

FORMULARIO ÚNICO DE SOLICITUD DE PATENTE
PCT
ENTRADA EN FASE NACIONAL

1) SOLICITUD DE			
☒ Patente de invención		☐ Patente de Modelo de Utilidad	
☐ Capítulo I		☒ Capítulo II	
2) SOLICITANTE (71)	Nombre Halliburton Energy Services, Inc. Dirección 10200 Bellaire Boulevard Houston Texas 77072-5206 Estados Unidos Nacionalidad o domicilio: Houston, Texas, Estados Unidos Lugar de constitución: Houston, Texas, Estados Unidos		IDENTIFICACIÓN C C ☐ NIT ☐ C.E ☐ OTRO ☐ NÚMERO <u>Cual</u>
	Teléfono Fax E. Mail		
3) REPRESENTANTE O APODERADO	Nombre DILIA MARIA RODRIGUEZ D ALEMAN Dirección Carrera 11 N 93-43 Of 404 Santafé de Bogotá D C Teléfono 6350835 Fax 6350824 E. Mail clarkemodet@clarkemodet.com.co		IDENTIFICACIÓN C C ☒ NIT ☐ C.E ☐ OTRO ☐ NÚMERO 41 654 882 TP 20824 CSJ
4) INVENTOR (ES) (72)	Nombre 1)Tare, Uday Arun, 2.) Mody, Fersheed Khodadad, 3) Mese, Ali I, 4.) Jiao, Di, 5) Hakimuddin, Mustafa. Dirección 1)Apartment #414, 2000 Bay Area Boulevard, Houston, Texas, 77058 USA, 2.) 5511 Dawnridge, Houston, Texas 77036 USA, 3) 10220 Memorial Drive Houston Texas 77024, USA, 4.) 2026 Autumn Fern Drive, Katy, Texas 77450 USA, 5.) 1111 Oak Mesa Court, Houston, Texas 77070 USA Nacionalidad o Domicilio Texas, USA		
5) PCT (86) Solicitud Internacional No PCT/US01/18134 Fecha JUNIO 5 2001 Publicación Internacional No WO 01/94749 A 1 Fecha Dic. 13, 2001			
6) Título (54) <u>METODO EN TIEMPO REAL PARA MANTENER LA ESTABILIDAD DE LA FORMACIÓN Y PARA SUPERVISAR LA INTERACCIÓN DE LA FORMACIÓN DE FLUIDOS</u>			
7) Clasificación Internacional (51) E21B 44/00 49/00, 21/08			
8) PRIORIDAD	33) País de Origen	(32) Fecha	(31) Número de Solicitud
	Estados Unidos	Junio 8, 2000	60/209 488
SI ☒ NO ☐			
9) Comprobante de pago N° 02-01,447 Fecha: Diciembre 4, 2002			
Instrucciones para el diligenciamiento del presente formulario Ver reverso de esta pagina			

020 0194749



Industria y Comercio
SUPERINTENDENCIA

SUPERINDUSTRIA Y COMERCIO
Radicación : 02110570 00000000 Folios: 277
Fecha (RAD): 2002-12-06 09:19:46
Trámite : 011 PCT-PATENT 379 FASE NACT 411 PRESENTAC
Dependencia: 2020 DIVISION DE NUEVAS CREACIONES

NIT : 800176089-2

RECIBO OFICIAL DE CAJA : 02 - 81.447
FECHA : DICIEMBRE 4 DE 2002

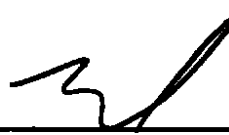
***** CONSIGNACION *****

DEPOSITANTE	TIPO PAGO	BANCO	CUENTA	No. PAGO	FECHA PBO	Vr. PAGO
CLARKE KODET Y CO. COLOMBIA	CONSIGNACION	BANCO POPULAR	050-00110-6	9023675	04/12/2002	2,401,000.00

***** CONCEPTO *****

CANT.	RENTISTICO	CONCEPTO	TOTAL CONCEPTO
1	50005-01-01 SOLICITUDES	1 TRAMITES DE SOL. DE PATENTE DE IN	378,000.00
		TOTAL :	\$ 378,000.00

SOM: TRESCIENTOS SETENTA Y OCHO MIL PESOS

RESPONSABLE : 

RECIBO DE CAJA APLICADO AL EXPEDIENTE No. _____

Carrera 13 No. 27-00 Pisos 5, 7 y 10
Conmutador 382 0840
Fax 350 5220
E-mail: info@sic.gov.co
www.sic.gov.co
Bogotá, D.C., Colombia

10)

ANEXOS

- ☒ 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
- ☒ Poderes, si fuera el caso
- ☐ Documento de cesión del inventor al solicitante o a su causante
- ☐ Declaraciones
- ☒ Copia de la solicitud Internacional. (Resumen, descripción, reivindicación, Dibujo).
- ☐ Traducción de la solicitud Internacional al castellano. (Resumen, descripción, reivindicación, Dibujo)
- ☒ 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. Notificación de cambio
 2. Notificación del recibo de la copia y países designados
 3. Solicitud PCT
 4. Hoja de Cálculo Capítulo II
 5. Opinión escrita
 6. Carta de retransmisión a la oficina de recepción de Estados Unidos
 7. Publicación Internacional
 8. Notificación de transmisión del reporte de búsqueda Internacional
 9. Patente Nr. 5,285,882
 10. Patente Nr. 4,710,908
 11. Publicación Internacional Nr. WO 01/25823 A 1

11) FIGURA CARACTERÍSTICA:

12) Solicitud concesión de la patente.

NOMBRE: DILIA RODRÍGUEZ D'ALEMAN

FIRMA:

C.C. 41.654.882 de Bogotá TP 20824 CSJ

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

TRADUCCIÓN OFICIAL No. 02/259 de un documento escrito en inglés, el cual para su identificación se sella con el sello del traductor al tiempo con la presente. Esta traducción ha sido preparada por Juan Pablo Piedrahita Aguilera, Traductor e Intérprete Oficial debidamente reconocido de conformidad con el Certificado de Idoneidad Profesional No. 0045 expedido por la Universidad Nacional de Colombia.

(Se traduce un Certificado Notarial y Apostilla No. N-306 065, escritos en inglés, adjuntos a un poder escrito en inglés y español otorgado con fecha Agosto 14, 2002.)

(En español e inglés, Poder firmado por William E Shull, Vicepresidente & Jefe Asesor Legal de Patentes, Kalliburton Energy Services Inc.)

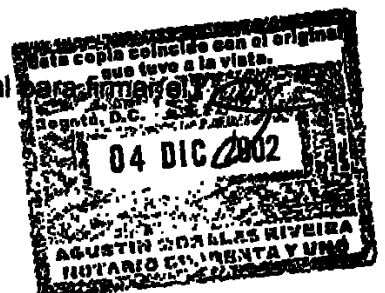
(Sello a Tinta: REVISADO, Operaciones, Legal (CRWES), Financiero)

CERTIFICADO NOTARIAL (Cuando el Solicitante es una Sociedad)

(Poderes otorgados en El Salvador, México, Estados Unidos de América y Venezuela)

Expedido hoy 14 de Agosto, 2002, el suscrito Notario CERTIFICA que:

- 1) William Shull (nombre de la persona que firma el poder), mayor de edad-y domiciliado en Ciprés, Texas, Estados Unidos de América, suscribió el anterior documento.
- 2) El otorgante le es conocido personalmente y tiene facultad legal para firmar el documento.



3) El otorgante ha suscrito el anterior documento en su facultad de Vicepresidente & Jefe Asesor Legal de Patentes de la persona jurídica Halliburton Energy Services Inc.

4) La mencionada persona jurídica con domicilio comercial en Houston, Texas, Estados Unidos de América, está debidamente constituida, tiene actualmente existencia legal y el fin para el cual se otorga este poder se encuentra dentro del alcanza de su objeto social.

5) El otorgante tiene en efecto la idoneidad referida y su representación es legal y está autorizado para otorgar este poder.

6) Fundamento las certificaciones 3), 4) y 5) en los documentos auténticos que para tal fin me fueron exhibidos.

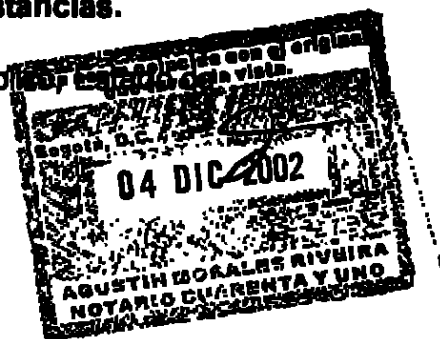
(Firmado) Tammy S. Brzozowski

Notario Público

Nota: a continuación el Consulado Colombiano debe legalizar la firma del Notario Público

Para todos los demás países el Señor Cónsul de Colombia o ante quien se otorgue, debe expedir una certificación dejando constancia de: 1) la existencia legal de la sociedad, 2) que cumple actualmente con su objeto social, y 3) que la persona o personas que otorgan este poder están facultadas para hacerlo. El Cónsul también certificará que los tuvo a la vista los documentos que prueban y acreditan tales circunstancias.

(Sello Notarial a Tinta: TAMMY S. BRZOZOWSKI, Notario Público en el Estado de Texas, Comisión vence 05-17-2005)



02/259

(Sello Pre-impreso del Estado de Texas)

El Estado de Texas

Secretario de Estado

APOSTILLA

(Convención de la Haya de Octubre 5 de 1961)

1. País: Estados Unidos de América
Este documento público
2. Ha sido firmado por TAMMY BRZOWSKI
3. Actuando en calidad de Notario Público, Estado de Texas
4. Lleva el sello/estampilla de TAMMY BRZOWSKI, Notario Público,
Estado de Texas, Comisión vence 05-17-05

CERTIFICADO

5. En Austin, Texas
6. Hoy Agosto 15, 2002
7. Por el Secretario de Estado de Texas
8. Certificado Número N-306065
9. (Sello) (Sello Pre-impreso del Estado de Texas)
10. (Firma)

(Firmado) Gwyn Shea
Secretario de Estado
ST/sjs

MINISTERIO DE RELACIONES
EXTERIORES
503514
Ten. Federico
CASA FIRMA AVALA EN EL
DOCUMENTO DESEAR
LOS FUNCIONES IN...

NO SE ASUME
RESPONSABILIDAD DEL TEXTO
2002 SEP - 6 A 11:11
DE LEGALIZACIONES
SANTAFE DE BOGOTA D.C.

ES TRADUCCIÓN FIEL Y COMPLETA de la cual se deja copia en los archivos de
esta oficina para su confrontación y a la cual me remito.

Bogotá, Septiembre 3 de 2002

Esta copia coincide con el original
que tuve a la vista.
Bogotá, D.C.
04 DE 2002
AGUSTIN TORALBA RIVERA
NOTARIO CUARENTA Y OCHO

P: yyy

POWER OF ATTORNEY

I (we), the undersigned

William Shull

legal representative(s) of

Halliburton Energy Services, Inc.
an organization existing under the laws of

Delaware, U.S.A.
and in present execution of its business activity, domiciled at
4100 Clinton Dr.

Houston, Texas 77020 U.S.A.
JOSEBY GRANT POWER OF ATTORNEY to DILIA MARIA RODRIGUEZ D'ALPAMAN, identification card No. 41.654.882 of Bogotá, and to ZORZDA and CLAUDIA LUCIA CARO RAMIREZ, tp. 36448, identification card No. 40.017.374 of Tunja, residing in Bogotá, Colombia, to act in the name 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:

Colombian Patent Application No.
02055681

1) Solicitar, transmitir, 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 etiquetas comerciales y denominaciones de origen; así como sus renovaciones, prórrogas, transacciones, cambios de nombre y/o domicilio, contratos y licencias.

2) Solicitar, tramitar, obtener y/o registrar derechos de autor, en cualquiera de sus presentaciones al como la protección de secretos industriales y know-how.

3) Solicitar, tramitar, otorgar y/o regular 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, impugnación, apelación, cancelación administrativa o judicial, nulidad, aplicación al consumidor, concesión de licencias, protección de secretos industriales y demás acciones y recursos relacionados con derechos derivados de las sumas 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(s) intervenir en juicios civiles, comerciales, penales, conciliación-administrativos, tutelas y de policía; en acciones o juicios promovidos por el (la) demandante o en contra el (ella).

5) Registrar nombres de dominio ante la entidad competente.

8) En el ejercicio de este mandato los mandatarios arriba mencionados quedan facultados para: conciliar, transar, transigir, comprometer en árbitros, desistir, recibir y tomar posesión de la cosa objeto de litigio y renunciar o desistír a derechos conciliados o en curso de conciliación, admitir los hechos del proceso.

3) Así mismo faculto (facultamos) a los mencionados apoderados para recibir notificaciones y designar apoderados judiciales o extrajudiciales, sustituir el presente poder y revocar las actuaciones que hicieren.

Dado y firmado en

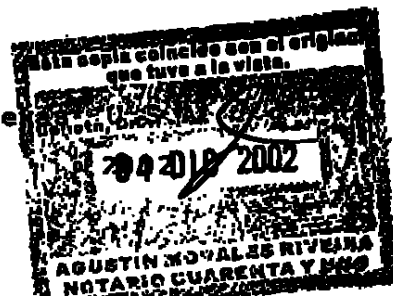
à los días de

Printed and signed at **Houston, Te**

on this 14 day of August

Firma / signature

William Shull
Vice President & Chief Patent Counsel
Halliburton Energy Services, Inc.



REVIEWED
Operations _____
Legal CR WES
Financial _____

UNPABLO

THE UNIVERSITY OF CHICAGO PRESS

CERTIFICADO NOTARIAL

(Cuando el solicitante es SOCIEDAD)
(Powers of attorney granted in: El Salvador, Estados Unidos, México y Venezuela)

A las _____ 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 _____

y lea 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 carácter 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 ostenta, 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 documentos mencionados.



TAMMY S. BRZOZOWSKI
Notary Public, State of Texas
Commission Expires 06-17-2005

Notario Público

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

CERTIFICADO NOTARIAL (Cuando el solicitante es INDIVIDUO)

A las _____ 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 Consol de Colombia debe autenticar la firma del Notario Público.

Para todos los demás países el Señor Consol de Colombia o ante quien se otorgue, debe expedir una certificación 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.

LEGALIZACIÓN POR EL CONSUL DE COLOMBIA
O POR APOSTILLA

NOTARIAL CERTIFICATE

(When the applicant is a CORPORATION)

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

This 14 day of August, 2002
the undersigned Notary CERTIFIES that:

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

of Cypress, legal age Texas, and domiciled in U.S.A. act 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 Vice President & Chief Patent Counsel of the juridical person _____

Halliburton Energy Services, Inc.

4. The mentioned juridical person with place of business in Houston, Texas U.S.A.

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 fact 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 authentic documents for such purpose were exhibited to me.

Tammy S. Brzozowski
Notary Public

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

NOTARIAL CERTIFICATE (When the applicant is an INDIVIDUAL)

On this _____ day of _____
the undersigned Notary CERTIFIES that:

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

of legal age and domiciled at _____

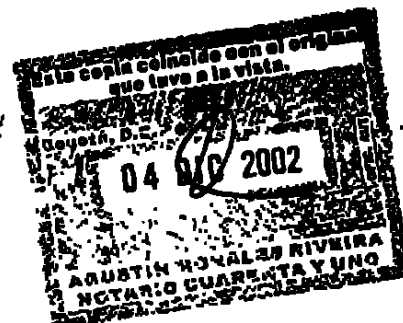
signed in his presence the foregoing document, the grantor is to him personally known and that he/she has legal capacity to execute the document.

Notary Public

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

For all other countries the Colombian Consul or before who it is granted must have a 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 these circumstances were exhibited to him.

LEGALIZATION BY THE COLOMBIAN CONSUL, OR BY APOSTILLE.





The State of Texas

Secretary of State

APOSTILLE

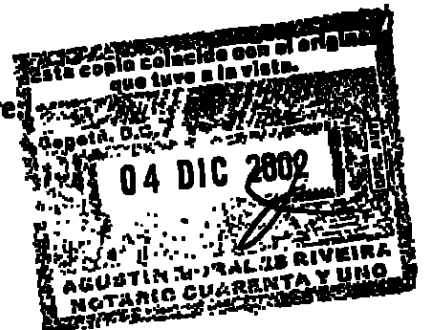
(Convention de La Haye du 5 Octobre 1961)

1. Country: United States of America
- This public document
2. has been signed by TAMMY S BRZOWSKI
3. acting in the capacity of Notary Public, State of Texas

4. and bears the seal/stamp of TAMMY S BRZOWSKI, Notary Public,
State of Texas, Commission Expires: 05-17-05

CERTIFIED

5. at Austin, Texas
6. on August 15, 2002
7. by the Secretary of State of Texas
8. Certificate No. N-306065
9. Seal
10. Signature:



A handwritten signature in cursive script that reads "Gwyn Shea".

Gwyn Shea
Secretary of State
ST/sjs



**REAL-TIME METHOD FOR MAINTAINING FORMATION STABILITY AND
MONITORING FLUID-FORMATION INTERACTION**

Related Application

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This application claims priority to U.S. Provisional Patent Application No 60/209,488, filed June 6, 2000.

Background of the Invention

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1. Field of the Invention

This invention relates to methods for predicting and maintaining wellbore stability during drilling, well servicing and production in subterranean formations, particularly hydrocarbon bearing subterranean formations.

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2. Description of Relevant Art

As used herein, the term "(in)stability" shall be understood to mean "stability or instability." Wellbore (in)stability in shales is a major problem costing the petroleum industry, according to conservative estimates, \$700 million annually. Understanding and modeling mechanisms of shale (in)stability is an ongoing industry effort. Drilling a hole into a formation in equilibrium induces stress concentration in the vicinity of the borehole. Interactions will occur if parameters such as chemical potential, electrical potential, thermal potential, ionic concentration, etc., of the drilling fluid and the shale formation fluid are not in equilibrium. Any differences in these parameters will alter the near wellbore pore pressure which in turn will influence the borehole equivalent stress-state and the shale mechanical strength thus affecting wellbore (in)stability. Tests conducted at compressive uniaxial and triaxial stress conditions in the past have indicated the strong influence of these parameters on shale strength.

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Wellbore instability predominantly occurs in chemically reactive shales that overlay reservoirs. A major concern of the drilling engineer is either keeping the borehole wall from collapsing (packing off) or fracturing (losing circulation).

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Past efforts to develop improved well bore models ("WBM") for shale drilling have been hampered by a limited understanding of the drilling fluid/shale interaction phenomenon. This limited understanding has resulted in drilling fluids being designed with properties inadequately or insufficiently optimized to prevent the onset of borehole (in)stability problems. Historically, wellbore (in)stability problems have been approached on a trial-and-error basis, going through a costly multi-well learning curve before arriving at reasonable

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solutions for optimized operations and systems.

Recent studies of fluid-shale interactions have produced fresh insights into the underlying causes of borehole (in)stability; and chemical potential related instabilities in shales have been identified. A chemical potential borehole stability model, derived for an arbitrary borehole orientation, has been successfully implemented to address borehole (in)stabilities. This model, based on a well-established elastic modeling approach, is discussed in Tare, U.A., and Mody, F.K.: "Novel Approach to Borehole Stability Modeling for ERD and Deepwater Drilling", paper SPE 52188, 1999 SPE Mid-Continent Operations Symposium, Oklahoma City, USA, March 28-31, 1999, incorporated herein by reference.

Advances in technology are providing wider and greater capabilities for new, more reliable, accurate and rugged downhole sensors and tools. Such apparatuses and sensors are increasingly able to collect and transmit information to the surface as it is happening.

With increasing economic demands on reducing rig downtimes associated with borehole instability problems, there is increasing need for the ability to predict and resolve instabilities in the field using MWD/LWD (measuring while drilling/logging while drilling) data in conjunction with prior geophysical and shale/fluid interaction knowledge. However, previous attempts have focused on earth stresses, using drilling data and borehole (in)stability modeling on a "post-mortem" basis, i.e., after substantial problems have occurred. There is a need for methods that enable instability problems to be avoided.

Summary of the Invention

A method is disclosed for maintaining subterranean formation stability, and particularly wellbore stability during drilling, well completion and servicing operations, and even during production and enhanced recovery operations. The method of the invention affords maintenance of wellbore stability throughout the life of a well penetrating a subterranean formation. Moreover, the method provides for real-time monitoring of fluid-formation interaction such that adjustments can be made before (in)stability problems occur.

In the method, initial formation characteristics or parameters are estimated or obtained and the rock strength of the formation is estimated. Characteristics of the fluids injected into the wellbore or the formation during drilling, or during well completion and servicing operations, or during production or enhanced recovery operations, are also estimated or obtained. This data concerning the formation and the fluids is input into a well-stability model and results are used to revise the estimates of the formation parameters and/or the fluid parameters or to adjust the fluid

composition or characteristics. These parameters and the model results are updated with real time formation measurements taken during the particular operation being conducted (i.e., drilling, well servicing, or production). Continued acquisition and processing of the formation data in the model allows the fluids to be adjusted as needed to avoid formation instability problems caused by interaction of the fluids with the formation.

Brief Description of the Drawings

Figures 1A and 1B are a flowchart or process map for a real-time wellbore stability process according to the invention.

Figure 2 is a schematic of a Pure Pressure Transmission experiment designed to study time-dependent alterations in shale properties as a function of drilling fluid exposure.

Figure 3 is a graph of the time dependent transient pore pressure response of Pierre II shale when exposed to a 20% w/w NaCl solution.

Figure 4 is a graph of the time dependent transient pore pressure response of Pierre II shale when exposed to a sodium silicate solution containing 20% w/w NaCl.

Figure 5 is a graph of the time dependent transient pore pressure response of Pierre II shale when exposed to a polymer in solution containing 20% w/w CaCl_2 salt and 2% KCl salt.

Figure 6 is a graph of the shale compressional acoustic wave response of Pierre II shale when exposed to a 20% w/w NaCl solution.

Figure 7 is a graph of the shale shear acoustic wave response of Pierre II shale when exposed to a 20% w/w NaCl solution.

Figure 8 is a graph of the shale compressional acoustic wave response of Pierre II shale when exposed to a sodium silicate solution containing 20% w/w NaCl.

Figure 9 is a graph of the shale shear acoustic wave response of Pierre II shale when exposed to a sodium silicate solution containing 20% w/w NaCl.

Figure 10 is a graph of the compressional acoustic wave response of Pierre II shale when exposed to a polymer in solution containing 20% w/w CaCl_2 salt and 2% KCl salt.

Figure 11 is a graph of the shear acoustic wave response of Pierre II shale when exposed to a polymer in solution containing 20% w/w CaCl_2 salt and 2% KCl salt.

Figure 12 is a graph of dynamic Young's modulus as a function of transient pore pressure for Pierre II shale exposed to a 20% NaCl solution.

Figure 13 is a graph of dynamic Young's modulus as a function of transient pore pressure for Pierre II shale exposed to a sodium silicate solution containing 20% w/w NaCl.

Figure 14 is a graph of dynamic Young's modulus as a function of transient pore pressure for Pierre II shale exposed to a polymer in solution containing 20% w/w CaCl_2 salt and 2% KCl salt.

Detailed Description of Preferred Embodiments

5 The following terms as used herein, and particularly as used in the figures, have the meaning indicated below:

Nomenclature

ϕ = Membrane efficiency, %

P = Pressure, m/L^2 , psi

10 E = Young's modulus m/L^2 , psi

A_w = Water activity

ΔP = Pressure drop, m/L^2 , psi

V = Acoustic Velocity, m/t , m/sec

Subscripts

15 ic = confining

o = external or pore fluid

fl = test fluid

sh = shale fluid

exp = experimental

20 p = sonic compressional waves

s = sonic shear waves

SI Metric Conversion Factors

$\text{ft} \times 3.048$ $\text{E}-01 = \text{m}$

$\text{in.} \times 2.54$ $\text{E}+00 = \text{cm}$

25 $\text{lbf} \times 4.448\ 222$ $\text{E}+00 = \text{N}$

$\text{psi} \times 6.894\ 757$ $\text{E}+00 = \text{kPa}$

30 In investigating the role of various potentials of drilling fluids on transient rock properties of shale and other subterranean formations subjected to compressive confining stress, we have discovered that properties of cores from such formations should be measured as a function of time when exposed to a drilling fluid, well service fluid, or enhanced production fluid, or even when subjected to production itself. Experiments were conducted under conditions simulating a borehole portion under geostatic stress with the wellbore surface exposed to a circulating drilling fluid. The results supported our discovery.

monitored.

PPT Test Details

The PPT tests provide a database including shale responses to various drilling fluids and salt solutions. For example, the PPT tests provide meaningful membrane efficiency numbers, allow for the study of more complex interaction between shale and drilling fluid to validate, verify, or confirm existing chemical potential poroelastic models, enable calibration of the shale response to known drilling fluids for optimum application in the field, and demonstrate simultaneous data acquisition of various responses to provide detailed shale property characterization as a function of drilling fluid exposure.

The three example fluids tested were a 20% w/w sodium chloride salt solution, a sodium silicate system comprising 20% w/w sodium chloride, and a polymer in solution comprising 20% w/w CaCl_2 salt and 2% KCl salt. It is important to establish a baseline of the shale response to the cation or cations that would be included in the drilling fluid system. Such a baseline helps in identifying or isolating shale alterations due to cation exchange. In addition this baseline helps differentiate, to a certain extent, the effects of the base salt solution and the effects of other shale modifying additives (e.g., silicates, polymers like partially-hydrolyzed poly-acrylamide, amphoterics etc.).

Discussion of Results

Based on the transient pore pressure response of Pierre II shale exposed to the test fluids, the sodium silicate solution comprising 20% w/w NaCl showed higher membrane efficiency numbers than the 20% w/w NaCl solution and the polymer in solution comprising 20% w/w CaCl_2 salt and 2% KCl salt (approximately 60% efficiency versus approximately 10% efficiency and approximately 5.30% efficiency respectively).

Figures 3, 4 and 5 show the time dependent transient pore pressure response of Pierre II shale when exposed to a 20% w/w NaCl solution, a sodium silicate system comprising 20% w/w NaCl and a polymer in solution comprising 20% w/w CaCl_2 salt and 2% KCl salt, respectively. The saturating fluid (simulated pore fluid) in all cases is 8% w/w NaCl solution. The shale acoustic (compressional and shear wave) response during the entire experiment for the 20% w/w NaCl solution is shown in Figures. 6 and 7. Figures. 8 and 9 provide the corresponding acoustic (compressional and shear wave) response of Pierre II shale when exposed to the sodium silicate solution comprising 20% w/w NaCl. Figures 10 and 11 provide the acoustic (compressional and shear wave) response of Pierre II shale when exposed to the polymer in

15
In the experiments, rock properties such as acoustic velocity and transient pressure for each core sample were measured simultaneously as a function of time during the experiments. This simultaneous measurement eliminated the anisotropy-associated differences obtained when different samples are used to determine the relationship between these characteristic parameters of the subterranean formations, and in these experiments, particularly the characteristic parameters of the shale formations. This testing enhanced understanding of the relationship between acoustical, mechanical, chemical, electrical and failure properties of the shale as a function of time when exposed to a fluid, and in these experiments, particularly when exposed to a drilling fluid. Such measurements provide the necessary precursor to determine the onset of time dependent in(in)stability, thus providing options to implement corrective measures in real time to alleviate (in)stability, according to the method of the present invention.

Without wishing to be limited by theory, we believe, based on our observations from these above experiments, that measurement of rock properties such as acoustic velocity as a function of the transient pressure of shales under simulated in-situ stress-state facilitates real time wellbore (in)stability logging using MWD/LWD or any other relevant information. This practice provides better real-time management of (in)stability problems in the field.

The present invention provides a method or process for maintaining formation stability through monitoring the interaction between the formation and fluids used in well drilling, servicing or production. Further, the present invention provides a real-time method for improved drilling, servicing and producing wellbores in or through subterranean formations by employing such monitoring and maintaining of well stability. The improvements of the invention are especially appreciated in operations in shale formations, although the invention is applicable as well to other types of subterranean formations. Similarly, the improvements of the invention are especially appreciated in drilling through subterranean formations, although the invention is applicable as well to other operations in subterranean formations, such as well completion and well servicing operations, and even to producing operations. Thus, the advantages of the invention are best realized when the invention is applied throughout the life of a wellbore in a subterranean formation, and especially a hydrocarbon bearing subterranean formation.

The method of the invention employs real-time wellbore stability modeling. Figures 1A and 1B present a process map of real-time wellbore stability modeling, specifically for example as applied to drilling operations. A similar map would be used for well completion or other service operations employing well service fluids instead of drilling fluids. Also, a similar map would be

used for well production operations, monitoring stability of a well as fluids may be produced from a formation, and monitoring stability of a well during various enhanced recovery operations (for enhancing recovery of hydrocarbons from the formation). In all such cases, the interaction of the formation to various fluids being introduced into or being produced from the wellbore are monitored. Hereinafter, the description of the invention will primarily be directed to drilling operations and to drilling fluids for example. However, the invention is not limited to such operations or fluids and may be similarly applied to well completion and service operations involving well service fluids and to production operations.

The initial step in the method or process of the invention involves constructing an earth-model (preferably including stresses, formation compressive and tensile strengths and geologic features) from a variety of sources such as pre-drill, seismic, and offset data. Based on the initial earth-model, predictions are made for mud weights, casing shoe locations, drilling fluid type and chemistry, etc. as would be known to those skilled in the art. Preferably simultaneously, laboratory tests are conducted for specific formations (e.g., shales) that are expected to be drilled, using either actual cores from such formations or representative outcrop samples. The tests are conducted using a variety of experimental apparatuses such as the Pore Pressure Transmission (PPT) test apparatus. Information on time-dependent formation (e.g., shale) behavior is obtained from such tests.

Further in the method of this invention, rock properties such as transient pore pressure, compressional and shear wave velocities, deformation, and strength of shale cores under triaxial stress are measured. These measurements are used to calibrate the wellbore stability model (also called the total potential model), such as the model shown in the flow diagrams in Figure 1B, for specific applications, such as, for example, drilling with programmed or planned drilling fluids through/into a reservoir overlying shales or other formations of interest. Measurements of static and dynamic rock properties as a function of the transient pressure of shales (or other formations of interest) under triaxial stress state enhances understanding of the relationship between these parameters. Such measurements also help in determining how economically to obtain these properties using MWD/LWD (measurement while drilling/logging while drilling) data.

During the drilling process, the earth-model and the total potential wellbore stability model are updated with real-time measurements while drilling (MWD) and/or using wireline logs or any other techniques for determining static and dynamic rock properties. The captured MWD and/or wireline data or data obtained from any other techniques is processed in real-time and this

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data is converted into input parameters for the wellbore stability model. The input parameters are thus calibrated with MWD and/or wireline data or data obtained from other techniques. The calibrated input parameters are then used in a wellbore stability model along with the laboratory time-dependent measurements.

- 5 For a given set of input parameters the wellbore stability model provided in Figure 1B can perform in three modes of analysis. These are briefly described below:
- Safe mud weight window prediction – Results obtained from this mode provide the upper and lower limit for a safe mud weight for a given composition of the drilling fluid as a function of the hole inclination angle and orientation. The upper limit in this case is the mud weight above which extension fracturing or fracture propagation would occur and would result in excessive drilling fluid losses. The lower limit is set by formation pore pressure or the minimum mud weight required to prevent borehole collapse, whichever is greater. In this mode, chemical and thermal interaction between the formation (mostly shale) and the drilling fluid can be incorporated.
 - 10 • Optimum chemical composition prediction (OBM) – In this mode of analysis the model provides the optimum chemical composition of the drilling fluid for a given mud weight, hole inclination and direction. In the absence of laboratory derived shale pore fluid potential, in-situ shale pore fluid potential can be predicted using a sub-module.
 - Optimum chemical composition of drilling fluid prediction (OBM) followed by safe mud weight window prediction – The model in this mode first optimizes the chemical composition of the drilling fluid for the actual (i.e., utilized currently in the field) mud weight followed by a prediction of the safe mud weight window as a function of hole angle for a given direction.
 - 20

All three modes have access to an empirical rock strength estimation module, as shown in Figure 1A.

25 The predictions from the wellbore stability model are sent to a visualization module (typically graphing of results) based on one of two types of activities—field implementation or feedback, as shown in Figure 1A—to be executed. These activities provide feedback into the data collection, processing and interpretation process and field implementation of the wellbore stability model results, as shown in figures 1A and 1B.

Wellbore Stability Model

The rationale for the wellbore stability model (total potential model) is as follows:

The fundamental direct and coupled flow phenomena, induced hydraulic gradients, chemical potential, electrical potential gradients and temperature gradients all influence rock properties and wellbore or formation stability. In most practical cases, however, the flow phenomena induced by the hydraulic gradient (i.e., mud filtrate invasion driven by overbalanced mud weight) and the chemical potential difference between the drilling fluid and shale (or formation) pore fluid (e.g., osmotic or diffusion transport of water molecules and/or ions and/or (hydrated) solutes in and out of the shale, electrical potential, thermal potential, etc.) are generally considered to be the more relevant driving forces for formation (in)stability. At any given time during the drilling operation, the (in)stability issue is ultimately controlled by the relationship between the borehole stress-state and the rock strength. As the rock strength is inversely related to the water content of the shale (or of the formation of interest), modification of pore pressure is a fundamental parameter in altering the effective stress-state around the wellbore. Adequate mud weight density is also needed for borehole stability.

The model used in the method of this invention is preferably based on well-established modeling principles such as described in Mody, F.K. and Hale, A.H.: "A Borehole Stability Model To Couple the Mechanics and Chemistry of Drilling Fluid/Shale Interaction", paper SPE 25728, 1993 IADC/SPE Drilling Conf., Amsterdam, Feb. 23-25, 1993; Bradley, W.B.: "Failure of Inclined Boreholes", *J. Energy Res. Tech.* (Dec. 1979) 232; *Trans., ADME*, 101; Tare, U.A., and Mody, F.K.: "Novel Approach to Borehole Stability Modeling for ERD and Deepwater Drilling", paper SPE 52188, 1999 SPE Mid-Continent Operations Symposium, Oklahoma City, USA, March 28-31, 1999; Tan, C.P., et al.: "Integrated Rock Mechanics and Drilling Fluid Design Approach to Manage Shale Instability", paper SPE 47259, SPE/ISRM Eurock '98, Trondheim, Norway, Jul. 8-10, 1998; and Ghassemi, A., et al.: "A Solution for Stress Distribution Around An Inclined Borehole in Shale", paper No. 043, *Int. J. Rock Mech. Min. Sci.* Vol. 35, No. 4/5, p.538-540, 1998, which are all incorporated herein by reference.

The first two of these references listed above have pertinent theoretically derived solutions to the model. The model incorporates chemical potential effects using the difference in the molar free energies (i.e., activity) of the drilling fluid and the shale pore fluid. Also incorporated in the model is the concept of reflection coefficient, σ , as discussed in Staverman, A.J.: "Theory of Measurement of Osmotic Pressure", *Recueil des Travaux Chimiques des Pays-Bas*, v.70, pp 344-352, (1951), incorporated herein by reference. The temperature difference between the formation and the drilling fluid directly affects the near-

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wellbore stress concentration. The model utilizes this temperature difference and calculates the effect of thermal stresses on the near-wellbore tangential stress where significant.

Experiments

5 Pore Pressure Transmission (PPT) Tests

The Pore Pressure Transmission (PPT) experiment has been designed to study time-dependent alterations in shale properties as a function of drilling fluid exposure. A schematic of this test is shown in Figure 2. The experiment consists of confining well-preserved shale cores or outcrops, under geostatic stress and then circulating (under confined dynamic conditions) test
10 fluids at the upstream side while measuring changes in the downstream pressure. The upstream pressure may be increased to simulate overbalance conditions representing downhole conditions. Typically during a drilling operation, hydraulic overbalance is maintained to provide the formation with net radial support. The downstream pressure indicates changes in the sample pore pressure at some distance into the wellbore.

15 Experimental Setup for PPT Tests

The experimental setup consists of a jacketed steel pressure vessel with built in pressure ports, connections and acoustic transducers. The sample (1 in. $\times$ 2 in.) is jacketed with a Teflon membrane after six extension-meter strain gauges are applied to measure the sample deformation. The entire assembly is placed in a temperature regulating device to ensure adequate control of the
20 experimental temperature.

Summary of PPT Test Procedure

A shale sample is equilibrated at a hydrostatic confining pressure P_c (e.g. 500 psi), under external fluid pressure p_o (e.g., 50 psi) on both ends, and at the specific test temperature. Fluid pressure is applied with simulated pore fluid. Once saturation is achieved, the upstream pressure
25 line is closed. The confining pressure is then increased to the required level for consolidation, P_k (e.g., 4000 psi). The system remains closed until the pressures at both the sample ends have stabilized. Upstream and downstream pressure is allowed to stabilize and equilibrate.

Upon stabilization of the pore pressure, the sample is allowed to consolidate. The downstream pressure of the sample is monitored.

30 After the pressures at both ends have stabilized, the pore fluid is replaced with a drilling fluid that is circulated at a constant pressure. The transient pressure behavior, sonic compression and shear travel times, radial and axial deformation, temperature, and circulation rate are

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monitored.

PPT Test Details

The PPT tests provide a database including shale responses to various drilling fluids and salt solutions. For example, the PPT tests provide meaningful membrane efficiency numbers, allow for the study of more complex interaction between shale and drilling fluid to validate, verify, or confirm existing chemical potential poroelastic models, enable calibration of the shale response to known drilling fluids for optimum application in the field, and demonstrate simultaneous data acquisition of various responses to provide detailed shale property characterization as a function of drilling fluid exposure.

The three example fluids tested were a 20% w/w sodium chloride salt solution, a sodium silicate system comprising 20% w/w sodium chloride, and a polymer in solution comprising 20% w/w CaCl_2 salt and 2% KCl salt. It is important to establish a baseline of the shale response to the cation or cations that would be included in the drilling fluid system. Such a baseline helps in identifying or isolating shale alterations due to cation exchange. In addition this baseline helps differentiate, to a certain extent, the effects of the base salt solution and the effects of other shale modifying additives (e.g., silicates, polymers like partially-hydrolyzed poly-acrylamide, amphoteric etc.).

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Based on the transient pore pressure response of Pierre II shale exposed to the test fluids, the sodium silicate solution comprising 20% w/w NaCl showed higher membrane efficiency numbers than the 20% w/w NaCl solution and the polymer in solution comprising 20% w/w CaCl_2 salt and 2% KCl salt (approximately 60% efficiency versus approximately 10% efficiency and approximately 5.30% efficiency respectively).

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solution comprising 20% w/w CaCl₂ salt and 2% KCl salt. One example rock property, the dynamic Young's modulus (E) (reflecting rock elasticity), calculated from the above acoustic data with respect to the three solutions is shown respectively in Figures. 12, 13 and 14. Each of the Figures 3-14 indicates the three stages of the PPT test. First, the shale is saturated with 8% w/w NaCl (simulated pore fluid); second, 8% w/w NaCl is circulated until equilibrium; and third, the shale is exposed to the test fluid.

Table 1 provides transient pore pressure data and corresponding calculated membrane efficiency in tabular form for the test fluids when exposed to Pierre II shale.

TABLE 1-MEMBRANE EFFICIENCY CALCULATION

Test Fluid	A _{wf}	A _{wsh}	ΔP _{th} psi	ΔP _{exp} psi	σ, % ΔP _{exp} /ΔP _{th}
20% w/w NaCl solution	0.83	0.95	2685	270	10.05
Sodium silicate solution comprising 20% w/w NaCl	0.83	0.95	2685	1604	59.74
Polymer solution comprising 20% w/w CaCl ₂ salt and 2% KCl salt	0.78	0.95	3920	208	5.30

where ΔP_{th} refers to the difference or change in theoretical pressure and ΔP_{exp} refers to the difference or change in experimental pressure.

The well known concept of "reflection coefficient" (i.e., membrane ideality) may be used for "leaky systems" including water based mud (WBM)/shale (or other formation) type systems for formation stability applications. For WBM/shale systems, membrane efficiency is not a clearly defined term (e.g., as an oil film on shales present in invert oil emulsion systems). The membrane efficiency of formation-fluid systems is due to a difference in mobility of water and solutes (ions) in shales. Thus membrane efficiency can be defined as:

$$\sigma = 1 - \frac{v_{solute}}{v_{water}} \tag{1}$$

If only the movement of water is allowed and all the solutes are rejected, the membrane is ideal semi-permeable (100% membrane efficiency or σ=1). However, for shales, the mobility of solutes is lower than that of water and the membrane is "non-ideal" or "leaky", 0<σ<1. A non-ideal membrane does not entirely restrict the transport of solutes. Membrane efficiency ("reflection coefficient") has a relationship with at least two key parameters of the WBM/shale system, i.e., the average 'effective' shale pore radius and the radius of hydrated ions present in the drilling fluid system.

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A mathematical representation to describe the driving force for the movement of water by an osmotic mechanism and one way or means of estimating membrane efficiency directly is shown in the following equation:

$$\left(\frac{RT}{V} \right) \times \ln \left(\frac{A_w}{A_{wa}} \right) = \pm (\sigma \times \Delta P_s) = \pm \sigma \times (P - P_p) \quad (2)$$

- 5 where A_{wf} is the water activity of the drilling fluid, which can be estimated a number of known ways, most notably, by partial vapor pressure determination, boiling point elevation, or directly using a hygrometer; A_{wa} is the water activity of the shale pore fluid and can be measured (for preserved shale cores) by partial vapor pressure determination; P_p is the far-field pore pressure; P is the near wellbore pore pressure; and σ is the membrane efficiency
10 term, or "reflection coefficient", specific to a shale/drilling fluid system.

Further discussion of the calculation of membrane efficiency may be found in references Mody, F.K. and Hale, A.H.: "A Borehole Stability Model To Couple the Mechanics and Chemistry of Drilling Fluid/Shale Interaction", paper SPE 25728, 1993 IADC/SPE Drilling Conf., Amsterdam, Feb. 23-25, 1993, and Staverman, A.J.: "Theory of Measurement of Osmotic
15 Pressure", Recueil des Travaux Chimiques des Pays-Bas, v.70, pp 344-352, (1951), which are incorporated herein by reference.

While the membrane efficiency for a 20% w/w NaCl solution when exposed to Pierre II shale is 10.05%, and the membrane efficiency for a polymer in solution comprising 20% w/w CaCl₂ salt and 2% KCl salt when exposed to Pierre II shale is 5.30%, the membrane
20 efficiency for sodium silicate systems is significantly higher at about 60%. For reference, an oil-based mud has a theoretical membrane efficiency close to 100%. Following the response of a sodium silicate solution with 20% w/w NaCl, the shale pore pressure decreases as a function of exposure time to the solution. Comparing the results among the three test fluids indicates that, when membrane efficiency numbers are significantly higher, drilling fluid water
25 activity that is lower than the shale pore fluid activity tends to reduce pore pressure and thereby contributes towards reducing near-wellbore effective stresses on a time-dependent basis.

Acquisition of acoustic data simultaneously with exposure of the rock to drilling fluid, in the field and in the PPT tests provides useful data to calculate dynamic changes in the rock
30 properties, changes that may be a result of that exposure. Comparing Figures 12, 13 and 14

shows changes in the dynamic Young's modulus as a function of transient pore pressure. Young's modulus, which is a measure of the stiffness or elastic properties of a rock, is but one example of a rock property. Similar computations can be made for dynamic Poisson's ratio and other rock properties derived from sonic data. In the example, when shale is exposed to 20% w/w NaCl solution, the effective stress changes from 2105 psi immediately after displacement to 2375 psi when the transient pore pressure has reached its lowest point (Figure 3). For the case when Pierre II shale is exposed to the sodium silicate fluid the effective stress increases from 860 psi immediately after displacing the simulated pore fluid with the test fluid to 2464 psi at the lowest point on the transient pore pressure curve (Figure 4). Inherent changes in effective stress can be observed from velocity data. For example, comparing Figures 6 and 10 with 8 shows a dramatic change in the compressional wave sonic velocity when the shale is exposed to the two test fluids. Similar observations can be made for the shear wave velocity profiles by comparing Figures 7 and 11 with 9. These comparisons provide additional means of observing transient pore pressure in the shales as a function of test fluid exposure.

This test example shows that mud systems should be calibrated, preferably with shale cores under in-situ conditions. PPT tests can provide meaningful membrane efficiency numbers which can then be used in a wellbore stability model for a realistic analysis. Additionally, a time-dependent chemical potential related shale transient pressure can be obtained, which can be used to analyze exposure time related borehole deterioration observed (based on the nature of the curve).

Input Parameters for Real - Time Wellbore Stability Modeling

Table 2 provides a list of input parameters for real-time borehole stability analysis according to the method of the invention and the possible sources where the data needed for the analysis can be obtained. The input parameters can be divided into five categories. These are:

- a) Insitu Stresses.
- b) Formation Data.
- c) Well Path Data.
- d) Drilling Fluid.
- e) Rock Strength.

Each of the above categories can be further sub-divided into individual subcategories. The possible sources for obtaining information for each input parameter subcategory are provided

in Table 2 (under the column heading Possible Source). The Input Parameters categories are discussed below:

(a) In-situ Stresses – These stresses affect the mud weights used to drill a borehole. When the stresses are higher than the rock strength failure occurs. The principle stresses control both fracturing as well as the collapse mode of wellbore failure. There are three principle earth stresses. The in-situ stresses are the minimum horizontal stress, maximum horizontal stress and the overburden stress. In a normal faulting environment such as that typically found in the Gulf of Mexico (away from any tectonic activity), the minimum horizontal stress is the least principle stress, the maximum horizontal stress is the intermediate principle stress, and the overburden stress is the maximum principle stress. The major source for obtaining magnitudes of the least principle stress in formations is by pressure testing in open boreholes. Information can be obtained from tests such as a leak-off test, extended leak-off test, mini-frac test, etc. Direction of the intermediate principle stress is obtained by measuring the location of borehole ovality (break-outs); the magnitude is estimated by back-calculating the break-out width for a given intermediate stress and the other two principle stresses, pore pressure and the rock strength. Comparison is made between the estimated and the actual observed breakout width. The overburden stress is typically obtained from an integrated bulk density log, by the actual measurement of drilled cuttings, etc.

(b) Formation Data – This data can be categorized into four sub-categories: temperature; rock properties; shale or pore water salinity; and pore pressure. Formation data is different for different formations. The formation temperature is typically estimated by running temperature measurement while drilling tools, infra-red techniques, etc. Rock properties are obtained either by direct measurement of actual cores in the laboratory or by empirical correlations based on wellbore measurements. Rock properties aid in modeling deformation behavior of specific formations. Shale activity or pore water salinity is used to estimate the chemical potential of the formation. A difference in potential between the drilling fluid and formation induces flow phenomenon from one to the other, i.e., flow occurs from higher potential to the source that contains lower potential. Osmotic membrane efficiency and the osmotic pressure are based on shale water activity. Shale water activity can be obtained from log based empirical correlations as provided in Table 2 or by actually measuring the relative humidity of a well preserved shale core in the laboratory. Pore pressure is critical information for drilling a well. Pore pressure affects the minimum mud weight used to drill and is related

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to total potential of the formation. Pore pressure is typically obtained from pressure build-up tests like drill-stem testing and repeat formation testing, as well as from empirical correlations using log and seismic information.

5 (c) Well Path – Drilling data includes well trajectory information like hole angle, well azimuth and other associated information on geology like presence of faults and other structures. Case histories of successful mud programs will also be a part of the drilling data.

(d) Drilling Fluid – This category includes three sub-categories. The drilling fluid density (Mud weight) can be captured in real-time (while drilling) by means of a pressure while drilling (PWD) tool. Accurate information of mud weight is necessary to ensure wellbore
10 stability. Field and laboratory densitometers may suffice if downhole tools measuring mud weight are not installed. Drilling fluid activity is a measure of the chemical potential of the drilling fluid. A difference in the activity of the drilling fluid and the shale pore fluid would induce osmotic fluid flow in the presence of a semi-permeable membrane. Drilling fluid activity can be measured directly using a hygrometer or a relative humidity meter or
15 indirectly by for example estimating solute concentrations in titration experiments. Membrane efficiency is a critical parameter that determines the effectiveness of a semi-permeable membrane to allow only the transport of fluids relative to the transport of solutes. Membrane efficiency of a drilling fluid – shale formation system can be estimated by laboratory measurements in a pore pressure transmissions test (PPT) apparatus. Time lapsed
20 measurements of shale properties of shales exposed to drilling fluids in a borehole can also lead to membrane efficiency estimations. Pore radii along with solute sizes and concentration may provide alternate ways of estimating membrane efficiency.

