 2-4 March 2004, M S Aston et al). The model fracture was formed from two rectangular-shaped rock pieces (of 0.3 milliDarcy permeability "Ohio" sandstone). Each rock piece had approximate dimensions of 5cm width x 20cm length x 1cm breadth. The two rock pieces were sandwiched together to create a fracture having a mouth aperture of 1mm with the aperture of the fracture tapering to 0.5mm at the far end thereof (fracture tip). A valve was provided at the exit from the fracture tip such that the fracture tip could be open or sealed. The rock sandwich was placed in a purpose-built holder that was supported in a load frame within a test cell. The fracture width was maintained constant using fixed spacers. The fluid

pressure within the fracture was measured just inside the mouth of the fracture using a pressure transducer. Initially, the fracture and the pore spaces in the rock were filled with a clear fluid (water) and the system was heated to a temperature of 60°C. A pressure of about 100 psi (0.69 M Pa) was applied to compress any air in the system. Drilling mud was then injected at a pressure of 400 psi (2.76 M Pa) into the mouth of the fracture with the fracture tip open (to give a differential pressure across the fracture of 300 psi (2.07 M Pa)). After 3 minutes, the exit from the fracture tip was closed using the valve so that pressure could build up inside the fracture (n.b. the initial driving force for bridge formation at the fracture mouth was fluid leak-off through the fracture tip). The injection pressure was then increased stepwise to 2000 psi (13.79 M Pa). A low pressure measured on the pressure transducer indicated an effective seal at the mouth of the fracture.

The results shown in Table 1 below compare the pressures measured just inside the fracture mouth for different drilling muds employed in the above test procedure. The pressure just inside the fracture mouth was measured after a steady value was reached at each injection pressure.

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Table 1 – Effectiveness of drilling muds in sealing a model fracture

Mud System		Pressure just inside fracture mouth, measured after different mud injection pressures (IP) in psi		
		IP 400 (2.76 M Pa)	IP 1000 (6.70 M Pa)	IP 2000 (13.79 M Pa)
Mud 1 (Comparative)	Base mud plus bridging particulate material mix A; API HTHP fluid loss = 3mls/30 minutes at a temperature of 60°C	300 (2.07 M Pa)	900 (6.21 M Pa)	1900 (13.10 M Pa)
Mud 2	As mud 1, but containing 5lb/bbl Pliolite, API HTHP fluid loss = 0.3 mls/30 minutes at a temperature of 60°C	0	30 (1.31 M Pa)	1900 (13.10 M Pa)
Mud 3	Base mud plus bridging particulate material mix B plus 5lb/bbl Pliolite (14.3 kg/m^3), API HTHP fluid loss = 0.1 mls/30 minutes at a temperature of 60°C	0	0	0

Mud 2 forms a more effective seal than Mud 1 (Comparative). This was achieved by reducing the API HTHP fluid loss of the mud system from 3 ml/30 minutes to 0.3 mls/30 minutes. Mud 3 achieved a total seal at the mouth of the fracture by using an improved bridging particulate material mix in a mud having an API HTHP fluid loss of 0.1 mls/30 minutes.

The formulation for the base mud employed in the above tests was as follows:

Mineral oil:	0.517 bbls (0.0822 m^3)
Versamul™ (emulsifier, ex MI)	4.7 lb/bbl (13.4 kg/m^3)

Versawet™ (wetting agent, ex MI)	7 lb/bbl (20.0 kg/m^3)
Geltone™ (organoclay, ex Halliburton)	6lb/bbl (17.2 kg/m^3)
Lime	5.25 lb/bbl (15.0 kg/m^3)
Calcium chloride	17.6 lb/bbl (50.4 kg/m^3)
Water	0.346 lb/bbl (1.0 kg/m^3)
Barite (barium sulfate)	50 lb/bbl (143 kg/m^3)
Hymod Prima Clay (simulated drill solids)	4.5 lb/bbl (12.9 kg/m^3)

Mud 1 is the base mud containing the following bridging particulate materials (mix A):

Baracarb™ 150:	46 lb/bbl (131.6 kg/m^3)
Baracarb™ 600:	9.3 lb/bbl (26.6 kg/m^3)

Mud 2 is as Mud 1 with the addition of 5 lb/bbl Pliolite® DF-01 (fluid loss control additive supplied by Goodyear)

Mud 3 is the base mud containing 5lb/bbl (143 kg/m^3) Pliolite® DF-01 and the following bridging particulate materials (mix B):

Baracarb™ 150:	18 lb/bbl (51.5 kg/m^3)
Baracarb™ 600:	18 lb/bbl (51.5 kg/m^3)
Steelseal™:	15 lb/bbl (42.9 kg/m^3)

Baracarb™ 150, Baracarb™ 600 and Steelseal™ were obtained from Halliburton. Baracarb™ 150 and Baracarb™ 600 are calcium carbonates with an average particle diameter of 150 microns and 600 microns, respectively. Steelseal™ is a graphitic carbon available from Halliburton, with an average size range of approximately 400 microns.

Example 2

A field test was conducted onshore in the Arkoma basin, USA, to determine whether the method of the present invention could raise fracture resistance in a shale formation. The well was a vertical well having a 9 5/8" (24.5 cm) casing. An extended leak off test (pill squeeze treatment) was performed in 10 feet (3.048 metres) of exposed shale formation (open hole) just below the 9 5/8" (24.5 cm) casing shoe. In this test, standard "leak-off" procedures were used whereby the annulus was closed whilst mud was pumped into the wellbore. Initially, a standard diesel based mud was present in the well bore and this mud was pumped into the wellbore at a rate of 0.25

bbls/minute (0.04 m^3/minute) until breakdown of the exposed shale formation occurred.

Figure 1 illustrates the extended leak-off pressure curve for the standard diesel based mud (curve 1). The shale formation fractured at about 1200 psi (8.27 M Pa), at which point pumping of the standard diesel based drilling mud was stopped to minimize fracture growth. The pressure stabilized at 800 psi (5.52 M Pa), which is the propagation pressure of the fractures determined by the far-field stress state. The excess pressure in the wellbore was bled off (back to hydrostatic pressure) so that the fractures closed and the leak-off procedure was then repeated by pumping a pill of a mud according to the present invention (hereinafter "Designer mud") into the wellbore also at a rate of 0.25 bbls/minute (0.04m^3/minute). Figure 1 additionally illustrates the extended leak off curve for the Designer mud (curve 2). The fractures induced in the wall of the open hole wellbore are bridged and sealed by the bridging particles and fluid loss additives of the Designer mud and the breakdown pressure of the strengthened formation climbs to above 2000 psi (13.79 M Pa) before the seal breaks down. This is an increase of about 850 psi (5.86 M Pa) formation breakdown pressure compared to the original state of the shale formation, equivalent to 5.4 pounds per gallon (ppg) (647 kg/m^3) mud weight.

The API HTHP fluid loss value for the Designer mud employed in the field trial was 0.45 mls at a temperature of 115 °F (46°C) (bottom hole temperature), while the standard diesel based mud had an API HTHP fluid loss of 10 mls at a temperature of 250°F (121°C). The Designer Mud was made by adding calcium carbonate bridging solids, graphitic material bridging solids, and fluid loss additives to the standard diesel based mud in accordance with the present invention. The bridging solids ranged in size from 10 to 800 microns and were added in an amount of 80 pounds per barrel (228.8 kg/m^3). The original standard diesel based mud had a mud weight of 9.0 ppg (1078 kg/m^3) and was free of added bridging solids.

Claims:

1. A method of reducing formation breakdown during the drilling of a wellbore which method comprises:

(a) circulating a drilling mud in the wellbore comprising (i) an aqueous or oil based fluid, (ii) at least one fluid loss additive at a concentration effective to achieve a high temperature high pressure (HTHP) fluid loss from the drilling mud of less than 2 ml/30 minutes wherein the HTHP fluid loss is determined using an HTHP test according to the specifications of the American Petroleum institute (API), as described in API Recommended Practice 13B-2 Third Edition, February 1998, Section 5.2.1 to 5.2.3 or Recommended Practice 13B-1 Second Edition, September 1997, Section 5.3.1 to 5.3.2, and (iii) a solid particulate bridging material having an average particle diameter of 25 to 2000 microns and a concentration of at least 0.5 pounds per barrel (1.43 kg/m^3);

(b) increasing the pressure in the wellbore to above the initial fracture pressure of the formation such that fractures are induced in the formation and a substantially fluid impermeable bridge comprising the solid particulate bridging material and the fluid loss additive(s) is formed at or near the mouth of the fractures thereby strengthening the formation;

(c) thereafter continuing to drill the wellbore with the pressure in the wellbore maintained at above the initial fracture pressure of the formation and below the breakdown pressure of the strengthened formation.

2. A method as claimed in Claim 1 wherein the pressure in the wellbore in step (c) is maintained at least 300 psi (2.07 M Pa) above the initial fracture pressure of the formation and below the breakdown pressure of the strengthened formation.

3. A method as claimed in Claims 1 or 2 wherein the solid particulate bridging material is added to a circulating drilling mud having an HTHP fluid loss value of less than 2 ml/30 minutes prior to increasing the pressure in the wellbore to above the initial fracture pressure of the formation.

4. A method as claimed in any one of the preceding claims wherein the strengthened formation is a depleted formation.

5. A method as claimed in any one of Claims 1 to 3 wherein the strengthened formation is a weak formation in a previously drilled section of wellbore.

6. A method as claimed in any one of the preceding claims wherein the drilling mud has a HTHP fluid loss value of less than 1 ml/30 minutes, preferably less than 0.5 ml/30 minutes.

7. A method as claimed in any one of the preceding claims wherein the concentration of solid particulate bridging material in the circulating drilling mud is at least 10 lb per barrel (26.6 kg/m^3), preferably at least 15 lb per barrel (42.9 kg/m^3).

8. A method as claimed in any one of the preceding claims wherein the drilling mud is recycled to the wellbore after separating material having a size of greater than 500 microns therefrom using a 35 mesh screen (US sieve series).

9. A method as claimed in Claim 8 wherein fresh solid particulate bridging material is added to the drilling mud prior to recycling the drilling mud to the wellbore.

10. A method as claimed in any one of Claims 1 to 7 wherein the drilling mud is recycled to the wellbore after separating drill cuttings from the drilling mud using a centrifuge or hydrocyclone.

11. A method as claimed in Claims 5 or 6 wherein a pill of the drilling mud having a concentration of solid particulate bridging material of at least 50 lb per barrel (143 kg/m^3) is circulated to the weak formation and is squeezed into the weak formation with the pressure in the wellbore in the vicinity of the weak formation maintained at above the initial fracture pressure of the weak formation.

12. A drilling mud composition comprising (a) an aqueous or oil based fluid; (b) at least one fluid loss additive at a concentration effective to achieve a high temperature high pressure (HTHP) fluid loss from the drilling mud of less than 2 ml/30 minutes wherein the HTHP fluid loss is determined using an HTHP test according to the specifications of the American Petroleum institute (API), as described in API Recommended Practice 13B-2 Third Edition, February 1998, Section 5.2.1 to 5.2.3 or

Recommended Practice 13B-1 Second Edition, September 1997, Section 5.3.1 to 5.3.2; and (c) a solid particulate bridging material having an average particle diameter in the range 50 to 1500 microns and a concentration of at least 0.5 pounds per barrel (1.43 kg/m^3).

13. A drilling mud composition as claimed in Claim 12 having a specific gravity in the range 0.9 to 2.5.

14. A drilling mud composition as claimed in Claims 12 or 13 wherein the solid particulate bridging material comprises at least one substantially crush resistant particulate solid selected from the group consisting of graphite, calcium carbonate (preferably marble), dolomite, celluloses, micas, sand and ceramic particles.

15. A drilling mud composition as claimed in any one of Claims 12 to 14 wherein the concentration of the solid particulate bridging material is at least 10 pounds per barrel (28.6 kg/m^3), preferably at least 15 pounds per barrel (42.9 kg/m^3).

16. A drilling mud composition as claimed in any one of claims 12 to 15 wherein the solid particulate bridging material has an average particle diameter in the range 250 to 1000 microns.

17. A drilling mud composition as claimed in any one of Claims 12 to 16 having an HTHP fluid loss value of less than 1 ml/30 minutes, preferably less than 0.5 ml/30 minutes.

18. A drilling mud composition as claimed in any one of Claims 12 to 17 wherein the fluid loss additive(s) is selected from organic polymers of natural or synthetic origin and finely dispersed clays.

Claims:

1. A method of reducing formation breakdown during the drilling of a wellbore which method comprises:

(a) circulating a drilling mud in the wellbore comprising (i) an aqueous or oil based fluid, (ii) at least one fluid loss additive at a concentration effective to achieve a high temperature high pressure (HTHP) fluid loss from the drilling mud of less than 2 ml/30 minutes wherein the HTHP fluid loss is determined using an HTHP test according to the specifications of the American Petroleum institute (API), as described in API Recommended Practice 13B-2 Third Edition, February 1998, Section 5.2.1 to 5.2.3 or Recommended Practice 13B-1 Second Edition, September 1997, Section 5.3.1 to 5.3.2, and (iii) a solid particulate bridging material having an average particle diameter of 25 to 2000 microns and a concentration of at least 0.5 pounds per barrel (1.43 kg/m^3);

(b) increasing the pressure in the wellbore to above the initial fracture pressure of the formation such that fractures are induced in the formation and a substantially fluid impermeable bridge comprising the solid particulate bridging material and the fluid loss additive(s) is formed at or near the mouth of the fractures thereby strengthening the formation;

(c) thereafter continuing to drill the wellbore with the pressure in the wellbore maintained at above the initial fracture pressure of the formation and below the breakdown pressure of the strengthened formation.

2. A method as claimed in Claim 1 wherein the pressure in the wellbore in step (c) is maintained at least 300 psi (2.07 M Pa) above the initial fracture pressure of the formation and below the breakdown pressure of the strengthened formation.

3. A method as claimed in Claims 1 or 2 wherein the solid particulate bridging material is added to a circulating drilling mud having an HTHP fluid loss value of less than 2 ml/30 minutes prior to increasing the pressure in the wellbore to above the initial fracture pressure of the formation.

4. A method as claimed in any one of the preceding claims wherein the strengthened formation is a depleted formation.

5. A method as claimed in any one of Claims 1 to 3 wherein the strengthened formation is a weak formation in a previously drilled section of wellbore.

6. A method as claimed in any one of the preceding claims wherein the drilling mud has a HTHP fluid loss value of less than 1 ml/30 minutes, preferably less than 0.5 ml/30 minutes.

7. A method as claimed in any one of the preceding claims wherein the concentration of solid particulate bridging material in the circulating drilling mud is at least 10 lb per barrel (26.6 kg/m^3), preferably at least 15 lb per barrel (42.9 kg/m^3).

8. A method as claimed in any one of the preceding claims wherein the drilling mud is recycled to the wellbore after separating material having a size of greater than 500 microns therefrom using a 35 mesh screen (US sieve series).

9. A method as claimed in Claim 8 wherein fresh solid particulate bridging material is added to the drilling mud prior to recycling the drilling mud to the wellbore.

10. A method as claimed in any one of Claims 1 to 7 wherein the drilling mud is recycled to the wellbore after separating drill cuttings from the drilling mud using a centrifuge or hydrocyclone.

11. A method as claimed in Claims 5 or 6 wherein a pill of the drilling mud having a concentration of solid particulate bridging material of at least 50 lb per barrel (143 kg/m^3) is circulated to the weak formation and is squeezed into the weak formation with the pressure in the wellbore in the vicinity of the weak formation maintained at above the initial fracture pressure of the weak formation.

12. A drilling mud composition comprising (a) an aqueous or oil based fluid; (b) at least one fluid loss additive at a concentration effective to achieve a high temperature high pressure (HTHP) fluid loss from the drilling mud of less than 2 ml/30 minutes wherein the HTHP fluid loss is determined using an HTHP test according to the specifications of the American Petroleum institute (API), as described in API Recommended Practice 13B-2 Third Edition, February 1998, Section 5.2.1 to 5.2.3 or

Recommended Practice 13B-1 Second Edition, September 1997, Section 5.3.1 to 5.3.2; and (c) a solid particulate bridging material having an average particle diameter in the range 50 to 1500 microns and a concentration of at least 0.5 pounds per barrel (1.43 kg/m^3).

13. A drilling mud composition as claimed in Claim 12 having a specific gravity in the range 0.9 to 2.5.

14. A drilling mud composition as claimed in Claims 12 or 13 wherein the solid particulate bridging material comprises at least one substantially crush resistant particulate solid selected from the group consisting of graphite, calcium carbonate (preferably marble), dolomite, celluloses, micas, sand and ceramic particles.

15. A drilling mud composition as claimed in any one of Claims 12 to 14 wherein the concentration of the solid particulate bridging material is at least 10 pounds per barrel (28.6 kg/m^3), preferably at least 15 pounds per barrel (42.9 kg/m^3).

16. A drilling mud composition as claimed in any one of claims 12 to 15 wherein the solid particulate bridging material has an average particle diameter in the range 250 to 1000 microns.

17. A drilling mud composition as claimed in any one of Claims 12 to 16 having an HTHP fluid loss value of less than 1 ml/30 minutes, preferably less than 0.5 ml/30 minutes.

18. A drilling mud composition as claimed in any one of Claims 12 to 17 wherein the fluid loss additive(s) is selected from organic polymers of natural or synthetic origin and finely dispersed clays.

METODO DE PERFORACION

La presente invención se refiere a la perforación de pozos a través de una formación subterránea y, más particularmente a un método para aumentar la resistencia a la fractura de la pared del pozo durante las operaciones de perforación.

La perforación de un pozo en la tierra mediante técnicas de perforación rotativa implica convencionalmente la circulación de un fluido de perforación desde la superficie de la tierra, descendentemente por una sarta de perforación que tiene un trépano de perforación en el extremo inferior de la misma, y a través de orificios previstos en el trépano, hasta el fondo del pozo y desde aquí de nuevo hacia la superficie a través de la corona anular formada alrededor de la sarta de perforación. Generalmente se emplean fluidos de perforación que están basados bien en petróleo o bien en agua. Dichos fluidos son tratados para proporcionar propiedades reológicas deseadas que hagan que los fluidos resulten particularmente útiles en la perforación de pozos.

Un problema encontrado frecuentemente en la perforación de un pozo es la pérdida de cantidades inaceptablemente altas de fluido de perforación dentro de las formaciones subterráneas penetradas por el pozo. Este problema suele conocerse generalmente como "pérdida de circulación" y las formaciones en las cuales se pierde el fluido de perforación suelen referirse como "zonas de pérdida de circulación" o "zonas de escape". Varias causas pueden ser las responsables de la pérdida de circulación encontrada en la perforación de un pozo. Por ejemplo, una formación penetrada por el pozo puede exhibir una permeabilidad desusualmente elevada o puede contener fracturas o fisuras en la misma. Además, puede que una formación simplemente no sea lo suficientemente competente para soportar la presión aplicada por el fluido de perforación y puede desplomarse bajo esta presión y

permitir que el fluido de perforación fluya al interior de la misma.

La presente invención está dirigida a esta última situación en donde la formación se desploma por la presión del fluido de perforación. Uno de los factores limitativos en la perforación de una porción particular de un pozo es el peso del lodo de circulación (densidad del fluido de perforación) que puede ser utilizado. Si se emplea un peso de lodo demasiado elevado, se crean fracturas en la pared del pozo con la consecuente pérdida de fluido de perforación y otros problemas operativos. Por otro lado, si se emplea un peso de lodo demasiado bajo, puede presentarse una invasión de fluidos en la formación, puede derrumbarse el pozo como consecuencia del soporte insuficiente frente a la presión de fluido en el pozo y, en casos extremos, la seguridad puede verse comprometida debido a la posibilidad de una erupción del pozo. En muchos casos, los pozos son perforados a través de zonas débiles o expuestas a la pérdida de circulación antes de alcanzar una zona de producción potencial, requiriendo ello el uso de un peso bajo de lodo y la instalación de sartas de entubado para proteger las zonas más débiles situadas por encima de una zona de producción potencial. En el caso de que pudiera emplearse un mayor peso de lodo en la perforación a través de zonas más débiles o agotadas, existe entonces el potencial de eliminar una o más sartas de entubado en el pozo. La eliminación de incluso una sola sarta de entubado de un pozo proporciona ahorros importantes en cuanto a tiempo, material y costes de perforación del pozo. De este modo, existe la necesidad de disponer de un método para la perforación de pozos en donde se utilice un peso de lodo mayor que aquel que podría utilizarse normalmente sin que surjan problemas de desplome de la formación.

De manera sorprendente, se ha comprobado ahora que el desplome de la formación durante la perforación se puede controlar mediante la perforación del pozo

utilizando un lodo de pérdida de fluido ultra-baja y manteniendo la presión del lodo de perforación por encima de la presión de fractura inicial de la formación y en donde las fracturas que son inducidas en la pared del pozo son puenteadas en o cerca de la boca del mismo mediante un material de macropartículas sólidas que se añade al lodo de perforación y en donde el puente es sellado por la acumulación de aditivos para controlar la pérdida de fluido en los vacíos existentes entre las partículas que efectúan el puente y/o la precipitación de aditivos para controlar la pérdida de fluido sobre las partículas que efectúan el puente. La presencia del puente impermeable al fluido en o cerca de la boca de la fractura fortalece la región de la formación próxima al pozo al generar una jaula de tensiones. A continuación, se continúa la perforación del pozo manteniendo la presión del lodo de perforación por debajo de la presión de desplome de la formación así consolidada.

De este modo, de acuerdo con un primer aspecto de la presente invención se proporciona un método para reducir el desplome de una formación durante la perforación de un pozo, cuyo método comprende:

(a) hacer circular por el pozo un lodo de perforación que comprende (i) un fluido a base de agua o petróleo, (ii) al menos un aditivo para controlar la pérdida de fluido en una concentración eficaz para conseguir una pérdida de fluido a elevada temperatura y elevada presión (HTHP) a partir del lodo de perforación menor de 2 ml/30 minutos y (iii) un material de puente en macropartículas sólidas que tiene un diámetro medio de partícula de 25 a 2.000 micrómetros y una concentración de al menos 0,5 libras por barril (1,43 kg/m^3);

(b) aumentar la presión en el pozo a un valor por encima de la presión de fractura inicial de la formación, de manera que se inducen fracturas en la formación y se forma un puente sustancialmente impermeable al fluido que comprende el material

en macropartículas sólidas y el aditivo o aditivos para controlar la pérdida de fluido en o cerca de la boca de las fracturas, con lo que la formación resulta así fortalecida; (c) continuar entonces la perforación del pozo manteniendo la presión en el mismo por encima de la presión de fractura inicial de la formación y por debajo de la presión de desplome de la formación fortalecida.

Para evitar dudas, la formación fortalecida puede ser una formación permeable o no permeable.

Sin animo de quedar limitados por cualquier teoría en particular, el mecanismo por el cual el método de la presente invención fortalece la pared del pozo y por tanto reduce el desplome de la formación es que, a medida que se induce deliberadamente una fractura en la pared del pozo, el material en macropartículas sólidas entra en la fractura y la puentea en o cerca de la boca de la fractura. Los aditivos que tradicionalmente se incluyen en el lodo de perforación para controlar la pérdida de fluido desde el lodo de perforación al interior de la formación, precipitan posteriormente sobre el material en macropartículas sólidas que puentea la fractura o rellena los vacíos existentes entre el material en macropartículas sólidas, estableciendo con ello una masa o puente inmóvil impermeable al fluido en o cerca de la boca de la fractura. Por tanto, el fluido procedente del lodo de perforación ya no puede pasar al interior de la fractura y la presión dentro de la fractura puede comenzar a disiparse hasta que llega a ser sustancialmente la misma que la presión de la formación circundante. La velocidad de reducción de la presión dentro de la fractura, más allá del puente, dependerá de la permeabilidad de la roca y de otros factores, tales como la acción de soporte del puente que mantiene el desplazamiento de la roca causado por la fractura y la acción de sellado del puente que evita la pérdida de fluido desde el lodo de perforación al interior de la fractura. El

desplazamiento de la roca causado por la fractura hace que la roca en la región de la formación próxima al pozo (por ejemplo, dentro de una distancia radial de hasta 5 pies (1,524 metros) desde la pared del pozo) se encuentre en un estado de compresión, aumentando con ello la "tensión circunferencial" y generando una "jaula de tensiones". En el caso de que exista una reducción de presión en la fractura más allá del puente, la fractura intentará cerrarse y ello impartirá tensión sobre la masa o puente inmóvil impermeable al fluido lo cual, a su vez, conduce a impartir una tensión de compresión adicional en la roca en la región de la formación próxima al pozo. La mayor tensión de compresión en la región de la formación próxima al pozo hace que la pared del pozo tenga una mayor resistencia frente a una fractura adicional. Por tanto, el método de la presente invención permite utilizar, en la perforación del pozo, un lodo de perforación de mayor densidad que aquel que podría utilizarse en ausencia de fortalecimiento de la formación. El método presenta también el efecto beneficioso adicional de reducir la pérdida de fluido desde el lodo de perforación al interior de la formación debido al sellado de las fracturas con la masa inmóvil impermeable al fluido.

El método del primer aspecto de la presente invención difiere de un "apantallamiento" de la extremidad de la fractura en que dicho "apantallamiento" requiere el uso de un lodo de perforación de alta pérdida de fluido, de manera que el material en macropartículas se acumula rápidamente en la extremidad de la fractura, sellando con ello la fractura y evitando que esta última se propague aún más. Por tanto, el experto en la materia podrá comprender que el uso de un lodo de perforación de pérdida de fluido ultra-baja decelerará la deposición de material en macropartículas en la extremidad de la fractura. Además, no existe conocimiento alguno del por qué puede ser preferible realizar el puente en o cerca de la boca de

una fractura. De este modo, los lodos de perforación convencionales utilizados en un "apantallamiento" de la extremidad de la fractura están diseñados de manera que el material en macropartículas penetra fácilmente en la fractura para depositarse en la extremidad de la misma. Igualmente, un "apantallamiento" de la extremidad de la fractura no crea una "jaula de tensiones" eficaz cerca del pozo. Aunque la roca en la extremidad de la fractura se encontrará bajo una mayor tensión por compresión (debido a la acumulación de material en macropartículas en la extremidad de la fractura), dicha tensión no se aplicará a la roca entre la extremidad de la fractura y la boca de la fractura. Por último, ha existido un prejuicio contra el uso de un lodo de perforación de baja pérdida de fluido debido a la creencia de que un lodo de baja pérdida de fluido desceleraría la "velocidad de penetración" mientras se realiza la operación de perforación. Por tanto, resultó sorprendente que un lodo de pérdida de fluido ultra-baja no reduzca de manera importante la "velocidad de penetración".

El valor de la pérdida de fluido para el lodo de perforación se determina empleando un ensayo normalizado de la pérdida de fluido a elevada temperatura y elevada presión (HTHP) de acuerdo con las especificaciones del American Petroleum Institute (API), como se describe en "Recommended Practice Standard Procedure for Field Testing Oil-Based Drilling Fluids", API Recommended Practice 13B-2 Tercera Edición, Febrero 1998, Sección 5.2.1 a 5.2.3; y "Recommended Practice Standard Procedure for Field Testing Oil-Based Drilling Fluids", API Recommended Practice 13B-1 Segunda Edición, Septiembre 1997, Sección 5.3.1 a 5.3.2. El ensayo utiliza una cuba a presión equipada con un papel de filtro endurecido normalizado como medio de filtración. El comportamiento de filtración del lodo de perforación se determina con un diferencial de presión normalizado de un lado a otro del papel de filtro de 500 psi (3,45 M Pa). Se deja que se forme una torta de filtración

sobre el papel de filtro durante 30 minutos y se anota entonces el volumen de filtrado recogido después de dicho periodo de 30 minutos. Debido a que el área de filtración (3,5 pulgadas cuadradas ($2,258x10^{-3}$ m^2)) de la cuba a presión es la mitad del área de filtración de un ensayo de pérdida de fluido a baja temperatura y baja presión (LTLP) según la norma API (7 pulgadas cuadradas $4,516x10^{-3}$ m^2)), el volumen de filtrado después de 30 minutos se duplica para proporcionar un valor corregido de la pérdida de fluido API. Convenientemente, la temperatura a la cual se efectúa el ensayo de pérdida de fluido a elevada temperatura y elevada presión (HTHP) corresponde a la temperatura existente en el pozo. Generalmente, la temperatura del ensayo es del orden de 50 a 150° C.

Por el término "presión de fractura" se quiere dar a entender la presión mínima del fluido en el pozo a la cual se crea una fractura en la pared del pozo. Como resultará evidente para el experto en la materia, la creación de una "jaula de tensiones" cerca del pozo aumentará la presión de fractura de la formación fortalecida. En consecuencia, por la expresión "presión de fractura inicial" de una formación se quiere dar a entender la presión de fractura de la formación antes de la creación de la "jaula de tensiones". La presión de fractura inicial de una formación se puede determinar fácilmente, por ejemplo, a partir de datos históricos.

Por la expresión "presión de desplome de la formación fortalecida" se quiere dar a entender la presión máxima del fluido que puede sostenerse dentro del pozo sin crear una fractura en la formación fortalecida y/o sin que se desplome el puente o puentes impermeables al fluido que se han formado en o cerca de la boca de la fractura o fracturas.

Adecuadamente, la presión en el pozo en la etapa (c) del método del primer aspecto de la presente invención es de al menos 50 psi (0,34 M Pa) por encima de la

presión de fractura inicial de la formación, con preferencia de al menos 300 psi (2,07 M Pa) por encima de la presión de fractura inicial de la formación, por ejemplo de 300 a 1.000 psi (2,07 a 6,90 M Pa) por encima de la presión de fractura inicial de la formación, con la condición de que la presión en el pozo en la etapa (c) se encuentre por debajo de la presión de desplome de la formación fortalecida.

Como es bien conocido para el experto en la materia, la presión en la formación aumenta generalmente con el incremento de la profundidad del pozo. Por tanto, generalmente es necesario aumentar de forma continua la presión del lodo de perforación durante la operación de perforación, por ejemplo, aumentando la densidad del lodo de perforación. Surge un problema cuando la presión incrementada del lodo de perforación excede de la presión de fractura inicial de una formación previamente perforada o excede de la presión de fractura inicial de una formación que todavía no ha sido perforada (referida de aquí en adelante como "formación débil"). Por tanto, el método del primer aspecto de la presente invención se puede emplear para fortalecer dichas formaciones débiles, permitiendo con ello que la presión del lodo de perforación que se utiliza para completar la operación de perforación pueda aumentarse a un valor por encima de la presión de fractura inicial de la formación débil. El método del primer aspecto de la presente invención resulta particularmente ventajoso cuando la formación débil es una formación agotada, es decir, una formación que tiene una menor presión en los poros debido a la producción de hidrocarburos a partir de la misma. Este descenso de la presión en los poros debilita la formación agotada, mientras que las formaciones de baja permeabilidad próximas o intercaladas pueden mantener su presión en los poros.

De este modo, en una modalidad específica del primer aspecto de la presente invención, se proporciona un método para reducir el desplome de una formación

durante la perforación de un pozo a través de una formación débil con un lodo de perforación en circulación, cuyo método comprende:

(a) hacer circular por el pozo un lodo de perforación que comprende (i) un fluido a base de agua o petróleo, (ii) al menos un aditivo para controlar la pérdida de fluido en una concentración eficaz para conseguir una pérdida de fluido a elevada temperatura y elevada presión (HTHP) a partir del lodo de perforación menor de 2 ml/30 minutos y (iii) un material de puente en macropartículas sólidas que tiene un diámetro medio de partícula de 25 a 2.000 micrómetros y una concentración de al menos 0,5 libras por barril (1,43 kg/m^3);

(b) aumentar la presión del lodo de perforación a un valor por encima de la presión de fractura inicial de la formación débil, de manera que se inducen fracturas en la formación débil y se forma un puente sustancialmente impermeable al fluido que comprende el material en macropartículas sólidas y el aditivo o aditivos para controlar la pérdida de fluido en o cerca de la boca de las fracturas, con lo que la formación débil resulta así fortalecida;

(c) continuar entonces la perforación del pozo manteniendo la presión en el mismo por encima de la presión de fractura inicial de la formación débil y por debajo de la presión de desplome de la formación fortalecida.

Queda contemplado que el pozo puede ser perforado empleando un lodo de perforación convencional hasta que la presión en el pozo se aproxime a la presión de fractura inicial de la formación débil. El lodo de perforación convencional se sustituye entonces por (o se convierte en) el lodo de perforación empleado en la etapa (a) antes de aumentar la presión en el pozo a un valor por encima de la presión de fractura inicial de la formación débil. El lodo de perforación convencional se puede convertir en el lodo de perforación empleado en la etapa (a) añadiendo al lodo

un aditivo para controlar la pérdida de fluido (ii) hasta que el valor de la pérdida de fluido HTHP es menor de 2 ml/30 minutos y añadiendo al lodo el material en macropartículas sólidas que efectúa el puente (iii) en una cantidad de al menos 0,5 libras por barril (1,43 kg/m^3). Convenientemente, el material en macropartículas sólidas que efectúa el puente (iii) se puede añadir a un lodo de perforación que comprende los componentes (i) y (ii) inmediatamente antes de aumentar la presión del lodo de perforación a un valor por encima de la presión de fractura inicial de la formación débil. De este modo, el lodo de perforación que se emplea para perforar el pozo hasta que la presión en el pozo se aproxima a la presión de fractura inicial de la formación débil, puede comprender los componentes (i) y (iii) en ausencia del componente (iii).

La formación débil puede residir en una sección del pozo previamente perforada y/o en la roca que próximamente ha de ser perforada. Cuando la formación débil se encuentra en la roca que ha de ser próximamente perforada, es necesario sustituir todo el fluido del pozo por el fluido de perforación empleado en la etapa (a). De este modo, la formación débil es fortalecida a medida que se perfora el pozo. Cuando la formación débil se encuentra en una sección del pozo previamente perforada, solo es necesario sustituir el fluido del pozo en la proximidad de la formación débil. De este modo, se puede introducir en el pozo, como una "píldora", un lodo de perforación que tiene una alta concentración del material sólido en macropartículas y se puede hacer circular hacia la formación débil en donde la composición concentrada del lodo de perforación es comprimida al interior de la formación débil a una presión por encima de la presión de fractura inicial de la formación débil, de manera que el material en macropartículas puentea las fracturas que son inducidas en la pared del pozo en o cerca de la boca del mismo.

Habitualmente, la píldora se comprime al interior de la formación débil sellando la corona anular entre una sarta de perforación y la pared del pozo, subiendo la sarta de perforación hasta que se encuentra inmediatamente por debajo de la formación débil y bombeando la píldora al interior del pozo por medio de la sarta de perforación hasta que la presión en la proximidad de la formación débil es mayor que la presión de fractura inicial. En general, el pozo se paraliza entonces durante un periodo de hasta 0,5 horas. Después de fortalecer la formación débil, se puede continuar la perforación del pozo empleando un lodo de perforación convencional, siempre que la presión en el pozo, en la proximidad de la formación fortalecida, se mantenga por debajo de la presión de desplome de la formación fortalecida. Adecuadamente, la concentración en la píldora del material que efectúa el puente deberá ser de al menos 50 libras por barril (143 kg/m^3), con preferencia de al menos 80 libras por barril (228,8 kg/m^3). Queda también contemplado que la "píldora" se puede emplear como un fluido de terminación y puede ser bombeada al interior del pozo con anterioridad a la aplicación de un cemento cuando se entuba el pozo.

En otro aspecto de la presente invención, se proporciona una composición de lodo de perforación que comprende (a) un fluido a base de agua o petróleo, (b) al menos un aditivo para controlar la pérdida de fluido en una concentración eficaz para conseguir una pérdida de fluido a elevada temperatura y elevada presión (HTHP) a partir del lodo de perforación menor de 2 ml/30 minutos y (c) un material de puente en macropartículas sólidas que tiene un diámetro medio de partícula de 25 a 2.000 micrómetros y una concentración de al menos 0,5 libras por barril (1,43 kg/m^3).

Adecuadamente, la densidad específica del lodo de perforación es del orden de 0,9 a 2,5, con preferencia del orden de 1,0 a 2,0.

Convenientemente, el material sólido en macropartículas que efectúa el

puente y que se incluye en el lodo de perforación para puentear las fracturas (de aquí en adelante "material de puente") comprende al menos un sólido en macropartículas sustancialmente resistente a la trituración, de manera que el material de puente mantiene abiertas las fracturas (grietas y fisuras) que son inducidas en la pared del pozo. Por el término "resistente a la trituración" se quiere dar a entender que el material de puente es físicamente lo suficientemente fuerte para soportar las tensiones de cierre ejercidas sobre el puente de la fractura. Materiales de puente preferidos para añadirse al lodo de perforación incluyen grafito, carbonato cálcico (preferentemente, mármol), dolomita ($MgCO_3 \cdot CaCO_3$), celulosas, micas, materiales consolidantes tales como arenas o partículas cerámicas y combinaciones de los anteriores. Estos materiales son muy inertes y son aceptables desde el punto de vista medioambiental. También queda contemplado que una porción del material de puente puede comprender detritos de perforación que tienen el diámetro medio de partícula deseado del orden de 25 a 2.000 micrómetros.

La concentración del material de puente puede variar con el lodo de perforación empleado y con las condiciones de uso. La concentración ha de ser al menos lo suficientemente grande para que el material de puente puentee rápidamente las fracturas (es decir, grietas y fisuras) que son inducidas en la pared del pozo, pero no deberá ser tan elevada que haga impracticable la circulación del lodo de perforación. Adecuadamente, el material de puente deberá puentear las fracturas que son inducidas en la pared del pozo en un plazo menor de 10 segundos, con preferencia menor de 5 segundos desde que se abre la fractura, de manera que la fractura se mantenga durante un corto periodo. De este modo, el sellado rápido de la fractura mitiga el riesgo de que se propague la fractura. Convenientemente, la concentración del material de puente en el lodo de perforación es de al menos 5

libras por barril (14,3 kg/m^3), con preferencia de al menos 10 libras por barril (28,6 kg/m^3), más preferentemente de al menos 15 libras por barril (42,9 kg/m^3), por ejemplo, al menos 30 libras por barril (85,8 kg/m^3). Sin embargo, como se ha indicado anteriormente, cuando el lodo de perforación se emplea en un tratamiento con "píldoras", la concentración del material de puente en macropartículas es adecuadamente de al menos 50 libras por barril (143 kg/m^3), con preferencia de al menos 80 libras por barril (228,8 kg/m^3).

Adecuadamente, el material de puente presenta unas dimensiones tales que no penetra por los poros de cualquier roca permeable a través de la cual está siendo perforado el pozo. Con preferencia, el material de puente tiene un diámetro medio de partícula del orden de 50 a 1.500 micrómetros, más preferentemente de 250 a 1.000 micrómetros. El material de puente puede comprender partículas sustancialmente esféricas. Sin embargo queda también contemplado que el material de puente puede comprender partículas alargadas, por ejemplo, varillas o fibras. Cuando el material de puente comprende partículas alargadas, la longitud media de las mismas deberá ser tal que las partículas alargadas sean capaces de puentear las fracturas inducidas o cerca de la boca de las mismas. Generalmente, las partículas alargadas tendrán una longitud media del orden de 25 a 2.000 micrómetros, con preferencia de 50 a 1.500 micrómetros y más preferentemente de 250 a 1.000 micrómetros.

El material de puente tiene unas dimensiones tales que forma fácilmente un puente en o cerca de la boca de las fracturas inducidas. Normalmente, las fracturas que son inducidas en la pared del pozo tienen un ancho en la boca del orden de 0,1 a 5 mm. El ancho de la fractura depende, entre otros factores, de la resistencia (rigidez) de la roca de la formación y del grado en el cual se aumenta la presión en el pozo a un valor por encima de la presión de fractura inicial de la formación durante la etapa

de inducción de la fractura (b) del método de la presente invención (en otras palabras, el ancho de la fractura depende de la diferencia de presión entre el lodo de perforación y la presión de fractura inicial de la formación durante la etapa de inducción de las fracturas). Es preferible que al menos una porción del material de puente, preferentemente una porción principal del material de puente, tenga un diámetro de partícula que se aproxime al ancho de la boca de la fractura. Con preferencia, el material de puente tiene una distribución de tamaño de partícula amplia (polidispersa).

Es necesario mantener el material de puente en suspensión en el lodo de perforación. En general, el lodo de perforación es reciclado al pozo después de separar prácticamente la totalidad de los detritos de perforación. Los detritos de perforación pueden ser separados empleando tamices como resulta bien conocido para el experto en la materia. Normalmente, el lodo de perforación se filtra empleando un tamiz de tamaño de malla 200 (serie de tamices US) que retiene partículas que tienen un tamaño mayor de 74 micrómetros. Sin embargo, en el método de la presente invención, es necesario filtrar el lodo empleando un tamiz más basto con el fin de evitar la separación del lodo de cantidades importantes del material de puente. Convenientemente, el lodo de perforación se filtra empleando un tamiz de malla 35 (serie de tamices US) que retiene partículas que tienen un tamaño mayor de 500 micrómetros. Sin embargo, si la reología del lodo se deteriora a través de la acumulación en el lodo de detritos finos de la perforación, puede ser necesario emplear tamices de malla más fina durante un corto periodo de tiempo. También queda contemplado que pueden emplearse métodos de separación que permitan la retención de los sólidos de material de puente pero que puedan separar del lodo de perforación una porción principal de los detritos, con preferencia prácticamente todos

los detritos. En particular, los detritos se pueden separar del lodo de perforación en base a diferencias en las densidades de los detritos y de las partículas de puente, por ejemplo, empleando centrífugas o hidrociclones. Con el fin de mantener la concentración del material de puente en el valor deseado en el lodo de perforación y/o mantener el valor de pérdida de fluido del lodo de perforación por debajo de 2 ml/30 minutos, puede ser necesario introducir material de puente nuevo y/o aditivos nuevos para controlar la pérdida de fluido, respectivamente, en el lodo de perforación en circulación. Alternativa o adicionalmente, se puede añadir lodo de perforación nuevo, bien de forma continua o bien de forma intermitente, al lodo de perforación que está circulando por el pozo.

El lodo de perforación tiene un valor de pérdida de fluido HTHP menor de 2 ml/30 minutos, con preferencia menor de 1 ml/30 minutos, más preferentemente menor de 0,5 ml/30 minutos, por ejemplo de 0,1 a 0,3 ml/30 minutos. Como resultará evidente para el experto en la materia, dichos valores de pérdida de fluido ultra-bajos se pueden conseguir incorporando en el lodo de perforación al menos un aditivo para controlar la pérdida de fluido. Sin que ello suponga una limitación a una teoría en particular, se cree que el aditivo o aditivos para controlar la pérdida de fluido se acumulará sobre el material sólido en macropartículas que puentea las fracturas en o cerca de la boca de las mismas, formando con ello una masa inmóvil impermeable al fluido. Cuando el material sólido en macropartículas que efectúa el puente es poroso, los aditivos para controlar la pérdida de fluido pueden entrar también en los poros del material de puente para sellar los poros.