(e) Rock Strength - Rock strength can be differentiated between two types--the compressive strength and the tensile strength. Rock strength is a critical input parameter
25 along with the stresses and can be defined by various failure models. The existing real-time wellbore stability process includes but is not be limited to failure models such as the Mohr-Coulomb Failure Criterion, Drucker-Prager model, Modified Lade Criterion, Hoek and Brown Expression, Johnston and Chiu Model, Peak Strength Criterion, Uniaxial Compressive Strength limitation, etc. Ideally direct measurements of stress versus strain on
30 well-preserved core samples in the laboratory in a poly-axial cell is preferred. In the absence of core samples various tests on drill cuttings and empirical correlation's using log data can provide rock strength estimations. For example if the water content of the shale can be

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estimated then a proprietary empirical correlation that uses water content and shale composition can be used to estimate rock strength.

Therefore,

Rock Strength $\propto f(\text{Shale Property})$

- 5 For example, Shale Property = Water content or Brinell Hardness or Cation Exchange Capacity or Porosity etc.

The numbers in Table 2 below have the following meanings:

1. X-ray Analysis of cuttings.
2. Nuclear Magnetic Resonance (NMR) logs (Wireline and/or MWD).
- 10 3. Resistivity/Conductivity logs (Wireline and/or MWD)
4. Mud Logs
5. Acoustic/Sonic compressional and shear wave logs (Wireline and/or MWD)
6. Pressure and Sampling tools like drill stem testing (Wireline and/or MWD) and repeat formation testing (RFT) tools.
- 15 7. MDT
8. Spontaneous Polarization (SP) Curve logs
9. Seismic processing/Vertical Seismic Profiling (VSP) techniques.
10. Pore pressure ahead of the bit techniques.
11. Pressure While Drilling (PWD) logs (MWD).
- 20 12. Empirical and analytical models using drilling fluid rheology, pressure, cuttings accumulation and temperature.
13. Leak-off test (LOT), Extended Leak-off Test (XLOT), Minifrac tests, Microfrac Tests, Formation Integrity Tests (FIT), Casing Integrity Tests (CIT).
14. Anelastic Strain Recovery (ASR) Techniques (including tests performed on cores and downhole)
- 25 15. Regional bulk density trends.
16. Integrated bulk density logs (Wireline and/or MWD)
17. Acoustic, four and six arm Calliper logs (Wireline and/or MWD), information on breakout angles, breakout volume and breakout length, etc.
18. Formation Evaluation (FE) Logs (Wireline and/or MWD)
- 30 19. Temperature logs (Wireline and/or MWD)
20. Neutron source (Nuclear) or Gamma-ray logs like neutron-slow-neutron logs, Double- or Multiple - Spaced Neutron (MS Neutron Curve) - Dual-Spacing Neutron Curve, Flowing Neutron Log (Nuclear Flolog - Lanc-Wells), etc. (Wireline and/or MWD)
21. Formation Imaging logs (Wireline and/or MWD).

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Table 2. List of input parameters for real-time wellbore stability analysis and possible sources where the data required to do the analysis can be obtained:

Possible Source	Intermediate Parameters	Input Parameter	
13, 14, empirical and analytical methods using log and regional information like the Daine's method, Eaton's technique, Pennabaker method, etc.		Minimum Horizontal Stress	I N S I T U S T R E S S E S
15, 16, empirical methods using log information and compaction trends, measurements on drill-cuttings (cuttings density measurements), etc.,		Overburden Stress	
14, 17, 21, fault stability and reactivation models,	Inequality (magnitude) and direction of horizontal stresses	Maximum Horizontal Stress	
19, field measurements like using infra-red techniques	Formation temperature and flow-line temperature	Temperature	F O R M A T I O N D A T A
Laboratory analysis of cores, measurements on cuttings, pressure pulsing the well, 2, 3, 5, 9, 13, 14, 20	Poisson's Ratio, Young's Modulus, Thermal Expansion coefficient, fluid and grain volume expansion factor, rock and fluid compressibility, rock and fluid bulk modulus, Skempton's Pore Pressure Coefficient, Biots Constant, etc.,	Rock Properties	
Log based empirical correlation's using the following measurements - 2, 3, 6, and 20. Laboratory measurements of shale cores using testing methods like, adsorption isotherm method, hygrometer reading and other relative humidity measurements, determination of shale pore water salinity from sand pore water salinity overlaying and underlying the shales		Shale Activity/Pore Water Salinity	
9, 3,5, Pressure Build-up tests like 6 and 7, 4, 2, 10, Ratio Methods, empirical methods using log information and compaction trends, etc.,	Pore Pressure Gradient	Pore Pressure	
Loggers or Drillers Depth, Reservoir modeling and interpretation tools	Depth, Well trajectory	D R I L L I N G D A T A	W E L L P A T H
Seismic information, drilling data, 18, etc.	Geologic information (presence of faults and types of faults)		
Case history for a local well where no or very few problems were seen	Successful mud programs		

11, 4, 12	Static and equivalent circulating density.	Mud Weight	D R I L L I N G F L U I D
Laboratory titration experiments like the Baroid method and the API method, drilling fluid daily reports		Drilling Fluid Activity	
Laboratory testing of preserved shale cores using experiments like the Pore Pressure Transmission (PPT) test, Linear Swell Meter Tests, measuring changes in formation properties using field information like, 2, 3, 5, 9, 13, 16, 17, 18, 19, 20	Time dependent changes in formation water content, porosity, resistivity, sonic velocity and travel time, formation density, etc.	Membrane Efficiency	
Microscopic Imaging Techniques, Physical Intrusion Techniques like mercury injection, and nuclear techniques such as using nuclear magnetic resonance techniques (laboratory or wireline or MWD), 2	Pore radii and distribution, solute/water relative mobility		
1, 2, 3, 4, 5, 8, 9, 18	Clay Content and Formation Type	R O C K S T R E N G T H	
3, 4, Di-adsorption methods such as Methylene Blue Tests or Compulsive Exchange Methods like the barium chloride compulsive exchange method	Cation Exchange Capacity (CEC)/Surface Area, Ionic Strength Modification Exchange Equations		
2, 3, 4, 5, 8, 10, 15, 16, 18, 20	Formation Water Content/Porosity/Permeability		
Laboratory analysis of cores, empirical correlation's using the following sources - 1, 2, 3, 4, 5, 17, 18, 20 and formation dielectric constant measurement.			

In applying the method of this invention, at least some understanding of the drilling fluid/formation interaction should preferably be obtained prior to applying any total potential or wellbore (in)stability model for a real-time drilling operation. A Pore Pressure Transmission (PPT) test or any other relevant test can be used to estimate the impact of a drilling fluid on the formation properties i.e., including but not limited to transient pore pressure, water content, electrical properties, acoustic properties, etc.

Changes in the shale stress due to alterations of the above mentioned properties can be obtained from the simultaneous acquisition of sonic compression and shear wave velocity data. A time-dependent total potential related shale transient pressure obtained from the PPT can be used to address issues where exposure time related borehole deterioration is observed.

The foregoing description of the invention is intended to be a description of preferred embodiments. Various changes in the details of the described method, including without limitation details concerning the wellbore stability model, can be made without departing from the intended scope of this invention as defined by the appended claims.

HALB:006WO

We claim:

1. A method employing drilling fluid for drilling a wellbore penetrating a subterranean formation, said method comprising real-time monitoring of the stability of said wellbore
5 using a wellbore stability model during said drilling of the wellbore.
2. The method of claim 1 comprising:
 - (a) obtaining preliminary values for mud weight and chemical composition of said drilling fluid using said wellbore stability model;
 - 10 (b) measuring acoustic, sonic, electrical, thermal and transient pressure responses of the formation;
 - (c) calibrating said wellbore stability model with said measurements; and
 - (d) obtaining values for drilling mud weight and chemical composition of said drilling fluid using said calibrated wellbore stability model.
- 15 3. The method of claim 2 wherein said chemical composition values comprise values for salinity.
4. The method of claim 2 further comprising repeating steps (b) and (d) during drilling
20 of said wellbore.
5. The method of claim 2 further comprising adjusting said drilling mud weight and salinity of said drilling fluid based on said values obtained with the calibrated wellbore stability model.
- 25 6. The method of claim 2 wherein said formation comprises shale.
7. The method of claim 2 wherein the measurements of step (b) are taken simultaneously during drilling of the wellbore in said formation.
- 30 8. A method employing well service fluid for servicing a wellbore penetrating a subterranean formation, said method comprising real-time monitoring of the stability

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of said wellbore using a wellbore stability model during said servicing of said wellbore.

9. The method of claim 8 comprising:

- 5 (a) obtaining preliminary values for weight and chemical composition of said well service fluid using said wellbore stability model;
- (b) measuring acoustic, sonic, electrical, thermal and transient pressure responses of the formation;
- (c) calibrating said wellbore stability model with said measurements; and
- 10 (d) obtaining values for the weight and chemical composition of said well service fluid using said calibrated wellbore stability model.

10. A method for enhancing the recovery of hydrocarbons from a hydrocarbon bearing formation employing enhanced recovery fluids, said method comprising real-time monitoring
15 of the stability of said formation using a wellbore stability model during said enhanced recovery.

11. A method for producing hydrocarbons from a hydrocarbon bearing formation while monitoring the stability of said formation, said method comprising real-time monitoring of
20 the stability of said formation using a wellbore stability model during said production.

12. A method for maintaining stability of a wellbore penetrating a subterranean formation during drilling or well servicing operations, or during production or enhanced recovery operations, using fluids introduced into said wellbore to facilitate said operations, said
25 method comprising:

- estimating characteristic properties of the formation;
- estimating in-situ stresses in the formation;
- estimating or determining characteristic properties of said fluids;
- estimating the rock strength of said formation;
- 30 conducting at least one pore pressure versus time laboratory test based on said estimations of fluid properties, formation properties, and rock strength;
- employing results of said test, said estimations of formation properties, in-situ

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stresses, rock strength, and said fluid properties in a wellbore stability model;

using results from said model to adjust estimates of said formation properties, in-situ stresses in the formation; and rock strength to update said wellbore stability model or using results from said model to adjust the properties of said fluids to maintain or enhance said
5 rock strength;

continuing during said operations to estimate or measure characteristic properties of the formation and of said fluids during said well operations and continuing to repeat or update on a real-time basis the estimates of in-situ stresses and rock strength based on said properties;

10 continuing to update the wellbore stability model and continuing to adjust on a real-time basis the properties of said fluids as needed to maintain or enhance said rock strength during said operations.

13. The method of claim 12 wherein at least the weight and salinity of said fluids are
15 adjusted in accordance with results from said wellbore stability model.

14. The method of claim 12 wherein said characteristic properties of the formation which are measured during said wellbore operations comprise acoustic, sonic, electrical, thermal, and transient pressure responses of the formation.

20

15. A method for maintaining stability of a wellbore penetrating a subterranean formation during operations comprising drilling, servicing, or producing wells employing fluids introduced into the wellbore to facilitate said operations, said method comprising monitoring on a real-time basis the interaction of said fluids on said formation and making adjustments in
25 the properties of said fluids to maintain or enhance the strength of said formation in contact with said fluids.

16. The method of claim 15 wherein monitoring of said interaction comprises taking real-time measurements of properties of the formation and using same in a wellbore stability
30 model.

17. The method of claim 16, further comprising using results from said wellbore stability

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model in making said adjustments in the properties of said fluids.

18. The method of claim 15 employing at least one pore pressure versus time laboratory test and wellbore stability modeling in making adjustments in the properties of said fluid.

5

19. A method for monitoring the interaction of a subterranean formation with fluids injected into or circulating in a wellbore penetrating said formation, said method comprising:

- constructing an earth-model of the formation adjacent or near the wellbore;
- 10 predicting suitable fluids for use in said wellbore;
- conducting laboratory experiments to ascertain time-dependent formation behavior in the presence of said predicted suitable fluids;
- measuring rock properties in said experiments;
- calibrating a wellbore stability model based on said measured rock properties;
- 15 injecting or circulating said fluids in said wellbore;
- measuring real-time static and dynamic rock properties while said fluids are in said wellbore;
- updating said wellbore stability model with said real-time measurements;
- adjusting the properties of said fluids as needed to maintain wellbore stability
- 20 according to said model.

20. The method of claim 19 wherein said real-time measuring of rock properties and said updating of the wellbore stability model are repeated during said injecting or circulating of said fluids in said wellbore enough times that the interaction of said subterranean formation
25 with said fluids may be monitored on a real-time basis.

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ABSTRACT

A real-time method is disclosed for maintaining subterranean formation stability through monitoring the interaction between the formation and fluids introduced into (or produced from) a wellbore penetrating the formation. The method employs real-time wellbore (in)stability logging methodology. The method is exemplified by a Pore Pressure Transmission (PPT) test. In such test, test fluids are exposed to Pierre II shales (20% w/w NaCl solution and sodium silicate fluid with 20% w/w NaCl, for example) in a PPT apparatus. Membrane efficiency of the two fluids when exposed to the outcrop shale is calculated, and based on the simultaneous acquisition of acoustic data, estimation of a dynamic rock property is made. Calibrating representative shale (or other formation) core responses to drilling fluids (or well service fluids, enhanced recovery fluids, or production fluids) under realistic in-situ conditions aids in accurately modeling for time-dependent formation (in)stability in the field for the entire life of the wellbore, from drilling, completion and through production.

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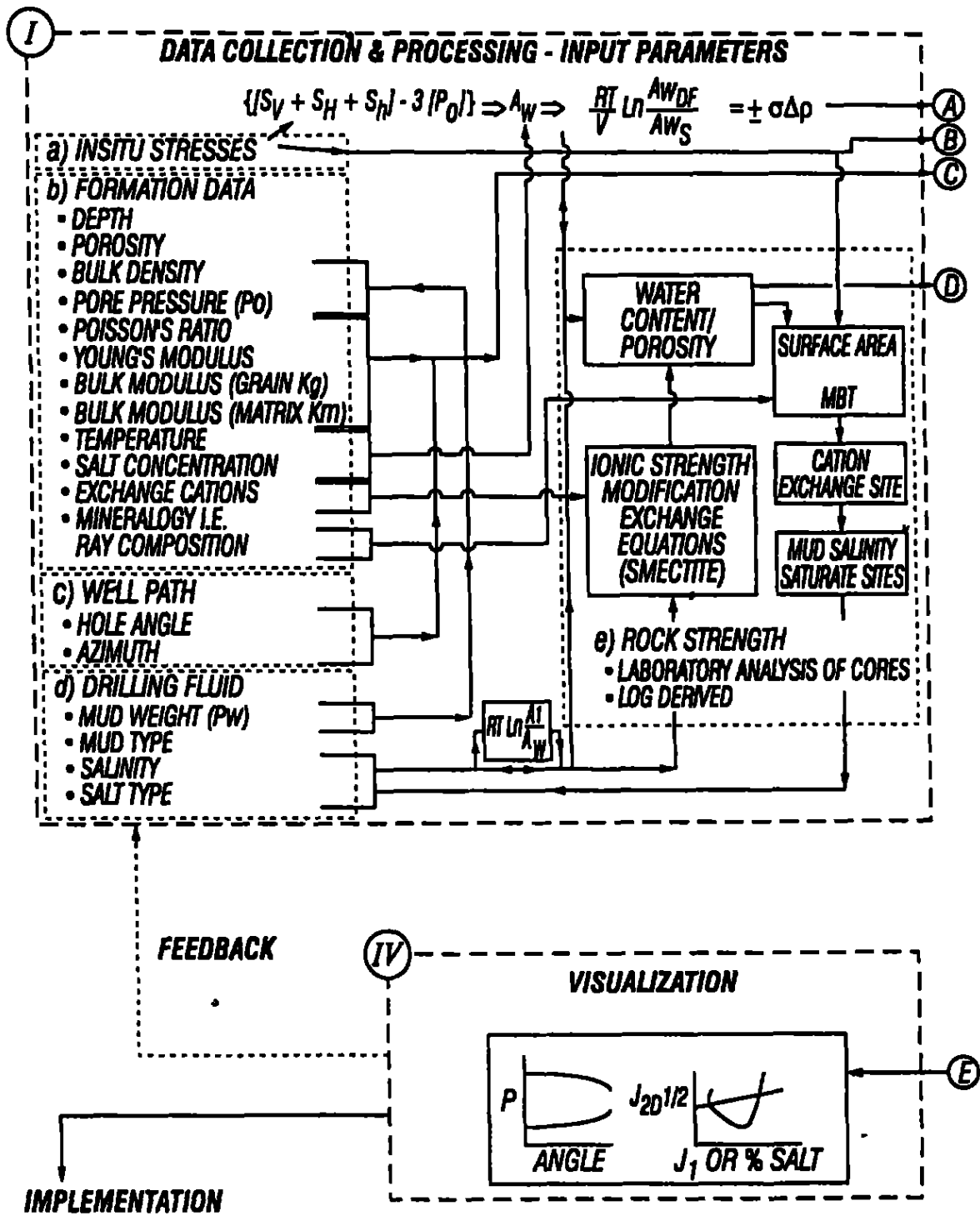


FIG. 1A

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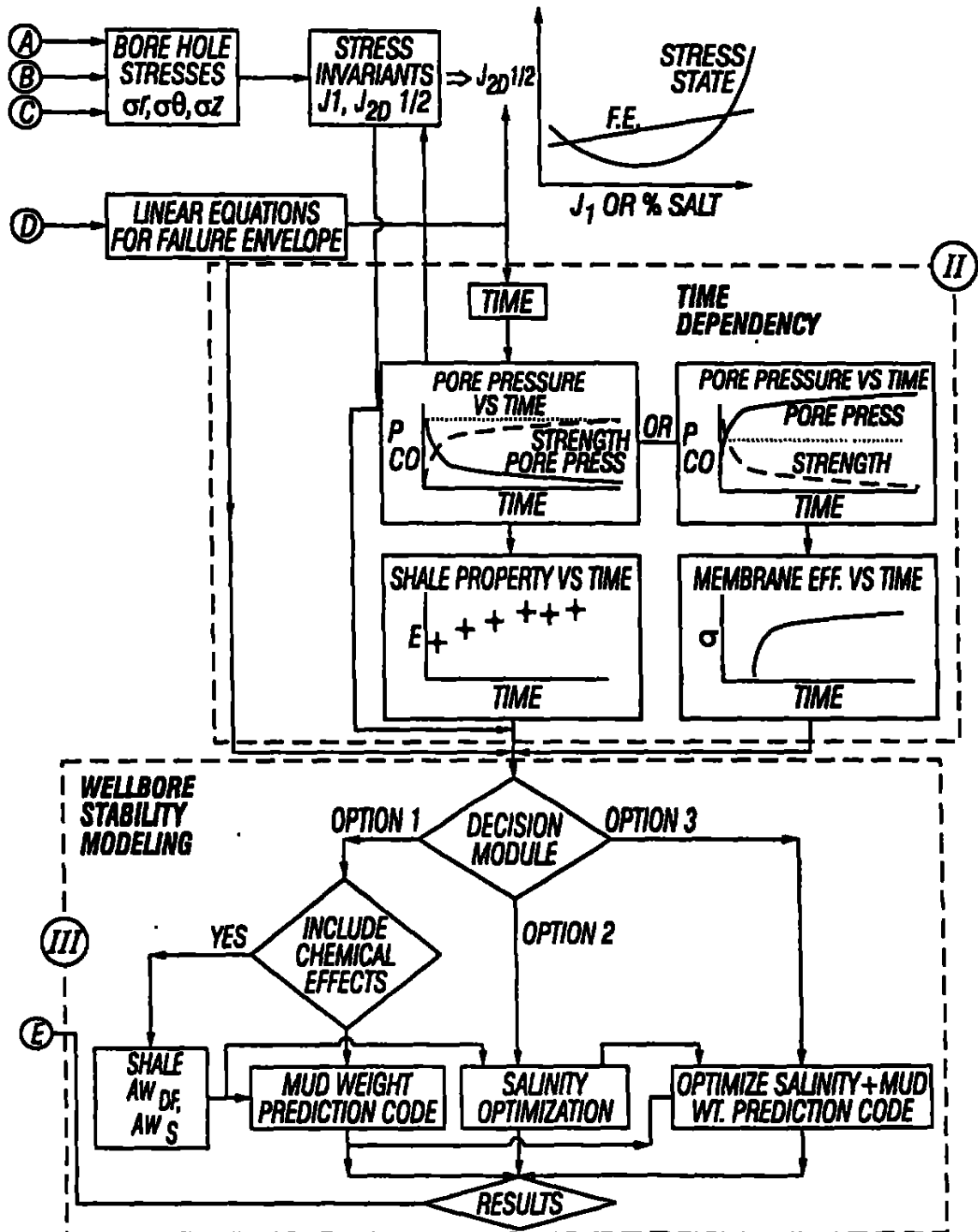
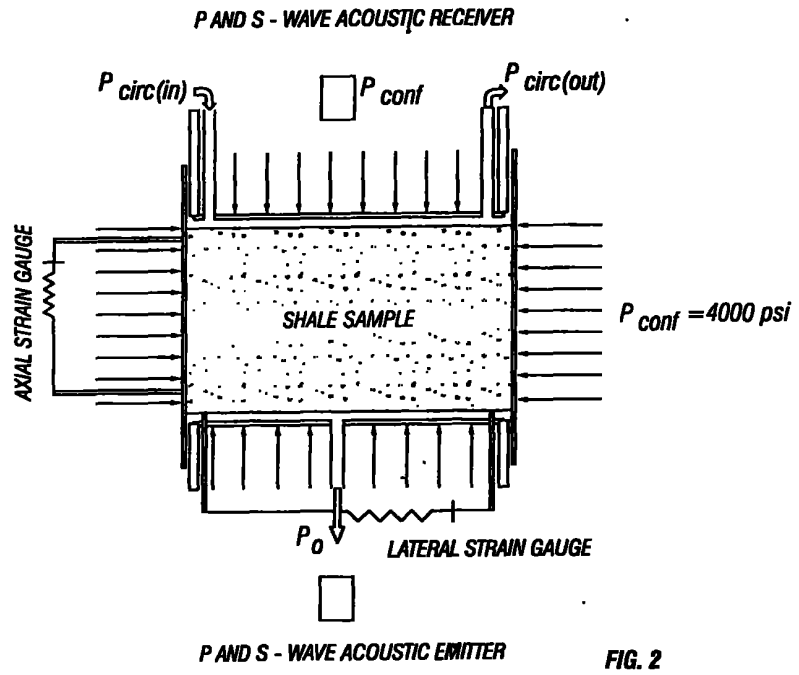


FIG. 1B

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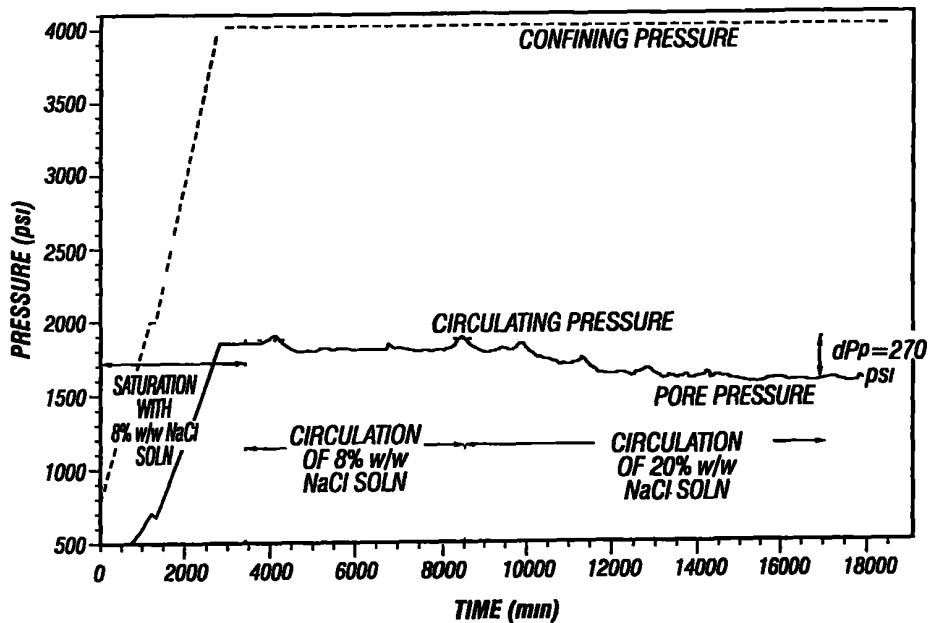
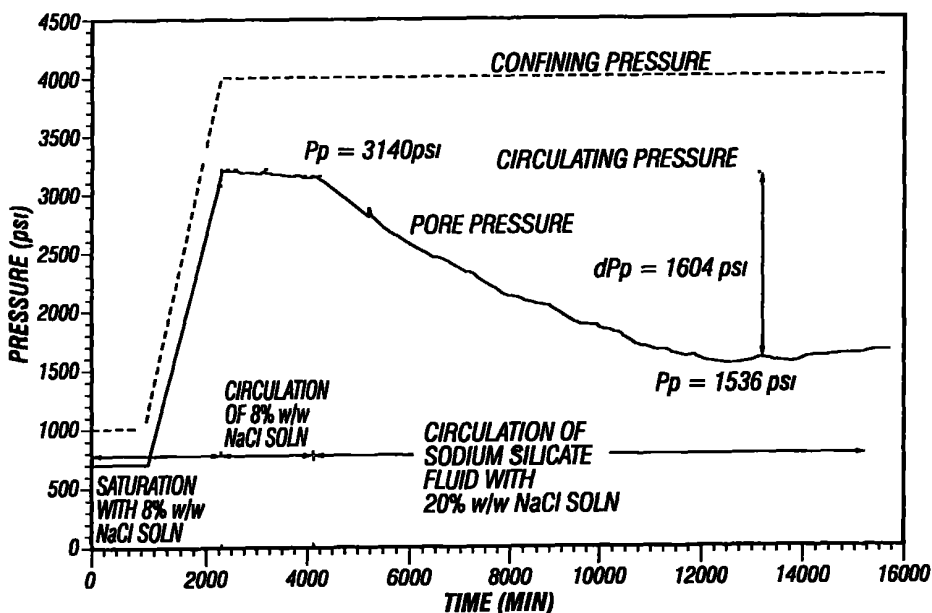


FIG 3

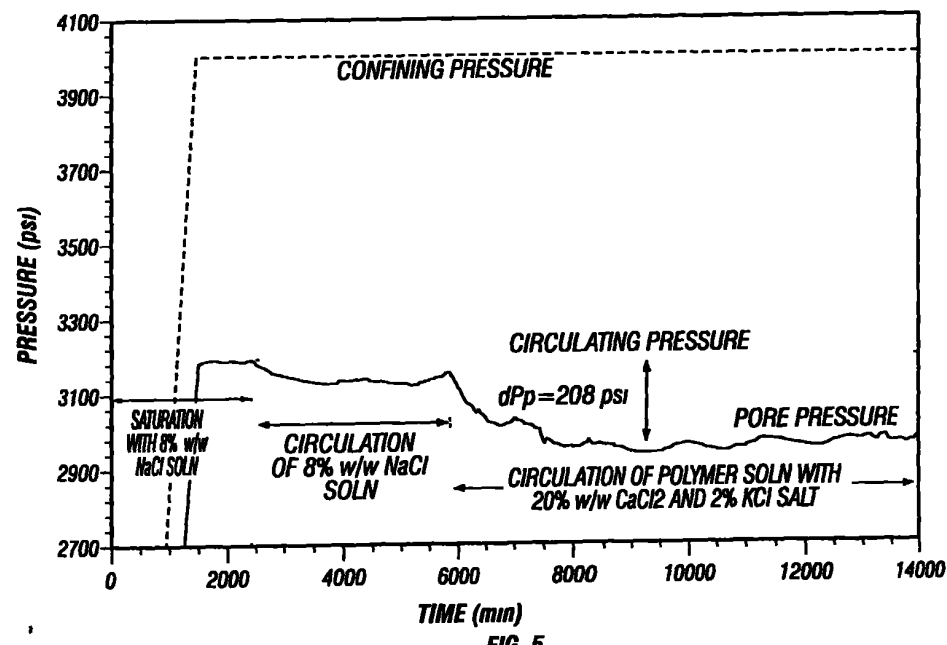
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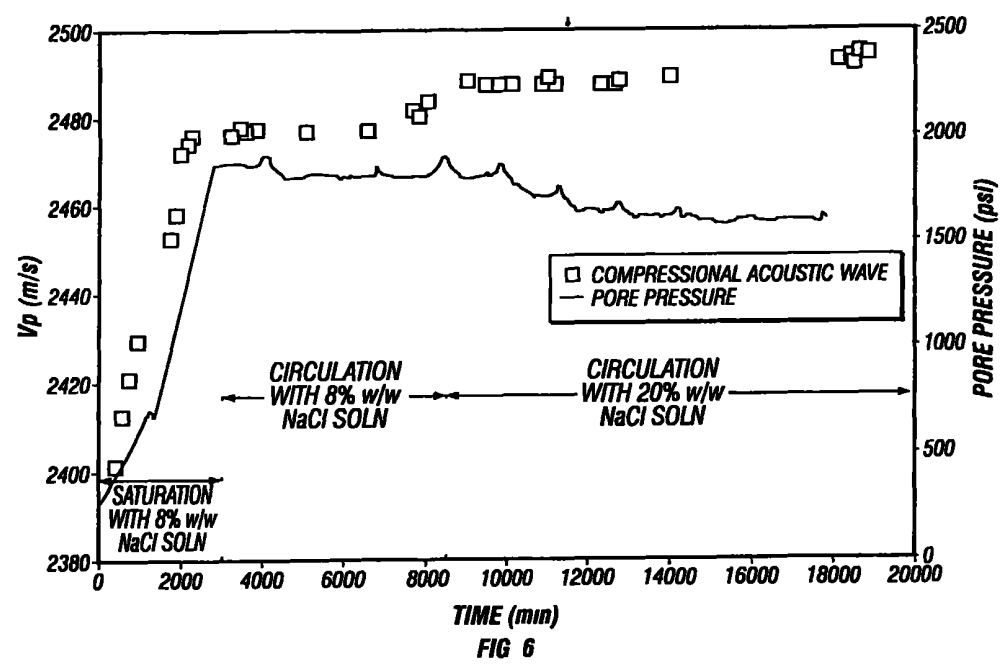
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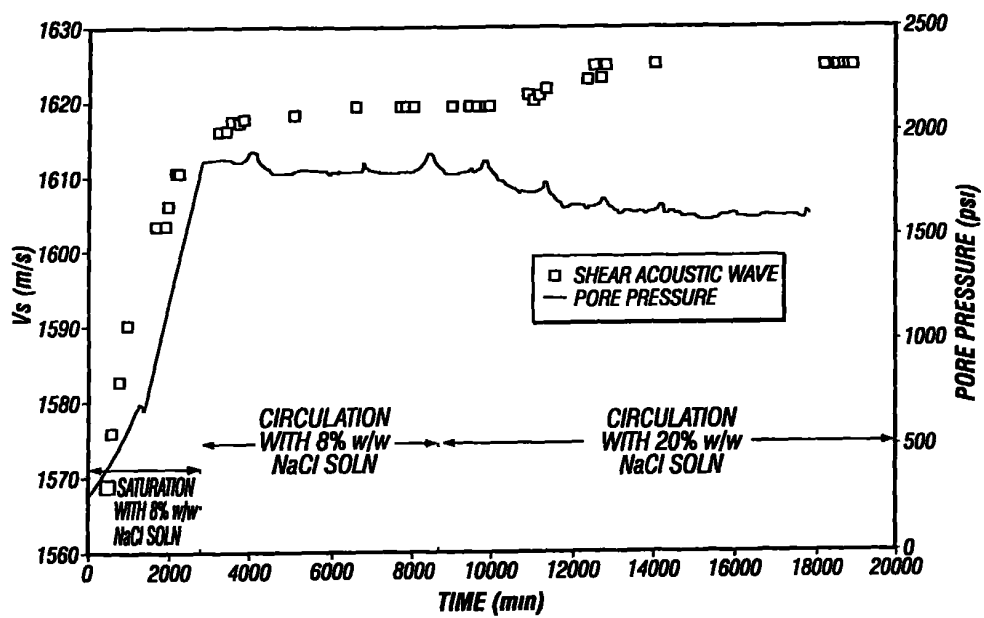
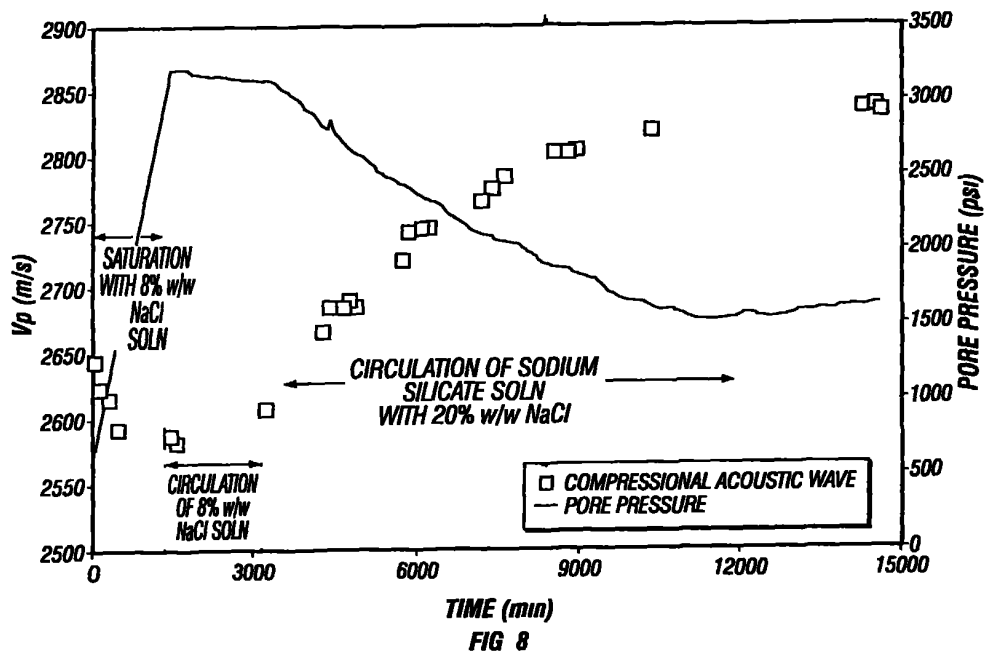


FIG 7

AA

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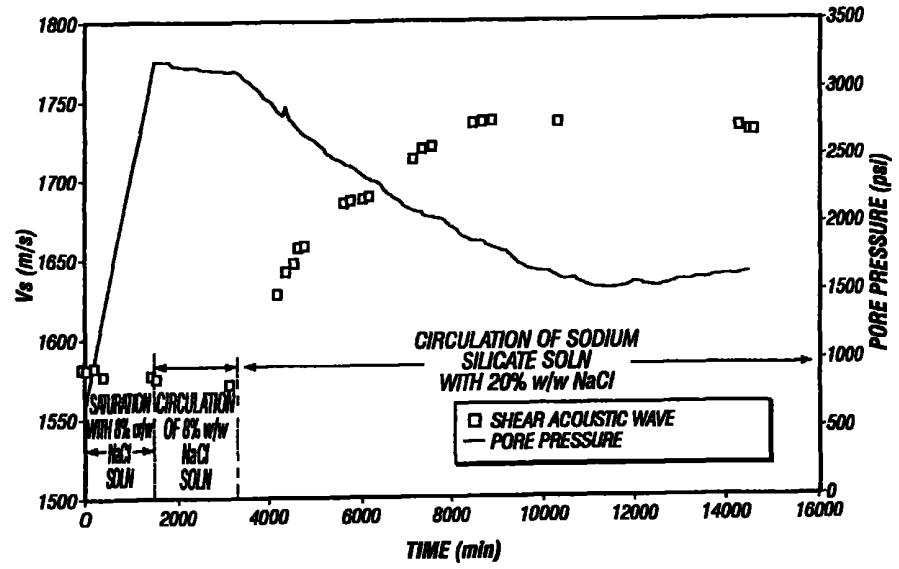
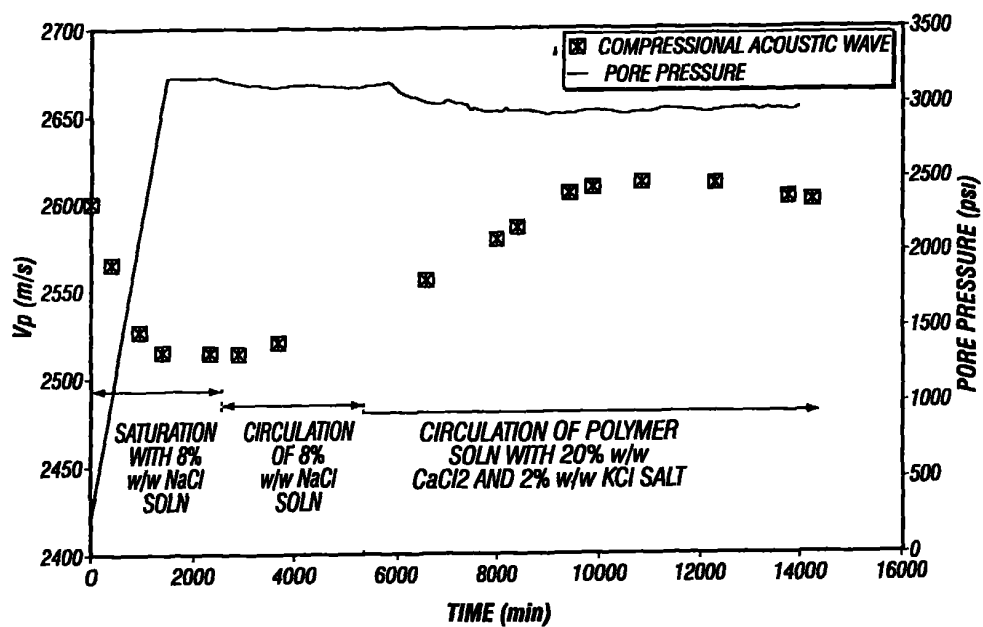


FIG 9

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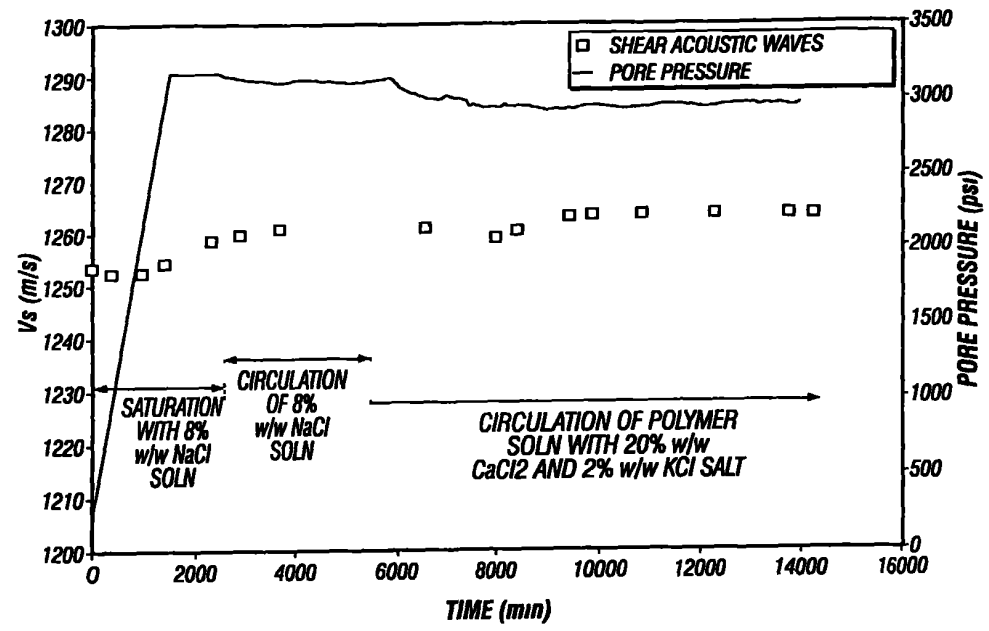


FIG 11

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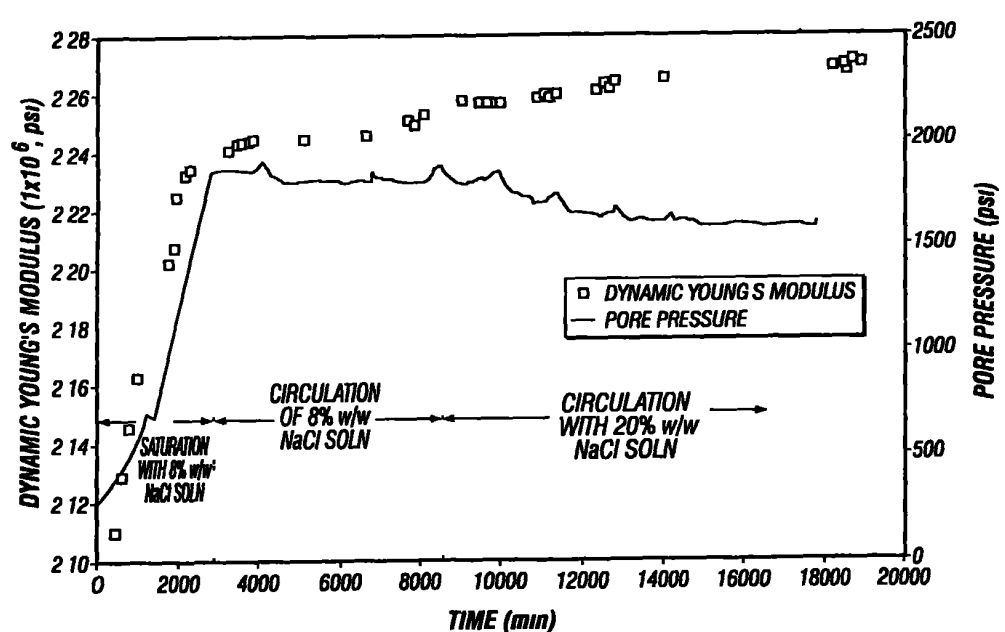


FIG 12

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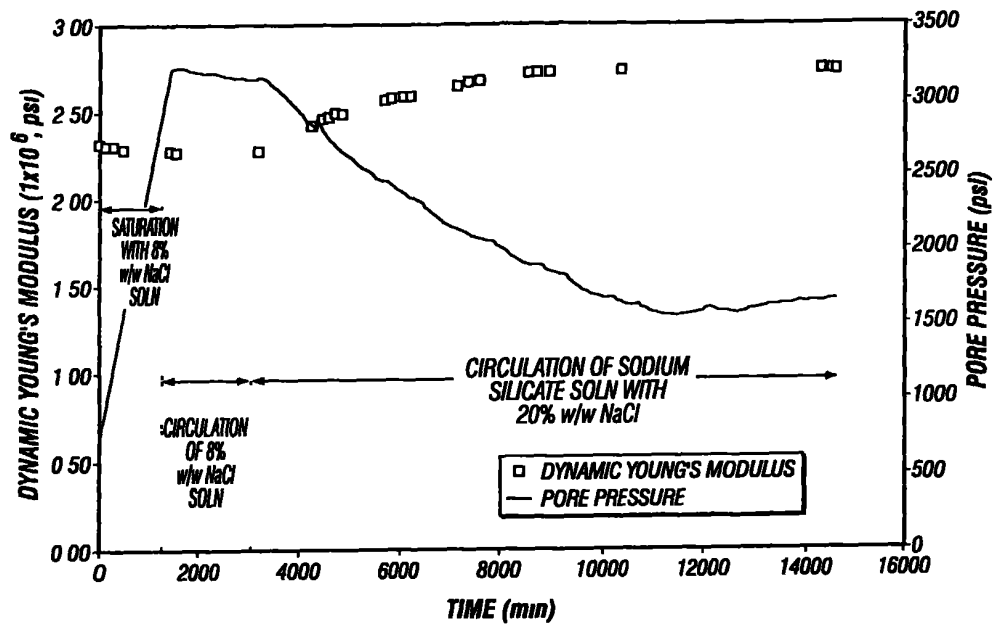


FIG 13

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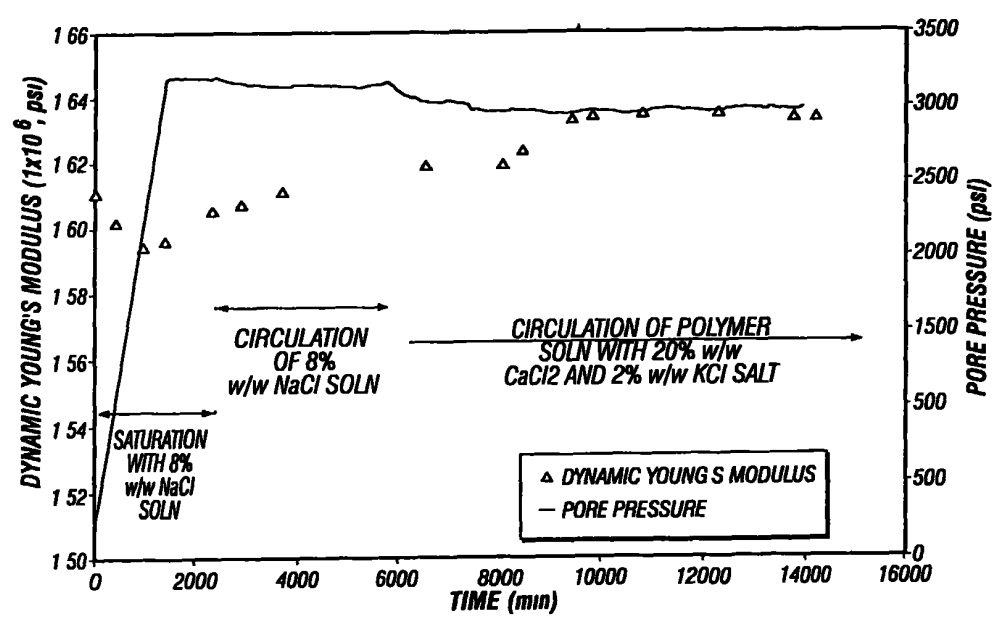


FIG 14

PATENT COOPERATION TREATY

PCT

NOTIFICATION OF THE RECORDING
OF A CHANGE(PCT Rule 92bis.1 and
Administrative Instructions, Section 422)

From the INTERNATIONAL BUREAU

To:

TRIPP, Karen, B.
P.O. Box 1301
Houston, TX 77251-1301
ETATS-UNIS D'AMERIQUEDate of mailing (day/month/year).
21 November 2001 (21.11.01)Applicant's or agent's file reference
HALB:006

IMPORTANT NOTIFICATION

International application No.
PCT/US01/18134International filing date (day/month/year)
05 June 2001 (05.06.01)

1. The following indications appeared on record concerning:

☐ the applicant ☐ the inventor ☒ the agent ☐ the common representative

Name and Address

TRIPP, Karen, B.
Suite 2690
1100 Louisiana Street
Houston, TX 77002
United States of America

State of Nationality

State of Residence

Telephone No.

(713) 658-9323

Facsimile No.

(713) 658-9410

Teleprinter No.

2. The International Bureau hereby notifies the applicant that the following change has been recorded concerning:

☐ the person ☐ the name ☒ the address ☐ the nationality ☐ the residence

Name and Address

TRIPP, Karen, B.
P.O. Box 1301
Houston, TX 77251-1301
United States of America

State of Nationality

State of Residence

Telephone No.

(713) 658-9323

Facsimile No.

(713) 658-9410

Teleprinter No.

3. Further observations, if necessary:

4. A copy of this notification has been sent to:

☒ the receiving Office ☐ the designated Offices concerned
☐ the International Searching Authority ☐ the elected Offices concerned
☐ the International Preliminary Examining Authority ☐ other:The International Bureau of WIPO
34, chemin des Colombettes
1211 Geneva 20, Switzerland

Facsimile No.: (41-22) 740.14.35

Authorized officer

R. Chrem

Telephone No.: (41-22) 338.83.38

PATENT COOPERATION TREATY

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PCT

NOTIFICATION OF RECEIPT OF
RECORD COPY

(PCT Rule 24.2(a))

From the INTERNATIONAL BUREAU

To:

TRIPP, Karen, B.
Suite 2690
1100 Louisiana Street
Houston, TX 77002
ETATS-UNIS D'AMERIQUEDate of mailing (day/month/year)
18 July 2001 (18.07.01)

IMPORTANT NOTIFICATION

Applicant's or agent's file reference
HALB:006International application No.
PCT/US01/18134

The applicant is hereby notified that the International Bureau has received the record copy of the international application as detailed below.

Name(s) of the applicant(s) and State(s) for which they are applicants:

HALLIBURTON ENERGY DEVICES, INC. (all designated States)

International filing date : 05 June 2001 (05.06.01)

Priority date(s) claimed : 06 June 2000 (06.06.00)

Date of receipt of the record copy
by the International Bureau : 28 June 2001 (28.06.01)

List of designated Offices :

AP : GH, GM, KE, LS, MW, MZ, SD, SL, SZ, TZ, UG, ZW

EA : AM, AZ, BY, KG, KZ, MD, RU, TJ, TM

FP : AT, RF, CH, CY, DE, DK, ES, FI, FR, GB, GR, IE, IT, LU, MC, NL, PT, SE, TR

OA : BF, BJ, CF, CG, CI, CM, GA, GN, GW, ML, MR, NE, SN, TD, TG

National : AE, AG, AL, AM, AT, AU, AZ, BA, BB, BG, BR, BY, BZ, CA, CH, CN, CO, CR, CU, CZ, DE, DK, DM, DZ,

EE, 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, NO, NZ, PL, PT, RO, RU, SD, SE, SG, SI, SK, SL, TJ, TM, TR, TT, TZ, UA, UG,

UZ, VN, YU, ZA, ZW

ATTENTION

The applicant should carefully check the data appearing in this Notification. In case of any discrepancy between these data and the indications in the international application, the applicant should immediately inform the International Bureau.

In addition, the applicant's attention is drawn to the information contained in the Annex, relating to:

☒ time limits for entry into the national phase☒ confirmation of precautionary designations☒ requirements regarding priority documents

A copy of this Notification is being sent to the receiving Office and to the International Searching Authority.

The International Bureau of WIPO
34, chemin des Colombettes
1211 Geneva 20, Switzerland

Authorized officer:

R. Chren

Facsimile No. (41-22) 740.14.35

Telephone No. (41-22) 338.83.38

Form PCT/IB/301 (July 1995)

004158582

INFORMATION ON TIME LIMITS FOR ENTERING THE NATIONAL PHASE

The applicant is reminded that the "national phase" must be entered before each of the designated Offices indicated in the Notification of Receipt of Record Copy (Form PCT/IB/301) by paying national fees and furnishing translations, as prescribed by the applicable national laws.

The time limit for performing these procedural acts is 20 MONTHS from the priority date or, for those designated States which the applicant elects in a demand for international preliminary examination or in a later election, 30 MONTHS from the priority date, provided that the election is made before the expiration of 19 months from the priority date. Some designated (or elected) Offices have fixed time limits which expire even later than 20 or 30 months from the priority date. In other Offices an extension of time or grace period, in some cases upon payment of an additional fee, is available.

In addition to these procedural acts, the applicant may also have to comply with other special requirements applicable in certain Offices. It is the applicant's responsibility to ensure that the necessary steps to enter the national phase are taken in a timely fashion. Most designated Offices do not issue reminders to applicants in connection with the entry into the national phase.

For detailed information about the procedural acts to be performed to enter the national phase before each designated Office, the applicable time limits and possible extensions of time or grace periods, and any other requirements, see the relevant Chapters of Volume II of the PCT Applicant's Guide. Information about the requirements for filing a demand for international preliminary examination is set out in Chapter IX of Volume I of the PCT Applicant's Guide.

GR and ES became bound by PCT Chapter II on 7 September 1986 and 8 September 1987, respectively, and may, therefore, be elected in a demand or a later election filed on or after 7 September 1986 and 8 September 1987, respectively, regardless of the filing date of the international application. (See second paragraph above.)

Note that only an applicant who is a national or resident of a PCT Contracting State which is bound by Chapter II has the right to file a demand for international preliminary examination.

CONFIRMATION OF PRECAUTIONARY DESIGNATIONS

This notification lists only specific designations made under Rule 4.8(a) in the request. It is important to check that these designations are correct. Errors in designations can be corrected where precautionary designations have been made under Rule 4.8(b). The applicant is hereby reminded that any precautionary designations may be confirmed according to Rule 4.8(c) before the expiration of 16 months from the priority date. If it is not confirmed, it will automatically be regarded as withdrawn by the applicant. There will be no reminder and no invitation. Confirmation of a designation consists of the filing of a notice specifying the designated State concerned (with an indication of the kind of protection or treatment desired) and the payment of the designation and confirmation fees. Confirmation must reach the receiving Office within the 16-month time limit.

REQUIREMENTS REGARDING PRIORITY DOCUMENTS

For applicants who have not yet complied with the requirements regarding priority documents, the following is recalled.

Where the priority of an earlier national, regional or international application is claimed, the applicant must submit a copy of the said earlier application, certified by the authority with which it was filed ("the priority document"), to the receiving Office (which will transmit it to the International Bureau) or directly to the International Bureau, before the expiration of 16 months from the priority date, provided that any such priority document may still be submitted to the International Bureau before that date of international publication of the international application, in which case that document will be considered to have been received by the International Bureau on the last day of the 16-month time limit (Rule 17.1(a)).

Where the priority document is issued by the receiving Office, the applicant may, instead of submitting the priority document, request the receiving Office to prepare and transmit the priority document to the International Bureau. Such request must be made before the expiration of the 16-month time limit and may be subjected by the receiving Office to the payment of a fee (Rule 17.1(b)).

If the priority document concerned is not submitted to the International Bureau or if the request to the receiving Office to prepare and transmit the priority document has not been made (and the corresponding fee, if any, paid) within the applicable time limit indicated under the preceding paragraphs, any designated State may disregard the priority claim, provided that no designated Office may disregard the priority claim concerned before giving the applicant an opportunity to furnish the priority document within a time limit which is reasonable under the circumstances.

Where several priorities are claimed, the priority date to be considered for the purposes of computing the 16-month time limit is the filing date of the earliest application whose priority is claimed.

IN THE UNITED STATES PATENT OFFICE
BEFORE THE INTERNATIONAL PRELIMINARY EXAMINING AUTHORITY

In Re Application of: Halliburton Energy Services, Inc.
International Application No: PCT/US01/18134
International Filing Date: 05 JUN 01
Priority Date: 06 JUN 00
Attorney Docket No: HALB:006
Title: REAL-TIME METHOD FOR MAINTAINING
FORMATION STABILITY AND MONITORING
FLUID-FORMATION INTERACTION

Commissioner for Patents
Box PCT
Washington, DC 20231
Attn: IPEA/US

TRANSMITTAL OF CHAPTER II DEMAND

Enclosed is a Chapter II Demand, a check for the fee for same, and a change of address
notice for the agent.

Respectfully submitted,

Date: 16 October 2001

Karen B. Tripp
Karen B. Tripp

Karen B. Tripp
Attorney at Law
P.O. Box 1301
1100 Louisiana, Suite 2690
Houston, Texas 77251-1301
United States of America
(713) 658-9323 - Phone
(713) 658-9410 - Fax
ktripp@tripplaw.com (e-mail)

The demand must be filed directly with the competent International Preliminary Examining Authority or, if two or more Authorities are 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

IPEA/ US

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 and hereby elects all eligible States (except where otherwise indicated).

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 HALB:008	
International application No. PCT/US01/18134	International filing date (day/month/year) 05 JUNE 2001 (05/06/01)	(Earliest) Priority date (day/month/year) 06 JUNE 2000 (06/06/00)	
Title of invention Real-Time Method for Maintaining Formation Stability and Monitoring Fluid -Formation Interaction			
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.) Halliburton Energy Services, Inc. 10200 Belleire Boulevard Houston, TX 77072-5208 US		Telephone No. 580 251 3012 Facsimile No. 580 251 3017 Teleprinter No. , Applicant's registration No. with the Office	
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.)			
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:	
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 a continuation sheet.			

Box No. III AGENT OR COMMON REPRESENTATIVE; OR ADDRESS FOR CORRESPONDENCE

The following person is ☒ agent ☐ common representativeand ☒ 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
The address must include postal code and name of country.)Tripp, Karen B.
Attorney at Law
P.O. Box 1301
1100 Louisiana Street, Suite 2600
Houston, TX 77251-1301
US

Telephone No.

713 658 9323

Facsimile No.

713 658 9410

Teleprinter No.

Agent's registration No. with the Office
30,452☐ 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 34the claims ☒ as originally filed☐ as amended under Article 19 (together with any accompanying statement)☐ as amended under Article 34the drawings ☒ as originally filed☐ as amended under Article 342 ☐ 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 20 months from the priority date unless the International Preliminary Examining Authority receives a copy of any amendments made under Article 19 or a notice from the applicant that he does not wish to make such amendments (Rule 69.1(d)). (This check-box may be marked only where the time limit under Article 19 has not yet expired.)

* 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 applicant hereby elects all eligible States (that is, all States which have been designated and which are bound by Chapter II of the PCT)

excluding the following States which the applicant wishes not to elect:

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:

- | | | |
|---|---|----------|
| 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 | 1 sheets |
| 6 | other (specify):
Change of Mailing Address for Agent | 1 sheets |

For International Preliminary Examining Authority use only

received	not received
☐	☐
☐	☐
☐	☐
☐	☐
☐	☐
☐	☐

The demand is also accompanied by the item(s) marked below:

- | | |
|--|--|
| 1. ☒ fee calculation sheet | 5. ☐ statement explaining lack of signature |
| 2. ☐ original separate power of attorney | 6. ☐ sequence listing in computer readable form |
| 3. ☐ original general power of attorney | 7. ☐ other (specify): |
| 4. ☐ copy of general power of attorney; reference number, if any: | |

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).

Karen B. Tripp

Karen B. Tripp

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 period 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.	

For International Bureau use only

Demand received from IPEA on:

IN THE UNITED STATES PATENT OFFICE
BEFORE THE INTERNATIONAL PRELIMINARY EXAMINING AUTHORITY

In Re Application of: Halliburton Energy Services, Inc.
International Application No: PCT/US01/18134
International Filing Date: 05 JUN 01
Priority Date: 06 JUN 00
Attorney Docket No: HALB:006
Title: REAL-TIME METHOD FOR MAINTAINING
FORMATION STABILITY AND MONITORING
FLUID-FORMATION INTERACTION

Commissioner for Patents
Box PCT
Washington, DC 20231
Attn: IPEA/US

CHANGE OF ADDRESS FOR AGENT

Please change the mailing address for the agent for all competent International
Authorities to the following:

Karen B. Tripp, Attorney at Law
P.O. Box 1301
Houston, Texas 77251-1301
US

The identity of the agent has not changed.

Respectfully submitted,

Date: 16 October 2001

Karen B. Tripp
Karen B. Tripp

Karen B. Tripp
Attorney at Law
1100 Louisiana, Suite 2690
Houston, Texas 77002
United States of America
(713) 658-9323 - Phone
(713) 658-9410 - Fax
ktripp@tripplaw.com (e-mail)

PCT

FEE CALCULATION SHEET

Annex to the Demand

International application No. PCT/US01/18134		For International Preliminary Examining Authority use only	
Applicant's or agent's file reference HALB:006		Date stamp of the IPEA	
Applicant Halliburton Energy Services, Inc.			
CALCULATION OF PRESCRIBED FEES			
1 Preliminary examination fee		750.00	P
2 Handling fee <i>(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)</i>		137.00	H
3 Total of prescribed fees Add the amounts entered at P and H and enter total in the TOTAL box		887.00	
		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 <i>(This mode of payment may not be available at all IPEAs)</i>			
☐ Authorization to charge the total fees indicated above.	IPEA: US	Deposit Account No. 50-0807	
☒ <i>(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.</i>	Date: October 16, 2001	Name: Karen B. Tripp	
	Signature: Karen B. Tripp		

PATENT COOPERATION TREATY

From the
INTERNATIONAL PRELIMINARY EXAMINING AUTHORITY

PCT

WRITTEN OPINION

(PCT Rule 66)

To: KAREN B. TRIPP
PO BOX 1301
1100 LOUISIANA ST STE 2690
HOUSTON TX 77251-1301Date of Mailing
(day/month/year)

05 AUG 2002

Applicant's or agent's file reference

HALB:006

REPLY DUE

within TWO months
from the above date of mailing

International application No.

PCT/US01/18134

International filing date (day/month/year)

05 JUNE 2001

Priority date (day/month/year)

05 JUNE 2001

International Patent Classification (IPC) or both national classification and IPC
IPC(7):E21B44/00 and US Cl.:702/9

Applicant

HALIBURTON ENERGY SERVICES, INC.

1. This written opinion is the first (first, etc.) drawn by the International Preliminary Examining Authority.

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

- I ☒ Basis of the opinion
- II ☐ Priority
- III ☐ Non-establishment of opinion with regard to novelty, inventive step or industrial applicability
- IV ☐ Lack of unity of invention
- V ☒ Reasoned statement under Rule 66.2(a)(ii) with regard to novelty, inventive step or industrial applicability: reasons and explanations supporting such statement
- VI ☐ Certain documents cited
- VII ☐ Certain defects in the international application
- VIII ☐ Certain observations on the international application

3. The applicant is hereby invited to reply to this opinion.

When? See the time limit indicated above. The applicant may, before the expiration of that time limit, request this Authority on grounds of extension, see Rule 66.3(d).

How? By submitting a written reply, accompanied, where appropriate, by amendments, according to Rule 66.3. For the form and the language of the amendments, see Rules 66.8 and 66.9.

Also For an additional opportunity to submit amendments, see Rule 66.4.
For the examiner's obligation to consider amendments and/or arguments, see Rule 66.4 bis.
For an informal communication with the examiner, see Rule 66.6.

If no reply is filed, the international preliminary examination report will be established on the basis of this opinion.

4. The final date by which the international preliminary examination report must be established according to Rule 69.3 is: 06 OCTOBER 2002Name and mailing address of the IPEA/US
Commissioner of Patents and Trademarks
Box PCT
Washington, D.C. 20231

Facsimile No. (703) 305-3230

Authorized officer

DONALD MCELHENY, JR.

Telephone No. (703) 305-4900

Form PCT/IPEA/406 (cover sheet) (July 1998)

WRITTEN OPINION

International application No.

PCT/IJSD1/18134

1. Basis of the opinion

1. With regard to the elements of the international application:*

- ☒ the international application as originally filed
- ☒ the description:
- pages 1-18 , as originally filed
- pages NONE , filed with the demand
- pages NONE , filed with the letter of _____
- ☒ the claims:
- pages 19-22 , as originally filed
- pages NONE , as amended (together with any statement) under Article 19
- pages NONE , filed with the demand
- pages NONE , filed with the letter of _____
- ☒ the drawings:
- pages 1-15 , as originally filed
- pages NONE , filed with the demand
- pages NONE , filed with the letter of _____
- ☒ the sequence listing part of the description:
- pages NONE , as originally filed
- pages NONE , filed with the demand
- pages NONE , filed with the letter of _____

2. With regard to the language, all the elements marked above were available or furnished to this Authority in the language in which the international application was filed, unless otherwise indicated under this item.

These elements were available or furnished to this Authority in the following language _____ which is:

- ☐ the language of a translation furnished for the purposes of international search (under Rule 23.1(b)).
- ☐ the language of publication of the international application (under Rule 48.3(b)).
- ☐ the language of the translation furnished for the purposes of international preliminary examination (under Rules 55.2 and/or 55.3).

3. With regard to any nucleotide and/or amino acid sequence disclosed in the international application, the written opinion was drawn on the basis of the sequence listing:

- ☐ contained in the international application in printed form.
- ☐ filed together with the international application in computer readable form.
- ☐ furnished subsequently to this Authority in written form.
- ☐ furnished subsequently to this Authority in computer readable form.
- ☐ The statement that the subsequently furnished written sequence listing does not go beyond the disclosure in the international application as filed has been furnished.
- ☐ The statement that the information recorded in computer readable form is identical to the written sequence listing has been furnished.

4. ☒ The amendments have resulted in the cancellation of:

- ☒ the description, pages NONE
- ☒ the claims, Nos. NONE
- ☒ the drawings, sheets/fig NONE

5. ☐ This opinion has been drawn as if (some of) the amendments 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)).

* Replacement sheets which have been furnished to the receiving Office in response to an invitation under Article 14 are referred to in this opinion as "originally filed".

WRITTEN OPINION

International application No.

PCT/US01/18134

V. Reasoned statement under Rule 66.2(a)(II) with regard to novelty, inventive step or industrial applicability; citations and explanations supporting such statement

1. statement

Novelty (N)	Claims	<u>2-7, 9-11</u>	YES
	Claims	<u>1, 8, 12, 13, 15-20</u>	NO
Inventive Step (IS)	Claims	<u>2-7, 9-11</u>	YES
	Claims	<u>1, 8, 12, 13, 15-20</u>	NO
Industrial Applicability (IA)	Claims	<u>1-20</u>	YES
	Claims	<u>NONE</u>	NO

2. citations and explanations

Claims 1, 8, 12, 13, and 15-20 lack novelty under PCT Article 33(2) as being anticipated by Leung et al. (5,285,692).

Leung et al. teach use of a real-time earth and wellbore model during drilling of the wellbore for the purpose of projecting and monitoring the stability of the wellbore and to control responses necessary to maintain integrity of the wellbore in view of updated monitoring readings. Use of laboratory tests assist in the accuracy of the model corrective adjustment. The fact that the drilling of a wellbore and functions associated with maintaining its integrity with wellbore fluids are both considered "servicing" of said wellbore, claims (e.g. 8) to "servicing" in the broadest sense are also taught by this reference.

Claims 2-7, 9-11, 14 meet the criteria set out in PCT Article 33(2)-(4), because the prior art does not teach or fairly suggest the use of a stability model of a wellbore during recovery stage of hydrocarbons nor require the specific combination of measuring sensors of acoustic, sonic, electrical, thermal and transient pressure response of the formation.

NEW CITATIONS

NONE

61

WRITTEN OPINION

International application No.
PCT/US01/18134

Supplemental Box
(To be used when the space in any of the preceding boxes is not sufficient)

Continuation of: Boxes I - VIII

Sheet 10

TIME LIMIT:

The time limit set for response to a Written Opinion may not be extended. 37 CFR 1.484(d). Any response received after the expiration of the time limit set in the Written Opinion will not be considered in preparing the International Preliminary Examination Report.

TRANSMITTAL LETTER TO THE
UNITED STATES RECEIVING OFFICE

Date	05 JUNE 01
International Application No.	
Agency Docket No.	HALB:008

I. Certification under 37 CFR 1.10 (If applicable)

EF307618012US	05 JUNE 01
Express Mail mailing number	Date of Deposit

I hereby certify that the application/correspondence attached hereto is being deposited with the United States Postal Service "Express Mail Post Office to Addressee" service under 37 CFR 1.10 on the date indicated above and is addressed to Assistant Commissioner for Patents, Washington, D.C. 20231.

<i>Karen B. Tripp</i>	KAREN B. TRIPP
Signature of person mailing correspondence	Typed or printed name of person mailing correspondence

II. ☒ New International Application

TITLE	REAL-TIME METHOD FOR MAINTAINING FORMATION STABILITY AND MONITORING FLUID-FORMATION INTERACTION	Earliest priority date (Day/Month/Year)
		08/08/00

SCREENING DISCLOSURE INFORMATION: In order to assist in screening the accompanying international application for purposes of determining whether a license for foreign transmittal should and could be granted and for other purposes, the following information is supplied. (Note: check as many boxes as apply):

A. ☐ The invention disclosed was not made in the United States.

B. ☐ There is no prior U.S. application relating to this invention.

C. ☒ The following prior U.S. application(s) contain subject matter which is related to the invention disclosed in the attached international application. (NOTE: priority to these applications may or may not be claimed on form PCT/RO/101, (Request) and this listing does not constitute a claim for priority).

application no.	60/209,488	filed on	08/08/00
application no.		filed on	

D. ☐ The present international application ☐ is identical ☐ contains less subject matter than that found in the prior U.S. application(s) identified in paragraph C.

E. ☒ The present international application ☒ contains additional subject matter not found in the prior U.S. application(s) identified in paragraph C. above. The additional subject matter is found on pages and ☒ DOES NOT ALTER ☐ MIGHT BE CONSIDERED TO ALTER the general nature of the invention in a manner which would require the U.S. application to have been made available for inspection by the appropriate defense agencies under 35 U.S.C. 181 and 37 CFR 5.1. See 37 CFR 5.13

III. ☐ A Response to an invitation from the RO/US. The following document(s) is (are) enclosed:

A. ☐ A Request for An Extension of Time to File a Response

B. ☐ A Power of Attorney (General or Regular)

C. ☐ Replacement pages:

pages		of the request (PCT/RO/101)	pages		of the figures
pages		of the description	pages		of the abstract
pages		of the claims			

D. ☐ Submission of Priority Documents

Priority document		Priority document	
-------------------	--	-------------------	--

E. ☐ Fees as specified on attached Fee Calculation sheet form PCT/RO/101 annex

IV. ☐ A Request for Rectification under PCT 91 ☐ A Petition ☐ A Sequence Listing Diskette

V. ☐ Other (please specify):

The person signing this form is the:

☐ Applicant	KAREN B. TRIPP, (Reg. No. 30,452)
☒ Attorney/Agent (Reg. No.)	Typed name of signer
☐ Common Representative	<i>Karen B. Tripp</i>
	Signature

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) HALB:008

Box No. I TITLE OF INVENTION REAL-TIME METHOD FOR MAINTAINING FORMATION STABILITY AND MONITORING FLUID-FORMATION INTERACTION	
Box No. II APPLICANT ☐ This person is also inventor	
Name and address: (Family name followed by given names; 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.) HALLIBURTON ENERGY SERVICES, INC. 10200 BELLAIRE BOULEVARD HOUSTON, TX 77072-5208 US	Telephone No. 580 251 3012 Facsimile No. 580 251 3017 Teleprinter No. 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	
Box No. III FURTHER APPLICANT(S) AND/OR (FURTHER) INVENTOR(S)	
Name and address: (Family name followed by given names; 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.) TARE, UDAY ARUN 2000 BAY AREA BLVD., APT #414 HOUSTON, TX 77058 IN	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: IN	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 names; for a legal entity, full official designation. The address must include postal code and name of country.) TRIPP, KAREN B. ATTORNEY AT LAW 1100 LOUISIANA STREET, SUITE 2080 HOUSTON, TX 77002 US	Telephone No. (713) 658-9323 Facsimile No. (713) 658-9410 Teleprinter No. Agent's registration No. with the Office 30,452
☐ 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 APPLICANTS AND/OR (FURTHER) INVENTOR(S)	
<i>If none of the following sub-boxes is used, this sheet should not be included in the request.</i>	
Name and address: (Family name followed by given names 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.) MODY, FERSHEED KHODADAD 5511 DAWN RIDGE HOUSTON, TX 77035	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 names 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.) MESE, ALI I. 10220 MEMORIAL DRIVE HOUSTON, TX 77024	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: TR	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 names 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.) JIAO, DI 2026 AUTUMN FERN DRIVE KATY, TX 77450	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: CN	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 names 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.) HAKIMUDDIN, MUSTAFA 1111 OAK MESA CT. HOUSTON, TX 77070	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: PAKISTAN	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 another continuation sheet.	

Box No.V	DESIGNATION OF STATES	Mark the applicable check-boxes below; at least one must be marked.
The following designations are hereby made under Rule 4 9(a):		
Regional Patent		
☒ AP	ARIPO Patent: GH Ghana, GM Gambia, KE Kenya, LS Lesotho, MW Malawi, MZ Mozambique, SD Sudan, SL Sierra Leone, SZ Swaziland, TZ United Republic of Tanzania, UG Uganda, ZW Zimbabwe, and any other State which is a Contracting State of the Harare Protocol and of the PCT	
☒ EA	Eurasian Patent: AM Armenia, AZ Azerbaijan, BY Belarus, KG Kyrgyzstan, KZ Kazakhstan, MD Republic of Moldova, RU Russian Federation, TJ Tajikistan, TM Turkmenistan, and any other State which is a Contracting State of the Eurasian	
☒ EP	European Patent: AT Austria, BE Belgium, CH & LI Switzerland and Liechtenstein, CY Cyprus, DE Germany, DK Denmark, ES Spain, FI Finland, FR France, GB United Kingdom, GR Greece, IE Ireland, IT Italy, LU Luxembourg, MC Monaco, NL Netherlands, PT Portugal, SE Sweden, TR Turkey, and any other State which is a Contracting State of the European Patent Convention and of the PCT	
☒ OA	OAPI Patent: BF Burkina Faso, BJ Benin, CF Central African Republic, CG Congo, CI Côte d'Ivoire, CM Cameroon, GA Gabon, GN Guinea, GW Guinea-Bissau, ML Mali, MR Mauritania, NE Niger, SN Senegal, TD Chad, TG Togo, and any other State which is a member State of OAPI and a Contracting State of the PCT (If other kind of protection or treatment desired, specify on dotted line)	
National Patent (If other kind of protection or treatment desired, specify on dotted line):		
☒ AE	United Arab Emirates	☒ GE Georgia
☒ AG	Antigua and Barbuda	☒ GH Ghana
☒ AL	Albania	☒ GM Gambia
☒ AM	Armenia	☒ HR Croatia
☒ AT	Austria	☒ HU Hungary
☒ AU	Australia	☒ ID Indonesia
☒ AZ	Azerbaijan	☒ IL Israel
☒ BA	Bosnia and Herzegovina	☒ IN India
		☒ IS Iceland
☒ BB	Barbados	☒ JP Japan
☒ BG	Bulgaria	☒ KE Kenya
☒ BR	Brazil	☒ KG Kyrgyzstan
☒ BY	Belarus	☒ KP Democratic People's Republic of Korea
☒ BZ	Belize	☒ KR Republic of Korea
☒ CA	Canada	☒ KZ Kazakhstan
☒ CH & LI	Switzerland and Liechtenstein	☒ LC Saint Lucia
☒ CN	China	☒ LK Sri Lanka
☒ CO	Colombia	☒ LR Liberia
☒ CR	Costa Rica	☒ LS Lesotho
☒ CU	Cuba	☒ LT Lithuania
☒ CZ	Czech Republic	☒ LU Luxembourg
☒ DE	Germany	☒ LV Latvia
☒ DK	Denmark	☒ MA Morocco
☒ DM	Dominica	☒ MD Republic of Moldova
☒ DZ	Algeria	
☒ EE	Estonia	☒ MG Madagascar
☒ ES	Spain	☒ MK The former Yugoslav Republic of Macedonia
☒ FI	Finland	☒ MN Mongolia
☒ GB	United Kingdom	
☒ GD	Grenada	
		☒ MW Malawi
		☒ MX Mexico
		☒ MZ Mozambique
		☒ NO Norway
		☒ NZ New Zealand
		☒ PL Poland
		☒ PT Portugal
		☒ RO Romania
		☒ RU Russian Federation
		☒ SD Sudan
		☒ SE Sweden
		☒ SG Singapore
		☒ SI Slovenia
		☒ SK Slovakia
		☒ SL Sierra Leone
		☒ TJ Tajikistan
		☒ TM Turkmenistan
		☒ TR Turkey
		☒ TT Trinidad and Tobago
		☒ TZ United Republic of Tanzania
		☒ UA Ukraine
		☒ UG Uganda
		☐ US United States of America
		☒ UZ Uzbekistan
		☒ VN Viet Nam
		☒ YU Yugoslavia
		☒ ZA South Africa
		☒ ZW Zimbabwe
Check-boxes below reserved for designating States which have become party to the PCT after issuance of this sheet:		
☐		☐
☐		☐
Precautionary Designation Statement: In addition to the designations made above, the applicant also makes under Rule 4.9(b) all other designations which would be permitted under the PCT except any designation(s) indicated in the Supplemental Box as being excluded from the scope of this statement. The applicant declares that those additional designations are subject to confirmation and that any designation which is not confirmed before the expiration of 13 months from the priority date is to be regarded as withdrawn by the applicant at the expiration of that time limit. (Confirmation (including fees) must reach the receiving Office within the 13-month time limit.)		

Supplemental Box*If the Supplemental Box is not used, this sheet should not be included in the request.*

1. *If, in any of the Boxes, except Boxes Nos VIII(1) to (v) for which a special continuation box is provided, the space is insufficient to furnish all the information: in such case, write "Continuation of Box No...." (indicate the number of the Box) and furnish the information in the same manner as required according to the captions of the Box in which the space was insufficient, in particular:*
 - (i) *If more than two persons are to be indicated as applicants and/or inventors and no "continuation sheet" is available: in such case, write "Continuation of Box No. III" and indicate for each additional person the same type of information as required in Box No. III. 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;*
 - (ii) *If, in Box No. II or in any of the sub-boxes of Box No. III, the indication "the States indicated in the Supplemental Box" is checked: in such case, write "Continuation of Box No. II" or "Continuation of Box No. III" or "Continuation of Boxes No. II and No. III" (as the case may be), indicate the name of the applicant(s) involved and, next to (each) such name, the State(s) (and/or, where applicable, ARIPO, Eurasian, European or OAPI patent) for the purposes of which the named person is applicant;*
 - (iii) *If, in Box No. II or in any of the sub-boxes of Box No. III, the inventor or the inventor/applicant is not inventor for the purposes of all designated States or for the purposes of the United States of America: in such case, write "Continuation of Box No. II" or "Continuation of Box No. III" or "Continuation of Boxes No. II and No. III" (as the case may be), indicate the name of the inventor(s) and, next to (each) such name, the State(s) (and/or, where applicable, ARIPO, Eurasian, European or OAPI patent) for the purposes of which the named person is inventor;*
 - (iv) *If, in addition to the agent(s) indicated in Box No. IV, there are further agents: in such case, write "Continuation of Box No. IV" and indicate for each further agent the same type of information as required in Box No. IV.*
 - (v) *If, in Box No. V, the name of any State (or OAPI) is accompanied by the indication "patent of addition," or "certificate of addition," or if, in Box No. V, the name of the United States of America is accompanied by an indication "continuation" or "continuation-in-part": in such case, write "Continuation of Box No. V" and the name of each State involved (or OAPI), and after the name of each such State (or OAPI), the number of the parent title or parent application and the date of grant of the parent title or filing of the parent application;*
 - (vi) *If, in Box No. VI, there are more than five earlier applications whose priority is claimed: in such case, write "Continuation of Box No. VI" and indicate for each additional earlier application the same type of information as required in Box No. VI.*
2. *If, with regard to the precautionary designation statement contained in Box No. V, the applicant wishes to exclude any State(s) from the scope of that statement: in such case, write "Designation(s) excluded from precautionary designation statement" and indicate the name or two-letter code of each State so excluded.*

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	regional application: regional Office	international application: receiving Office
item (1) 08/06/00	80/208,488	US		
item (2)				
item (3)				
item (4)				
item (5)				

☐ 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) ☐ item (4) ☐ item (5) ☐ 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 :	
☐ 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 :	
☐ Box No. VIII (iv) Declaration of inventorship (only for the purposes of the designation of the United States of America) :	
☐ Box No. VIII (v) Declaration as to non-prejudicial disclosures or exceptions to lack of novelty :	

Box No. IX CHECK LIST: LANGUAGE OF FILING

This international application contains:	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
(a) the following number of sheets in paper form:		
request (including declaration sheets) :	1. ☒ fee calculation sheet	:
description (excluding sequence listing part) :	2. ☐ original separate power of attorney	:
claims :	3. ☐ original general power of attorney	:
abstract :	4. ☐ copy of general power of attorney; reference number, if any:	:
drawings :	5. ☐ statement explaining lack of signature	:
Sub-total number of sheets :	6. ☐ priority document(s) identified in Box No. VI as item(s):	:
sequence listing part of description (actual number of sheets if filed in paper form, whether or not also filed in computer readable form; see (b) below) :	7. ☐ translation of international application into (language):	:
Total number of sheets :	8. ☐ separate indications concerning deposited microorganism or other biological material	:
(b) sequence listing part of description filed in computer readable form	9. ☐ sequence listing in computer readable form (indicate also type and number of carriers (diskette, CD-ROM, CD-R or other))	:
(i) ☐ only (under Section 801 (a)(i))	(i) ☐ copy submitted for the purposes of international search under Rule 13ter only (and not as part of the international application)	:
(ii) ☐ in addition to being filed in paper form (under Section 801 (a)(ii))	(ii) ☐ (only where check-box (b)(i) or (b)(ii) is marked in left column) additional copies including, where applicable, the copy for the purposes of international search under Rule 13ter	:
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	10. ☒ other (specify): post card receipt; transmittal letter, ...	:
Figure of the drawings which should accompany the abstract: 1A	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).

	Karen B. Tripp
---	----------------

For receiving Office use only		2. Drawings: ☐ received: ☐ not received:
1. Date of actual receipt of the purported international application:		
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	

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FEE CALCULATION SHEET

Annex to the Request

Applicant's or agent's file reference HALB:006		For receiving Office use only International Application No. Date stamp of the receiving Office	
Applicant Halliburton Energy Services, Inc.			
CALCULATION OF PRESCRIBED FEES			
1. TRANSMITTAL FEE		240.00	T
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International search to be carried out by <u>EP</u> <i>(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.)</i>			
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Basic Fee			
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Designation Fees			
The international application contains <u>all</u> designations.			
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AUTHORIZATION TO CHARGE (OR CREDIT) DEPOSIT ACCOUNT <i>(This mode of payment may not be available at all receiving Offices)</i>			
☐ Authorization to charge the total fees indicated above.		Receiving Office: RO/ <u>US</u> Deposit Account No.: <u>50-0807</u>	
☒ <i>(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.</i>		Date: <u>June 5, 2001</u>	
☒ Authorization to charge the fee for priority document.		Name: <u>Karen B. Tripp</u> Signature: <u>Karen B. Tripp</u>	

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

Applicant's or agent's file reference Applicant Halliburton Energy Services, Inc.	HALB:008	International Application No. Date stamp of the receiving Office
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CALCULATION OF PRESCRIBED FEES

1. TRANSMITTAL FEE 240.00 **T**

2. SEARCH FEE 700.00 **S**
 International search to be carried out by EP
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TOTAL

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 Deposit Account No.: 50-0807
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 Signature: Karen B. Tripp

PATENT COOPERATION TREATY

From the INTERNATIONAL BUREAU

PCT

NOTICE INFORMING THE APPLICANT OF THE
COMMUNICATION OF THE INTERNATIONAL
APPLICATION TO THE DESIGNATED OFFICES

(PCT Rule 47.1(c), first sentence)

To: TRIPP, Karen, B. P.O. Box 1301 Houston, TX 77251-1301 ETATS-UNIS D'AMERIQUE
--

Date of mailing (day/month/year) 13 December 2001 (13.12.01)			
Applicant's or agent's file reference HALB:008		IMPORTANT NOTICE	
International application No. PCT/US01/18134	International filing date (day/month/year) 05 June 2001 (05.06.01)	Priority date (day/month/year) 06 June 2000 (06.06.00)	
Applicant HALLIBURTON ENERGY DEVICES, INC.			

1. Notice is hereby given that the International Bureau has communicated, as provided in Article 20, the international application to the following designated Offices on the date indicated above as the date of mailing of this notice:
 KP, KR

In accordance with Rule 47.1(c), third sentence, those Offices will accept the present notice as conclusive evidence that the communication of the international application has duly taken place on the date of mailing indicated above and no copy of the international application is required to be furnished by the applicant to the designated Office(s).

2. The following designated Offices have waived the requirement for such a communication at this time:

AE, AG, AL, AM, AP, AT, AU, AZ, BA, BB, BG, BR, BY, BZ, CA, CH, CN, CO, CR, CU, CZ, DE, DK, DM, DZ, EA, EE, EP, ES, FI, GB, GD, GE, GH, GM, HR, HU, ID, IL, IN, IS, JP, KE, KG, KZ, LC, LK, LR, LS, LT, LU, LV, MA, MD, MG, MK, MN, MW, MX, MZ, NO, NZ, OA, PL, PT, RO, RU, SD, SE, SG, SI, SK, SL, TJ, TM, TR, TT, TZ, UA, UG, UZ,

The communication will be made to those Offices only upon their request. Furthermore, those Offices do not require the applicant to furnish a copy of the international application (Rule 48.1(a-bis)).

3. Enclosed with this notice is a copy of the international application as published by the International Bureau on 13 December 2001 (13.12.01) under No. WO 01/94749

REMINDER REGARDING CHAPTER II (Article 31(2)(a) and Rule 54.2)

If the applicant wishes to postpone entry into the national phase until 30 months (or later in some Offices) from the priority date, a demand for international preliminary examination must be filed with the competent International Preliminary Examining Authority before the expiration of 18 months from the priority date.

It is the applicant's sole responsibility to monitor the 18-month time limit.

Note that only an applicant who is a national or resident of a PCT Contracting State which is bound by Chapter II has the right to file a demand for international preliminary examination (at present, all PCT Contracting States are bound by Chapter II).

REMINDER REGARDING ENTRY INTO THE NATIONAL PHASE (Article 22 or 39(1))

If the applicant wishes to proceed with the international application in the national phase, he must, within 20 months or 30 months, or later in some Offices, perform the acts referred to therein before each designated or elected Office.

For further important information on the time limits and acts to be performed for entering the national phase, see the Annex to Form PCT/IB/301 (Notification of Receipt of Record Copy) and the PCT Applicant's Guide, Volume II.

The International Bureau of WIPO 34, chemin des Colombettes 1211 Geneva 20, Switzerland Facsimile No. (41-22) 740.14.35	Authorized officer J. Zahra Telephone No. (41-22) 338.91.11
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(19) World Intellectual Property Organization
International Bureau



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13 December 2001 (13.12.2001)

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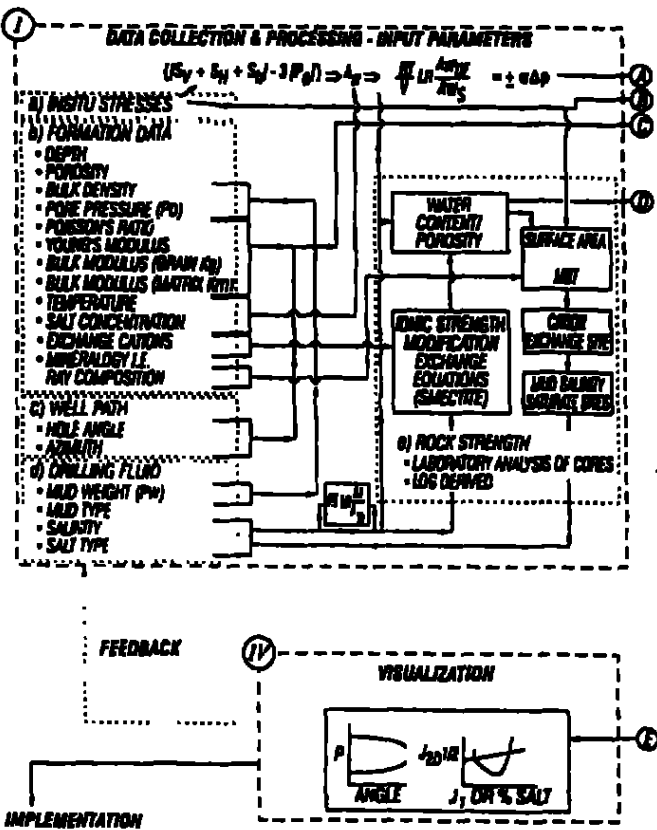
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- (74) Agent: TRIPP, Karen, B.; P.O. Box 1301, Houston, TX 77251-1301 (US).
- (81) Designated States (national): AE, AG, AL, AM, AT, AU, AZ, BA, BB, BG, BR, BY, BZ, CA, CH, CN, CO, CR, CU, CZ, DE, DK, DM, DZ, EE, ES, FI, GB, GD, GE, GH, GM, HR, HU, 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, NO, NZ, PL, PT, RO, RU, SD, SE, SG, SI, SK, SL, TJ, TM, TR, TT, TZ, UA, UG, UZ, VN, YU, ZA, ZW.
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[Continued on next page]

(54) Title: REAL-TIME METHOD FOR MAINTAINING FORMATION STABILITY



(57) Abstract: A real-time method is disclosed for maintaining subterranean formation stability through monitoring the interaction between the formation and fluids introduced into (or produced from) a wellbore penetrating the formation. The method employs real-time wellbore (in)stability logging methodology. The method is exemplified by a Pore Pressure Transmission (PPT) test. In such test, test fluids are exposed to Pierre II shales (20 % w/w NaCl solution and sodium silicate fluid with 20 % w/w NaCl, for example) in a PPT apparatus. Membrane efficiency of the two fluids when exposed to the outcrop shale is calculated, and based on the simultaneous acquisition of acoustic data, estimation of a dynamic rock property is made. Calibrating representative shale (or other formation) core response to drilling fluids (or well service fluids, enhanced recovery fluids, or production fluids) under realistic in-situ conditions aids in accurately modeling for time-dependent formation (in)stability in the field for the entire life of the wellbore, from drilling, completion and through production.

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IT, LU, MC, NL, PT, SE, TR), OAPI patent (BF, BJ, CF, CG, CI, CM, GA, GN, GW, ML, MR, NE, SN, TD, TG).

For two-letter codes and other abbreviations, refer to the "Guidance Notes on Codes and Abbreviations" appearing at the beginning of each regular issue of the PCT Gazette.

Published:

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amendments

REAL-TIME METHOD FOR MAINTAINING FORMATION STABILITY

Related Application

This application claims priority to U.S. Provisional Patent Application No. 60/209,488, filed June 6, 2000.

Background of the Invention1. Field of the Invention

This invention relates to methods for predicting and maintaining wellbore stability during drilling, well servicing and production in subterranean formations, particularly hydrocarbon bearing subterranean formations.

2. Description of Relevant Art

As used herein, the term "(in)stability" shall be understood to mean "stability or instability." Wellbore (in)stability in shales is a major problem costing the petroleum industry, according to conservative estimates, \$700 million annually. Understanding and modeling mechanisms of shale (in)stability is an ongoing industry effort. Drilling a hole into a formation in equilibrium induces stress concentration in the vicinity of the borehole. Interactions will occur if parameters such as chemical potential, electrical potential, thermal potential, ionic concentration, etc., of the drilling fluid and the shale formation fluid are not in equilibrium. Any differences in these parameters will alter the near wellbore pore pressure which in turn will influence the borehole equivalent stress-state and the shale mechanical strength thus affecting wellbore (in)stability. Tests conducted at compressive uniaxial and triaxial stress conditions in the past have indicated the strong influence of these parameters on shale strength.

Wellbore instability predominantly occurs in chemically reactive shales that overlay reservoirs. A major concern of the drilling engineer is either keeping the borehole wall from collapsing (packing off) or fracturing (losing circulation).

Past efforts to develop improved well bore models ("WBM") for shale drilling have been hampered by a limited understanding of the drilling fluid/shale interaction phenomenon. This limited understanding has resulted in drilling fluids being designed with properties inadequately or insufficiently optimized to prevent the onset of borehole (in)stability problems. Historically, wellbore (in)stability problems have been approached on a trial-and-error basis, going through a costly multi-well learning curve before arriving at reasonable

solutions for optimized operations and systems.

Recent studies of fluid-shale interactions have produced fresh insights into the underlying causes of borehole (in)stability; and chemical potential related instabilities in shales have been identified. A chemical potential borehole stability model, derived for an arbitrary borehole orientation, has been successfully implemented to address borehole (in)stabilities. This model, based on a well-established elastic modeling approach, is discussed in Tare, U.A., and Mody, F.K.: "Novel Approach to Borehole Stability Modeling for HRD and Deepwater Drilling", paper SPE 52188, 1999 SPE Mid-Continent Operations Symposium, Oklahoma City, USA, March 28-31, 1999, incorporated herein by reference.

Advances in technology are providing wider and greater capabilities for new, more reliable, accurate and rugged downhole sensors and tools. Such apparatuses and sensors are increasingly able to collect and transmit information to the surface as it is happening.

With increasing economic demands on reducing rig downtimes associated with borehole instability problems, there is increasing need for the ability to predict and resolve instabilities in the field using MWD/LWD (measuring while drilling/logging while drilling) data in conjunction with prior geophysical and shale/fluid interaction knowledge. However, previous attempts have focused on earth stresses, using drilling data and borehole (in)stability modeling on a "post-mortem" basis, i.e., after substantial problems have occurred. There is a need for methods that enable instability problems to be avoided.

Summary of the Invention

A method is disclosed for maintaining subterranean formation stability, and particularly wellbore stability during drilling, well completion and servicing operations, and even during production and enhanced recovery operations. The method of the invention affords maintenance of wellbore stability throughout the life of a well penetrating a subterranean formation.

Moreover, the method provides for real-time monitoring of fluid-formation interaction such that adjustments can be made before (in)stability problems occur.

In the method, initial formation characteristics or parameters are estimated or obtained and the rock strength of the formation is estimated. Characteristics of the fluids injected into the wellbore or the formation during drilling, or during well completion and servicing operations, or during production or enhanced recovery operations, are also estimated or obtained. This data concerning the formation and the fluids is input into a well-stability model and results are used to revise the estimates of the formation parameters and/or the fluid parameters or to adjust the fluid

composition or characteristics. These parameters and the model results are updated with real time formation measurements taken during the particular operation being conducted (i.e., drilling, well servicing, or production). Continued acquisition and processing of the formation data in the model allows the fluids to be adjusted as needed to avoid formation instability problems caused by interaction of the fluids with the formation.

Brief Description of the Drawings

Figures 1A and 1B are a flowchart or process map for a real-time wellbore stability process according to the invention.

Figure 2 is a schematic of a Pore Pressure Transmission experiment designed to study time-dependent alterations in shale properties as a function of drilling fluid exposure.

Figure 3 is a graph of the time dependent transient pore pressure response of Pierre II shale when exposed to a 20% w/w NaCl solution.

Figure 4 is a graph of the time dependent transient pore pressure response of Pierre II shale when exposed to a sodium silicate solution containing 20% w/w NaCl.

Figure 5 is a graph of the time dependent transient pore pressure response of Pierre II shale when exposed to a polymer in solution containing 20% w/w CaCl_2 salt and 2% KCl salt.

Figure 6 is a graph of the shale compressional acoustic wave response of Pierre II shale when exposed to a 20% w/w NaCl solution.

Figure 7 is a graph of the shale shear acoustic wave response of Pierre II shale when exposed to a 20% w/w NaCl solution.

Figure 8 is a graph of the shale compressional acoustic wave response of Pierre II shale when exposed to a sodium silicate solution containing 20% w/w NaCl.

Figure 9 is a graph of the shale shear acoustic wave response of Pierre II shale when exposed to a sodium silicate solution containing 20% w/w NaCl.

Figure 10 is a graph of the compressional acoustic wave response of Pierre II shale when exposed to a polymer in solution containing 20% w/w CaCl_2 salt and 2% KCl salt.

Figure 11 is a graph of the shear acoustic wave response of Pierre II shale when exposed to a polymer in solution containing 20% w/w CaCl_2 salt and 2% KCl salt.

Figure 12 is a graph of dynamic Young's modulus as a function of transient pore pressure for Pierre II shale exposed to a 20% NaCl solution.

Figure 13 is a graph of dynamic Young's modulus as a function of transient pore pressure for Pierre II shale exposed to a sodium silicate solution containing 20% w/w NaCl.

Figure 14 is a graph of dynamic Young's modulus as a function of transient pore pressure for Pierre II shale exposed to a polymer in solution containing 20% w/w CaCl_2 salt and 2% KCl salt.