Aditivos adecuados para controlar la pérdida de fluido que pueden incorporarse en el lodo de perforación de la presente invención incluyen polímeros orgánicos de origen natural o sintético. Polímeros adecuados incluyen almidón o

almidones químicamente modificados; derivados de celulosa tales como carboximetilcelulosa y celulosa polianiónica (PAC); goma guar y goma de xantano; homopolímeros y copolímeros de monómeros seleccionados del grupo consistente en ácido acrílico, acrilamida, ácido archilamido-2-metilpropanosulfónico (AMPS), ácido estirenosulfónico, N-vinilacetamida, N-vinilpirrolidona y N,N-dimetilacrilamida, en donde el copolímero tiene un peso molecular medio en número de 100.000 a 1.000.000 y con preferencia de 200.000 a 500.000; asfaltos (por ejemplo, asfaltos sulfonados); gilsonita; lignito y sus derivados, ácido húmico; lignina y sus derivados tales como ligninsulfonatos o ligninsulfonatos poliméricos condensados; y combinaciones de los anteriores. Estos aditivos poliméricos son particularmente adecuados para utilizarse en lodos de perforación a base de petróleo. Como alternativa o, en adición, al empleo de dichos aditivos poliméricos, la pérdida de fluido del lodo de perforación de la presente invención se puede reducir añadiendo al lodo de perforación partículas finamente dispersas tales como arcillas (por ejemplo, ilita, caolinita, bentonita o sepiolita). Adecuadamente, las partículas finamente dispersas tienen un tamaño medio de partícula menor de 10 micrómetros, con preferencia menor de 5 micrómetros, por ejemplo de 1 micrómetro aproximadamente. Preferentemente, el lodo de perforación contiene un intervalo uniforme/continuo de tamaños de partícula que oscila desde 1 micrómetro aproximadamente para los aditivos reductores de la pérdida de fluido a un diámetro medio de partícula del material de puente de hasta 2.000 micrómetros, es decir, presenta una distribución del tamaño de partícula amplia (polidispersa).

Queda contemplado que un lodo de perforación a base de petróleo puede contener una cantidad importante de una fase acuosa discontinua dispersada en una fase oleosa continua por medio de al menos un emulsionante (una emulsión de agua

en aceite). El valor de la pérdida de fluido de dichos lodos de perforación puede variar en función de la relación de petróleo a agua y de la naturaleza del emulsionante o emulsionantes utilizados para formar la emulsión de agua en aceite (y por tanto del tamaño de las gotitas dispersas de agua). Con preferencia, el contenido en agua del lodo de perforación es del orden de 80:20 a 50:50, más preferentemente de 70:30 a 55:45. Los emulsionantes preferidos incluyen imidazolinas, ácidos grasos y combinaciones de los mismos.

Lodos de perforación a base de petróleo que presentan una pérdida de fluido ultra-baja, particularmente preferidos, se describen en SPE 77446, "Towards Zero Fluid Loss Oil Based Muds". M. Aston, P. Mihalik, J. Tunbridge y S. Clarke, publicado en 2002.

La eficacia del método de la presente invención ha quedado demostrada en condiciones tanto de laboratorio como del campo, como se expone en los siguientes ejemplos.

Ejemplo 1

Se evaluaron en el laboratorio formulaciones de lodos a base de petróleo inyectando diferentes lodos de perforación en una fractura modelo (como se describe en SPE/IADC 87130, "Drilling Fluids for Wellbore Strengthening", 2-4 Marzo 2004, M.S. Aston et al). La fractura modelo se formó a partir de dos piezas de roca de configuración rectangular (de piedra arenisca "Ohio" con una permeabilidad de 0,3 miliDarcy). Cada pieza de roca tenía unas dimensiones aproximadas de 5 cm de ancho x 20 cm de longitud x 1 cm de profundidad. Las dos piezas de roca fueron emparedadas de forma conjunta para crear una fractura que tiene una abertura de boca de 1 mm, conificando la abertura de la fractura a 0,5 mm en el extremo distante de la misma (extremidad de la fractura). Se proporcionó una válvula en la salida de la

extremidad de la fractura, de manera que la extremidad de la fractura pudiera ser abierta o sellada. El emparedado de roca se colocó en un apoyo construido para ese fin, el cual se soportó en una estructura de carga dentro de una cuba de ensayo. El ancho de la fractura se mantuvo constante empleando separadores fijos. Se midió la presión de fluido dentro de la fractura justo en el interior de la boca de la fractura empleando un transductor de presión. Inicialmente, la fractura y los espacios porosos de la roca se llenaron con un fluido limpio (agua) y el sistema se calentó a una temperatura de 60° C. Se aplicó una presión de alrededor de 100 psi (0,69 M Pa) para comprimir cualquier aire presente en el sistema. Se inyectó entonces lodo de perforación a una presión de 400 psi (2,76 M Pa) al interior de la boca de la fractura manteniendo abierta la extremidad de la fractura (para proporcionar una presión diferencial de un lado a otro de la fractura de 300 psi (2,07 M Pa)). Después de 3 minutos, se cerró la salida de la extremidad de la fractura empleando la válvula, de manera que se pudiera acumular presión dentro de la fractura (nota: la fuerza de impulsión inicial para la formación del puente en la boca de la fractura fue para evitar pérdidas de fluido a través de la extremidad de la fractura). Se aumentó entonces la presión de inyección gradualmente a 2.000 psi (13,97 M Pa). Una presión baja medida en el transductor de presión indicó un sellado eficaz en la boca de la fractura.

Los resultados ofrecidos en la siguiente tabla 1 comparan las presiones medidas justo dentro de la boca de la fractura para diferentes lodos de perforación utilizados en el procedimiento de ensayo anterior. La presión justo en el interior de la boca de la fractura se midió después de alcanzarse un valor constante en cada presión de inyección.

Tabla 1 - Eficacia de lodos de perforación en el sellado de una fractura modelo

Sistema de lodo		Presión justo dentro de la boca de la fractura, medida después de diferentes presiones de inyección del lodo (IP) en psi		
		IP 400 (2,76 M Pa)	IP 1.000 (6,70 M Pa)	IP 2.000 (13,79 M Pa)
Lodo 1 (Comparativo)	Mezcla A de lodo base más material de puente en macropartículas; pérdida de fluido HTHP API = 3 ml/30 min a una temperatura de 60° C	300 (2,07 M Pa)	900 (6,21 M Pa)	1.900 (13,10 M Pa)
Lodo 2	Como el lodo 1, pero conteniendo 5 lb/bbl Pliolita, pérdida de fluido HTHP API = 0,3 ml/30 min a una temperatura de 60° C	0	30 (1,31 M Pa)	1.900 (13,10 M Pa)
Lodo 3	Mezcla B de lodo base más material de puente en macropartículas más 5 lb/bbl Pliolita (14,3 kg/m^3). pérdida de fluido HTHP API = 0,1 ml/30 min a una temperatura de 60° C	0	0	0

El lodo 2 forma un sellado más eficaz que el lodo 1 (Comparativo). Esto se consiguió reduciendo la pérdida de fluido HTHP API del sistema de lodo desde 3 ml/30 minutos a 0,3 ml/30 minutos. El lodo 3 consiguió un sellado total en la boca de la fractura empleando una mezcla mejorada de material de puente en macropartículas en un lodo que tiene una pérdida de fluido HTHP API de 0,1 ml/30 minutos.

La formulación para el lodo base empleado en los ensayos anteriores fue como sigue:

Aceite mineral:	0,517 bbls (0,0822 m^3)
Versamul™ (emulsionante de MI)	4,7 lb/bbl (13,4 kg/m^3)

Versawet™ (agente humectante de MI)	7 lb/bbl (20,0 kg/m^3)
Geltone™ (organoarcilla de Halliburton)	6 lb/bbl (17,2 kg/m^3)
Cal	5,25 lb/bbl (15,0 kg/m^3)
Cloruro cálcico	17,6 lb/bbl (50,4 kg/m^3)
Agua	0,346 lb/bbl (1,0 kg/m^3)
Barita (sulfato de bario)	50 lb/bbl (143 kg/m^3)
Hymod Prima Clay (sólidos de perforación simulados)	4,5 lb/bbl (12,9 kg/m^3)

El lodo 1 es el lodo base que contiene los siguientes materiales de puente en macropartículas (mezcla A):

Baracarb™ 150:	46 lb/bbl (131,6 kg/m^3)
Baracarb™ 600:	9,3 lb/bbl (26,6 kg/m^3)

El lodo 2 es como el lodo 1 pero con la adición de 5 lb/bbl Pliolite® DF-01 (aditivo para el control de la pérdida de fluido suministrado por Goodyear).

El lodo 3 es el lodo base conteniendo 5 lb/bbl (143 kg/m^3) Pliolite® DF-01 y los siguientes materiales de puente en macropartículas (mezcla B):

Baracarb™ 150:	18lb/bbl (51,5 kg/m^3)
Baracarb™ 600:	18 lb/bbl (51,5 kg/m^3)
Steelseal™:	15 lb/bbl (42,9 kg/m^3)

Baracarb™ 150, Baracarb™ 600 y Steelseal™ se obtuvieron en Halliburton. Baracarb™ 150 y Baracarb™ 600 son carbonatos de calcio con un diámetro medio de partícula de 150 micrómetros y 600 micrómetros, respectivamente. Steelseal™ es un carbón grafítico suministrado por Halliburton, con un intervalo de tamaño medio de aproximadamente 400 micrómetros.

Ejemplo 2

Se llevó a cabo un ensayo práctico en tierra en el estanque de Arkoma, USA, para determinar si el método de la presente invención podía aumentar o no la resistencia de la fractura en una formación de pizarra. El pozo fue un pozo vertical con un entubado de 9 5/8" (24,5 cm). Se realizó un ensayo de obturación prolongada

(tratamiento de la píldora por compresión) en 10 pies (3,048 metros) de formación de pizarra expuesta (agujero abierto) justo por debajo de la zapata del entubado de 9 5/8" (24,5 cm). En este ensayo, se emplearon procedimientos de "obturación" normalizados en donde la corona anular estaba cerrada mientras se bombeaba lodo al interior del pozo. Inicialmente, estaba presente en el pozo un lodo a base de diesel normalizado y este lodo fue bombeado al interior del pozo a una velocidad de 0,25 bbls/minuto (0,04 m^3/minuto) hasta que se presentó el desplome de la formación de pizarra expuesta.

La figura 1 ilustra la curva de presión de obturación prolongada para el lodo a base de diesel normalizado (curva 1). La formación de pizarra se fracturó a 1.200 psi (8,27 M Pa) aproximadamente, en cuyo momento se detuvo el bombeo del lodo de perforación a base de diesel normalizado, para reducir al mínimo el crecimiento de la fractura. La presión se estabilizó en 800 psi (5,52 M Pa), que es la presión de propagación de las fracturas determinada por el estado de tensión en campo lejano. El exceso de presión en el pozo fue purgado (de nuevo a presión hidrostática), de manera que se cerraron las fracturas y se repitió entonces el procedimiento de obturación bombeando una píldora de un lodo de acuerdo con la presente invención (de aquí en adelante "lodo del inventor") al interior del pozo, también a una velocidad de 0,25 bbls/minuto (0,04 m^3/minuto). La figura 1 ilustra además la curva de obturación prolongada para el lodo del inventor (curva 2). Las fracturas inducidas en la pared del pozo abierto son puenteadas y selladas por las partículas de puente y aditivos reductores de la pérdida de fluido del lodo del inventor y la presión de desplome de la formación fortalecida asciende a un valor por encima de 2.000 psi (13,79 M Pa) antes de que se desplome el sellado. Se trata esto de un incremento de alrededor de 850 psi (5,86 M Pa) en la presión de desplome de la formación en

comparación con el estado original de la formación de pizarra, equivalente a un peso de lodo de 5,4 libras por galón (ppg) (647 kg/m^3).

El valor de pérdida de fluido HTHP API para el lodo del inventor empleado en la prueba práctica fue de 0,45 ml a una temperatura de 115° F (46° C) (temperatura en el fondo del pozo), mientras que el lodo a base de diesel normalizado tenía una pérdida de fluido HTHP API de 10 ml a una temperatura de 250° F (121° C). El lodo del inventor se preparó añadiendo sólidos de puente de carbonato cálcico, sólidos de puente de material grafítico y aditivos reductores de la pérdida de fluido al lodo a base de diesel normalizado de acuerdo con la presente invención. El tamaño de los sólidos de puente osciló entre 10 y 800 micrómetros y dichos sólidos se añadieron en una cantidad de 80 libras por barril (228,8 kg/m^3). El lodo a base de diesel normalizado original tenía un peso de lodo de 9,0 ppg (1.078 kg/m^3) y estaba libre de sólidos de puente incorporados.

REIVINDICACIONES

1.- Un método para reducir el desplome de una formación durante la perforación de un pozo, caracterizado porque comprende:

(a) hacer circular por el pozo un lodo de perforación que comprende (i) un fluido a base de agua o petróleo, (ii) al menos un aditivo para controlar la pérdida de fluido en una concentración eficaz para conseguir una pérdida de fluido a elevada temperatura y elevada presión (HTHP) a partir del lodo de perforación menor de 2 ml/30 minutos, en donde la pérdida de fluido HTHP se determina empleando un ensayo HTHP de acuerdo con las especificaciones del American Petroleum institute (API), como se describe en API Recommended Practice 13B-2 Tercera Edición, Febrero 1998, Sección 5.2.1 a 5.2.3 o Recommended Practice 13B-1 Segunda Edición, Septiembre 1997, Sección 5.3.1 a 5.3.2, y (iii) un material de puente en macropartículas sólidas que tiene un diámetro medio de partícula de 25 a 2.000 micrómetros y una concentración de al menos 0,5 libras por barril (1,43 kg/m^3);

(b) aumentar la presión en el pozo a un valor por encima de la presión de fractura inicial de la formación, de manera que se inducen fracturas en la formación y se forma un puente sustancialmente impermeable al fluido que comprende el material en macropartículas sólidas y el aditivo o aditivos para controlar la pérdida de fluido en o cerca de la boca de las fracturas, con lo que la formación resulta así fortalecida;

(c) continuar entonces la perforación del pozo manteniendo la presión en el mismo por encima de la presión de fractura inicial de la formación y por debajo de la presión de desplome de la formación fortalecida.

2.- Un método según la reivindicación 1, caracterizado porque la presión en el pozo en la etapa (c) se mantiene en al menos 300 psi (2,07 M Pa) por encima de la presión de fractura inicial de la formación y por debajo de la presión de desplome

de la formación fortalecida.

3.- Un método según la reivindicación 1 o 2, caracterizado porque el material de puente en macropartículas sólidas se añade a un lodo de perforación en circulación que tiene un valor de pérdida de fluido HTHP menor de 2 ml/30 minutos antes de aumentar la presión en el pozo a un valor por encima de la presión de fractura inicial de la formación.

4.- Un método según cualquiera de las reivindicaciones anteriores, caracterizado porque la formación fortalecida es una formación agotada.

5.- Un método según cualquiera de las reivindicaciones 1 a 3, caracterizado porque la formación fortalecida es una formación débil en una sección de pozo previamente perforada.

6.- Un método según cualquiera de las reivindicaciones anteriores, caracterizado porque el lodo de perforación tiene un valor de pérdida de fluido HTHP menor de 1 ml/30 minutos, con preferencia menor de 0,5 ml/30 minutos.

7.- Un método según cualquiera de las reivindicaciones anteriores, caracterizado porque la concentración de material de puente en macropartículas sólidas en el lodo de perforación en circulación es de al menos 10 libras por barril (26,6 kg/m^3), con preferencia de al menos 15 libras por barril (42,9 kg/m^3).

8.- Un método según cualquiera de las reivindicaciones anteriores, caracterizado porque el lodo de perforación se recicla al pozo después de separar del mismo el material que tiene un tamaño mayor de 500 micrómetros empleando un tamiz de malla 35 (serie de tamices US).

9.- Un método según la reivindicación 8, caracterizado porque se añade material de puente nuevo en macropartículas sólidas al lodo de perforación antes de reciclar el lodo de perforación al pozo.

10.- Un método según cualquiera de las reivindicaciones 1 a 7, caracterizado porque el lodo de perforación se recicla al pozo después de separar del mismo los detritos de perforación empleando una centrífuga o hidrociclón.

11.- Un método según la reivindicación 5 o 6, caracterizado porque se hace circular por la formación débil una píldora del lodo de perforación que tiene una concentración de material de puente en macropartículas sólidas de al menos 50 libras por barril (143 kg/m^3) y se comprime dicha píldora dentro de la formación débil, manteniendo la presión en el pozo en la proximidad de la formación débil en una valor por encima de la presión de fractura inicial de la formación débil.

12.- Una composición de lodo de perforación, caracterizada porque comprende (a) un fluido a base de agua o petróleo, (b) al menos un aditivo para controlar la pérdida de fluido en una concentración eficaz para conseguir una pérdida de fluido a elevada temperatura y elevada presión (HTHP) a partir del lodo de perforación menor de 2 ml/30 minutos, en donde la pérdida de fluido HTHP se determina empleando un ensayo HTHP de acuerdo con las especificaciones del American Petroleum institute (API). como se describe en API Recommended Practice 13B-2 Tercera Edición, Febrero 1998, Sección 5.2.1 a 5.2.3 o Recommended Practice 13B-1 Segunda Edición, Septiembre 1997, Sección 5.3.1 a 5.3.2, y (c) un material de puente en macropartículas sólidas que tiene un diámetro medio de partícula de 50 a 1.500 micrómetros y una concentración de al menos 0,5 libras por barril (1,43 kg/m^3).

13.- Una composición de lodo de perforación según la reivindicación 12, caracterizada porque tiene una densidad específica del orden de 0,9 a 2,5.

14.- Una composición de lodo de perforación según la reivindicación 12 o 13, caracterizada porque el material de puente en macropartículas sólidas comprende

al menos un sólido en macropartículas sustancialmente resistente a la trituración y seleccionado del grupo consistente en grafito, carbonato cálcico (preferentemente mármol), dolomita, celulosas, micas, arena y partículas cerámicas.

15.- Una composición de lodo de perforación según cualquiera de las reivindicaciones 12 a 14, caracterizada porque la concentración del material de puente en macropartículas sólidas es de al menos 10 libras por barril (28,6 kg/m^3), con preferencia de al menos 15 libras por barril (42,9 kg/m^3).

16.- Una composición de lodo de perforación según cualquiera de las reivindicaciones 12 a 15, caracterizada porque el material de puente en macropartículas sólidas tiene un diámetro medio de partícula del orden de 250 a 1.000 micrómetros.

17.- Una composición de lodo de perforación según cualquiera de las reivindicaciones 12 a 16, caracterizada porque tiene un valor de pérdida de fluido HTHP menor de 1 ml/30 minutos, con preferencia menor de 0,5 ml/30 minutos.

18.- Una composición de lodo de perforación según cualquiera de las reivindicaciones 12 a 17, caracterizada porque el aditivo o aditivos para controlar la pérdida de fluido se eligen entre polímeros orgánicos de origen natural o sintético y arcillas finamente dispersas.

RESUMEN

Un método para reducir el desplome de una formación durante la perforación de un pozo, cuyo método comprende: (a) hacer circular por el pozo un lodo de perforación que comprende (i) un fluido a base de agua o petróleo, (ii) al menos un aditivo para controlar la pérdida de fluido en una concentración eficaz para conseguir una pérdida de fluido a elevada temperatura y elevada presión (HTHP) a partir del lodo de perforación menor de 2 ml/30 minutos y (iii) un material de puente en macropartículas sólidas que tiene un diámetro medio de partícula de 25 a 2.000 micrómetros y una concentración de al menos 0,5 libras por barril (1,43 kg/m^3); (b) aumentar la presión en el pozo a un valor por encima de la presión de fractura inicial de la formación, de manera que se inducen fracturas en la formación y se forma un puente sustancialmente impermeable al fluido que comprende el material en macropartículas sólidas y el aditivo o aditivos para controlar la pérdida de fluido en o cerca de la boca de las fracturas, con lo que la formación resulta así fortalecida; (c) continuar entonces la perforación del pozo manteniendo la presión en el mismo por encima de la presión de fractura inicial de la formación y por debajo de la presión de desplome de la formación fortalecida.

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4th May 2005

PAT/FMC/jnw/098/10061

BY COURIER

Dear Sirs

International Patent Application No: PCT/GB2004/003154
International Filing date 19 July 2004
Our Ref: Case 10061

This is in response to the Written Opinion dated 10 February 2005, that has been issued in respect of the above-identified International patent application.

Please replace the claims as previously filed with new claims 1 to 18.

Claims 1 and 12 have been amended by incorporating the feature "wherein the HTHP fluid loss is determined using an HTHP test according to the specifications of the American Petroleum Institute (API), as described in API Recommended Practice 13B-2 Third Edition, February 1998, Section 5.2.1 to 5.2.3 or Recommended Practice 13B-1 Second Edition, September 1997, Section 5.3.1 to 5.3.2." Basis for this amendment is to be found at page 4, line 24 to page 5, line 7 of the present application.

Claim 12 has also been amended such that the bridging particulate material has an average particle diameter in the range 50 to 1500 microns. Support for this amendment is provided at page 8, lines 31 to 32 of the specification.

Claim 16 has been amended such that the average particle diameter is in the range 250 to 1000 microns. Basis for this amendment is provided at page 8, lines 31 to 33 of the specification.

contd/....

Re: Item V

EP 1074598 (D1) discloses a drilling fluid comprising an aqueous base fluid, a bridging agent and a fluid loss control additive (see paragraph [0011]). The bridging material may be calcium carbonate or dolomite at a concentration of 5 to 50 ppb (see paragraphs [0031 to [0033]). The fluid loss of the drilling fluid is said to be less than 10 ml as measured at a temperature of 185°C and 250 psi differential pressure across a 5 micron disk for 30 minutes (see paragraph [0041]). D1 teaches that a fluid loss measured under these conditions is a high temperature, high pressure fluid loss (see paragraph [0059]). However, the measurement was carried out at a lower differential pressure (250 psi) and a higher temperature (185°C) than employed in the test of amended Claim 12. Thus, the test according to the specification of the American Petroleum Institute (API) is carried out at a differential pressure of 500 psi and a temperature of up to 177°C (see Item VIII). The person skilled in the art would understand that the volume of filtrate collected in Example 10 of D1 is likely to be considerably less than if the test had been performed at the higher differential pressure of the API test. The Examiner states that Example 10 of D1 shows HTHP fluid loss of between 1.5 and 4 ml in 30 minutes. However, the lower values of fluid loss for Example 10 relate to "spurt loss" during the initial period of the test. The fluid loss values at 30 minutes were from 3 to 4 ml i.e. greater than the upper limit for the fluid loss value of Claim 12.

As acknowledged by the Examiner, there is no disclosure of a particle size range of 25 to 2000 microns for the bridging agent of D1. The bridging agent employed in the fluids of D1 is said to have particles that have been sized to have a particle size distribution sufficient to seal off the pores of the formations contacted by the well drilling and servicing fluid (see paragraph [0030]). Similarly, in document D4 (US 6,403,537), the system preferably includes bridging agents to bridge the pores in the formation. In contrast, the bridging particulate material of the composition of Claim 12 of the present application is sized so as to readily form a bridge at or near the mouth of induced fractures as opposed to being sized to bridge the pores. Typically, the fractures that are induced in the wellbore wall have a fracture width at the mouth in the range 0.1 to 5 mm (100 to 5000 microns) and it is preferred that at least a portion of the bridging material has a particle diameter approaching the width of the fracture mouth (see page 9, lines 8 to 18 of the present application). In contrast, the pores of a formation typically have a pore throat width of less than 50 microns. Accordingly, the preferred calcium carbonate particles of D4, having a mean particle size of about 30 microns, are the ideal size for bridging the pores of a formation. Larger particles are preferred for bridging at or near the mouth of the induced fractures. Thus, in Example 1 of the present application, the bridging particulate materials have average particle diameters of 150, 600 and approximately 400 microns. In order to further distinguish the composition of Claim 12 from the cited art, the range for the average

particle diameter of Claim 12 has been amended to exclude particles having a mean particle size of about 30 microns. The Applicant therefore believes that (a) the use of the bridging particles of the composition of Claim 12 is different to the use of the bridging particles of the compositions of documents D1 and D4 and (b) the size of the bridging particles of the composition of amended Claim 12 is different to the size of the preferred bridging particles of document D4. Accordingly, the range of particle sizes in amended Claim 12 is not unduly broad.

Applicant therefore considers that amended Claim 12 and dependent Claims 13 to 18 are inventive in the light of document D1 when taken alone and when combined with document D4.

Re: Item VII

1) The expression incorporated by reference, has been deleted from Page 11 of the present application.

2) The units "pounds per barrel", "bbls" (barrels), "lb per barrel", "lb/bbl", "psi", "pounds per gallon", "ppg" (pounds per gallon), and "feet" employed in Claims 1, 7, 11, 12 and 15 and on page 4-8, 12-15 have been additionally expressed in terms of the units stipulated by Rule 10.1/(1)/and/(b) PCT.

Re: Item VIII

The Examiner considered that the subject matter of claims 1, 6, 12 and 17 was not clear (Art. 6 PCT) because the operating conditions of the HTHP fluid loss measurement were not given. Claims 1 and 12 have been amended to clarify the test is carried out according to the specifications of the American Petroleum Institute (API). Claims 6 and 17 are dependent upon Claims 1 and 12 respectively and therefore also incorporate this amendment. Copies of the API test procedures are enclosed. The API test employs a Whatman No. 50 or S&S 576, or equivalent, filter paper, as the filtration medium and a differential pressure across the filtration medium of 500 psi. The test temperature may be up to and including 350°F (177°C). However, the test temperature is not fixed. Instead, as stated at page 5, lines 5 to 7 of the present application:

"Suitably, the temperature at which the high temperature high pressure (HTHP) fluid loss test is carried out corresponds to the temperature in the borehole. Generally, the test temperature is in the range 50 to 150°C."

A replacement description and replacement set of claims is enclosed in duplicate. Owing to the large number of amendments, a marked-up

description and claims is provided with the amendments highlighted in bold.

Yours faithfully

F. M. Collins

Dr F M Collins
Authorised Agent

Encs.

Amended page 102

Case 10061(2)

DRILLING METHOD

The present invention relates to drilling of wells through a subterranean formation, and more particularly to a method of increasing the resistance of the wellbore wall to fracturing during drilling operations.

Conventionally, the drilling of a well into the earth by rotary drilling techniques, involves the circulation of a drilling fluid from the surface of the earth down a drill string having a drill bit on the lower end thereof and through ports provided in the drill bit to the well bottom and thence back to the surface through the annulus formed about the drill string. Commonly, drilling fluids are employed that are either oil or water based. These fluids are treated to provide desired rheological properties which make the fluids particularly useful in the drilling of wells.

A problem often encountered in the drilling of a well is the loss of unacceptably large amounts of drilling fluid into subterranean formations penetrated by the well. This problem is often referred to generally as "lost circulation," and the formations into which the drilling fluid is lost are often referred to as "lost circulation zones" or "thief zones". Various causes may be responsible for the lost circulation encountered in the drilling of a well. For example, a formation penetrated by the well may exhibit unusually high permeability or may contain fractures or crevices therein. In addition, a formation may simply not be sufficiently competent to support the pressure applied by the drilling fluid and may break down under this pressure and allow the drilling fluid to flow thereinto.

It is this latter situation where the formation is broken down by the pressure of the drilling fluid to which the present invention is addressed. One of the limiting factors in drilling a particular portion of a well is the mud weight (density of the drilling fluid)

that can be used. If too high a mud weight is used, fractures are created in the wall of the borehole with resulting loss of drilling fluid and other operating problems. On the other hand, if too low a mud weight is used, encroachment of formation fluids can occur. borehole collapse may occur due to insufficient support from the fluid pressure in the wellbore, and in extreme cases safety can be compromised due to the possibility of a well blowout. In many cases, wells are drilled through weak or lost-circulation-prone zones prior to reaching a potential producing zone, requiring use of a low mud weight and installation of sequential casing strings to protect weaker zones above a potential producing zone. If a higher weight mud could be used in drilling through weaker or depleted zones, then there is a potential for eliminating one or more casing strings in the well. Elimination of even one casing string from a well provides important savings in time, material and costs of drilling the well. Thus, there is a need for a method of drilling boreholes using a higher mud weight than could normally be used without encountering formation breakdown problems.

Surprisingly, it has now been found that formation breakdown during drilling can be controlled by drilling the borehole using an ultra-low fluid loss mud with the pressure of the drilling mud maintained at above the initial fracture pressure of the formation wherein the fractures that are induced in the wellbore wall are bridged at or near the mouth thereof by a solid particulate material that is added to the drilling mud and the bridge is sealed by the accumulation of fluid loss additives in the voids between the bridging particles and/or the precipitation of fluid loss additives onto the bridging particles. The presence of the fluid impermeable bridge at or near the mouth of the fracture strengthens the near wellbore region of the formation by generating a stress cage. Thereafter, the drilling of the wellbore is continued with the pressure of the drilling mud maintained at below the breakdown pressure of the strengthened formation.

Thus, according to a first aspect of the present invention there is provided a method of reducing formation breakdown during the drilling of a wellbore which method comprises:

(a) circulating a drilling mud in the wellbore comprising (i) an aqueous or oil based fluid, (ii) at least one fluid loss additive at a concentration effective to achieve a high temperature high pressure (HTHP) fluid loss from the drilling mud of less than 2 ml/30 minutes and (iii) a solid particulate bridging material having an average particle diameter of 25 to 2000 microns and a concentration of at least 0.5 pounds per barrel

(1.43 kg/m^3);

(b) increasing the pressure in the wellbore to above the initial fracture pressure of the formation such that fractures are induced in the formation and a substantially fluid impermeable bridge comprising the solid particulate material and the fluid loss additive(s) is formed at or near the mouth of the fractures thereby strengthening the formation;

(c) thereafter continuing to drill the wellbore with the pressure in the wellbore maintained at above the initial fracture pressure of the formation and below the breakdown pressure of the strengthened formation.

For avoidance of doubt, the strengthened formation may be a permeable or non-permeable formation.

Without wishing to be bound by any theory, the mechanism by which the method of the present invention strengthens the wall of the wellbore and hence reduces formation breakdown is that as a fracture is deliberately induced in the wellbore wall, the solid particulate material enters and bridges the fracture at or near the mouth of the fracture. Additives which are conventionally included in the drilling mud to reduce loss of fluid from the drilling mud into the formation subsequently either precipitate on the solid particulate material that bridges the fracture or fill the voids between the solid particulate material thereby establishing a fluid impermeable immobile mass or bridge at or near the mouth of the fracture. Accordingly, fluid from the drilling mud can no longer pass into the fracture and the pressure within the fracture may begin to dissipate until it is substantially the same as the pressure of the surrounding formation. The rate of reduction in pressure within the fracture beyond the bridge will depend on the rock permeability and other factors such as the supporting action of the bridge which maintains the rock displacement caused by the fracture and the sealing action of the bridge which prevents fluid loss from the drilling mud into the fracture. The rock displacement caused by the fracture places the rock in the near wellbore region of the formation (for example, within a radial distance of up to 5 feet (1.524 metres) from the wellbore wall) in a state of compression, thereby increasing the "hoop stress" and generating a "stress cage". If there is a reduction in pressure in the fracture beyond the bridge, the fracture will attempt to close and this will impart stress on the fluid impermeable immobile mass or bridge which, in turn, leads to additional compressive stress being imparted to the rock in the near wellbore region of the formation. The

increased compressive stress in the near wellbore region of the formation results in the wall of the wellbore having a greater resistance to further fracturing. The method of the present invention therefore allows a drilling mud of higher density to be employed in drilling the wellbore than could be used in the absence of strengthening of the formation. The method also has a further beneficial effect of reducing loss of fluid from the drilling mud into the formation owing to the sealing of the fractures with the fluid impermeable immobile mass.

The method of the first aspect of the present invention differs from a conventional "tip screen out" in that a "tip screen out" requires the use of a high fluid loss drilling mud so that particulate material accumulates rapidly at the fracture tip thereby sealing the fracture and preventing further propagation of the fracture. The person skilled in the art would therefore have concerns that the use of an ultra-low fluid loss drilling mud would slow down deposition of particulate material at the fracture tip. Furthermore, there was no understanding that it may be preferable to bridge at or near the mouth of a fracture. Thus, conventional drilling muds employed in a "tip screen out" are designed so that the particulate material readily penetrates into the fracture to deposit at the fracture tip. Also, a "tip screen out" does not create an effective near wellbore "stress cage". Although the rock at the fracture tip would be under increased compressive stress (owing to the accumulation of particulate material at the fracture tip), this would not apply to the rock between the fracture tip and the mouth of the fracture. Finally, there was a prejudice against using a low fluid loss drilling mud owing to a belief that a low fluid loss mud would slow down the "rate of penetration" while drilling. It was therefore surprising that an ultra-low fluid loss mud does not significantly reduce the "rate of penetration".

The fluid loss value for the drilling mud is determined using a standard high temperature high pressure (HTHP) fluid loss test, according to the specifications of the American Petroleum Institute (API), as described in "Recommended Practice Standard Procedure for Field Testing Oil-Based Drilling Fluids", API Recommended Practice 13B-2 Third Edition, February 1998, Section 5.2.1 to 5.2.3; and "Recommended Practice Standard Procedure for Field Testing Water-Based Drilling Fluids", API Recommended Practice 13B-1 Second Edition, September 1997, Section 5.3.1 to 5.3.2. The test employs a pressurized cell fitted with a standard hardened filter paper as a filtration medium. The filtration behaviour of the drilling mud is determined with a

standard pressure differential across the filter paper of 500 psi (3.45 M Pa). A filter cake is allowed to build up on the filter paper for 30 minutes and the volume of filtrate collected after this 30 minute period is then recorded. Because the filtration area (3.5 square inches (2.258×10^{-3} m^2)) of the pressurized cell is half the filtration area of a standard API low temperature low pressure (LTLP) fluid loss test (7 square inches (4.516×10^{-3} m^2)), the filtrate volume after 30 minutes is doubled to give a corrected API fluid loss value. Suitably, the temperature at which the high temperature high pressure (HTHP) fluid loss test is carried out corresponds to the temperature in the borehole. Generally, the test temperature is in the range 50 to 150°C.

By "fracture pressure" is meant the minimum fluid pressure in the wellbore at which a fracture is created in the wellbore wall. As would be evident to the person skilled in the art, creation of a near wellbore "stress cage" will increase the fracture pressure of the strengthened formation. Accordingly, by "initial fracture pressure" of a formation is meant the fracture pressure of the formation prior to creation of the "stress cage". The initial fracture pressure of a formation may be readily determined, for example, from historical data.

By "breakdown pressure of the strengthened formation" is meant the maximum fluid pressure that can be sustained within the wellbore without creating a fracture in the strengthened formation and/or without breaking down the fluid impermeable bridge(s) that has been formed at or near the mouth of the fracture(s).

Suitably, the pressure in the wellbore in step (c) of the method of the first aspect of the present invention is at least 50 psi (0.34 M Pa) above the initial fracture pressure of the formation, preferably, at least 300 psi (2.07 M Pa) above the initial fracture pressure of the formation, for example 300 to 1000 psi (2.07 to 6.90 M Pa) above the initial fracture pressure of the formation, with the proviso that the pressure in the wellbore in step (c) is below the breakdown pressure of the strengthened formation.

As is well known to the person skilled in the art, formation pressure generally increases with increasing depth of the wellbore. It is therefore generally necessary to continuously increase the pressure of the drilling mud during the drilling operation, for example, by increasing the density of the drilling mud. A problem arises when the increased pressure of the drilling mud exceeds the initial fracture pressure of a previously drilling formation or exceeds the initial fracture pressure of a formation that is yet to be drilled (hereinafter referred to as "weak formation"). The method of the first

aspect of the present invention may therefore be used to strengthen such weak formations thereby allowing the pressure of the drilling mud that is employed for completing the drilling operation to be increased to above the initial fracture pressure of the weak formation. The method of the first aspect of the present invention is particularly advantageous where the weak formation is a depleted formation i.e. a formation having a decreased pore pressure owing to production of hydrocarbons therefrom. This decrease in pore pressure weakens the depleted formation while neighbouring or inter-bedded low permeability formations may maintain their pore pressure.

Thus, in a specific embodiment of the first aspect present invention there is provided a method of reducing formation breakdown during the drilling of a wellbore through a weak formation with a circulating drilling mud which method comprises:
(a) circulating in a wellbore a drilling mud comprising (i) an aqueous or oil based fluid, and (ii) at least one fluid loss additive at a concentration effective to achieve a high temperature high pressure (HTHP) fluid loss from the drilling mud of less than 2 ml/30 minutes and (iii) a solid particulate bridging material having an average particle diameter of 25 to 2000 microns and a concentration of at least 0.5 pounds per barrel (1.43 kg/m^3);
(b) increasing the pressure of the drilling mud to above the initial fracture pressure of the weak formation such that fractures are induced in the weak formation and a substantially fluid impermeable bridge comprising the solid particulate material and the fluid loss additive(s) is formed at or near the mouth of the fractures thereby strengthening the weak formation;
(c) thereafter continuing to drill the wellbore with the pressure in the wellbore maintained at above the initial fracture pressure of the weak formation and below the breakdown pressure of the strengthened formation.

It is envisaged that the wellbore may be drilled using a conventional drilling mud until the pressure in the wellbore approaches the initial fracture pressure of the weak formation. The conventional drilling mud is then replaced by (or converted into) the drilling mud employed in step (a) before increasing the pressure in the wellbore to above the initial fracture pressure of the weak formation. The conventional drilling mud may be converted into the drilling mud employed in step (a) by adding at least one fluid loss additive (ii) to the mud until the HTHP fluid loss value of the mud is less than 2

ml/30 minutes and adding the solid particulate bridging material (iii) to the mud in an amount of at least 0.5 pound per barrel (1.43 kg/m^3). Suitably, the solid particulate bridging material (iii) may be added to a drilling mud comprising components (i) and (ii) immediately before increasing the pressure of the drilling mud to above the initial fracture pressure of the weak formation. Thus, the drilling mud that is used to drill the wellbore until the pressure in the wellbore approaches the initial fracture pressure of the weak formation may comprise components (i) and (ii) in the absence of component (iii).

The weak formation may lie in a previously drilled section of the wellbore and/or in the rock that is about to be drilled. Where the weak formation is in the rock that is about to be drilled, it is necessary to replace the entire wellbore fluid with the drilling mud employed in step (a). Thus, the weak formation is strengthened as the wellbore is being drilled. Where the weak formation lies in a previously drilled section of the wellbore, it is only neeessary to replace the wellbore fluid in the vicinity of the weak formation. Thus, a drilling mud having a high concentration of the particulate solid material may be introduced into the wellbore as a "pill" and may be circulated to the weak formation where the concentrated drilling mud composition is squeezed into the weak formation at a pressure above the initial fracture pressure of the weak formation so that the bridging particulate material bridges the fractures that are induced in the wellbore wall at or near the mouth thereof. Typically, the pill is squeezed into the weak formation by sealing the annulus between a drill string and the wellbore wall, raising the drill string until it lies immediately below the weak formation, and pumping the pill into the wellbore via the drill string until the pressure in the vicinity of the weak formation is greater than the initial fracture pressure. Generally, the well is then shut in for a period of up to 0.5 hour. After strengthening the weak formation, drilling of the wellbore may be continued using a conventional drilling mud with the proviso that the pressure in the wellbore in the vicinity of the strengthened formation is maintained below the breakdown pressure of the strengthened formation. Suitably, the concentration of bridging material in the pill should be at least 50 pounds per barrel (143 kg/m^3), preferably at least 80 lb per barrel (228.8 kg/m^3). It is also envisaged that the "pill" may be employed as a completion fluid and may be pumped into the wellbore in advance of a cement when casing a wellbore.

In a further aspect of the present invention there is provided a drilling mud composition comprising (a) an aqueous or oil based fluid, (b) at least one fluid loss

additive at a concentration effective to achieve a high temperature high pressure (HTHP) fluid loss from the drilling mud of less than 2 ml/30 minutes and (c) a solid particulate bridging material having an average particle diameter of 25 to 2000 microns and a concentration of at least 0.5 pounds per barrel (1.43 kg/m^3).

Suitably, the specific gravity of the drilling mud is in the range 0.9 to 2.5, preferably in the range 1.0 to 2.0.

Suitably, the solid particulate bridging material that is included in the drilling mud to bridge the fractures (hereinafter "bridging material") comprises at least one substantially crush resistant particulate solid such that the bridging material props open the fractures (cracks and fissures) that are induced in the wall of the wellbore. By "crush resistant" is meant that the bridging material is physically strong enough to withstand the closure stresses exerted on the fracture bridge. Preferred bridging materials for adding to the drilling mud include graphite, calcium carbonate (preferably, marble), dolomite ($MgCO_3.CaCO_3$), celluloses, micas, proppant materials such as sands or ceramic particles and combinations thereof. These materials are very inert and are environmentally acceptable. It is also envisaged that a portion of the bridging material may comprise drill cuttings having the desired average particle diameter in the range of 25 to 2000 microns.

The concentration of the bridging material may vary with the drilling mud used and the conditions of use. The concentration must be at least great enough for the bridging material to rapidly bridge the fractures (i.e. cracks and fissures) that are induced in the wall of the wellbore but should not be so high as to make circulation of the drilling mud impractical. Suitably, the bridging material should bridge the fractures that are induced in the wellbore wall within less than 10 seconds, preferably less than 5 seconds from when the fracture opens so that the fracture remains short. Thus, rapid sealing of the fracture mitigates the risk of the fracture propagating. Suitably, the concentration of bridging material in the drilling mud is at least 5 pounds per barrel (14.3 kg/m^3), preferably at least 10 pounds per barrel (28.6 kg/m^3), more preferably at least 15 pounds per barrel (42.9 kg/m^3), for example, at least 30 pounds per barrel (85.8 kg/m^3). However, as discussed above, where the drilling mud is employed in a "pill" treatment, the concentration of the bridging particulate material is suitably at least 50 pounds per barrel (143 kg/m^3), preferably at least 80 pounds per barrel (228.8 kg/m^3).

Suitably, the bridging material is sized so as not to enter the pores of any

permeable rock through which the wellbore is being drilled. Preferably, the bridging material has an average particle diameter in the range 50 to 1500 microns, more preferably 250 to 1000 microns. The bridging material may comprise substantially spherical particles. However, it is also envisaged that the bridging material may comprise elongate particles, for example, rods or fibres. Where the bridging material comprises elongate particles, the average length of the elongate particles should be such that the elongate particles are capable of bridging the induced fractures at or near the mouth thereof. Typically, the elongate particles will have an average length in the range 25 to 2000 microns, preferably 50 to 1500 microns, more preferably 250 to 1000 microns.