Detailed Description of Preferred Embodiments

- 5 The following terms as used herein, and particularly as used in the figures, have the meaning indicated below:

Nomenclature

δ = Membrane efficiency, %

P = Pressure, m/L^2 , psi

- 10 E = Young's modulus m/L^2 , psi

A_w = Water activity

ΔP = Pressure drop, m/L^2 , psi

V = Acoustic Velocity, m/t , m/sec

Subscripts

- 15 ic = confining

o = external or pore fluid

fl = test fluid

sh = shale fluid

exp = experimental

- 20 p = sonic compressional waves

s = sonic shear waves

SI Metric Conversion Factors

ft $\times$ 3.048 E-01 = m

in. $\times$ 2.54 E+00 = cm

- 25 lbf $\times$ 4.448 222 E+00 = N

psi $\times$ 6.894 757 E+00 = kPa

- 30 In investigating the role of various potentials of drilling fluids on transient rock properties of shale and other subterranean formations subjected to compressive confining stress, we have discovered that properties of cores from such formations should be measured as a function of time when exposed to a drilling fluid, well service fluid, or enhanced production fluid, or even when subjected to production itself. Experiments were conducted under conditions simulating a borehole portion under geostatic stress with the wellbore surface exposed to a circulating drilling fluid. The results supported our discovery.

In the experiments, rock properties such as acoustic velocity and transient pressure for each core sample were measured simultaneously as a function of time during the experiments. This simultaneous measurement eliminated the anisotropy-associated differences obtained when different samples are used to determine the relationship between these characteristic parameters of the subterranean formations, and in these experiments, particularly the characteristic parameters of the shale formations. This testing enhanced understanding of the relationship between acoustical, mechanical, chemical, electrical and failure properties of the shale as a function of time when exposed to a fluid, and in these experiments, particularly when exposed to a drilling fluid. Such measurements provide the necessary precursor to determine the onset of time dependent in(in)stability, thus providing options to implement corrective measures in real time to alleviate (in)stability, according to the method of the present invention.

Without wishing to be limited by theory, we believe, based on our observations from these above experiments, that measurement of rock properties such as acoustic velocity as a function of the transient pressure of shales under simulated in-situ stress-state facilitates real time wellbore (in)stability logging using MWD/LWD or any other relevant information. This practice provides better real-time management of (in)stability problems in the field.

The present invention provides a method or process for maintaining formation stability through monitoring the interaction between the formation and fluids used in well drilling, servicing or production. Further, the present invention provides a real-time method for improved drilling, servicing and producing wellbores in or through subterranean formations by employing such monitoring and maintaining of well stability. The improvements of the invention are especially appreciated in operations in shale formations, although the invention is applicable as well to other types of subterranean formations. Similarly, the improvements of the invention are especially appreciated in drilling through subterranean formations, although the invention is applicable as well to other operations in subterranean formations, such as well completion and well servicing operations, and even to producing operations. Thus, the advantages of the invention are best realized when the invention is applied throughout the life of a wellbore in a subterranean formation, and especially a hydrocarbon bearing subterranean formation.

The method of the invention employs real-time wellbore stability modeling. Figures 1A and 1B present a process map of real-time wellbore stability modeling, specifically for example as applied to drilling operations. A similar map would be used for well completion or other service operations employing well service fluids instead of drilling fluids. Also, a similar map would be

used for well production operations, monitoring stability of a well as fluids may be produced from a formation, and monitoring stability of a well during various enhanced recovery operations (for enhancing recovery of hydrocarbons from the formation). In all such cases, the interaction of the formation to various fluids being introduced into or being produced from the wellbore are monitored. Hereinafter, the description of the invention will primarily be directed to drilling operations and to drilling fluids for example. However, the invention is not limited to such operations or fluids and may be similarly applied to well completion and service operations involving well service fluids and to production operations.

The initial step in the method or process of the invention involves constructing an earth-model (preferably including stresses, formation compressive and tensile strengths and geologic features) from a variety of sources such as pre-drill, seismic, and offset data. Based on the initial earth-model, predictions are made for mud weights, casing shoe locations, drilling fluid type and chemistry, etc. as would be known to those skilled in the art. Preferably simultaneously, laboratory tests are conducted for specific formations (e.g., shales) that are expected to be drilled, using either actual cores from such formations or representative outcrop samples. The tests are conducted using a variety of experimental apparatuses such as the Pore Pressure Transmission (PPT) test apparatus. Information on time-dependent formation (e.g., shale) behavior is obtained from such tests.

Further in the method of this invention, rock properties such as transient pore pressure, compressional and shear wave velocities, deformation, and strength of shale cores under triaxial stress are measured. These measurements are used to calibrate the wellbore stability model (also called the total potential model), such as the model shown in the flow diagrams in Figure 1B, for specific applications, such as, for example, drilling with programmed or planned drilling fluids through/into a reservoir overlaying shales or other formations of interest. Measurements of static and dynamic rock properties as a function of the transient pressure of shales (or other formations of interest) under triaxial stress state enhances understanding of the relationship between these parameters. Such measurements also help in determining how economically to obtain these properties using MWD/LWD (measurement while drilling/logging while drilling) data.

During the drilling process, the earth-model and the total potential wellbore stability model are updated with real-time measurements while drilling (MWD) and/or using wireline logs or any other techniques for determining static and dynamic rock properties. The captured MWD and/or wireline data or data obtained from any other techniques is processed in real-time and this

data is converted into input parameters for the wellbore stability model. The input parameters are thus calibrated with MWD and/or wireline data or data obtained from other techniques. The calibrated input parameters are then used in a wellbore stability model along with the laboratory time-dependent measurements.

5 For a given set of input parameters the wellbore stability model provided in Figure 1B can perform in three modes of analysis. These are briefly described below:

- Safe mud weight window prediction – Results obtained from this mode provide the upper and lower limit for a safe mud weight for a given composition of the drilling fluid as a function of the hole inclination angle and orientation. The upper limit in this case is the mud weight above which extension fracturing or fracture propagation would occur and would result in excessive drilling fluid losses. The lower limit is set by formation pore pressure or the minimum mud weight required to prevent borehole collapse, whichever is greater. In this mode, chemical and thermal interaction between the formation (mostly shale) and the drilling fluid can be incorporated.
- 15 • Optimum chemical composition prediction (OBM) – In this mode of analysis the model provides the optimum chemical composition of the drilling fluid for a given mud weight, hole inclination and direction. In the absence of laboratory derived shale pore fluid potential, in-situ shale pore fluid potential can be predicted using a sub-module.
- Optimum chemical composition of drilling fluid prediction (OBM) followed by safe mud weight window prediction – The model in this mode first optimizes the chemical composition of the drilling fluid for the actual (i.e., utilized currently in the field) mud weight followed by a prediction of the safe mud weight window as a function of hole angle for a given direction.

25 All three modes have access to an empirical rock strength estimation module, as shown in Figure 1A.

The predictions from the wellbore stability model are sent to a visualization module (typically graphing of results) based on one of two types of activities—field implementation or feedback, as shown in Figure 1A—to be executed. These activities provide feedback into the data collection, processing and interpretation process and field implementation of the wellbore stability model results, as shown in figures 1A and 1B.

Wellbore Stability Model

The rationale for the wellbore stability model (total potential model) is as follows:

The fundamental direct and coupled flow phenomena, induced hydraulic gradients, chemical potential, electrical potential gradients and temperature gradients all influence rock properties and wellbore or formation stability. In most practical cases, however, the flow phenomena induced by the hydraulic gradient (i.e., mud filtrate invasion driven by overbalanced mud weight) and the chemical potential difference between the drilling fluid and shale (or formation) pore fluid (e.g., osmotic or diffusion transport of water molecules and/or ions and/or (hydrated) solutes in and out of the shale, electrical potential, thermal potential, etc.) are generally considered to be the more relevant driving forces for formation (in)stability. At any given time during the drilling operation, the (in)stability issue is ultimately controlled by the relationship between the borehole stress-state and the rock strength. As the rock strength is inversely related to the water content of the shale (or of the formation of interest), modification of pore pressure is a fundamental parameter in altering the effective stress-state around the wellbore. Adequate mud weight density is also needed for borehole stability.

The model used in the method of this invention is preferably based on well-established modeling principles such as described in Mody, F.K. and Hale, A.H.: "A Borehole Stability Model To Couple the Mechanics and Chemistry of Drilling Fluid/Shale Interaction", paper SPE 25728, 1993 IADC/SPE Drilling Conf, Amsterdam, Feb. 23-25, 1993; Bradley, W.B.: "Failure of Inclined Boreholes", J. Energy Res. Tech. (Dec. 1979) 232; Trans., AIME, 101; Tara, U.A., and Mody, F.K.: "Novel Approach to Borehole Stability Modeling for ERD and Deepwater Drilling", paper SPE 52188, 1999 SPE Mid-Continent Operations Symposium, Oklahoma City, USA, March 28-31, 1999; Tan, C.P., et al.: "Integrated Rock Mechanics and Drilling Fluid Design Approach to Manage Shale Instability", paper SPE 47259, SPE/ISRM Eurock '98, Trondheim, Norway, Jul. 8-10, 1998; and Ghassemi, A., et al.: "A Solution for Stress Distribution Around An Inclined Borehole in Shale", paper No. 043, Int. J. Rock Mech. Min. Sci. Vol. 35, No. 4/5, p.538-540, 1998, which are all incorporated herein by reference.

The first two of these references listed above have pertinent theoretically derived solutions to the model. The model incorporates chemical potential effects using the difference in the molar free energies (i.e., activity) of the drilling fluid and the shale pore fluid. Also incorporated in the model is the concept of reflection coefficient, σ , as discussed in Staverman, A.J.: "Theory of Measurement of Osmotic Pressure", Recueil des Travaux Chimiques des Pays-Bas, v.70, pp 344-352, (1951), incorporated herein by reference. The temperature difference between the formation and the drilling fluid directly affects the near-

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wellbore stress concentration. The model utilizes this temperature difference and calculates the effect of thermal stresses on the near-wellbore tangential stress where significant.

Experiments

5 Pore Pressure Transmission (PPT) Tests

The Pore Pressure Transmission (PPT) experiment has been designed to study time-dependent alterations in shale properties as a function of drilling fluid exposure. A schematic of this test is shown in Figure 2. The experiment consists of confining well-preserved shale cores or outcrops, under geostatic stress and then circulating (under confined dynamic conditions) test
10 fluids at the upstream side while measuring changes in the downstream pressure. The upstream pressure may be increased to simulate overbalance conditions representing downhole conditions. Typically during a drilling operation, hydraulic overbalance is maintained to provide the formation with net radial support. The downstream pressure indicates changes in the sample pore pressure at some distance into the wellbore.

15 Experimental Setup for PPT Tests

The experimental setup consists of a jacketed steel pressure vessel with built in pressure ports, connections and acoustic transducers. The sample (1 in. x 2 in.) is jacketed with a Teflon membrane after six extension-meter strain gauges are applied to measure the sample deformation. The entire assembly is placed in a temperature regulating device to ensure adequate control of the
20 experimental temperature.

Summary of PPT Test Procedure

A shale sample is equilibrated at a hydrostatic confining pressure P_c (e.g. 500 psi), under external fluid pressure p_e (e.g., 50 psi) on both ends, and at the specific test temperature. Fluid pressure is applied with simulated pore fluid. Once saturation is achieved, the upstream pressure
25 line is closed. The confining pressure is then increased to the required level for consolidation, P_c (e.g., 4000 psi). The system remains closed until the pressures at both the sample ends have stabilized. Upstream and downstream pressure is allowed to stabilize and equilibrate.

Upon stabilization of the pore pressure, the sample is allowed to consolidate. The downstream pressure of the sample is monitored.

30 After the pressures at both ends have stabilized, the pore fluid is replaced with a drilling fluid that is circulated at a constant pressure. The transient pressure behavior, sonic compression and shear travel times, radial and axial deformation, temperature, and circulation rate are

monitored.

PPT Test Details

The PPT tests provide a database including shale responses to various drilling fluids and salt solutions. For example, the PPT tests provide meaningful membrane efficiency numbers, allow for the study of more complex interaction between shale and drilling fluid to validate, verify, or confirm existing chemical potential poroelastic models, enable calibration of the shale response to known drilling fluids for optimum application in the field, and demonstrate simultaneous data acquisition of various responses to provide detailed shale property characterization as a function of drilling fluid exposure.

The three example fluids tested were a 20% w/w sodium chloride salt solution, a sodium silicate system comprising 20% w/w sodium chloride, and a polymer in solution comprising 20% w/w CaCl_2 salt and 2% KCl salt. It is important to establish a baseline of the shale response to the cation or cations that would be included in the drilling fluid system. Such a baseline helps in identifying or isolating shale alterations due to cation exchange. In addition this baseline helps differentiate, to a certain extent, the effects of the base salt solution and the effects of other shale modifying additives (e.g., silicates, polymers like partially-hydrolyzed poly-acrylamide, amphoterics etc.).

Discussion of Results

Based on the transient pore pressure response of Pierre II shale exposed to the test fluids, the sodium silicate solution comprising 20% w/w NaCl showed higher membrane efficiency numbers than the 20% w/w NaCl solution and the polymer in solution comprising 20% w/w CaCl_2 salt and 2% KCl salt (approximately 60% efficiency versus approximately 10% efficiency and approximately 5.30% efficiency respectively).

Figures 3, 4 and 5 show the time dependent transient pore pressure response of Pierre II shale when exposed to a 20% w/w NaCl solution, a sodium silicate system comprising 20% w/w NaCl and a polymer in solution comprising 20% w/w CaCl_2 salt and 2% KCl salt, respectively. The saturating fluid (simulated pore fluid) in all cases is 8% w/w NaCl solution. The shale acoustic (compressional and shear wave) response during the entire experiment for the 20% w/w NaCl solution is shown in Figures. 6 and 7. Figures. 8 and 9 provide the corresponding acoustic (compressional and shear wave) response of Pierre II shale when exposed to the sodium silicate solution comprising 20% w/w NaCl. Figures 10 and 11 provide the acoustic (compressional and shear wave) response of Pierre II shale when exposed to the polymer in

solution comprising 20% w/w CaCl₂ salt and 2% KCl salt. One example rock property, the dynamic Young's modulus (E) (reflecting rock elasticity), calculated from the above acoustic data with respect to the three solutions is shown respectively in Figures. 12, 13 and 14. Each of the Figures 3-14 indicates the three stages of the PPT test. First, the shale is saturated with 8% w/w NaCl (simulated pore fluid); second, 8% w/w NaCl is circulated until equilibrium; and third, the shale is exposed to the test fluid.

Table 1 provides transient pore pressure data and corresponding calculated membrane efficiency in tabular form for the test fluids when exposed to Pierre II shale.

TABLE 1-MEMBRANE EFFICIENCY CALCULATION

Test Fluid	A _{wi}	A _{wf}	ΔP _{the} psi	ΔP _{exp} psi	σ, % ΔP _{exp} /ΔP _{the}
20% w/w NaCl solution	0.83	0.95	2685	270	10.05
Sodium silicate solution	0.83	0.95	2685	1604	59.74
comprising 20% w/w NaCl					
Polymer solution comprising	0.78	0.95	3920	208	5.30
20% w/w CaCl ₂ salt and 2% KCl salt					

where ΔP_{the} refers to the difference or change in theoretical pressure and ΔP_{exp} refers to the difference or change in experimental pressure.

The well known concept of "reflection coefficient" (i.e., membrane ideality) may be used for "leaky systems" including water based mud (WBM)/shale (or other formation) type systems for formation stability applications. For WBM/shale systems, membrane efficiency is not a clearly defined term (e.g., as an oil film on shales present in invert oil emulsion systems). The membrane efficiency of formation-fluid systems is due to a difference in mobility of water and solutes (ions) in shales. Thus membrane efficiency can be defined as:

$$\sigma = 1 - \frac{v_{solute}}{v_{water}} \quad (1)$$

If only the movement of water is allowed and all the solutes are rejected, the membrane is ideal semi-permeable (100% membrane efficiency or σ=1). However, for shales, the mobility of solutes is lower than that of water and the membrane is "non-ideal" or "leaky", 0<σ<1. A non-ideal membrane does not entirely restrict the transport of solutes. Membrane efficiency ("reflection coefficient") has a relationship with at least two key parameters of the WBM/shale system, i.e., the average 'effective' shale pore radius and the radius of hydrated ions present in the drilling fluid system.

A mathematical representation to describe the driving force for the movement of water by an osmotic mechanism and one way or means of estimating membrane efficiency directly is shown in the following equation:

$$\left(\frac{RT}{V} \right) \times \ln \left(\frac{A_{wf}}{A_{sh}} \right) = \pm (\sigma \times \Delta P_r) = \pm \sigma \times (P - P_p) \quad (2)$$

5 where A_{wf} is the water activity of the drilling fluid, which can be estimated a number of known ways, most notably, by partial vapor pressure determination, boiling point elevation, or directly using a hygrometer; A_{sh} is the water activity of the shale pore fluid and can be measured (for preserved shale cores) by partial vapor pressure determination; P_p is the far-field pore pressure; P is the near wellbore pore pressure; and σ is the membrane efficiency
10 term, or "reflection coefficient", specific to a shale/drilling fluid system.

Further discussion of the calculation of membrane efficiency may be found in references Mody, F.K. and Hale, A.H.: "A Borehole Stability Model To Couple the Mechanics and Chemistry of Drilling Fluid/Shale Interaction", paper SPE 25728, 1993 IADC/SPE Drilling Conf., Amsterdam, Feb. 23-25, 1993, and Staverman, A.J.: "Theory of Measurement of Osmotic
15 Pressure", Recueil des Travaux Chimiques des Pays-Bas, v.70, pp 344-352, (1951), which are incorporated herein by reference.

While the membrane efficiency for a 20% w/w NaCl solution when exposed to Pierre II shale is 10.05%, and the membrane efficiency for a polymer in solution comprising 20% w/w CaCl_2 salt and 2% KCl salt when exposed to Pierre II shale is 5.30%, the membrane
20 efficiency for sodium silicate systems is significantly higher at about 60%. For reference, an oil-based mud has a theoretical membrane efficiency close to 100%. Following the response of a sodium silicate solution with 20% w/w NaCl, the shale pore pressure decreases as a function of exposure time to the solution. Comparing the results among the three test fluids indicates that, when membrane efficiency numbers are significantly higher, drilling fluid water
25 activity that is lower than the shale pore fluid activity tends to reduce pore pressure and thereby contributes towards reducing near-wellbore effective stresses on a time-dependent basis.

Acquisition of acoustic data simultaneously with exposure of the rock to drilling fluid, in the field and in the PPT tests provides useful data to calculate dynamic changes in the rock
30 properties, changes that may be a result of that exposure. Comparing Figures 12, 13 and 14

shows changes in the dynamic Young's modulus as a function of transient pore pressure. Young's modulus, which is a measure of the stiffness or elastic properties of a rock, is but one example of a rock property. Similar computations can be made for dynamic Poisson's ratio and other rock properties derived from sonic data. In the example, when shale is exposed to 20% w/w NaCl solution, the effective stress changes from 2105 psi immediately after displacement to 2375 psi when the transient pore pressure has reached its lowest point (Figure 3). For the case when Pierre II shale is exposed to the sodium silicate fluid the effective stress increases from 860 psi immediately after displacing the simulated pore fluid with the test fluid to 2464 psi at the lowest point on the transient pore pressure curve (Figure 4). Inherent changes in effective stress can be observed from velocity data. For example, comparing Figures 6 and 10 with 8 shows a dramatic change in the compressional wave sonic velocity when the shale is exposed to the two test fluids. Similar observations can be made for the shear wave velocity profiles by comparing Figures 7 and 11 with 9. These comparisons provide additional means of observing transient pore pressure in the shales as a function of test fluid exposure.

This test example shows that mud systems should be calibrated, preferably with shale cores under in-situ conditions. PPT tests can provide meaningful membrane efficiency numbers which can then be used in a wellbore stability model for a realistic analysis. Additionally, a time-dependent chemical potential related shale transient pressure can be obtained, which can be used to analyze exposure time related borehole deterioration observed (based on the nature of the curve).

Input Parameters for Real - Time Wellbore Stability Modeling

Table 2 provides a list of input parameters for real-time borehole stability analysis according to the method of the invention and the possible sources where the data needed for the analysis can be obtained. The input parameters can be divided into five categories. These are:

- a) Insitu Stresses.
- b) Formation Data.
- c) Well Path Data.
- d) Drilling Fluid.
- e) Rock Strength.

Each of the above categories can be further sub-divided into individual subcategories. The possible sources for obtaining information for each input parameter subcategory are provided

in Table 2 (under the column heading Possible Source). The Input Parameters categories are discussed below:

(a) **In-situ Stresses** – These stresses affect the mud weights used to drill a borehole. When the stresses are higher than the rock strength failure occurs. The principle stresses control both fracturing as well as the collapse mode of wellbore failure. There are three principle earth stresses. The in-situ stresses are the minimum horizontal stress, maximum horizontal stress and the overburden stress. In a normal faulting environment such as that typically found in the Gulf of Mexico (away from any tectonic activity), the minimum horizontal stress is the least principle stress, the maximum horizontal stress is the intermediate principle stress, and the overburden stress is the maximum principle stress. The major source for obtaining magnitudes of the least principle stress in formations is by pressure testing in open boreholes. Information can be obtained from tests such as a leak-off test, extended leak-off test, mini-frac test, etc. Direction of the intermediate principle stress is obtained by measuring the location of borehole ovality (break-outs); the magnitude is estimated by back-calculating the break-out width for a given intermediate stress and the other two principle stresses, pore pressure and the rock strength. Comparison is made between the estimated and the actual observed breakout width. The overburden stress is typically obtained from an integrated bulk density log, by the actual measurement of drilled cuttings, etc.

(b) **Formation Data** – This data can be categorized into four sub-categories: temperature; rock properties; shale or pore water salinity, and pore pressure. Formation data is different for different formations. The formation temperature is typically estimated by running temperature measurement while drilling tools, infra-red techniques, etc. Rock properties are obtained either by direct measurement of actual cores in the laboratory or by empirical correlations based on wellbore measurements. Rock properties aid in modeling deformation behavior of specific formations. Shale activity or pore water salinity is used to estimate the chemical potential of the formation. A difference in potential between the drilling fluid and formation induces flow phenomenon from one to the other, i.e., flow occurs from higher potential to the source that contains lower potential. Osmotic membrane efficiency and the osmotic pressure are based on shale water activity. Shale water activity can be obtained from log based empirical correlations as provided in Table 2 or by actually measuring the relative humidity of a well preserved shale core in the laboratory. Pore pressure is critical information for drilling a well. Pore pressure affects the minimum mud weight used to drill and is related

estimated then a proprietary empirical correlation that uses water content and shale composition can be used to estimate rock strength.

Therefore,

Rock Strength $\propto f(\text{Shale Property})$

- 5 For example, Shale Property = Water content or Brinell Hardness or Cation Exchange Capacity or Porosity etc.

The numbers in Table 2 below have the following meanings:

1. X-ray Analysis of cuttings.
2. Nuclear Magnetic Resonance (NMR) logs (Wireline and/or MWD).
- 10 3. Resistivity/Conductivity logs (Wireline and/or MWD)
4. Mud Logs
5. Acoustic/Sonic compressional and shear wave logs (Wireline and/or MWD)
6. Pressure and Sampling tools like drill stem testing (Wireline and/or MWD) and repeat formation testing (RFT) tools.
- 15 7. MDT
8. Spontaneous Polarization (SP) Curve logs
9. Seismic processing/Vertical Seismic Profiling (VSP) techniques.
10. Pore pressure ahead of the bit techniques.
11. Pressure While Drilling (PWD) logs (MWD).
- 20 12. Empirical and analytical models using drilling fluid rheology, pressure, cuttings accumulation and temperature.
13. Leak-off test (LOT), Extended Leak-off Test (XLOT), Minifrac tests, Microfrac Tests, Formation Integrity Tests (FIT), Casing Integrity Tests (CIT).
14. Anelastic Strain Recovery (ASR) Techniques (including tests performed on cores and downhole)
- 25 15. Regional bulk density trends.
16. Integrated bulk density logs (Wireline and/or MWD)
17. Acoustic, four and six arm Caliper logs (Wireline and/or MWD), information on breakout angles, breakout volume and breakout length, etc.
18. Formation Evaluation (FE) Logs (Wireline and/or MWD)
- 30 19. Temperature logs (Wireline and/or MWD)
20. Neutron source (Nuclear) or Gamma-ray logs like neutron-slow-neutron logs, Double- or Multiple - Spaced Neutron (MS Neutron Curve) - Dual-Spacing Neutron Curve, Flowing Neutron Log (Nuclear Flolog - Lane-Wells), etc. (Wireline and/or MWD)
21. Formation Imaging logs (Wireline and/or MWD).

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Table 2. List of input parameters for real-time wellbore stability analysis and possible sources where the data required to do the analysis can be obtained:

Possible Source	Intermediate Parameters	Input Parameter	
13, 14, empirical and analytical methods using log and regional information like the Daine's method, Eaton's technique, Pennebaker method, etc.		Minimum Horizontal Stress	I N S I T U S T R E S S E S
15, 16, empirical methods using log information and compaction trends, measurements on drill-cuttings (cuttings density measurements), etc.,		Overburden Stress	
14, 17, 21, fault stability and reactivation models,	Inequality (magnitude) and direction of horizontal stresses	Maximum Horizontal Stress	
19, field measurements like using infra-red techniques	Formation temperature and flow-line temperature	Temperature	F O R M A T I O N D A T A
Laboratory analysis of cores, measurements on cuttings, pressure pulsing the well, 2, 3, 5, 9, 13, 14, 20	Poisson's Ratio, Young's Modulus, Thermal Expansion coefficient, fluid and grain volume expansion factor, rock and fluid compressibility, rock and fluid bulk modulus, Skempton's Pore Pressure Coefficient, Biots Constant, etc.,	Rock Properties	
Log based empirical correlation's using the following measurements - 2, 3, 6, and 20. Laboratory measurements of shale cores using testing methods like, adsorption isotherm method, hygrometer reading and other relative humidity measurements, determination of shale pore water salinity from sand pore water salinity overlaying and underlying the shales		Shale Activity/Pore Water Salinity	
9, 3,5, Pressure Build-up tests like 6 and 7, 4, 2, 10, Ratio Methods, empirical methods using log information and compaction trends, etc.,	Pore Pressure Gradient	Pore Pressure	
Loggers or Drillers Depth, Reservoir modeling and interpretation tools	Depth, Well trajectory	D r i l l i n g D a t a	W E L L P A T H
Seismic information, drilling data, 18, etc.	Geologic information (presence of faults and types of faults)		
Case history for a local well where no or very few problems were seen	Successful mud programs		

11, 4, 12	Static and equivalent circulating density.	Mud Weight	D R I L L I N G F L U I D
Laboratory titration experiments like the Baroid method and the API method, drilling fluid daily reports		Drilling Fluid Activity	
Laboratory testing of preserved shale cores using experiments like the Pore Pressure Transmission (PPT) test, Linear Swell Meter Tests, measuring changes in formation properties using field information like, 2, 3, 5, 9, 13, 16, 17, 18, 19, 20	Time dependent changes in formation water content, porosity, resistivity, sonic velocity and travel time, formation density, etc.	Membrane Efficiency	
Microscopic Imaging Techniques, Physical Intrusion Techniques like mercury injection, and nuclear techniques such as using nuclear magnetic resonance techniques (laboratory or wireline or MWD), 2	Pore radii and distribution, solute/water relative mobility		
1, 2, 3, 4, 5, 8, 9, 18	Clay Content and Formation Type	ROCK STRENGTH	
3, 4, Di-adsorption methods such as Methylene Blue Tests or Compulsive Exchange Methods like the barium chloride compulsive exchange method	Cation Exchange Capacity (CEC)/Surface Area, Ionic Strength Modification Exchange Equations		
2, 3, 4, 5, 8, 10, 15, 16, 18, 20	Formation Water Content/Porosity/Permeability		
Laboratory analysis of cores, empirical correlation's using the following sources - 1, 2, 3, 4, 5, 17, 18, 20 and formation dielectric constant measurement.			

In applying the method of this invention, at least some understanding of the drilling fluid/formation interaction should preferably be obtained prior to applying any total potential or wellbore (in)stability model for a real-time drilling operation. A Pore Pressure Transmission (PPT) test or any other relevant test can be used to estimate the impact of a drilling fluid on the formation properties i.e., including but not limited to transient pore pressure, water content, electrical properties, acoustic properties, etc.

Changes in the shale stress due to alterations of the above mentioned properties can be obtained from the simultaneous acquisition of sonic compression and shear wave velocity data. A time-dependent total potential related shale transient pressure obtained from the PPT can be used to address issues where exposure time related borehole deterioration is observed.

The foregoing description of the invention is intended to be a description of preferred embodiments. Various changes in the details of the described method, including without limitation details concerning the wellbore stability model, can be made without departing from the intended scope of this invention as defined by the appended claims.

We claim:

1. A method employing drilling fluid for drilling a wellbore penetrating a subterranean formation, said method comprising real-time monitoring of the stability of said wellbore
5 using a wellbore stability model during said drilling of the wellbore.

2. The method of claim 1 comprising:

(a) obtaining preliminary values for mud weight and chemical composition of said drilling fluid using said wellbore stability model;

10 (b) measuring acoustic, sonic, electrical, thermal and transient pressure responses of the formation;

(c) calibrating said wellbore stability model with said measurements; and

(d) obtaining values for drilling mud weight and chemical composition of said drilling fluid using said calibrated wellbore stability model.

15 3. The method of claim 2 wherein said chemical composition values comprise values for salinity.

20 4. The method of claim 2 further comprising repeating steps (b) and (d) during drilling of said wellbore.

5. The method of claim 2 further comprising adjusting said drilling mud weight and salinity of said drilling fluid based on said values obtained with the calibrated wellbore stability model.

25 6. The method of claim 2 wherein said formation comprises shale.

7. The method of claim 2 wherein the measurements of step (b) are taken simultaneously during drilling of the wellbore in said formation.

30 8. A method employing well service fluid for servicing a wellbore penetrating a subterranean formation, said method comprising real-time monitoring of the stability

of said wellbore using a wellbore stability model during said servicing of said wellbore.

9. The method of claim 8 comprising:

- (a) obtaining preliminary values for weight and chemical composition of said well service fluid using said wellbore stability model;
- (b) measuring acoustic, sonic, electrical, thermal and transient pressure responses of the formation;
- (c) calibrating said wellbore stability model with said measurements; and
- (d) obtaining values for the weight and chemical composition of said well service fluid using said calibrated wellbore stability model.

10. A method for enhancing the recovery of hydrocarbons from a hydrocarbon bearing formation employing enhanced recovery fluids, said method comprising real-time monitoring of the stability of said formation using a wellbore stability model during said enhanced recovery.

11. A method for producing hydrocarbons from a hydrocarbon bearing formation while monitoring the stability of said formation, said method comprising real-time monitoring of the stability of said formation using a wellbore stability model during said production.

12. A method for maintaining stability of a wellbore penetrating a subterranean formation during drilling or well servicing operations, or during production or enhanced recovery operations, using fluids introduced into said wellbore to facilitate said operations, said method comprising:

- estimating characteristic properties of the formation;
- estimating in-situ stresses in the formation;
- estimating or determining characteristic properties of said fluids;
- estimating the rock strength of said formation;
- conducting at least one pore pressure versus time laboratory test based on said estimations of fluid properties, formation properties, and rock strength;
- employing results of said test, said estimations of formation properties, in-situ

stresses, rock strength, and said fluid properties in a wellbore stability model;

using results from said model to adjust estimates of said formation properties, in-situ stresses in the formation; and rock strength to update said wellbore stability model or using results from said model to adjust the properties of said fluids to maintain or enhance said rock strength;

continuing during said operations to estimate or measure characteristic properties of the formation and of said fluids during said well operations and continuing to repeat or update on a real-time basis the estimates of in-situ stresses and rock strength based on said properties;

continuing to update the wellbore stability model and continuing to adjust on a real-time basis the properties of said fluids as needed to maintain or enhance said rock strength during said operations.

13. The method of claim 12 wherein at least the weight and salinity of said fluids are adjusted in accordance with results from said wellbore stability model.

14. The method of claim 12 wherein said characteristic properties of the formation which are measured during said wellbore operations comprise acoustic, sonic, electrical, thermal, and transient pressure responses of the formation.

15. A method for maintaining stability of a wellbore penetrating a subterranean formation during operations comprising drilling, servicing, or producing wells employing fluids introduced into the wellbore to facilitate said operations, said method comprising monitoring on a real-time basis the interaction of said fluids on said formation and making adjustments in the properties of said fluids to maintain or enhance the strength of said formation in contact with said fluids.

16. The method of claim 15 wherein monitoring of said interaction comprises taking real-time measurements of properties of the formation and using same in a wellbore stability model.

17. The method of claim 16, further comprising using results from said wellbore stability

model in making said adjustments in the properties of said fluids.

18. The method of claim 15 employing at least one pore pressure versus time laboratory test and wellbore stability modeling in making adjustments in the properties of said fluid.

5

19. A method for monitoring the interaction of a subterranean formation with fluids injected into or circulating in a wellbore penetrating said formation, said method comprising:

constructing an earth-model of the formation adjacent or near the wellbore;

10

predicting suitable fluids for use in said wellbore;

conducting laboratory experiments to ascertain time-dependent formation behavior in the presence of said predicted suitable fluids;

measuring rock properties in said experiments;

calibrating a wellbore stability model based on said measured rock properties;

injecting or circulating said fluids in said wellbore;

measuring real-time static and dynamic rock properties while said fluids are in said wellbore;

updating said wellbore stability model with said real-time measurements;

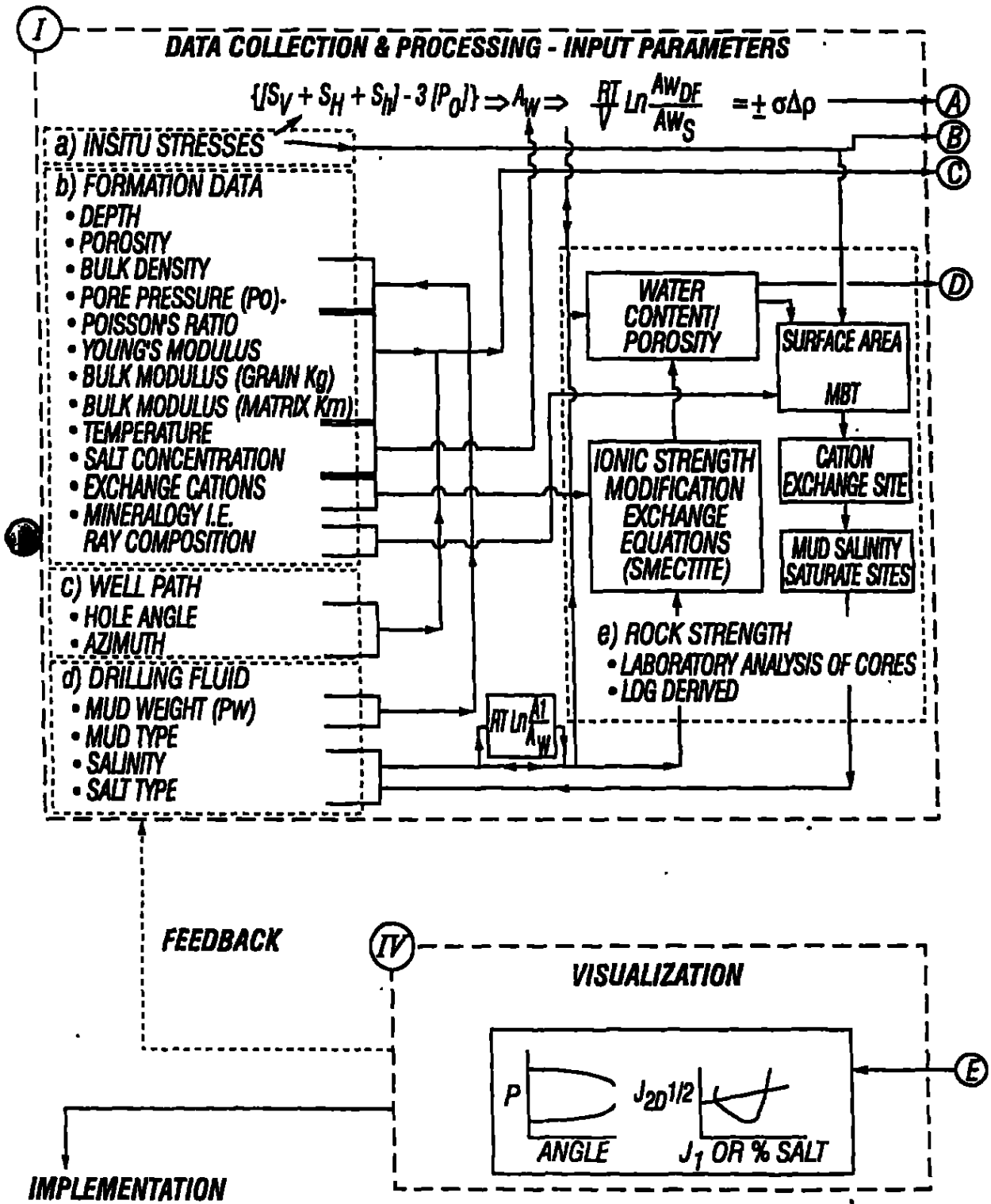
adjusting the properties of said fluids as needed to maintain wellbore stability

20 according to said model.

20. The method of claim 19 wherein said real-time measuring of rock properties and said updating of the wellbore stability model are repeated during said injecting or circulating of said fluids in said wellbore enough times that the interaction of said subterranean formation with said fluids may be monitored on a real-time basis.

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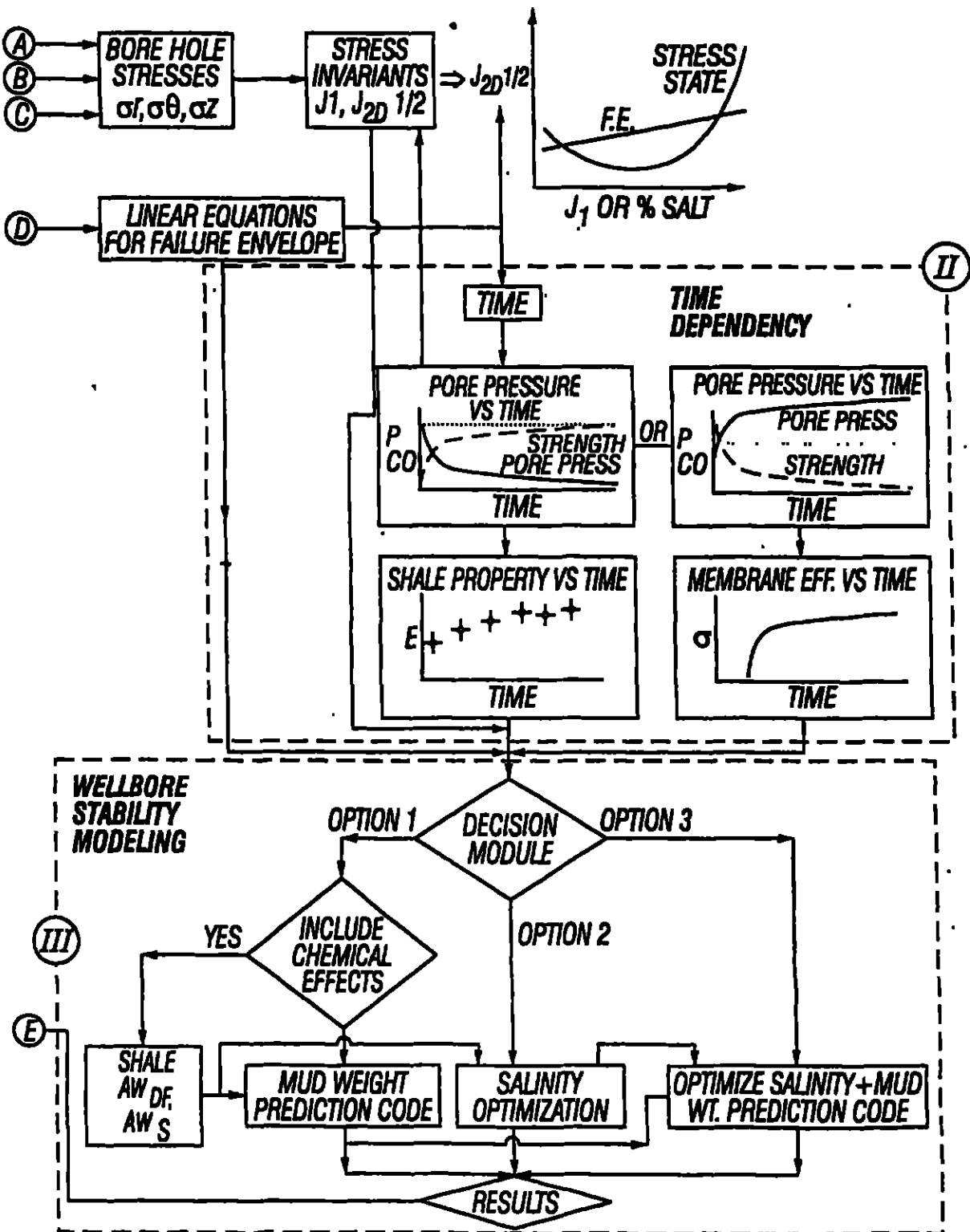
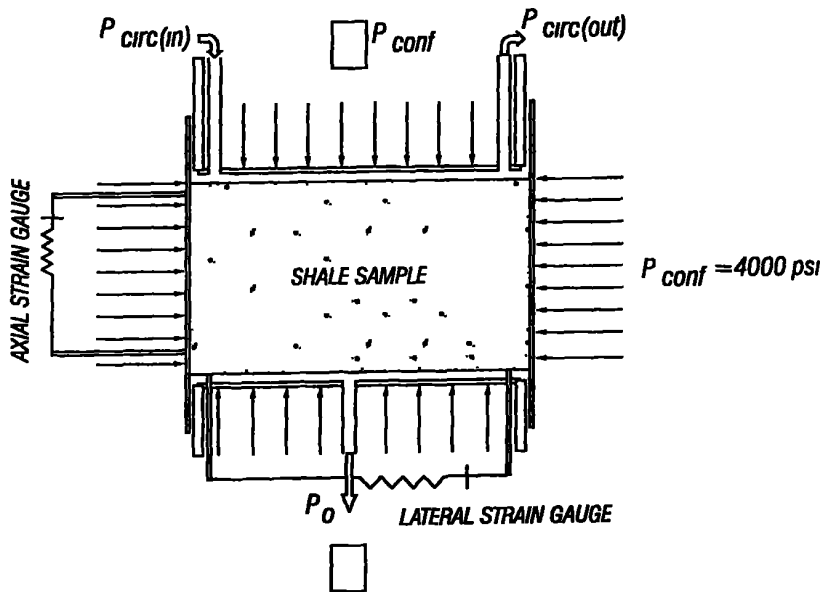


FIG. 1B

P AND S WAVE ACOUSTIC RECEIVER



P AND S WAVE ACOUSTIC EMITTER

FIG 2

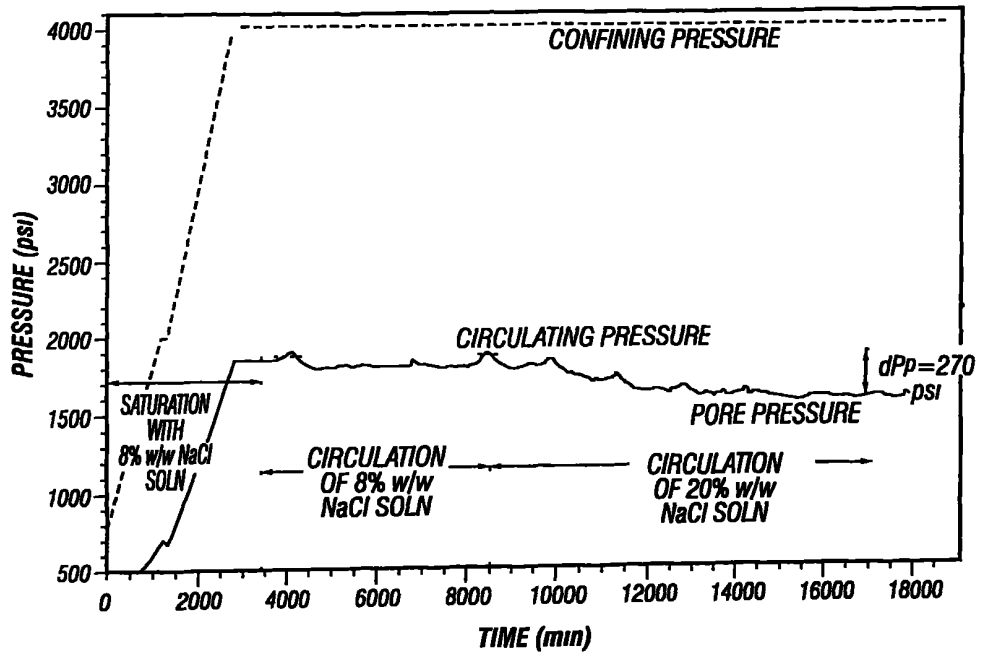


FIG 3

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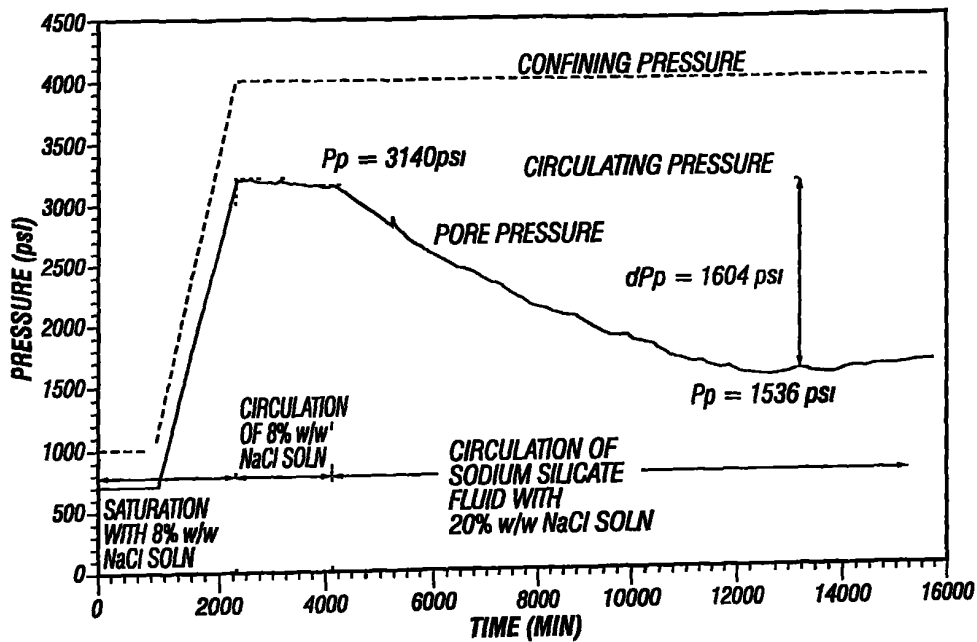


FIG 4

100

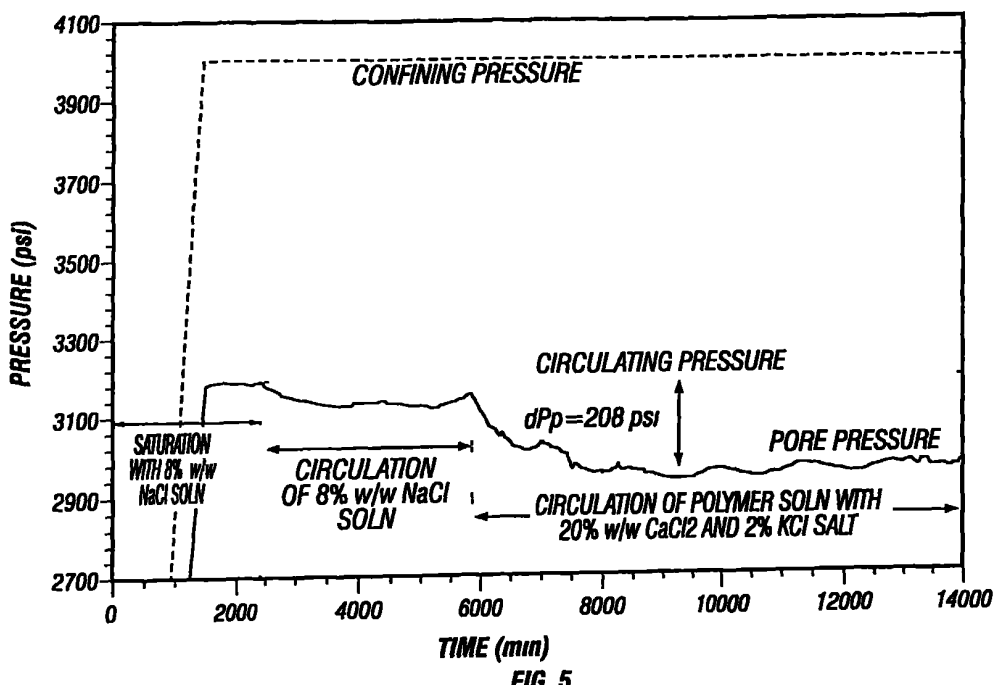
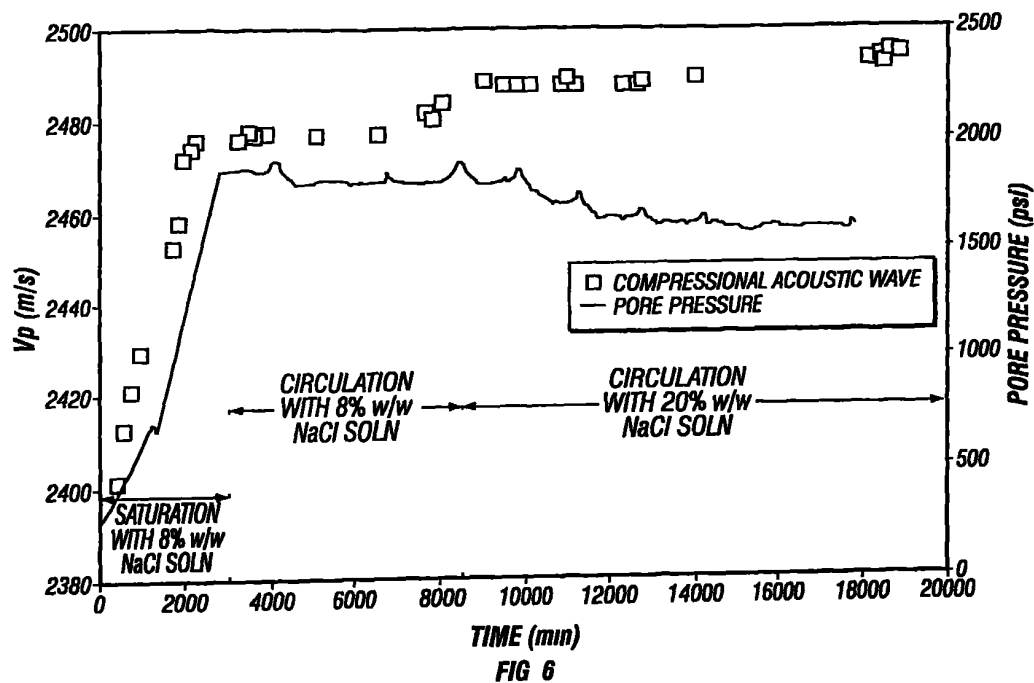


FIG 5



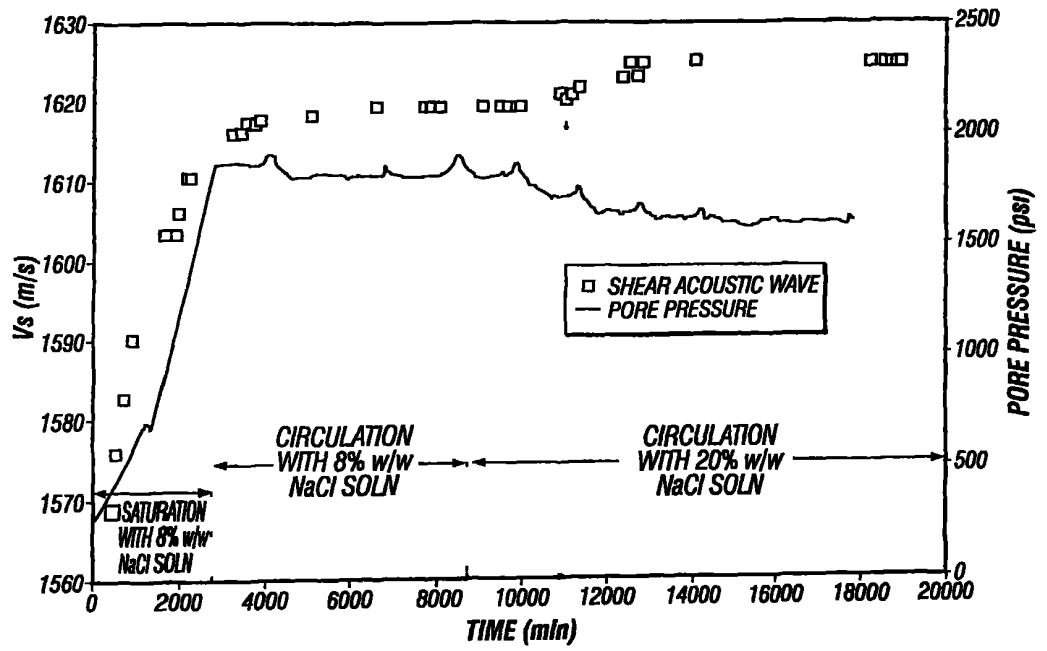
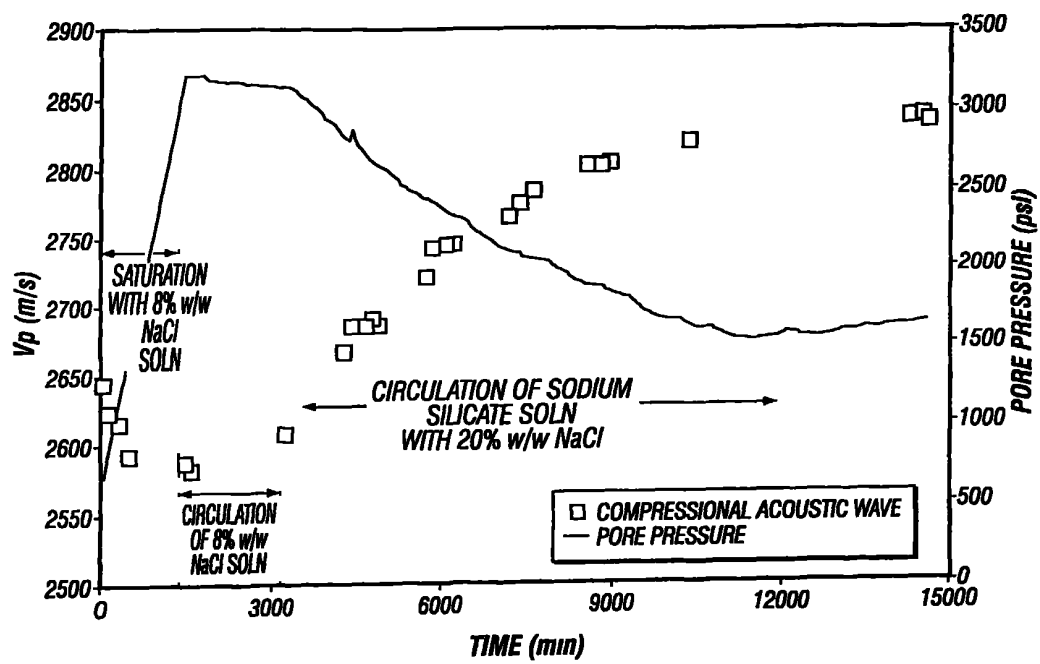


FIG 7

~~102~~

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10/15

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101

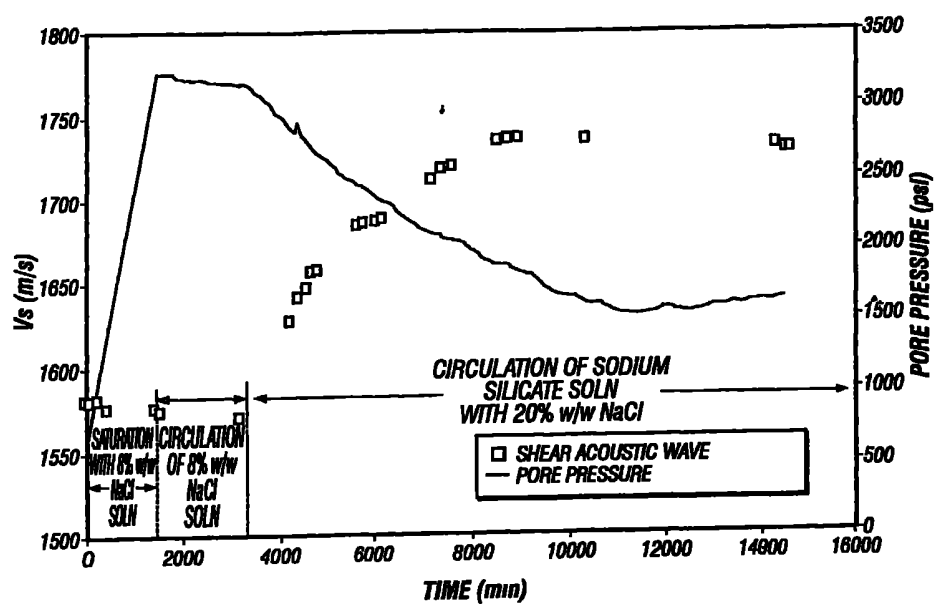


FIG 9

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PCTUS01/181A

105

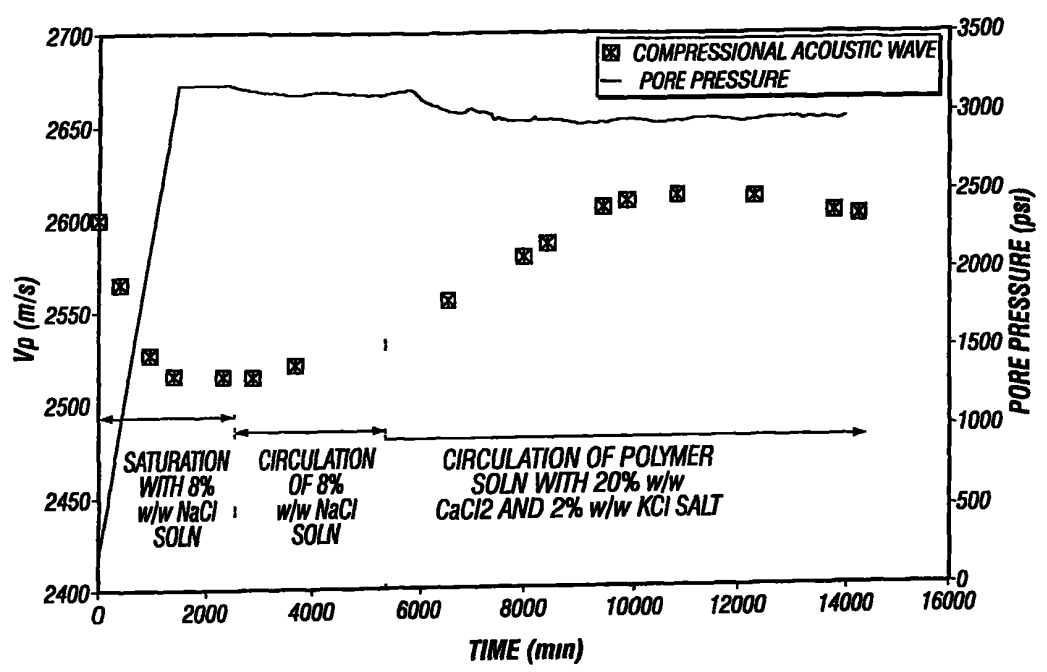


FIG 10

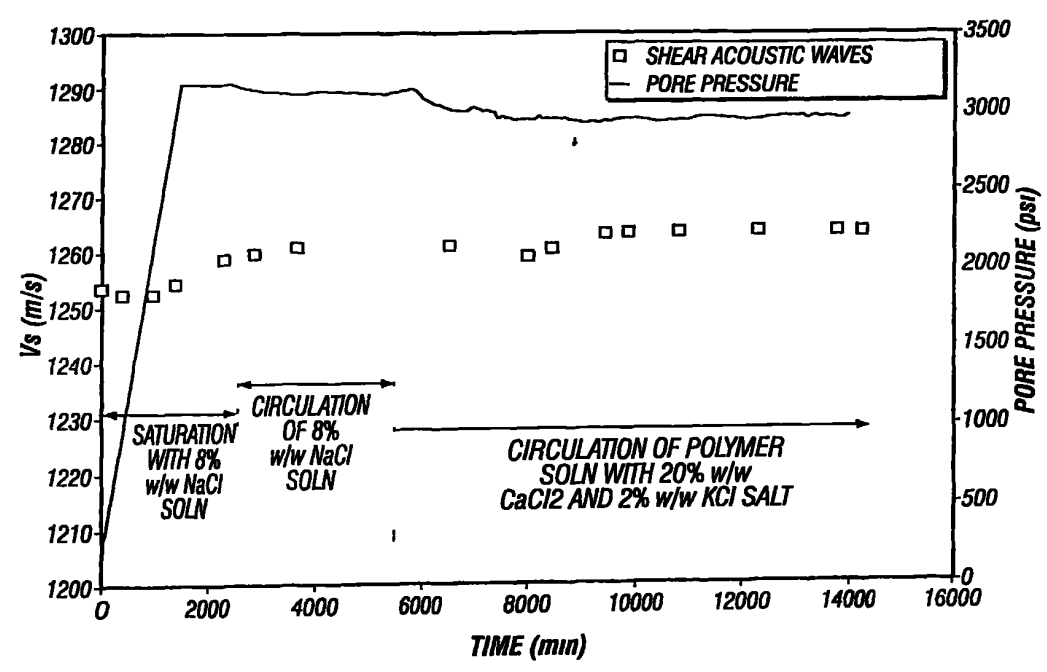


FIG 11

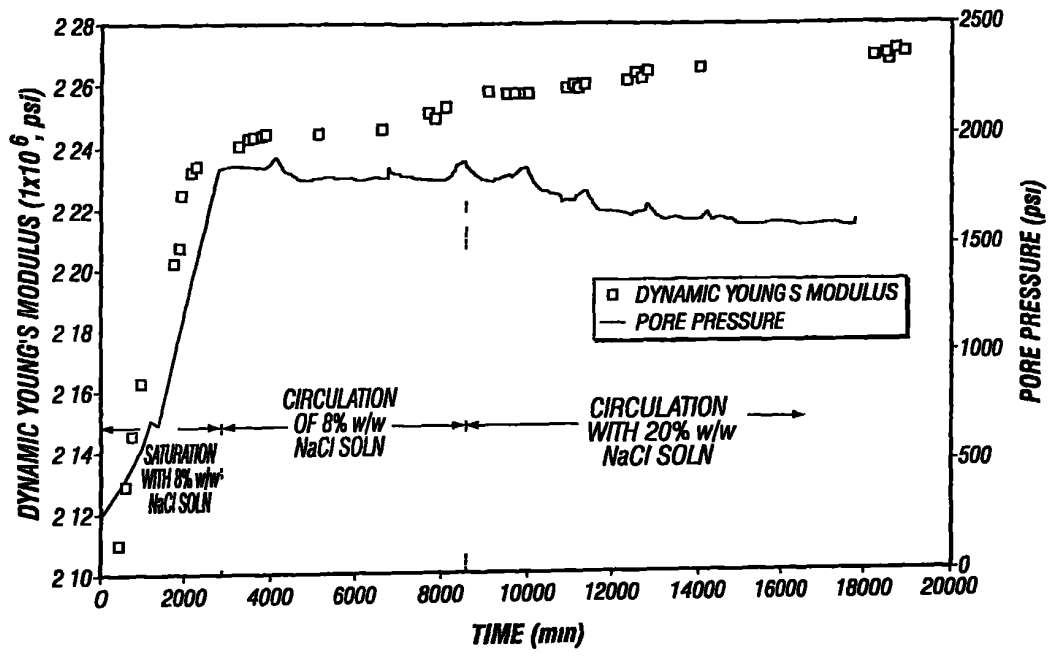


FIG 12

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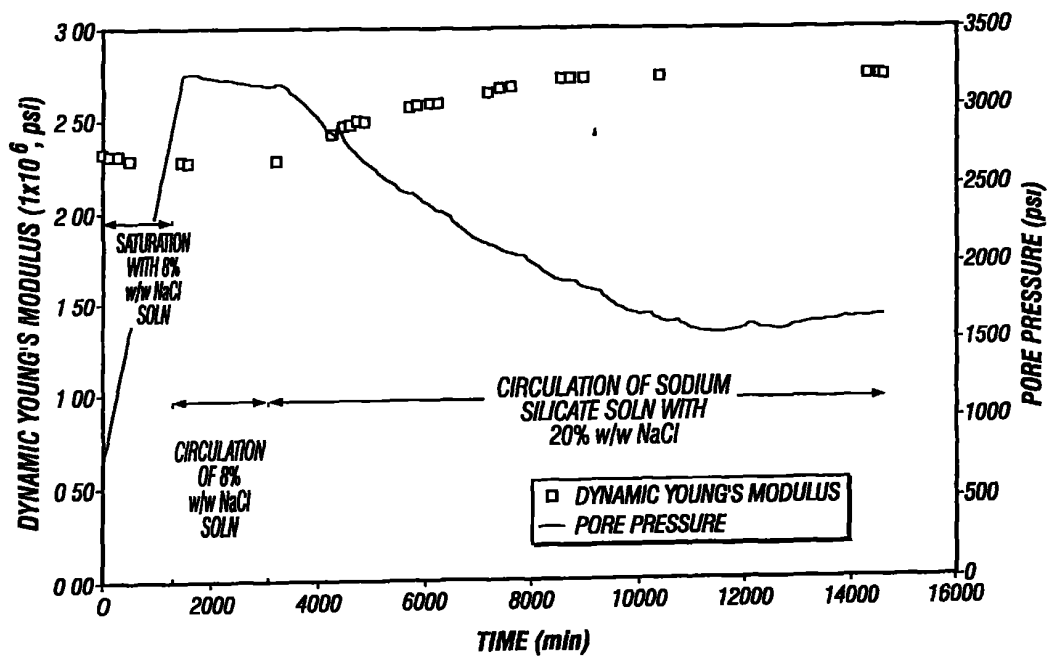


FIG 13

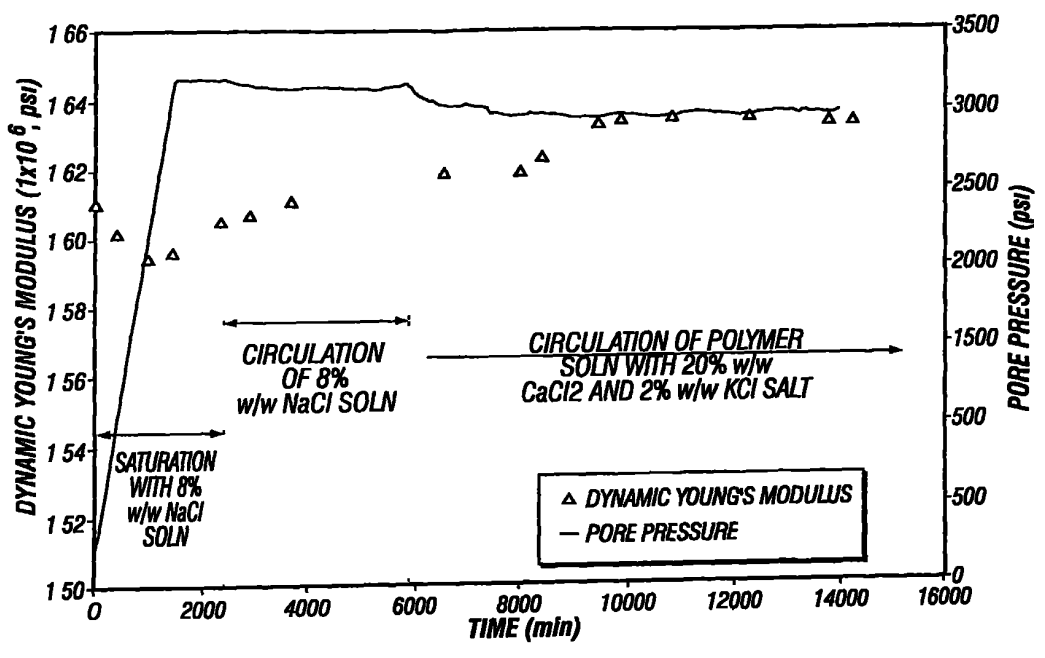


FIG 14

INTERNATIONAL SEARCH REPORT

Int'l Application No

PCT/US 01/18134

110

A. CLASSIFICATION OF SUBJECT MATTER

IPC 7 E21B44/00 E21B49/00 E21B21/08

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 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 WPI Data TULSA

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
P X	WO 01 25823 A (SCHLUMBERGER CA LTD SCHLUMBERGER SERVICES PETROL (FR) SCHLUMBERG) 12 April 2001 (2001-04-12) page 10 line 18 - line 22 page 12 line 13 - line 19 page 16 line 16 - line 22	8 10 11
X	US 5 285 692 A (LEUNG PETER K ET AL) 15 February 1994 (1994-02-15) column 6 line 20 - column 8 line 64 claim 1	12 13 15-20
A	US 4 710 906 A (BRADLEY WILLIAM B ET AL) 1 December 1987 (1987-12-01) column 5 line 3 - line 15	1-20
-/-		



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.

Z document member of the same patent family

Date of the actual receipt of the international search report

3 October 2001

Date of mailing of the international search report

16/10/2001

Name and mailing address of the ISA

European Patent Office P.B. 5616 Patentkan 2
NL 2280 HV Rijswijk
Tel (+31 70) 340-0040, Tel. 31 051 spo nl
Fax (+31-70) 340-3016

Authorized officer

Garrido Garcia M

Form PCTAB/E 0 (second sheet) (July 1992)

INTERNATIONAL SEARCH REPORT

Int'l Application No
PCT/US 01/18134

C.(Continuation) DOCUMENTS CONSIDERED TO BE RELEVANT

Category *	Citation of documents, with indication, where appropriate, of the relevant passages	Relevant to claim No.
A	WO 99 00575 A (BAKER HUGHES INC) 7 January 1999 (1999-01-07) page 14, line 18 - line 23 page 23, line 23 -page 24, line 9	1-20
A	EP 0 881 357 A (HALLIBURTON ENERGY SERV INC) 2 December 1998 (1998-12-02) abstract	1-20
A	Y ABOUSLEIMAN, S EKBOTE ET AL.: "Time-dependent coupled processes in wellbore design and stability: PBORE-3D" SPE 56759, 3 - 6 October 1999, XP002179122 the whole document	1-20

INTERNATIONAL SEARCH REPORT

Information on patent family members

Int'l Application No

PCT/US 01/18134

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1100 Louisiana Street Suite 2690
Houston Texas 77002
UNITED STATES OF AMERICA

Date 16/10/2001

11/15/006420

11/15/006420

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PCT

**NOTIFICATION OF TRANSMITTAL OF
THE INTERNATIONAL SEARCH REPORT
OR THE DECLARATION**

(PCT Rule 44.1)

Applicant's or agent's file reference
HALB 006

FOR FURTHER ACTION See paragraphs 1 and 4 below

International application No.
PCT/US 01/18134

International filing date
(day/month/year) 05/06/2001

Applicant

HALLIBURTON ENERGY SERVICES INC

- 1 ☒ The applicant is hereby notified that the international Search Report has been established and is transmitted herewith
Filing of amendments and statement under Article 18:
The applicant is entitled if he so wishes to amend the claims of the international Application (see Rule 48)

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 is 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 Further action(s)** The applicant is reminded of the following

Shortly after 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 90bis.1 and 90bis.3, respectively, before the completion of the technical preparations for international publication.

Within 18 months from the priority date 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)

Within 30 months from the priority date the applicant must perform the prescribed acts for entry into the national phase before all designated Offices which have not been elected in the demand or in a later election within 19 months from the priority date or could not be elected because they are not bound by Chapter II

Name and mailing address of the International Searching Authority

 **E**uropean Patent Office P.B. 5818 Patentaan 2
NL 2280 HV Rijswijk
Tel (+31 70) 340-2040 T 31 651 epo nl
Fax (+31 70) 340-3016

Authorized officer
Christine Schipflinger

Abstract

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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 letter 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 18, 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 18 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 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 28, 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 18 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, 18 and 17; new claims 20 and 21 added."

"Statement under Article 19(1)" (Rule 48.4)

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).

Consequences 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.

PCT

INTERNATIONAL SEARCH REPORT

(PCT Article 18 and Rules 43 and 44)

Applicant's or agent's file reference HALB:006	FOR FURTHER ACTION see Notification of Transmittal of International Search Report (Form PCT/ISA/220) as well as, where applicable, item 5 below.	
International application No. PCT/US 01/18134	International filing date (day/month/year) 05/06/2001	(Earliest) Priority Date (day/month/year) 06/06/2000
Applicant HALLIBURTON ENERGY SERVICES, INC.		

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 4 sheets.

☒ 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, the International search was carried out on the basis of the sequence listing:

☐ contained in the international application in written form.

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

☐ furnished subsequently to this Authority in written form.

☐ furnished subsequently to this Authority in computer readable form.

☐ the statement that the subsequently furnished written sequence listing does not go beyond the disclosure in the international application as filed has been furnished.

☐ the statement that the information recorded in computer readable form is identical to the written sequence listing has been furnished.

2. ☐ Certain claims were found unsearchable (See Box I).

3. ☐ Unity of invention is lacking (see Box II).

4. With regard to the title,

☐ the text is approved as submitted by the applicant.

☒ the text has been established by this Authority to read as follows:

REAL-TIME METHOD FOR MAINTAINING FORMATION STABILITY

5. With regard to the abstract,

☒ 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 III. The applicant may, within one month from the date of mailing of this international search report, submit comments to this Authority.

6. The figure of the drawings to be published with the abstract is Figure No.

☒ as suggested by the applicant.

☐ because the applicant failed to suggest a figure.

☐ because this figure better characterizes the invention.

1a

☐ None of the figures.

INTERNATIONAL SEARCH REPORT

International Application No

PCT/US 01/18134

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A. CLASSIFICATION OF SUBJECT MATTER

IPC 7 E21B44/00 E21B49/00 E21B21/08

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 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, WPI Data, TULSA

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category *	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
P, X	WO 01 25823 A (SCHLUMBERGER CA LTD ;SCHLUMBERGER SERVICES PETROL (FR); SCHLUMBERG) 12 April 2001 (2001-04-12) page 10, line 18 - line 22 page 12, line 13 - line 19 page 16, line 16 - line 22	8,10,11
X	US 5 285 692 A (LEUNG PETER K ET AL) 15 February 1994 (1994-02-15) column 6, line 20 -column 8, line 64; claim 1	12,13, 15-20
A	US 4 710 906 A (BRADLEY WILLIAM B ET AL) 1 December 1987 (1987-12-01) column 5, line 3 - line 15	1-20
	-/-	



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 doubt on priority claims 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.

Z document member of the same patent family

Date of the actual completion of the international search

3 October 2001

Date of mailing of the international search report

16/10/2001

Name and mailing address of the ISA

European Patent Office, P.O. Box 1
NL - 2200 HV Rijswijk
Tel: (+31-70) 340-2040, Tx: 31 651 apo nl
Fax: (+31-70) 340-3016

Authorized officer

Garrido Garcia, M

INTERNATIONAL SEARCH REPORT

International Application No

PCT/US 01/18134

119

C.(Continuation) DOCUMENTS CONSIDERED TO BE RELEVANT		
Category *	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
A	WD 99 00575 A (BAKER HUGHES INC) 7 January 1999 (1999-01-07) page 14, line 18 - line 23 page 23, line 23 -page 24, line 9	1-20
A	EP 0 881 357 A (HALLIBURTON ENERGY SERV INC) 2 December 1998 (1998-12-02) abstract	1-20
A	Y ABOUSLEIMAN, S EKBOTE ET AL.: "Time-dependent coupled processes in wellbore design and stability: PBORE-3D" SPE 56759, 3 - 6 October 1999, XP002179122 the whole document	1-20

INTERNATIONAL SEARCH REPORT

Information on patent family members

International Application No

PCT/US 01/18134

120

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WO 0125823	A	12-04-2001	GB 2354852 A AU 7535000 A WO 0125823 A1	04-04-2001 10-05-2001 12-04-2001
US 5285692	A	15-02-1994	US 5205164 A NO 913409 A	27-04-1993 02-03-1992
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WO 9900575	A	07-01-1999	AU 5248598 A AU 8164898 A GB 2334108 A , B WO 9900575 A2 US 6176323 B1	15-05-1998 19-01-1999 11-08-1999 07-01-1999 23-01-2001
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United States Patent [19]
Steiger et al.

US005285692A
[11] Patent Number: 5,285,692
[45] Date of Patent: Feb. 15, 1994

[54] METHODS FOR MEASURING PHYSICAL
PARAMETERS OF A LOW PERMEABILITY
ROCK FORMATION IN SITU

4,631,677 12/1986 Park et al. 364/422
4,638,447 1/1987 Odch 344/334
4,643,019 2/1987 Jones 73/38

[75] Inventors: Ronald P. Steiger, Houston; Peter K.
Leung, Sugar Land, both of Tex.

(List continued on next page.)

[73] Assignee: Exxon Production Research
Company, Houston, Tex.

OTHER PUBLICATIONS

[21] Appl. No.: 931,865

[22] Filed: Aug. 18, 1992

Related U.S. Application Data

[62] Division of Ser. No. 577,337, Aug. 31, 1990, Pat. No.
5,205,164.

[51] Int. Cl.⁵ G01N 3/00

[52] U.S. Cl. 73/866; 73/397

[58] Field of Search 73/152, 153, 38, 39,
73/866

[56] References Cited

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"Predictions of Wellbore Stability In Shale Formations
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1989.

"The Mechanics of Soils," Atkinson et al. 1978, pp.
118-144, 184-209, 292-343.

"Soil Mechanics," Lambe et al., 1969, Chapter 20, pp.
295-303.

Primary Examiner—Donald O. Woodiel

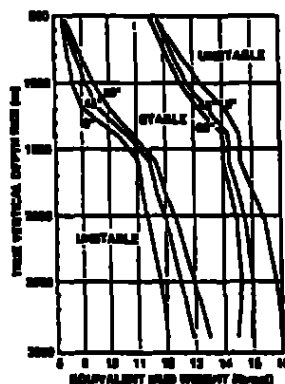
Assistant Examiner—R. Biagel

Attorney, Agent, or Firm—Guy McClung

[57] ABSTRACT

A method for determining drilling fluid density for
stabilizing a wellbore including obtaining shale cuttings
from a wellbore. In one embodiment of a method ac-
cording to this invention, shale cuttings are obtained
from a wellbore and their index properties, including
but not limited to surface area, is measured; mean effec-
tive stress around the wellbore is calculated using the
geostatic overburden in situ stress, the field pore pres-
sure, and the total stress around the wellbore; the in situ
shale strength is determined using a correlation between
surface area, mean effective stress and shale strength;
and drilling fluid density is determined using the shale
strength. Methods for determining in situ shale
strengths, elastic properties, pore pressures, and forma-
tion stresses of low permeability rocks.

4 Claims, 5 Drawing Sheets



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U.S. PATENT DOCUMENTS

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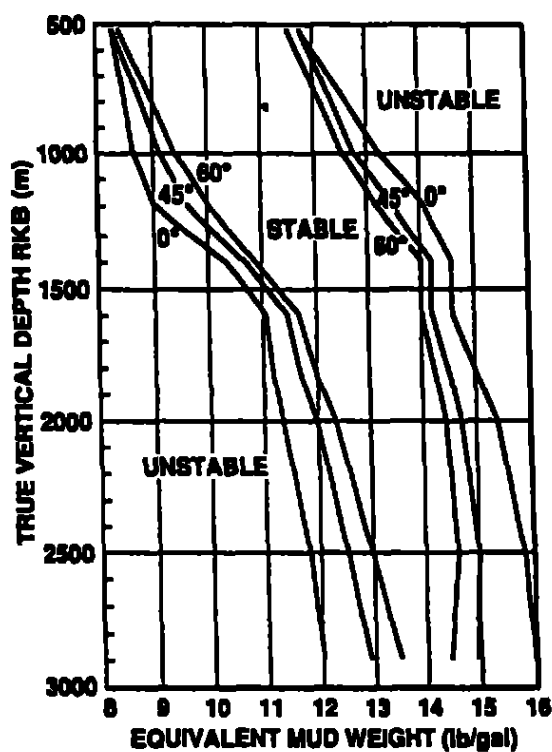


FIG. 1

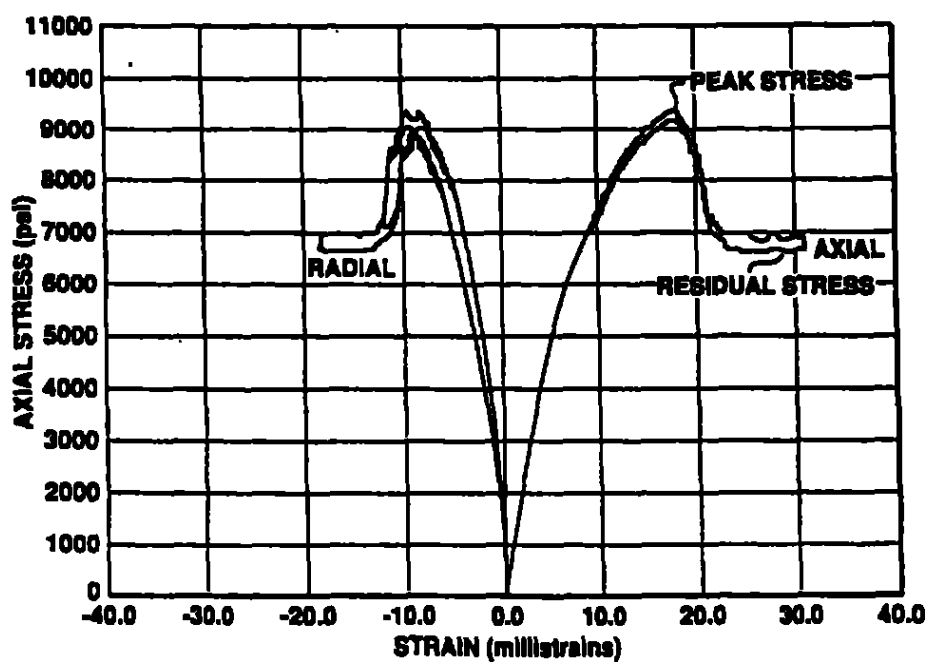


FIG. 2

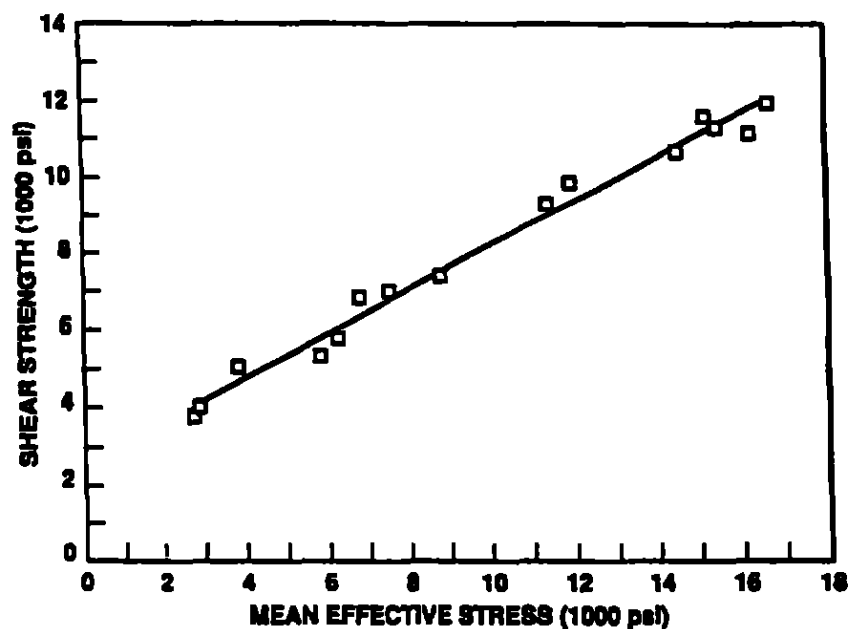


FIG. 3

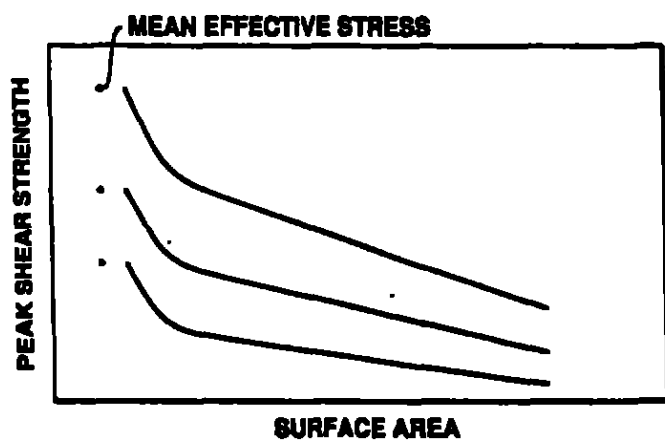


FIG. 4

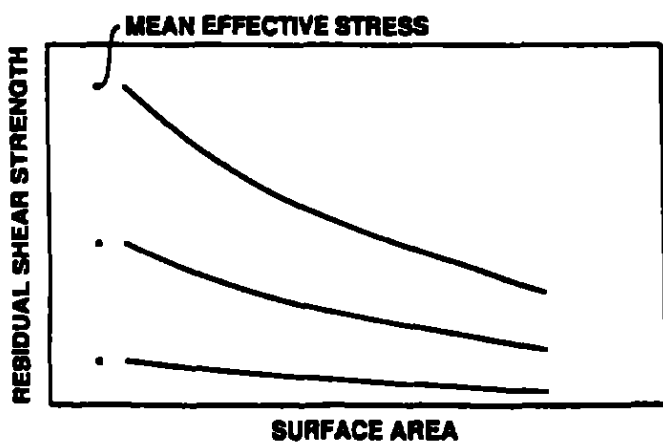


FIG. 5

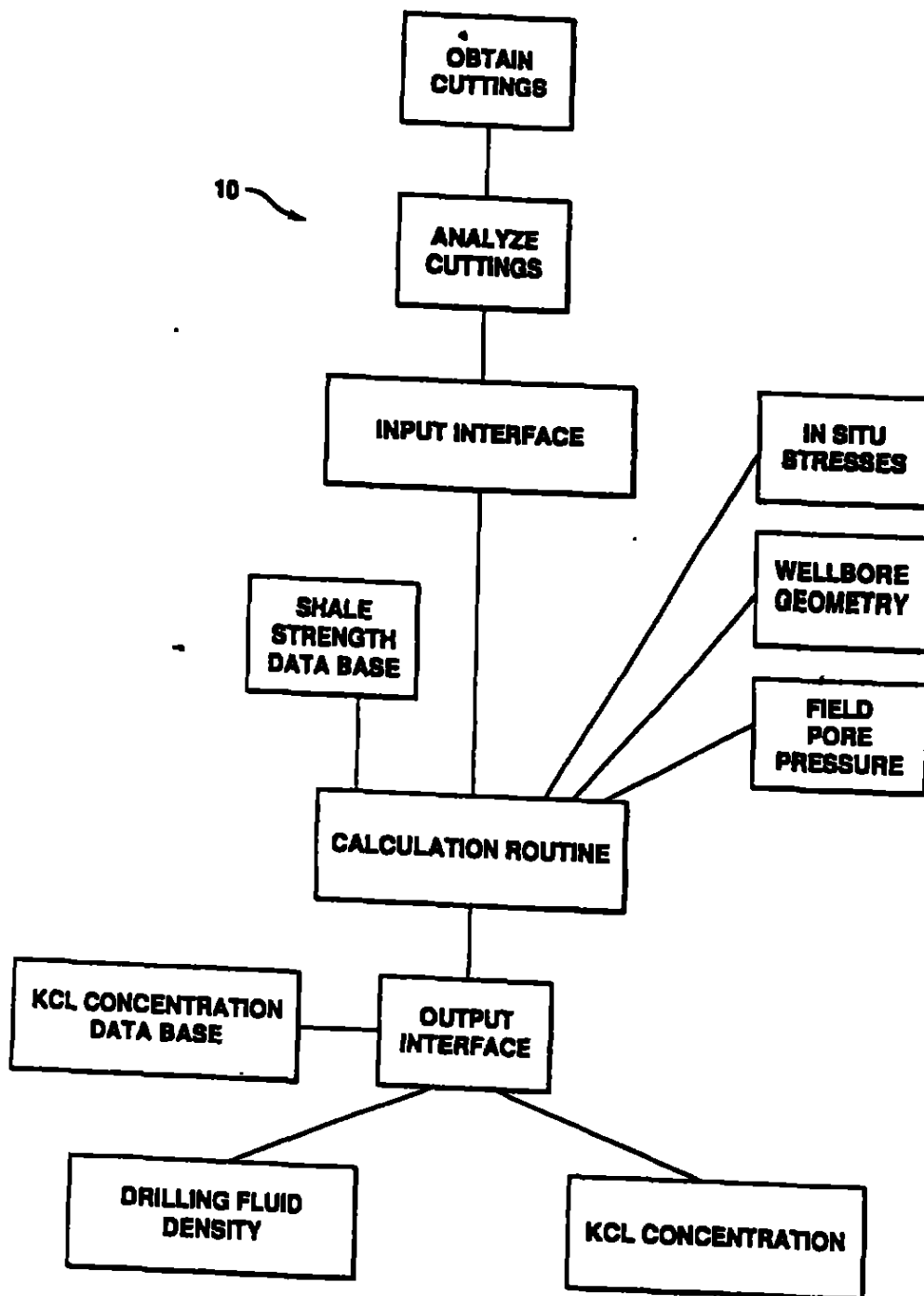


FIG. 6

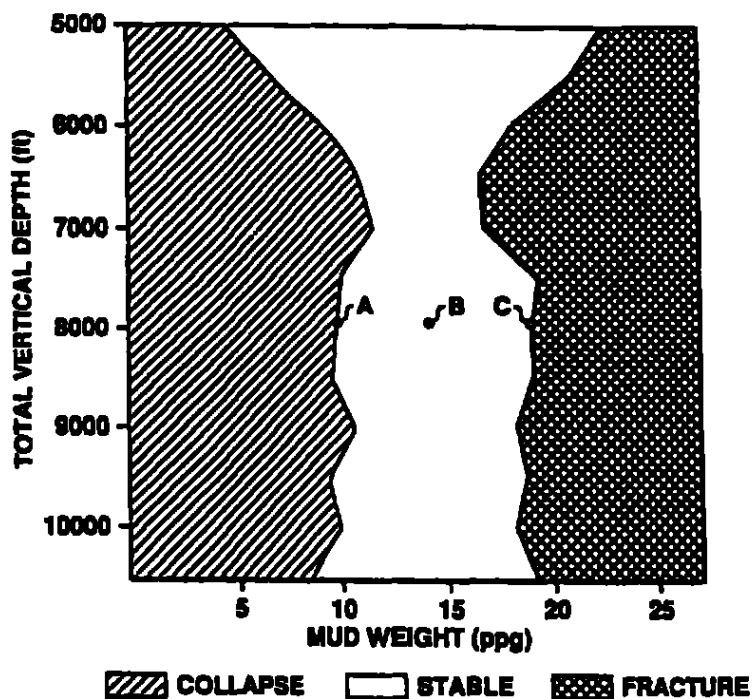


FIG. 7

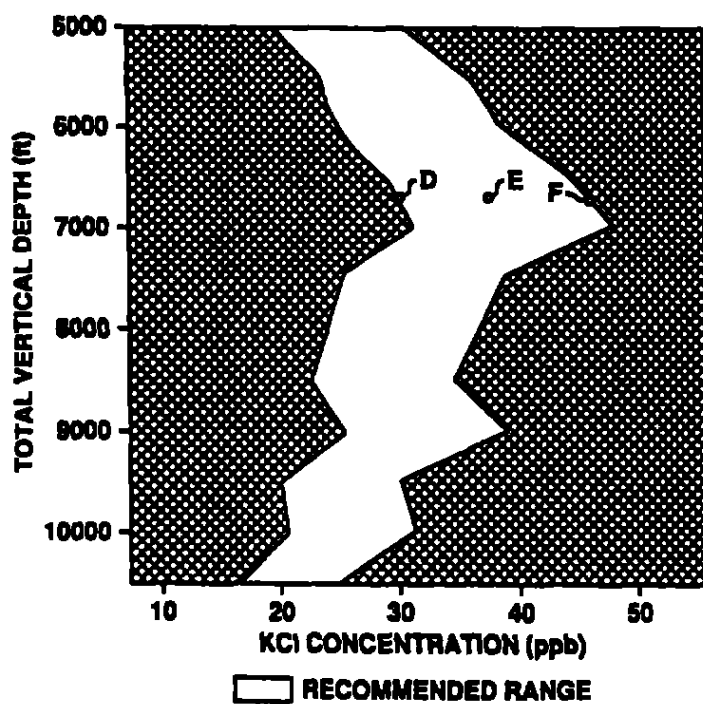


FIG. 8

diagnose it by variations in form or additions of further improvements.

DESCRIPTION OF THE DRAWINGS

So that the manner in which the above-recited features, advantages and objects of the invention, as well as others which will become clear, are attained and can be understood in detail, more particular description of the invention briefly summarized above may be had by reference to certain embodiments thereof which are illustrated in the appended drawings, which drawings form a part of this specification. It is to be noted, however, that the appended drawings illustrate preferred embodiments of the invention and are therefore not to be considered limiting of its scope, for the invention may admit to other equally effective equivalent embodiments.

FIG. 1 is a graph of wellbore stability charts.

FIG. 2 is a graph of stress-strain curves for a low permeability shale.

FIG. 3 is a graph of a failure criterion for a shale.

FIG. 4 is a graph of peak shale strength correlation according to the present invention.

FIG. 5 is a graph of residual shale strength correlation according to the present invention.

FIG. 6 is a flow chart of a method according to the present invention.

FIG. 7 is a graphical representation of results obtained utilizing methods according to the present invention.

FIG. 8 is a graphical representation of potassium chloride concentrations obtained using prior art methods.

FIG. 9 shows the strength-mean effective stress relationship for different shales.

FIG. 10 is a schematic representation of a method according to this invention.

FIG. 11 presents a graph of a rock's ultrasonic velocity versus its mean effective stress.

DESCRIPTION OF EMBODIMENTS PREFERRED AT THE TIME OF FILING FOR THIS PATENT

A method 10 according to the present invention is represented schematically in FIG. 6. According to this method, shale cuttings are obtained ("OBTAIN CUTTINGS") from a wellbore and their surface area is measured or determined ("ANALYZE CUTTINGS"). One way to determine surface area, presented in U.S. Pat. No. 4,876,512 co-owned with this application and fully incorporated herein, includes measuring the dielectric constant of a shale and then determining its surface area.

From typical sources, e.g. density logs and extended leak off tests, in situ geostatic stresses are determined ("IN SITU STRESSES"). Density log data is used to calculate a vertical stress component and extended leak off test data is used to calculate a horizontal stress component. These two components are then used to calculate the total in situ stress.

From typical sources, e.g. mud logging reports, and well data from other wells, data are obtained for calculating field pore pressure ("FIELD PORE PRESSURE"). The wellbore geometry ("WELLBORE GEOMETRY") (depth, dimension, direction) is obtained from conventional sources, e.g. such as well survey data. Using conventional methods, e.g. linear elastic equations, total stress around the wellbore is calculated.

["CALCULATION ROUTINE"] By subtracting the field pore pressure from this total stress, the mean effective stress around the wellbore is determined. ["CALCULATION ROUTINE"]

By using correlations of mean effective stress and shale shear strength (determined from a shale strength data base for shales from, e.g., data derived from tests according to the four-previously described and appended co-pending applications) the in situ strength of the shale under study is determined ("CALCULATION ROUTINE"). Equations shown below for exemplary calculations are used in correlating stress and strength.