The bridging material is sized so as to readily form a bridge at or near the mouth of the induced fractures. Typically, the fractures that are induced in the wellbore wall have a fracture width at the mouth in the range 0.1 to 5mm. The fracture width is dependent, amongst other factors, upon the strength (stiffness) of the formation rock and the extent to which the pressure in the wellbore is increased to above initial fracture pressure of the formation during the fracture induction step (b) of the method of the present invention (in other words, the fracture width is dependent on the pressure difference between the drilling mud and the initial fracture pressure of the formation during the fracture induction step). It is preferred that at least a portion of the bridging material, preferably, a major portion of the bridging material has a particle diameter approaching the width of the fracture mouth. Preferably, the bridging material has a broad (polydisperse) particle size distribution.

It is necessary to keep the bridging material in suspension in the drilling mud. Generally, a drilling mud is recycled to the wellbore after removal of substantially all of the drill cuttings. The drill cuttings may be removed using screens as would be well known to the person skilled in the art. Typically the drilling mud is filtered using a 200 mesh size screen (US sieve series) that retains particles having a size of greater than 74 microns. However, in the method of the present invention, it is necessary to filter the mud using a coarser screen so as to avoid separation of substantial amounts of the bridging material from the mud. Suitably, the drilling mud is filtered using a 35 mesh screen (US sieve series) that retains particles having a size of greater than 500 microns. However, if the rheology of the mud deteriorates through the accumulation of fine drill cuttings in the mud, it may be necessary to employ finer mesh screens for a short period

of time. It is also envisaged that separation methods may be employed which allow the bridging solids to be retained but a major portion of the cuttings, preferably substantially all of the cuttings, to be separated from the drilling mud. In particular, the cuttings may be separated from the drilling mud by relying on differences in the densities of the cuttings and the bridging particles, for example, using centrifuges or hydrocyclones. In order to maintain the concentration of the bridging material at the desired value in the drilling mud and/or to maintain the fluid loss value of the drilling mud at below 2 ml/30 minutes. it may be necessary to introduce fresh bridging material and/or fresh fluid loss additives respectively into the circulating drilling mud. Alternatively, or in addition, fresh drilling mud may be either continuously or intermittently added to the drilling mud that is being circulated in the wellbore.

The drilling mud has an HTHP fluid loss value of less than 2 ml/30 minutes, preferably, less than 1 ml/30 minutes, more preferably less than 0.5 ml/30 minutes, for example 0.1 to 0.3 ml/30 minutes. As would be well known to the person skilled in the art, such ultra-low fluid loss values may be achieved by incorporating at least one fluid loss additive in the drilling mud. Without wishing to be bound by any theory, it is believed that the fluid loss additive(s) will build up on the solid particulate material that bridges the fractures at or near the mouth thereof thereby forming a fluid impermeable immobile mass. Where the solid particulate bridging material is porous, the fluid loss additives may also enter the pores of the bridging material to seal the pores.

Suitable fluid loss additives that may be incorporated in the drilling mud of the present invention include organic polymers of natural or synthetic origin. Suitable polymers include starch or chemically modified starches; cellulose derivatives such as carboxymethylcellulose and polyanionic cellulose (PAC); guar gum and xanthan gum; homopolymers and copolymers of monomers selected from the group consisting of acrylic acid, acrylamide, acrylamido-2-methyl propane sulfonic acid (AMPS), styrene sulphonic acid, N-vinyl acetamide, N-vinyl pyrrolidone, and N,N-dimethylacrylamide wherein the copolymer has a number average molecular weight of from 100,000 to 1,000,000, and preferably 200,000 to 500,000; asphalts (for example, sulphonated asphalts); gilsonite; lignite and its derivative, humic acid; lignin and its derivatives such as lignin sulfonates or condensed polymeric lignin sulfonates; and combinations thereof. These polymeric additives are particularly suitable for use in oil based drilling muds. As an alternative or, in addition, to employing such polymeric additives, the fluid loss

from the drilling mud of the present invention may be reduced by adding finely dispersed particles such as clays (for example, illite, kaolinite, bentonite, or sepiolite) to the drilling mud. Suitably, the finely dispersed particles have an average particle size of less than 10 microns, preferably, less than 5 microns, for example, about 1 micron. Preferably, the drilling mud contains a smooth/continuous range of particle sizes ranging from about 1 micron for the finely dispersed particulate fluid loss additives to an average particle diameter of the bridging material of up to 2000 microns i.e. has a broad (polydisperse) particle size distribution.

It is envisaged that an oil based drilling mud may contain a significant amount of a discontinuous water phase dispersed in a continuous oil phase by means of at least one emulsifier (a water-in-oil emulsion). The fluid loss value of such drilling muds may vary depending upon the oil to water ratio and the nature of the emulsifier(s) employed to form the water-in-oil emulsion (and hence on the size of the dispersed water droplets). Preferably, the water content of the drilling mud is in the range 80:20 to 50:50, more preferably 70:30 to 55:45. Preferred emulsifiers include imidazolines, fatty acids and combinations thereof.

Particularly preferred ultra-low fluid loss oil based drilling muds are described in SPE 77446, "Towards Zero Fluid Loss Oil Based Muds", M Aston, P Mihalik, J Tunbridge and S Clarke, published 2002.

The effectiveness of the method of the present invention has been demonstrated in both laboratory and field conditions as shown by the following Examples.

Example 1

Oil based mud formulations were evaluated in the laboratory by injecting different drilling muds into a model fracture (as described in SPE/IADC 87130, "Drilling Fluids for Wellbore Strengthening, 2-4 March 2004, M S Aston et al). The model fracture was formed from two rectangular-shaped rock pieces (of 0.3 milliDarcy permeability "Ohio" sandstone). Each rock piece had approximate dimensions of 5cm width x 20cm length x 1cm breadth. The two rock pieces were sandwiched together to create a fracture having a mouth aperture of 1mm with the aperture of the fracture tapering to 0.5mm at the far end thereof (fracture tip). A valve was provided at the exit from the fracture tip such that the fracture tip could be open or sealed. The rock sandwich was placed in a purpose-built holder that was supported in a load frame within a test cell. The fracture width was maintained constant using fixed spacers. The fluid

pressure within the fracture was measured just inside the mouth of the fracture using a pressure transducer. Initially, the fracture and the pore spaces in the rock were filled with a clear fluid (water) and the system was heated to a temperature of 60°C. A pressure of about 100 psi (0.69 M Pa) was applied to compress any air in the system. Drilling mud was then injected at a pressure of 400 psi (2.76 M Pa) into the mouth of the fracture with the fracture tip open (to give a differential pressure across the fracture of 300 psi (2.07 M Pa)). After 3 minutes, the exit from the fracture tip was closed using the valve so that pressure could build up inside the fracture (n.b. the initial driving force for bridge formation at the fracture mouth was fluid leak-off through the fracture tip). The injection pressure was then increased stepwise to 2000 psi (13.79 M Pa). A low pressure measured on the pressure transducer indicated an effective seal at the mouth of the fracture.

The results shown in Table 1 below compare the pressures measured just inside the fracture mouth for different drilling muds employed in the above test procedure. The pressure just inside the fracture mouth was measured after a steady value was reached at each injection pressure.

Table 1 – Effectiveness of drilling muds in sealing a model fracture

Mud System		Pressure just inside fracture mouth, measured after different mud injection pressures (IP) in psi		
		IP 400 (2.76 M Pa)	IP 1000 (6.70 M Pa)	IP 2000 (13.79 M Pa)
Mud 1 (Comparative)	Base mud plus bridging particulate material mix A; API HTHP fluid loss = 3mls/30 minutes at a temperature of 60°C	300 (2.07 M Pa)	900 (6.21 M Pa)	1900 (13.10 M Pa)
Mud 2	As mud 1, but containing 5lb/bbl Pliolite, API HTHP fluid loss = 0.3 mls/30 minutes at a temperature of 60°C	0	30 (1.31 M Pa)	1900 (13.10 M Pa)
Mud 3	Base mud plus bridging particulate material mix B plus 5lb/bbl Pliolite (14.3 kg/m^3), API HTHP fluid loss = 0.1 mls/30 minutes at a temperature of 60°C	0	0	0

Mud 2 forms a more effective seal than Mud 1 (Comparative). This was achieved by reducing the API HTHP fluid loss of the mud system from 3 ml/30 minutes to 0.3 mls/30 minutes. Mud 3 achieved a total seal at the mouth of the fracture by using an improved bridging particulate material mix in a mud having an API HTHP fluid loss of 0.1 mls/30 minutes.

The formulation for the base mud employed in the above tests was as follows:

Mineral oil:	0.517 bbls (0.0822 m^3)
Versamul™ (emulsifier, ex MI)	4.7 lb/bbl (13.4 kg/m^3)

Versawet™ (wetting agent, ex MI)	7 lb/bbl (20.0 kg/m^3)
Geltone™ (organoclay, ex Halliburton)	6lb/bbl (17.2 kg/m^3)
Lime	5.25 lb/bbl (15.0 kg/m^3)
Calcium chloride	17.6 lb/bbl (50.4 kg/m^3)
Water	0.346 lb/bbl (1.0 kg/m^3)
Barite (barium sulfate)	50 lb/bbl (143 kg/m^3)
Hymod Prima Clay (simulated drill solids)	4.5 lb/bbl (12.9 kg/m^3)

Mud 1 is the base mud containing the following bridging particulate materials (mix A):

Baracarb™ 150:	46 lb/bbl (131.6 kg/m^3)
Baracarb™ 600:	9.3 lb/bbl (26.6 kg/m^3)

Mud 2 is as Mud 1 with the addition of 5 lb/bbl Pliolite® DF-01 (fluid loss control additive supplied by Goodyear)

Mud 3 is the base mud containing 5lb/bbl (143 kg/m^3) Pliolite® DF-01 and the following bridging particulate materials (mix B):

Baracarb™ 150:	18 lb/bbl (51.5 kg/m^3)
Baracarb™ 600:	18 lb/bbl (51.5 kg/m^3)
Steelseal™:	15 lb/bbl (42.9 kg/m^3)

Baracarb™ 150, Baracarb™ 600 and Steelseal™ were obtained from Halliburton. Baracarb™ 150 and Baracarb™ 600 are calcium carbonates with an average particle diameter of 150 microns and 600 microns, respectively. Steelseal™ is a graphitic carbon available from Halliburton, with an average size range of approximately 400 microns.

Example 2

A field test was conducted onshore in the Arkoma basin, USA, to determine whether the method of the present invention could raise fracture resistance in a shale formation. The well was a vertical well having a 9 5/8" (24.5 cm) casing. An extended leak off test (pill squeeze treatment) was performed in 10 feet (3.048 metres) of exposed shale formation (open hole) just below the 9 5/8" (24.5 cm) casing shoe. In this test, standard "leak-off" procedures were used whereby the annulus was closed whilst mud was pumped into the wellbore. Initially, a standard diesel based mud was present in the well bore and this mud was pumped into the wellbore at a rate of 0.25

bbls/minute (**0.04 m^3/minute**) until breakdown of the exposed shale formation occurred.

Figure 1 illustrates the extended leak-off pressure curve for the standard diesel based mud (curve 1). The shale formation fractured at about 1200 psi (**8.27 M Pa**), at which point pumping of the standard diesel based drilling mud was stopped to minimize fracture growth. The pressure stabilized at 800 psi (**5.52 M Pa**), which is the propagation pressure of the fractures determined by the far-field stress state. The excess pressure in the wellbore was bled off (back to hydrostatic pressure) so that the fractures closed and the leak-off procedure was then repeated by pumping a pill of a mud according to the present invention (hereinafter "Designer mud") into the wellbore also at a rate of 0.25 bbls/minute (**0.04m^3/minute**). Figure 1 additionally illustrates the extended leak off curve for the Designer mud (curve 2). The fractures induced in the wall of the open hole wellbore are bridged and sealed by the bridging particles and fluid loss additives of the Designer mud and the breakdown pressure of the strengthened formation climbs to above 2000 psi (**13.79 M Pa**) before the seal breaks down. This is an increase of about 850 psi (**5.86 M Pa**) formation breakdown pressure compared to the original state of the shale formation, equivalent to 5.4 pounds per gallon (ppg) (**647 kg/m^3**) mud weight.

The API HTHP fluid loss value for the Designer mud employed in the field trial was 0.45 mls at a temperature of 115 °F (46°C) (bottom hole temperature), while the standard diesel based mud had an API HTHP fluid loss of 10 mls at a temperature of 250°F (121°C). The Designer Mud was made by adding calcium carbonate bridging solids, graphitic material bridging solids, and fluid loss additives to the standard diesel based mud in accordance with the present invention. The bridging solids ranged in size from 10 to 800 microns and were added in an amount of 80 pounds per barrel (**228.8 kg/m^3**). The original standard diesel based mud had a mud weight of 9.0 ppg (**1078 kg/m^3**) and was free of added bridging solids.

Claims:

1. A method of reducing formation breakdown during the drilling of a wellbore which method comprises:

(a) circulating a drilling mud in the wellbore comprising (i) an aqueous or oil based fluid, (ii) at least one fluid loss additive at a concentration effective to achieve a high temperature high pressure (HTHP) fluid loss from the drilling mud of less than 2 ml/30 minutes **wherein the HTHP fluid loss is determined using an HTHP test according to the specifications of the American Petroleum institute (API), as described in API Recommended Practice 13B-2 Third Edition, February 1998, Section 5.2.1 to 5.2.3 or Recommended Practice 13B-1 Second Edition, September 1997, Section 5.3.1 to 5.3.2,** and (iii) a solid particulate bridging material having an average particle diameter of 25 to 2000 microns and a concentration of at least 0.5 pounds per barrel (1.43 kg/m^3);

(b) increasing the pressure in the wellbore to above the initial fracture pressure of the formation such that fractures are induced in the formation and a substantially fluid impermeable bridge comprising the solid particulate bridging material and the fluid loss additive(s) is formed at or near the mouth of the fractures thereby strengthening the formation;

(c) thereafter continuing to drill the wellbore with the pressure in the wellbore maintained at above the initial fracture pressure of the formation and below the breakdown pressure of the strengthened formation.

2. A method as claimed in Claim 1 wherein the pressure in the wellbore in step (c) is maintained at least 300 psi (2.07 M Pa) above the initial fracture pressure of the formation and below the breakdown pressure of the strengthened formation.

3. A method as claimed in Claims 1 or 2 wherein the solid particulate bridging material is added to a circulating drilling mud having an HTHP fluid loss value of less than 2 ml/30 minutes prior to increasing the pressure in the wellbore to above the initial fracture pressure of the formation.

4. A method as claimed in any one of the preceding claims wherein the strengthened formation is a depleted formation.

5. A method as claimed in any one of Claims 1 to 3 wherein the strengthened formation is a weak formation in a previously drilled section of wellbore.

6. A method as claimed in any one of the preceding claims wherein the drilling mud has a HTHP fluid loss value of less than 1 ml/30 minutes, preferably less than 0.5 ml/30 minutes.

7. A method as claimed in any one of the preceding claims wherein the concentration of solid particulate bridging material in the circulating drilling mud is at least 10 lb per barrel (26.6 kg/m^3), preferably at least 15 lb per barrel (42.9 kg/m^3).

8. A method as claimed in any one of the preceding claims wherein the drilling mud is recycled to the wellbore after separating material having a size of greater than 500 microns therefrom using a 35 mesh screen (US sieve series).

9. A method as claimed in Claim 8 wherein fresh solid particulate bridging material is added to the drilling mud prior to recycling the drilling mud to the wellbore.

10. A method as claimed in any one of Claims 1 to 7 wherein the drilling mud is recycled to the wellbore after separating drill cuttings from the drilling mud using a centrifuge or hydrocyclone.

11. A method as claimed in Claims 5 or 6 wherein a pill of the drilling mud having a concentration of solid particulate bridging material of at least 50 lb per barrel (143 kg/m^3) is circulated to the weak formation and is squeezed into the weak formation with the pressure in the wellbore in the vicinity of the weak formation maintained at above the initial fracture pressure of the weak formation.

12. A drilling mud composition comprising (a) an aqueous or oil based fluid; (b) at least one fluid loss additive at a concentration effective to achieve a high temperature high pressure (HTHP) fluid loss from the drilling mud of less than 2 ml/30 minutes **wherein the HTHP fluid loss is determined using an HTHP test according to the specifications of the American Petroleum institute (API), as described in API Recommended Practice 13B-2 Third Edition, February 1998, Section 5.2.1 to 5.2.3**

or Recommended Practice 13B-1 Second Edition, September 1997, Section 5.3.1 to 5.3.2; and (c) a solid particulate bridging material having an average particle diameter in the range 50 to 1500 microns and a concentration of at least 0.5 pounds per barrel (1.43 kg/m^3).

13. A drilling mud composition as claimed in Claim 12 having a specific gravity in the range 0.9 to 2.5.

14. A drilling mud composition as claimed in Claims 12 or 13 wherein the solid particulate bridging material comprises at least one substantially crush resistant particulate solid selected from the group consisting of graphite, calcium carbonate (preferably marble), dolomite, celluloses, micas, sand and ceramic particles.

15. A drilling mud composition as claimed in any one of Claims 12 to 14 wherein the concentration of the solid particulate bridging material is at least 10 pounds per barrel (28.6 kg/m^3), preferably at least 15 pounds per barrel (42.9 kg/m^3).

16. A drilling mud composition as claimed in any one of claims 12 to 15 wherein the solid particulate bridging material has an average particle diameter in the range 250 to 1000 microns.

17. A drilling mud composition as claimed in any one of Claims 12 to 16 having an HTHP fluid loss value of less than 1 ml/30 minutes, preferably less than 0.5 ml/30 minutes.

18. A drilling mud composition as claimed in any one of Claims 12 to 17 wherein the fluid loss additive(s) is selected from organic polymers of natural or synthetic origin and finely dispersed clays.

Case 10061(2)

Abstract

DRILLING METHOD

A method of reducing formation breakdown during the drilling of a wellbore which method comprises:

(a) circulating a drilling mud in the wellbore comprising (i) an aqueous or oil based fluid, (ii) at least one fluid loss additive at a concentration effective to achieve a high temperature high pressure (HTHP) fluid loss from the drilling mud of less than 2 ml/30 minutes and (iii) a solid particulate bridging material having an average particle diameter of 25 to 2000 microns and a concentration of at least 0.5 pounds per barrel;

(b) increasing the pressure in the wellbore to above the initial fracture pressure of the formation such that fractures are induced in the formation and a substantially fluid impermeable bridge comprising the solid particulate bridging material and the fluid loss additive(s) is formed at or near the mouth of the fractures thereby strengthening the formation;

(c) thereafter continuing to drill the wellbore with the pressure in the wellbore maintained at above the initial fracture pressure of the formation and below the breakdown pressure of the strengthened formation.

CG
RRH

PATENT COOPERATION TREATY

From the INTERNATIONAL SEARCHING AUTHORITY

PCT

NOTIFICATION OF TRANSMITTAL OF THE INTERNATIONAL SEARCH REPORT AND THE WRITTEN OPINION OF THE INTERNATIONAL SEARCHING AUTHORITY, OR THE DECLARATION

(PCT Rule 44.1)

To:
BP INTERNATIONAL LIMITED
Patents & Agreements
Attn. Collins, Frances Mary
Chertsey Road, Sunbury-on-Thames
Middlesex, TW16 7LN
UNITED KINGDOM

06 DEC 2004

Applicant's or agent's file reference 10061	FOR FURTHER ACTION See paragraphs 1 and 4 below
International application No. PCT/GB2004/003154	International filing date (day/month/year) 19/07/2004
Applicant BP EXPLORATION OPERATING COMPANY LIMITED	

Date of mailing (day/month/year) 06/12/2004

1. [x] The applicant is hereby notified that the international search report and the written opinion of the International Searching Authority have been established and are transmitted herewith.

   Filing of amendments and statement under Article 19:
   The applicant is entitled, if he so wishes, to amend the claims of the International Application (see Rule 46):

   When? The time limit for filing such amendments is normally 2 months from the date of transmittal of the International Search Report; however, for more details, see the notes on the accompanying sheet.

   Where? Directly to the International Bureau of WIPO, 34 chemin des Colombettes 1211 Geneva 20, Switzerland, Facsimile No.: (41-22) 740.14.35

   For more detailed instructions, see the notes on the accompanying sheet.

2. [ ] The applicant is hereby notified that no international search report will be established and that the declaration under Article 17(2)(a) to that effect and the written opinion of the International Searching Authority are transmitted herewith.

3. [ ] With regard to the protest against payment of (an) additional fee(s) under Rule 40.2, the applicant is notified that:

   [ ] the protest together with the decision thereon has been transmitted to the International Bureau together with the applicant's request to forward the texts of both the protest and the decision thereon to the designated Offices.

   [ ] no decision has been made yet on the protest; the applicant will be notified as soon as a decision is made.

4. **Reminders**

   Shortly after the expiration of 18 months from the priority date, the international application will be published by the International Bureau. If the applicant wishes to avoid or postpone publication, a notice of withdrawal of the international application, or of the priority claim, must reach the International Bureau as provided in Rules 90*bis*.1 and 90*bis*.3, respectively, before the completion of the technical preparations for international publication.

   The applicant may submit comments on an informal basis on the written opinion of the International Searching Authority to the International Bureau. The International Bureau will send a copy of such comments to all designated Offices unless an international preliminary examination report has been or is to be established. These comments would also be made available to the public but not before the expiration of 30 months from the priority date.

   Within 19 months from the priority date, but only in respect of some designated Offices, a demand for international preliminary examination must be filed if the applicant wishes to postpone the entry into the national phase until 30 months from the priority date (in some Offices even later); otherwise, the applicant must, within 20 months from the priority date, perform the prescribed acts for entry into the national phase before those designated Offices.

   In respect of other designated Offices, the time limit of 30 months (or later) will apply even if no demand is filed within 19 months.

   See the Annex to Form PCT/IB/301 and, for details about the applicable time limits, Office by Office, see the *PCT Applicant's Guide*, Volume II, National Chapters and the WIPO Internet site.

Name and mailing address of the International Searching Authority	Authorized officer
European Patent Office, P.B. 5818 Patentlaan 2 NL-2280 HV Rijswijk Tel. (+31-70) 340-2040, Tx. 31 651 epo nl, Fax: (+31-70) 340-3016	Maruska Galatioto

NOTES TO FORM PCT/ISA/220

These Notes are intended to give the basic instructions concerning the filing of amendments under article 19. The Notes are based on the requirements of the Patent Cooperation Treaty, the Regulations and the Administrative Instructions under that Treaty. In case of discrepancy between these Notes and those requirements, the latter are applicable. For more detailed information, see also the PCT Applicant's Guide, a publication of WIPO.

In these Notes, "Article", "Rule", and "Section" refer to the provisions of the PCT, the PCT Regulations and the PCT Administrative Instructions respectively.

INSTRUCTIONS CONCERNING AMENDMENTS UNDER ARTICLE 19

The applicant has, after having received the international search report, one opportunity to amend the claims of the international application. It should however be emphasized that, since all parts of the international application (claims, description and drawings) may be amended during the international preliminary examination procedure, there is usually no need to file amendments of the claims under Article 19 except where, e.g. the applicant wants the latter to be published for the purposes of provisional protection or has another reason for amending the claims before international publication. Furthermore, it should be emphasized that provisional protection is available in some States only.

What parts of the international application may be amended?

Under Article 19, only the claims may be amended.

During the international phase, the claims may also be amended (or further amended) under Article 34 before the International Preliminary Examining Authority. The description and drawings may only be amended under Article 34 before the International Examining Authority.

Upon entry into the national phase, all parts of the international application may be amended under Article 28 or, where applicable, Article 41.

When? Within 2 months from the date of transmittal of the international search report or 16 months from the priority date, whichever time limit expires later. It should be noted, however, that the amendments will be considered as having been received on time if they are received by the International Bureau after the expiration of the applicable time limit but before the completion of the technical preparations for international publication (Rule 46.1).

Where not to file the amendments?

The amendments may only be filed with the International Bureau and not with the receiving Office or the International Searching Authority (Rule 46.2).

Where a demand for international preliminary examination has been/is filed, see below.

How? Either by cancelling one or more entire claims, by adding one or more new claims or by amending the text of one or more of the claims as filed.

A replacement sheet must be submitted for each sheet of the claims which, on account of an amendment or amendments, differs from the sheet originally filed.

All the claims appearing on a replacement sheet must be numbered in Arabic numerals. Where a claim is cancelled, no renumbering of the other claims is required. In all cases where claims are renumbered, they must be renumbered consecutively (Administrative Instructions, Section 205(b)).

The amendments must be made in the language in which the international application is to be published.

What documents must/may accompany the amendments?

Letter (Section 205(b)):

The amendments must be submitted with a letter.

The letter will not be published with the international application and the amended claims. It should not be confused with the "Statement under Article 19(1)" (see below, under "Statement under Article 19(1)").

The letter must be in English or French, at the choice of the applicant. However, if the language of the international application is English, the letter must be in English; if the language of the international application is French, the letter must be in French.

The letter must indicate the differences between the claims as filed and the claims as amended. It must, in particular, indicate, in connection with each claim appearing in the international application (it being understood that identical indications concerning several claims may be grouped), whether

(i) the claim is unchanged;

(ii) the claim is cancelled;

(iii) the claim is new;

(iv) the claim replaces one or more claims as filed;

(v) the claim is the result of the division of a claim as filed.

The following examples illustrate the manner in which amendments must be explained in the accompanying letter:

1. [Where originally there were 48 claims and after amendment of some claims there are 51]:
"Claims 1 to 29, 31, 32, 34, 35, 37 to 48 replaced by amended claims bearing the same numbers; claims 30, 33 and 36 unchanged; new claims 49 to 51 added."

2. [Where originally there were 15 claims and after amendment of all claims there are 11]:
"Claims 1 to 15 replaced by amended claims 1 to 11."

3. [Where originally there were 14 claims and the amendments consist in cancelling some claims and in adding new claims]:
"Claims 1 to 6 and 14 unchanged; claims 7 to 13 cancelled; new claims 15, 16 and 17 added." or
"Claims 7 to 13 cancelled; new claims 15, 16 and 17 added; all other claims unchanged."

4. [Where various kinds of amendments are made]:
"Claims 1-10 unchanged; claims 11 to 13, 18 and 19 cancelled; claims 14, 15 and 16 replaced by amended claim 14; claim 17 subdivided into amended claims 15, 16 and 17; new claims 20 and 21 added."

"Statement under article 19(1)" (Rule 46.4)

The amendments may be accompanied by a statement explaining the amendments and indicating any impact that such amendments might have on the description and the drawings (which cannot be amended under Article 19(1)).

The statement will be published with the international application and the amended claims.

It must be in the language in which the international application is to be published.

It must be brief, not exceeding 500 words if in English or if translated into English.

It should not be confused with and does not replace the letter indicating the differences between the claims as filed and as amended. It must be filed on a separate sheet and must be identified as such by a heading, preferably by using the words "Statement under Article 19(1)."

It may not contain any disparaging comments on the international search report or the relevance of citations contained in that report. Reference to citations, relevant to a given claim, contained in the international search report may be made only in connection with an amendment of that claim.

Consequence if a demand for international preliminary examination has already been filed

If, at the time of filing any amendments under Article 19, a demand for international preliminary examination has already been submitted, the applicant must preferably, at the same time of filing the amendments with the International Bureau, also file a copy of such amendments with the International Preliminary Examining Authority (see Rule 62.2(a), first sentence).

Consequence with regard to translation of the international application for entry into the national phase

The applicant's attention is drawn to the fact that, where upon entry into the national phase, a translation of the claims as amended under Article 19 may have to be furnished to the designated/elected Offices, instead of, or in addition to, the translation of the claims as filed.

For further details on the requirements of each designated/elected Office, see Volume II of the PCT Applicant's Guide.

BNSDOCID: <XB____ISA220NOENP4_I_>

PATENT COOPERATION TREATY

PCT

INTERNATI NAL SEARCH REPORT

(PCT Article 18 and Rules 43 and 44)

Applicant's or agent's file reference	FOR FURTHER ACTION	see Form PCT/ISA/220 as well as, where applicable, item 5 below.
10061		
International application No.	International filing date *(day/month/year)*	(Earliest) Priority Date *(day/month/year)*
PCT/GB2004/003154	19/07/2004	25/07/2003

Applicant

BP EXPLORATION OPERATING COMPANY LIMITED

This International Search Report has been prepared by this International Searching Authority and is transmitted to the applicant according to Article 18. A copy is being transmitted to the International Bureau.

This International Search Report consists of a total of 3 sheets.

[X] It is also accompanied by a copy of each prior art document cited in this report.

1. **Basis of the report**
   a. With regard to the language, the international search was carried out on the basis of the international application in the language in which it was filed, unless otherwise indicated under this item.
      [ ] The international search was carried out on the basis of a translation of the international application furnished to this Authority (Rule 23.1(b)).
   b. [ ] With regard to any nucleotide and/or amino acid sequence disclosed in the international application, see Box No. I.

2. [ ] Certain claims were found unsearchable (See Box II).

3. [ ] Unity of invention is lacking (see Box III).

4. With regard to the title,
   [X] the text is approved as submitted by the applicant.
   [ ] the text has been established by this Authority to read as follows:

5. With regard to the abstract,
   [X] the text is approved as submitted by the applicant.
   [ ] the text has been established, according to Rule 38.2(b), by this Authority as it appears in Box No. IV. The applicant may, within one month from the date of mailing of this international search report, submit comments to this Authority.

6. With regards to the drawings,
   a. the figure of the drawings to be published with the abstract is Figure No. _____
      [ ] as suggested by the applicant.
      [ ] as selected by this Authority, because the applicant failed to suggest a figure.
      [ ] as selected by this Authority, because this figure better characterizes the invention.
   b. [X] none of the figures is to be published with the abstract.

INTERNATI NAL SEARCH REPORT

International Application No
PCT/GB2004/003154

A. CLASSIFICATION OF SUBJECT MATTER
IPC 7 E21B33/13

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
IPC 7 C09K E21B

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practical, search terms used)
EPO-Internal

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category *	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	EP 1 074 598 A (TEXAS UNITED CHEMICAL CORP) 7 February 2001 (2001-02-07) paragraph '0011! - paragraph '0015! paragraph '0025! - paragraph '0034! paragraph '0059!	12-18
X	US 6 391 830 B1 (DOBSON JR JAMES W ET AL) 21 May 2002 (2002-05-21) column 2, line 38 - column 6, line 59 examples 1-10	12-18
A	GB 2 351 098 A (SOFITECH NV) 20 December 2000 (2000-12-20) page 6 claims 1-5	1-18
A	US 6 403 537 B1 (PERRICONE CHARLES ET AL) 11 June 2002 (2002-06-11) the whole document	1-18

☐ Further documents are listed in the continuation of box C.

☒ Patent family members are listed in annex.

* Special categories of cited documents :

"A" document defining the general state of the art which is not considered to be of particular relevance

"E" earlier document but published on or after the international filing date

"L" document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)

"O" document referring to an oral disclosure, use, exhibition or other means

"P" document published prior to the international filing date but later than the priority date claimed

"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention

"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone

"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art.

"&" document member of the same patent family

Date of the actual completion of the international search	Date of mailing of the international search report
29 November 2004	06/12/2004

Name and mailing address of the ISA	Authorized officer
European Patent Office, P.B. 5818 Patentlaan 2 NL - 2280 HV Rijswijk Tel. (+31-70) 340-2040, Tx. 31 651 epo nl, Fax: (+31-70) 340-3016	Zimpfer, E

3

Form PCT/ISA/210 (second sheet) (January 2004)

INTERNATIONAL SEARCH REPORT

Information on patent family members

International Application No
PCT/GB2004/003154

Patent document cited in search report	Publication date	Patent family member(s)	Publication date
EP 1074598 A	07-02-2001	US 6300286 B1	09-10-2001
		AU 771831 B2	01-04-2004
		AU 4894800 A	08-02-2001
		BR 0012955 A	18-06-2002
		CA 2314806 A1	05-02-2001
		EP 1074598 A1	07-02-2001
		ID 26742 A	08-02-2001
		NO 20003972 A	06-02-2001
		WO 0110976 A1	15-02-2001
		US 6391830 B1	21-05-2002
		US 2002028750 A1	07-03-2002
US 6391830 B1	21-05-2002	US 6300286 B1	09-10-2001
		US 2002028750 A1	07-03-2002
		AU 771831 B2	01-04-2004
		AU 4894800 A	08-02-2001
		BR 0012955 A	18-06-2002
		CA 2314806 A1	05-02-2001
		EP 1074598 A1	07-02-2001
		ID 26742 A	08-02-2001
		NO 20003972 A	06-02-2001
		WO 0110976 A1	15-02-2001
GB 2351098 A	20-12-2000	AU 769301 B2	22-01-2004
		AU 6428000 A	09-01-2001
		BR 0011751 A	30-04-2002
		CA 2377504 A1	28-12-2000
		WO 0078890 A1	28-12-2000
		EP 1194497 A1	10-04-2002
		MX PA01013202 A	14-07-2003
		NO 20016190 A	15-02-2002
US 6403537 B1	11-06-2002	US 2004072695 A1	15-04-2004
		AU 1520500 A	29-05-2000
		GB 2361948 A ,B	07-11-2001
		WO 0027944 A1	18-05-2000

PATENT COOPERATION TREATY

From the
INTERNATIONAL SEARCHING AUTHORITY

To:

see form PCT/ISA/220

PCT

WRITTEN OPINION OF THE INTERNATIONAL SEARCHING AUTHORITY

(PCT Rule 43*bis*.1)

Date of mailing *(day/month/year)* see form PCT/ISA/210 (second sheet)	
Applicant's or agent's file reference see form PCT/ISA/220	FOR FURTHER ACTION See paragraph 2 below
International application No. PCT/GB2004/003154	International filing date *(day/month/year)* 19.07.2004
Priority date *(day/month/year)* 25.07.2003	
International Patent Classification (IPC) or both national classification and IPC E21B33/13	
Applicant BP EXPLORATION OPERATING COMPANY LIMITED	

1. This opinion contains indications relating to the following items:

- ☒ Box No. I Basis of the opinion
- ☒ Box No. II Priority
- ☐ Box No. III Non-establishment of opinion with regard to novelty, inventive step and industrial applicability
- ☐ Box No. IV Lack of unity of invention
- ☒ Box No. V Reasoned statement under Rule 43*bis*.1(a)(i) with regard to novelty, inventive step or industrial applicability; citations and explanations supporting such statement
- ☐ Box No. VI Certain documents cited
- ☒ Box No. VII Certain defects in the international application
- ☒ Box No. VIII Certain observations on the international application

2. **FURTHER ACTION**

If a demand for international preliminary examination is made, this opinion will usually be considered to be a written opinion of the International Preliminary Examining Authority ("IPEA"). However, this does not apply where the applicant chooses an Authority other than this one to be the IPEA and the chosen IPEA has notified the International Bureau under Rule 66.1*bis*(b) that written opinions of this International Searching Authority will not be so considered.

If this opinion is, as provided above, considered to be a written opinion of the IPEA, the applicant is invited to submit to the IPEA a written reply together, where appropriate, with amendments, before the expiration of three months from the date of mailing of Form PCT/ISA/220 or before the expiration of 22 months from the priority date, whichever expires later.

For further options, see Form PCT/ISA/220.

3. For further details, see notes to Form PCT/ISA/220.

Name and mailing address of the ISA:	Authorized Officer
European Patent Office D-80298 Munich Tel. +49 89 2399 - 0 Tx: 523656 epmu d Fax: +49 89 2399 - 4465	Zimpfer, E Telephone No. +49 89 2399-7881

Form PCT/ISA/237 (Cover Sheet) (January 2004)

WRITTEN OPINION OF THE INTERNATIONAL SEARCHING AUTHORITY

International application No.
PCT/GB2004/003154

Box No. I Basis of the opinion

1. With regard to the **language**, this opinion has been established on the basis of the international application in the language in which it was field, unless otherwise indicated under this item.

   ☐ This opinion has been established on the basis of a translation from the original language into the following language , which is the language of a translation furnished for the purposes of international search (under Rules 12.3 and 23.1(b)).

2. With regard to any **nucleotide and/or amino acid sequence** disclosed in the international application and necessary to the claimed invention, this opinion has been established on the basis of:

   a. type of material:

   ☐ a sequence listing

   ☐ table(s) related to the sequence listing

   b. format of material:

   ☐ in written format

   ☐ in computer readable form

   c. time of filing/furnishing:

   ☐ contained in the international application as filed.

   ☐ filed together with the international application in computer readable form.

   ☐ furnished subsequently to this Authority for the purposes of search.

3. ☐ In addition, in the case that more than one version or copy of a sequence listing and/or table relating thereto has been filed or furnished, the required statements that the information in the subsequent or additional copies is identical to that in the application as filed or does not go beyond the application as filed, as appropriate, were furnished.

4. Additional comments:

WRITTEN OPINION OF THE INTERNATIONAL SEARCHING AUTHORITY

International application No.
PCT/GB2004/003154

Box No. II Priority

1. ☒ The following document has not been furnished:

   ☒ copy of the earlier application whose priority has been claimed (Rule 43*bis*.1 and 66.7(a)).

   ☐ translation of the earlier application whose priority has been claimed (Rule 43*bis*.1 and 66.7(b)).

   Consequently it has not been possible to consider the validity of the priority claim. This opinion has nevertheless been established on the assumption that the relevant date is the claimed priority date.

2. ☐ This opinion has been established as if no priority had been claimed due to the fact that the priority claim has been found invalid (Rules 43*bis*.1 and 64.1). Thus for the purposes of this opinion, the international filing date indicated above is considered to be the relevant date.

3. Additional observations, if necessary:

Box No. V Reasoned statement under Rule 43*bis*.1(a)(i) with regard to novelty, inventive step or industrial applicability; citations and explanations supporting such statement

1. Statement

Novelty (N)	Yes:	Claims	1-18
	No:	Claims	
Inventive step (IS)	Yes:	Claims	1-11
	No:	Claims	12-18
Industrial applicability (IA)	Yes:	Claims	1-18
	No:	Claims	

2. Citations and explanations

see separate sheet

Box No. VII Certain defects in the international application

The following defects in the form or contents of the international application have been noted:

see separate sheet

Box No. VIII Certain observations on the international application

The following observations on the clarity of the claims, description, and drawings or on the question whether the claims are fully supported by the description, are made:

see separate sheet

Re Item V

Reasoned statement with regard to novelty, inventive step or industrial applicability; citations and explanations supporting such statement

The following documents (D) are referred to in this communication; the numbering will be adhered to in the rest of the procedure :

D1: EP-A-1 074 598 (TEXAS UNITED CHEMICAL CORP) 7 February 2001 (2001-02-07)
D2: US-B-6 391 8301 (DOBSON JR JAMES W ET AL) 21 May 2002 (2002-05-21)
D3: GB-A-2 351 098 (SOFITECH NV) 20 December 2000 (2000-12-20)
D4: US-B-6 403 537 (CHESSER BILLY G. ET AL) 11 June 2002 (2002-06-11)

1. Novelty :

1.1 Since none of the documents cited in the search report disclose all the features of independent claim 1, it is considered that said claim as well as dependent claims 2-11 are novel over said prior art documents.

1.2 Since none of the documents cited in the search report disclose all the features of independent claim 12, it is considered that said claim as well as dependent claims 13-18 are novel over said prior art documents.

2. Inventive step :

2.1 Since none of the prior art document teaches or fairly suggests the specific method of reducing formation breakdown as claimed in claim 1, it appears to be non-obvious to the skilled person.

Hence, **claim 1**, as well as dependent **claims 2-11**, are considered as being inventive.

2.2 **Document D1**, considered as being the closest prior art, discloses a drilling fluid comprising an aqueous base fluid, a bridgingagent and a fluid loss control additive (see [0011]) at concentrations to achieve a fluid loss of less than 10 ml as measured at 180F (85C) and 250 psi differential pressure across a 5 micron disk for 30 minutes. Example 10 shows values of fluid loss varying between 1.5ml and 4ml in 30 minutes at said HTHP conditions.
Examples of representative bridging material are calcium carbonate or dolomite (see §[0032]-[0033]) at concentrations from 5 ppb to 50 ppb.

The subject-matter of **claim 12** differs from disclosure of **D1**, since it contains the following additionnal features :

- the HTHP fluid loss is less than 2ml/30 minutes
- the bridging material has an average particle diameter of 25 microns to 2000 microns.

Considering that :

- the bridging particulates are the same in D1 as in claim 12,
- their use is the same
- the range claimed is very broad,

this features doesn't appear to be a differentiating feature between the disclosure of **document D1** and the subject-matter of said claim 12. This fact is confirmed in **document D4**, disclosing a very similar composition, and where the prefered calcium carbonate particles have an average diameter of 30 microns (see D4 col2 l56-65).

As indicated at point **VIII-1**, the operating conditions of the HTHP fluid loss measure is unclear in claim 1, as well as the influences of Temperature and Pressure on the HTHP-fluid loss value. So, no direct comparison is possible.
Futhermore, the values given in example 10, and the values claimed are very close together.
Hence, the technical problem solved by the differentiating feature "fluid loss value" of said drilling composition is therefore absolutely not clear.

Therefore, **claim 12** is not considered as being inventive at this stage of the procedure.

2.3 Dependent **claims 13-18** do not appear to contain any additional features which, in combination with the features of any claim to which they refer, meet the requirements of the EPC with respect to inventive step.

Re Item VII
Certain defects in the international application

1. The used expression "incorporation by reference", as mentioned on page 11 in the present description, is not recognised in the PCT and should be deleted.

2. The units "pounds per barrel", "bbls", "lb per barrel", "lb/bbl", "psi", "pounds per

gallon", "ppg", "feet" employed in **claims 1, 7, 11, 12 and 15** and on pages 4-8, 12-15 are not additionally expressed in terms of the units stipulated by Rule 10.1/(a)/and/(b) PCT. This should be corrected.

Re Item VIII

Certain observations on the International application

1. The subject-mater of **claims 1, 6, 12 and 17** is not clear (Art. 6 PCT) because the operating conditions of the HTHP fluid loss measurement are not given. The pressure, the temperature and the characteristics of the used filter are not given in said claims.

   Therefore, it is not possible to compare the claimed value of "less than 2ml / 30 minutes" to the values given in the prior art documents, as for example in **D1** (see p4 l45-55) : *"less than 10 ml/30 minutes at 185°F, 250 psi differential pressure, across a 5 micron disk"*.

(19) Europäisches Patentamt
European Patent Office
Office européen des brevets

(11) EP 1 074 598 A1

(12) EUROPEAN PATENT APPLICATION

(43) Date of publication:
07.02.2001 Bulletin 2001/06

(51) Int Cl.[7]: C09K 7/02, E21B 43/25

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(54) Divalent cation-containing well drilling and servicing fluids

(57) The invention provides clay-free, preferably biopolymer free, well drilling and servicing fluids comprising an aqueous divalent cation-containing water soluble salt, a bridging agent, and a pre-gelatinized crosslinked amylopectin starch suspending agent and fluid loss control additive. The concentration of the starch derivative is sufficient to provide the fluid with the following characteristics: (a) a low shear rate viscosity less than about 10,000 centipoise; (b) a high shear rate viscosity at 511 sec^{-1} in the range from about 15 to about 70 centipoise measured at 120°F; (c) a fluid loss less than about 10 milliliters as measured at 185°F and 250 psi differential pressure across a 5 micron disk for 30 minutes; and (d) anti-settling characteristics as exhibited upon static aging the fluid for 16 hours at 185°F.