It is preferred, but not necessary, that KCl (potassium chloride) concentration ("KCL concentration data base") be one parameter determined with this method ("calculation routine"). Such determinations are known in the prior art.

Using the total wellbore stress, the mean effective stress around the wellbore, and in situ shale shear strength, failure criteria are defined for the shale under study ("CALCULATION ROUTINE"); i.e., the strength less than which the shale will fail is determined. Then, using an iterative process described in detail below, an appropriate drilling fluid density is determined ("CALCULATION ROUTINE"). Also, KCl concentration is calculated.

A typical method according to this invention includes the following steps (assume Poisson's Ratio = 0.4):

1. calculate depth from the mud line (MdlDpt) (e.g. from the seafloor):

$$MdlDpt = TVD - WtrDpt$$

Where, WtrDpt = Water Depth

On land, WtrDpt = 0

TVD = True Vertical Depth

2. Calculate hole direction in relation to Maximum Horizontal Stress (MaxHrStr):

$$\theta_{\text{hole}} = \sin^{-1} \left(\frac{WtrAss - MaxHrStrAss}{MaxHrStrAss} \right)$$

Alpha = Wellbore drift or angle

[WtrAss = Wellbore Azimuth
MaxHrStrAss = Azimuth of the maximum horizontal stress]

3. Convert in-situ stress gradient to total stress:

$$\text{Sigma1} = \text{OverburdenGrd} (\text{Overburden stress gradient}) \cdot MdlDpt$$

$$\text{Sigma2} = \text{MaxHrStrGrd} (\text{Maximum horizontal stress gradient}) \cdot MdlDpt$$

$$\text{Sigma3} = \text{MinHrStrGrd} (\text{Minimum horizontal stress gradient}) \cdot MdlDpt$$

$$\text{PorePr} = \text{PorePrGrd} (\text{Pore pressure gradient}) \cdot MdlDpt$$

4. Transform stresses in (Sigma 1,2,3) coordinates into new local coordinate relative to the hole (x,y,z) yielding new coordinates in x,y,z system:

$$\text{Sigma} = \text{Sigma}_1 \cdot \cos^2(\text{Beta}) + \text{Sigma}_2 \cdot \sin^2(\text{Beta})$$
$$\text{Sigma}_y = (\text{Sigma}_1 \cdot \sin^2(\text{Beta}) + \text{Sigma}_2 \cdot \cos^2(\text{Beta})) \cdot \cos^2(\text{Alpha}) + \text{Sigma} \cdot \sin^2(\text{Alpha})$$
$$\text{Sigma}_x = (\text{Sigma}_1 \cdot \sin^2(\text{Beta}) + \text{Sigma}_2 \cdot \cos^2(\text{Beta})) \cdot \sin^2(\text{Alpha}) + \text{Sigma} \cdot \cos^2(\text{Alpha})$$
$$\text{Tauxy} = 0.5 (\text{Sigma}_1 - \text{Sigma}_2) \cdot \sin(2 \cdot \text{Beta}) \cdot \cos(\text{Alpha})$$
$$\text{Tauxx} = 0.5 (\text{Sigma}_1 - \text{Sigma}_2) \cdot \sin(2 \cdot \text{Beta}) \cdot \sin(\text{Alpha})$$
$$\text{Tauxz} = 0.5 (\text{Sigma}_1 - \text{Sigma}_2) \cdot \sin(2 \cdot \text{Beta}) \cdot \cos(\text{Alpha})$$

5. Calculate surface area:

a. DCM (dielectric constant measurement yields DCM) option (U.S. Pat. No. 4,876,512)

$$\text{SurfArea} = 0.0331 \cdot \text{DCM}^2 + 2.19 \cdot \text{DCM} - 43.93$$

b. Direct measurement [e.g. EGME method]

6. Calculate Poisson ratio (PoisRt):

$$\text{PoisRt} = f(\text{SurfArea, mean effective stress})$$

7. Set Theta (angle around wellbore) to zero degree
8. Calculate effective confining stress (EffStress) as a function of Theta:

$$A1 = \text{Sigma}_1 + \text{Sigma}_2$$

$$A2 = 2 \cdot (\text{Sigma}_1 - \text{Sigma}_2) \cdot \cos(2 \cdot \text{Theta})$$

$$A3 = 4 \cdot \text{Tauxy} \cdot \sin(2 \cdot \text{Theta})$$

$$c = \text{Sigma}_1 - \text{PoisRt} \cdot (A1 + A3)$$

$$d = A1 - A2 - A3$$

$$\text{EffStress} = (c + d/3) - \text{PorePres}$$

[PorePres = in situ pore pressure of the formation]

TABLE II-continued				
K	L	M	N	O
TVD	Minimum	Maximum	Estimated	Estimated
ft	Mod Wt.	Mod Wt.	Min KCl	Max KCl
	ppg	ppg	ppb	ppb
9				
5500.0	6.9	21.4	24.3	37.1
6000.0	9.5	18.5	23.8	39.4
6500.0	11.3	16.9	20.4	43.2
7000.0	11.9	17.0	21.9	48.6
7500.0	20.3	19.5	25.8	39.4
8000.0	18.0	19.3	24.3	37.1
8500.0	9.8	19.2	22.8	34.7
9000.0	10.8	18.4	23.8	39.4
9500.0	9.5	18.8	19.8	30.1
10000.0	10.0	18.3	20.4	31.3
10500.0	8.5	18.2	18.0	24.3

9. Calculate rock strength (Rock Strgh):

$$\text{RockStrgh} = \exp(\exp(2.452251 - (.1495 \cdot 1) \cdot (\text{SurfArea}))) + (\text{EffStress} \cdot (.605 - (.0004 \cdot \text{SurfArea})))$$

[e.g. exp² means e²; exp^{exp} means e^e]
[ln=log]

10. Calculate collapse mud weight (CpMW):

$$\text{Taux} = 2 \cdot (\text{Tauxy} \cdot \cos(\text{Theta}) - \text{Tauxx} \cdot \sin(\text{Theta}))$$

$$b1 = 9 \cdot d^2 - 12 \cdot (d^2 + c^2 - c \cdot d - 4.5 \cdot \text{RockStrgh}^2 + 3 \cdot \text{Taux}^2)$$

If b1 > 0 b2 = square root (b1)

If b1 < 0 b2 = "not"

$$\text{CpMW} = (c + d - b2) / (6 \cdot \text{TVD} \cdot 0.052)$$

11. Calculate maximum allowable mud weight:

$$\text{FracMW} = (d - \text{PorePres}) / (\text{TVD} \cdot 0.052)$$

[FracMW is the mud weight that will cause fracturing of the wellbore]

12. Increase Theta 5 degrees, 72 times, to 360 degree. For each increment, repeat steps 8-10 to obtain CpMW and FracMW. Find and save the maximum

TABLE I

A		B		C		D		E		F		G		H		I		J	
SURVEY		STRESS		ROCK															
TVD	Drift	Drift	Drift	Drift	Drift	Drift	Drift	Drift	Drift	Drift	Drift	Drift	Drift	Drift	Drift	Drift	Drift	Drift	Drift
ft	Decimal	Decimal	Decimal	Decimal	Decimal	Decimal	Decimal	Decimal	Decimal	Decimal	Decimal	Decimal	Decimal	Decimal	Decimal	Decimal	Decimal	Decimal	Decimal
5000.0	0.000	10.000	0.500	0.900	0.720	0.720	0.720	40.000	108.0	40.000									
5500.0	15.000	15.000	0.500	0.900	0.720	0.720	0.720	40.000	123.0	44.000									
6000.0	25.000	10.000	0.600	0.900	0.720	0.720	0.720	40.000	135.0	49.000									
6500.0	30.000	10.000	0.625	0.900	0.720	0.720	0.720	40.000	140.0	50.000									
7000.0	35.000	10.000	0.600	0.900	0.720	0.720	0.720	40.000	175.0	55.000									
7500.0	45.000	0.000	0.500	0.900	0.720	0.800	0.800	40.000	135.0	43.000									
8000.0	50.000	10.000	0.475	0.900	0.720	0.750	0.750	40.000	125.0	42.000									
8500.0	60.000	5.000	0.437	0.900	0.720	0.720	0.720	40.000	115.0	39.200									
9000.0	65.000	15.000	0.437	0.900	0.720	0.720	0.720	40.000	115.0	42.300									
9500.0	75.000	10.000	0.437	0.900	0.720	0.720	0.720	40.000	95.0	42.500									
10000.0	85.000	5.000	0.437	0.900	0.720	0.720	0.720	40.000	100.0	43.200									
10500.0	90.000	5.000	0.437	0.900	0.720	0.720	0.720	40.000	70.0	30.100									

TABLE II

K	L	M	N	O
TVD	Minimum	Maximum	Estimated	Estimated
ft	Mod Wt.	Mod Wt.	Min KCl	Max KCl
	ppg	ppg	ppb	ppb
5000.0	4.7	23.0	20.4	31.3

collapse MW and minimum fracture KW around the wellbore.

65 Tables I and II present input and output data for typical determinations using methods according to the present invention. Table I represents the following input data:

Column	
A	Total vertical depth
B	Drift angle of the wellbore
C	Assigned angle of the wellbore
D	In Situ Pore pressure of the rock
E	Overburden stress
F	Minimum horizontal stress gradient
G	Maximum horizontal stress gradient
H	Maximum horizontal stress azimuth
I	Rock surface area (BOMI direct measurement method) or
J	Rock surface area (DCM method)

(I is in mcm²/gram; J is in mcm²/cm²; only one input value from either column I or J is required)

Table II presents the following output data:

Column	
K	Total vertical depth
L	Collapse mud weight, i.e. minimum required mud weight to keep wellbore stable
M	Fracture mud weight, i.e. maximum mud weight the wellbore can take before fracture occurs
N	Minimum desirable KCl amount
O	Maximum desirable KCl amount

FIG. 7 presents a graphic representation of desirable and undesirable drilling fluid (in this case mud) weights for a particular wellbore. The figure shows the combinations of mud weight and depth that results in compressive failure, stable conditions, or tensile failure. For example, three points at the same depth have been indicated in FIG. 7, points A, B and C. Point A represents the minimum mud weight that is needed to prevent wellbore collapse operation to the left of this point results in brittle or ductile collapse with the accompanying problems of tight holes, stuck pipe, etc. Point B is located in a stable region where compressive failure and lost circulation will not occur. Point C represents the maximum mud weight that the wellbore can take before lost circulations occur. Operation to the right of Point C causes the bore hole wall to fracture resulting in lost circulation.

FIG. 8 presents potassium chloride concentration in the drilling mud. This is determined with prior art methods. Three points have been indicated, points D, E, and F. Point D represents the minimum KCl concentration level that is required to effectively inhibit shale swelling. Point E represents an intermediate KCl concentration at which shale hydration is inhibited. Point F represents the preferred upper range of KCl concentration that will effectively inhibit shale swelling.

Another shale strength-mean effective stress data base correlation according to the present invention is developed with ultrasonic velocity data. Ultrasonic velocity values for a particular field shale at depth are determined by prior art wellbore logging techniques and are then compared to the data base, e.g., in the laboratory, to obtain in situ shale strength.

Another remote-from-the-hole test data base correlation according to the present invention is developed for several different types of shales with data including ultrasonic velocity, surface area, and mean effective stress laboratory test measurements. The ultrasonic velocity values for different shales are functions of mean effective stress as derived by methods described in our copending application entitled "Apparatus and

Methods For Measuring Ultrasonic Velocities In Materials," producing results as shown in FIG. 11. Also, the surface areas of each of the shale types are determined and correlated with ultrasonic velocity and mean effective stress; e.g., in FIG. 11 Shale I has a low surface area and Shale II has a high surface area. Then in situ field pore pressure can be determined by combining field measurements of in situ (vertical) overburden stress, horizontal stress, ultrasonic velocity log data, and surface areas of shale cuttings. The in situ horizontal stress is determined by a prior art hydraulic leakoff (hydraulic microfracture) test. The in situ overburden stress is derived from prior art density log data. The mean effective stress is determined by comparing the surface area of the field shale cuttings and the log derived ultrasonic velocity from the zone of interest to the surface area-ultrasonic velocity-mean effective stress correlation from the laboratory test shale data base. The following method is used to obtain in situ pore pressure (u):

$$p' = (\sigma_1 + 2 \sigma_3) / 3 - u \tag{1}$$

where

p' = mean effective stress

σ_1 = overburden stress

σ_3 = horizontal stress

$$\sigma_1 = \sum_{i=1}^n \gamma_i \Delta h_i$$

derived from the field density log where γ_i = log density derived at each depth interval, Δh_i is determined from the extended hydraulic leakoff test

p' is determined from the surface area-ultrasonic velocity-mean effective stress laboratory test data base correlation.

Then from (1):

$$u = (\sigma_1 + 2 \sigma_3) / 3 - p' \tag{2}$$

The pore pressure (u) is determined by applying values for σ_1 , σ_3 and p' to equation (2).

In like manner, the following method is used to determine in situ field horizontal stress in an interval where the pore pressure has been measured or determined by prior art geophysical and drilling engineering methods by combining the value with the in situ shale surface area value determined from measurements of cuttings and by comparing the surface area to the shale surface area-ultrasonic velocity-mean effective stress laboratory stress data base correlation to obtain in situ mean effective stress (p'). The following method is then used to obtain in situ horizontal stress (σ_3):

The overburden stress (σ_1) is determined by using

$$\sigma_1 = \sum_{i=1}^n \gamma_i \Delta h_i \text{ (see above)}$$

and

$$\sigma_1 = \frac{3(p' + u) - \sigma_3}{2} \quad (3)$$

The in situ horizontal stress (σ_1) is determined by applying values for p' , u and σ_3 to equation (3).

The copending application entitled "Methods and Apparatus For Measurement of the Strength, Pore Pressures, and Mechanical Properties of Low Permeability Geologic Materials," discloses how to obtain elastic properties, (e.g. Poisson's ratio, bulk modulus, Young's modulus, shear modulus, etc.) for a low permeability rock such as a shale and shows that elastic properties can be correlated with mean effective stress for such rock. The invention disclosed herein also shows that the elastic properties for different types of rocks can be correlated with mean effective stress and an index property (e.g. measured specific surface area).

In general, rock having lower specific surface area displays higher elastic properties, i.e. higher values for Young's modulus, bulk modulus, etc. and lower values for Poisson's ratio.

The techniques described herein for determining strength of shale formation can also apply to solve other engineering problems related to construction work taking place in shale formations. Such applications include open pit mining, tunnel mining, road cut, tunnel construction, etc.) In these applications, a small amount of disturbed or undisturbed sample (approximately 10 grams) is collected from the representative shale formation. Then, the sample is analyzed using the EGME surface area technique or the dielectric constant method to obtain specific surface and measurements. The in situ strength of the formation then is estimated using the shale strength-surface area-mean effective stress correlations such as those presented in FIGS. 4 and 5. Alternatively, the sample is used to determine another index property. The in situ strength of the formation then is estimated using the shale strength-index property-mean effective stress correlation. Alternatively the sample is used to determine an index property that is then used to estimate elastic properties, such as a Poisson ratio and Young's modulus, using shale elastic property-index property-means effective stress correlations.

Knowing the in situ formation strength or elastic properties, engineering analyses can be conducted to obtain necessary design parameters. For example, in an open pit mining area, it is very important to determine the maximum slope angle that can be cut through the formation without causing slope failure. For this application, a small amount of out-crop sample will be collected and analyzed to obtain surface area estimates. Formation strength then is estimated using the shale strength-surface area-mean effective stress correlation. With formation strength, conventional slope stability analysis can be conducted to determine the maximum slope angle.

A preferred embodiment of the EGME shale surface area determination method is as follows:

1. Grind shale sample to pass 200 mesh screen
2. Cone, quarter and weigh 1.5 g sieved shale (<200 mesh) into 250 ml beaker.
3. Add 50 ml 30% hydrogen peroxide (H_2O_2) cautiously with occasional stirring. Let set overnight or until sample stops bubbling.

4. Filter through Whatman #50 filter paper using a stainless steel filter press at 100 p.s.i.
5. Rinse with 20 ml deionized water and filter through cake. Repeat twice.
6. Allow filter cake sample to dry in air.
7. Grind cake and sieve (200 mesh).
8. Weigh 1.1 g shale into a dry, weighed 35 ml weighing dish.
9. Dry sample in a vacuum desiccator over granular phosphorous pentoxide (P_2O_5) for three hours. Release vacuum using room air passed through silica gel desiccant.
10. Reweigh sample immediately and calculate weight of dry sample.
11. Add 3 ml ethylene glycol monoethyl ether (EGME) to sample and swirl gently. Let set 30 minutes with lid on.
12. In a shallow dish add 75 g EGME to 50 g anhydrous calcium chloride pellets (4-20 mesh) ($CaCl_2$) and place in bottom of desiccator. Leave dish lid slightly ajar and surround dish with $CaCl_2$.
13. Place sample in desiccator and evacuate for 45 minutes. Seal desiccator and let set overnight.
14. Release vacuum using room air passed through silica gel.
15. Reweigh sample immediately and calculate gain as mg EGME/g dry sample.
16. Shale surface area (m^2/g) =

$$\frac{\text{mg EGME/g dry sample}}{0.12}$$

In conclusion, therefore, it is seen that the present invention and the embodiments disclosed herein are well adapted to carry out the objectives and obtain the ends set forth at the outset. Certain changes can be made in the method and apparatus without departing from the spirit and the scope of this invention. It is realized that changes are possible and it is further intended that each element or step recited in any of the following claims is to be understood as referring to all equivalent elements or steps for accomplishing substantially the same results in substantially the same or equivalent manner. It is intended to cover the invention broadly in whatever form its principles may be utilized. The present invention is, therefore, well adapted to carry out the objects and obtain the ends and advantages mentioned, as well as others inherent therein.

What is claimed is:

1. A method for measuring in situ pore pressure of a specimen low permeability rock, the method comprising obtaining a first rock sample from a first in situ location, measuring an index property of the first rock sample and obtaining a value for it, pressurizing the first rock sample triaxially by applying a load to it and a confining pressure, measuring continuously and recording the first rock sample's pore pressure while applying the load to it, applying the confining pressure to the first rock sample while applying the load to it, measuring and recording the ultrasonic velocities of the first rock sample at different pore pressures, determining the mean effective stress of the first rock sample at each different pore pressure,

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performing the previously-listed steps for a plurality of different rock samples from in situ locations, correlating ultrasonic velocity values and mean effective stress values with measured index property values for each sample and plotting a point on a graph for each such correlation, determining a curve that fits the plot of points representing each ultrasonic velocity versus its corresponding index property value and mean effective stress, measuring in situ ultrasonic velocities through the specimen, measuring the index property of the specimen, locating on the curve a point corresponding to the measured index property value and ultrasonic velocity value of the specimen, and then locating the mean effective stress value of the specimen corresponding to that index property value and ultrasonic velocity value, determining the in situ vertical stress of the specimen and horizontal stresses of the specimen, using the in situ mean effective stress from the curve, the in situ vertical stress and in situ horizontal stresses to determine the in situ pore pressure of the specimen.

2. The method of claim 1 wherein the index property is surface area.

3. A method for measuring in situ horizontal stress of a low permeability formation, the method comprising obtaining a first rock sample from a first in situ location, measuring an index property of the first rock sample and obtaining a value for it, pressurizing the first rock sample triaxially by simultaneously applying a load to it and a confining pressure,

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measuring continuously and recording the first rock sample's pore pressure while applying the load to the first rock sample, applying the confining pressure to the first rock sample while applying the load to it, measuring and recording ultrasonic velocities through the first rock sample at different pore pressures, determining the mean effective stress of the first rock sample at each different pore pressure, performing the previously-listed steps for a plurality of different rock samples from the in situ location, correlating ultrasonic velocity values and mean effective stress values with measured index property values for each sample and plotting a point on a graph for each such condition, determining a curve that fits the plot of points representing each ultrasonic velocity versus its corresponding index property value and mean effective stress value, measuring the in situ ultrasonic velocity through an in situ specimen low permeability rock, measuring the index property of the in situ specimen, locating on the curve a point corresponding to the measured index property value of the in situ specimen and ultrasonic velocity value, then locating the mean effective stress value corresponding to that index property and ultrasonic velocity value, determining the in situ vertical stress and pore pressure of the in situ specimen, and using the in situ mean effective stress from the curve, the in situ vertical stress and pore pressure to determine the in situ horizontal stress of the in situ specimen.

4. The method of claim 3 wherein the index property is surface area.



United States Patent (19)
Bradley et al.

(11) **Patent Number:** 4,710,906
(45) **Date of Patent:** Dec. 1, 1987

[34] **METHOD AND SYSTEM FOR MONITORING THE STABILITY OF BOREHOLES**

[75] **Inventors:** William B. Bradley, Dallas; Philip Hallbrook, Houston, both of Tex.

[73] **Assignee:** NL Industries, Inc., New York, N.Y.

[21] **Appl. No.:** 891,773

[22] **Filed:** Jul. 30, 1986

[51] **Int. CL⁴** G01V 1/00

[52] **U.S. Cl.** 367/35; 367/86;
73/151; 175/40

[58] **Field of Search** 367/25, 35, 37, 73,
367/84; 181/105; 73/783, 784, 151; 175/50;
166/250

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Primary Examiner—Charles T. Jordan

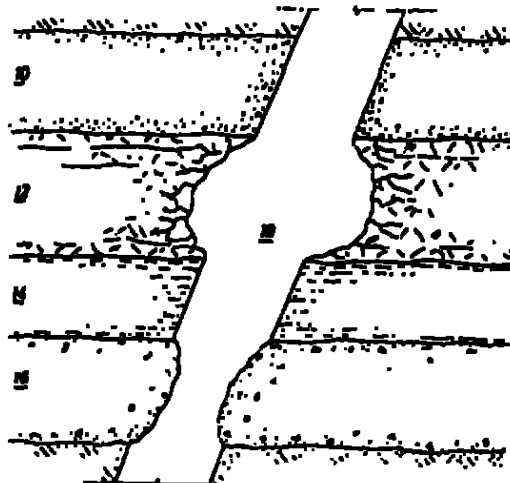
Assistant Examiner—John W. Eldred

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Zamecki & Anderson

[57] **ABSTRACT**

The potential for failure of a formation is predicated by using standard logging apparatus and techniques to monitor the change in a formation characteristic over an extended time period. Changes in this characteristic are attributed to absorption of fluid by the formation which could lead to a possible breakdown of the structural integrity of the formation.

2 Claims, 7 Drawing Figures



Folio 131

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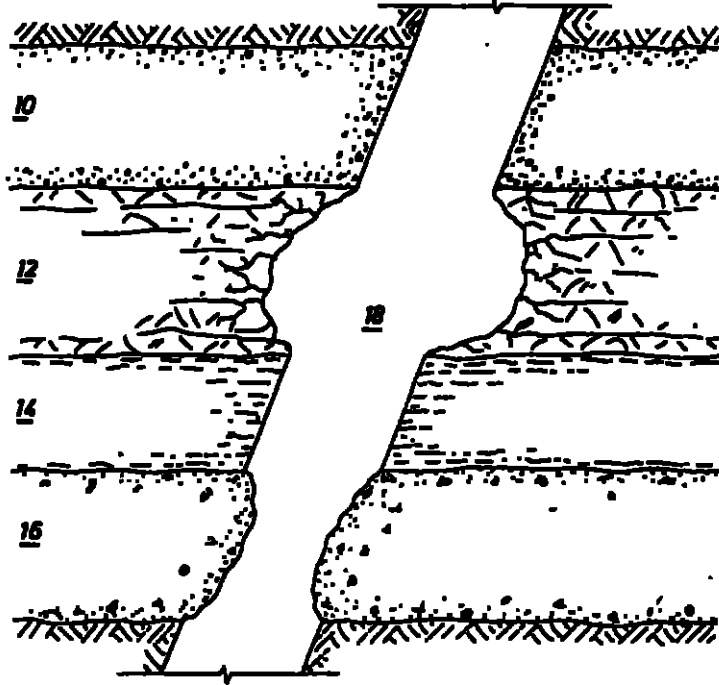


FIG. 1

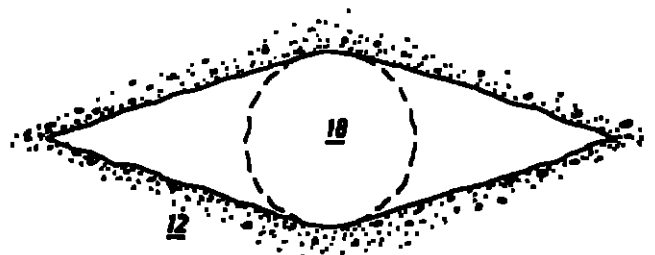


FIG. 2

FIG. 3

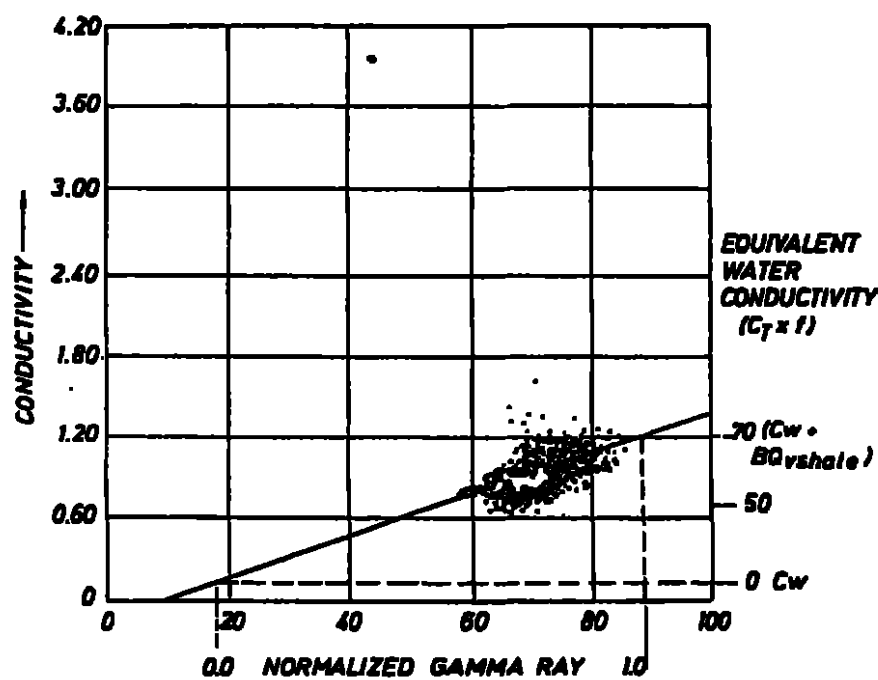
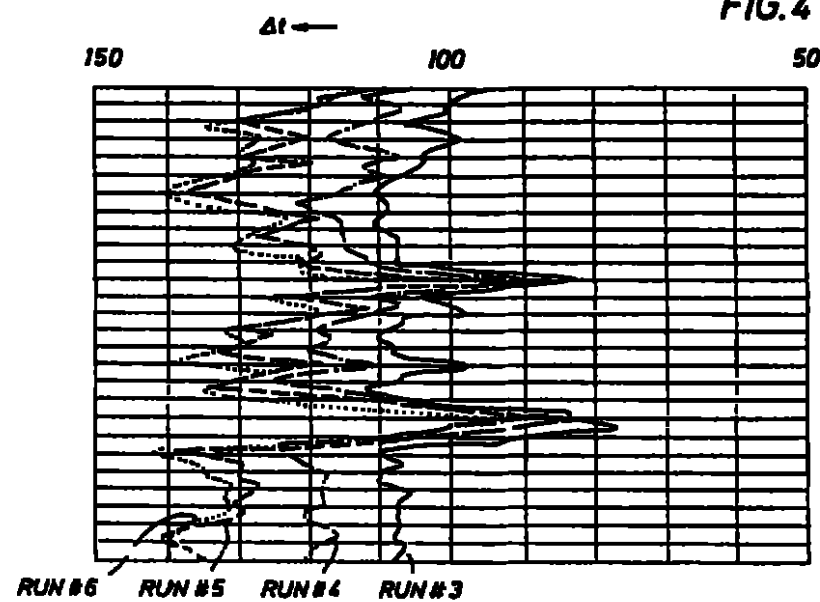


FIG. 4



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FIG 5A

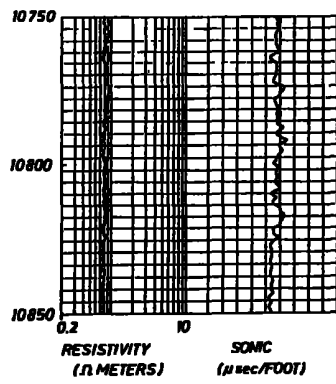


FIG 5B

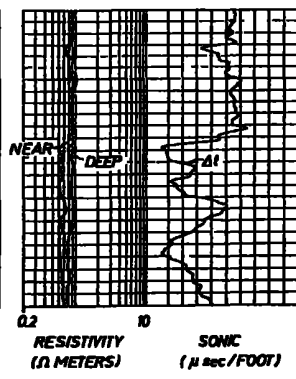
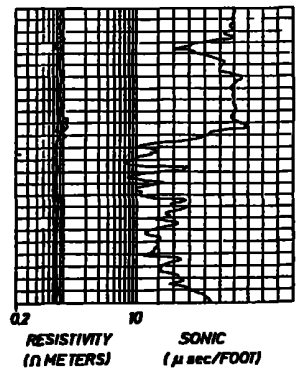


FIG 5C



METHOD AND SYSTEM FOR MONITORING THE STABILITY OF BOREHOLES

BACKGROUND OF THE INVENTION

1. Field of the Invention

The present invention relates to a method and system for detecting instability of formations through which a borehole passes and in particular to measuring change in a logable characteristic as an indicator of the change in the tendency of a formation to swell.

2. Description of the Background

There are many factors to be considered in drilling a borehole in the earth. One important factor which must be considered is the stability of the various formations through which the borehole passes. There are well known methods and apparatus for dealing with unstable formations, and it becomes a significant factor in determining which method and apparatus will be the most appropriate and when they must be utilized. For example, one way of dealing with an unstable formation is to change the drilling mud. Some drilling muds will have less of a tendency to invade and/or react with a surrounding formation than another drilling mud, the difference being primarily due to the chemical composition of the drilling mud and its relative density. Most drilling muds contain chemical compounds which keep the mud clays in suspension. These same compounds react with shale formations causing them to break down. This could lead to failure of the borehole if corrective action is not promptly instituted.

The detection and prevention of borehole failure resulting from enlargement (sloughing) or contraction (tight hole) is an important factor in the successful drilling of a well. Borehole instability occurs when a stress in the formation at the borehole wall exceeds the strength of the formation. The interaction of the drilling muds, in particular with shale formations, can result in swelling of the shale and failure of the well bore. The swelling of shales constitute a major cause of borehole instability since most muds and limestones are not affected by normal drilling muds. The measurement of the initial shale properties and subsequent change in these properties would allow the direct monitoring of borehole stability and lead to a substantial reduction in the cost of drilling.

There have been attempts to monitor swellings of formations, due to adsorption of drilling muds and pressure changes. However, these have all had several major problems including the fact that they depended upon particles returned to the surface and required wet chemistry analysis. It is substantially impossible to determine exactly where the particles originated from in the borehole. Also, there are substantial delays associated with wet chemistry analysis.

SUMMARY OF THE INVENTION

The present invention utilizes logging measurements, such as resistivity, gamma ray or porosity, taken with any logging equipment, either measuring-while-drilling or wire line, to measure characteristic of a formation, particularly those formations believed to have a tendency toward instability. Subsequent readings of the same characteristic are made over extended time periods. The change noted in measured characteristic can be compared to laboratory test results of known similar formations, the testing having been done under as close as possible to in situ conditions. By knowing the change

in the formation characteristic, the drilling engineer is able to predict any decrease in stability and take such steps as are necessary to prevent degradation of the borehole due to the collapse of a particular formation.

BRIEF DESCRIPTION OF THE DRAWINGS

The present invention will now be described by way of example with reference to the accompanying drawings in which:

FIG. 1 is a schematic side elevation through a borehole showing failure of a formation resulting in borehole enlargement and reduction;

FIG. 2 is a schematic transverse section through the borehole of FIG. 1;

FIG. 3 is a Gamma Ray-Conductivity graph showing the method for estimating BQ_r for shale;

FIG. 4 is a sonic logging graph showing the effect of shale hydration over several logging runs; and

FIGS. 5A, 5B and 5C are a set of graphs of sonic and resistivity logs (ISF/Sonic) showing the effect of shale hydration over a time period.

DETAILED DESCRIPTION OF THE PREFERRED EMBODIMENT

The least expensive drilling fluid is a water-based mud while includes, other than water and earth solids (mostly clay) a complex three-phase mixture of liquids, reactive solids and inert solids, at least some of which are intended to keep the mixture fluid. However, when such a drilling fluid is used in a shale formation, the water can be absorbed into the shale and/or the mud contents chemically react to create a weakened formation. The present invention contemplates the use of any formation logging device, including both wire line and measuring-while-drilling devices such as resistivity, gamma ray or porosity measuring devices, possibly having multiple depth investigation capability, to measure a characteristic of a formation. The measurements of this characteristic are repeated over a time span with any change being an indicator of a change in the structural integrity of the formation. Samples of a suspect formation can be laboratory tested to determine the characteristics of absorption versus the various mud systems.

FIG. 1 schematically illustrates four consecutive formations 10, 12, 14 and 16 traversed by borehole 18. Formations 10 and 14 are stable while formation 12 is sloughing to enlarge the borehole and formation 16 is collapsing to contract the borehole. In the case of either unstable formation 12, 16, the instability would be the result of absorption/reaction of the drilling fluid by the formation. Any instability will be three-dimensional in nature and rarely uniform with respect to the borehole axis, as schematically illustrated in FIG. 2.

The present invention detects a tendency toward instability by measuring the change of a formation characteristic by resistivity, gamma ray, and/or porosity measurement techniques as the drilling fluid is absorbed. When shales come into contact with water-based drilling muds, they begin to absorb the water and other drilling mud compounds and normally tend to swell and lose their strength characteristics. A shale's tendency to change its strength is directly related to its cation exchange capacity, which also effects its initial detectable electrical resistivity. The most susceptible shales can be readily identified by an initial logging run.

The ultimate swelling potential of a formation is determined by its cation exchange capacity. This can be estimated from log-derived measurements using the equation:

$$C_f = 1/F(C_w + BQ_c)$$

where:

C_f = formation conductivity (mhos/m)

F = formation resistivity factor

C_w = water conductivity (mhos/m)

BQ_c = cation exchange capacity/pore volume

Usually the shale volume can be estimated from a normalized gamma ray response. Gamma ray response usually ranges from 10-20 API units for clean sands with no BQ_c to approximately 100 for a shale. A shale baseline can be estimated in a given well by connecting the high gamma ray values. Relative shale volume is assumed to be 1.0 on this line and is linearly scaled between this and zero for the clean sand baseline.

Assuming the bulk shale mineralogy does not change over a given interval, BQ_c shale can be determined by crossplotting normalized gamma ray response vs. conductivity as shown in FIG. 3.

When measured conductivity (C_f) is multiplied by either known or estimated formation resistivity factor (F^*), BQ_c shale is the slope of the crossplot relationship.

Through this normalized γ -ray—excess conductivity relationship ($AC_f \Delta F / \Delta \gamma$ -ray), one can predict shale swelling tendency and cation exchange capacity from a normalized gamma ray response.

The slope of a normalized γ -ray—excess conductivity relationship tends to remain constant within the same formation, which can be hundreds of feet thick. However, the slope may be different in different formations. Thus, many crossplots must be examined and interpreted so that the normalized γ -ray—excess conductivity slope can be changed where appropriate.

The salinity of the water in which the clays are immersed is directly proportional to the C_w intercept on the righthand side of the plot of FIG. 3.

The two parameters, C_w and BQ_c , can be used to design drilling fluid systems so that casing can be set before significant shale hydration. This log analysis procedure could substitute for the techniques set out in U.S. Pat. No. 4,495,292. The two main advantages of the present method are that (1) no wet chemical analysis techniques are involved, and (2) the depth of the problem swelling shale is known. The latter is not true in a method relying upon cuttings which are well mixed when they arrive at the surface.

A shale's swelling tendency, however, is only part of the problem in predicting borehole failure. The rate of shale swelling from hydration can vary drastically depending on the initial structure of the shale. A shale which is highly fractured, with the same electrical properties and ultimate swelling tendency, can fail ten to one hundred times faster than an unfractured shale due to its initial structure. A fractured shale is initially much weaker than an unfractured shale. Further, the existing fracture planes provide easy avenues for deep penetration of fresh water drilling fluid into the formation. When this occurs, the initial hydration occurs along initial planes of weakness and failure can occur rapidly.

The progress of shale hydration and its effect on borehole stability can be monitored through repeated

logging of a formation. Following are two examples which demonstrate this technique.

FIG. 4 shows the effect of shale hydration on a transit time log. These logging runs occurred as follows:

Run No.	Days After Initial Penetration
3	3
4	13
5	25
6	35

In this example, clean sandstones with low swelling potential have initial transit times below 115 microseconds/foot. Shaley sandstones and shales have initially higher transit times. Through time, the clean sandstones show little change in transit time indicating no change in structure or porosity. However, the shales and shaley sandstones show increases in transit time from 7 to 20 microseconds per foot, indicating that shale hydration has occurred. In general, the risk of borehole failure is proportional to this increase in transit time. The shale from 9300' to 9328' decreased about 10 microseconds/foot. It is more stable than the shales above or below. The lower shales have transit times in the 135-150 microseconds/foot range. These shales have a high failure risk. For comparison, the transit time of water, which has no shear strength, is 190-200 microseconds/foot.

FIGS. 5A, 5B and 5C show the effect of shale hydration on resistivity and transit time:

Logging Run No.	Time Since Initial Penetration
1 (FIG. 5A)	1 day
2 (FIG. 5B)	8 days
3 (FIG. 5C)	11 days

This stratigraphic interval is composed of shales and a few very shaley sands. The shale from 10790 to 10850 does not show any anomalous resistivity or transit time on the initial logging run. However, during the second logging run (8 days later), the sonic transit time had increased from 100 to 150 microseconds/foot. The near borehole resistivity (SFL-B) decreased from 0.9 to 0.6 m. Both measurements indicate a considerable increase in average shale porosity. Any other porosity sensitive logging measurement would be similarly affected.

There was further shale hydration between Run No. 2 and Run No. 3. Average shale transit time continued to increase between 10790' and 10850'. A caliper log run at this time indicated that the borehole had closed in by about one inch in this interval. The open hole below 10790' could have been lost if this well were not cased rapidly at this time.

Shale swelling can produce enough of an increase in the dimensions of the formation that the stress within the shale can cause fracturing or plastic deformation which will further decrease the shale's strength. If such swelling is allowed to proceed, i.e. the well is not cased, then failure of the shale formation will result. Absorption of drilling fluid by shale produces, in addition to swelling, a reduction in the shale's electrical resistivity, due to an increase in the fluid content. The relation between the change in electrical resistivity and swelling stress within the shale can be determined in the labora-

tory for different types of shales. This testing must be done under an in situ simulated condition.

By repeating logging measurements of shale formations during and after drilling of a well, the change in a logged characteristic of the shale over a time period can be noted. This change in characteristic can then be used to predict the increase in the swelling stress in the shale. The swelling stress can be used to estimate the stability condition of the well bore, including how close the well bore currently is to instability and the time to failure of the formation. With this information available, modifications can be made to the drilling program to minimize the potential problems and causes of well bore instability.

The foregoing disclosure and description of the invention is illustrative and explanatory thereof, and various changes in the method steps may be made within the scope of the appended claims without departing from the spirit of the invention.

What is claimed is:

1. A method for monitoring the stability of an earth borehole through a shale formation, said borehole containing drilling fluid, comprising the steps of:

running, at a first point in time, a well logging instrument through the borehole along the shale formation of interest, while taking an initial measurement of a characteristic of said shale formation;

running, at a second point in time subsequent to said first point in time, a well logging instrument through the borehole along said shale formation of interest, while taking a second measurement of said characteristic of said shale formation; and

combining said first and second measurements to determine the extent to which the shale formation of interest has swelled due to the interaction of the drilling fluid in the borehole with the said shale formation.

2. The method according to claim 1, including, in addition thereto, the step of comparing the extent to which the shale formation has swelled with known test results from similar shale formations.

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(54) Method for controlling the development of an oil or gas reservoir

(57) Development of an oil or gas reservoir is controlled using a neural network and genetic algorithm program to define a neural network topology and the optimal inputs for that topology. The topology is defined from identified and selected parameters (1) associated with the formation or formations in which actual wells are

drilled in the reservoir, and (2) associated with the drilling, completion and stimulation of those wells, and (3) associated with the oil or gas production from the wells. Subsequent drilling, completion and stimulation of the reservoir is determined and applied based on hypothetical alternatives input to the topology and resulting outputs.

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Description

This invention relates generally to the management of oil or gas reservoirs and, more particularly, to a method of controlling the development of such a reservoir.

An oil or gas reservoir is a zone in the earth that contains, or is thought to contain, one or more sources of oil or gas. When such a reservoir is found, typically one or more wells are drilled into the earth to tap into the source(s) of oil or gas for producing them to the surface.

The art and science of managing oil or gas reservoirs has progressed over the years. Various techniques have been used for trying to determine if sufficient oil or gas is in a given reservoir to warrant drilling, and if so, how best to develop the reservoir to produce any oil or gas that is actually found.

One technique has simply used human experience. Individuals have become skilled in studying data obtained from a given reservoir and then applying their experience to make determinations about the given reservoir and how, if at all, to develop it.

Computer modeling techniques have more recently been used.

Previous types of reservoir models have been based on linear mathematical analyses using only a few input parameters (e.g., two or three parameters such as reservoir quality, location, treatment rate, etc.). More recently, neural network modeling of reservoirs has been used. Neural network modeling is advantageous because it can develop correlations between a relatively large number of input parameters and one or more output parameters that would be difficult if not impossible to obtain using linear mathematical techniques.

Neural network techniques have been applied to predicting the production from gas storage reservoirs after training the network on previously drilled and treated wells. This prior neural network development has relied on a human expert designing the neural topology or correlation between inputs and outputs and selecting the optimal inputs for the topology. Even using an expert, there is much educated trial and error effort spent finding a desired topology and corresponding optimal inputs. This is time consuming and expensive and must typically be done for each different reservoir, and it requires a highly skilled human expert to provide useful results.

The ability to more quickly and less expensively analyze a reservoir by whatever means is becoming more and more important. Companies that provide goods and services for use in developing oil or gas reservoirs are basing major business decisions on entire reservoir analysis rather than just individual wells for which they may be hired for a particular job. Because these decisions need to be made quickly as opportunities present themselves, there is the need for an improved method of analyzing oil or gas reservoirs and particularly for controlling the subsequent development of reservoirs that appear to be favourable for oil or gas production.

The present invention reduces or mitigates the above-noted and other shortcomings of the prior art by providing a novel and improved method of controlling the development of an oil or gas reservoir. The present invention utilizes neural network technology so that multiple input parameters can be used for determining a meaningful correlation with a desired output, but the present invention further automates this process to overcome the deficiencies in the prior expert trial-and-error neural network technique. In particular, the present invention uses genetic algorithms to define the neural network topology and corresponding optimal inputs.

Advantages which can be achieved by the present invention include the ability to create a model of a given reservoir more quickly and less expensively than the aforementioned techniques. The present invention can be used to optimize production from an oil or gas reservoir per dollar spent on stimulation as opposed to simply determining a maximum possible production which may or may not be obtainable most cost effectively. By optimizing production per stimulation dollar the customer can get the highest return on investment. The present invention can also be used in determining whether development of a reservoir should be pursued (and thus whether a service company, for example, should bid on a job pertaining to that reservoir). The present invention is also advantageous in determining how many and where wells should be drilled in the reservoir, in designing optimum systems for completing or treating wells (e.g., gravel packing perforating, acidizing, fracturing, etc.), and in evaluating performance.

The method of controlling development of an oil or gas reservoir in accordance with the present invention can be defined as comprising steps of

- (a) selecting an oil or gas reservoir wherein the reservoir has a plurality of wells drilled therein from which oil or gas has been produced
- (b) identifying well drilling parameters associated with drilling of the plurality of wells,
- (c) identifying well completion parameters associated with completing the plurality of wells
- (d) identifying well stimulation parameters associated with stimulating the plurality of wells,
- (e) identifying formation parameters associated with the locations in the reservoir where the plurality of wells are drilled
- (f) identifying production parameters associated with the production of the oil or gas from the plurality of wells
- (g) selecting at least one drilling parameter, at least one completion parameter, at least one stimulation parameter,

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at least one formation parameter, and at least one production parameter from among the identified well drilling parameters, well completion parameters, well stimulation parameters, formation parameters, and production parameters;

(h) converting the selected parameters to encoded digital signals for a computer;

(i) defining in the computer a neural network topology representing a relationship between the selected drilling, completion, stimulation and formation parameters and the at least one selected production parameter in response to the encoded digital signals, including manipulating the encoded digital signals in the computer using genetic algorithms to define the neural network topology;

(j) entering into the computer as inputs to the defined neural network topology a first group of additional encoded digital signals representing proposed drilling, completion, stimulation and formation parameters of the same type as the selected drilling, completion, stimulation and formation parameters, and generating an output from the defined neural network topology in response;

(k) repeating step (j) using at least a second group of additional encoded digital signals representing other proposed drilling, completion, stimulation and formation parameters; and

(l) controlling further development of the oil or gas reservoir in response to at least one of the generated outputs, including at least one step selected from the group consisting of (1) drilling at least one new well in the reservoir in response to the generated output and (2) treating at least one well in the reservoir in response to the generated output

The present invention can also be defined as a method of generating a model of an oil or gas reservoir in a digital computer for use in analyzing the reservoir. This comprises providing the computer with a data base for a plurality of wells actually drilled in the reservoir, including parameters of physical attributes of the wells; providing the computer with a neural network and genetic algorithm application program to define a neural network topology within the computer in response to the parameters in the data base; and initiating the computer such that the neural network and genetic algorithms within the application program automatically define the neural network topology and the input data used to optimally form the topology in response to the data base of the parameters of physical attributes of the wells. This method can further comprise: determining a hypothetical set of parameters of physical attributes corresponding to at least some of the physical attribute parameters of the data base; providing the computer with the determined hypothetical set of parameters; calculating in the computer, using the defined neural network topology, a production parameter correlated to the hypothetical set of parameters; and operating a display device in response to the calculated production parameter so that an individual viewing the display device tracks possible production from a well to which the hypothetical set of parameters is applied prior to any actual corresponding production occurring. The method can additionally comprise drilling an actual well in the reservoir in response to the display of possible production. It can still further comprise, determining additional data and providing the additional data to the data base of the computer, including measuring and recording actual parameters of physical attributes of the actual well drilled in the reservoir; and initiating the computer such that the neural network and genetic algorithm application program automatically operates within the computer to redefine the neural network topology in response to the data base of parameters of physical attributes of the wells, which data base includes the additional data.

The resultant trained network can then be used as a fit function for another genetic algorithm program to allow the optimization of the input parameters that can be changed. These changeable parameters are any but the reservoir parameters since the reservoir parameters are fixed if the well is drilled in a specific location. The reservoir parameters can also be optimized by using the neural network and genetic algorithm to select the location that should have the reservoir parameters which should optimize final production

Therefore, from the foregoing, it is a general object of the present invention to provide a novel and improved method of controlling development of an oil or gas reservoir. Other and further objects, features and advantages of the present invention will be readily apparent to those skilled in the art when the following description of the preferred embodiments is read in conjunction with the accompanying drawings

BRIEF DESCRIPTION OF THE DRAWINGS

FIG. 1 is a block diagram and pictorial illustration representing an oil or gas reservoir having a plurality of wells with which the present invention is used.

FIG. 2 is a graph showing a comparison between actual production and predicted production for a specific reservoir to which the present invention was applied

FIG. 3 is a graph showing a sensitivity analysis when different parameters were varied for wells in the reservoir of FIG. 2. The base parameters that were varied were from the wells as treated

FIG. 4 is a graph showing the sensitivity analysis of the reservoir of FIG. 2 when all wells are stimulated with the same treatment. These treatment parameters are varied. The formation parameters were also varied to show which

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formation parameter had the greatest effect on production in this particular application.