The low shear rate viscosity of the fluids can be increased without increasing the high shear rate viscosity above about 70 centipoise by incorporating magnesium oxide and/or dipotassium hydrogen phosphate in the fluids.

The invention also provides a method of making the clay-free well drilling and servicing fluid and a process of drilling, completing, and working over a well with the clay-free fluid.

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Description

Background of the Invention

[0001] The present invention relates to clay-free aqueous well drilling and servicing fluids, methods of preparation thereof, and method of drilling a well therewith.

[0002] The use of fluids for conducting various operations in the boreholes of subterranean oil and gas wells which contact a producing formation are well known. Thus drill-in fluids are utilized when initially drilling into producing formations. Completion fluids are utilized when conducting various completion operations in the producing formations. Workover fluids are utilized when conducting workover operations of previously completed wells.

[0003] One of the most important functions of these fluids is to seal off the face of the wellbore so that the fluid is not lost to the formation. Ideally this is accomplished by depositing a filter cake of the solids in the fluid over the surface of the borehole without any loss of solids to the formation. In other words, the solids in the fluid bridge over the formation pores rather than permanently plugging the pores. This is particularly critical in conducting horizontal drilling operations within hydrocarbon-containing formations.

[0004] Many clay-free fluids have been proposed for contacting the producing zone of oil and gas wells. See for example the following U.S. Patents: Jackson et al. 3,785,438; Alexander 3,872,018; Fischer et al. 3,882,029; Walker 3,956,141; Smithey 3,986,964; Jackson et al. 4,003,838; Mondshine 4,175,042; Mondshine 4,186,803; Mondshine 4,369,843; Mondshine 4,620,596; Dobson, Jr. et al. 4,822,500, and Johnson 5,504,062.

[0005] These fluids generally contain polymeric viscosifiers such as certain polysaccharides or polysaccharide derivatives, polymeric fluid loss control additives such as lignosulfonates, polysaccharides or polysaccharide derivatives, and bridging solids. As disclosed in Dobson, Jr. et al. U.S. Patent No. 4,822,500, a xanthan biopolymer and an epichlorohydrin crosslinked hydroxypropyl starch fluid loss control additive synergistically interact to provide suspension and fluid loss control in certain of these fluids.

[0006] Magnesium oxide has been disclosed for use in various polysaccharide-containing fluids to increase the thermal stability thereof. See for example the following U.S. patents: Jackson 3,852,201; Jackson 3,953,335; Hartfield 3,988,246; Jackson 4,025,443; and Dobson, Jr. 5,514,644.

[0007] It is well known that certain biopolymer-containing fluids are shear thinning, exhibiting a high low shear rate viscosity and a low high shear rate viscosity. A near zero shear rate (0.06 to 0.11 sec^{-1}) viscosity provides a numerical value related to the ability of a fluid to suspend particles or cuttings under static conditions. Conversely, viscosity measured at shear rates above 20 sec^{-1} relates to the hole cleaning capability of a fluid under annular flow conditions.

[0008] It is known to use dense brines as the base aqueous liquid for high density drilling and well servicing fluids. Such fluids contain minimal soluble bridging solids concentration and viscosifying polymer additives. The most commercially available dense brines contain calcium chloride, calcium bromide, and zinc bromide. However, utilization of the brines has been limited. Generally, watersoluble polymers used for viscosity and filtration control do not perform well in calcium bromide and zinc bromide brines. Examples of the use of dense brines for use in well drilling and servicing fluids are as follows: Swartwout et al. U.S. Patent No. 5,612,293; Dobson, Jr. et al. U.S. Patent No. 5,616,541; Dobson, Jr. et al. U.S. Patent No. 5,728,652; Dobson, Jr. et al. U.S. Patent No. 5,728,654; Vollmer et al. U.S. Patent No. 5,785,747; and Dobson, Jr. et al. U.S. Patent No. 5,804,535.

[0009] Clean-up of the filter cake deposited on the sides of the borehole is a critical part of the completion process to ensure maximum productivity from a wellbore. Poor wall cake development allows particulates or liquids to enter the formation resulting in internal formation damage. Solids or polymers which have not been removed from the surface of a borehole can also impede the flow of hydrocarbons by plugging a prepacked screen during production. Filter cake removal is generally undertaken by treating the wellbore with concentrated acid solution, particularly hydrochloric acid. Dobson, Jr. et al. U.S. Patent No. 5,607,905 discloses the incorporation of certain inorganic peroxides into the filter cake which enhance the removal of the filter cake upon contacting it with an acidic solution. Brannon et al. U.S. Patent No. 5,881,813 discloses an enzyme-containing clean-up fluid for degrading the residual polymeric viscosifiers present in filter cakes from drill-in fluids or present in the formation from other well treating fluids.

[0010] While these improvements in formulating well drilling and servicing fluids from high density brines have had commercial success, there is still a need for such fluids which exhibit enhanced particulate suspension characteristics at lower viscosities and which are easier and more completely removed from wellbores, screens, and the like present in hydrocarbon-containing formations.

Summary of the Invention

[0011] The invention provides clay-free well drilling and servicing fluids comprising an aqueous brine which contains at least 1.2 equivalents per liter of a water soluble divalent cation salt, a particulate bridging agent which is insoluble in the aqueous brine, and a starch derivative which functions as a combination suspending agent and fluid loss control

agent. The starch derivative is used in a concentration sufficient to provide the fluid with the following characteristics: (a) a low shear rate viscosity less than about 10,000 centipoise; (b) a high shear rate viscosity at 511 sec^{-1} in the range from about 15 to about 70 centipoise measured at 120°F; (c) a fluid loss less than about 10 milliliters as measured at 185°F and 250 psi differential pressure across a 5 micron disk for 30 minutes; and (d) anti-settling characteristics as exhibited upon static aging the fluid for 16 hours at 185°F. The invention further provides that the low shear rate viscosity can be increased without raising the high shear rate viscosity above about 70 centipoise by incorporating magnesium oxide and/or dipotassium hydrogen phosphate in the fluids.

[0012] The preferred modified starch comprises amylopectin, such as a waxy starch, that has been crosslinked to the extent that the viscosity of a basic aqueous amylopectin starch suspension undergoing crosslinking is within about 25% to about 60% of the maximum viscosity that can be obtained, preferably from about 25% to less than about 50%, and pre-gelatinized.

[0013] The invention further comprises a process for preparing the clay-free fluids, and a process of drilling, completing, or working over a well with the clay-free fluids.

[0014] While the invention is susceptible to various modifications and alternative forms, specific embodiments thereof will hereinafter be described in detail and shown by way of example. It should be understood, however, that it is not intended to limit the invention to the particular forms disclosed, but, on the contrary, the invention is to cover all modifications and alternatives falling within the spirit and scope of the invention as expressed in the appended claims.

[0015] The compositions can comprise, consist essentially of, or consist of the stated materials. The method can comprise, consist essentially of, or consist of the stated steps with the stated materials.

Detailed Description of the Invention

[0016] The present invention is based on the discovery that certain starch derivatives function in certain dense brines to impart suspension characteristics and fluid loss control characteristics to the brines.

[0017] The brines useful in the compositions and processes of the invention contain at least 0.6 equivalents per liter of one or more water soluble divalent cation salts. Preferred divalent cations are the alkaline earth metal salts and/or zinc salts. The preferred anion is a halide, most preferably chloride and/or bromide. Most preferred divalent cations are selected from the group consisting of calcium, magnesium, zinc, and mixtures thereof. Thus the most preferred salts are selected from the group consisting of calcium chloride, calcium bromide, magnesium chloride, magnesium bromide, zinc chloride, zinc bromide and mixtures thereof. Other divalent cation water soluble salts may be present in the brine.

[0018] The preferred brines have a density of at least about 10.0 ppg.

[0019] Starch is a natural polymer containing an abundance of hydroxyl groups. Each anhydroglucose unit contains two secondary hydroxyls and a large majority contain primary hydroxyls. These hydroxyls potentially are able to react with any chemical capable of reacting with alcoholic hydroxyls. This would include a wide range of compounds such as acid anhydrides, organic chloro compounds, aldehydes, epoxy, ethylenic compounds, etc. When the specified chemical contains two or more moieties capable of reacting with hydroxyl groups, there is the possibility of reacting two different hydroxyls resulting in crosslinking between hydroxyls on the same molecule or on different molecules.

[0020] The chemistry of starch and the preparation of a multitude of derivatives thereof is well known. A book entitled "Modified Starches: Properties and Uses," by O.B. Wurzburg, 1986 (CRC Press, Inc., Boca Raton, Florida, U.S.A.) is an excellent source for information in the preparation of modified starches. In regards to the preparation of the crosslinked starches of this invention, the chapter entitled "Crosslinked Starches" is particularly pertinent.

[0021] Representative crosslinking materials are epichlorohydrin and other epihalohydrins, formaldehyde, phosphorous oxychloride, trimetaphosphate, dialdehydes, vinyl sulfone, diepoxides, diisocyanates, bis(hydroxymethyl) ethylene urea, and the like. The preferred crosslinking compound is epichlorohydrin.

[0022] Crosslinking of the starch results in an increase in the molecular weight of the starch and an increase in the viscosity of aqueous dispersions of the starch.

[0023] The reaction conditions used in making crosslinked starches vary widely depending upon the specific bi-or polyfunctional reagent used for the crosslinking. In general, most of the reactions are run on aqueous suspensions of starch at temperatures ranging from room temperature up to about 50°C. Often an alkali such as sodium hydroxide is used to promote reaction. The reactions are normally run under neutral to fairly alkaline conditions, but below the level which will peptize or swell the starch. If the crosslinking reaction is run in an aqueous suspension of starch, when the desired level of crosslinking (usually as measured by some type of viscosity or rheology test) is reached, the starch suspension is neutralized and the starch is filtered and washed to remove salts, any unreacted reagent, and other impurities produced by side reactions of the crosslinking reagent with water. Konigsberg U.S. Pat. No. 2,500,950 discloses the crosslinking of starch with epoxyhalogen compounds such as epichlorohydrin. If desired, the starch can be suspended in non-aqueous liquids or aqueous solutions containing water soluble organic liquids during crosslinking. See for example Kesler et al. U.S. Patent No. 2,845,417, incorporated herein by reference.

[0024] It is preferred that the amylopectin starch for use in the present invention be crosslinked with epichlorohydrin in a basic aqueous starch suspension at a temperature and for a period of time such that the Brabander viscosity of the suspension is within about 25% to about 60% of the maximum attainable viscosity, preferably from about 25% to less than about 50% of the maximum attainable viscosity. The viscosity will vary by the amount of crosslinking and the test conditions, i.e., temperature, concentrations, etc. A viscosity peak indicates maximum crosslinking. When the desired viscosity is reached, the crosslinking reaction is terminated. A Brabender Viscometer is a standard viscometer readily available on the open market and well known to those skilled in the art.

[0025] As indicated, the crosslinked amylopectin starch of this invention is pre-gelatinized. The term "gelatinization" is well known in the art and is generally used to describe the swelling and hydration of starches. Starch granules are insoluble in cold water but imbibe water reversibly and swell slightly. However, in hot water, a large irreversible swelling occurs producing gelatinization. Gelatinization takes place over a discrete temperature range that depends on starch type. Since gelatinization increases the viscosity of a starch suspension, the gelatinization of the starch is preferably conducted after the amylopectin starch is crosslinked to the desired extent as indicated herein. Certain chemicals increase the gelatinization temperature range of starches and thus such chemicals can be present during the crosslinking of the amylopectin in order that the crosslinking temperature can be increased without gelatinization of the starch occurring. The term "pre-gelatinized" indicates that the crosslinked amylopectin has been gelatinized such that the crosslinked amylopectin does not undergo gelatinization upon adding it to the brines of the present invention.

[0026] The crosslinked amylopectin is normally gelatinized by heating the crosslinked amylopectin at a temperature above the gelatinization temperature, such as during drying of the crosslinked starch slurry.

[0027] As indicated, the pre-gelatinized crosslinked amylopectin for use in the present invention is preferably derived from a waxy starch, preferably waxy corn (maize) starch. As is known, waxy starches are virtually all amylopectin whereas common starches contain both amylose and amylopectin molecules. For the purposes of disclosing and claiming this invention, the amylopectin contains less than about 10% by weight amylose, preferably not more than about 5% amylose and most preferably less than 1% amylose.

[0028] The brines may contain other compatible water soluble salts therein. The term "compatible" as used herein in regards to the present invention refers to a salt which does not result in precipitate formation in the brine and/or which does not prevent the disclosed pre-gelatinized crosslinked amylopectin starch from providing the brines with the characteristics set forth herein.

[0029] The fluids of this invention may contain other functional additives to impart specific properties to the fluids. Thus the fluids may contain weight materials (which may function as bridging agents in an appropriate particle size range), corrosion inhibitors, anti-oxidants, oxygen scavengers, reducing agents, supplemental fluid loss control additives, supplemental viscosifiers, and the like.

[0030] The fluids of this invention must have a bridging agent incorporated therein. The bridging agents useful in this invention are well known in the art. They are solid, particulate, water soluble salts or acid soluble materials the particles of which have been sized to have a particle size distribution sufficient to seal off the pores of the formations contacted by the well drilling and servicing fluid as is well known in the art. See for example Dobson, Jr. et al U.S. Patent No. 5,616,541 and Johnson U.S. Patent No. 5,504,082, both incorporated herein by reference. The bridging agent must not be appreciably soluble in the liquid used to prepare the fluid.

[0031] Representative water soluble salt bridging agents include sodium chloride, potassium chloride, magnesium chloride, potassium formate, calcium bromide, calcium chloride, and the like.

[0032] Preferred bridging agents have a specific gravity less than about 3.0 and are sufficiently acid soluble such that they readily decompose upon acidizing the filter cake and deposits in the borehole. Representative bridging agents are calcium carbonate, dolomite (calcium magnesium carbonate), colemanite, ulexite, analcite, apatite, bauxite, brucite, gibsite, and hydrotalcite.

[0033] The concentration of the bridging agents will be sufficient that, together with the concentration of the starch derivative, the fluids exhibit a fluid loss less than about 10 milliliters as measured at 185°F and 250 psi differential pressure across a 5 micron disk for 30 minutes. Generally the concentration of the bridging agents will be from about 5 ppb to about 50 ppb, preferably from about 10 ppb to about 30 ppb.

[0034] The concentration of the starch derivative must be sufficient to provide the fluid with the following characteristics: (a) a low shear rate viscosity less than about 10,000 centipoise; (b) a high shear rate viscosity at 511 sec^{-1} in the range from about 15 to about 70 centipoise measured at 120°F; (c) a fluid loss less than about 10 milliliters as measured at 185°F and 250 psi differential pressure across a 5 micron disc for 30 minutes; and (d) anti-settling characteristics as exhibited upon static aging the fluid for 16 hours at 185°F. Generally, the concentration of the starch derivative will be from about 5 ppb to about 12 ppb, preferably from about 6 ppb to about 11 ppb, and most preferably from about 7 ppb to about 10 ppb.

[0035] It is a novel feature of the invention that the starch derivative imparts excellent suspension characteristics to the fluids at the low viscosities imparted to the fluids. This is in direct contrast with fluids containing water soluble polymer viscosifiers, such as biopolymers, such as xanthan gum, scleroglucan gum, succinoglycan gum, and the like,

in the dense brines used in the fluids of this invention.

[0036] It is preferred that the fluids of the invention do not contain any polymeric viscosifiers, such as biopolymers, i.e., the preferred fluids are biopolymer free.

[0037] Without being limited thereby, we believe that the buoyancy of the brines contributes to the suspension characteristics of the brines. Thus as the density of the dense brines increases, less viscosity development by the starch derivative is necessary for the excellent suspension characteristics observed. This has not been previously known. Indeed, prior art fluids as exemplified by the patents disclosed hereinbefore indicate that the fluids contain a biopolymer or amorphous silica viscosifier and suspending agent and generally a starch or derivative thereof as a filtration control additive.

[0038] The fluids of the invention may be prepared and the method of the invention practiced, by mixing the dense divalent cation-containing brine as set forth herein with the starch derivative, and the bridging agent, and any optional additives as disclosed herein. The concentration of the starch as disclosed herein is that concentration which will provide the fluid with the following characteristics: (a) a low shear rate viscosity less than about 10,000 centipoise; (b) a high shear rate viscosity at 511 sec^{-1} in the range from about 15 to about 70 centipoise measured at 120°F; (c) a fluid loss less than about 10 milliliters as measured at 185°F and 250 psi differential pressure across a 5 micron disk for 30 minutes; and (d) anti-settling characteristics as exhibited upon static aging the fluid for 16 hours at 185°F.

[0039] After static aging the fluids in sealed pint jars, any separation or syneresis was noted by measuring the depth of separation. For purposes of this invention, the fluids of the invention exhibit no more than ¼ inch separation which is about 10% by volume. The settling characteristics of the aged fluids is then determined by inserting a spatula carefully into the fluids and observing if any solids had separated from the fluid. For purposes of this invention, the fluids exhibit no settling of solids.

[0040] The fluids of the invention are useful in various petroleum recovery operations such as well drilling, including drilling into hydrocarbon-containing formations, completion, workover and the like all as are well known in the art. Specifically the fluids of the invention are useful in drilling a well wherein the drilling fluid is circulated within a borehole being drilled as drilling proceeds, and in well completion and workover methods wherein a subterranean formation is contacted with an aqueous fluid to form a bridge and seal on the formation, all as are well known in the art.

[0041] The low shear rate viscosity (LSRV) for purposes of this invention is obtained using a Brookfield Model LVTDV-1 viscometer having a number I or 2 spindle at 0.3 revolutions per minute (shear rate of 0.0636 sec^{-1}). The fluid loss characteristics of the fluids are obtained by a modified API filtration test. Thus to an API high temperature filtration cell with removable end cages is added a 5 micron disk (i.e., an aluminum oxide (Alloxite™) ceramic disk having 5 micron pore throats, from 600 to 750 md permeability, which is 2.5 inches in diameter and 0.25 inch in depth) saturated with water. The fluid to be tested is poured along the inside edge of the filtration cell. The filtration test is then conducted for 30 minutes at the desired temperature of 185°F under a pressure differential of 250 pounds per square inch supplied by nitrogen. The spurt loss is measured as the amount of fluid expelled from the filtration cell until the flow of fluid is reduced to drops. The fluid loss is measured as the total amount of fluid collected in 30 minutes.

[0042] The viscosities in centipoise at 1022 sec^{-1}, 511 sec^{-1}, 340.7 sec^{-1}, 170.3 sec^{-1}, 10.22 sec^{-1}, and 5.11 $^{-1}$ are obtained by utilizing a Fann 35 Viscometer at 600 rpm, 300 rpm, 200 rpm, 100 rpm, 6 rpm, and 3 rpm by multiplying the Fann dial reading by 0.5, 1, 1.67, 3, 50, and 100, respectively.

[0043] In order to more completely describe the invention, the following non-limiting examples are given. In these examples and this specification, the following abbreviations may be used: API = American Petroleum Institute; XLAPS = the pre-gelatinized epichlorohydrin crosslinked amylopectin starch derivative of this invention which has been crosslinked to the extent that the viscosity of a basic aqueous amylopectin starch suspension undergoing crosslinking is within about 25% about 60% of the maximum viscosity which can be obtained; LSRV = Brookfield low shear rate viscosity at .03 revolutions per minute; 0.0636 sec^{-1}, in centipoise; high shear rate viscosity = Fann viscosity at 511 sec^{-1} in centipoise; sec = second(s); ppg = pounds per gallon; ppb = pounds per 42 gallon barrel; °F = degrees Fahrenheit; ml = milliliters; min = minutes; cp = centipoise; rpm = revolutions per minute; in = inches.

Example 1

[0044] 12.5 ppg fluids were prepared containing 0.98 bbl equivalents of a 12.25 ppg $CaBr_2$ brine, 23 ppb of a calcium carbonate bridging agent, and the concentrations of XLAPS, xanthan gum, scleroglucan gum, and succinoglycan gum set forth in Table 1. The rheology of the fluids before and after aging 16 hours at 85°C (185°F), and an indication of the suspension characteristics of the fluids after the static aging, were measured.

[0045] The data are set forth in Table 1.

Example 2

[0046] 13.5 ppg fluids were prepared containing 0.81 bbl equivalents of a 14.2 ppg $CaBr_2$ brine, 0.16 bbl equivalents

of water, 26 ppb calcium carbonate bridging agent, and the concentrations of XLAPS, xanthan gum, scleroglucan gum, and succinoglycan gum set forth in Table 2. The fluids were evaluated as in Example 1. The data are set forth in Table 2.

Example 3

[0047] 14.5 ppg fluids were prepared containing 0.74 bbl equivalents of a 14.2 ppg $CaBr_2$ brine, 0.14 bbl equivalents of a 19.2 ppg $CaBr_2/ZnBr_2$ brine, 0.10 bbl equivalents of water, 0.25 ppb magnesium oxide, 23 ppb calcium carbonate bridging agent, and the concentrations of XLAPS, xanthan gum, scleroglucan gum, and succinoglycan gum set forth in Table 3. The fluids were evaluated as in Example 1. The data are set forth in Table 3.

Example 4

[0048] 15.5 ppg fluids were prepared containing 0.58 bbl equivalents of a 14.2 ppg $CaBr_2$ brine, 0.31 bbl equivalents of a 19.2 ppg $CaBr_2/ZnBr_2$ brine, 0.08 bbl equivalents of water, 0.25 ppb magnesium oxide, 25 ppb calcium carbonate bridging agent, and the concentrations of XLAPS, xanthan gum, scleroglucan gum, and succinoglycan gum set forth in Table 4. The fluids were evaluated as in Example 1. The data are set forth in Table 4.

Example 5

[0049] 16.5 ppg fluids were prepared containing 0.41 bbl equivalents of a 14.2 ppg $CaBr_2$ brine, 0.52 bbl equivalents of a 19.2 ppg $CaBr_2/ZnBr_2$, 0.05 bbl equivalents of water, 0.25 ppb of magnesium oxide, 23 ppb calcium carbonate bridging agent, and the concentrations of XLAPS, xanthan gum, scleroglucan gum, and succinoglycan gum set forth in Table 5. The fluids were evaluated as in Example 1. The data are set forth in Table 5.

[0050] In Tables 1-5, fluids C, D and E which don't contain the XLAPS of this invention are not examples of the invention, and are presented for comparison purposes only. The data indicate the excellent suspension characteristics of the fluids containing the XLAPS even at very low LSRV, and the very poor suspension characteristics of the fluids containing only the biopolymers. Incorporation of a biopolymer into the XLAPS-containing fluids increased the high shear rate viscosity and affected the LSRV in various ways depending upon the density of the fluids. The data also indicate that, in general, the LSRV decreases and the high shear rate viscosity increases as the concentration of zinc bromide in the fluids increases. However, the excellent suspension characteristics of the fluids was maintained.

Example 6

[0051] CaCl2 fluids having densities of 9.5, 10.35 and 11.3 ppg were prepared each containing 8 ppb XLAPS and the concentration of MgO and calcium carbonate bridging agent set forth in Table 6. The fluids were evaluated as in Example 1. The data obtained are set forth in Table 6.

[0052] The data indicate that: (1) the density of the fluids should be greater than 9.5 ppg, preferably at least about 10.0 ppg; (2) magnesium oxide can be added to increase the viscosity of the fluids, as desired, especially the LSRV; and (3) the excellent suspension characteristics of the fluids of the fluids of the invention even at low LSRV.

Example 7

[0053] 14.6 ppg $CaBr_2/ZnBr_2$ fluids were prepared each containing 8 ppb XLAPS, 24 ppb $CaCO_3$ bridging agent, 0.71 bbl 14.2 ppg $CaBr_2$, 0.11 bbl water, 0.17 bbl 19.2 ppg $CaBr_2/ZnBr_2$, and the concentrations of MgO, MgO_2, sodium thiosulfate, and K_2HPO_4 set forth in Table 7. The fluids were evaluated as in Example 1. The data obtained are set forth in Table 7.

[0054] The data indicate that the magnesium oxide enhanced the thermal stability of the fluids containing the magnesium peroxide and sodium thiosulfate, and that the K_2HPO_4 increases the viscosity of the fluid after aging at 185°F, especially the LSRV.

Example 8

[0055] A 14.6 ppg $CaBr_2/ZnBr_2$ fluid was prepared as in Example 7 containing 8 ppb XLAPS, 0.25 ppg MgO, and 24 ppb $CaCO_3$ bridging agent. The rheology of the fluid was measured at 120°F initially and after aging the fluid for the time set forth in Table 8 at 185°F. The data obtained are set forth in Table 8.

[0056] The data indicate the excellent thermal stability and suspension characteristics of the fluid.

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Example 9

[0057] 10.35 ppb $MgCl_2$ fluids were prepared containing 0.97 bbl of 10.0 ppg $MgCl_2$ brine, 8 ppb XLAPS, 26 ppb calcium carbonate bridging agent, and either 0 or 0.25 ppb MgO. The fluids were evaluated as before. The data obtained are set forth in Table 7.

[0058] The data indicate the excellent suspension characteristics of the XLAPS in $MgCl_2$-containing brines, and the increase of the LSRV upon addition of the MgO.

Example 10

[0059] The high temperature, high pressure fluid loss for fluids 4-A, Table 4, and 5-A, Table 5, were determined at 185°F, 250 psi differential pressure across a 5 micron disk. The data obtained are as follows. Fluid 4-A: Initial - Spurt Loss = 1.5 ml, 30 min. = 3 ml; Aged @ 185°F - Spurt Loss = 2.5 ml, 30 min = 3.5 ml. Fluid 5-A: Initial - Spurt Loss = 1.5 ml, 30 min = 3 ml; Aged @ 185°F - Spurt Loss = 2 ml, 30 min = 4 ml.

[0060] These data illustrate the excellent fluid loss characteristics of the fluids of this invention.

[0061] The data in the Tables indicate that the LSRV of the fluids of this invention can be increased by the addition of magnesium oxide, dipotassium hydrogen phosphate, or biopolymers to the fluids, particularly after subjecting the fluids to elevated temperatures as would occur on using the fluids in the drilling or servicing of wells. The data also indicate that only low concentrations of the biopolymer can be incorporated into the fluids without unduly raising the high shear rate viscosity, i.e., at 511 sec^{-1}. Thus the LSRV of the fluids can be increased without unduly raising the high shear rate viscosity by the addition of magnesium oxide and/or dipotassium hydrogen phosphate to the fluids, preferably in an amount from about 0.1 ppb to about 5 ppb. It is another aspect of the invention to increase the low shear rate viscosity of the fluids of the invention without increasing the high shear rate viscosity above about 70 centipoise by the addition of magnesium oxide and/or dipotassium hydrogen phosphate to the fluids. Thus the low shear rate viscosity of the fluids can be greater than 10,000 centipoise upon the addition of an additive which raises the low shear rate viscosity of the fluids without raising the high shear rate viscosity above about 70.

Table 1

12.5 ppg $CaBr_2$ Fluids								
Fluid	1-A	1-B	1-C	1-D	1-E	1-F	1-G	1-H
XLAPS, ppb	8.0	10.0	0	0	0	8.0	8.0	8.0
Xanthan, ppb	0	0	1.5	0	0	1.5	0	0
Scleroglucan, ppb	0	0	0	1.5	0	0	1.5	0
Succinoglycan, ppb	0	0	0	0	1.5	0	0	1.5
Initial Rheology at 120°F								
1022 sec^{-1}, cp	18	30	15.5	14.5	11	80	49	65
511 sec^{-1}, cp	22	40	19	2112	11	4	70	90
10.22 sec^{-1}, cp	150	150	50	350	0	650	850	300
0.0636 sec^{-1}, cp	3039	2600	1920	9,878	120	17,700	54,300	700
STI	138	65	101	470	10	155	776	8
Static Aged at 185°F for 16 hours								
Separation	None	None	Total	None	Total	None	None	None
Settling	None	None		None		None	None	None
1022 sec^{-1}, cp	17.5	29.5	14.5	14	10	75	47.5	55
511 sec^{-1}, cp	20	38	17	21	11	105	72	72
10.22 sec^{-1}, cp	50	150	50	350	100	500	900	150
0.0636 sec^{-1}, cp	440	500	600	12,357	0	10,300	50,700	900
STI	22	13	5	588	0	98	704	12.5

Table 2

13.5 ppg $CaBr_2$ Fluids								
Fluid	2-A	2-B	2-C	2-D	2-E	2-F	2-G	2-H
XLAPS, ppb	7.0	10.0	0	0	0	8.0	8.0	8.0
Xanthan, ppb	0	0	1 5	0	0	1.5	0	0
Scleroglucan, ppb	0	0	0	1.5	0	0	1.5	0
Succinoglycan, ppb	0	0 0	0	1.5	0	0	1.5	
Initial Rheology at 120°F								
1022 sec^{-1}, cp	18.5	35	23.5	4.5	4.5	89	37.5	65
511 sec^{-1}, cp	23	47	30	4	5	140	44	85
10.22 sec^{-1}, cp	200	200	150	0	0	900	100	150
0.0636 sec', cp	5700	9200	280	60	100	13,500	300	800
STI	248	196	9	15	20	96	7	9
Static Aged at 185°F for 16 hours								
Separation, in Settling	None None	None None	Total	Total	Total	None None	0.5 None	None None
1022 sec^{-1}, cp	20.5	40	19.5	4	25.5	95	37.5	99
511 sec^{-1}, cp	25	53	24	4	33	145	43	142
10.22 sec^{-1}, cp	150	200	50	0	150	1100	150	1000
0.0636 sec^{-1}, cp	1180	7200	100	20	280	19,800	4800	16,100
STI	47	136	4	5	9	137	112	113

Table 3

14.5 ppg $CaBr_2/ZnBr_2$ Fluids								
Fluid	3-A	3-B	3-C	3-D	3-E	3-F	3-G	3-H
XLAPS, ppb	7.0	10.0	0	0	0	8.0	8.0	8.0
Xanthan, ppb	0	0	1.5	0	0	1.5	0	0
Scleroglucan, ppb	0	0	0	1.5	0	0	1.5	0
Succinoglycan, ppb	0	0	0	0	1.5	0	0	1.5
Initial Rheology at 120°F								
1022 sec^{-1}, cp	19	38.5	14	13	3.5	75	72.5	31.5
511 sec^{-1}, cp	23	50	17	14	4	109	90	37
10.22 sec^{-1}, cp	150	200	100	100	0	600	150	50
0.0636 sec', cp	2200	8000	20	60	60	6900	500	1300
STI	96	160	1	4	15	63	6	35
Static Aged at 185°F for 16 hours								
Separation Settling	None None	None None	Total	Total	Total	None None	None None	None None
1022 sec^{-1}, cp	19.5	41	25	10	20.5	78.5	66	74
511 sec^{-1}, cp	23	53	34	11	26	117	80	107
10.22 sec^{-1}, cp	100	200	200	100	150	900	150	850
0.0636 sec^{-1}, cp	680	3800	200	20	140	18,700	600	10,600
STI	30	72	6	2	5	160	7.5	99

Table 4

15.5 ppg $CaBr_2/ZnBr_2$ Fluids								
Fluid	4-A	4-B	4-C	4-D	4-E	4-F	4-G	4-H
XLAPS, ppb	8.0	10.0	0	0	0	8.0	8.0	8.0
Xanthan, ppb	0	0	1.5	0	0	1 5	0	0
Scleroglucan, ppb	0	0	0	1.5	0	0	1.5	0
Succinoglycan, ppb	0	0	0	0	1.5	0	0	1.5
Initial Rheology at 120°F								
1022 sec^{-1}, cp	29	46.5	11.5	16	5.5	96	89	36.5
511 sec^{-1}, cp	37	61	13	16	6	145	110	43
10.22 sec^{-1}, cp	150	300	0	0	50	1050	150	50
0.0636 sec^{-1}, cp	2000	7600	40	20	80	6800	600	400
STI	54	126	3	1	13	47	5	9
Static Aged at 185°F for 16 hours								
Separation	None	None	Total	Total	Total	None	None	None
Settling	None	None				None	None	None
1022 sec^{-1}, cp	31.5	47	21.5	12	29.5	100	77	90
511 sec^{-1}, cp	39	61	27	12	39	148	85	126
10.22 sec^{-1}, cp	150	200	150	0	200	1000	150	900
0.0636 sec^{-1}, cp	900	2400	80	0	80	7800	300	7400
STI	23	39	3	0	2	53	4	59

Table 5

16.5 ppg $CaBr_2/ZnBr_2$ Fluids								
Fluid	5-A	5-B	5-C	5-D	5-E	5-F	5-G	5-H
XLAPS, ppb	8.0	10.0	0	0	0	8.0	8.0	8.0
Xanthan, ppb	0	0	1.5	0	0	1.5	0	0
Scleroglucan, ppb	0	0	0	1.5	0	0	1.5	0
Succinoglycan, ppb	0	0	0	0	1.5	0	0	1.5
Initial Rheology at 120°F								
1022 sec^{-1}, cp	38	44.5	10.5	22	6	117	120	93.5
511 sec^{-1}, cp	42	55	12	24	7	165	150	112
10.22 sec^{-1}, cp	150	200	100	50	50	900	250	200
0.0636 sec^{-1}, cp	500	7800	40	0	20	4800	800	600
STI	12	142	3	0	3	29	5	5
Static Aged at 185°F for 16 hours								
Separation	None	None	Total	Total	Total	None	None	None
Settling	None	None				None	None	None
1022 sec^{-1}, cp	37.5	65	20	16.5	20.5	127	92	144
511 sec^{-1}, cp	48	83	25	18	25	178	108	198
10.22 sec^{-1}, cp	150	300	100	0	100	1050	200	1350
0.0636 sec^{-1}, cp	500	2100	360	20	200	5700	400	15,000
STI	11	25	14	1	8	228	4	76

Table 6

$CaCl_2$ Fluids 8 ppb XLAPS						
Fluid	6-A	6-B	6-C	6-D	6-E	6-F
Density, ppg	9.5	9.5	10.35	10.35	11.3	11.3
9.15 ppg $CaCl_2$, bbl	0.97	0.97	0	0	0	0
10.0 ppg $CaCl_2$, bbl	0	0	0.97	0.97	0	0
11.0 ppg $CaCl_2$, bbl	0	0	0	0	0.97	0.97
$CaCO_3$, ppb	25	25	26	26	25	25
MgO, ppb	0	0.25	0	0.25	0	0.25
Initial Rheology at 120°F						
1022 sec^{-1}, cp	8.5	11.5	15	19	26.5	31
511 sec^{-1}, cp	11	17	18	27	33	41
10.22 sec^{-1}, cp	50	250	50	300	150	300
0.0636 sec^{-1}, cp	5520	15,737	2300	16,357	4000	20,296
STI	502	926	128	606	121	495
Static Aged at 185°F for 16 hours						
Separation, in	1	1.25	0.25	0.25	0.25	None
Settling	Settling	Settling	None	None	None	None
1022 sec^{-1}, cp	8.5	13	15.5	22.5	26	35
511 sec^{-1}, cp	11	19	19	33	33	48
10.22 sec^{-1}, cp	50	250	0	480	150	500
0.0636 sec^{-1}, cp	3500	21,695	1120	33,693	1820	33,896
STI	318	1142	59	1021	55	706

Table 7

8 ppb XLAPS						
	14.6 ppg $CaBr_2/ZnBr_2$ Fluids				10.35 ppg $MgCl_2$	
Fluid	7-A	7-B	7-C	7-D	9-A	9-B
MgO, ppb	0.25	0	0	0.25	0	0.25
Mg Peroxide, ppb	0.5	0.5	0.5	0	0	0
Sodium Thiosulphate, ppb	0.5	0.5	1.0	0	0	0
K_2HPO_4, ppb	0	0	3.0	0	0	0
Initial Rheology at 120°F						
1022 sec^{-1}, cp	23.5	24	23	26.5	20.5	19
511 sec^{-1}, cp	30	30	29	34	23	27
10.22 sec^{-1}, cp	200	100	100	200	150	50
0.0636 sec^{-1}, cp	3200	3500	3479	4000	4599	6399
STI	107	117	120	118	200	237
Static Aged at 185°F for 16 hours						
Separation, in	None	None	None	None	0.25	0.25
Settling	None	None	None	None	None	None
1022 sec^{-1}, cp	25	24.5	32.5	27	22	21.5
511 sec^{-1}, cp	31	30	44	35	28	30
10.22 sec^{-1}, cp	100	50	450	200	250	150
0.0636 sec^{-1}, cp	6000	520	24,595	2100	6019	11,618
STI	194	17 559	57		215	397

Table 8

14.6 ppg $CaBr_2/ZnBr_2$ Fluids							
5 ppb XLAPS, 0.25 ppb MgO							
Hr. Aged @ 185°F	0	16	36	62	72	144	316
1022 sec^{-1}, cp	26.5	27	28.5	29.5	29.5	28	29.5
511 sec^{-1}, cp	34	35	37	39	39	37	39
340.7 sec^{-1}, cp	39	40.5	43.5	46.5	46.5	45	46.5
170.3 sec^{-1}, cp	51	54	57	63	63	63	63
10.22 sec^{-1}, cp	200	200	200	250	300	250	250
5.11 sec^{-1}, cp	300	300	300	400	400	400	400
0.0636 sec^{-1}, cp	3997	1240	2100	5599	5919	6079	5059
STI	118	35	57	144	152	164	130
Separation	-	None	None	None	None	None	None
Settling	-	None	None	None	None	None	None

Claims

1. A clay-free well drilling and servicing fluid comprising an aqueous brine containing at least 1.2 equivalents per liter of a water soluble divalent cation salt, a particulate bridging agent which is insoluble in the aqueous liquid, and a starch derivative wherein the concentration of the starch derivative is sufficient to provide the fluid with the following characteristics: (a) a low shear rate viscosity less than about 10,000 centipoise; (b) a high shear rate viscosity at 511 sec^{-1} in the range from about 15 to about 70 centipoise measured at 120°F; (c) a fluid loss less than about 10 milliliters as measured at 185°F and 250 psi differential pressure across a 5 micron disk for 30 minutes; and (d) anti-settling characteristics as exhibited upon static aging the fluid for 16 hours at 185°F.

2. The fluid of Claim 1 wherein the starch derivative comprises a pre-gelatinized crosslinked amylopectin starch which has been crosslinked to the extent that the viscosity of a basic aqueous amylopectin starch suspension undergoing crosslinking is within about 25% to about 60% of the maximum viscosity which can be obtained.

3. The fluid of Claim 2 wherein the amylopectin starch is crosslinked with epichlorohydrin.

4. The fluid of Claim 3 wherein the density of the fluid is at least about 10 ppg.

5. The fluid of Claim 3 wherein the water soluble divalent cation salt is selected from the group consisting of the alkaline earth metal halide salts, the zinc halide salts, and mixtures thereof.

6. The fluid of Claim 3 wherein the concentration of the starch derivative is from about 5 ppb to about 12 ppb.

7. The fluid of Claim 3, 4, 5, or 6 additionally containing an additive selected from the group consisting of magnesium oxide, dipotassium hydrogen phosphate, and mixtures thereof, in an amount sufficient to increase the low shear rate viscosity without increasing the high shear rate viscosity above 70 centipoise.

8. A process of preparing a clay-free well drilling and servicing fluid, the fluid comprising an aqueous brine containing at least 1.2 equivalents per liter of a water soluble divalent cation salt and a particulate bridging agent which is insoluble in the aqueous liquid, which comprises adding to the fluid a starch derivative in an amount sufficient to provide the fluid with the following characteristics: (a) a low shear rate viscosity less than about 10,000 centipoise; (b) a high shear rate viscosity at 511 sec^{-1} in the range from about 15 to about 70 centipoise measured at 120°F; (c) a fluid loss less than about 10 milliliters as measured at 185°F and 250 psi differential pressure across a 5 micron disk for 30 minutes; and (d) anti-settling characteristics as exhibited upon static aging the fluid for 16 hours at 185°F.

9. The process of Claim 8 wherein the starch derivative comprises a pre-gelatinized crosslinked amylopectin starch which has been crosslinked to the extent that the viscosity of a basic aqueous amylopectin starch suspension

undergoing crosslinking is within about 25% to about 60% of the maximum viscosity which can be obtained.

10. The process of Claim 9 wherein the amylopectin starch is crosslinked with epichlorohydrin.

11. The process of Claim 10 wherein the density of the fluid is at least about 10 ppg.

12. The process of Claim 10 wherein the water soluble divalent cation salt is selected from the group consisting of the alkaline earth metal halide salts, the zinc halide salts, and mixtures thereof.

13. The process of Claim 10 wherein the concentration of the starch derivative is from about 5 ppb to about 12 ppb.

14. The process of Claim 10, 11, 12, or 13 additionally containing an additive selected from the group consisting of magnesium oxide, dipotassium hydrogen phosphate, and mixtures thereof, in an amount sufficient to increase the low shear rate viscosity without increasing the high shear rate viscosity above 70 centipoise.

15. A process of drilling a well wherein a drilling fluid is circulated within the wellbore being drilled as drilling proceeds which comprises using as the drilling fluid the fluid of Claim 1, 2, 3, 4, 5, or 6.

16. In a process of completing or working over a well wherein a subterranean formation is contacted with an aqueous liquid, the improvement comprising using as the aqueous fluid the fluid of Claim 1, 2, 3, 4, 5, or 6.

17. A process of drilling a well wherein a drilling fluid is circulated within the wellbore being drilled as drilling proceeds which comprises using as the drilling fluid the fluid of Claim 1, 2, 3, 4, 5, or 6, wherein the fluid additionally contains an additive selected from the group consisting of magnesium oxide, dipotassium hydrogen phosphate, and mixtures thereof, in an amount sufficient to increase the low shear rate viscosity without increasing the high shear rate viscosity above 70 centipoise.

18. In a process of completing or working over a well wherein a subterranean formation is contacted with an aqueous liquid, the improvement comprising using as the aqueous fluid the fluid of Claim 1, 2, 3, 4, 5, or 6, wherein the fluid additionally contains an additive selected from the group consisting of magnesium oxide, dipotassium hydrogen phosphate, and mixtures thereof, in an amount sufficient to increase the low shear rate viscosity without increasing the high shear rate viscosity above 70 centipoise.

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European Patent Office

EUROPEAN SEARCH REPORT

Application Number
EP 00 30 6654

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Category	Citation of document with indication, where appropriate, of relevant passages	Relevant to claim	CLASSIFICATION OF THE APPLICATION (Int.Cl.7)
X	EP 0 758 011 A (TEXAS UNITED CHEMICAL CORP) 12 February 1997 (1997-02-12) * page 2, line 55 - page 3, line 49 * * page 4, line 3 - page 5, line 55 * * page 6, line 12 - line 47; claims 1-11; examples 1-3 *	1-18	C09K7/02 E21B43/25
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The present search report has been drawn up for all claims

Place of search	Date of completion of the search	Examiner
THE HAGUE	8 November 2000	Boulon, A

CATEGORY OF CITED DOCUMENTS

X : particularly relevant if taken alone
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ANNEX TO THE EUROPEAN SEARCH REPORT ON EUROPEAN PATENT APPLICATION NO. EP 00 30 6654

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For more details about this annex : see Official Journal of the European Patent Office, No. 12/82

US006391830B1

(12) **United States Patent**
Dobson, Jr. et al.