DETAILED DESCRIPTION OF THE INVENTION

5 With the present invention, one can analyze an oil or gas reservoir, determine if it is worth pursuing, and if it is, how to further develop it. Such further management includes drilling additional wells, reworking existing wells in the reservoir, or performing new treating or stimulation procedures. Specific drilling information that can be derived from the present invention includes where to drill and how or what type of drilling to perform, and examples of particular treating or stimulation procedures that can result from the present invention include particular types of perforating, acidizing, fracturing or gravel packing procedures. Thus, the present invention provides a method of controlling development of an oil or gas reservoir. In particular, it is a computer-implemented method of controlling development of an oil or gas reservoir by enabling an individual to observe through the operation of the computer a simulated production of oil or gas from the reservoir before an actual well is drilled in the reservoir to try to obtain therefrom actual production corresponding to the simulated production. As part of this, the present invention includes a method of generating a model of an oil or gas reservoir in a digital computer for use in analyzing the reservoir.

15 The present invention is typically applied to a specific selected reservoir, however, particular results obtained with regard to one reservoir might be useful as at least a starting point for the analysis of another reservoir which has not begun to be developed, and thus from which specific types of data may not be available. Once such data are available, then the method of the present invention could be used with regard to that specific reservoir. Accordingly, FIG. 1 shows the method pertaining to a subterranean reservoir 2 containing one or more deposits of oil or gas. The reservoir 2 is located beneath the earth's surface 4 through which a plurality of wells 6a-6n have been drilled. Each of the wells 6 has conventional wellhead equipment 8 at the surface 4, and each well 6 has downhole equipment 10 which penetrates the earth and communicates with one or more oil-bearing or gas-bearing formations or zones of the reservoir 2. The wells 6 are existing, actual wells from which oil or gas production has been obtained.

25 FIG. 1 shows that each of the wells 6 has been drilled by a suitable drilling process 12. Examples include rotary bit drilling with liquid drilling fluids and air drilling. Some type of completion process 13 (e.g., cementing, perforating, etc.) has been performed on each well. Additionally, each well is shown to have had some type of stimulation process 14 applied to it. Examples include stimulation with a proppant laden fluid having a base fluid of a linear gel, cross linked gel, foam or any other suitable fluid. The stimulation fluid can also be an acid or any other existing or future stimulation fluid or process designed for enhancing the production from a well. As a result of the foregoing, production 16 was obtained from the respective wells. Respectively associated with or derived from each drilling 12, completion 13, stimulation 14 and production 16 are respective drilling parameters 18, completion parameters 19, stimulation parameters 20, and production parameters 22. In addition to parameters 18, 19, 20, 22, there are also formation parameters 24 which define characteristics regarding the subterranean earth and structure and reservoir 2. More generally, there are well implementation parameters (which include parameters 18, 19, 20 and 24 in the preferred embodiment) and well production parameters (parameters 22 for the above). The specific values of the production parameters for a given well are to some degree or another the result of the specific values or implementations of the well implementation parameters, and it is the determination of this relationship that is one aspect of the present invention.

35 Examples of drilling parameters 18 pertinent to the present inventions include but are not limited to the following: type of drilling, drilling fluid, days to drill, drilling company, time of year drilling started and completed, and day and year drilling completed. These drilling parameters are obtained from the drilling records maintained on each well by the well's operating company.

40 Examples of completion parameters 19 pertinent to the present invention include but are not limited to the following: number of perforations, size of perforations, orientation of perforations, perforations per foot, depth of top and bottom of perforations, casing size, and tubing size. These parameters can be obtained from the operating company's records of how the well was completed. In some instances this information can be verified by well logs.

45 Examples of stimulation parameters 20 pertinent to the present inventions include but are not limited to the following: base fluid type, pad volume, pad rate, treating volume, treating rate, proppant type, proppant size, proppant volume, proppant concentration, gas volume for foam fluids, foam quality type of gas, acid type and concentration, acid volume, average acid injection rate, day and year of treatment, and service company performing treatment. Of the above parameters, the following information is obtained from the operating company's or service company's job treatment ticket: base fluid type, proppant type, proppant size, type of gas, acid type and concentration, day and year of treatment, and service company performing treatment. The other above-listed stimulation parameters are obtained by measuring instruments (flowmeters, densimeters, etc.) which are on the flowlines and transmit the information back to a computer which records the information real-time throughout the job. These values are then provided by the service company to the operating company in the form of a job report or ticket. These values are then taken from the job report or ticket and manually entered into a data base of pertinent information for treating the reservoir.

50 Examples of formation parameters 24 pertinent to the present invention include but are not limited to the following:

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porosity, permeability, shut in bottom hole pressure, depth of top of pay zone, depth of bottom of pay zone, latitude, longitude, surface altitude, zone, and reservoir quality. The porosity, permeability, depth of the top and bottom of pay zone and zone are determined directly by well logging. The shut in bottom hole pressure is a measured parameter. The latitude, longitude and surface altitude are obtained from surveying records showing the location of the well on the earth's surface. The reservoir quality is a calculated value particular to different areas. An example would be a reservoir quality calculated from $(\text{permeability}) \times (\text{total feet of pay zone}) \times (\text{shut in bottom hole pressure})^2$.

Examples of production parameters 22 pertinent to the present invention include but are not limited to the following: day and year of start of production, six month cumulative gas and/or oil production, and twelve month cumulative gas and/or oil production. This information is obtained from the operating company's records or from a company such as Dwight's that maintains data bases on oil and gas production.

Of the parameters that are identified or available with regard to any particular drilling 12, completion 13, stimulation 14, production 15 or formation, certain ones are selected manually or by the genetic algorithms as desired to input into a computer 26 of the present invention. The parameters that are selected are provided as encoded electrical signals either as taken directly from the sensing devices used in the aforementioned operations or by converting them into appropriate encoded electrical signals (e.g., translation of a numeral or letter into a corresponding encoded electrical signal such as by entering the numeral or letter through a keyboard of the computer 26). These signals are stored in the memory of the computer 26 such that the encoded electrical signals representing the parameters from a respective well are associated for use in the computer 26 as subsequently described. This provides to the computer 26 a data base of the plurality of parameters for the plurality of wells 6 actually drilled in the reservoir 2.

The computer 26 is of any suitable type capable of performing the neural network operations of the present invention. This typically includes a computer of the 386 - 25 MHz type or larger. Specific models of suitable computers include IBM ValuePoint model 100dx4 and Dell 75 MHz Pentium.

Examples of suitable operating systems with which a selected computer should be programmed for running particular known types of application programs referred to below include: Windows 3.1, Windows 95, and Windows NT. Software is also available that will run on UNIX, DOS, OS/2.1 and Macintosh System 7.x operating systems.

The computer 26 is programmed with a neural and genetic application program 28. The neural section allows the training of topologies selected by the genetic portion of the program. The neural and genetic program is any suitable type, but the following are examples of specific programs: NeuroGenetic Optimizer by BioComp Systems, Inc., Neuralyst by Cheshire Engineering Corporation, and BrainMaker Genetic Training Option by California Scientific Software. The same results could be achieved by using separate neural network software and genetic algorithm software and then linking them in the computer. An example of these separate software programs is NeuroShell 2 neural net software and GeneHunter genetic algorithm software by Ward Systems Group, Inc. The particular implementation of the program (s) 28 operates with the aforementioned data base of the computer 26.

Once the selected parameters are in the data base in the computer 26, and the neural and genetic program 28 is provided in the computer 26, operation of computer 26 is initiated such that the application program 28 automatically selects through the genetic algorithms, the inputs which have substantial impact on the well production and the corresponding topology which yields a predicted production that most nearly matches the actual measured production. This neural network topology represents the correlation or relationship between the selected drilling, completion, well stimulation and formation parameters and the at least one selected production parameter. These parameters are manipulated in their encoded digital signal format in the computer using the genetic algorithms to define the neural network topology.

The following process is used to obtain and train the networks in a particular implementation. First, the data base is organized in a comma delimited format (*.csv) with the outputs in the far right columns. Next, the NeuroGenetic Optimizer (NGO) program is started. The NGO is set to operate in the function approximation mode. Next, the number of outputs in the data base to be matched are selected. The data file (*.csv) is selected. After selecting the data file, the NGO separates the data into a train and a test data group. The default for this selection places 50% of the data in the train data group and 50% in the test data group. These groups are selected such that the means of the train and test data groups are within a user specified number of standard deviations of the complete data set. This automated splitting saves many hours of manual labor attempting to come up with statistically valid splits by hand.

Neural parameters are selected next. A selection of a limit on the number of neurons in a hidden layer places boundaries on the search region of the genetic algorithm. Hidden layers can be limited to 1 or 2. The smaller number narrows the search region of the genetic algorithm. The types of transfer functions (hyperbolic tangent, logistic, or linear) can be set for the hidden layers. The above three transfer functions will automatically be used for the search region for the output layer if the system is not limited only to linear outputs. The linear output limit is selected to allow better predictions outside the data space of the original training data. "Optimizing" neural training mode is selected to activate the genetic algorithms. Neural training parameters are set such that the system will look at all data at least twenty times with a maximum passes setting of one hundred and a limit to stop training if thirty passes occur without finding a new best accuracy. A variable learning rate (.8 to .1) and variable momentum (.6 to .1) are suitable for this

system. These variable rates operate such that, for example, the learning rate would be .8 on the first pass and 1 on the one hundredth pass if the maximum passes is set at one hundred. Next, the genetic parameters are set. The population size is set at thirty and a selection mode is set such that fifty percent of the population yielding a neural topology and selected input parameters having the greatest impact with that topology will survive to be used as the breeding stock for the next generation. The mating technique selected is a tail swap with the remaining population refilled by cloning. A mutation rate of .25 is used.

Next the system parameters are set. For this application the "average absolute accuracy" is selected for determining the accuracy of each topology examined by the NGO algorithms. The system is set to stop optimizing when either fifty generations have passed in the genetic algorithm or when an "average absolute error" of "0.0" is reached for one of the topologies.

The system is now set to run. While running, the system will train on the training data set and test the error on the test data set. This will determine the validity of each topology tested since the system will not see the test data set during training, only after the topology is trained with the training data. As the system continues to run, the ten topologies with the best accuracies are saved for further analysis. When the system has reached the fiftieth generation or the population convergence factor stops improving, the ten best topologies are examined. The best topologies are again run but this time the maximum passes is changed to three hundred. This allows each topology to be trained to its maximum capability as some of the original ten best will have still been improving in accuracy when the one hundred passes was reached. Typically, the topology with the simplest form and highest accuracy is selected.

When satisfied with a particular topology, then this topology can be used as a fit function in another genetic algorithm program (e.g., GeneHunter sold by Ward Systems Group, Inc.). This arrangement allows the full optimization of site selection, drilling, completion, reservoir, and stimulation parameters to provide the optimum conditions to maximize the production from a reservoir.

The above-mentioned method has advantages over conventional methods because the conventional methods would use a human expert to either manually or with some other software or method attempt to split the data set in representative train and test sets. As mentioned previously, this process can take many hours if done manually where using a neural-genetic process to provide the split takes a matter of seconds. Conventional means also require the expert to determine which of the input data has the greatest impact on the prediction accuracy along with using an educated trial and error (trial and guess) method for determining which topology to try next. This, too, is time consuming; but in the present invention the use of genetics to make the selection reduces the solution to a matter of minutes or hours depending on the size and number of inputs and outputs for the data set and the size of the topologies examined.

As a result of the foregoing, the neural network topology, or correlation, is created and resides within the computer 26 as designated by the box 32 shown in FIG. 1. In actuality, the correlation 32 is not something distinct from the programs 28, 30 but is an internal result of weighting functions or matrix which is applied when new parameters are input. For example, after the neural topology is defined, an add-in to NGO is Penney which provides an Application Programming Interface (API) that can be used to develop Excel based applications. NGO also provides the weight functions in matrix format such that the matrices can be included in any application program written for analyzing a particular reservoir.

Once the correlation 32 has been defined, specific values or implementations of additional parameters 34 of the same types as the drilling parameters 18, completion parameters 19, stimulation parameters 20 and formation parameters 24 can be input into the computer 26 for use by the correlation 32 in generating an output 36 defining a resultant production parameter or parameters. Proposed parameters 34 can be one or more groups of additional encoded digital signals representing proposed drilling, completion, well stimulation and formation parameters of the same type as the selected drilling, completion, well stimulation and formation parameters 18, 19, 20, 24. These typically pertain to a proposed well that might be drilled and/or treated in accordance with a respective additional, hypothetical set of parameters 34. The output 36 simulates a production from such a proposed well. A representation of the simulated production output 36 is displayed for observation by an individual, such as through a monitor of the computer 26. This display can be alphanumeric or graphical as representing a flow from a depicted well. Through operation of the display device in response to the output 36 an individual viewing the display device tracks possible production from a well to which a group from the hypothetical set of parameters 34 is applied prior to any actual corresponding production occurring.

From the output 36 further development of the oil or gas reservoir is controlled. This includes either new drilling and completion 35 or new stimulation 40 (on new or old wells). If new drilling occurs, the output 36 can be used in selecting a location to drill the well in the reservoir 2 as determined from the corresponding group or set of input proposed parameters 34. The output 36 can also be used in forming a stimulation fluid and pumping the stimulation fluid into the well in response to the generated output 36 as also determined from the corresponding group or set of input proposed parameters 34. That is, once the desired output is obtained from the aforementioned hypothetical input and resultant output process using the correlation 32, the parameters of the corresponding input set are used to locate, drill, complete and/or stimulate. For example, the input set of parameters may contain location information to specify

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where a new well is to be drilled in the reservoir, or the input set may contain stimulation fluid parameters and pumping parameters that designate the composition of an actual fluid to be formed and the rate or rates at which it is to be pumped into a well, which fluid fabrication and pumping would occur using known techniques.

One way to obtain the foregoing is to use the correlation 32 to select a job that falls in the median range for all wells treated in the reservoir. Next, each of the parameters is varied and input to the neural network to determine how sensitive the reservoir is to each parameter. This is the approach of Examples 1-3 given below.

Another approach is as follows. After the best neural topology is determined using the NGO (for the specific implementation referred to above), the neural network is used as a fit function to a genetic algorithm which holds the reservoir parameters fixed and optimizes the treatment for each set of reservoir parameters. This optimization can be on maximum production, maximum production per dollar spent on stimulation, maximum production per dollar spent on well from drilling through production, etc. Another neural net is trained with NGO which predicts the well parameters from latitude and longitude. Next, the genetic algorithm is used to find the optimum latitude, longitude and treating parameters to maximize production. The reservoir parameters are fixed to the values predicted by the second neural network for each input of latitude and longitude. The result of this process is the optimal location to drill a new well along with how to drill, complete and stimulate. This is only one method with many others possible. If the well is already drilled and completed, only the optimization of production with treating parameters is performed.

Further development of the oil or gas reservoir can also be controlled in the following manner. This includes computing a cost for implementing the proposed drilling, completion, stimulation and formation parameters of the proposed parameters 34 as used in performing the new drilling and completion 38 or the new stimulation 40. This further includes computing a revenue for the projected production of each of the generated outputs 38. A ratio of the revenue to costs is then determined and the generated output 38 having the highest ratio is selected as the output to use in the further development of the reservoir when it is desired to try to maximize the production per dollar invested in obtaining the production. These steps are used when two or more groups of proposed parameters 34 are used with the correlation 32 to generate respective outputs 38.

The method of the present invention can further comprise initiating the computer 28 such that the neural-genetic program 25 automatically operates within the computer 25 to redefine the neural network topology (i.e., the correlation 32). This is performed in response to the data base of parameters with which the original correlation was defined and with additional data that have been measured and recorded with regard to the actual wells drilled or stimulated with the new drilling and completion 38 or new stimulation 40 procedures. Thus, as additional data is obtained during the further development of the reservoir 2, the correlation 32 can be refined.

The following are examples for a particular implementation of the present invention.

Example 1

The present invention was used with a group of forty wells in the Cleveland formation in the Texas panhandle. A quantitative trend result representing the output 36 in FIG. 1 was obtained in two days after identification and selection of the following parameters: completion date, frac date, stimulation fluid type, total clean fluid, carbon dioxide amount, total proppant, maximum proppant concentration, average injection rate, permeability, average porosity, shut-in bottom hole pressure, formation quality, net height of pay zone, and middle of the perforated interval. The last six of the foregoing parameters are referred to as formation parameters and are not variable for a particular well because they are fixed by the formation itself. The other parameters, referred to as surface parameters which encompass the drilling, completion and stimulation parameters 12, 13, 14, can be changed for subsequent wells; however, in defining a particular neural network topology these parameters are fixed by what was actually done at the wells used in creating the topology.

The graph of FIG. 2 shows the accuracy of the correlation 32 derived for the forty wells in the Cleveland formation. Twenty percent (i.e. eight) of the wells were removed from the data set before obtaining the correlation. For a one hundred percent correlation, all data would lie on diagonal line 42 in FIG. 2. The thirty-two solid circles designate the predicted versus actual production for the thirty-two wells used to train the neural network to create the correlation. After the correlation was obtained, the corresponding parameters for the eight wells originally removed from the data set were input as the proposed parameters 34 to test the correlation to predict the production on wells the system had never seen. The actual versus predicted production parameters for these eight wells are designated in FIG. 2 by the hollow circles.

Example 2

The method of the present invention was also used to test for parameter sensitivity. Having a model of the reservoir allows various parameters to be changed to determine the sensitivity of the reservoir to changes in the parameters. All bars with vertical interior lines shown in FIG. 3 are for surface parameters which can be changed by the operator.

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and the bars with horizontal interior lines are for the parameters fixed by the formation. Although for a specific application the formation parameters are fixed, for purposes of testing effects of changes in parameters, the formation parameters designated in FIG. 3 were changed by ten percent. This analysis left all wells as originally treated and varied one parameter at a time. Each of the bars to the right of the "normal bar" (which represents the sum of the six-month cumulative productions of all forty wells referred to in Example 1) shows the potential change in production by a ten percent variation of the parameter associated with the respective bar in the graph of FIG. 3. For example, to produce the bar above "proppant" in FIG. 3, all parameters recorded from the way the wells were treated and the formation parameters were left at their as-treated values while the quantity of proppant was changed by ten percent. With all other parameters constant and the proppant quantities changed by ten percent, this new set of data was run through the neural network and the predicted productions from all wells were summed to get the cumulative production. This new cumulative production obtained by changing only the proppant by ten percent was plotted as a bar above the word "proppant." The same procedure was used to vary each of the other listed parameters one at a time. The graph of FIG. 3 shows the greatest change results from the variation of the shut-in bottom hole pressure parameter.

Example 3

To be able to determine parameter sensitivities to various fluid treatment types, the same type sensitivity analysis was done but with regard to a standardized job with only the fluid type being different. The parameters of the standard job were as follows:

Proppant	200,000 pounds
Clean Fluid	80,000 gallons
CO ₂	100 Tons (0 if not foam)
Average Injection Rate	55 barrels per minute
Maximum Proppant Concentration	68.5 parts per gallon

Referring to FIG. 4, the second row of bars marked "as treated" in this graph correspond to the sensitivity analyses shown in FIG. 3. The other bars show the sensitivity analyses for each fluid type using the above standard treatment. The foam gel treatments show to be inferior to the other treatments including the "as treated group." The gel acid and foam acid show to be better than the as treated. The foam cross-link treatments were the best in the analysis but the validity of this may be questioned due to not having a sufficiently large sample of foam cross-link jobs (there were only four wells treated with a foam cross-link treatment in the original data set used to form the model). If the four-well sample is significantly correct, then there is room for drastic improvement in production using a foam cross-link fluid in this reservoir.

The following chart shows whether the individual parameters in Examples 2 and 3 were increased (+) or decreased (-) to achieve an increase in the production:

	AS TREATED	FOAM GEL	GEL ACID	FOAM ACID	FOAM XLINK
NORMAL	0	0	0	0	0
PROPPANT	+	+	-	+	+
CLEAN FLUID	-	-	-	+	+
PERMEABILITY	+	+	+	+	+
POROSITY	+	+	+	+	+
NET PAY	+	+	+	+	+
CO ₂	+	+	0	+	+
AVG INJ RATE	+	+	+	-	+
MID PERF	-	-	-	-	-
SIBHP	+	+	+	+	+

NOTE: Peak occurred at 60 bpm. Above or below showed drop. Therefore, max increases seen with nine percent increase of avg inj rate for this fluid.

Thus, the present invention is well adapted to carry out the objects and attain the ends and advantages mentioned above as well as those inherent therein. While preferred embodiments of the invention have been described for the purpose of this disclosure, changes in the construction and arrangement of parts and the performance of steps can be made by those skilled in the art, which changes are encompassed within the spirit of this invention as defined by the appended claims.

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Claims

1. A method of controlling development of an oil or gas reservoir, which has a plurality of wells drilled therein from which oil or gas has been produced: which method comprises the steps of:

(a) identifying well drilling parameters associated with drilling of the plurality of wells; well completion parameters associated with completing the plurality of wells; well stimulation parameters associated with stimulating the plurality of wells; formation parameters associated with the locations in the reservoir where the plurality of wells are drilled; and production parameters associated with the production of the oil or gas from the plurality of wells;

(b) selecting at least one drilling parameter, at least one completion parameter, at least one stimulation parameter, at least one formation parameter, and at least one production parameter from among the identified said parameters;

(c) converting the selected parameters to encoded digital signals for a computer;

(d) defining in the computer a neural network topology representing a relationship between the selected drilling, completion, stimulation and formation parameters and the at least one selected production parameter in response to the encoded digital signals, including manipulating the encoded digital signals in the computer using genetic algorithms to define the neural network topology;

(e) entering into the computer as inputs to the defined neural network topology a first group of additional encoded digital signals representing proposed drilling, completion, stimulation and formation parameters of the same type as the selected drilling, completion, stimulation, and formation parameters, and generating an output from the defined neural network topology in response;

(f) repeating step (e) using at least a second group of additional encoded digital signals representing other proposed drilling, completion, stimulation and formation parameters; and

(g) controlling further development of the oil or gas reservoir in response to at least one of the generated outputs, including at least one step selected from (1) drilling at least one new well in the reservoir in response to the generated output and (2) treating at least one well in the reservoir in response to the generated output.

2. A method according to claim 1, wherein the step of drilling at least one new well in the reservoir includes selecting a location to drill the well in the reservoir in response to the generated output, and/or the step of treating at least one well includes forming a stimulation fluid and pumping the stimulation fluid into the well in response to the generated output.

3. A method according to claim 1 or 2, wherein step (g) further includes computing a cost for implementing the proposed drilling, well stimulation and formation parameters represented by the respective encoded digital signals of each group in steps (e) and (f); computing a revenue for each of the generated outputs; and selecting the generated output having the highest computed revenue to corresponding computed cost ratio as the generated output in response to which the further development of the reservoir is controlled.

4. A computer-implemented method of controlling development of an oil or gas reservoir by enabling an individual to observe through the operation of the computer a simulated production of oil or gas from the reservoir before an actual well is drilled in the reservoir to try to obtain therefrom actual production corresponding to the simulated production, said method comprising:

(a) selecting an oil or gas reservoir having a known configuration of equipment disposed therein defining a plurality of actual wells drilled in the reservoir and further having a plurality of known well implementation parameters and well production parameters for each of the actual wells;

(b) simulating each of the actual wells in the computer, including translating selected ones of the known parameters of the actual wells into encoded electrical signals for the computer and storing the encoded electrical signals in memory of the computer such that the encoded electrical signals representing the selected well implementation parameters for a respective actual well are associated with the encoded electrical signals representing the selected production parameters for the same respective well;

(c) determining with the computer a correlation for the reservoir between the types of the selected well implementation parameters and the types of production parameters in response to the plurality of simulated wells including creating in the computer a neural network topology defining the correlation using predetermined genetic algorithms and the stored encoded electrical signals;

(d) indicating to the computer a proposed well for the reservoir, including translating well implementation parameters for the proposed well into encoded electrical signals and storing the encoded electrical signals in the

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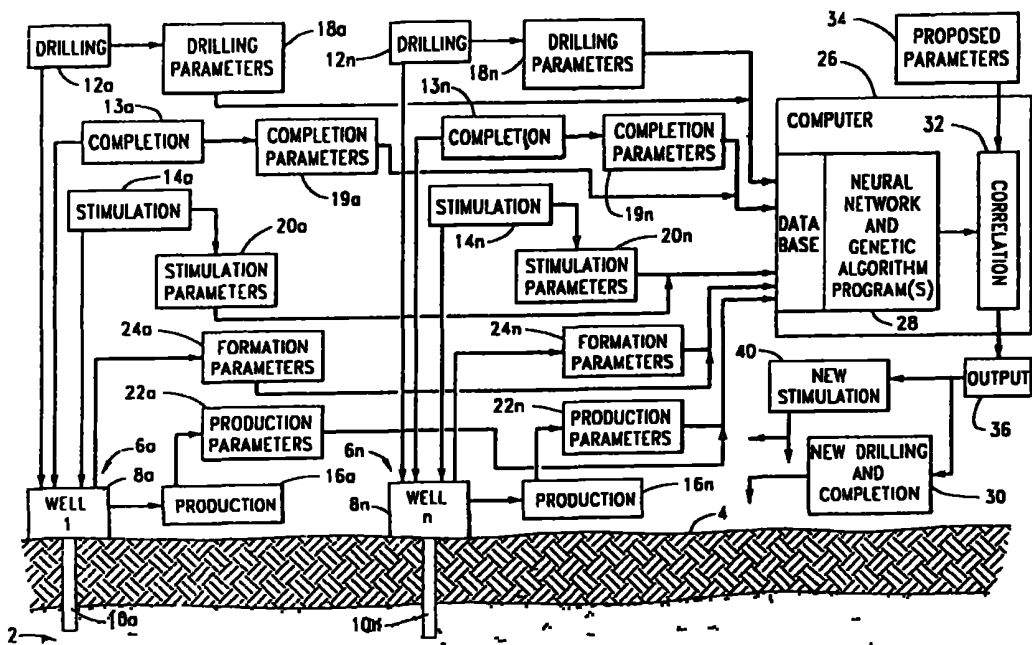


FIG. 1

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computer

(e) simulating with the computer a production from the proposed well including generating an output representing the production in response to the encoded electrical signals of step (d) and the correlation of step (c) such that the generated output is correlated to the encoded electrical signals of step (d) by the correlation of step (c) and

(f) displaying for observation by an individual a representation of the simulated production

5 A method according to claim 4 further comprising drilling an actual well in the reservoir based on the well implementation parameters of step (d) including selecting a location to drill the well in the reservoir in response to the displayed representation of the simulated production and optionally treating the drilled well including forming a stimulation fluid and pumping the stimulation fluid into the well in response to the well implementation parameters of step (d)

10 6. A method according to claim 4 or 5 further comprising repeating steps (d) (e) and (f) for a plurality of simulated proposed wells computing a cost for implementing the proposed well implementation parameters for each of the plurality of simulated proposed wells and computing a revenue for each of the simulated productions for the proposed wells and drilling an actual well in the reservoir corresponding to the simulated proposed well having the highest ratio of computed revenue to corresponding computed cost.

15 7 A method of generating a model of an oil or gas reservoir in a digital computer for use in analyzing the reservoir comprising providing the computer with a data base for a plurality of wells actually drilled in the reservoir including parameters of physical attributes of the wells providing the computer with a neural network and genetic algorithm application program to define a neural network topology within the computer in response to the parameters in the data base and initiating the computer such that the neural network and genetic algorithms within the application program automatically define the neural network topology and the input data used to optimally form the topology in response to the data base of the parameters of physical attributes of the wells

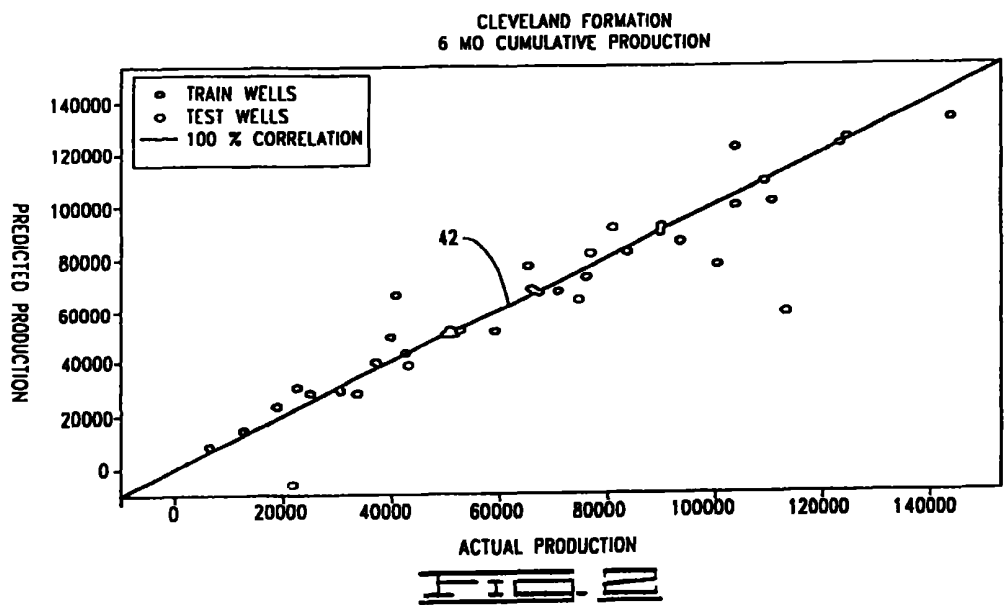
20 8 A method according to claim 7 further comprising determining a hypothetical set of parameters of physical attributes corresponding to at least some of the physical attribute parameters of the data base providing the computer with the determined hypothetical set of parameters calculating in the computer using the defined neural network topology a production parameter correlated to the hypothetical set of parameters, and operating a display device in response to the calculated production parameter so that an individual viewing the display device tracks possible production from a well to which the hypothetical set of parameters is applied prior to any actual corresponding production occurring

25 9 A method as defined in claim 8 further comprising drilling an actual well in the reservoir in response to the display of possible production

30 10 A method as defined in claim 9 further comprising determining additional data and providing the additional data to the data base of the computer including measuring and recording actual parameters of physical attributes of the actual well drilled in the reservoir and initiating the computer such that the neural network and genetic algorithm application program automatically operates within the computer to redefine the neural network topology in response to the data base of parameters of physical attributes of the wells which data base includes the additional data

ENCLOSURE 6 08/28/82

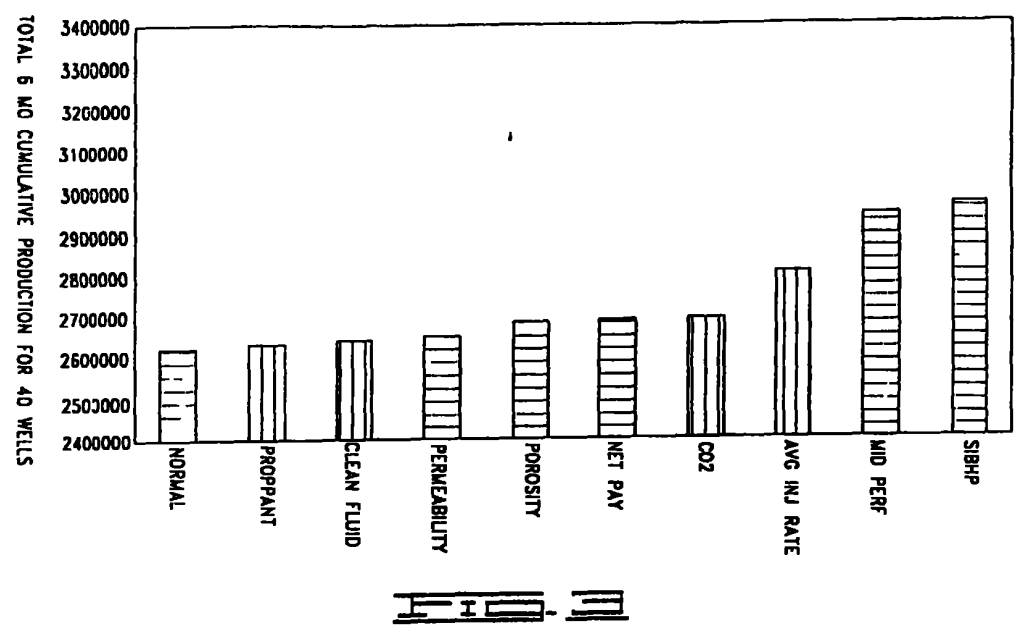
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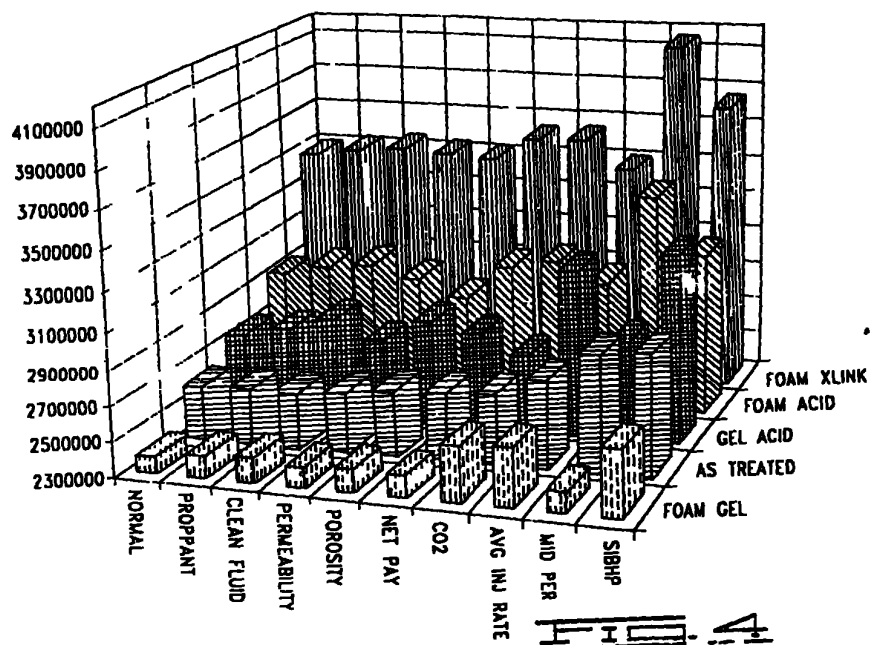


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(54) Title: DRILLING SYSTEM WITH SENSORS FOR DETERMINING PROPERTIES OF DRILLING FLUID DOWNHOLE			
(57) Abstract			
The present invention provides a drilling system for drilling oilfield boreholes or wellbores utilizing a drill string having a drilling assembly conveyed downhole by a tubing (usually a drill pipe or coiled tubing). The drilling assembly includes a bottom hole assembly (BHA) and a drill bit. The bottom hole assembly preferably contains commonly used measurement-while-drilling sensors. The drill string also contains a variety of sensors for determining downhole various properties of the drilling fluid. Sensors are provided to determine density, viscosity, flow rate, clarity, compressibility, pressure and temperature of the drilling fluid at one or more downhole locations. Chemical detection sensors for detecting the presence of gas (methane) and H₂S are disposed in the drilling assembly. Sensors for determining fluid density, viscosity, pH, solid content, fluid clarity, fluid compressibility, and a spectroscopy sensor are also disposed in the BHA. Data from such sensors may be processed downhole and/or at the surface. Corrective actions are taken based upon the downhole measurements at the surface which may require altering the drilling fluid composition, altering the drilling fluid pump rate or shutting down the operation to clean wellbore. The drilling system contains one or more models, which may be stored in memory downhole or at the surface. These models are utilized by the downhole processor and the surface computer to determine desired fluid parameters for continued drilling. The drilling system is dynamic, in that the downhole fluid sensor data is utilized to update models and algorithms during drilling of the wellbore and the updated models are then utilized for continued drilling operations.			

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DRILLING SYSTEMS WITH SENSORS FOR DETERMINING PROPERTIES OF DRILLING FLUID DOWNHOLE

BACKGROUND OF THE INVENTION

1. Field of the Invention

5 This invention relates generally to drilling systems for forming or drilling wellbores or boreholes for the production of hydrocarbons from subsurface formations and more particularly to drilling systems utilizing sensors for determining downhole parameters relating to the fluid in the wellbore during drilling of the wellbores. The measured fluid parameters include chemical properties including
10 chemical composition (gas, pH, H₂S, etc.), physical properties including density, viscosity, clarity, lubricity, color, compressibility, accumulation of cuttings, pressure and temperature profiles or distribution along wellbores. This invention further relates to taking actions based at least in part on the downhole measured fluid parameters, including adjusting the properties of the drilling fluid supplied from the surface, fluid
15 flow rate, hole cleaning, and taking corrective actions when a kick is detected, thereby improving the efficiency and effectiveness of the drilling operations.



2. Description Of The Related Art

20 To recover oil and gas from subsurface formations, wellbores (also referred to as boreholes) are drilled by rotating a drill bit attached at an end of a drill string. The

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drill string includes a drill pipe or a coiled tubing (referred herein as the "tubing") that has a drill bit at its downhole end and a bottomhole assembly (BHA) above the drill bit. The wellbore is drilled by rotating the drill bit by rotating the tubing and/or by a mud motor disposed in the BHA. A drilling fluid commonly referred to as the "mud")
5 is supplied under pressure from a surface source into the tubing during drilling of the wellbore. The drilling fluid operates the mud motor (when used) and discharges at the drill bit bottom. The drilling fluid then returns to the surface via the annular space (annulus) between the drill string and the wellbore wall or inside. Fluid returning to the surface carries the rock bits (cuttings) produced by the drill bit as it disintegrates
10 the rock to drill the wellbore.

In overburdened wellbores (when the drilling fluid column pressure is greater than the formation pressure), some of the drilling fluid penetrates into the formation, thereby causing a loss in the drilling fluid and forming an invaded zone around the
15 wellbore. It is desirable to reduce the fluid loss into the formation because it makes it more difficult to measure the properties of the virgin formation, which are required to determine the presence and retrievability of the trapped hydrocarbons. In underbalanced drilling, the fluid column pressure is less than the formation pressure, which causes the formation fluid to enter into the wellbore. This invasion may
20 reduce the effectiveness of the drilling fluid.

A substantial proportion of the current drilling activity involves directional boreholes (deviated and horizontal boreholes) and/or deeper boreholes to recover

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greater amounts of hydrocarbons from the subsurface formations and also to recover previously unrecoverable hydrocarbons. Drilling of such boreholes require the drilling fluid to have complex physical and chemical characteristics. The drilling fluid is made up of a base such as water or synthetic material and may contain a number of additives depending upon the specific application. A major component in the success the drilling operation is the performance of the drilling fluid, especially for drilling deeper wellbores, horizontal wellbores and wellbores in hostile environments (high temperature and pressure). These environments require the drilling fluid to excel in many performance categories. The drilling operator and the mud engineer determine the type of the drilling fluid most suitable for the particular drilling operations and then utilize various additives to obtain the desired performance characteristics such as viscosity, density, gelation or thixotropic properties, mechanical stability, chemical stability, lubricating characteristics, ability to carry cuttings to the surface during drilling, ability to hold in suspension such cuttings when fluid circulation is stopped, environmental harmony, non-corrosive effect on the drilling components, provision of adequate hydrostatic pressure and cooling and lubricating impact on the drill bit and BHA components.

A stable borehole is generally a result of a chemical and/or mechanical balance of the drilling fluid. With respect to the mechanical stability, the hydrostatic pressure exerted by the drilling fluid in overburdened wells is normally designed to exceed the formation pressures. This is generally controlled by controlling the fluid density at the surface. To determine the fluid density during drilling, the operators take into

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account prior knowledge, the behavior of rock under stress, and their related deformation characteristics, formation dip, fluid velocity, type of the formation being drilled, etc. However, the actual density of the fluid is not continuously measured downhole, which may be different from the density assumed by the operator.

5 Further, the fluid density downhole is dynamic, i.e., it continuously changes depending upon the actual drilling and borehole conditions, including the downhole temperature and pressure. Thus, it is desirable to determine density of the wellbore fluid downhole during the drilling operations and then to alter the drilling fluid composition at the surface to obtain the desired density and/or to take other
10 corrective actions based on such measurements. The present invention provides drilling apparatus and methods for downhole determination of the fluid density during the drilling of the wellbores.

It is common to determine certain physical properties in the laboratories from
15 fluid samples taken from the returning wellbore fluid. Such properties typically include fluid compressibility, rheology, viscosity, clarity and solid contents. However, these parameters may have different values downhole, particularly near the drill bit than at the surface. For example, the fluid viscosity may be different downhole than the viscosity determined at the surface even after accounting for the effect of
20 downhole pressure and temperature and other factors. Similarly, the compressibility of the drilling fluid may be different downhole than at the surface. If a gas zone is penetrated and the gas enters the drilling fluid, the compressibility of drilling fluid can change significantly. The present invention provides drilling apparatus and methods

for determining in-situ the above-noted physical parameters during drilling of the wellbores.

Substantially continuous monitoring of pressure gradient and differential pressure between the drill string inside and the annulus can provide indication of kicks, accumulation of cuttings and washed zones. Monitoring of the temperature gradient can qualitative measure of the performance of the drilling fluid and the drill bit. The present invention provides distributed sensors along the drill string to determine the pressure and temperature gradient and fluid flow rate at selected locations in the wellbore.

Downhole determination of certain chemical properties of the drilling fluid can provide on-line information about the drilling conditions. For example, presence of methane can indicate that the drilling is being done through a gas bearing formation and thus provide an early indication of a potential kick (kick detection). Oftentimes the presence of gas is detected when the gas is only a few hundred feet below the surface, which sometimes does not allow the operator to react and take preventive actions, such as closing valves or shutting down drilling to prevent a blow out. The present invention provides an apparatus and method for detecting the presence of gas and performs kick detection.

Corrosion of equipment in the wellbore is usually due to the presence of carbon dioxide, hydrogen sulphide (H_2S) and oxygen. Low pH and salt contaminated

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wellbore fluids are more corrosive. Prior art does not provide any methods for measuring the pH of drilling fluid or the presence of H₂S downhole. The returning wellbore fluid is analyzed at the surface to determine the various desired chemical properties of the drilling fluid. The present invention provides method for determining
5 downhole certain chemical properties of the wellbore fluid.

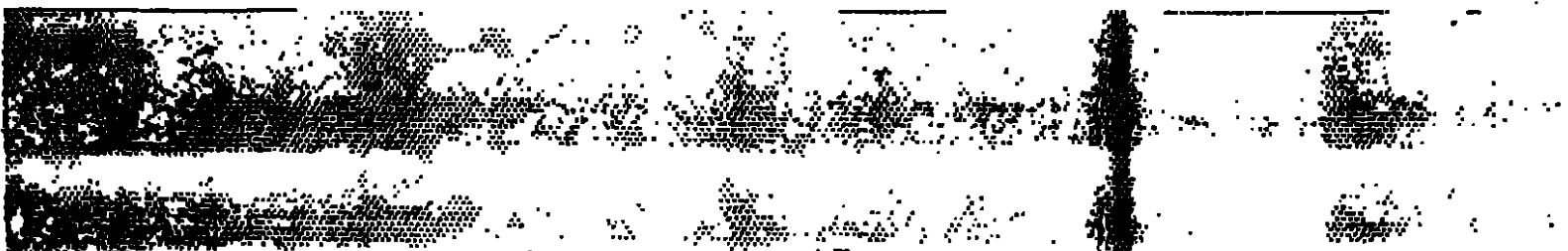
As noted above, an important function of the drilling fluid is to transport cuttings from the wellbore as the drilling progresses. Once the drill bit has created a drill cutting, it should be removed from under the bit. If the cutting remains under the
10 bit it is redrilled into smaller pieces, adversely affecting the rate of penetration, bit life and mud properties. The annular velocity needs to be greater than the slip velocity for cuttings to move uphole. The size, shape and weight of the cuttings determine the viscosity necessary to control the rate of settling through the drilling fluid. Low shear rate viscosity controls the carrying capacity of the drilling fluid. The density of
15 the suspending fluid has an associated buoyancy effect on cuttings. An increase in density usually has an associated favorable affect on the carrying capacity of the drilling fluid. In horizontal wellbores, heavier cuttings can settle on the bottom side of the wellbore if the fluid properties and fluid speed are not adequate. Cuttings can also accumulate in washed-out zones. Prior art drilling tools do not determine density
20 of the fluid downhole and do not provide an indication of whether cuttings are settling or accumulating at any place in the wellbore. The present invention utilizes downhole sensors and devices to determine the density of the fluid downhole and to provide an indication whether excessive cuttings are present at certain locations

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along the borehole.

In the oil and gas industry, various devices and sensors have been used to determine a variety of downhole parameters during drilling of wellbores. Such tools
5 are generally referred to as the measurement-while-drilling (MWD) tools. The general emphasis of the industry has been to use MWD tools to determine parameters relating to the formations, physical condition of the tool and the borehole. Very few measurements are made relating to the drilling fluid. The majority of the measurements relating to the drilling fluid are made at the surface by analyzing
10 samples collected from the fluid returning to the surface. Corrective actions are taken based on such measurements, which in many cases take a long time and do not represent the actual fluid properties downhole.

The present invention addresses several of the above-noted deficiencies and
15 provides drilling systems for determining downhole various properties of the wellbore fluid during the drilling operations, including temperature and pressures at various locations, fluid density, accumulation of cuttings, viscosity, color, presence of methane and hydrogen sulphide, pH of the fluid, fluid clarity, and fluid flow rate along the wellbore. Parameters from the downhole measurements may be computed by a
20 downhole computer or processor or at the surface. A surface computer or control system displays necessary information for use by the driller and may be programmed to automatically take certain actions, activate alarms if certain unsafe conditions are detected, such as entry into a gas zone, excessive accumulation of cuttings



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downhole, etc. are detected. The surface computer communicates with the downhole processors via a two-way telemetry system.

SUMMARY OF THE INVENTION

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The present invention provides a drilling system for drilling oilfield wellbores. A drilling assembly or bottom hole assembly (BHA) having a drill bit at an end is conveyed into the wellbore by a suitable tubing such as a drill pipe or coiled tubing. The drilling assembly may include a drill motor for rotating the drill bit. A drilling fluid is supplied under pressure from a source thereof at the surface into the tubing. The drilling fluid discharges at the drill bit bottom. The drilling fluid along with the drill cuttings circulates to the surface through the wellbore annulus. One or more shakers or other suitable devices remove cuttings from the returning fluid. The clean fluid discharges into the source.

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In one embodiment, a plurality of pressure sensors are disposed, spaced apart, at selected locations in the drilling assembly and along the drill string to determine the pressure gradient of the fluid inside the tubing and in the annulus. The pressure gradient may be utilized to determine whether cuttings are accumulating within a particular zone. If the pressure at any point is greater than a predetermined value, or is approaching a leak off test (LOT) pressure or the pressure integrity test (PIT) pressure, the system provides a warning to the operator to clean the wellbore prior to further drilling of the wellbore. The pressure difference between zones determined

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from the distributed pressure sensor measurements also can provide an indication of areas or depths where the cuttings have accumulated. Any step change in the pressure gradient is an indication of a localized change in the density of the fluid. The distributed pressure measurements along the wellbore in conjunction with
5 temperature measurements can also be utilized to perform reservoir modeling while the wellbore is being drilled instead of conducting expensive tests after the wellbore has been drilled. Such modeling at this early stage can provide useful information about the reservoirs surrounding the wellbore. Additionally, differential pressure sensors may be disposed at selected locations on the drill string to provide pressure
10 difference between the pressure of the fluid inside the drill string and the fluid in the annulus.

Fluid flow measuring devices may be disposed in the drill string to determine the fluid flow through the drill string and the annulus at selected locations along the
15 wellbore. This information may be utilized to determine the fluid loss into the formation in the zones between the flow sensor locations and to determine wash out zones.

A plurality of temperature sensors are likewise disposed to determine the
20 temperature of the fluid inside the tubing and the drilling assembly and the temperature of the fluid in the annulus near the drill bit, along the drilling assembly and along the tubing. A distributed temperature sensor arrangement can provide the temperature gradient from the drill bit to any location on the drill string. Extreme

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localized temperatures can be detrimental to the physical and/or chemical properties of the drilling fluid. Substantially continuous monitoring of the distributed temperature sensors provides an indication of the effectiveness of the drilling fluid.