(10) **Patent No.: US 6,391,830 B1**
(45) **Date of Patent: *May 21, 2002**

(54) **DIVALENT CATION-CONTAINING WELL DRILLING AND SERVICING FLUIDS**

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(73) Assignee: **Texas United Chemical Company, LLC., Houston, TX (US)**

(*) Notice: Subject to any disclaimer, the term of this patent is extended or adjusted under 35 U.S.C. 154(b) by 0 days.

This patent is subject to a terminal disclaimer.

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(63) Continuation-in-part of application No. 09/368,947, filed on Aug. 5, 1999, now Pat. No. 6,300,286.

(51) **Int. Cl.**[7] **C09K 7/02**

(52) **U.S. Cl.** **507/111**; 507/140; 507/145; 507/212; 507/269; 507/272; 507/277; 507/906; 507/925

(58) **Field of Search** 507/111, 140, 507/145, 212, 269, 272, 277, 906, 925

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Primary Examiner—Philip Tucker
(74) *Attorney, Agent, or Firm*—Roy F. House

(57) **ABSTRACT**

The invention provides clay-free, preferably biopolymer free, well drilling and servicing fluids comprising an aqueous divalent cation-containig water soluble salt, a bridging agent, and a pre-gelatinized crosslinked amylopectin starch suspending agent and fluid loss control additive. The concentration of the starch derivative is sufficient to provide the fluid with the following charactristics: (a) a low shear rate viscosity less than about 10,000 centipoise; (b) a high shear rate viscosity at 511 sec^{-1} in the range from about 15 to about 70 centipoise measured at 120° F.; (c) a fluid loss less than about 10 milliliters as measured at 185° F. and 250 psi differential pressure across a 5 micron disk for 30 minutes; and (d) anti-settling characteristics as exhibited upon static aging the fluid for 16 hours at 185° F. The low shear rate viscosity of the fluids can be increased without increasing the high shear rate viscosity above about 70 centipoise by incorporating magnesium oxide and/or dipotassium hydrogen phosphate in the fluids. The invention also provides a method of making the clay-free well drilling and servicing fluid and a process of drilling, completing, and working over a well with the clay-free fluid.

24 Claims, No Drawings

DIVALENT CATION-CONTAINING WELL DRILLING AND SERVICING FLUIDS

This is a continuation-in-part of U.S. patent application Ser. No. 09/368,947 filed Aug. 5, 1999 now U.S. Pat. No. 6,300,286.

BACKGROUND OF THE INVENTION

The present invention relates to clay-free aqueous well drilling and servicing fluids, methods of preparation thereof, and method of drilling a well therewith.

The use of fluids for conducting various operations in the boreholes of subterranean oil and gas wells which contact a producing formation are well known. Thus drill-in fluids are utilized when initially drilling into producing formations. Completion fluids are utilized when conducting various completion operations in the producing formations. Workover fluids are utlized when conducting workover operations of previously completed wells.

One of the most important functions of these fluids is to seal off the face of the wellbore so that the fluid is not lost to the formation. Ideally this is accomplished by depositing a filter cake of the solids in the fluid over the surface of the borehole without any loss of solids to the formation. In other words, the solids in the fluid bridge over the formation pores rather than permanently plugging the pores. This is particularly critical in conducting horizontal drilling operations within hydrocarbon-containing formations.

Many clay-free fluids have been proposed for contacting the producing zone of oil and gas wells. See for example the following U.S. Patents: Jackson et al. U.S. Pat. No. 3,785,438; Alexander U.S. Pat. No. 3,872,018; Fischer et al. U.S. Pat. No. 3,882,029; Walker U.S. Pat. No. 3,956,141; Smithey U.S. Pat. No. 3,986,964; Jackson et al. U.S. Pat. No. 4,003,838; Mondshine U.S. Pat. No. 4,175,042; Mondshine U.S. Pat. No. 4,186,803; Mondshine U.S. Pat. No. 4,369,843; Mondshine U.S. Pat. No. 4,620,596; Dobson, Jr. et al. U.S. Pat. No. 4,822,500, and Johnson U.S. Pat. No. 5,504,062.

These fluids generally contain polymeric viscosifiers such as certain polysaccharides or polysaccharide derivatives, polymeric fluid loss control additives such as lignosulfonates, polysaccharides or polysaccharide derivatives, and bridging solids. As disclosed in Dobson, Jr. et al. U.S. Pat. No. 4,822,500, a xanthan biopolymer and an epichlorohydrin crosslinked hydroxypropyl starch fluid loss control additive synergistically interact to provide suspension and fluid loss control in certain of these fluids.

Magnesium oxide has been disclosed for use in various polysaccharide containing fluids to increase the thermal stability thereof. See for example the following U.S. patents: Jackson U.S. Pat. No. 3,852,201; Jackson U.S. Pat. No. 3,953,335; Hartfield U.S. Pat. No. 3,988,246; Jackson U.S. Pat. No. 4,025,443; and Dobson, Jr. U.S. Pat. No. 5,514,644.

It is well known that certain biopolymer-containing fluids are shear thinning, exhibiting a high low shear rate viscosity and a low high shear rate viscosity. A near zero shear rate (0.06 to 0.11 sec^{-1}) viscosity provides a numerical value related to the ability of a fluid to suspend particles or cuttings under static conditions. Conversely, viscosity measured at shear rates above 20 sec^{-1} relates to the hole cleaning capability of a fluid under annular flow conditions.

It is known to use dense brines as the base aqueous liquid for high density drilling and well servicing fluids. Such fluids contain minimal soluble bridging solids concentration

and viscosifying polymer additives. The most commercially available dense brines contain calcium chloride, calcium bromide, and zinc bromide. However, utilization of the brines has been limited. Generally, water-soluble polymers used for viscosity and filtration control do not perform well in calcium bromide and zinc bromide brines. Examples of the use of dense brines for use in well drilling and servicing fluids are as follows: Swartwout et al. U.S. Pat. No. 5,612,293; Dobson, Jr. et al. U.S. Pat. No. 5,616,541; Dobson, Jr. et al. U.S. Pat. No. 5,728,652; Dobson, Jr. et al. U.S. Pat. No. 5,728,654; Vollmer et al. U.S. Pat. No. 5,785,747; and Dobson, Jr. et al. U.S. Pat. No. 5,804,535.

Clean-up of the filter cake deposited on the sides of the borehole is a critical part of the completion process to ensure maximum productivity from a wellbore. Poor wall cake development allows particulates or liquids to enter the formation resulting in internal formation damage. Solids or polymers which have not been removed from the surface of a borehole can also impede the flow of hydrocarbons by plugging a prepacked screen during production. Filter cake removal is generally undertaken by treating the wellbore with concentrated acid solution, particularly hydrochloric acid. Dobson, Jr. et al. U.S. Pat. No. 5,607,905 discloses the incorporation of certain inorganic peroxides into the filter cake which enhance the removal of the filter cake upon contacting it with an acidic solution. Brannon et al. U.S. Pat. No. 5,881,813 discloses an enzyme-containing clean-up fluid for degrading the residual polymeric viscosifiers present in filter cakes from drill-in fluids or present in the formation from other well treating fluids.

While these improvements in formulating well drilling and servicing fluids from high density brines have had commercial success, there is still a need for such fluids which exhibit enhanced particulate suspension characteristics at lower viscosities and which are easier and more completely removed from wellbores, screens, and the like present in hydrocarbon-containing formations.

SUMMARY OF THE INVENTION

The invention provides clay-free well drilling and servicing fluids comprising an aqueous brine which contains at least 1.2 equivalents per liter of a water soluble divalent cation salt, a particulate bridging agent which is insoluble in the aqueous brine, and a starch derivative which functions as a combination suspending agent and fluid loss control agent. The starch derivative is used in a concentration sufficient to provide the fluid with the following characteristics: (a) a low shear rate viscosity less than about 10,000 centipoise; (b) a high shear rate viscosity at 511 sec^{-1} in the range from about 15 to about 70 centipoise measured at 120° F.; (c) a fluid loss less than about 10 milliliters as measured at 185° F. and 250 psi differential pressure across a 5 micron disk for 30 minutes; and (d) anti-settling characteristics as exhibited upon static aging the fluid for 16 hours at 185° F. The invention further provides that the low shear rate viscosity can be increased without raising the high shear rate viscosity above about 70 centipoise by incorporating magnesium oxide and/or dipotassium hydrogen phosphate in the fluids.

The preferred modified starch comprises amylopectin, such as a waxy starch, that has been crosslinked to the extent that the viscosity of a basic aqueous amylopectin starch suspension undergoing crosslinking is within about 25% to about 60% of the maximum viscosity that can be obtained, preferably from about 25% to less than about 50%, and pre-gelatinized.

The invention further comprises a process for preparing the clay-free fluids, and a process of drilling, completing, or working over a well with the clay-free fluids.

While the invention is susceptible to various modifications and alternative forms, specific embodiments thereof will hereinafter be described in detail and shown by way of example. It should be understood, however, that it is not intended to limit the invention to the particular forms disclosed, but, on the contrary, the invention is to cover all modifications and alternatives falling within the spirit and scope of the invention as expressed in the appended claims.

The compositions can comprise, consist essentially of, or consist of the stated materials. The method can comprise, consist essentially of, or consist of the stated steps with the stated materials.

DETAILED DESCRIPTION OF THE INVENTION

The present invention is based on the discovery that certain starch derivatives function in certain dense brines to impart suspension characteristics and fluid loss control characteristics to the brines.

The brines useful in the compositions and processes of the invention contain at east 0.6 equivalents per liter of one or more water soluble divalent cation salts. referred divalent cations are the alkaline earth metal salts and/or zinc salts. The referred anion is a halide. most preferably chloride and/or bromide. Most preferred divalent cations are selected from the group consisting of calcium, magnesium, zinc, and mixtures thereof. Thus the most preferred salts are selected from the group consisting of calcium chloride, calcium bromide, magnesium chloride, magnesium bromide, zinc chloride, zinc bromide and mixtures thereof. Other divalent cation water soluble salts may be present in the brine.

The preferred brines have a density of at least about 10.0 ppg.

Starch is a natural polymer containing an abundance of hydroxyl groups. Each anhydroglucose unit contains two secondary hydroxyls and a large majority contain primary hydroxyls. These hydroxyls potentially are able to react with any chemical capable of reacting with alcoholic hydroxyls. This would include a wide range of compounds such as acid anhydrides, organic chloro compounds, aldehydes, epoxy, ethylenic compounds, etc. When the specified chemical contains two or more moieties capable of reacting with hydroxyl groups, there is the possibility of reacting two different hydroxyls resulting in crosslinking between hydroxyls on the same molecule or on different molecules.

The chemistry of starch and the preparation of a multitude of derivatives thereof is well known. A book entitled "Modified Starches: Properties and Uses," by O. B. Wurzburg, 1986 (CRC Press, Inc., Boca Raton, Fla., U.S.A.) is an excellent source for information in the preparation of modified starches. In regards to the preparation of the crosslinked starches of this invention, the chapter entitled "Crosslinked Starches" is particularly pertinent.

Representative crosslinking materials are epichlorohydrin and other epihalohydrns, formaldehyde, phosphorous oxychloride, trimetaphosphate, dialdehydes, vinyl sulfone, diepoxides, diisocyanates, bis(hydroxymethyl)ethylene urea, and the like. The preferred crosslinking compound is epichlorohydrin.

Crosslinking of the starch results in an increase in the molecular weight of the starch and an increase in the viscosity of aqueous dispersions of the starch.

The reaction conditions used in making crosslinked starches vary widely depending upon the specific bi-or polyfunctional reagent used for the crosslinking. In general, most of the reactions are run on aqueous suspensions of starch at temperatures ranging from room temperature up to about 50° C. Often an alkali such as sodium hydroxide is used to promote reaction. The reactions are normally run under neutral to fairly alkaline conditions, but below the level which will peptize or swell the starch. If the crosslinking reaction is run in an aqueous suspension of starch, when the desired level of crosslinking (usually as measured by some type of viscosity or rheology test) is reached, the starch suspension is neutralized and the starch is filtered and washed to remove salts, any unreacted reagent, and other impurities produced by side reactions of the crossliking reagent with water. Konigsberg U.S. Pat. No. 2,500,950 discloses the crosslinking of starch with epoxyhalogen compounds such as epichlorohydrin. If desired, the starch can be suspended in non-aqueous liquids or aqueous solutions containing water soluble organic liquids during crosslinking. See for example Kesler et al. U.S. Pat. No. 2,845,417, incorporated herein by reference.

It is preferred that the amylopectin starch for use in the present invention be crosslinked with epichlorohydrin in a basic aqueous starch suspension at a temperature and for a period of time such that the Brabander viscosity of the suspension is within about 25% to about 60% of the maximum attainable viscosity, preferably from about 25% to less than about 50% of the maximum attainable viscosity. The viscosity will vary by the amount of crosslinking and the test conditions, i.e., temperature, concentrations, etc. A viscosity peak indicates *maximum* crosslinking. When the desired viscosity is reached, the crosslinkug reaction is terminated. A Brabender Viscometer is a standard viscometer readily available on the open market and well known to those skilled in the art.

As indicated, the crosslinked amylopectin starch of this invention is pre-gelatinized. The term "gelatinization" is well known in the art and is generally used to describe the swelling and hydration of starches. Starch granules are insoluble in cold water but imbibe water reversibly and swell slightly. However, in hot water, a large irreversible swelling occurs producing gelatinization. Gelatinization takes place over a discrete temperature range that depends on starch type. Since gelatinization increases the viscosity of a starch suspension, the gelatinization of the starch is preferably conducted after the amylopectin starch is crosslinked to the desired extent as indicated herein. Certain chemicals increase the gelatinization temperature range of starches and thus such chemicals can be present during the crosslinking of the amylopectin in order that the crosslinling temperature can be increased without gelatinization of the starch occurring. The term "pre-gelatmized" indicates that the crosslinked amylopectin has been gelatinized such that the crosslinked amylopectin does not undergo gelatinization upon adding it to the brines of the present invention.

The crosslinked amylopectin is normally gelatinized by heating the crosslinked amylopectin at a temperature above the gelatinization temperature, such as during drying of the crosslinked starch slurry.

As indicated, the pre-gelatinized crosslinked amylopectin for use in the present invention is preferably derived from a waxy starch, preferably waxy corn (maize) starch. As is known, waxy starches are virtually all amylopectin whereas common starches contain both amylose and amylopectin molecules. For the purposes of disclosing and claiming this invention, the amylopectin contains less than about 10% by weight amylose, preferably not more than about 5% amylose and most preferably less than 1% amylose.

The brines may contain other compatible water soluble salts therein. The term "compatible" as used herein in

regards to the present invention refers to a salt which does not result in precipitate formation in the brine and/or which does not prevent the disclosed pre-gelatinized crosslinked amylopectin starch from providing the brines with the characteristics set forth herein.

The fluids of this invention may contain other functional additives to impart specific properties to the fluids. Thus the fluids may contain weight materials (which may function as bridging agents in an appropriate particle size range), corrosion inhibitors, anti-oxidants, oxygen scavengers, reducing agents, supplemental fluid loss control additives, supplemental viscosifiers, and the like.

The fluids of this invention must have a bridging agent incorporated therein. The bridging agents useful in this invention are well known in the art. They are solid, particulate, water soluble salts or acid soluble materials the particles of which have been sized to have a particle size distribution sufficient to seal off the pores of the formations contacted by the well drilling and servicing fluid as is well known in the art. See for example Dobson, Jr. et al U.S. Pat. No. 5,616,541 and Johnson U.S. Pat. No. 5,504,062, both incorporated herein by reference. The bridging agent must not be appreciably soluble in the liquid used to prepare the fluid.

Representative water soluble salt bridging agents include sodium chloride, potassium chloride, magnesium chloride, potassium formate, calcium bromide, calcium chloride, and the like.

Preferred bridging agents have a specific gravity less than about 3.0 and are sufficiently acid soluble such that they readily decompose upon acidizing the filter cake and deposits in the borehole. Representative bridging agents are calcium carbonate, dolomite (calcium magnesium carbonate), colemanite, ulexite, analcite, apatite, bauxite, brucite, gibsite, and hydrotalcite.

The concentration of the bridging agents will be sufficient that, together with the concentration of the starch derivative, the fluids exhibit a fluid loss less than about 10 milliliters as measured at 185° F. and 250 psi differential pressure across a 5 micron disk for 30 minutes. Generally the concentration of the bridging agents will be from about 5 ppb to about 50 ppb, preferably from about 10 ppb to about 30 ppb.

The concentration of the starch derivative must be sufficient to provide the fluid with the following characteristics: (a) a low shear rate viscosity less than about 10,000 centipoise; (b) a high shear rate viscosity at 511 sec^{-1} in the range from about 15 to about 70 centipoise measured at 120° F.; (c) a fluid loss less than about 10 milliliters as measured at 185° F. and 250 psi differential pressure across a 5 micron disc for 30 minutes; and (d) anti-settling characteristics as exhibited upon static aging the fluid for 16 hours at 185° F. Generally, the concentration of the starch derivative will be from about 5 ppb to about 12 ppb, preferably from about 6 ppb to about 11 ppb, and most preferably from about 7 ppb to about 10 ppb.

It is a novel feature of the invention that the starch derivative imparts excellent suspension characteristics to the fluids at the low viscosities imparted to the fluids. This is in direct contrast with fluids containing water soluble polymer viscosifiers, such as biopolymers, such as xanthan gum, scleroglucan gum, succinoglycan gum, and the like, in the dense brines used in the fluids of this invention.

It is preferred that the fluids of the invention do not contain any polymeric viscosifiers, such as biopolymers, i.e., the preferred fluids are biopolymer free.

Without being limited thereby, we believe that the buoyancy of the brines contributes to the suspension characteristics of the brines. Thus as the density of the dense brines increases, less viscosity development by the starch derivative is necessary for the excellent suspension characteristics observed. This has not been previously known. Indeed, prior art fluids as exemplified by the patents disclosed hereinbefore indicate that the fluids contain a biopolymer or amorphous silica viscosifier and suspending agent and generally a starch or derivative thereof as a filtration control additive.

The fluids of the invention may be prepared and the method of the invention practiced, by mixing the dense divalent cation-containing brine as set forth herein with the starch derivative, and the bridging agent, and any optional additives as disclosed herein. The concentration of the starch as disclosed herein is that concentration which will provide the fluid with the following characteristics: (a) a low shear rate viscosity less than about 10,000 centipoise; (b) a high shear rate viscosity at 511 sec^{-1} in the range from about 15 to about 70 centipoise measured at 120° F.; (c) a fluid loss less than about 10 milliliters as measured at 185° F. and 250 psi differential pressure across a 5 micron disk for 30 minutes; and (d) anti-settling characteristics as exhibited upon static aging the fluid for 16 hours at 185° F.

After static aging the fluids in sealed pint jars, any separation or syneresis was noted by measuring the depth of separation. For purposes of this invention, the fluids of the invention exhibit no more than ½ inch separation which is about 10% by volume. The settling characteristics of the aged fluids is then determined by inserting a spatula carefully into the fluids and observing if any solids had separated from the fluid. For purposes of this invention, the fluids exhibit no settling of solids.

The fluids of the invention are useful in various petroleum recovery operations such as well drilling, including drilling into hydrocarbon-containing formations, completion, workover and the like all as are well known in the art. Specifically the fluids of the invention are useful in drilling a well wherein the drilling fluid is circulated within a borehole being drilled as drilling proceeds, and in well completion and workover methods wherein a subterranean formation is contacted with an aqueous fluid to form a bridge and seal on the formation, all as are well known in the art.

The low shear rate viscosity (LSRV) for purposes of this invention is obtained using a Brookfield Model LVTDV-1 viscometer having a number 1 or 2 spindle at 0.3 revolutions per minute (shear rate of 0.0636 sec^{-1}). The fluid loss characteristics of the fluids are obtained by a modified API filtration test. Thus to an API high temperature filtration cell with removable end cages is added a 5 micron disk (i.e., an aluminum oxide (Aloxite™) ceramic disk having 5 micron pore throats, from 600 to 750 md permeability, which is 2.5 inches in diameter and 0.25 inch in depth) saturated with water. The fluid to be tested is poured along the inside edge of the filtration cell. The filtration test is then conducted for 30 minutes at the desired temperature of 185° F. under a pressure differential of 250 pounds per square inch supplied by nitrogen. The spurt loss is measured as the amount of fluid expelled from the filtration cell until the flow of fluid is reduced to drops. The fluid loss is measured as the total amount of fluid collected in 30 minutes.

The viscosities in centipoise at 1022 sec^{-1}, 511 sec^{-1}, 340.7 sec^{-1}, 170.3 sec^{-1}, 10.22 sec^{-1}, and 5.11 sec^{-1} are obtained by utilizing a Fann 35 Viscometer at 600 rpm, 300 rpm, 200 rpm, 100 rpm, 6 rpm, and 3 rpm by multiplying the Fann dial reading by 0.5, 1, 1.67, 3, 50, and 100, respectively.

In order to more completely describe the invention, the following non-limiting examples are given. In these

examples and this specification, the following abbreviations may be used: API=American Petroleum Institute; XLAPS=the pre-gelatinized epichlorohydrin crosslinked amylopectin starch derivative of this invention which has been crosslinked to the extent that the viscosity of a basic aqueous amylopectin starch suspension undergoing crosslinking is within about 25% about 60% of the maximum viscosity which can be obtained; LSRV=Brookfield low shear rate viscosity at 0.03 revolutions per minute; 0.0636 sec^{-1}, in centipoise; high shear rate viscosity=Fann viscosity at 511 sec^{-1} in centipoise; sec=second(s); ppg=pounds per gallon; ppb=pounds per 42 gallon barrel; °F.=degrees Fahrenheit; ml=milliliters; min=minutes; cp=centipoise; rpm=revolutions per minute; in=inches.

EXAMPLE 1

12.5 ppg fluids were prepared containing 0.98 bbl equivalents of a 12.25 ppg $CaBr_2$ brine, 23 ppb of a calcium carbonate bridging agent, and the concentrations of XLAPS, xanthan gum, scleroglucan gum, and succinoglycan gum set forth in Table 1. The rheology of the fluids before and after aging 16 hours at 85° C. (185° F.), and an indication of the suspension characteristics of the fluids after the static aging, were measured.

The data are set forth in Table 1.

EXAMPLE 2

13.5 ppg fluids were prepared containing 0.81 bbl equivalents of a 14.2 ppg $CaBr_2$ brine, 0.16 bbl equivalents of water, 26 ppb calcium carbonate bridging agent, and the concentrations of XLAPS, xanthan gum, scleroglucan gum, and succinoglycan gum set forth in Table 2. The fluids were evaluated as in Example 1. The data are set forth in Table 2.

EXAMPLE 3

14.5 ppg fluids were prepared containing 0.74 bbl equivalents of a 14.2 ppg $CaBr_2$ brine, 0.14 bbl equivalents of a 19.2 ppg $CaBr_2/ZnBr_2$ brine, 0.10 bbl equivalents of water, 0.25 ppb magnesium oxide, 23 ppb calcium carbonate bridging agent, and the concentrations of XLAPS, xanthan gum, scleroglucan gum, and succinoglycan gum set forth in Table 3. The fluids were evaluated as in Example 1. The data are set forth in Table 3.

EXAMPLE 4

15.5 ppg fluids were prepared containing 0.58 bbl equivalents of a 14.2 ppg $CaBr_2$ brine, 0.31 bbl equivalents of a 19.2 ppg $CaBr_2/ZnBr_2$ brine, 0.08 bbl equivalents of water, 0.25 ppb magnesium oxide, 25 ppb calcium carbonate bridging agent, and the concentrations of XLAPS, xanthan gum, scleroglucan gum, and succinoglycan gum set forth in Table 4. The fluids were evaluated as in Example 1. The data are set forth in Table 4.

EXAMPLE 5

16.5 ppg fluids were prepared containing 0.41 bbl equivalents of a 14.2 ppg $CaBr_2$ brine, 0.52 bbl equivalents of a 19.2 ppg $CaBr_2/ZnBr_2$, 0.05 bbl equivalents of water, 0.25 ppb of magnesium oxide, 23 ppb calcium carbonate bridging agent, and the concentrations of XLAPS, xanthan gum, scleroglucan gum, and succinoglycan gum set forth in Table 5. The fluids were evaluated as in Example 1. The data are set forth in Table 5.

In Tables 1–5, fluids C, D and E which don't contain the XLAPS of this invention are not examples of the invention, and are presented for comparison purposes only. The data indicate the excellent suspension characteristics of the fluids containing the XLAPS even at very low LSRV, and the very poor suspension characteristics of the fluids containing only the biopolymers. Incorporation of a biopolymer into the XLAPS-containing fluids increased the high shear rate viscosity and affected the LSRV in various ways depending upon the density of the fluids. The data also indicate that, in general, the LSRV decreases and the high shear rate viscosity increases as the concentration of zinc bromide in the fluids increases. However, the excellent suspension characteristics of the fluids was maintained.

EXAMPLE 6

CaCl2 fluids having densities of 9.5, 10.35 and 11.3 ppg were prepared each containing 8 ppb XLAPS and the concentration of MgO and calcium carbonate bridging agent set forth in Table 6. The fluids were evaluated as in Example 1. The data obtained are set forth in Table 6.

The data indicate that: (1) the density of the fluids should be greater than 9.5 ppg, preferably at least about 10.0 ppg; (2) magnesium oxide can be added to increase the viscosity of the fluids, as desired, especially the LSRV; and (3) the excellent suspension characteristics of the fluids of the fluids of the invention even at low LSRV.

EXAMPLE 7

14.6 ppg $CaBr_2/ZnBr_2$ fluids were prepared each containing 8 ppb XLAPS, 24 ppb $CaCO_3$ bridging agent, 0.71 bbl 14.2 ppg $CaBr_2$, 0.11 bbl water, 0.17 bbl 19.2 ppg $CaBr_2/ZnBr_2$, and the concentrations of MgO, MgO_2, sodium thiosulfate, and K_2HPO_4 set forth in Table 7. The fluids were evaluated as in Example 1. The data obtained are set forth in Table 7.

The data indicate that the magnesium oxide enhanced the thermal stability of the fluids containing the magnesium peroxide and sodium thiosulfate, and that the K_2HPO_4 increases the viscosity of the fluid after aging at 185° F., especially the LSRV.

EXAMPLE 8

A 14.6 ppg $CaBr_2/ZnBr_2$ fluid was prepared as in Example 7 containing 8 ppb XLAPS, 0.25 ppg MgO, and 24 ppb $CaCO_3$ bridging agent. The rheology of the fluid was measured at 120° F. initially and after aging the fluid for the time set forth in Table 8 at 185° F. The data obtained are set forth in Table 8.

The data indicate the excellent thermal stability and suspension characteristics of the fluid.

EXAMPLE 9

10.35 ppb $MgCl_2$ fluids were prepared containing 0.97 bbl of 10.0 ppg $MgCl_2$ brine, 8 ppb XLAPS, 26 ppb calcium carbonate bridging agent, and either 0 or 0.25 ppb MgO. The fluids were evaluated as before. The data obtained are set forth in Table 7.

The data indicate the excellent suspension characteristics of the XLAPS in $MgCl_2$-containing brines, and the increase of the LSRV upon addition of the MgO.

EXAMPLE 10

The high temperature, high pressure fluid loss for fluids 4-A, Table 4, and 5-A, Table 5, were determined at 185° F., 250 psi differential pressure across a 5 micron disk. The data

obtained are as follows. Fluid 4-A: Initial—Spurt Loss=1.5 ml, 30 min.=3 ml; Aged @ 185° F.—Spurt Loss=2.5 ml, 30 min=3.5 ml. Fluid 5-A: Initial—Spurt Loss=1.5 ml, 30 min=3 ml; Aged @ 185° F.—Spurt Loss=2 ml, 30 min=4 ml.

These data illustrate the excellent fluid loss characteristics of the fluids of this invention.

The data in the Tables indicate that the LSRV of the fluids of this invention can be increased by the addition of magnesium oxide, dipotassium hydrogen phosphate, or biopolymers to the fluids, particularly after subjecting the fluids to elevated temperatures as would occur on using the fluids in the drilling or servicing of wells. The data also indicate that only low concentrations of the biopolymer can be incorporated into the fluids without unduly raising the high shear rate viscosity, i.e., at 511 sec^{-1}. Thus the LSRV of the fluids can be increased without unduly raising the high shear rate viscosity by the addition of magnesium oxide and/or dipotassium hydrogen phosphate to the fluids, preferably in an amount from about 0.1 ppb to about 5 ppb. It is another aspect of the invention to increase the low shear rate viscosity of the fluids of the invention without increasing the high shear rate viscosity above about 70 centipoise by the addition of magnesium oxide and/or dipotassium hydrogen phosphate to the fluids. Thus the low shear rate viscosity of the fluids can be greater than 10,000 centipoise upon the addition of an additive which raises the low shear rate viscosity of the fluids without raising the high shear rate viscosity above about 70.

TABLE 1

12.5 ppg $CaBr_2$ Fluids								
Fluid	1-A	1-B	1-C	1-D	1-E	1-F	1-G	1-H
XLAPS, ppb	8.0	10.0	0	0	0	8.0	8.0	8.0
Xanthan, ppb	0	0	1.5	0	0	1.5	0	0
Scleroglucan, ppb	0	0	0	1.5	0	0	1.5	0
Succinoglycan, ppb	0	0	0	0	1.5	0	0	1.5
Initial Rheology at 120° F.								
1022 sec^{-1}, cp	18	30	15.5	14.5	11	80	49	65
511 sec^{-1}, cp	22	40	19	2112	11	4	70	90
10.22 sec^{-1}, cp	150	150	50	350	0	650	850	300
0.0636 sec^{-1}, cp	3039	3400	1920	9,878	120	17,700	54,300	700
STI	138	65	101	470	10	155	776	8
Static Aged at 185° F. for 16 hours								
Separation	None	None	Total	None	Total	None	None	None
Settling	None	None		None		None	None	None
1022 sec^{-1}, cp	17.5	29.5	14.5	14	10	75	47.5	55
511 sec^{-1}, cp	20	38	17	21	11	105	72	72
10.22 sec^{-1}, cp	50	150	50	350	100	500	900	150
0.0636 sec^{-1}, cp	440	500	600	12,357	0	10,300	50,700	900
STI	22	13	5	588	0	98	704	12.5

TABLE 2

13.5 ppg $CaBr_2$ Fluids								
Fluid	2-A	2-B	2-C	2-D	2-E	2-F	2-G	2-H
XLAPS, ppb	7.0	10.0	0	0	0	8.0	8.0	8.0
Xanthan, ppb	0	0	1.5	0	0	1.5	0	0
Scleroglucan, ppb	0	0	0	1.5	0	0	1.5	0
Succinoglycan, ppb	0	0	0	0	1.5	0	0	1.5
Initial Rheology at 120° F.								
1022 sec^{-1}, cp	18.5	35	23.5	4.5	4.5	89	37.5	65
511 sec^{-1}, cp	23	47	30	4	5	140	44	85
10.22 sec^{-1}, cp	200	200	150	0	0	900	100	150
0.0636 sec^{-1}, cp	5700	9200	280	60	100	13,500	300	800
STI	248	196	9	15	20	96	7	9
Static Aged at 185° F. for 16 hours								
Separation, in	None	None	Total	Total	Total	None	0.5	None
Settling	None	None				None	None	None
1022 sec^{-1}, cp	20.5	40	19.5	4	25.5	95	37.5	99
511 sec^{-1}, cp	25	53	24	4	33	145	43	142
10.22 sec^{-1}, cp	150	200	50	0	150	1100	150	1000
0.0636 sec^{-1}, cp	1180	7200	100	20	280	19,800	4800	16,100
STI	47	136	4	5	9	137	112	113

TABLE 3

14.5 ppg CaBr2/ZnBr2 Fluids

Fluid	3-A	3-B	3-C	3-D	3-E	3-F	3-G	3-H
XLAPS, ppb	7.0	10.0	0	0	0	8.0	8.0	8.0
Xanthan, ppb	0	0	1.5	0	0	1.5	0	0
Scleroglucan, ppb	0	0	0	1.5	0	0	1.5	0
Succinoglycan, ppb	0	0	0	0	1.5	0	0	1.5
Initial Rheology at 120° F.								
1022 sec^{-1}, cp	19	38.5	14	13	3.5	75	72.5	31.5
511 sec^{-1}, cp	23	50	17	14	4	109	90	37
10.22 sec^{-1}, cp	150	200	100	100	0	600	150	50
0.0636 sec^{-1}, cp	2200	8000	20	60	60	6000	500	1300
STI	9s	160	1	4	15	63	6	35
Static Aged at 185° F. for 16 hours								
Separation	None	None	Total	Total	Total	None	None	None
Settling	None	None				None	None	None
1022 sec^{-1}, cp	19.5	41	25	10	20.5	78.5	66	74
511 sec^{-1}, cp	23	53	34	11	26	117	80	107
10.22 sec^{-1}, cp	100	200	200	100	150	900	150	850
0.0636 sec^{-1}, cp	680	3800	200	20	140	18,700	600	10,600
STI	30	72	6	2	5	160	7.5	99

TABLE 4

15.5 ppg CaBr2/ZnBr2 Fluids

Fluid	4-A	4-B	4-C	4-D	4-E	4-F	4-G	4-H
XLAPS, ppb	8.0	10.0	0	0	0	8.0	8.0	8.0
Xanthan, ppb	0	0	1.5	0	0	1.5	0	0
Scleroglucan, ppb	0	0	0	1.5	0	0	1.5	0
Succinoglycan, ppb 0	0	0	0	0	1.5	0	0	1.5
Initial Rheology at 120° F.								
1022 sec^{-1}, cp	29	46.5	11.5	16	5.5	96	89	36.5
511 sec^{-1}, cp	37	61	13	16	6	145	110	43
10.22 sec^{-1}, cp	150	300	0	0	50	1050	150	50
0.0636 sec^{-1}, cp	2000	7600	40	20	80	6800	600	400
STI	54	126	3	1	13	47	5	9
Static Aged at 185° F. for 16 hours								
Separation	None	None	Total	Total	Total	None	None	None
Settling	None	None				None	None	None
1022 sec^{-1}, cp	31.5	47	21.5	12	29.5	100	77	90
511 sec^{-1}, cp	39	61	27	12	39	148	85	126
10.22 sec^{-1}, cp	150	200	150	0	200	1000	150	900
0.0636 sec^{-1}, cp	900	2400	80	0	80	7600	300	7400
STI	23	39	3	0	2	53	4	59

TABLE 5

16.5 ppg CaBr2/ZnBr2 Fluids

Fluid	5-A	5-B	5-C	5-D	5-E	5-F	5-G	5-H
XLAPS, ppb	8.0	10.0	0	0	0	8.0	8.0	8.0
Xanthan, ppb	0	0	1.5	0	0	1.5	0	0
Scleroglucan, ppb	0	0	0	1.5	0	0	1.5	0
Succinoglycan, ppb	0	0	0	0	1.5	0	0	1.5
Initial Rheology at 120° F.								
1022 sec^{-1}, cp	38	44.5	10.5	22	6	117	120	93.5
511 sec^{-1}, cp	42	55	12	24	7	165	150	112
10.22 sec^{-1}, cp	150	200	100	50	50	900	250	200
0.0636 sec^{-1}, cp	500	7800	40	0	20	4800	800	600

TABLE 5-continued

14.5 ppg CaBr$_2$/ZnBr$_2$ Fluids								
Fluid	5-A	5-B	5-C	5-D	5-E	5-F	5-G	5-H
STI	12	142	3	0	3	29	5	5
Static Aged at 185° F. for 16 hours								
Separation	None	None	Total	Total	Total	None	None	None
Settling	None	None				None	None	None
1022 sec^{-1}, cp	37.5	65	20	16.5	20.5	127	92	144
511 sec^{-1}, cp	46	83	25	18	25	178	108	198
10.22 sec^{-1}, cp	150	300	100	0	100	1050	200	1350
0.0636 sec^{-1}, cp	500	2100	300	20	200	5700	400	15,000
STI	11	25	14	1	8	228	4	76

TABLE 6

CaCl$_2$ Fluids 8 ppb XLAPS						
Fluid	6-A	6-B	6-C	6-D	6-E	6-F
Density, ppg	9.5	9.5	10.35	10.35	11.3	11.3
9.15 ppg CaCl$_2$, bbl	0.97	0.97	0	0	0	0
10.0 ppg CaCl$_2$, bbl	0	0	0.97	0.97	0	0
11.0 ppg CaCl$_2$, bbl	0	0	0	0	0.97	0.97
CaCO$_3$, ppb	25	25	26	26	25	25
MgO, ppb	0	0.25	0	0.25	6	0.25
Initial Rheology at 120° F.						
1022 sec^{-1}, cp	8.5	11.5	15	19	26.5	31
511 sec^{-1}, cp	11	17	18	27	33	41
10.22 sec^{-1}, cp	50	250	50	300	150	300
0.0636 sec^{-1}, cp	5520	15,737	2300	16,357	4000	20,296
STI	502	926	128	606	121	495
Static Aged at 185° F. for 16 hours						
Separation, in	1	1.25	0.25	0.25	0.25	None
Settling	Settling	Settling	None	None	None	None
1022 sec^{-1}, cp	8.5	13	15.5	22.5	26	35
511 sec^{-1}, cp	11	19	19	33	33	48
10.22 sec^{-1}, cp	50	250	0	400	150	500
0.0636 sec^{-1}, cp	3500	21,695	1120	33,693	1820	33,896
STI	318	1142	59	1021	55	706

TABLE 7

8 ppb XLAPS						
	14.6 ppg CaBr$_2$/ZnBr$_2$ Fluids				10.35 ppg MgCl$_2$	
Fluid	7-A	7-B	7-C	7-D	9-A	9-B
MgO, ppb	0.25	0	0	0.25	0	0.25
Mg Peroxide, ppb	0.5	0.5	0.5	0	0	0
Sodium Thiosulphate, ppb	0.5	0.5	1.0	0	0	0
K_2HPO_4, ppb	0	0	3.0	0	0	0
Initial Rheology at 120° F.						
1022 sec^{-1}, cp	23.5	24	23	26.5	20.5	19
511 sec^{-1}, cp	30	30	29	34	23	27
10.22 sec^{-1}, cp	200	100	100	200	150	50
0.0636 sec^{-1}, cp	3200	3500	3479	4000	4599	6399
STI	107	117	120	118	200	237
Static Aged at 185° F. for 16 hours						
Separation, in	None	None	None	None	0.25	0.25
Settling	None	None	None	None	None	None
1022 sec^{-1}, cp	25	24.5	32.5	27	22	21.5
511 sec^{-1}, cp	31	30	44	35	28	30
10.22 sec^{-1}, cp	100	50	450	200	250	150
0.0636 sec^{-1}, cp	6000	520	24,595	2100	8019	11,618
STI	194	17	559	57	215	387

TABLE 8

14.6 ppg CaBr$_2$/ZnBr$_2$ Fluids 8 ppb XLAPS, 0.25 ppb MgO							
Hr. Aged @ 185° F.	0	16	36	62	72	144	316
1022 sec^{-1}, cp	26.5	27	28.5	29.5	29.5	28	29.5
511 sec^{-1}, cp	34	35	37	39	39	37	39
340.7 sec^{-1}, cp	39	40.5	43.5	46.5	46.5	45	46.5
170.3 sec^{-1}, cp	51	54	57	63	63	63	63
10.22 sec^{-1}, cp	200	200	200	250	300	250	250
5.11 sec^{-1}, cp	300	300	300	400	400	400	400
0.0636 sec^{-1}, cp	3997	1240	2100	5599	5919	6079	5059

TABLE 8-continued

14.6 ppg CaBr/ZnBr, Fluids 8 ppb SLAPS, 0.25 ppb MgO							
Hr. Aged @ 185° F.	0	16	36	62	72	144	316
STI	118	35	57	144	152	184	130
Separation	—	None	None	None	None	None	None
Settling	—	None	None	None	None	None	None

What is claimed is:

1. A clay-free well drilling and servicing fluid comprising an aqueous brine containing at least 1.2 equivalents per liter of a water soluble divalent cation salt, a particulate bridging agent which is insoluble in the aqueous liquid, and a starch derivative wherein the concentration of the starch derivative is sufficient to provide the fluid with the following characteristics: (a) a low shear rate viscosity less than about 10,000 centipoise; (b) a high shear rate viscosity at 511 sec^{-1} in the range from about 15 to about 70 centipoise measured at 120° F.; (c) a fluid loss less than about 10 milliliters as measured at 185° F. and 250 psi differential pressure across a 5 micron disk for 30 minutes; and (d) anti-settling characteristics as exhibited upon static aging the fluid for 16 hours at 185° F., and wherein the starch derivative comprises a pre-gelatinized crosslinked amylopectin starch which has been crosslinked to the extent that the viscosity of a basic aqueous amylopectin starch suspension undergoing crosslinking is within about 25% to about 60% of the maximum viscosity which can be obtained.

2. The fluid of claim 1 wherein the amylopectin starch is crosslinked with epichlorohydrin.

3. The fluid of claim 2 wherein the density of the fluid is at least about 10 ppg.

4. The fluid of claim 2 wherein the water soluble divalent cation salt is selected from the group consisting of the alkaline earth metal halide salts, the zinc halide salts, and mixtures thereof.

5. The fluid of claim 2 wherein the concentration of the starch derivative is from about 5 ppb to about 12 ppb.

6. The fluid of claim 2, 3, 4, or 5 additionally containing an additive selected from the group consisting of magnesium oxide, dipotassium hydrogen phosphate, and mixtures thereof, in an amount sufficient to increase the low shear rate viscosity without increasing the high shear rate viscosity above 70 centipoise.

7. A process of preparing a clay-free well drilling and servicing fluid, the fluid comprising an aqueous brine containing at least 1.2 equivalents per liter of a water soluble divalent cation salt and a particulate bridging agent which is insoluble in the aqueous liquid, which comprises adding to the fluid a starch derivative in an amount sufficient to provide the fluid with the following characteristics: (a) a low shear rate viscosity less than about 10,000 centipoise; (b) a high shear rate viscosity at 511 sec^{-1} in the range from about 15 to about 70 centipoise measured at 120° F.; (c) a fluid loss less than about 10 milliliters as measured at 185° F. and 250 psi differential pressure across a 5 micron disk for 30 minutes; and (d) anti-settling characteristics as exhibited upon static aging the fluid for 16 hours at 185° F., wherein the starch derivative comprises a pre-gelatinized crosslinked amylopectin starch which has been crosslinked to the extent that the viscosity of a basic aqueous amylopectin starch suspension undergoing crosslinking is within about 25% to about 60% of the maximum viscosity which can be obtained.

8. The process of claim 7 wherein the amylopectin starch is crosslinked with epichlorohydrin.

9. The process of claim 8 wherein the density of the fluid is at least about 10 ppg.

10. The process of claim 8 wherein the water soluble divalent cation salt is selected from the group consisting of the alkaline earth metal halide salts, the zinc halide salts, and mixtures thereof.

11. The process of claim 8 wherein the concentration of the starch derivative is from about 5 ppb to about 12 ppb.

12. The process of claim 8, 9, 10, or 11 additionally containing an additive selected from the group consisting of magnesium oxide, dipotassium hydrogen phosphate, and mixtures thereof, in an amount sufficient to increase the low shear rate viscosity without increasing the high shear rate viscosity above 70 centipoise.

13. A process of drilling a well wherein a drilling fluid is circulated within the wellbore being drilled as drilling proceeds which comprises using as the drilling fluid the fluid of claim 1, 2, 3, 4, or 5.

14. In a process of completing or working over a well wherein a subterranean formation is contacted with an aqueous liquid, the improvement comprising using as the aqueous fluid the fluid of claim 1, 2, 3, 4, or 5.

15. A process of drilling a well wherein a drilling fluid is circulated within the wellbore being drilled as drilling proceeds which comprises using as the drilling fluid the fluid of claim 1, 2, 3, 4, or 5, wherein the fluid additionally contains an additive selected from the group consisting of magnesium oxide, dipotassium hydrogen phosphate, and mixtures thereof, in an amount sufficient to increase the low shear rate viscosity without increasing the high shear rate viscosity above 70 centipoise.

16. In a process of completing or working over a well wherein a subterranean formation is contacted with an aqueous liquid, the improvement comprising using as the aqueous fluid the fluid of claim 1, 2, 3, 4, or 5, wherein the fluid additionally contains an additive selected from the group consisting of magnesium oxide, dipotassium hydrogen phosphate, and mixtures thereof, in an amount sufficient to increase the low shear rate viscosity without increasing the high shear rate viscosity above 70 centipoise.

17. The fluid of claim 1, 4, or 5 wherein the density of the fluid is at least about 10 ppg.

18. The fluid of claim 17 additionally containing an additive selected from the group consisting of magnesium oxide, dipotassium hydrogen phosphate, and mixtures thereof, in an amount sufficient to increase the low shear rate viscosity without increasing the high shear rate viscosity above 70 centipoise.

19. The process of claim 7, 10, 11 wherein the density of the fluid is at least about 10 ppg.

20. The process of claim 19 additionally containing an additive selected from the group consisting of magnesium oxide, dipotassium hydrogen phosphate, and mixtures thereof, in an amount sufficient to increase the low shear rate viscosity without increasing the high shear rate viscosity above 70 centipoise.

21. The process of claim 13 wherein the density of the fluid is at least about 10 ppg.

22. The process of claim 14 wherein the density of the fluid is at least about 10 ppg.

23. The process of claim 15 wherein the density of the fluid is at least about 10 ppg.

24. The process of claim 16 wherein the density of the fluid is at least about 10 ppg.

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(54) Abstract Title
Water based wellbore fluids

(57) A water based wellbore fluid, e.g. a drilling, fracturing, gravel packing or workover fluid, comprises a fluid loss additive and a bridging material that are hydrophobic in nature, hydrophobically modified or oil wettable. The wellbore fluid generates an active filter cake that once formed, is impermeable to an aqueous phase, thus reducing fluid loss and ensuring reduced damage to the formation, yet simultaneously is permeable to the back flow of hydrocarbons during a hydrocarbon recovery process. The fluid loss additive may be a hydrophobically modified starch, polyanionic cellulose, carboxymethylcellulose or poly-hydroxypropylmethacrylate. The bridging material may be hydrophobically coated calcium carbonates, zinc carbonates, barium carbonates, hematite, ilmenite, magnesium oxide, barite, silica particles, clay particles or microspheres. The bridging agent may also be 1-S-endo-Borneol, camphor, beta carotene, lycophene, cholesterol, lanosterol or agnosterol.

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WATER BASED WELLBORE FLUIDS

The invention relates to wellbore fluids used during a hydrocarbon recovery process, such as drilling, fracturing, gravel packing and wellbore workover. More precisely, the present invention relates to water based fluids.

Wellbore fluids used in the hydrocarbon containing subterranean zones must fulfil besides the usual functions of a drilling fluid also more specific requirements to ensure minimum damage to the formation. The currently available water based drilling fluids are able to ensure minimum damage to the formation and completion due to the selection of the right particle size distribution of the bridging solids, the choice of the fluid loss additive and other components of the fluid.

With standard graded calcium carbonate based drilling fluids and the subsequent filter cake it produces, the initial return permeability may be high. However, the presence of drill-solids can be enough to significantly affect the filter cake behaviour, so reduce the effective permeability of the reservoir and as such a stimulation treatment would be recommended to substantially remove the filter cake.

Furthermore an increasing practice is the drilling of unconsolidated sand reservoirs, where there is a requirement for sand control techniques. One common practice is to use gravel packs. Unfortunately the gravel pack tends to exacerbate the changes in filter cake behaviour, the formation damage level and so the effective permeability, even with clay-free wellbore fluid. This is further exacerbated with the drill-solid contaminated well-bore fluid where the return permeability can be zero up to differential pressures of 400kPa.

Any attempt to remove the drill-solid from the mud with the technique commonly used on the surface (e.g. sieves, hydrocyclones, centrifuges) would inevitably remove as well at least partially the bridging solids and so affect not only their concentration but also their particle size distribution in the mud. The fluid potential for minimal formation damage achieved by the right bridging solid concentration and especially particle size distribution would therefore be detrimentally affected.

In summary the ultimate productivity of a well can be strongly impacted by the damaging potential of the well-bore fluid, the detrimental effect of drill-solids to filter cake performance and the complication of the compatibility of well bore fluid components with the sand control techniques. This means that there will be in many instances a requirement for stimulation of the filter cake, where the stimulation process in itself can be ultimately damaging to the completion or reservoir. Accordingly there is a need for a well-bore fluid that will be non-damaging to the hydrocarbon formation and the sand control techniques and also not require any external stimulation process to allow hydrocarbons to flow.

The use of wellbore fluids for conducting various operations in oil and gas wells which contact a producing formation are well known. Drill-in fluids are used when initially drilling into producing formations. Completion fluids can be used when conducting various completion operations in the producing formations. Workover fluids are utilized when conducting remedial operations to the wellbore and hardware.

One of the most important function of these fluids is to seal off the face of the wellbore so that excessive fluid is not lost to the formation, so reducing the potential for formation damage and hence ensuring a better reservoir productivity.

Many concepts have been proposed for contacting the producing zone of oil and gas wells.

These fluids generally contain polymeric viscosifiers such as polysaccharides, polymeric fluid loss control additives such as lignosulfonates or polysaccharides and bridging solids.

Some provide better fluid loss reducing properties by providing new modifications to the fluid loss additive (e.g. US4652384, US5851959), by using pore blocking water swellable gel (e.g. WO9702330, US4526240), by replacing the bridging solids (e.g. US5228524, US5504062, EP0691454, US3878141, US3785438, GB2120302, US3788406, GB570329) or by using a sealant composition (e.g. EP0899317, US5529123). GB2120302 includes the use of hydrophobially coated glass particles to improve fluid loss properties. It has also been proposed to use a well drilling system that generates an easily removeable filter cake or a treatment to remove the filter cake (e.g. EP0672740, US5783527, WO9805734).

In most of the above mentioned documents, the hydrocarbon recovery process includes a preliminary filter cake treatment or removal to achieve a better productivity. Some inventions mentioned include the use of oil wettable, hydrophobic or hydrophobically modified bridging

solids or components. However their intention is to improve fluid loss properties or create a new type of gravel pack.

A main object of the present invention is a water based wellbore fluid comprising a fluid loss additive and a bridging material that are hydrophobic in nature, hydrophobically modified or oil wettable. Wellbore fluids are referred to as mud, drill fluid, drill-in fluid, completion fluid, workover fluid or kill fluid.

The concept behind the present invention is to provide a water based drilling fluid system which generates an active filter cake. Whereby the active filter cake once formed is impermeable to an aqueous phase, thus reducing fluid loss and ensuring reduced damage to the formation, yet simultaneously is permeable to the back flow of hydrocarbons during a hydrocarbon recovery process.

The permeability of the filter cake to hydrocarbons does not rely on the presence of oil soluble material as constituent but on the presence of constituents reducing the interfacial tension to hydrocarbons enabling the creation of paths for hydrocarbons to flow through the filter cake. In this manner the filter cake will not break or disperse so eliminating potential damage to the completion from filter cake fragments.

The use of oil soluble material is one way of designing an active filter cake. However in our preferred embodiment we use a different principle in which the properties of the active filter cake are achieved without desegregation of the filter cake during a hydrocarbon recovery process. This presents the advantage of keeping intact both properties of the active filter cake. (permeability to hydrocarbons and impermeability to an aqueous phase).

Nevertheless our preferred embodiment can be combined with the use of oil soluble material. This presents the advantage of creating paths for hydrocarbons through the cake and improving the accessibility of the oil to the oil soluble material inside the filter cake.

The filter cake is preferably compatible with the formation and the completion hardware and techniques i.e. the permeability of the filter cake to hydrocarbons is not significantly affected by varying the type of formation or by using different types of completion.

The drilling fluid system of the present invention generates preferably an active filter cake without the need of a subsequent external stimulation (chemical or mechanical treatment). The

cake can be easily removed or stay in the well during a hydrocarbon recovery process. Due to the presence of new hydrophobic components or hydrophobic modifications brought to conventional components of well fluids, those fluids generate filter cakes with the hydrophobic sites organised and structured in such a way that the hydrocarbons can flow easily through the filter cake during a hydrocarbon recovery process.

The fluid loss additive of the present invention is preferably selected from hydrophobically modified starch, polyanionic cellulose, carboxymethylcellulose, hydrophobically modified synthetic polymers e.g. poly-hydroxypropylmethacrylate. Most preferred fluid loss additive is a polymerised starch or a starch modified by hydroxymethylation, hydroxypropylation, by other hydroxyalkylations or by crosslinking reactions using agents such as phosphorous oxychloride, epichlohydrin, cyanuric chloride, formaldehyde or others.

Examples of hydrophobic bridging materials are known from the British Patent Application 9907017.9 filed on March 27th, 1999 that discloses a wellbore-fluid additive which is a ground crystalline material of melting point over 80°C, preferably over 10°C which is readily soluble in produced hydrocarbons such as crude oil and lighter condensates and which exhibits a molecular weight of less than 1000, and preferably less than 650. Examples of low molecular weight crystalline additives are 1-S-endo-Borneol, camphor or iodine. Other examples include beta carotene with a melting point of 184 degrees Celsius and a molecular weight of 537, lycophene (175;537); cholesterol (150;387), lanosterol (139; 426) and agnosterol (165; 424).

The bridging solid of the present invention may also be constituted of a hydrophobically coated substrate selected among The substrate for the hydrophobic coating is selected among carbonates such as calcium carbonates, zinc carbonates, barium carbonates, coated metal oxide such as hematite, ilmenite, magnesium oxide or other particles such as barite, silica particles, clay particles, microspheres.

The hydrophobic coating is achieved by adsorption of substances onto the surface of a particle or molecule by physisorption or chemical reactions with reactive groups that are present on the surface of this particle or molecule. Examples for such substances are selected among fatty oils, fatty acids, fatty esters, carboxylated, sulfonated, sulfated, phosphonated hydrophobic material, surfactants that would generate a hydrophobic coating, organosilane grafting agents. Those substances introduce alkylsilyl groups or hydrocarbon groups like alkyl groups,

especially of long chain onto the surface of the substrate. Coating processes or examples are described in WO9916834, EP0826414, US5183710, EP0606174.

These and other features of the invention will become appreciated and understood by those skilled in the art from the detailed description of the following examples.

Preparation and dynamic ageing (Hot rolling) of muds

The well drilling fluids were prepared according to the following procedure.

1. The brine phase including water as base fluid, salts, a biocide and an antifoaming agent was prepared using an Heidolph paddle mixer.

2. A vortex is created with the paddle mixer to add the polymers (viscosifier, fluid loss additive...) slowly into the brine phase, ensuring that all polymer has completely dispersed. Mixing is continued for a further 30 min. The mixer speed is readjusted as necessary.

3. Other powdered additives (carbonates, clays, magnesium oxide for pH adjustment...) are slowly added into the vortex and mixted for a further 15 min.

4. The mixture is transferred to a Silverson LR2 mixer and mixed at 6000 rpm for 5 minutes.

5. The mixture is transferred back to the Heidolph and mixed for a further 10 minutes. The pH and rheological properties are measured.

Dynamic ageing was carried out by hot rolling the fluids in cells pressurised at 250 psi with nitrogen in an oven for 16 hours. After cooling, the muds were homogenised with a Heidolph paddle mixer for 10 min and the pH and rheological properties were measured. For all formulations a pH in the range 9-10 was used.

Rheology before (BHR) and after hot rolling (AHR)

The measurements were performed at 120°F (49°C) with a 6 speed Fann rheometer BHR (before hot rolling) and AHR (after hot rolling). The rheological properties of the drilling fluids are described by the plastic viscosity in centipoise PV (based on the reading at 600 rpm and 300rpm) and the yield point in pounds per 100 square feet YP. The gel strengths are evaluated by the 10 second and 10 minute gel strengths in pounds per 100 square feet.

HPHT fluid loss

The HPHT spurt loss after 20 sec. and HPHT Fluid-Loss after 16hrs were obtained during the formation damage study when forming the filter-cake on a formation core (filtration area 5.06 cm^2 and length 3cm) or aloxite ceramic disc, (filtration area: 23.8 cm^2 and length 0.6cm).

Formation damage studies

Formation damage is defined as any process that impairs the permeability of reservoir formations to the extent that hydrocarbon production in wells is reduced. Formation damage can occur at all stages of well construction, completion, workover or during production.

1. Experimental set-up

The basis of measuring formation damage is the measurement of the permeability of a core of formation (or a synthetic ceramic disc simulating the formation) to the flow of kerosene (simulating the hydrocarbons) before and after a drilling fluid has been filtered through it. The measurement of the flow rate of kerosene is based on the logging of the flow rate of kerosene (in ml/s) at equilibrium through a core (or disc) of known diameter and length. From the Darcy equation below we are able to calculate the permeability of the core (K) in Darcy : K = (Q □□□L) / (DP . A), where Q is the rate of kerosene flow ml/s, □□ is the fluid viscosity of the kerosene in centiPoise, L is the length of the core or disc (cm), DP□ is the pressure drop across the core or disc (atmospheres), A is the surface area of the core (cm^2)

In the described examples, the flow of kerosene was carried out typically at 80°C. The core (or disc) is mounted at one end of a double ended HPHT cell, with the kerosene flowing into the cell filled with kerosene or the packing simulation saturated with brine above the core (or disc). The kerosene displaces rapidly the brine phase and overflows through a top valve into the beaker.

The kerosene is transported under pressure from a cylinder into the reservoir. The kerosene is then passed vertically upwards through a heating jacket to preheat it prior to entering the cell which is also heated. Pressure is regulated for stable kerosene flows through the core (or discs).

2. Initial permeability

The cores of Clashach sandstone (typical initial permeability 700-1200mD) were dry cored from a solid sample of material and cut with a diamond saw to a standard length of 3.00cm and diameter 2.54cm. The cores were then placed in a vacuum dessicator, kept under vacuum for 2 hours to remove trapped air from the cores before being tipped into a brine solution typically potassium chloride (3%) or sodium chloride/ calcium chloride brine (9.5% and 0.5% respectively) to saturate for 24 hours.

Initial permeabilities were measured with odourless kerosene using the apparatus described above with the kerosene pre heater and the HTHP jacket preset to typically 80°C. The cell was allowed to equilibrate prior to runs being made at 10, 6, 4 and 2psi. Kerosene flow rate was measured by logging the weight of oil deposited into a beaker every 10 seconds. Kerosene flow was continued until either a minimum of kerosene was flowed through the core or a minimum of time had elapsed (whichever was the sooner) to ensure equilibrium was reached. The data file was converted to a spreadsheet and input into the Darcy equation that allowed for the variables of core length, diameter and kerosene viscosity to be altered.

Analysis of the resultant graph shows that a plateau is reached after a period of time. By identifying the point at which this plateau is reached, the average permeability at the equilibrium level can be calculated. In addition the standard deviation of this area can be calculated in order to give a measure of the degree of accuracy of the average.

The aluminium oxide discs with a permeability of 20D to air and porosity of 60 microns (according to the manufacturer HILTON Instruments) were tipped into a brine solution typically potassium chloride (3%) and placed in a vacuum dessicator, kept under vacuum for 2 hours to remove trapped air.

Initial permeabilities with or without a gravel pack were measured. The results being more consistent due to the controlled synthesis of the discs and the well defined gravel packs, the filter cake was formed. The percentage of return permeability taken as reference was calculated using an average initial permeability for runs being made at 4, 3, 2 and 1psi.

3. Mud-off

The mud off stage of the procedure is carried out statically after dynamic ageing of the muds. If present, the kerosene in the cell was replaced by the mud after rinsing with a 3% potassium chloride brine. The mud was then filtered, through the core (filtration area 5.06 cm^2, core length 3 cm) or disc (filtration area 23.8 cm^2, width 0.6cm) for 16 hours typically at 80°C and 500 psi.

Following the mud-off the cell was rinsed out three times with fresh brines to remove the excess mud. Care was taken in the cleaning process in order not to disturb the filter cake on top of the core or disc.

4. Return permeability

To simulate standalone completions in consolidated formations (stable holes), the cell was filled with fresh kerosene and the formation damage cell was reassembled. Return permeabilities were carried out in an identical fashion to those for the initial permeability measurements. The flow back is carried out at constant differential pressure. The differential pressure is increased stepwise until flow is initiated. The differential pressure at which the flow starts is referred in the present invention to the Flow Initiation Pressure (FIP).

To simulate gravel packed wells, a sand pack was used. A sufficient volume of a 3% potassium chloride brine is placed above the filter cake, the cell is filled by pouring and packing the sand to fill the cell (up to the top). If necessary more brine is added to allow saturation and tight packing of the sand. The cell is then reassembled, with the 45-micron mesh size screen between the gravel-pack and the top lid of the cell.

Example 1

The following base formulation 1 was mixed according to the general procedure described above and subsequently dynamically heat aged at 80°C for 16hours. It represents the case of a standard calcium carbonate reservoir fluid currently available on the market for most reservoir drilling applications.

Formulation 1 has a density of 1.17 g/cm^3 (9.8 ppg or pounds per gallon) and comprises Brine NaCl 6.9wt.%, KCl 4wt.% in fresh water; Biocide 0.00057 g/cm^3 (0.2ppb (pounds per barrel of 42 gallon); an antifoamer 0.2ppb; Fluid Loss Additive (starch) 0.0142 g/cm^3 (5 ppb);

Viscosifier (scleroglucan) 0.0037 g/cm^3 (1.3 ppb); Bridging material (standard calcium carbonate) 0.1283 g/cm^3 (45ppb); pH control additive (magnesium oxide) 0.000856 g/cm^3 (0.3ppb).

Formulation 2 is identical to formulation1 but further contains 0.042786 g/cm^3 (15ppb) of drill-solids (clay).

Example 1 illustrates the background for this invention. It shows the adverse effect of clay added to the standard calcium carbonate formulation on the return permeability for a standalone simulated well. A sandstone Clashach core of initial permeability 750mD is used. Filtration is carried out for 16 hours at 80°C and differential pressure of 3.447 MPa (500 psi, pounds per square inch). The following rheological properties AHR at 48.88°C (120F) and percentage return permeabilities at 80°C after filtration were measured.

	Standalone simulated well	
	Formulation 1	Formulation 2
Rheology: PV/YP	10/20	20/13
Gels: 10s./10 min.	10/12	4/8
HTHT@80°C -500 psi	6ml (32ml)*	7.5ml (27ml)*
Return Permeability	96%	64%

()*for a 60 micron aloxite disc

Example 2

Example 2 illustrates the background for this invention. It shows the effect of clay added to the standard calcium carbonate formulation on the return permeability for a gravel packed simulated well. The presence of the gravel pack reduces drastically the back flow of hydrocarbons.

A 60 microns aloxite disc, with a 20/40 (0.425 to 0.85 mm sized sand). sand pack of is used. Filtration is carried out for 16hours at 80°C and differential pressure of 500 psi.

	20/40 Gravel packed simulated well	
	Formulation 1	Formulation 2
HTHT@80°C-500 psi	31ml	28ml
Return Permeability	10%	0%

Example 3

Example 3 illustrates the background for this invention. It shows the effect of temperature on the return permeability for a gravel packed simulated well and formulation 2.

A 60 microns aloxite disc, with a 12/20 sand pack is used. A 12/20 sand is more permeable than a 20/40 sand (0.425 to 0.85 mm sized sand). Filtration is carried out for 16hours at various temperatures and differential pressure of 500 psi. The following rheological properties AHR at the filtration temperature (when lower than 120F) or at 120F (when higher than 120F) and percentage return permeabilities after filtration at this temperature were measured.

	12/20 gravel pack simulated well / Formulation 2		
	80°C	40°C	21°C
Rheology: PV/YP	19/16	20/19	29/28
Gels: 10s./10 min.	7/14	7/24	9/28
HTHT@80°C-500 psi	27ml	24ml	19ml
Return Permeability	5%	17%	20%

Example 4

Example 4 shows the effect of a change in the Fluid Loss Additive/Viscosifier ratio in formulation 2 on the return permeability for the gravel packed simulated well. A 60 microns aloxite disc and sand pack 20/40 is used. Filtration is carried out at 80°C and differential pressure of 500 psi.

	Gravel pack 20/40 simulated well	
	Formulation 2 / FLA/Visc. 8ppb/1.3ppb	Formulation 2 / FLA/Visc. 7ppb/2ppb
Rheology: PV/YP	29/26	26/26
Gels: 10s./10 min.	6/11	12/19
HTHT@80°F-500 psi	21ml	24ml
Return Permeability	0%	0%

Example 5

Example 5 shows the effect of a change of the brine phase in formulation 2 on the return permeability for the gravel packed simulated well. A 60 microns aloxite disc and sand pack 20/40 of is used. Filtration is carried out at 80°C and differential pressure of 500 psi.

	Gravel pack 20/40 simulated well Formulation 2 / Brine phase:			
	$CaCl_2$ - 10ppb	$CaCl_2$ - 35ppb	$CaCl_2$/KCl 10ppb/10ppb	$CaCl_2$/KCl 35ppb/10ppb
Rheology: PV/YP	8/41	8/47	15/28	22/28
Gels: 10s./10 min.	18/21	17/20	13/20	12/19
HTHT@80°C-500 psi	27ml	26ml	31ml	24ml
Return Permeability	0%	0%	0%	0%

Example 6

Example 6 shows the effect of a change of type of viscosifier in formulation 1 and 2 on the return permeability for the gravel packed simulated well. A 60 microns aloxite disc and sand pack 20/40 of is used. Filtration is carried out at 80°C and differential pressure of 500 psi.

	Gravel pack 20/40 simulated well	
	Formulation 1/ Viscosifier: xanthan 1.3ppb	Formulation 2 / Viscosifier: xanthan 1.3ppb
Rheology: PV/YP	11/21	13/21
Gels: 10s./10 min.	5/6	9/10
HTHT@80°C -500 psi	34ml	27ml
Return Permeability	7%	0%

Example 7

The following base formulation 3 was mixed according to the general procedure described above and subsequently dynamically heat aged at 80°C for 16 hours.

Formulation 3 has a density of 9.8ppg (pounds per gallon) and comprises: Brine NaCl 6.9wt.%, KCl 4wt.% in fresh water; Biocide 0.2ppb (pounds per barrel); an antifoamer 0.2ppb; Fluid Loss Additive (starch) 5ppb; Viscosifier (scleroglucan) 2ppb; Bridging material (hydrophobically coated calcium carbonate / standard calcium carbonate 18ppb / 27ppb) 45ppb; Drilling solids (clay) 15ppb; pH control additive (magnesium oxide) 0.3ppb.

Example 7 shows the effect of using as bridging solids a blend of hydrophobically coated and standard non-coated calcium carbonate on the return permeability for the gravel packed simulated well. A 60 microns aloxite disc and sand pack 20/40 is used. Filtration is carried out at 80°C and differential pressure of 500 psi.

	Gravel pack 20/40 simulated well
	Formulation 3
Rheology: PV/YP	24/25
Gels: 10s./10 min.	8/27
HTHT@ 80°C -500 psi	26
Return Permeability	0%

Example 8

The following base formulation 4 was mixed according to the general procedure described above and subsequently dynamically heat aged at 80°C for 16 hours.

Formulation 4 has a density of 9.8 ppg (pounds per gallon) and comprises: Brine NaCl 6.9wt.%, KCl 4wt.% in fresh water; Biocide 0.2ppb (pounds per barrel); an antifoamer 0.2ppb; Fluid Loss Additive (hydrophobically modified starch) 8 ppb; Viscosifier (scleroglucan) 2 ppb; Bridging material (standard calcium carbonate) 45ppb; Drilling solids (clay) 15ppb; pH control additive (magnesium oxide) 0.3ppb.

Example 8 shows the effect of using as Fluid Loss Additive a hydrophobically modified starch on the return permeability for the gravel packed simulated well. A 60 microns aloxite disc and sand pack 20/40 of is used. Filtration is carried out at 80°C and differential pressure of 500 psi.

	Gravel pack 20/40 simulated well Formulation 4
Rheology: PV/YP	19/16
Gels: 10s./10 min.	5/9
HTHT@80°C -500 psi	21ml
Return Permeability	0%

Example 9

The following base formulation 5 and 6 were mixed according to the general procedure described above and subsequently dynamically heat aged at 80°C for 16 hours. The formulation includes the combination of a coated calcium carbonate and a hydrophobically modified starch and drilling solids (clay).

Formulation 5 has a density of 9.8 ppg (pounds per gallon) and comprises: Brine NaCl 6.9wt.%, KCl 4wt.% in fresh water; Biocide 0.2ppb (pounds per barrel); an antifoamer 0.2ppb; Fluid Loss Additive (hydrophobically modified starch) 8 ppb; Viscosifier (scleroglucan) 2 ppb; Bridging material (hydrophobically coated calcium carbonate / standard calcium carbonate)

18ppb / 27ppb) 45ppb; Drilling solids (clay) 15ppb; pH control additive (magnesium oxide) 0.3ppb.

Formulation 6 is the same as formulation 5 except that the bridging agent comprises 27ppb of hydrophobically coated calcium carbonate and 18ppb of standard calcium carbonate.

Example 9 shows the beneficial effect of the coated calcium carbonate and hydrophobically modified starch on the return permeability in formulation 5 for the gravel packed simulated well. A 60 microns aloxite disc and sand pack 20/40 are used. Filtration is carried out at 80°C and differential pressure of 500 psi.

The following rheological properties AHR at 120F and percentage return permeabilities at 80°C after filtration were measured.

	Gravel pack 20/40 simulated well	
	Formulation 5	Formulation 6
Rheology: PV/YP	20/20	21/22
Gels: 10s./10 min.	5/18	6/12
HTHT@80°C-500 psi	20ml	24ml
Return Permeability	33%	15%

Formulation 6 shows the effect of a change in ratio for the bridging solids in formulation 3 on the return permeability for the gravel packed simulated well.

Example 10

Example 10 exemplifies the present invention. It shows a minimal effect of a change in the brine phase in formulation 5 on the return permeability for the gravel packed simulated well. A 60 microns aloxite disc and sand pack 20/40 are used. Filtration is carried out at 80°C and differential pressure of 500 psi.

	Gravel pack 20/40 simulated well	
	Formulation 5/ Brine phase : CaCl2 10wt.%	Formulation 5 / Brine phase : CaCl2 2.9wt.%. KCl 2.9wt.%
Rheology: PV/YP	26/36	28/28

Gels: 10s./10 min.	8/10	6/18
HTHT@80C°-500 psi	19ml	22ml
Return Permeability	22%	27%

Example 11

Example 11 exemplifies the present invention. It shows the effect of an addition of a lubricant into formulation 5 on the return permeability for the gravel packed simulated well. A 60 microns aloxite disc and sand pack 20/40 are used. Filtration is carried out at 80°C and differential pressure of 500 psi.

	Gravel pack 20/40 simulated well
	Formulation 5 + 3%v/v lubricant
Rheology: PV/YP	24/22
Gels: 10s./10 min.	6/12
HTHT@80°C-500 psi	14ml
Return Permeability	37%

The flow initiation pressures (FIP) measured for the examples of the present invention were below 30 psi and in most cases below 10psi. The channels of hydrocarbons through the filter cakes were demonstrated by the presence of isolated spots in the middle of the filter cake after flowing back a kerosene dyed with iodine or a commercially available UV-visible dye.

Simultaneously to the increased permeability of the active filter cake to hydrocarbons, it can be seen by comparing examples 1-8 for conventional drilling fluids with examples 9-11 for drilling fluids of the present invention that the generated active filter cake is able to ensure a smaller damage to the formation, by reducing fluid loss and particulate invasion. Indeed the measured fluid losses in examples 9-11 are significantly lower than in examples 1-3. No turbidity indicative for the loss of solid particles is observed in the filtrate.

Example 4 shows that higher Fluid Loss Additive concentrations in a standard calcium carbonate drilling fluid reduces the fluid loss but does not improve the return permeability permeability of a simulated gravel packed well. Example 5 and 6 show that changing the brine phase or the type of viscosifier in a standard calcium carbonate drilling fluid has no effect on the return permeability of a simulated gravel packed well.

The disclosed drilling fluid system fulfils the usual functions of a conventional drilling fluid. The rheological properties of the drilling fluids of the present invention are perfectly acceptable.

Examples 9-11 describe the performance of the present invention in unfavourable scenarios in which the well is gravel packed and the drilling fluid contaminated by a substantial amount of drill-solids (clay). Example 9 illustrates the present invention with the combination of a hydrophobically coated calcium carbonate and a hydrophobically modified starch. The coated calcium carbonate is used in a blend with non coated calcium carbonate. The example shows the effect of a different ratio between coated and non-coated calcium carbonate on the return permeability. The performance of the drilling system in generating an active filter cake is not improved in this example by an increased amount of coated material. When using a blend of calcium carbonates, the success relies also on the choice of the right particle size distributions of both coated and non-coated components. A change of the ratio coated/non-coated calcium carbonate also affects in this example the overall particle size distribution.

Example 7 illustrates that the use of an oil wettable bridging material alone is not enough for getting return permeability. On the other hand example 8 illustrates that the use of a hydrophobically modified starch alone is not enough either for getting return permeabilty. The combination of both a modified starch and modified calcium carbonate is therefore a requirement to observe return permeability.

Example 10 demonstrates the performance of the present invention in combination with different brine phases.

In example 11, the performance of the active filter cake is enhanced by adding 3%v/v of a lubricant to a formulation of the present invention. The lubricant as a source of hydrophobic sites and because of its emulsifying properties lowering the yield strength of the filter cake contributes to the performance of the active filter cake.

Claims

1. A water based wellbore fluid comprising a fluid loss additive and a bridging material that are hydrophobic in nature, hydrophobically modified or oil wettable.

2. A fluid according to claim 1, wherein said fluid loss additive is selected from hydrophobically modified starch, polyanionic cellulose, carboxymethylcellulose, hydrophobically modified synthetic polymers e.g. poly-hydroxypropylmethacrylate.

3. A fluid according to claim 2 wherein said starch is a polymerised starch or a starch modified by hydroxymethylation, hydroxypropylation, by other hydroxyalkylations or by crosslinking reactions using agents such as phosphorous oxychloride, epichlohydrin, cyanuric chloride, formaldehyde or others.

4. A fluid according to claim 1, wherein said bridging solid is selected from hydrophobically modified inorganic salts, hydrophobic or hydrophobically modified inorganic or organic material.

5. A fluid according to claim 4, wherein said inorganic salts or inorganic material are selected among hydrophobically coated calcium carbonates, zinc carbonates, barium carbonates, hematite, ilmenite, magnesium oxide, barite, silica particles, clay particles, microspheres.

6. A fluid according to claim 5, wherein the hydrophobic coating is selected from fatty oils, fatty acid, fatty esters, carboxylated hydrophobic material or any surfactants that would generate a hydrophobic coating.

7. A fluid according to claim 1 wherein the bridging agent is a ground crystalline material of melting point over 80°C, preferably over 10°C which is readily soluble in produced hydrocarbons such as crude oil and lighter condensates and which exhibits a molecular weight of less than 1000, and preferably less than 650.

8. A fluid according to claim 7, wherein said bridging agent is selected from 1-S-endo-Borneol, camphor, beta carotene, lycophene, cholesterol, lanosterol, agnosterol.

9. Use of the wellbore fluid according to any of claims 1 to 8 as a drilling fluids.

The Patent Office

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Application No:	GB 9914351.3	**Examiner:**	D.B. Pepper
Claims searched:	1-9	**Date of search:**	25 August 1999

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Search Report under Section 17

Databases searched:

UK Patent Office collections, including GB, EP, WO & US patent specifications, in:

UK Cl (Ed.Q): E1F FGP, FJT, FPA, FPD

Int Cl (Ed.6): C09K; E21B

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X	Document indicating lack of novelty or inventive step	A	Document indicating technological background and/or state of the art.
Y	Document indicating lack of inventive step if combined with one or more other documents of same category.	P	Document published on or after the declared priority date but before the filing date of this invention.
&	Member of the same patent family	E	Patent document published on or after, but with priority date earlier than, the filing date of this application.

(12) **United States Patent**
Chesser et al.

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(54) **DRILLING FLUID SYSTEMS WITH IMPROVED FLUID LOSS PROPERTIES**

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(58) **Field of Search** 507/120, 906

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(57) **ABSTRACT**

A drilling fluid system comprising a brine and a quantity of cationic copolymers comprising a ratio of acrylamide monomers to cationic derivatives of acrylamide monomers, wherein the quantity and the ratio are effective to maintain effective rheology and fluid loss control in said drilling fluid system at temperatures of at least about 250° C. for at least about 16 hours.

190 Claims, No Drawings

DRILLING FLUID SYSTEMS WITH IMPROVED FLUID LOSS PROPERTIES

This application claims benefit of Provisional Appln. No. 60/107,487 filed Nov. 6, 1998.

FIELD OF THE INVENTION

The present invention relates to brine based drilling fluid system with improved fluid loss control properties at high temperatures provided by cationic polymers.

BACKGROUND OF THE INVENTION

Filtration control is one of the most important properties of a drilling fluid, particularly when drilling through permeable formations where the hydrostatic pressure exceeds the formation pressure. It is important for a drilling fluid to quickly form a filter cake which effectively minimizes fluid loss, but which also is thin and dispersible enough to allow product to flow into the wellbore during production.

Filtration control additives for brines typically are nonionic water soluble polymers, such as starches, derivatized starches, gums, derivatized gums, and cellulosics. These polymers have certain advantages, but suffer from the disadvantage that they have a relatively low hydration rate in brines—particularly in high density brines, where very little water actually is available to hydrate and swell the polymers.

Another disadvantage of nonionic water-soluble polymers is that they have limited temperature stability. As wells are drilled deeper, higher bottomhole tempt are encountered. Today's drilling fluids need to maintain stable rheology and low filtration at temperatures above 300° F. Unfortunately, the nonionic water soluble polymers currently in use are not stable at exceeding about 225° F. with extended aging times.

Filtration control additives are needed which will quickly form a thin, dispersible filter cake, and which also have high temperature stability for prolonged period of time.

SUMMARY OF THE INVENTION

The present invention provides a drilling fluid system comprising a brine comprising a quantity of cationic copolymer comprising a ratio of acrylamide monomers to cationic derivatives of acrylamide monomers, wherein the quantity and the ratio are effective to maintain effective rheology and fluid loss control in the drilling fluid system at temperatures of at least about 250° F. for at east about 16 hours.

DETAILED DESCRIPTION OF THE INVENTION

The present invention provides a drilling fluid system, preferably for use as a drill-in or completion fluid, which quickly forms a thin, dispersable filter cake and which is stable for prolonged periods of time at high temperatures.

The drilling fluid system comprises an aqueous brine, preferably a "high density brine" (defined below), a viscosifier, a bridging agent, a pH stabilizer, and one or more fluid loss control additive(s). A preferred fluid loss control additive comprises cationic copolymers.

The cationic copolymers of the present invention may be used as an additive in substantially any aqueous brine drilling fluid system. However, not all types of drilling fluid systems encounter extremely high temperatures. Because of this, a preferred use for the drilling fluid system of the present invention is as a drill-in or completion fluid—fluids which are more likely to be exposed to higher downhole temperatures for prolonged periods of time.

Preferred drill-in and completion fluids are brines having a density of at east about 9 lb/gal, most preferably "high density brines," defined herein to mean brines having a density of at least about 12–17 lb/gal. The brines may contain substantially any suitable salts, including, but not necessarily lifted to salts based on metals, such as calcium, magnesium, sodium, potassium, cesium, zinc, aluminum, and lithium. Salts of calcium and zinc are preferred. The salts may contain substantially any anions, with preferred anions being less expensive anions including, but not necessarily limited to chlorides, bromides, formates, acetates, and nitrates. Most preferred salts are calcium bromide and zinc bromide.

For purposes of the present invention, the term "cationic copolymers" is defined to refer to cationic copolymers which provide effective rheology and filtration control at temperatures greater than about 250° F., preferably about 300° F., most preferably about 325° F., for about 16 hours, preferably for about 48 hours or more. For purposes of the present application, effective rheology is defined to mean structure which is sufficient to suspend bridging agents but not excessive so as to cause high equivalent circulating densities. Effective filtration control is defined to mean control which provides a low filtration rate with a thin, dispersable filter cake.

Preferred cationc copolymr include, but are not necessarily limited to copolymers comprising, and preferably consisting essentially of monomers of acrylamide and monomers of a cationic derivative of acrylamide. Preferred cationic derivatives of acrylamide for use in such copolymers are quaternary salts of N,N-dialkylaminoacrylamide wherein the size of the alkyl groups is limited by solubility to about 5, preferably about 4, most preferably about 1–3 carbon atoms. A preferred cationic quaternary salt is quaternary methyl N,N-dimethylaminoethylmethacrylamide. The copolymers preferably comprise a ratio of from about 3:1 to about 1:1 of the cationic monomer.

Cationic copolymers suitable for use in the present invention are commercially available from Fritz Industries, Inc., Dallas, Tex., under the name EXP-8 EMULSION POLYMER. In order to achieve the desired rheological and filtration control, the fluid should contain from about 1 lb/bbl to about 10 lb/bbl of a 35% active solution of the cationic copolymer in a suitable carrier, such as oil, which translates to about 0.35 to about 3.5 lb/bbl active cationic copolymer.

The cationic copolymers can be used alone or used in conjunction with a different type of fluid loss additive, preferably a 2-amino-2-methyl propane sulfonic acid (AMPS) additive, such as KEM SEAL PLUS®, available from Baker Hughes INTEQ. Where a combination of cationic copolymer and another fluid loss additive is used, the ratio of cationic copolymer to the other fluid loss additive preferably is about 2:1 to about 1:2, most preferably about 1:1.

The system preferably includes bridging agents to bridge the pores in the formation. Suitable bridging agents include, but are not necessarily limited to ground marble or calcium carbonate particles, such as MIL-CARB®, available from Baker Hughes INTEQ. Preferred calcium carbonate particles have a mean particle size of about 30 microns. Calcium carbonate has the advantage that it is acid soluble, and therefore can be removed from the formation by acid flushing. If calcium carbonate is used as the bridging agent, about 50 pounds should be used per barrel of brine.

The system also preferably includes a viscosifier, such as SALT WATER GEL®, available from Baker-Hughes

INTEQ, Houston, Tex. A preferred viscosifier is EXP-77, a cellulosic blend, also available from Baker Hughes INTEQ.

Finally, the system includes a suitable material for adjusting the pH of the system to from about 9 to about 10. Suitable materials include, but are not necessarily limited to hydrous oxides of divalent cations. A preferred material is MgO.

A preferred basic formulation for a drilling fluid system according to the present invention is given in the following table:

Component/Product	Quantity
Brine (12–17 lb/gal density)	.36–.91 gal
EXP-77	5–15 lb/bbl
MIL-CARB ®	50 lb/bbl
MgO	3–5 lb/bbl
Cationic Copolymer (35% active)	1–10 lb/bbl
KEM SEAL PLUS ®	0–4 lb/bbl

The invention will be more clearly understood with reference to the following examples, which are illustrative only and should not be construed as limiting the present invention.

EXAMPLE I

Tests were conducted to determine fluid properties of two fluids having the following compositions:

	CONCENTRATION (g)	
COMPONENT	Fluid 1	Fluid 2
$CaCl_2/CaBr_2$ Brine (13.5 lb/gal density)	510.5	508
EXP-77	10	10
MIL-CARB ®	50	50
MgO	3	3
Cationic Copolymer (35% active)	5.7	5.7
KEM SEAL PLUS ®	—	2

In order to prepare the fluids, the brine was placed in a 1000 ml. beaker and a Silverson L4RT Mixer shaft with a small hole sleeve was inserted. The speed of the mixer was adjusted to 7000 rpm. The EXP-77 was added to the brine and the fluid was mixed for 5 minutes. The MIL-CARB® and MgO were added, and mixing was continued for 5 minutes at 5000 rpm The cationic copolymer then was added, and the resulting fluid was mixed at 5000 rpm for another 5 minutes. Rheology tests were run immediately. The fluids exhibited the following properties:

	Properties			
	Fluid 1		Fluid 2	
Fann 35 @ 120° F.	Initial	After Hot Rolling 16 hr @ 325° F.	Initial	After Hot Rolling 16 hr @ 325° F.
Fann 600 rpm	155	117	148	114
Fann 300 rpm	87.5	64	83.5	63
Fann 200 rpm	62.5	48.5	60	48
Fann 100 rpm	35	31.5	33.5	32
Fann 6 rpm	3.5	10	3	10.5
Fann 3 rpm	2.5	8.5	2.5	9.5
pH (10% disp.)	9.3	9.3	9.1	9.4
API Fluid Loss, ml.	0.0		0.0	
HTHP Fluid Loss, ml. x 2*		16.0		10.0

*325° F., 500 psi, 0.5 hr, paper disc

Fluid loss values measured for both of the foregoing fluids were less than the values typically achievable using biopolymers. Because the fluid containing KEM-SEAL PLUS® achieved a fluid loss of only 10.0 ml., it was concluded that a preferred system is a combination of the cationic copolymer and KEMSEAL PLUS®.

EXAMPLE II

Tests were conducted on a fluid having the following composition to determine fluid properties:

COMPONENT	CONCENTRATION (g)
$CaCl_2/CaBr_2$ Brine (13.5 lb/gal density)	508
EXP-77	10
MIL-CARB ®	50
MgO	3
Cationic Copolymer (35% active)	5.7
KEM SEAL PLUS ®	2

The fluid exhibited the following properties:

	Properties		
Fann 35 @ 120° F.	Initial	After Hot Rolling 16 hrs @ 325° F.	After Hot Rolling 48 hrs @325° F.
Fann 600 rpm	148	114	98
Fann 300 rpm	83.5	63	62
Fann 200 rpm	60	48	47
Fann 100 rpm	33.5	32	32
Fann 6 rpm	3	10.5	10.5
Fann 3 rpm	2.5	8.5	9
pH (10% disp.)		9.4	8.9
API Fluid Loss, ml.	0.0		
HTHP Fluid Loss, ml. x 2*		10.0	14.8

*325° F., 500 psi, 0.5 hr, paper disc

The combination of cationic copolymers with KEM SEAL PLUS® was tested after hot rolling for 16 hours, and after hot rolling for 48 hours. A 10.0 ml. fluid loss was obtained at 16 hours, increasing to 14.8 ml. after 48 hours. Both fluid loss values are better than those achievable using biopolymers as filtration control additives under similar conditions.

Many modifications and variations may be made to the embodiments described herein without departing from the spirit of the present invention. The embodiments described herein are illustrative only should not be construed as limiting the scope of the present invention.

We claim:

1. A drilling fluid system comprising:

a brine comprising an amount of at least one bridging agent and a quantity of cationic copolymer comprising a first ratio of acrylamide monomers to cationic derivatives of acrylamide monomers comprising quaternary salts of N,N-dialkylaminoacrylamide,

wherein said quantity of said cationic polymer and said amount of said bridging agent are effective to form a filter cake which provides effective filtration control and rheology in said drilling fluid system at temperatures of at least about 250° F. for at least about 16 hours.

2. A drilling fluid system comprising:

a brine comprising a viscosifier, a density of about 9 lb/gal or greater, an amount of at least one bridging agent, and a quantity of cationic copolymer comprising a first ratio of acrylamide monomers to cationic derivatives of acrylamide monomers comprising quaternary salts of N,N-dialkylaminoacrylamide;

wherein said quantity of said cationic polymer and said amount of said bridging agent are effective to form a filter cake which provides effective filtration control and rheology in said drilling fluid system at temperatures of at least about 250° F. for at least about 16 hours.

3. A drilling fluid system comprising a brine comprising an amount of at least one bridging agent and about 0.35 to about 3.5 lb/bbl of active cationic copolymer comprising a first ratio of acrylamide monomers to cationic derivatives of said acrylamide monomers of from about 3:1 to about 1:1, wherein said cationic derivatives of said acrylamide monomers comprise quaternary salts of N,N-dialkylaminoacrylamide.

4. A drilling fluid system comprising a brine comprising a viscosifier, a density of about 9 lb/gal or greater, an amount of at least one bridging agent, and a quantity of cationic copolymer comprising a first ratio of acrylamide monomers to cationic derivatives of acrylamide monomers comprising quaternary salts of N,N-dialkylaminoacrylamide.

5. A drilling fluid system comprising:

a brine comprising an amount of at least one bridging agent and a quantity of cationic copolymer comprising a first ratio of acrylamide monomers to cationic derivatives of acrylamide monomers comprising quaternary alkyl salts of N,N-dialkylaminoalkylmethacrylamide;

wherein said quantity of said cationic polymer and said amount of said bridging agent are effective to form a filter cake which provides effective filtration control and rheology in said drilling fluid system at temperatures of at least about 250° F. for at least about 16 hours.

6. A drilling fluid system comprising:

a brine comprising a viscosifier, a density of about 9 lb/gal or greater, an amount of at least one bridging agent, and a quantity of cationic copolymer comprising a first ratio of acrylamide monomers to cationic derivatives of acrylamide monomers comprising quaternary alkyl salts of N,N-dialkylaminoalkylmethacrylamide;

wherein said quantity of said cationic polymer and said amount of said bridging agent are effective to form a filter cake which provides effective filtration control and rheology in said drilling fluid system at temperatures of at least about 250° F. for at least about 16 hours.

7. A drilling fluid system comprising a brine comprising an amount of at least one bridging agent and about 0.35 to about 3.5 lb/bbl of active cationic copolymer comprising a first ratio of acrylamide monomers to cationic derivatives of said acrylamide monomers of from about 3:1 to about 1:1, wherein said cationic derivatives of said acrylamide monomers comprise quaternary alkyl salts of N,N-dialkylamino alkylmethacrylamide.

8. The drilling fluid system of claim 4 wherein said quarternary salts comprise quaternary alkyl salts of N,N-dialkylaminoalkylmethacrylamide.

9. A drilling fluid system comprising:

a brine comprising an amount of at least one bridging agent and a quantity of cationic copolymer comprising a first ratio of acrylamide monomers to cationic derivatives of acrylamide monomers comprising quaternary methyl N,N-dimethylaminoethylmethacrylamide;

wherein said quantity of said cationic polymer and said amount of said bridging agent are effective to form a filter cake which provides effective filtration control and rheology in said drilling fluid system at temperatures of at least about 250° F. for at least about 16 hours.

10. A drilling fluid system comprising:

a brine comprising a viscosifier, and a density of about 9 lb/gal or greater, and an amount of at least one bridging agent and a quantity of cationic copolymer comprising a first ratio of acrylamide monomers to cationic derivatives of acrylamide monomers comprising quaternary methyl N,N-dimethylaminoethylmethacrylamide;

wherein said quantity of said cationic polymer and said amount of said bridging agent are effective to form a filter cake which provides effective filtration control and rheology in said drilling fluid system at temperatures of at least about 250° F. for at least about 16 hours.

11. The drilling fluid system of claim 5 wherein said quaternary salts comprise quaternary methyl N,N-dimethylaminoethylmethacrylamide.

12. A drilling fluid system comprising a brine comprising an amount of at least one bridging agent and about 0.35 to about 3.5 lb/bbl of active cationic copolymer comprising a first ratio of acrylamide monomers to quaternary methyl N,N-dimethylaminoethylmethacrylamide monomers of from about 3:1 to about 1:1.

13. The drilling fluid system of claim 1 wherein said first ratio is from about 3:1 to about 1:1.

14. The drilling fluid system of claim 2 wherein said first ratio is from about 3:1 to about 1:1.

15. The drilling fluid system of claim 4 wherein said first ratio is from about 3:1 to about 1:1.

16. The drilling fluid system of claim 1 wherein

said brine comprises a density of about 9.0 lb/gal or greater; and,

said brine further comprises a fluid loss control additive comprising 2-amino-2-methyl propane sulfonic acid.

17. The drilling fluid system of claim 16 wherein said cationic polymer and said fluid loss control additive are present in said drilling fluid system at a second ratio of from about 2:1 to about 1:2.

18. The drilling fluid system of claim 16 wherein said cationic polymer and said fluid loss control additive are present in said drilling fluid system at a second ratio of about 1:1.

19. The drilling fluid system of claim 12 wherein

said brine comprises a density of about 9.0 lb/gal or greater; and,

said brine further comprises a fluid loss control additive comprising 2-amino-2-methyl propane sulfonic acid.

20. The drilling fluid system of claim 19 wherein said cationic polymer and said fluid loss control additive are present in said drilling fluid system at a second ratio of from about 2:1 to about 1:2.

21. The drilling fluid system of claim 19 wherein said cationic polymer and said fluid loss control additive are present in said drilling fluid system at a second ratio of about 1:1.

22. The drilling fluid system of claim 12 wherein said brine has a density of at least about 9 lb/gal.

23. The drilling fluid system of claim 1 wherein said brine has a density of from about 12 to about 17 lb/gal.

24. The drilling fluid system of claim 2 wherein said brine has a density of from about 12 to about 17 lb/gal.

25. The drilling fluid system of claim 12 wherein said brine has a density of from about 12 to about 17 lb/gal.

26. A method comprising adding to a drilling fluid system comprising a brine and an amount of at least one bridging agent, a quantity of cationic copolymers comprising a first ratio of acrylamide monomers to cationic derivatives of acrylamide monomers comprising quaternary salts of N,N-dialkylaminoacrylamide, wherein said quantity of said cationic polymer and said amount of said bridging agent are effective to form a filter cake which provides effective filtration control and maintains effective rheology in said drilling fluid system at temperatures of at least about 250° F. for at least about 16 hours.

27. The method of claim 26 wherein said drilling fluid system comprises

a viscosifier; and

a density of about 9 lb/gal or greater.

28. A method for treating a drilling fluid system comprising a brine to control fluid loss properties comprising adding to said drilling fluid system about 0.35 to about 3.5 lb/bbl of active cationic copolymer comprising quaternary salts of N,N-dialkylaminoacrylamide and comprising a first ratio of acrylamide monomers to cationic derivatives of said acrylamide monomers of from about 3:1 to about 1:1 and an amount of at least one bridging agent, said first ratio of monomers to cationic derivatives and said amount of said bridging agent being effective to form a filter cake.

29. A method comprising adding to a drilling fluid system comprising a brine and an amount of at least one bridging agent, a quantity of cationic copolymers comprising a first ratio of acrylamide monomers to cationic derivatives of acrylamide monomers, wherein said quantity of said cationic polymer and said amount of said bridging agent are effective to form a filter cake which provides effective filtration control and maintains effective rheology in said drilling fluid system at temperatures of at least about 250° F. for at least about 16 hours, wherein said quaternary salts comprise quaternary alkyl salts of N,N-dialkylaminoalkylmethacrylamide.

30. The method of claim 27 wherein said quartemary salts comprise quaternary alkyl salts of N,N-dialkylaminoalkylmethacrylamide.

31. The method of claim 28 wherein said quartemary salts comprise quaternary alkyl salts of N,N-dialkylaminoalkylmethacrylamide.

32. A method for treating a drilling fluid system comprising a brine and an amount of at least one bridging agent to control fluid loss properties comprising adding to said drilling fluid system from about 0.35 to about 3.5 lb/bbl of cationic copolymer comprising a first ratio of acrylamide monomers to quaternary methyl N,N-dimethylaminoethylmethacrylamide monomers of from about 3:1 to about 1:1, said first ratio of acrylamide monomers to quaternary methyl N,N-dimethylaminoethylmethacrylamide monomers and said integral amount of solid particles being effective to form a filter cake.

33. The method of claim 26 wherein

said brine comprises a density of about 9 lb/gal or greater; and,

said method further comprises adding to said drilling fluid system a portion of a fluid loss control additive comprising 2-amino-2-methyl propane sulfonic acid which is effective to reduce fluid loss in said drilling fluid system to an amount less than fluid loss achieved using said cationic copolymer, alone.

34. The method of claim 33 wherein said quantity of said cationic copolymer is at a second ratio of from about 2:1 to about 1:2 to said amount of said fluid loss control additive.

35. The method of claim 33 wherein said quantity of said cationic copolymer is at a second ratio of about 1:1 to said amount of said fluid loss control additive.

36. The method of claim 32 where

said brine comprises a density of about 9 lb/gal or greater; and,

said method further comprises adding to said drilling fluid system a portion of a fluid loss control additive comprising 2-amino-2-methyl propane sulfonic acid which is effective to reduce fluid loss in said drilling fluid system to an amount less than fluid loss achieved using said cationic copolymer, alone.

37. The method of claim 36 wherein said quantity of said cationic copolymer is at a second ratio of from about 2:1 to about 1:2 to said amount of said fluid loss control additive.

38. The method of claim 36 wherein said quantity of said cationic copolymer is at a second ratio of about 1:1 to said amount of said fluid loss control additive.

39. The method of claim 32 wherein said brine has a density of at least about 9 lb/gal.

40. The method of claim 32 wherein said brine has a density of from about 12 to about 17 lb/gal.

41. A drilling fluid system comprising a brine comprising an amount of at least one bridging agent and about 0.35 to about 3.5 lb/bbl of active cationic copolymer comprising a first ratio of acrylamide monomers to cationic derivatives of said acrylamide monomers of from about 3:1 to about 1:1, wherein said cationic derivatives of said acrylamide monomers comprise quaternary salts of N,N-dialkylaminoacrylamide, wherein said quantity of said cationic polymer and said amount of said bridging agent are effective to form a filter cake which provides effective filtration control.

42. The method of claim 27 wherein said first ratio is from about 3:1 to about 1:1.

43. The method of claim 26 wherein said first ratio is from about 3:1 to about 1:1.

44. The method of claim 29 wherein said first ratio is from about 3:1 to about 1:1.

45. The method of claim 30 wherein said first ratio is from about 3:1 to about 1:1.

46. The method of claim 33 wherein said first ratio is from about 3:1 to about 1:1.

47. The method of claim 34 wherein said first ratio is from about 3:1 to about 1:1.

48. The method of claim 35 wherein said first ratio is from about 3:1 to about 1:1.

49. The method of claim 36 wherein said first ratio is from about 3:1 to about 1:1.

50. The method of claim 37 wherein said first ratio is from about 3:1 to about 1:1.

51. The method of claim 38 wherein said first ratio is from about 3:1 to about 1:1.

52. The method of claim 28 wherein said drilling fluid system comprises a density of about 9 lb/gal or greater.

53. The method of claim 31 wherein said drilling fluid system comprises a density of about 9 lb/gal or greater.

54. The method of claim 32 wherein said drilling fluid system comprises a density of about 9 lb/gal or greater.

55. The method of claim 42 wherein said drilling fluid system comprises a density of about 9 lb/gal or greater.

56. The method of claim 44 wherein said drilling fluid system comprises a density of about 9 lb/gal or greater.

57. The method of claim 46 wherein said drilling fluid system comprises a density of about 9 lb/gal or greater.

58. The method of claim 27 wherein said brine has a density of from about 12 to about 17 lb/gal.

59. The method of claim 29 wherein said brine has a density of from about 12 to about 17 lb/gal.

60. The method of claim 30 wherein said brine has a density of from about 12 to about 17 lb/gal.

61. The method of claim 31 wherein said brine has a density of from about 12 to about 17 lb/gal.

62. The method of claim 33 wherein said brine has a density of from about 12 to about 17 lb/gal.

63. The method of claim 34 wherein said brine has a density of from about 12 to about 17 lb/gal.

64. The method of claim 35 wherein said brine has a density of from about 12 to about 17 lb/gal.

65. The method of claim 36 wherein said brine has a density of from about 12 to about 17 lb/gal.

66. The method of claim 37 wherein said brine has a density of from about 12 to about 17 lb/gal.

67. The method of claim 38 wherein said brine has a density of from about 12 to about 17 lb/gal.

68. The drilling fluid system of claim 5 wherein said first ratio is from about 3:1 to about 1:1.

69. The drilling fluid system of claim 6 wherein said first ratio is from about 3:1 to about 1:1.

70. The drilling fluid system of claim 8 wherein said first ratio is from about 3:1 to about 1:1.

71. The drilling fluid system of claim 9 wherein said first ratio is from about 3:1 to about 1:1.

72. The drilling fluid system of claim 10 wherein said first ratio is from about 3:1 to about 1:1.

73. The drilling fluid system of claim 11 wherein said first ratio is from about 3:1 to about 1:1.

74. The drilling fluid system of claim 16 wherein said first ratio is from about 3:1 to about 1:1.

75. The drilling fluid system of claim 17 wherein said first ratio is from about 3:1 to about 1:1.

76. The drilling fluid system of claim 18 wherein said first ratio is from about 3:1 to about 1:1.

77. The drilling fluid system of claim 19 wherein said first ratio is from about 3:1 to about 1:1.

78. The drilling fluid system of claim 20 wherein said first ratio is from about 3:1 to about 1:1.

79. The drilling fluid system of claim 21 wherein said first ratio is from about 3:1 to about 1:1.

80. The drilling fluid system of claim 22 wherein said first ratio is from about 3:1 to about 1:1.

81. The drilling fluid system of claim 23 wherein said first ratio is from about 3:1 to about 1:1.

82. The drilling fluid system of claim 24 wherein said first ratio is from about 3:1 to about 1:1.

83. The drilling fluid system of claim 25 wherein said first ratio is from about 3:1 to about 1:1.

84. The drilling fluid system of claim 3 wherein said brine further comprises a fluid loss control additive comprising 2-amino-2-methyl propane sulfonic acid.

85. The drilling fluid system of claim 84 wherein said cationic polymer and said fluid loss control additive are present in said drilling fluid system at a second ratio of from about 2:1 to about 1:2.

86. The drilling fluid system of claim 84 wherein said cationic polymer and said fluid loss control additive are present in said drilling fluid system at a second ratio of about 1:1.

87. The drilling fluid system of claim 4 wherein said brine further comprises a fluid loss control additive comprising 2-amino-2-methyl propane sulfonic acid.

88. The drilling fluid system of claim 87 wherein said cationic polymer and said fluid loss control additive are present in said drilling fluid system at a second ratio of from about 2:1 to about 1:2.

89. The drilling fluid system of claim 87 wherein said cationic polymer and said fluid loss control additive are present in said drilling fluid system at a second ratio of about 1:1.

90. The drilling fluid system of claim 5 wherein said brine further comprises a fluid loss control additive comprising 2-amino-2-methyl propane sulfonic acid.

91. The drilling fluid system of claim 90 wherein said cationic polymer and said fluid loss control additive are present in said drilling fluid system at a second ratio of from about 2:1 to about 1:2.

92. The drilling fluid system of claim 90 wherein said cationic polymer and said fluid loss control additive are present in said drilling fluid system at a second ratio of about 1:1.

93. The drilling fluid system of claim 6 wherein said brine further comprises a fluid loss control additive comprising 2-amino-2-methyl propane sulfonic acid.

94. The drilling fluid system of claim 93 wherein said cationic polymer and said fluid loss control additive are present in said drilling fluid system at a second ratio of from about 2:1 to about 1:2.

95. The drilling fluid system of claim 93 wherein said cationic polymer and said fluid loss control additive are present in said drilling fluid system at a second ratio of about 1:1.

96. The drilling fluid system of claim 6 wherein said brine further comprises a fluid loss control additive comprising 2-amino-2-methyl propane sulfonic acid.

97. The drilling fluid system of claim 96 wherein said cationic polymer and said fluid loss control additive are present in said drilling fluid system at a second ratio of from about 2:1 to about 1:2.

98. The drilling fluid system of claim 96 wherein said cationic polymer and said fluid loss control additive are present in said drilling fluid system at a second ratio of about 1:1.

99. The drilling fluid system of claim 8 wherein said brine further comprises a fluid loss control additive comprising 2-amino-2-methyl propane sulfonic acid.

100. The drilling fluid system of claim 99 wherein said cationic polymer and said fluid loss control additive are present in said drilling fluid system at a second ratio of from about 2:1 to about 1:2.

101. The drilling fluid system of claim 99 wherein said cationic polymer and said fluid loss control additive are present in said drilling fluid system at a second ratio of about 1:1.

102. The drilling fluid system of claim 9 wherein said brine further comprises a fluid loss control additive comprising 2-amino-2-methyl propane sulfonic acid.

103. The drilling fluid system of claim 102 wherein said cationic polymer and said fluid loss control additive are present in said drilling fluid system at a second ratio of from about 2:1 to about 1:2.

104. The drilling fluid system of claim 102 wherein said cationic polymer and said fluid loss control additive are present in said drilling fluid system at a second ratio of about 1:1.

105. The drilling fluid system of claim 10 wherein said brine further comprises a fluid loss control additive comprising 2-amino-2-methyl propane sulfonic acid.

106. The drilling fluid system of claim 105 wherein said cationic polymer and said fluid loss control additive are present in said drilling fluid system at a second ratio of from about 2:1 to about 1:2.

107. The drilling fluid system of claim 105 wherein said cationic polymer and said fluid loss control additive are present in said drilling fluid system at a second ratio of about 1:1.

108. The drilling fluid system of claim 11 wherein said brine further comprises a fluid loss control additive comprising 2-amino-2-methyl propane sulfonic acid.

109. The drilling fluid system of claim 108 wherein said cationic polymer and said fluid loss control additive are present in said drilling fluid system at a second ratio of from about 2:1 to about 1:2.

110. The drilling fluid system of claim 108 wherein said cationic polymer and said fluid loss control additive are present in said drilling fluid system at a second ratio of about 1:1.

111. The drilling fluid system of claim 12 wherein said brine further comprises a fluid loss control additive comprising 2-amino-2-methyl propane sulfonic acid.

112. The drilling fluid system of claim 111 wherein said cationic polymer and said fluid loss control additive are present in said drilling fluid system at a second ratio of from about 2:1 to about 1:2.

113. The drilling fluid system of claim 111 wherein said cationic polymer and said fluid loss control additive are present in said drilling fluid system at a second ratio of about 1:1.

114. The drilling fluid system of claim 13 wherein said brine further comprises a fluid loss control additive comprising 2-amino-2-methyl propane sulfonic acid.

115. The drilling fluid system of claim 114 wherein said cationic polymer and said fluid loss control additive are present in said drilling fluid system at a second ratio of from about 2:1 to about 1:2.

116. The drilling fluid system of claim 114 wherein said cationic polymer and said fluid loss control additive are present in said drilling fluid system at a second ratio of about 1:1.

117. The drilling fluid system of claim 14 wherein said brine further comprises a fluid loss control additive comprising 2-amino-2-methyl propane sulfonic acid.

118. The drilling fluid system of claim 117 wherein said cationic polymer and said fluid loss control additive are present in said drilling fluid system at a second ratio of from about 2:1 to about 1:2.

119. The drilling fluid system of claim 117 wherein said cationic polymer and said fluid loss control additive are present in said drilling fluid system at a second ratio of about 1:1.

120. The drilling fluid system of claim 15 wherein said brine further comprises a fluid loss control additive comprising 2-amino-2-methyl propane sulfonic acid.

121. The drilling fluid system of claim 120 wherein said cationic polymer and said fluid loss control additive are present in said drilling fluid system at a second ratio of from about 2:1 to about 1:2.

122. The drilling fluid system of claim 120 wherein said cationic polymer and said fluid loss control additive are present in said drilling fluid system at a second ratio of about 1:1.

123. The drilling fluid system of claim 22 wherein said brine further comprises a fluid loss control additive comprising 2-amino-2-methyl propane sulfonic acid.

124. The drilling fluid system of claim 123 wherein said cationic polymer and said fluid loss control additive are present in said drilling fluid system at a second ratio of from about 2:1 to about 1:2.

125. The drilling fluid system of claim 123 wherein said cationic polymer and said fluid loss control additive are present in said drilling fluid system at a second ratio of about 1:1.

126. The drilling fluid system of claim 23 wherein said brine further comprises a fluid loss control additive comprising 2-amino-2-methyl propane sulfonic acid.

127. The drilling fluid system of claim 126 wherein said cationic polymer and said fluid loss control additive are present in said drilling fluid system at a second ratio of from about 2:1 to about 1:2.

128. The drilling fluid system of claim 126 wherein said cationic polymer and said fluid loss control additive are present in said drilling fluid system at a second ratio of about 1:1.

129. The drilling fluid system of claim 24 wherein said brine further comprises a fluid loss control additive comprising 2-amino-2-methyl propane sulfonic acid.

130. The drilling fluid system of claim 129 wherein said cationic polymer and said fluid loss control additive are present in said drilling fluid system at a second ratio of from about 2:1 to about 1:2.

131. The drilling fluid system of claim 129 wherein said cationic polymer and said fluid loss control additive are present in said drilling fluid system at a second ratio of about 1:1.

132. The drilling fluid system of claim 25 wherein said brine further comprises a fluid loss control additive comprising 2-amino-2-methyl propane sulfonic acid.

133. The drilling fluid system of claim 132 wherein said cationic polymer and said fluid loss control additive are present in said drilling fluid system at a second ratio of from about 2:1 to about 1:2.

134. The drilling fluid system of claim 132 wherein said cationic polymer and said fluid loss control additive are present in said drilling fluid system at a second ratio of about 1:1.

135. The drilling fluid system of claim 3 wherein said brine has a density of at least about 9 lb/gal.

136. The drilling fluid system of claim 5 wherein said brine has a density of at least about 9 lb/gal.

137. The drilling fluid system of claim 7 wherein said brine has a density of at least about 9 lb/gal.

138. The drilling fluid system of claim 9 wherein said brine has a density of at least about 9 lb/gal.

139. The drilling fluid system of claim 12 wherein said brine has a density of at least about 9 lb/gal.

140. The drilling fluid system of claim 13 wherein said brine has a density of at least about 9 lb/gal.

141. The drilling fluid system of claim 71 wherein said brine has a density of at least about 9 lb/gal.

142. The drilling fluid system of claim 84 wherein said brine has a density of at least about 9 lb/gal.

143. The drilling fluid system of claim 90 wherein said brine has a density of at least about 9 lb/gal.

144. The drilling fluid system of claim 96 wherein said brine has a density of at least about 9 lb/gal.

145. The drilling fluid system of claim 97 wherein said brine has a density of at least about 9 lb/gal.

146. The drilling fluid system of claim 102 wherein said brine has a density of at least about 9 lb/gal.

147. The drilling fluid system of claim 111 wherein said brine has a density of at least about 9 lb/gal.

148. The drilling fluid system of claim 112 wherein said brine has a density of at least about 9 lb/gal.

149. The drilling fluid system of claim 113 wherein said brine has a density of at least about 9 lb/gal.

150. The drilling fluid system of claim 114 wherein said brine has a density of at least about 9 lb/gal.

151. The drilling fluid system of claim 115 wherein said brine has a density of at least about 9 lb/gal.

152. The drilling fluid system of claim 116 wherein said brine has a density of at least about 9 lb/gal.

153. The drilling fluid system of claim 4 wherein said brine has a density of from about 12 to about 17 lb/gal.

154. The drilling fluid system of claim 5 wherein said brine has a density of from about 12 to about 17 lb/gal.

155. The drilling fluid system of claim 6 wherein said brine has a density of from about 12 to about 17 lb/gal.

156. The drilling fluid system of claim 7 wherein said brine has a density of from about 12 to about 17 lb/gal.

157. The drilling fluid system of claim 8 wherein said brine has a density of from about 12 to about 17 lb/gal.

158. The drilling fluid system of claim 9 wherein said brine has a density of from about 12 to about 17 lb/gal.

159. The drilling fluid system of claim 10 wherein said brine has a density of from about 12 to about 17 lb/gal.

160. The drilling fluid system of claim 11 wherein said brine has a density of from about 12 to about 17 lb/gal.

161. The drilling fluid system of claim 12 wherein said brine has a density of from about 12 to about 17 lb/gal.

162. The drilling fluid system of claim 13 wherein said brine has a density of from about 12 to about 17 lb/gal.

163. The drilling fluid system of claim 14 wherein said brine has a density of from about 12 to about 17 lb/gal.

164. The drilling fluid system of claim 15 wherein said brine has a density of from about 12 to about 17 lb/gal.

165. The drilling fluid system of claim 16 wherein said brine has a density of from about 12 to about 17 lb/gal.

166. The drilling fluid system of claim 17 wherein said brine has a density of from about 12 to about 17 lb/gal.

167. The drilling fluid system of claim 18 wherein said brine has a density of from about 12 to about 17 lb/gal.

168. The drilling fluid system of claim 19 wherein said brine has a density of from about 12 to about 17 lb/gal.

169. The drilling fluid system of claim 20 wherein said brine has a density of from about 12 to about 17 lb/gal.

170. The drilling fluid system of claim 21 wherein said brine has a density of from about 12 to about 17 lb/gal.

171. The drilling fluid system of claim 22 wherein said brine has a density of from about 12 to about 17 lb/gal.

172. The method of claim 66 wherein said brine has a density of from about 12 to about 17 lb/gal.

173. The method of claim 67 wherein said brine has a density of from about 12 to about 17 lb/gal.

174. The drilling fluid system of claim 68 wherein said brine has a density of from about 12 to about 17 lb/gal.

175. The drilling fluid system of claim 69 wherein said brine has a density of from about 12 to about 17 lb/gal.

176. The drilling fluid system of claim 70 wherein said brine has a density of from about 12 to about 17 lb/gal.

177. The drilling fluid system of claim 71 wherein said brine has a density of from about 12 to about 17 lb/gal.

178. The drilling fluid system of claim 72 wherein said brine has a density of from about 12 to about 17 lb/gal.

179. The drilling fluid system of claim 73 wherein said brine has a density of from about 12 to about 17 lb/gal.

180. The drilling fluid system of claim 74 wherein said brine has a density of from about 12 to about 17 lb/gal.

181. The drilling fluid system of claim 75 wherein said brine has a density of from about 12 to about 17 lb/gal.

182. The drilling fluid system of claim 76 wherein said brine has a density of from about 12 to about 17 lb/gal.

183. The drilling fluid system of claim 77 wherein said brine has a density of from about 12 to about 17 lb/gal.

184. The drilling fluid system of claim 78 wherein said brine has a density of from about 12 to about 17 lb/gal.

185. The drilling fluid system of claim 79 wherein said brine has a density of from about 12 to about 17 lb/gal.

186. The drilling fluid system of claim 80 wherein said brine has a density of from about 12 to about 17 lb/gal.

187. The drilling fluid system of claim 84 wherein said brine has a density of from about 12 to about 17 lb/gal.

188. The drilling fluid system of claim 85 wherein said brine has a density of from about 12 to about 17 lb/gal.

189. The drilling fluid system of claim 86 wherein said brine has a density of from about 12 to about 17 lb/gal.

190. The drilling fluid system of claim 90 wherein said brine has a density of from about 12 to about 17 lb/gal.

* * * * *

UNITED STATES PATENT AND TRADEMARK OFFICE

CERTIFICATE OF CORRECTION

PATENT NO. : 6,403,537 B1 Page 1 of 1
DATED : June 11, 2002
INVENTOR(S) : Billy G. Chesser, Charles Perricone and George W. Bettge

It is certified that error appears in the above-identified patent and that said Letters Patent is hereby corrected as shown below:

Title page,
Item [57], **ABSTRACT**, after the word "250°", delete the letter "C" and insert -- F --.

Column 1,
Line 9, after the phrase "drilling fluid" delete the word "system" and insert the word – systems --.
Line 30, after the word "bottomhole" delete the word "tempt" and insert the word -- temperatures --.
Line 34, before the word "exceeding" insert the word – temperatures --.

Column 2,
Line 2, delete the word "east" and insert the word -- least --.
Line 50, delete the word "PLUSH" and insert the word -- PLUS --.

Signed and Sealed this

Thirty-first Day of December, 2002

JAMES E. ROGAN
Director of the United States Patent and Trademark Office

UNITED STATES PATENT AND TRADEMARK OFFICE
CERTIFICATE OF CORRECTION

PATENT NO. : 6,403,537 B1
DATED : June 11, 2002
INVENTOR(S) : Billy G. Chesser, Charles Perricone and George W. Bettge

It is certified that error appears in the above-identified patent and that said Letters Patent is hereby corrected as shown below:

Column 5,
Lines 5, 17-18, 37-38, 43-44 and 55-56, delete "acrylamide monomers to cationic derivatives of acrylamide monomers" and insert -- cationic derivatives of acrylamide monomers to acrylamide monomers --.
Lines 8, 20, 46 and 58, delete "cationic polymer" and insert -- cationic copolymer --.
Lines 29-30 and 66-67, delete "acrylamide monomers to cationic derivatives of said acrylamide monomers" and insert -- cationic derivatives of acrylamide monomers to acrylamide monomers --.

Column 6,
Lines 10-11, delete "acrylamide monomers to cationic derivatives of acrylamide monomers" and insert -- cationic derivatives of acrylamide monomers to acrylamide monomers --.
Lines 13 and 25, delete "cationic polymer" and insert -- cationic copolymer --.
Lines 22-23, delete "acrylamide monomers to cationic derivatives of acrylamide monomers" and insert -- cationic derivatives of acrylamide monomers to acrylamide monomers --.

Column 7,
Lines 16-17, 33-34 and 41-42, delete "acrylamide monomers to cationic derivatives of acrylamide monomers" and insert -- cationic derivatives of acrylamide monomers to acrylamide monomers --.
Lines 18-19 and 42-43, delete "cationic polymer" and insert -- cationic copolymer --.

Column 8,
Lines 38-39, delete "acrylamide monomers to cationic derivatives of said acrylamide monomers" and insert -- cationic derivatives of acrylamide monomers to acrylamide monomers --.
Line 43, delete "cationic polymer" and insert -- cationic copolymer --.

Column 9,
Line 67, delete "cationic polymer" and insert -- cationic copolymer --.

Column 10,
Lines 4, 11, 15, 21, 25, 32, 36, 43, 47, 54, 58 and 65, delete "cationic polymer" and insert -- cationic copolymer --.

Column 11,
Lines 2, 9, 12, 19, 23, 30, 34, 40, 44, 51, 55, 61 and 66, delete "cationic polymer" and insert -- cationic copolymer --.

UNITED STATES PATENT AND TRADEMARK OFFICE

CERTIFICATE OF CORRECTION

PATENT NO. : 6,403,537 B1
DATED : June 11, 2002
INVENTOR(S) : Billy G. Chesser, Charles Perricone and George W. Bettge

It is certified that error appears in the above-identified patent and that said Letters Patent is hereby corrected as shown below:

Column 12,
Lines 5, 9, 16, 20, 26, 30, 37 and 41, delete "cationic polymer" and insert -- cationic copolymer --.

Signed and Sealed this

Twentieth Day of May, 2003

JAMES E. ROGAN
Director of the United States Patent and Trademark Office

PCT

REQUEST

The undersigned requests that the present international application be processed according to the Patent Cooperation Treaty.

For receiving Office use only

International Application No.

International Filing Date

Name of receiving Office and "PCT International Application"

Applicant's or agent's file reference *(if desired) (12 characters maximum)* 10061

Box No. I TITLE OF INVENTION

DRILLING METHOD

Box No. II APPLICANT ☐ This person is also inventor

Name and address: *(Family name followed by given name; for a legal entity, full official designation. The address must include postal code and name of country. The country of the address indicated in this Box is the applicant's State (that is, country) of residence if no State of residence is indicated below.)*

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Teleprinter No.

Applicant's registration No. with the Office

State *(that is, country)* of nationality: GB

State *(that is, country)* of residence: GB

This person is applicant for the purposes of: ☐ all designated States ☒ all designated States except the United States of America ☐ the United States of America only ☐ the States indicated in the Supplemental Box

Box No. III FURTHER APPLICANT(S) AND/OR (FURTHER) INVENTOR(S)

Name and address: *(Family name followed by given name; for a legal entity, full official designation. The address must include postal code and name of country. The country of the address indicated in this Box is the applicant's State (that is, country) of residence if no State of residence is indicated below.)*

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This person is:
☒ applicant only
☐ applicant and inventor
☐ inventor only *(If this check-box is marked, do not fill in below.)*

Applicant's registration No. with the Office

State *(that is, country)* of nationality: US

State *(that is, country)* of residence: US

This person is applicant for the purposes of: ☐ all designated States ☒ all designated States except the United States of America ☐ the United States of America only ☐ the States indicated in the Supplemental Box

☒ Further applicants and/or (further) inventors are indicated on a continuation sheet.

Box No. IV AGENT OR COMMON REPRESENTATIVE; OR ADDRESS FOR CORRESPONDENCE

The person identified below is hereby/has been appointed to act on behalf of the applicant(s) before the competent International Authorities as: ☒ agent ☐ common representative

Name and address: *(Family name followed by given name; for a legal entity, full official designation. The address must include postal code and name of country.)*

COLLINS, Frances Mary
BP International Limited
Patents & Agreements
Chertsey Road, Sunbury on Thames
Middlesex, TW16 7LN
United Kingdom

Telephone No.
01932 763343

Facsimile No.
01932 762388

Teleprinter No.

Agent's registration No. with the Office

☐ **Address for correspondence:** Mark this check-box where no agent or common representative is/has been appointed and the space above is used instead to indicate a special address to which correspondence should be sent.

Continuation of Box No. III FURTHER APPLICANT(S) AND/OR (FURTHER) INVENTOR(S)

If none of the following sub-boxes is used, this sheet should not be included in the request.

Name and address: *(Family name followed by given name; for a legal entity, full official designation. The address must include postal code and name of country. The country of the address indicated in this Box is the applicant's State (that is, country) of residence if no State of residence is indicated below.)*

ALBERTY, Mark William
2918 Rosemary Park Lane
Houston
Texas 77082
United States of America

This person is:
- ☐ applicant only
- ☒ applicant and inventor
- ☐ inventor only *(If this check-box is marked, do not fill in below.)*

Applicant's registration No. with the Office

State *(that is, country)* of nationality: US

State *(that is, country)* of residence: US

This person is applicant for the purposes of: ☐ all designated States ☐ all designated States except the United States of America ☒ the United States of America only ☐ the States indicated in the Supplemental Box

Name and address: *(Family name followed by given name; for a legal entity, full official designation. The address must include postal code and name of country. The country of the address indicated in this Box is the applicant's State (that is, country) of residence if no State of residence is indicated below.)*

ASTON, Mark Shelton
35 Fairfax Road
Teddington
Middlesex TW11 9DJ
United Kingdom

This person is:
- ☐ applicant only
- ☒ applicant and inventor
- ☐ inventor only *(If this check-box is marked, do not fill in below.)*

Applicant's registration No. with the Office

State *(that is, country)* of nationality: GB

State *(that is, country)* of residence: GB

This person is applicant for the purposes of: ☐ all designated States ☐ all designated States except the United States of America ☒ the United States of America only ☐ the States indicated in the Supplemental Box

Name and address: *(Family name followed by given name; for a legal entity, full official designation. The address must include postal code and name of country. The country of the address indicated in this Box is the applicant's State (that is, country) of residence if no State of residence is indicated below.)*

McLEAN, Michael Richard
8 Riverfield Road
Staines
Middlesex TW18 2EE
United Kingdom

This person is:
- ☐ applicant only
- ☒ applicant and inventor
- ☐ inventor only *(If this check-box is marked, do not fill in below.)*

Applicant's registration No. with the Office

State *(that is, country)* of nationality: GB

State *(that is, country)* of residence: GB

This person is applicant for the purposes of: ☐ all designated States ☐ all designated States except the United States of America ☒ the United States of America only ☐ the States indicated in the Supplemental Box

Name and address: *(Family name followed by given name; for a legal entity, full official designation. The address must include postal code and name of country. The country of the address indicated in this Box is the applicant's State (that is, country) of residence if no State of residence is indicated below.)*

This person is:
- ☐ applicant only
- ☐ applicant and inventor
- ☐ inventor only *(If this check-box is marked, do not fill in below.)*

Applicant's registration No. with the Office

State *(that is, country)* of nationality:

State *(that is, country)* of residence:

This person is applicant for the purposes of: ☐ all designated States ☐ all designated States except the United States of America ☐ the United States of America only ☐ the States indicated in the Supplemental Box

☐ Further applicants and/or (further) inventors are indicated on another continuation sheet.

Box No. V DESIGNATIONS

The filing of this request constitutes under Rule 4.9(a), the designation of all Contracting States bound by the PCT on the international filing date, for the grant of every kind of protection available and, where applicable, for the grant of both regional and national patents.

However,

☐ DE Germany is not designated for any kind of national protection

☐ KR Republic of Korea is not designated for any kind of national protection

☐ RU Russian Federation is not designated for any kind of national protection

(The check-boxes above may be used to exclude (irrevocably) the designations concerned in order to avoid the ceasing of the effect, under the national law, of an earlier national application from which priority is claimed. See the Notes to Box No. V as to the consequences of such national law provisions in these and certain other States.)

Box No. VI PRIORITY CLAIM

The priority of the following earlier application(s) is hereby claimed:

Filing date of earlier application *(day/month/year)*	Number of earlier application	Where earlier application is:		
		national application: country or Member of WTO	regional application:* regional Office	international application: receiving Office
item (1) 25/07/2003 (25 July 2003)	60/489,917	US		
item (2)				
item (3)				

☐ Further priority claims are indicated in the Supplemental Box.

The receiving Office is requested to prepare and transmit to the International Bureau a certified copy of the earlier application(s) *(only if the earlier application was filed with the Office which for the purposes of this international application is the receiving Office)* identified above as:

☐ all items ☐ item (1) ☐ item (2) ☐ item (3) ☐ other, see Supplemental Box

* *Where the earlier application is an ARIPO application, indicate at least one country party to the Paris Convention for the Protection of Industrial Property or one Member of the World Trade Organization for which that earlier application was filed (Rule 4.10(b)(ii)):* ....

Box No. VII INTERNATIONAL SEARCHING AUTHORITY

Choice of International Searching Authority (ISA) *(if two or more International Searching Authorities are competent to carry out the international search, indicate the Authority chosen; the two-letter code may be used)*:

ISA / EP

Request to use results of earlier search; reference to that search *(if an earlier search has been carried out by or requested from the International Searching Authority):*

Date *(day/month/year)* Number Country *(or regional Office)*

Box No. VIII DECLARATIONS

The following declarations are contained in Boxes Nos. VIII (i) to (v) *(mark the applicable check-boxes below and indicate in the right column the number of each type of declaration)*:			Number of declarations
☐ Box No. VIII (i)	Declaration as to the identity of the inventor	:	
☒ Box No. VIII (ii)	Declaration as to the applicant's entitlement, as at the international filing date, to apply for and be granted a patent	:	1
☒ Box No. VIII (iii)	Declaration as to the applicant's entitlement, as at the international filing date, to claim the priority of the earlier application	:	1
☒ Box No. VIII (iv)	Declaration of inventorship (only for the purposes of the designation of the United States of America)	:	2
☐ Box No. VIII (v)	Declaration as to non-prejudicial disclosures or exceptions to lack of novelty	:	

Box No. VIII (ii) DECLARATION: ENTITLEMENT TO APPLY FOR AND BE GRANTED A PATENT

The declaration must conform to the standardized wording provided for in Section 212; see Notes to Boxes Nos. VIII, VIII (i) to (v) (in general) and the specific Notes to Box No. VIII (ii). If this Box is not used, this sheet should not be included in the request.

Declaration as to the applicant's entitlement, as at the international filing date, to apply for and be granted a patent (Rules 4.17(ii) and 51*bis*.1(a)(ii)), in a case where the declaration under Rule 4.17(iv) is not appropriate:

In relation to this international application, BP Exploration Operating Company Limited is entitled to apply for and be granted a patent by virtue of the following :

BP Exploration Operating Company Limited is entitled as employer of the inventors ASTON, Mark Shelton and McLEAN, Michael Richard

This declaration is made for the purposes of all designations (except the designation of the United States of America).

In relation to this international application, BP Corporation North America Inc is entitled to apply for and be granted a patent by virtue of the following :

BP Corporation North America Inc is entitled as employer of the inventor ALBERTY, Mark William

This declaration is made for the purposes of all designations (except the designation of the United States of America),

☐ This declaration is continued on the following sheet, "Continuation of Box No. VIII (ii)".

Box No. VIII (iii) DECLARATION: ENTITLEMENT TO CLAIM PRIORITY

The declaration must conform to the standardized wording provided for in Section 213; see Notes to Boxes Nos. VIII, VIII (i) to (v) (in general) and the specific Notes to Box No. VIII (iii). If this Box is not used, this sheet should not be included in the request.

Declaration as to the applicant's entitlement, as at the international filing date, to claim the priority of the earlier application specified below, where the applicant is not the applicant who filed the earlier application or where the applicant's name has changed since the filing of the earlier application (Rules 4.17(iii) and 51*bis*.1(a)(iii)):

In relation to this international application, BP Exploration Operating Company Limited and BP Corporation North America Inc are entitled to claim priority of earlier application no. US 60/489,917 dated 25th July 2003 by virtue of the following :

an assignment from Mark William ALBERTY, Mark Shelton ASTON and Michael Richard McLEAN dated 25th July 2003

This declaration is made for the purposes of all designations.

☐ **This declaration is continued on the following sheet, "Continuation of Box No. VIII (iii)".**

Box No. VIII (iv) DECLARATION: INVENTORSHIP (only for the purposes of the designation of the United States of America)

The declaration must conform to the following standardized wording provided for in Section 214; see Notes to Boxes Nos. VIII, VIII (i) to (v) (in general) and the specific Notes to Box No. VIII (iv). If this Box is not used, this sheet should not be included in the request.

Declaration of Inventorship (Rules 4.17(iv) and 51*bis*.1(a)(iv))
for the purposes of the designation of the United States of America:

I hereby declare that I believe I am the original, first and sole (if only one inventor is listed below) or joint (if more than one inventor is listed below) inventor of the subject matter which is claimed and for which a patent is sought.

This declaration is directed to the international application of which it forms a part (if filing declaration with application).

This declaration is directed to international application No. PCT/..... (if furnishing declaration pursuant to Rule 26*ter*).

I hereby declare that my residence, mailing address, and citizenship are as stated next to my name.

I hereby state that I have reviewed and understand the contents of the above-identified international application, including the claims of said application. I have identified in the request of said application, in compliance with PCT Rule 4.10, any claim to foreign priority, and I have identified below, under the heading "Prior Applications," by application number, country or Member of the World Trade Organization, day, month and year of filing, any application for a patent or inventor's certificate filed in a country other than the United States of America, including any PCT international application designating at least one country other than the United States of America, having a filing date before that of the application on which foreign priority is claimed.

Prior Applications: .....

.....

I hereby acknowledge the duty to disclose information that is known by me to be material to patentability as defined by 37 C.F.R. § 1.56, including for continuation-in-part applications, material information which became available between the filing date of the prior application and the PCT international filing date of the continuation-in-part application.

I hereby declare that all statements made herein of my own knowledge are true and that all statements made on information and belief are believed to be true; and further that these statements were made with the knowledge that willful false statements and the like so made are punishable by fine or imprisonment, or both, under Section 1001 of Title 18 of the United States Code and that such willful false statements may jeopardize the validity of the application or any patent issued thereon.

Name: ALBERTY, Mark William

Residence: Houston, USA
(city and either US state, if applicable, or country)

Mailing Address: 2918 Rosemary Park Lane, Houston, Texas 77082, USA

.....

Citizenship: American

Inventor's Signature: Mark W Alberty
(if not contained in the request, or if declaration is corrected or added under Rule 26*ter* after the filing of the international application. The signature must be that of the inventor, not that of the agent)

Date: 28 July 2004
(of signature which is not contained in the request, or of the declaration that is corrected or added under Rule 26*ter* after the filing of the international application)

Name: Mark Shelton ASTON

Residence: Teddington, UK
(city and either US state, if applicable, or country)

Mailing Address: 35 Fairfax Road, Teddington, Middlesex, TW11 9DJ, UK

.....

Citizenship: British

Inventor's Signature: .....
(if not contained in the request, or if declaration is corrected or added under Rule 26*ter* after the filing of the international application. The signature must be that of the inventor, not that of the agent)

Date: .....
(of signature which is not contained in the request, or of the declaration that is corrected or added under Rule 26*ter* after the filing of the international application)

☒ This declaration is continued on the following sheet, "Continuation of Box No. VIII (iv)".

Box No. VIII (iv) DECLARATION: INVENTORSHIP (only for the purposes of the designation of the United States of America)

The declaration must conform to the following standardized wording provided for in Section 214; see Notes to Boxes Nos. VIII, VIII (i) to (v) (in general) and the specific Notes to Box No. VIII (iv). If this Box is not used, this sheet should not be included in the request.

Declaration of inventorship (Rules 4.17(iv) and 51*bis*.1(a)(iv)) for the purposes of the designation of the United States of America:

I hereby declare that I believe I am the original, first and sole (if only one inventor is listed below) or joint (if more than one inventor is listed below) inventor of the subject matter which is claimed and for which a patent is sought.

This declaration is directed to the international application of which it forms a part (if filing declaration with application).

This declaration is directed to international application No. PCT/..... (if furnishing declaration pursuant to Rule 26*ter*).

I hereby declare that my residence, mailing address, and citizenship are as stated next to my name.

I hereby state that I have reviewed and understand the contents of the above-identified international application, including the claims of said application. I have identified in the request of said application, in compliance with PCT Rule 4.10, any claim to foreign priority, and I have identified below, under the heading "Prior Applications," by application number, country or Member of the World Trade Organization, day, month and year of filing, any application for a patent or inventor's certificate filed in a country other than the United States of America, including any PCT international application designating at least one country other than the United States of America, having a filing date before that of the application on which foreign priority is claimed.

Prior Applications: .....

.....

I hereby acknowledge the duty to disclose information that is known by me to be material to patentability as defined by 37 C.F.R. § 1.56, including for continuation-in-part applications, material information which became available between the filing date of the prior application and the PCT international filing date of the continuation-in-part application.

I hereby declare that all statements made herein of my own knowledge are true and that all statements made on information and belief are believed to be true; and further that these statements were made with the knowledge that willful false statements and the like so made are punishable by fine or imprisonment, or both, under Section 1001 of Title 18 of the United States Code and that such willful false statements may jeopardize the validity of the application or any patent issued thereon.

Name: ALBERTY, Mark William

Residence: Houston, USA
(city and either US state, if applicable, or country)

Mailing Address: 2918 Rosemary Park Lane, Houston, Texas 77082, USA

.....

Citizenship: American

Inventor's Signature: .....
(if not contained in the request, or if declaration is corrected or added under Rule 26*ter* after the filing of the international application. The signature must be that of the inventor, not that of the agent)

Date: .....
(of signature which is not contained in the request, or of the declaration that is corrected or added under Rule 26*ter* after the filing of the international application)

Name: Mark Shelton ASTON

Residence: Teddington, UK
(city and either US state, if applicable, or country)

Mailing Address: 35 Fairfax Road, Teddington, Middlesex, TW11 9DJ, UK

.....

Citizenship: British

Inventor's Signature: M-S-Aston
(if not contained in the request, or if declaration is corrected or added under Rule 26*ter* after the filing of the international application. The signature must be that of the inventor, not that of the agent)

Date: 13/8/04
(of signature which is not contained in the request, or of the declaration that is corrected or added under Rule 26*ter* after the filing of the international application)

☒ This declaration is continued on the following sheet, "Continuation of Box No. VIII (iv)".

Continuation of Box No. VIII (i) to (v) DECLARATION

If the space is insufficient in any of Boxes Nos. VIII (i) to (v) to furnish all the information, including in the case where more than two inventors are to be named in Box No. VIII (iv), in such case, write "Continuation of Box No. VIII ..." (indicate the item number of the Box) and furnish the information in the same manner as required for the purposes of the Box in which the space was insufficient. If additional space is needed in respect of two or more declarations, a separate continuation box must be used for each such declaration. If this Box is not used, this sheet should not be included in the request.

Name : McLEAN, Michael Richard
Residence : Staines, UK
Mailing Address : 8 Riverfield Road, Staines, Middlesex, TW18 2EE, UK
Citizenship : British

Signature _____ Date : 8th August 2004

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PCT

POWER OF ATTORNEY

(for an international application filed under the Patent Cooperation Treaty)

(PCT Rule 90.4)

The undersigned applicant(s) *(Names should be indicated as they appear in the request)*:

ALBERTY, Mark William
ASTON, Mark Shelton
McLEAN, Michael Richard

hereby appoints (appoint) the following person as: ☒ agent ☐ common representative

Name and address
(Family name followed by given name; for a legal entity, full official designation. The address must include postal code and name of country.)

COLLINS, Frances Mary, and
PREECE, Michael, HYMERS, Ronald Robson and BARLOW, Michael Thomas as Additional Agents
all professional representatives of BP International Limited, Patents & Agreements, Chertsey Road, Sunbury on Thames, Middlesex, TW16 7LN, United Kingdom

to represent the undersigned before

☒ all the competent International Authorities
☐ the International Searching Authority only
☐ the International Preliminary Examining Authority only

in connection with the international application identified below:

Title of the invention: Drilling Method

Applicant's or agent's file reference: 10061

International application number (if already available):

filed with the following Office GB as receiving Office
and to make or receive payments on behalf of the undersigned.

Signature of the applicant(s) *(where there are several applicants, each of them must sign; next to each signature, indicate the name of the person signing and the capacity in which the person signs, if such capacity is not obvious from reading the request or this power)*:

Mark W. Alberty 28.7.04
ALBERTY, Mark William

ASTON, Mark Shelton

McLEAN, Michael Richard

Date:

Form PCT/Model of power of attorney (for a given international application) (July 1992)

PCT

POWER OF ATTORNEY

(for an international application filed under the Patent Cooperation Treaty)

(PCT Rule 90.4)

The undersigned applicant(s) *(Names should be indicated as they appear in the request)*:

ALBERTY, Mark William
ASTON, Mark Shelton
McLEAN, Michael Richard

hereby appoints (appoint) the following person as: ☒ agent ☐ common representative

Name and address
(Family name followed by given name; for a legal entity, full official designation. The address must include postal code and name of country.)

COLLINS, Frances Mary, and
PREECE, Michael, HYMERS, Ronald Robson and BARLOW, Michael Thomas as Additional Agents
all professional representatives of BP International Limited, Patents & Agreements, Chertsey Road, Sunbury on Thames, Middlesex, TW16 7LN, United Kingdom

to represent the undersigned before

☒ all the competent International Authorities
☐ the International Searching Authority only
☐ the International Preliminary Examining Authority only

in connection with the international application identified below:

Title of the invention: Drilling Method

Applicant's or agent's file reference: 10061

International application number (if already available):

filed with the following Office GB as receiving Office
and to make or receive payments on behalf of the undersigned.

Signature of the applicant(s) *(where there are several applicants, each of them must sign; next to each signature, indicate the name of the person signing and the capacity in which the person signs, if such capacity is not obvious from reading the request or this power)*:

ALBERTY, Mark William

M.S. Ash 13.08.04
ASTON, Mark Shelton

11.08.04
McLEAN, Michael Richard

Date:

Form PCT/Model of power of attorney (for a given international application) (July 1992)

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Box No. IX CHECK LIST; LANGUAGE OF FILING

This international application contains:

(a) in paper form, the following number of sheets:

request (including declaration sheets)	:	8
description (excluding sequence listing and/or tables related thereto)	:	15
claims	:	3
abstract	:	1
drawings	:	1
Sub-total number of sheets	:	28
sequence listing	:	
tables related thereto	:	
(for both, actual number of sheets if filed in paper form, whether or not also filed in computer readable form; see (c) below)		
Total number of sheets	:	28

(b) ☐ only in computer readable form (Section 801(a)(i))
- (i) ☐ sequence listing
- (ii) ☐ tables related thereto

(c) ☐ also in computer readable form (Section 801(a)(ii))
- (i) ☐ sequence listing
- (ii) ☐ tables related thereto

Type and number of carriers (diskette, CD-ROM, CD-R or other) on which are contained the
- ☐ sequence listing: .....
- ☐ tables related thereto: .....

(additional copies to be indicated under items 9(ii) and/or 10(ii), in right column)

This international application is accompanied by the following item(s) *(mark the applicable check-boxes below and indicate in right column the number of each item)*:

		Number of items
1. ☒ fee calculation sheet	:	1
2. ☒ original separate power of attorney	:	1
3. ☐ original general power of attorney	:	
4. ☒ copy of general power of attorney; reference number, if any:	:	2
5. ☐ statement explaining lack of signature	:	
6. ☐ priority document(s) identified in Box No. VI as item(s):	:	
7. ☐ translation of international application into *(language)*:	:	
8. ☐ separate indications concerning deposited microorganism or other biological material	:	
9. ☐ sequence listing in computer readable form *(indicate type and number of carriers)*		
(i) ☐ copy submitted for the purposes of international search under Rule 13*ter* only (and not as part of the international application)	:	
(ii) ☐ *(only where check-box (b)(i) or (c)(i) is marked in left column)* additional copies including, where applicable, the copy for the purposes of international search under Rule 13*ter*	:	
(iii) ☐ together with relevant statement as to the identity of the copy or copies with the sequence listing mentioned in left column	:	
10. ☐ tables in computer readable form related to sequence listing *(indicate type and number of carriers)*		
(i) ☐ copy submitted for the purposes of international search under Section 802(b-*quater*) only (and not as part of the international application)	:	
(ii) ☐ *(only where check-box (b)(ii) or (c)(ii) is marked in left column)* additional copies including, where applicable, the copy for the purposes of international search under Section 802(b-*quater*)	:	
(iii) ☐ together with relevant statement as to the identity of the copy or copies with the tables mentioned in left column	:	
11. ☐ other *(specify)*:	:	

Figure of the drawings which should accompany the abstract: One

Language of filing of the international application: English

Box No. X SIGNATURE OF APPLICANT, AGENT OR COMMON REPRESENTATIVE

Next to each signature, indicate the name of the person signing and the capacity in which the person signs (if such capacity is not obvious from reading the request).

M Pre

PREECE, Michael
Additional Authorised Agent

For receiving Office use only

1. Date of actual receipt of the purported international application:

2. Drawings:
- ☐ received:
- ☐ not received:

3. Corrected date of actual receipt due to later but timely received papers or drawings completing the purported international application:

4. Date of timely receipt of the required corrections under PCT Article 11(2):

5. International Searching Authority (if two or more are competent): ISA /

6. ☐ Transmittal of search copy delayed until search fee is paid

For International Bureau use only

Date of receipt of the record copy by the International Bureau:

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This sheet is not part of and does not count as a sheet of the international application.

PCT

FEE CALCULATION SHEET

Annex to the Request

For receiving Office use only

International Application No.

Date stamp of the receiving Office

Applicant's or agent's file reference: 10061

Applicant: BP EXPLORATION OPERATING COMPANY LIMITED et al

CALCULATION OF PRESCRIBED FEES

1. TRANSMITTAL FEE . . . . . £55.00 [T]

2. SEARCH FEE . . . . . £1078.00 [S]

International search to be carried out by _____

(If two or more International Searching Authorities are competent to carry out the international search, indicate the name of the Authority which is chosen to carry out the international search.)

3. INTERNATIONAL FILING FEE

Where items (b) and/or (c) of Box No. IX apply, enter Sub-total number of sheets
Where items (b) and (c) of Box No. IX do not apply, enter Total number of sheets } 28

[i1] first 30 sheets . . . . . £628.00 [i1]

[i2] _____ (number of sheets in excess of 30) x £7.00 (fee per sheet) = _____ [i2]

[i3] additional component (only if sequence listing and/or tables related thereto are filed in computer readable form under Section 801(a)(i), or both in that form and on paper, under Section 801(a)(ii)):

400 x _____ (fee per sheet) = _____ [i3]

Add amounts entered at i1, i2 and i3 and enter total at I . . . . £628.00 [I]

(Applicants from certain States are entitled to a reduction of 75% of the international filing fee. Where the applicant is (or all applicants are) so entitled, the total to be entered at I is 25% of the international filing fee.)

4. FEE FOR PRIORITY DOCUMENT *(If applicable)* . . . . . [P]

5. TOTAL FEES PAYABLE . . . . . £1761.00 TOTAL

Add amounts entered at T, S, I and P, and enter total in the TOTAL box

MODE OF PAYMENT

- ☐ authorization to charge deposit account (see below)
- ☐ postal money order
- ☐ cash
- ☐ coupons
- ☒ cheque
- ☐ bank draft
- ☐ revenue stamps
- ☐ other *(specify)*:

AUTHORIZATION TO CHARGE (OR CREDIT) DEPOSIT ACCOUNT

(This mode of payment may not be available at all receiving Offices)

Receiving Office: RO/ _____

Deposit Account No.: _____

Date: _____

Name: _____

Signature: _____

- ☐ Authorization to charge the total fees indicated above.
- ☐ *(This check-box may be marked only if the conditions for deposit accounts of the receiving Office so permit)* Authorization to charge any deficiency or credit any overpayment in the total fees indicated above.
- ☐ Authorization to charge the fee for priority document.

PCT

POWER OF ATTORNEY

(for an international application filed under the Patent Cooperation Treaty)

(PCT Rule 90.4)

The undersigned applicant(s) *(Names should be indicated as they appear in the request)*:

BP EXPLORATION OPERATING COMPANY LIMITED
BP CORPORATION NORTH AMERICA INC

hereby appoints (appoint) the following person as: ☒ agent ☐ common representative

Name and address
(Family name followed by given name; for a legal entity, full official designation. The address must include postal code and name of country.)

COLLINS, Frances Mary, and
PREECE, Michael, HYMERS, Ronald Robson and BARLOW, Michael Thomas as Additional Agents
all professional representatives of BP International Limited, Patents & Agreements, Chertsey Road, Sunbury on Thames, Middlesex, TW16 7LN, United Kingdom

to represent the undersigned before

☒ all the competent International Authorities
☐ the International Searching Authority only
☐ the International Preliminary Examining Authority only

in connection with the international application identified below:

Title of the invention: Drilling Method

Applicant's or agent's file reference: 10061

International application number (if already available):

filed with the following Office GB as receiving Office
and to make or receive payments on behalf of the undersigned.

Signature of the applicant(s) *(where there are several applicants, each of them must sign; next to each signature, indicate the name of the person signing and the capacity in which the person signs, if such capacity is not obvious from reading the request or this power)*:

HYMERS, Ronald Robson
By Power of Attorney
for BP Exploration Operating Company Limited

PREECE, Michael
By Power of Attorney
for BP Corporation North America Inc

Date: 19th July 2004

Form PCT/Model of power of attorney (for a given international application) (July 1992)

1 of 1

Fee Sheet (FS2)
(Non-Deposit Account Holders)

The Patent Office

Account No. CO3022

Name BP INTERNATIONAL LIMITED
Address PATENTS & AGREEMENTS
CHERTSEY ROAD
SUNBURY-ON-THAMES, MIDDLESEX
TW16 7LN, ENGLAND

Contact Christine Gravenell

Tel No. 01932 763343

Fax No. 01932 762388

E-Mail Address

Payment Method

a) **Bank transfer of** (see Note 2) £_____
on (date) _____
OR

b) **Cheque enclosed for** (see Note 3) £ £1761.00

Fee Sheet Reference (see Note 4) 10061

Date 19/07/04

	Form type (P/TM/D PCT/EP) (see Note 5)	Form Number	Name, Number or Other Identifier	Amount of Fee £
1	PCT	RO/101	PCT Request for BP Case No. 10061	1761.00
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Page	of	pages	Total	£1761.00

The demand must be filed directly with the competent International Preliminary Examining Authority or, if two or more Authorities are competent, with the one chosen by the applicant. The full name or two-letter code of that Authority may be indicated by the applicant on the line below:

IPEA/ _____

PCT

CHAPTER II

DEMAND

under Article 31 of the Patent Cooperation Treaty:
The undersigned requests that the international application specified below be the subject of international preliminary examination according to the Patent Cooperation Treaty.

For International Preliminary Examining Authority use only	
Identification of IPEA	Date of receipt of DEMAND

Box No. I IDENTIFICATION OF THE INTERNATIONAL APPLICATION

Applicant's or agent's file reference: 10061

International application No.	International filing date *(day/month/year)*	(Earliest) Priority date *(day/month/year)*
PCT/GB2004/003154	19/07/2004	25/07/2003

Title of invention: Drilling Method

Box No. II APPLICANT(S)

Name and address: *(Family name followed by given name; for a legal entity, full official designation. The address must include postal code and name of country.)*

BP EXPLORATION OPERATING COMPANY LIMITED
Chertsey Road
Sunbury on Thames
Middlesex, TW16 7BP
United Kingdom

Telephone No.:
Facsimile No.:
Teleprinter No.:
Applicant's registration No. with the Office:

State *(that is, country)* of nationality: GB
State *(that is, country)* of residence: GB

Name and address: *(Family name followed by given name; for a legal entity, full official designation. The address must include postal code and name of country.)*

BP CORPORATION NORTH AMERICA INC
4101 Winfield Road
Warrenville
Illinois 60555
United States of America

State *(that is, country)* of nationality: US
State *(that is, country)* of residence: US

Name and address: *(Family name followed by given name; for a legal entity, full official designation. The address must include postal code and name of country.)*

ALBERTY, Mark William
2918 Rosemary Park Lane
Houston
Texas 77082
United States of America

State *(that is, country)* of nationality: US
State *(that is, country)* of residence: US

☒ Further applicants are indicated on a continuation sheet.

Sheet No. 2

International application No.
PCT/GB2004/003154

Continuation of Box No. II APPLICANT(S)

If none of the following sub-boxes is used, this sheet should not be included in the demand.

Name and address: *(Family name followed by given name; for a legal entity, full official designation. The address must include postal code and name of country.)*

ASTON, Mark Shelton
35 Fairfax Road
Teddington
Middlesex TW11 9DJ
United Kingdom

State *(that is, country)* of nationality:	State *(that is, country)* of residence:
GB	GB

Name and address: *(Family name followed by given name; for a legal entity, full official designation. The address must include postal code and name of country.)*

McLEAN, Michael Richard
8 Riverfield Road
Staines
Middlesex TW18 2EE
United Kingdom

State *(that is, country)* of nationality:	State *(that is, country)* of residence:
GB	GB

Name and address: *(Family name followed by given name; for a legal entity, full official designation. The address must include postal code and name of country.)*

State *(that is, country)* of nationality:	State *(that is, country)* of residence:

Name and address: *(Family name followed by given name; for a legal entity, full official designation. The address must include postal code and name of country.)*

State *(that is, country)* of nationality:	State *(that is, country)* of residence:

☐ Further applicants are indicated on another continuation sheet.

Sheet No. 3

International application No.
PCT/GB2004/003154

Box No. III AGENT OR COMMON REPRESENTATIVE; OR ADDRESS FOR CORRESPONDENCE

The following person is ☒ agent ☐ common representative

and ☒ has been appointed earlier and represents the applicant(s) also for international preliminary examination.

☐ is hereby appointed and any earlier appointment of (an) agent(s)/common representative is hereby revoked.

☐ is hereby appointed, specifically for the procedure before the International Preliminary Examining Authority, in addition to the agent(s)/common representative appointed earlier.

Name and address: *(Family name followed by given name; for a legal entity, full official designation. The address must include postal code and name of country.)*

COLLINS, Frances Mary
BP International Limited
Patents & Agreements
Chertsey Road, Sunbury on Thames,
Middlesex, TW16 7LN, United Kingdom

Telephone No.
01932 763205

Facsimile No.
01932 762388

Teleprinter No.

Agent's registration No. with the Office

☐ **Address for correspondence:** Mark this check-box where no agent or common representative is/has been appointed and the space above is used instead to indicate a special address to which correspondence should be sent.

Box No. IV BASIS FOR INTERNATIONAL PRELIMINARY EXAMINATION

Statement concerning amendments:*

1. The applicant wishes the international preliminary examination to start on the basis of:

☒ the international application as originally filed

the description ☒ as originally filed
☐ as amended under Article 34

the claims ☒ as originally filed
☐ as amended under Article 19 (together with any accompanying statement)
☐ as amended under Article 34

the drawings ☒ as originally filed
☐ as amended under Article 34

2. ☐ The applicant wishes any amendment to the claims under Article 19 to be considered as reversed.

3. ☐ The applicant wishes the start of the international preliminary examination to be postponed until the expiration of the applicable time limit under Rule 69.1(d).

4. ☐ The applicant expressly wishes the international preliminary examination to start earlier than at the expiration of the applicable time limit under Rule *54bis*.1(a).

* Where no check-box is marked, international preliminary examination will start on the basis of the international application as originally filed or, where a copy of amendments to the claims under Article 19 and/or amendments of the international application under Article 34 are received by the International Preliminary Examining Authority before it has begun to draw up a written opinion or the international preliminary examination report, as so amended.

Language for the purposes of international preliminary examination: English

☒ which is the language in which the international application was filed.

☐ which is the language of a translation furnished for the purposes of international search.

☐ which is the language of publication of the international application.

☐ which is the language of the translation (to be) furnished for the purposes of international preliminary examination.

Box No. V ELECTION OF STATES

The filing of this demand constitutes the election of all Contracting States which are designated and are bound by Chapter II of the PCT.

International application No.
PCT/GB2004/003154

Box No. VI CHECK LIST

The demand is accompanied by the following elements, in the language referred to in Box No. IV, for the purposes of international preliminary examination:

			For International Preliminary Examining Authority use only: received	not received
1. translation of international application	:	sheets	☐	☐
2. amendments under Article 34	:	sheets	☐	☐
3. copy (or, where required, translation) of amendments under Article 19	:	sheets	☐	☐
4. copy (or, where required, translation) of statement under Article 19	:	sheets	☐	☐
5. letter	:	sheets	☐	☐
6. other *(specify)*	:	sheets	☐	☐

The demand is also accompanied by the item(s) marked below:

1. ☒ fee calculation sheet
2. ☐ original separate power of attorney
3. ☐ original general power of attorney
4. ☐ copy of general power of attorney; reference number, if any:
5. ☐ statement explaining lack of signature
6. ☐ sequence listing in computer readable form
7. ☐ tables in computer readable form related to a sequence listing
8. ☐ other *(specify)*:

Box No. VII SIGNATURE OF APPLICANT, AGENT OR COMMON REPRESENTATIVE

Next to each signature, indicate the name of the person signing and the capacity in which the person signs (if such capacity is not obvious from reading the demand).

RRH

HYMERS, Ronald Robson
Additional Authorised Agent

For International Preliminary Examining Authority use only

1. Date of actual receipt of DEMAND:

2. Adjusted date of receipt of demand due to CORRECTIONS under Rule 60.1(b):

3. ☐ The date of receipt of the demand is AFTER the expiration of 19 months from the priority date and item 4 or 5, below, does not apply.
   ☐ The applicant has been informed accordingly.
4. ☐ The date of receipt of the demand is WITHIN the time limit of 19 months from the priority date as extended by virtue of Rule 80.5.
5. ☐ Although the date of receipt of the demand is after the expiration of 19 months from the priority date, the delay in arrival is EXCUSED pursuant to Rule 82.
6. ☐ The date of receipt of the demand is AFTER the expiration of the time limit under Rule 54*bis*.1(a) and item 7 or 8, below, does not apply.
7. ☐ The date of receipt of the demand is WITHIN the time limit under Rule 54*bis*.1(a) as extended by virtue of Rule 80.5.
8. ☐ Although the date of receipt of the demand is after the expiration of the time limit under Rule 54*bis*.1(a), the delay in arrival is EXCUSED pursuant to Rule 82.

For International Bureau use only

Demand received from IPEA on:

CHAPTER II

PCT

FEE CALCULATION SHEET

Annex to the Demand

International application No. PCT/GB2004/003154	For International Preliminary Examining Authority use only
Applicant's or agent's file reference 10061	Date stamp of the IPEA

Applicant

BP Exploration Operating Company Limited

CALCULATION OF PRESCRIBED FEES

1. Preliminary examination fee	1530.00 P	
2. Handling fee *(Applicants from certain States are entitled to a reduction of 75% of the handling fee. Where the applicant is (or all applicants are) so entitled, the amount to be entered at H is 25% of the handling fee.)*	129.00 H	
3. Total of prescribed fees Add the amounts entered at P and H and enter total in the TOTAL box	1659.00 TOTAL	

MODE OF PAYMENT

☒ authorization to charge deposit account with the IPEA (see below)	☐ cash
☐ cheque	☐ revenue stamps
☐ postal money order	☐ coupons
☐ bank draft	☐ other *(specify)*:

AUTHORIZATION TO CHARGE (OR CREDIT) DEPOSIT ACCOUNT

(This mode of payment may not be available at all IPEAs)

IPEA/ EP

☐ Authorization to charge the total fees indicated above.

☐ *(This check-box may be marked only if the conditions for deposit accounts of the IPEA so permit)* Authorization to charge any deficiency or credit any overpayment in the total fees indicated above.

Deposit Account No.: 28050129

Date: 18th February 2005

Name: Christine Gravenell

Signature: Gravenell

See Notes to the fee calculation sheet

PATENT CO PERATION TREATY

From the
INTERNATIONAL PRELIMINARY EXAMINING AUTHORITY

PCT

To:
COLLINS, Frances Mary
BP INTERNATIONAL LIMITED
Patents & Agreements
Chertsey Road
Sunbury-on-Thames
Middlesex TW16 7LN
GRANDE BRETAGNE

NOTIFICATION OF RECEIPT OF DEMAND BY COMPETENT INTERNATIONAL PRELIMINARY EXAMINING AUTHORITY

(PCT Rules 59.3(e) and 61.1(b), first sentence and Administrative Instructions, Section 601(a))

Date of mailing *(day/month/year)*	02-03-2005
Applicant's or agent's file reference: 10061	IMPORTANT NOTIFICATION

International application No.	International filing date *(day/month/year)*	Priority date *(day/month/year)*
PCT/GB2004/003154	19/07/2004	25/07/2003

Applicant

BP EXPLORATION OPERATING COMPANY LIMITED et al.

1. The applicant is hereby notified that this International Preliminary Examining Authority considers the following date as the date of receipt of the demand for international preliminary examination of the international application:

21/02/2005

2. This date of receipt is:

- [x] the actual date of receipt of the demand by this Authority (Rule 61.1(d)).
- [ ] the actual date of receipt of the demand on behalf of the [illegible] (Rule 59.3(e)).
- [ ] the date on which this Authority has, in response to [illegible] to correct defects in the demand (Form PCT/IPEA/404), received the required corrections.

3. [ ] **ATTENTION:** That date of receipt is after the expiration of 19 months from the priority date. Consequently, in respect of some Offices, the demand does not have the effect of postponing the entry into the national phase until 30 months from the priority date (or later in some Offices) (Article 39(1)) and the acts for entry into the national phase must therefore be performed within 20 months from the priority date (or later in some Offices). However, in respect of some other Offices, the time limit of 30 months (or later) may nevertheless apply. See the Annex to Form PCT/IB/301 and, for details about the applicable time limits, Office by Office, see the *PCT Applicant's Guide*, Volume II, National Chapters and the WIPO Internet site.

[ ] *(If applicable)* This notification confirms the information given by telephone, facsimile transmission or in person on:

4. Only where paragraph 3 applies, a copy of this notification has been sent to the International Bureau.

Name and mailing address of the IPEA/	Authorized officer
European Patent Office D-80298 Munich Tel. (+49-89) 2399-0, Tx: 523656 epmu d Fax: (+49-89) 2399-4465	ALMALE MURILLO J Tel. (+49-89) 2399-8059 (25/02/2005)

Form PCT/IPEA/402 (April 2002; reprint January 2004)

PATENT COOPERATION TREATY

From the INTERNATIONAL BUREAU

PCT

INFORMATION CONCERNING ELECTED OFFICES NOTIFIED OF THEIR ELECTION

(PCT Article 31(7) and Rule 61.3)

To:

COLLINS, Frances, Mary
BP International Limited
Patents & Agreements
Chertsey Road
Sunbury on Thames
Middlesex TW16 7LN
ROYAUME-UNI

19 APR 2005

Date of mailing *(day/month/year)*	
14 April 2005 (14.04.2005)	
Applicant's or agent's file reference	**IMPORTANT INFORMATION**
10061	

International application No.	International filing date *(day/month/year)*	Priority date *(day/month/year)*
PCT/GB2004/003154	19 July 2004 (19.07.2004)	25 July 2003 (25.07.2003)

Applicant

BP EXPLORATION OPERATING COMPANY LIMITED et al

1. The applicant is hereby informed that the International Bureau has, according to Article 31(7), notified each of the following Offices of its election:

   EP: AT, BE, BG, CH, CY, CZ, DE, DK, EE, ES, FI, FR, GB, GR, HU, IE, IT, LU, MC, NL, PL, PT, RO, SE, SI, SK, TR

   National: BG, CA, CN, CZ, DE, JP, KP, KR, MN, NO, PL, RO, RU, SK, US

2. The following Offices have waived the requirement for the notification of their election; the notification will be sent to them by the International Bureau only upon their request:

   AP: BW, GH, GM, KE, LS, MW, MZ, NA, SD, SL, SZ, TZ, UG, ZM, ZW
   EA: AM, AZ, BY, KG, KZ, MD, RU, TJ, TM
   OA: BF, BJ, CF, CG, CI, CM, GA, GN, GQ, GW, ML, MR, NE, SN, TD, TG
   National: AE, AG, AL, AM, AT, AU, AZ, BA, BB, BR, BW, BY, BZ, CH, CO, CR, CU, DK, DM, DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, HR, HU, ID, IL, IN, IS, KE, KG, KZ, LC, LK, LR, LS, LT, LU, LV, MA, MD, MG, MK, MW, MX, MZ, NA, NI, NZ, OM, PG, PH, PT, SC, SD, SE, SG, SL, SY, TJ, TM, TN, TR, TT, TZ, UA, UG, UZ, VC, VN, YU, ZA, ZM, ZW

3. Since the election(s) was (were) made before the expiration of 19 months from the priority date, the applicant is reminded that he must enter the "national phase" before the expiration of 30 months from the priority date before each of the Offices listed above. This must be done by paying the national fee(s) and furnishing, if prescribed, a translation of the international application (Article 39(1)(a)), as well as, where applicable, by furnishing a translation of any annexes of the international preliminary report on patentability (Chapter II of the Patent Cooperation Treaty) (Article 36(3)(b) and Rule 74.1).

   Some Offices have fixed time limits expiring later than the above-mentioned time limit. See the Annex to Form PCT/IB/301 and, for details about the applicable time limits, Office by Office, see the *PCT Applicant's Guide*, Volume II, National Chapters, the *PCT Newsletter* and the WIPO Internet site, updated regularly.

The International Bureau of WIPO
34, chemin des Colombettes
1211 Geneva 20, Switzerland

Facsimile No.+41 22 740 14 35

Authorized officer

Nora Lindner

Facsimile No.+41 22 338 89 65

PATENT COOPERATION TREATY

From the
INTERNATIONAL PRELIMINARY EXAMINING AUTHORITY

To:

COLLINS, Frances Mary
BP INTERNATIONAL LIMITED
Patents & Agreements
Chertsey Road
Sunbury-on-Thames
Middlesex TW16 7LN
GRANDE BRETAGNE

Received on P. C.T.
- 7 JUN 2005

PCT

NOTIFICATION OF TRANSMITTAL OF THE INTERNATIONAL PRELIMINARY REPORT ON PATENTABILITY
(PCT Rule 71.1)

Date of mailing *(day/month/year)*	06.06.2005
Applicant's or agent's file reference: 10061	**IMPORTANT NOTIFICATION**

International application No.	International filing date *(day/month/year)*	Priority date *(day/month/year)*
PCT/GB2004/003154	19.07.2004	25.07.2003

Applicant
BP EXPLORATION OPERATING COMPANY LIMITED et al.

1. The applicant is hereby notified that this International Preliminary Examining Authority transmits herewith the international preliminary report on patentability and its annexes, if any, established on the international application.

2. A copy of the report and its annexes, if any, is being transmitted to the International Bureau for communication to all the elected Offices.

3. Where required by any of the elected Offices, the International Bureau will prepare an English translation of the report (but not of any annexes) and will transmit such translation to those Offices.

4. **REMINDER**

   The applicant must enter the national phase before each elected Office by performing certain acts (filing translations and paying national fees) within 30 months from the priority date (or later in some Offices) (Article 39(1)) (see also the reminder sent by the International Bureau with Form PCT/IB/301).

   Where a translation of the international application must be furnished to an elected Office, that translation must contain a translation of any annexes to the international preliminary report on patentability. It is the applicant's responsibility to prepare and furnish such translation directly to each elected Office concerned.

   For further details on the applicable time limits and requirements of the elected Offices, see Volume II of the PCT Applicant's Guide.

   The applicant's attention is drawn to Article 33(5), which provides that the criteria of novelty, inventive step and industrial applicability described in Article 33(2) to (4) merely serve the purposes of international preliminary examination and that "any Contracting State may apply additional or different criteria for the purposes of deciding whether, in that State, the claimed inventions is patentable or not" (see also Article 27(5)). Such additional criteria may relate, for example, to exemptions from patentability, requirements for enabling disclosure, clarity and support for the claims.

Name and mailing address of the international preliminary examining authority:	Authorized Officer
European Patent Office *D-80298 Munich* Tel. +49 89 2399 - 0 Tx: 523656 epmu d Fax: +49 89 2399 - 4465	Ipinazar, P Tel. +49 89 2399-8131

Form PCT/IPEA/416 (January 2004)

CG/R2

PATENT COOPERATION TREATY

From the INTERNATIONAL BUREAU

PCT

NOTIFICATION CONCERNING SUBMISSION OR TRANSMITTAL OF PRIORITY DOCUMENT

(PCT Administrative Instructions, Section 411)

To:

COLLINS, Frances, Mary
BP International Limited
Patents & Agreements
Chertsey Road
Sunbury on Thames
Middlesex TW16 7LN
United Kingdom

Date of mailing (day/month/year) 22 October 2004 (22.10.2004)	
Applicant's or agent's file reference 10061	**IMPORTANT NOTIFICATION**
International application No. PCT/GB2004/003154	International filing date (day/month/year) 19 July 2004 (19.07.2004)
International publication date (day/month/year) Not yet published	Priority date (day/month/year) 25 July 2003 (25.07.2003)
Applicant BP EXPLORATION OPERATING COMPANY LIMITED et al	

1. By means of this Form, which replaces any previously issued notification concerning submission or transmittal of priority documents, the applicant is hereby notified of the date of receipt by the International Bureau of the priority document(s) relating to all earlier application(s) whose priority is claimed. Unless otherwise indicated by the letters "NR", in the right-hand column or by an asterisk appearing next to a date of receipt, the priority document concerned was submitted or transmitted to the International Bureau in compliance with Rule 17.1(a) or (b).

2. (If applicable) The letters "NR" appearing in the right-hand column denote a priority document which, on the date of mailing of this Form, had not yet been received by the International Bureau under Rule 17.1(a) or (b). Where, under Rule 17.1(a), the priority document must be submitted by the applicant to the receiving Office or the International Bureau, but the applicant fails to submit the priority document within the applicable time limit under that Rule, the attention of the applicant is directed to Rule 17.1(c) which provides that no designated Office may disregard the priority claim concerned before giving the applicant an opportunity, upon entry into the national phase, to furnish the priority document within a time limit which is reasonable under the circumstances.

3. (If applicable) An asterisk(*) appearing next to a date of receipt, in the right-hand column, denotes a priority document submitted or transmitted to the International Bureau but not in compliance with Rule 17.1(a) or (b) (the priority document was received after the time limit prescribed in Rule 17.1(a) or the request to prepare and transmit the priority document was submitted to the receiving Office after the applicable time limit under Rule 17.1(b)). Even though the priority document was not furnished in compliance with Rule 17.1(a) or (b), the International Bureau will nevertheless transmit a copy of the document to the designated Offices, for their consideration. In case such a copy is not accepted by the designated Office as priority document, Rule 17.1(c) provides that no designated Office may disregard the priority claim concerned before giving the applicant an opportunity, upon entry into the national phase, to furnish the priority document within a time limit which is reasonable under the circumstances.

Priority date	Priority application No.	Country or regional Office or PCT receiving Office	Date of receipt of priority document
25 July 2003 (25.07.2003)	60/489,917	US	14 Sept 2004 (14.09.2004)

The International Bureau of WIPO
34, chemin des Colombettes
1211 Geneva 20, Switzerland

Facsimile No. (41-22) 338.89.65

Authorized officer

Sylvie SOBEZYNSKI

Telephone No. (41-22) 338 8087

Radicacion 1 [redacted] Folios: 179
Fecha [redacted]: 2002-01-24 17:08:08
Tramite 1 011 PCT-PATENTE 379 FASE NACI 411 PRESENTAC
Dependencia: 2020 DIVISION DE NUEVAS CREACIONES

REQUISITOS NECESARIOS PARA PRESENTACION Y AGILIZACION DE TRAMITE

	USUARIO	RADICADOR
PATENTE DE INVENCIÓN X PCT MODELO DE UTILIDAD	( )	( )
- Indicación de que se solicita la concesión de una patente.	( )	(X)
- Datos de identificación del solicitante o de la persona que se presenta la solicitud.	( )	(X)
- Descripción de la invención.	( )	(X)
- Dibujos de ser estos pertinentes.	( )	(X)
- Comprobante de Pago de las tasas establecidas.		
COMPLETA (X)	INCOMPLETA ( )	( )
DISEÑO INDUSTRIAL ( )		
- Indicación de que se solicita el registro de Diseño Industrial	( )	( )
- Datos de identificación del solicitante o de la persona que presenta	( )	( )
- la solicitud.		
- Representación gráfica o fotográfica del Diseño Industrial o muestra del Material que incorpora el diseño.	( )	( )
Comprobante de pago de las tasas establecidas	( )	( )
COMPLETA ( )	INCOMPLETA ( )	( )
ESQUEMA DE TRAZADO ( )		
- Indicación de que solicita el registro de un Esquema de trazado.	( )	( )
- Datos de identificación del solicitante o de la persona que presenta La solicitud.	( )	( )
Representación gráfica del esquema de trazado	( )	( )
Comprobante de pago de las tasas establecidas.	( )	( )
COMPLETA ( )	INCOMPLETA ( )	( )

Firma Responsable:

Fecha:

176

REPUBLICA DE COLOMBIA
SUPERINTENDENCIA DE INDUSTRIA Y COMERCIO

Bogotá,
2020

Doctor(a)
RODRIGUEZ DILIA MARIA

REFERENCIA	Radicación No.	6 6387
	Solicitud internacional	GB2004/03154
	Fecha inicio fase nacional	27/02/2006
	Trámite	11
	Evento	379
	Actuación	430
	Oficio No.	3971

Como resultado del examen de forma, realizado con fundamento en el artículo 38 de la Decisión 486 de la Comisión de la Comunidad Andina, artículo 27 del Tratado de Cooperación en Materia de Patentes (PCT), regla 51 bis del Reglamento y Circular Única de la Superintendencia de Industria y Comercio, se le comunica que:

1. La solicitud no contiene la copia del documento en que consta la cesión del derecho a la pátente del inventor al solicitante o a su causante. (Art. 26-k) Decisión 486.

2. La solicitud no contiene el poder debidamente otorgado por la sociedad BP CORPORATION NORTH AMERICA INC., con el lleno de los requisitos exigidos por los artículos 63 y subsiguientes del Código de Procedimiento Civil. Adicionalmente, deberá presentar el documento que acredita la existencia y representación legal de la sociedad solicitante.

En cumplimiento de lo dispuesto por el artículo 39 de la Decisión 486, se le requiere para que dentro del término de dos meses siguientes a la fecha de notificación del presente oficio, complete los requisitos anteriormente enunciados. En caso de no dar cumplimiento al presente requerimiento, la solicitud se considerará abandonada y perderá su prelación.

Notifíquese el presente oficio conforme a lo dispuesto en el numeral 5.2, literal e), del capítulo quinto del título primero de la Circular Unica No.10 de 2001.

ALIX CARMENZA CESPEDES DE VERGEL
Jefe de la división de Nuevas Creaciones

El anterior requerimiento fue notificado por fijación en lista de fecha 07 ABR. 2006
adpall