5 In the embodiments described above or in an alternative embodiment, one or more acoustic sensors are disposed in the drill string. The acoustic sensors preferably are ultrasonic sensors to determine reflections of the ultrasonic signals from elements within the borehole, such as suspended or accumulated cuttings. The response of such sensors is utilized to determine the accumulation of cuttings in the
10 wellbore during drilling. A plurality of ultrasonic sensors disposed around the drill string can provide an image of the wellbore fluid in the annulus. The depth of investigation may be varied by selecting a suitable frequency from a range of frequencies. A plurality of such sensor arrangements can provide discretely disposed along the drill string can provide such information over a significant length of the drill
15 string.

The drill string also contains a variety of sensors for determining downhole various properties of the wellbore fluid. Sensors are provided to determine density, viscosity, flow rate, pressure and temperature of the drilling fluid at one or more
20 downhole locations. Chemical detection sensors for detecting the presence of gas (methane), CO₂ and H₂S are disposed in the drilling assembly. Sensors for determining fluid density, viscosity, pH, solid content, fluid clarity, fluid compressibility, and a spectroscopy sensor are also disposed in the BHA. Data from

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such sensors is processed downhole and/or at the surface. Based upon the downhole measurements corrective actions are taken at the surface which may require altering the drilling fluid composition, altering the drilling fluid pump rate or shutting down the operation to clean the wellbore. The drilling system contains one
5 or more models, which may be stored in memory downhole or at the surface. These models are utilized by the downhole processor and the surface computer to determine desired fluid parameters for continued drilling. The drilling system is dynamic, in that the downhole fluid sensor data is utilized to update models and algorithms during drilling of the wellbore and the updated models are then utilized for continued drilling
10 operations.

Examples of the more important features of the invention thus have been summarized rather broadly in order that detailed description thereof that follows may be better understood, and in order that the contributions to the art may be
15 appreciated. There are, of course, additional features of the invention that will be described hereinafter and which will form the subject of the claims appended hereto.

BRIEF DESCRIPTION OF THE DRAWINGS

20 For detailed understanding of the present invention, reference should be made to the following detailed description of the preferred embodiment, taken in conjunction with the accompanying drawings, in which like elements have been given like numerals and wherein:

Figure 1 shows a schematic diagram of a drilling system having a drill string containing a drill bit, mud motor, measurement-while-drilling devices, downhole processing unit and various sensors for determining properties of the drilling fluid
5 according to one embodiment of the present invention.

Figure 2A shows a schematic diagram of a drilling assembly with a plurality of pressure sensors and differential pressure sensors according to the present invention.

10 Figure 2B shows a schematic diagram of a drilling assembly with a plurality of temperature sensors according to one embodiment of the present invention.

Figure 3 shows a schematic diagram of a sensor for determining the density of the drilling fluid.

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Figure 4 shows a schematic of a drill string with a plurality of acoustic devices for determining selected properties of drilling fluid according to the present invention.

Figure 4A shows an arrangement of a plurality of acoustic sensor elements for
20 use in the acoustic systems shown in Figure 4.

Figure 4B shows a display of the fluid characteristics obtained by an acoustic device of the system of Figure 4.



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Figure 5 shows a schematic diagram of a sensor for determining the viscosity of the drilling fluid.

5 Figure 6 shows a schematic diagram of a sensor for determining the compressibility of the drilling fluid.

Figure 7 shows a schematic diagram of a sensor for determining the clarity of the drilling fluid.

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Figure 8 shows a schematic diagram of a fiber optic sensor for determining certain chemical properties of the drilling fluid.

Figure 9 is a schematic illustration of a fiber optic sensor system for
15 monitoring chemical properties of produced fluids;

Figure 10 is a schematic illustration of a fiber optic sol gel indicator probe for use with the sensor system of Figure 9;

20 Figure 11 is a schematic illustration of an embodiment of an Infrared sensor carried by the bottomhole assembly for determining properties of the wellbore fluid.

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169**DESCRIPTION OF THE PREFERRED EMBODIMENTS**

In general, the present invention provides a drilling system for drilling oilfield boreholes or wellbores utilizing a drill string having a drilling assembly conveyed
5 downhole by a tubing (usually a drill pipe or coiled tubing). The drilling assembly includes a bottom hole assembly (BHA) and a drill bit. The bottom hole assembly preferably contains commonly used measurement-while-drilling sensors. The drill string also contains a variety of sensors for determining downhole various properties of the wellbore fluid. Sensors are provided to determine density, viscosity, flow rate,
10 pressure and temperature of the drilling fluid at one or more downhole locations. Chemical detection sensors for detecting the presence of gas (methane), CO₂ and H₂S are disposed in the drilling assembly. Sensors for determining fluid density, viscosity, pH, solid content, fluid clarity, fluid compressibility, and a spectroscopy sensor are also disposed in the BHA. Data from such sensors may is processed
15 downhole and/or at the surface. Corrective actions are taken based upon the downhole measurements at the surface which may require altering the drilling fluid composition, altering the drilling fluid pump rate or shutting down the operation to clean the wellbore. The drilling system contains one or more models, which may be stored in memory downhole or at the surface. These models are utilized by the
20 downhole processor and the surface computer to determine desired fluid parameters for continued drilling. The drilling system is dynamic, in that the downhole fluid sensor data is utilized to update models and algorithms during drilling of the wellbore and the updated models are then utilized for continued drilling operations.

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Figure 1 shows a schematic diagram of a drilling system 10 having a drilling string 20 shown conveyed in a borehole 26. The drilling system 10 includes a conventional derrick 11 erected on a platform 12 which supports a rotary table 14 that is rotated by a prime mover such as an electric motor (not shown) at a desired rotational speed. The drill string 20 includes a drill pipe 22 extending downward from the rotary table 14 into the borehole 26. A drilling assembly or borehole assembly (BHA) 90 carrying a drill bit 50 is attached to the bottom end of the drill string. The drill bit disintegrates the geological formations (rocks) when it is rotated to drill the borehole 26 producing rock bits (cuttings). The drill string 20 is coupled to a drawworks 30 via a kelly joint 21, swivel 28 and line 29 through a pulley 23. During the drilling operations the drawworks 30 is operated to control the weight on the bit, which is an important parameter that affects the rate of penetration. The operation of the drawworks 30 is well known in the art and is thus not described in detail herein. Figure 1 shows the use of drill pipe 22 to convey the drilling assembly 90 into the borehole 26. Alternatively, a coiled tubing with an injector head (not shown) may be utilized to convey the drilling assembly 90. For the purpose of this invention, drill pipe and coiled tubing are referred to as the "tubing". The present invention is equally applicable to both drill pipe and coiled tubing drill strings.

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During drilling operations a suitable drilling fluid 31 (commonly referred to as the "mud" from a mud pit (source) 32 is supplied under pressure to the tubing 22 by a mud pump 34. The term "during drilling" herein means while drilling or when

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drilling is temporarily stopped for adding pipe or taking measurement without retrieving the drill string. The drilling fluid 31 passes from the mud pump 34 into the tubing 22 via a desurger 36, fluid line 38 and the kelly joint 21. The drilling fluid 31a travels through the tubing 22 and discharges at the borehole bottom 51 through openings in the drill bit 50. The drilling fluid 31b carrying drill cuttings 86 circulates uphole through the annular space (annulus) 27 between the drill string 20 and the borehole 26 and returns to the mud pit 32 via a return line 35. A shaker 85 disposed in the fluid line 35 removes the cuttings 86 from the returning fluid and discharges the clean fluid into the pit 32. A sensor S₁, preferably placed in the line 38, provides the rate of the fluid 31 being supplied to the tubing 22. A surface torque sensor S₂ and a speed sensor S₃ associated with the drill string 20 respectively provide measurements about the torque and the rotational speed of the drill string. Additionally, a sensor S₄ associated with line 29 is used to provide the hook load of the drill string 20.

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In some applications the drill bit 50 is rotated by only rotating the drill pipe 22. However, in many applications, a downhole motor or mud motor 55 is disposed in the drilling assembly 90 to rotate the drill bit 50. The drilling motor rotates when the drilling fluid 31a passes through the mud motor 55. The drill pipe 22 is rotated usually to supplement the rotational power supplied by the mud motor, or to effect changes in the drilling direction. In either case, the rate of penetration (ROP) of the drill bit 50 for a given formation and the type of drilling assembly used largely depends upon the weight on bit (WOB) and the drill bit rotational speed.

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The embodiment of Figure-1 shows the mud motor 55 coupled to the drill bit 50 via a drive shaft (not shown) disposed in a bearing assembly 57. The mud motor 55 transfers power to the drive shaft via one or more hollow shafts that run through the resistivity measuring device 64. The hollow shaft enables the drilling fluid to pass from the mud motor 55 to the drill bit 50. Alternatively, the mud motor 55 may be coupled below the resistivity measuring device 64 or at any other suitable place in the drill string 90. The mud motor 55 rotates the drill bit 50 when the drilling fluid 31 passes through the mud motor 55 under pressure. The bearing assembly 57 supports the radial and axial forces of the drill bit 50, the downthrust of the drill motor and the reactive upward loading from the applied weight on bit. Stabilizers 58a and 58b coupled spaced to the drilling assembly 90 acts as a centralizer for the drilling assembly 90.

15 A surface control unit 40 receives signals from the downhole sensors and devices (described below) via a sensor 43 placed in the fluid line 38, and signals from sensors S₁, S₂, S₃, hook load sensor S₄ and any other sensors used in the system and processes such signals according to programmed instructions provided to the surface control unit 40. The surface control unit 40 displays desired drilling parameters and other information on a display/monitor 42, which information is utilized by an operator to control the drilling operations. The surface control unit 40 contains a computer, memory for storing data, recorder for recording data and other peripherals. The surface control unit 40 also includes models or programs, processes data

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according to programmed instructions and responds to user commands entered through a suitable device. The control unit 40 is preferably adapted to activate alarms 44 when certain unsafe or undesirable operating conditions occur.

5 Still referring to Figure 1, the drilling assembly 90 contains sensors and devices which are generally used for drilling modern boreholes, including formation evaluation sensors, sensors for determining borehole properties, tool health and drilling direction. Such sensors are often referred to in the art as the measurement-while-drilling devices or sensors. The drilling system 10 further includes a variety of
10 sensors and devices for determining the drilling fluid 31 properties and condition of the drilling fluid during drilling of the wellbore 26 according to the present invention. The generally used MWD sensors will be briefly described first along with general description of downhole processor for processing sensor data and signals. The sensors used for determining the various properties or characteristics of the drilling or
15 wellbore fluid are described thereafter.

The MWD sensors preferably include a device 64 for measuring the formation resistivity near and/or in front of the drill bit, a gamma ray device 76 for measuring the formation gamma ray intensity and devices 67 for determining drilling direction
20 parameters, such as azimuth, inclination and x-y-z location of the drill bit 50. The resistivity device 64 is preferably coupled above a lower kick-off subassembly 62 and provides signals from which resistivity of the formation near or in front of the drill bit 50 is determined. The resistivity device 64 or a second resistivity device (not shown)

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may be is utilized to measure the resistivity of the drilling fluid 31 downhole. An inclinometer 74 and gamma the ray device 76 are suitably placed along the resistivity measuring device 64 for determining the inclination of the portion of the drill string near the drill bit 50 and the formation gamma ray intensity respectively. Any suitable
5 Inclinometer and gamma ray device, however, may be utilized for the purposes of this invention. In addition, an azimuth device, such as a magnetometer or a gyroscopic device, may be utilized to determine the drill string azimuth. A nuclear magnetic resonance (NMR) device may also be used to provide measurements for a number of formation parameters. The above-described devices are known in the art and
10 therefore are not described in detail herein.

Still referring to Figure 1, logging-while-drilling (LWD) devices, such as devices for measuring formation porosity, permeability and density, may be placed above the mud motor 64 in the housing 78 for providing information useful for evaluating and
15 testing subsurface formations along borehole 26. Any commercially available devices may be utilized as the LWD devices.

The bottomhole assembly 90 includes one or more processing units 70 which preferably includes one or more processors or computers, associated memory and
20 other circuitry for processing signals from the various downhole sensors and for generating corresponding signals and data. The processors and the associated circuit elements are generally denoted by numeral 71. Various models and algorithms to process sensor signals, and data and to compute parameters of interest, such as

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annulus pressure gradients, temperature gradients, physical and chemical properties of the wellbore fluid including density, viscosity, clarity, resistivity and solids content are stored in the downhole memory for use by the processor 70. The models, are also be provided to the surface control unit 40. A two-way telemetry 72 provides
5 two-way communication of signals and data between the downhole processing units 70 and the surface control unit 40. Any telemetry system, including mud pulse, acoustic, electromagnetic or any other known telemetry system may be utilized in the system 10 of this invention. The processing units 70 is adapted to transmit parameters of interest, data and command signals to the surface control unit 40 and
10 to receive data and command signals from the surface control unit 40.

As noted above, the drilling system 10 of this invention includes sensors for determining various properties of the drilling fluid, including physical and chemical properties, chemical composition and temperature and pressure distribution along the
15 wellbore 26. Such sensors and their uses according to the present invention will now be described.

FIGS. 1 and 2A show the placement of pressure sensors and differential pressure sensors according to one embodiment of the drill string 20. Referring to
20 these figures, a plurality of pressure sensors P_1 - P_n are disposed at selected locations on the drill string 20 to determine the pressure of the fluid flowing through the drill string 20 and the annulus 27 at various locations. A pressure sensor P_1 is placed near the drill bit 50 to continuously monitor the pressure of the fluid leaving the drill

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bit 50. Another pressure sensor P_n is disposed to determine the annulus pressure a short distance below the upper casing 87. Other pressure sensors P_2 - P_{n-1} are distributed at selected locations along the drill string 20. Also, pressure sensors P_1' - P_m' are selectively placed within the drill string 20 to provide pressure measurements of the drilling fluid flowing through the tubing 22 and the drilling assembly 90 at such selected locations. Additionally, differential pressure sensors DP_1 - DP_n disposed on the drill string provide continuous measurements of the pressure difference between the fluid in the annulus 27 and the drill string 20. Pressure sensors P_1'' - P_k'' may be disposed azimuthally at one or more locations to determine the pressure circumferentially at selected locations on the drill string 20. The azimuthal pressure profile can provide useful information about accumulation of cuttings along a particular side of the drill string 20.

Control of formation pressure is one of the primary functions of the drilling fluids. The hydrostatic pressure exerted by the fluid 31a and 31b column is the primary method of controlling the pressure of the formation 95. Whenever the formation pressure exceeds the pressure exerted on the formation 95 by the drilling fluid at a given, formation fluids 96 enter the wellbore, causing a "kick." A kick is defined as any unscheduled entry of formation fluids into the wellbore. Early detection of kicks and prompt initiation of control procedures are keys to successful well control. If kicks are not detected early enough or controlled properly when detected, a blowout can occur. One method of detecting kicks according to the present invention is by monitoring the pressure gradient in the wellbore. The

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distributed pressure sensor P_1-P_n and $P_1'-P_m'$ shown in FIGS. 1 and 2A provide the pressure gradient along the drill string or wellbore. Any sudden or step change in pressure between adjacent pressure sensors P_1-P_n when correlated with other parameters, such as mud weight and geological information can provide an indication of the kick. Monitoring of the wellbore pressure gradient can provide relative early indication of the presence of kicks and their locations or depths. Corrective action, such as changing the drilling fluid density, activating appropriate safety devices, and shutting down the drilling, if appropriate, can be taken. In one embodiment the downhole processing unit 70 processes the pressure sensor signals and determines if a kick is present and its corresponding well depth and transmits signals indicative of such parameters to the control unit 40 at the surface. The surface unit 40 may be programmed to display such parameters, activate appropriate alarms and/or cause the wellbore 26 to shut down.

Pressure sensors $P_1'-P_n'$ determine the pressure profile of the drilling fluid 31a flowing inside the drill string 20. Comparison of the annulus pressure and the pressure inside the drill string provides useful information about pressure anomalies in the wellbore 26 and an indication of the performance of the drilling motor 55. The differential pressure sensors DP_1-DP_n provide continuous information about the difference in pressure of the drilling fluid in the drill string 22 and the annulus 27.

Figure 1 and 2B show the placement of temperature sensors in one embodiment of the drill string 20. Referring to these figures, a plurality of temperature sensors T_1-T_l are placed at selected location in the drill string. One or

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more temperature sensors such as sensor T_1 are placed in the drill bit 50 to monitor the temperature of the drill bit and the drilling fluid near the drill bit. A temperature sensor T_2 placed within the drill string 20 above the drill bit 50 provides information about the temperature of the drilling fluid 31a entering the drill bit 50. The difference in temperature between T_1 and T_2 is an indication of the performance of the drill bit 50 and the drilling fluid 31. A large temperature difference may be due to one or more of: a relatively low fluid flow rate, drilling fluid composition, drill bit wear, weight on bit and drill bit rotational speed. The control unit 70 transmits the temperature difference information to the surface for the operator to take corrective actions. The corrective action may include increasing the drilling fluid flow rate, speed, reducing the drill bit rotational speed, reducing the weight or force on bit, changing the mud composition and/or replacing the drill bit 50. The rate of penetration (ROP) is also continuously monitored, which is taken into effect prior to taking the above described corrective actions.

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Temperature sensors T_2 - T_1 provide temperature profile or gradient of the fluid temperature in the drill string and in the annulus 27. This temperature gradient provides information regarding the effect of drilling and formations on the wellbore fluid thermal properties of the capacity of the particular drilling fluid is determined from these temperature measurements. The pressure gradient determined from the distributed pressure sensors (see Figure 2A) and the temperature gradient described with respect to Figure 2B can be used to perform reservoir modeling during drilling of the wellbore. Reservoir modeling provides maps or information about the location

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and availability of hydrocarbons within a formation or field. Initial reservoir models are made from seismic data prior to drilling wellbores in a field, which are updated after the wellbore has been drilled and during production. The present invention, however, provides an apparatus and method for updating the reservoir models during
5 drilling of the wellbores from the availability of the pressure and temperature gradients or profiles of the wellbore during drilling. The reservoir modeling is preferably done at the surface and the results may be utilized to alter drilling direction or other drilling parameters as required.

10 One or more temperature sensors such as sensor T₆, placed in the drilling motor 55, determine the temperature of the drilling motor. Temperature sensors such as sensors T₇-T₈ disposed within the drill string 20 provide temperature profile of the drilling fluid passing through the drilling assembly and the mud motor 55. The above-noted temperature measurement can be used with other measurement and
15 knowledge of the geological or rock formations to optimize drilling operations. Predetermined temperature limits are preferably stored in the memory of the processor 70 and if such values are exceeded, the processor 70 alerts the operator or causes the surface control unit 40 to take corrective actions, including shutting down the drilling operation.

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In prior art, mud mix is designed based on surface calculations which generally make certain assumptions about the downhole conditions including estimates of temperature and pressure downhole. In the present invention, the mud mix may be

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designed based on in-situ downhole conditions, including temperature and pressure values.

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Still referring to Figures 1 and 2B, a plurality of flow rate sensors V₁-V_r are
5 disposed in the drill string 20 to determine the fluid flow rate at selected locations in the drill string 20 and in the annulus 27. Great differences in the flow rate between the high side and the low side of the drill string provides at least qualitative measure and the location of the accumulation of cuttings and the locations where relatively large amounts of the drilling fluid are penetrating in the formation.

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The above described pressure sensors, temperature sensors and flow rate sensors may be arrayed on an optic fiber and disposed over a great length of the drill string, thus providing a relatively large number of distributed fiber optic sensors along the drill string. A light source at the surface or downhole can provide the light
15 energy. Fiber optic sensors offer a relatively inexpensive way of deploying a large number of sensors to determine the desired pressure, temperature, flow rate and acoustic measurements.

During drilling of wellbores, it is useful to determine physical properties of the
20 drilling fluid. Such properties include density, viscosity, lubricating compressibility, clarity, solids content and rheology. Prior art methods usually employ testing and analysis of fluid samples taken from the wellbore fluid returning to the surface. Such methods do not provide in-situ measurements downhole during the drilling process

and may not provide accurate measurement of the corresponding downhole values. The present invention provides devices and sensors for determining such parameters downhole during drilling of the wellbores.

5 The density of the fluid entering the drill string 20 and that of the returning fluid is generally determined at the surface. The present invention provides methods of determining the fluid density downhole. Referring to FIGS. 1 and 3, in one method, the drilling fluid 31 is passed into a chamber or a line 104 via a tubing 102 that contains a screen 108, which filters the drill cuttings 86. A differential pressure
10 sensor 112 determines the difference in pressure 114 (ΔP) due to the fluid column in the chamber, which provides the density of the fluid 31. A downhole-operated control valve 120 controls the inflow of the drilling fluid 31 into the chamber 104. A control valve 122 is used to control the discharge of the fluid 31 into the annulus 27. The downhole processor 70 controls the operation of the valves 120 and 122 and
15 preferably processes signals from the sensor 112 to determine the fluid density. The density may be determined by the surface unit 40 from the sensor 112 signals transmitted to the surface. If the downhole fluid density differs from the desired or surface estimated or computed downhole density, then mud mix is changed to achieve the desired downhole density. Alternatively, unfiltered fluid may also be
20 utilized to determine the density of the fluid in the annulus 27. Other sensors, including sonic sensors, may also be utilized to determine the fluid density downhole without retrieving samples to the surface during the drilling process. Spaced apart density sensors can provide density profile of the drilling fluid in the wellbore.

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Downhole measurements of the drilling fluid density provide accurate measure of the effectiveness of the drilling fluid. From the density measurements, among other things, it can be determined (a) whether cuttings are effectively being transported to the surface, (b) whether there is barite sag, i.e., barite is falling out of the drilling fluid, and (c) whether there is gas contamination or solids contamination. Downhole fluid density measurements provide substantially online information to the driller to take the necessary corrective actions, such as changing the fluid density, fluid flow rate, types of additives required, etc.

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Figure 4 shows an ultrasonic sensor system that may be utilized to determine the amount of cuttings present in the annulus and the borehole size. Referring to FIGs. 1 and 4, as an example, the drill string 20 is shown to contain three spaced apart acoustic sensor arrangements 140a-140c. Each of the acoustic sensor arrangements contains one or more transmitters which transmit sonic signals at a predetermined frequency which is selected based on the desired depth of investigation. For determining the relative amount of the solids in the drilling fluid, the depth of investigation may be limited to the average borehole 27 diameter size depicted by numerals 142a-142c. Each sensor arrangement also includes one or more receivers to detect acoustic signals reflecting from the solids in the drilling fluid 31. The same sensor element may be used both as a transmitter and receiver. Depending upon the axial coverage desired, a plurality of sensor elements may be arranged around the drilling assembly. One such arrangement or configuration is

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shown in Figure 4A, wherein a plurality of sensor elements 155 are symmetrically arranged around a selected section of the drilling assembly 90. Each element 155 may act as a transmitter and a receiver. Such ultrasonic sensor arrangements are known in the art and are, thus, not described in detail herein.

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During drilling of the wellbore (i.e. when drilling is in progress or when drilling is temporarily stopped to take measurements), signals from each of the sensor arrangements 140a-140c are processed by the downhole processor 70 to provide images of the fluid volumes 142a-142c in the annulus 27. Figure 4B shows an example of a radial image in a flat form that may be provided by the sensor arrangement 140a. The image 150, if rolled end to end at low sides 154 will be the image of volume 142a surrounding the sensor arrangement 140a. Image 150 shows a cluster 160 of sonic reflections at the low side 156, indicating a large number of solids (generally cuttings) accumulating on the low side 154 and relatively few reflections 162 at the high side 156, indicating that cuttings are flowing adequately along the high side 156 of the borehole 27. This method provides a visual indication of the presence of solids surrounding an area of investigation around each sensor 140a-140c. Spaced apart sensors 140a-140c provide such information over an extended portion of the drill string and can point to local accumulation areas.

Corrective action, such as increasing the flow rate, hole cleaning, and bit replacement can then be taken. By varying the frequency of transmission, depth of investigation can be varied to determine the borehole size and other boundary conditions.

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Figure 5 shows a device 190 for use in the drilling assembly for determining viscosity of the drilling fluid downhole. The device contains a chamber 180, which includes two members 182a and 182b, at least one of which moves relative to the other. The members 182a and 182b preferably are in the form of plates facing each other with a small gap 184 therebetween. Filtered drilling fluid from 31 from the annulus 27 enters the chamber 180 via an inlet line 186 when the control valve 188 is opened. The gap 184 is filled with the drilling fluid 31. The members 182a and 182b are moved to determine the friction generated by the drilling fluid relative to a known reference value, which provides a measure of the viscosity of the drilling fluid.

The members 182a and 182b may be operated by a hydraulic device, an electrical device or any other device (not shown) and controlled by the downhole processor 70. In one embodiment, the signals generated by the device 190 are processed by the processor 70 to provide viscosity of the drilling fluid. Fluid from the chamber 180 is discharged into the wellbore 26 via line 187 by opening the control valve 189. The control valves 188 and 189 are controlled by the processor 70. Alternatively, any other suitable device may be utilized to determine the viscosity of the drilling fluid downhole. For example a rotating viscometer (known in the art) may be adapted for use in the drill string 20 or an ultrasonic (acoustic) device may be utilized to determine the viscosity downhole. Since direct measurements of the downhole pressure and temperature are available at or near the sample location, the viscosity and density of the drilling fluid are calculated as a function of such parameters in the present invention. It should be obvious that the signals from the sensor 190 may be transmitted to the surface and processed by the surface processor 40 to determine

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the viscosity.

The device 190 may be reconfigured or modified wherein the members 182a and 182b rub against each other. In such a configuration, the friction can represent
5 the lubricity of the drilling fluid. The signals are processed as described

Fluid compressibility of the wellbore fluid is another parameter that is often useful in determining the condition and the presence of gas present in the drilling fluid. Figure 6 shows a device 210 for use in the BHA for determining compressibility of the drilling fluid downhole. Drilling fluid 31 is drawn into an air tight cylinder 200
10 via a tubing 201 by opening a valve 202 and moving the piston 204. The fluid 31 is drawn into the chamber 200 at a controlled rate to preserve the fluid characteristics as they exist in the annulus 27. To determine the compressibility of the drilling fluid 31, the piston 204 is moved inward while the control valve 202 is closed. The reduction in fluid volume is determined from the travel distance of the piston.
15 Movement of the piston 202 may be controlled electrically by a motor or by an hydraulic or a pneumatic pressure. The operation of the device 210 (control valve 201 and the piston 204) is controlled by the processor 70 (see Figure 1). The processor 70 receives signals from the device 210 corresponding to the piston travel and computes therefrom compressibility of the fluid 31. It should be noted that for
20 the purposes of this invention any other suitable device may be utilized for determining compressibility of the drilling fluid downhole. The compressibility herein is determined under actual downhole conditions compared to compressibility determined on the surface, which tends to simulate the downhole conditions.

Compressibility for water, oil, and gas (hydrocarbon) is different. For example downhole compressibility measurements can indicate whether gas or air is present. If it is determined that air is present, defoamers can be added to the drilling fluid 31
5 supplied to wellbore. Presence of gas may indicate kicks. Other gases that may be present are acidic gases such as carbon dioxide and hydrogen sulphide. A model can be provided to the downhole processor 70 to compute the compressibility and the presence of gases. The computed results are transmitted to the surface via telemetry 72. Corrective actions are then taken based on the computed values. The
10 compressibility also affects performance of the mud motor 55. Compressible fluid passing through the drilling motor 55 is less effective than non-compressible fluids. Maintaining the drilling fluid free from gases allows operating the mud motor at higher efficiency. Thus, altering compressibility can improve the drilling rate.

15 As noted above, clarity of drilling fluid in the annulus can provide useful information about the drilling process. Figure 7 shows a device 250 for use in the drilling assembly for in-situ determination of clarity of the drilling fluid during the drilling of the wellbore. The device 250 contains a chamber 254 through which a sample of the drilling fluid is passed by opening an inlet valve 264 and closing an
20 outlet valve 266. Drilling fluid 31 may be stored in the chamber 254 by closing the valve 266 or may be allowed to flow through by opening both valves 264 and 266. A light source 260 at one end 257 of the chamber 254 transmits light into the chamber 254. A detector 262 at an opposite end 257 detects the amount of light

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received through the fluid 31 or in the alternative the amount of light dispersed by the fluid 31. Since the amount of light supplied by the source 260 is known, the detector provides a measure of the relative clarity of the drilling fluid 31. The portions of the ends 255 and 257 that are used for transmitting or detecting the light are

5 transparent while the remaining outside areas of the chamber 254 are opaque.

The downhole processor 70 (Figure 1) controls the operation of the light source 260, receives signals from the detector 262 and computes the clarity value based on models or programmed instructions provided to the processor 70. The

10 clarity values may be determined continuously by allowing the drilling fluid 31 to flow continuously through the chamber or periodically. Inferences respecting the types of cuttings, solid content and formation being drilled can be made from the clarity values. The clarity values are transmitted uphole via telemetry 72 (Figure 1) for display and for the driller to take necessary corrective actions.

15

The drilling assembly 90 also may include sensors for determining certain other properties of the drilling fluid. For example a device for determining the pH of the drilling fluid may be installed in the bottomhole assembly. Any commercially available device may be utilized for the purpose of this invention. Value of pH of the drilling

20 fluid provides a measure of gas influx or water influx. Water influx can deteriorate the performance of oil based drilling fluids.

Chemical properties, such as presence of gas (methane), hydrogen sulphide,

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carbon dioxide, and oxygen of the drilling fluid are measured at the surface from drilling fluid samples collected during the drilling process. However, in many instances it is more desirable to determine such chemical properties of the drilling fluid downhole.

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In one embodiment of this invention, application specific fiber optic sensors are utilized to determine various chemical properties. The sensor element is made of a porous glass having an additive specific to measuring the desired chemical property of the drilling fluid. Such porous glass material is referred to as sol-gel. The sol-gel method produces a highly porous glass. Desired additives are stirred into the glass during the sol-gel process. It is known that some chemicals have no color and, thus, do not lend themselves to analysis by standard optical techniques. But there are substances that will react with these colorless chemicals and produce a particular color, which can be detected by the fiber optic sensor system. The sol-gel matrix is porous, and the size of the pores is determined by how the glass is prepared. The sol-gel process can be controlled to create a sol-gel indicator composite with pores small enough to trap an indicator in the matrix and large enough to allow ions of a particular chemical of interest to pass freely in and out and react with the indicator. Such a composite is called a sol-gel indicator. A sol-gel indicator can be coated on a probe which may be made from steel or other base materials suitable for downhole applications. Also, sol gel indicator have a relatively quick response time. The indicators are small and rugged and thus suitable for borehole applications. The sol-gel indicator may be calibrated at the surface and it tends to remain calibrated during

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downhole use. Compared to a sol-gel indicator, other types of measuring devices, such as a pH meter, require frequent calibrations. Sol-gel indicators tend to be self-referencing. Therefore, reference and sample measurements may be taken utilizing the same probe.

5

Figure 8 shows a schematic diagram of an embodiment of a fiber-optic device 300 with a sol-gel indicator 310. The sensor 300 contains the sol-gel indicator or member 310 and a fluid path 314 that provides the drilling fluid to the member 310. Light 316 is supplied from a source 320 via a fiber-optic cable 312 to the sol-gel member 310. The light 316 travels past the member 310 and is reflected back from a light mirror 304 at the end opposite to the light source 320. Light 316 reflected back to the cable 312 is detected and processed by the downhole processor 70 (Figure 1). The sol-gel member 310 will change color when it comes in contact with the particular chemical for which it is designed. Otherwise, the color will remain substantially unchanged. Therefore, the additive in the sol-gel member is chosen for detecting a particular chemical in the drilling fluid 31. In the preferred embodiment, a sensor each for detecting methane (gas), hydrogen sulphide and pH are disposed at suitable locations in the drill string. More than one such sensors may be distributed along the drill string. Sensors for detecting other chemical properties of the drilling fluid may also be utilized.

Figures 9 and 10 show an alternative configuration for the sol-gel fiber optic sensor arrangement. A probe is shown at 416 connected to a fiber optic cable 418

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which is in turn connected both to a light source 420 and a spectrometer 422. As shown in Figure 10, probe 416 includes a sensor housing 424 connected to a lens 426. Lens 426 has a sol gel coating 428 thereon which is tailored to measure a specific downhole parameter such as pH or is selected to detect the presence, absence or amount of a particular chemical such as oxygen, H₂S or the like. Attached to and spaced from lens 426 is a mirror 430. During use, light from the fiber optic cable 418 is collimated by lens 426 whereupon the light passes through the sol gel coating 428 and sample space 432. The light is then reflected by mirror 430 and returned to the fiber optical cable. Light transmitted by the fiber optic cable is measured by the spectrometer 422. Spectrometer 422 (as well as light source 420) may be located either at the surface or at some location downhole. Based on the spectrometer measurements, a control computer 414, 416 will analyze the measurement and based on this analysis, the chemical injection apparatus 408 will change the amount (dosage and concentration), rate or type of chemical being injected downhole into the well. Information from the chemical injection apparatus relating to amount of chemical left in storage, chemical quality level and the like will also be sent to the control computers. The control computer may also base its control decision on input received from surface sensor 415 relating to the effectiveness of the chemical treatment on the produced fluid, the presence and concentration of any impurities or undesired by-products and the like. As noted above, the bottomhole sensors 410 may be distributed along the drill string 20 for monitoring the chemical content of the wellbore fluid as it travels up the wellbore at any number of locations.

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Alternatively a spectrometer may be utilized to monitor certain properties of downhole fluids. The sensor includes a glass or quartz probe, one end or tip of which is placed in contact with the fluid. Light supplied to the probe is refracted based on
5 the properties of the fluid. Spectral analysis of the refracted light is used to determine and monitor the properties of the wellbore fluid, which include the water, gas, oil and solid contents and the density.

It is known that infrared and near infrared light spectra can produce distinct
10 peaks for different types of chemicals in a fluid. In one embodiment of the present invention a spectroscopy device utilizing infrared or near infrared technique is utilized to detect the presence of certain chemicals, such as methane. The device contains a chamber which houses a fluid sample. Light passing through the fluid sample is detected and processed to determine the presence of the desired chemical.

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Figure 11 is a schematic illustration of an embodiment of an infrared sensor carried by the bottomhole assembly for determining properties of the wellbore fluid. The infrared device 500 is carried by a suitable section 501 of the drill string 502. The drilling fluid 31a supplied from the surface passes through the drill string interior
20 to the bottom of the borehole 502. The wellbore fluid 31b returning to the surface contains the drill cuttings and may contain the formation fluids. The optical sensing device 500 includes a broadband light source 510 (e.g. an incandescent lamp), an acousto-optical tunable filter (AOTF) based monochromator 512, one or more optical

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detectors 514 to detect the reflected radiation and one or more total reflectance (TR) crystal coupled to the monochromator 512 and the detectors 514 by optical fibers.

The monochromatic radiation with a wavelength defined by the monochromator 512 enters the TR crystal(s) 516 and is reflected by its surface which interfaces the high-pressure drilling fluid 316. Due to specific absorption properties the reflected radiation is attenuated at specified wavelengths which are characteristic for the analytes to be determined and evaluated. The reflected radiation intensity is measured by the detector(s) 514 which are connected to an onboard computer or processor 518, which serves for data acquisition, spectra analysis, and control of the AOTF proper operation (by means of a reference detector inside the monochromator). The more sophisticated analysis scheme includes one TR crystal mounted in a housing on the outside of the drilling tube and a second TR crystal mounted in a housing on the inside surface of the drilling tube. This configuration makes it possible to obtain the pure spectrum of the gas or liquid which is infused from the formation being drilled by subtracting the spectrum of the drilling liquid inside the tube from the spectrum of the liquid in the borehole outside the tube, which is a mixture of the drilling liquid with the influx from the formation. This method also is used to determine the weight or volume percent of analytes in the wellbore fluid.

In operation, broadband radiation from the light source enters the monochromator, where the AOTF (an acousto-optic crystal tuned by RF generator)

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selects narrow-width spectral bands at specified wavelengths which are characteristic for the chemical compounds to be determined and evaluated. This monochromatic radiation is delivered to one of at least two TR crystals, which are mounted in pockets on the interior and the exterior walls the drilling assembly by
5 optical fibers.

The monochromatic radiation with a wavelength defined by the monochromator enters the TR crystal and it is internally reflected by the surface, which interfaces the high-pressure drilling fluid. Due to specific absorption properties
10 of molecules of the analytes, radiation reflected by the interface is attenuated at the specific wavelengths by the magnitude which is characteristic of the quantity of the compound molecules in the fluid. The reflected radiation is delivered to a detector(s), which, in turn, is(are) connected to an onboard computer, which serves for data acquisition, spectra analysis, and control of the AOTF proper operation (by means of
15 a reference detector inside the monochromator).

20 This configuration allows to obtain quantity of substance (an analyte) of interest in the drilling fluid, and, also utilizing two TR crystals – the pure spectrum of the gas or liquid, which may infuse from the formation being drilled, by subtracting the spectrum of the drilling liquid inside the tube from the spectrum of the liquid in the borehole outside the tube. The last may be a mixture of the drilling liquid with the influx from the formation.

Some of the advantages of the above-described optical spectroscopic sensor

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are:

- Diamond or sapphire may be used as the internal reflection element. It eliminates problems associated with attack on the sensing element's surface in high-pressure and high-temperature environment. The probe combines the chemical and pressure resistance of diamond with the flexibility and photometric accuracy of spectral analysis required for measurements and on-line process control in harsh environment.
- The sensor is a multitask apparatus, which can easily be re-tuned for identification of any chemical substance of interest via software. Optical-IR spectroscopy offers the advantages of continuous real-time direct monitoring of all the functional molecular groups which characterize molecular structure of the fluid, and the determination of hydrocarbon and water mixtures physical properties.
- The TR sampling method is not sensitive to small particle admixtures and successfully operates in a turbid liquid.
- The sensor is an all-solid-state and rigid device without moving parts.

This invention also provides a method of detecting the presence and relative quantity of a various materials in the drilling fluid by utilizing what is referred herein as "tags." In this method, any material containing hydrogen atoms, such as aqueous-based fluids, lubricants added to the drilling fluid, and emulsion-based fluids, such as olefins and linear alpha olefins can be tagged at the surface prior to supplying the

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drilling fluid with such materials to the borehole. The material to be tagged is combined with a suitable material that will replace one or more hydrogen atoms of the material to be tagged such as deuterium. The altered material is referred to as the "tagged material." A known quantity of the tagged material is mixed with the drilling fluid at the surface. A detector designed to detect the tagged material is disposed the drill string 20, preferably in the drilling assembly 90. During drilling, the detector detects the presence and relative quantity of the tagged material downhole. Comparison of the downhole measurements and the known values mixed at the surface provide information about the changes in such materials due to the drilling activity. The downhole processor 70 coupled to the detector transmits the computed measurements to the surface. If the downhole measurement and the surface known values differ more than a predetermined value, the amount of such material is adjusted to maintain the downhole values within a desired range. Several materials may be tagged at any given time. A separate detector for each tagged material or a common detector that can detect more than one type of tagged material may be utilized to detect the tagged materials.

In addition to the above-noted sensors, the drilling assembly 90 of the present invention also may include one or more sample collection and analysis device. Such a device is utilized to collect samples to be retrieved to the surface during tripping of the drill bit or for performing sample analysis during drilling. Also, in some cases it is desirable to utilize a sensor in the drilling assembly for determining lubricity and transitivity of the drilling fluid. Electrical properties such as the resistivity and

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dielectric constant of the wellbore drilling fluid may be determined from the above-noted resistivity device or by any other suitable device. Drilling fluid resistivity and dielectric constant can provide information about the presence of hydrocarbons in water-based drilling fluids and of water in oil-based drilling fluids. Further, a high pressure liquid chromatographer packaged for use in the drill string and any suitable calorimeter may also be disposed in the drill string to measure chemical properties of the drilling fluid.

In the present invention, it is preferred that signals from the various above described sensors are processed downhole in one or more of the processors, such as processor 70 to determine a value of the corresponding parameters of interest. The computed parameters are then transmitted to the surface control unit 40 via the telemetry 72. The surface control unit 40 displays the parameters on display 42. If any of the parameters is outside its respective limits, the surface control unit activates the alarm 44 and/or shuts down the operation as dictated by programmed instructions provided to the surface control unit 40. The present invention provides in-situ measurements of a number of properties of the drilling fluid that are not usually computed downhole during the drilling operation. Such measurements are utilized substantially online to alter the properties of the drilling fluid and to take other corrective actions to perform drilling at enhanced rates of penetration and extended drilling tool life.

The foregoing description is directed to particular embodiments of the present

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invention for the purpose of illustration and explanation. It will be apparent, however, to one skilled in the art that many modifications and changes to the embodiment set forth above are possible without departing from the scope and the spirit of the invention. It is intended that the following claims be interpreted to

5 embrace all such modifications and changes.

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198**WHAT IS CLAIMED IS:**

- 1 1. A drilling system for use in drilling of a wellbore, said drilling system having a
2 source supplying drilling fluid under pressure to the wellbore, comprising:
 - 3 (a) a drill string having;
 - 4 (i) a tubing adapted to extend from the surface into the wellbore;
 - 5 (ii) a drilling assembly coupled to the tubing, said drilling assembly
6 having a drill bit at an end thereof for drilling the wellbore; and
 - 7 (b) a plurality of pressure sensors disposed in the drill string, at least one
8 sensor in said plurality of sensors being disposed in the drilling assembly
9 and the tubing for determining the pressure of the drilling fluid at spaced
0 locations in the wellbore during drilling of the wellbore.
- 1 2. The drilling system according to claim 1, wherein the pressure sensors in the
2 plurality of sensors are distributed in the drill string in a manner that provides a
3 pressure gradient of the drilling fluid over a selected segment of the wellbore.
- 1 3. The drilling system of claim 2 wherein the selected segment is one of (a) a
2 section extending along the wellbore, (b) a section circumferentially disposed along
3 the drill string.
- 1 4. The drilling system of claim 1 further comprising a plurality of temperature sensors
2 carried by the drill string providing a temperature gradient of the wellbore fluid during
3 drilling of the wellbore.

1 5. The drilling system of claim 4 further comprising a processor for determining
2 reservoir condition by utilizing measurements from said pressure and temperature
3 sensors.

1 6. A drilling system for use in drilling of a wellbore wherein a drilling fluid is
2 supplied under pressure to the wellbore during the drilling of the wellbore, said drilling
3 system comprising:

4 (a) a drill string having

5 (i) a tubing extending from a surface location into the wellbore;

6 (ii) a drilling assembly coupled to the tubing, said drilling assembly
7 having a drill bit at an end thereof for drilling the wellbore; and

8 (b) a plurality of temperature sensors disposed in the drill string for
9 providing a temperature gradient of the drilling fluid in the wellbore over
10 a selected section of the wellbore during drilling of the wellbore.

1 7. A drilling system for use in drilling of a wellbore wherein a drilling fluid is
2 supplied under pressure to the wellbore during the drilling of the wellbore, said drilling
3 system comprising:

4 (a) a drill string having

5 (i) a tubing extending from a surface location into the wellbore;

6 (ii) a drilling assembly coupled to the tubing, said drilling assembly
7 having a drill bit at an end thereof for drilling the wellbore; and

8 (b) a plurality of sensors carried by the drill string providing flow rate

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measurement of the drilling fluid within the drill string and in an annulus between the drill string and the wellbore;

- (c) a processor determining from said flow rate measurements accumulation of cuttings in the wellbore.

8. A drill string for use in drilling of a wellbore, said wellbore filled with a drilling fluid during drilling of the wellbore, comprising:

- (a) a tubing adapted to extend from the surface into the wellbore;
- (b) a drilling assembly coupled to the tubing, said drilling assembly having a drill bit at an end thereof for drilling the wellbore; and
- (c) a sensor carried by the drill string for determining a property of the drilling fluid downhole during the drilling of the wellbore, said sensor selected from a group of sensors consisting of (i) a sensor for determining density of a fluid sample; (ii) an acoustic sensor for determining density of the drilling fluid flowing through an annulus; (iii) an acoustic sensor for determining characteristics of cuttings in the drilling fluid; (iv) a sensor for determining viscosity of the drilling fluid; (v) a sensor for determining lubricity; (vi) a sensor for determining compressibility; (vii) a sensor for determining clarity of the drilling fluid; (viii) a sol-gel device for determining chemical composition of the drilling fluid; (ix) a fiber-optic sensor for determining a chemical property of the drilling fluid; (x) a spectrometer for determining a selected parameter of the drilling fluid; (xi) a sensor adapted to measure force required by a member to move over said drilling fluid; and (xii) a sensor for

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20 determining influx of the formation fluid into the wellbore.

1 9. A method of determining the relative amount of a component material of a
2 drilling fluid supplied from a surface source to a wellbore at a downhole location
3 during the drilling of said wellbore, comprising:

4 (a) tagging a known quantity of the component material prior to adding said
5 component material into the drilling fluid;

6 (b) adding the known quantity of the tagged component material to the
7 drilling fluid and supplying said drilling fluid with the tagged component
8 material to the wellbore during the drilling of the wellbore; and

9 (c) taking measurements downhole of a parameter representative of the
10 relative amount of the tagged component material in the drilling fluid by
11 a sensor disposed in the wellbore.

1 10. The method of claim 9, wherein the chemical structure of the component
2 material includes a hydrogen atom.

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1 11 The method of claim 9 further comprising processing said measurements to
2 determine the relative amount of the tagged material in the wellbore.

12. The method of claim 11 wherein said processing is done at least in part
2 downhole.

1 13. The method of claim 11 further comprising determining the difference between

2 the relative amount of the tagged component material determined from the downhole
3 measurements and the relative amount of the tagged material added at the surface
4 and adjusting the amount of such component material added to the drilling fluid
5 untagged if said difference is greater than a predetermined value.

1 14. A system for monitoring a parameter of interest of a drilling fluid in a wellbore
2 during drilling of the wellbore, comprising:

- 3 (a) a downhole tool for use in the drilling of the wellbore; and
4 (a) a spectrometric device carried by the downhole tool, said spectrometric
5 device comprising:
6 - an energy source supplying a selected form of energy;
7 - at least one sensing element exposed to the drilling fluid, said
8 sensing element providing signals responsive to the supplied
9 energy representative of the parameter of interest; and
10 - a spectrometer for processing the signals from the sensing
11 element to determine the parameter of interest.

1 15. The system of claim 14 wherein the parameter of interest is one of (a)
2 presence of a hydrocarbon of interest in the drilling fluid, (b) presence of water in the
3 drilling fluid, (c) amount of solids in the drilling fluid, (d) density of the drilling fluid, (e)
composition of the drilling fluid downhole, (f) pH of the drilling fluid, and (g) presence
5 of H₂S in the drilling fluid.

1 16. The system of claim 14 wherein the selected energy is one of visible light,

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2 infrared, near infrared, ultraviolet, radio frequency, electromagnetic energy, and
3 nuclear energy.

1 17. The system of claim 14 wherein the at least one sensing element includes at
2 least two sensing elements for determining the parameter of interest of the drilling
3 fluid in the downhole tool and in an annulus between the downhole tool and the
4 wellbore.

1 18. A downhole tool for use in drilling of a wellbore containing drilling fluid during
2 the drilling of said wellbore, said downhole tool comprising at least one fiber optic
3 sensor providing measurements for an operating parameter of the drilling fluid during
4 the drilling of the wellbore, said sensor being one of (i) a chemical sensor, (ii) a
5 radiation spectrometer, (iii) a flow rate sensor, (iv) a plurality of spaced apart pressure
6 sensors for providing pressure gradient along a selected section of the wellbore, and
7 (v) a plurality of temperature sensors providing temperature gradient of the wellbore
8 fluid along a selected section of the wellbore.

1 19. The downhole tool of claim 18 wherein the at least one fiber optic sensor
2 includes a set of sensors and, said downhole tool further comprising a processor
3 associated with the downhole tool multiplexes between such sensors according to
4 programmed instructions provided to the processor to obtain measurements of the
5 desired parameters of interest.

1 20. A downhole tool for use in drilling a wellbore wherein a drilling fluid circulates

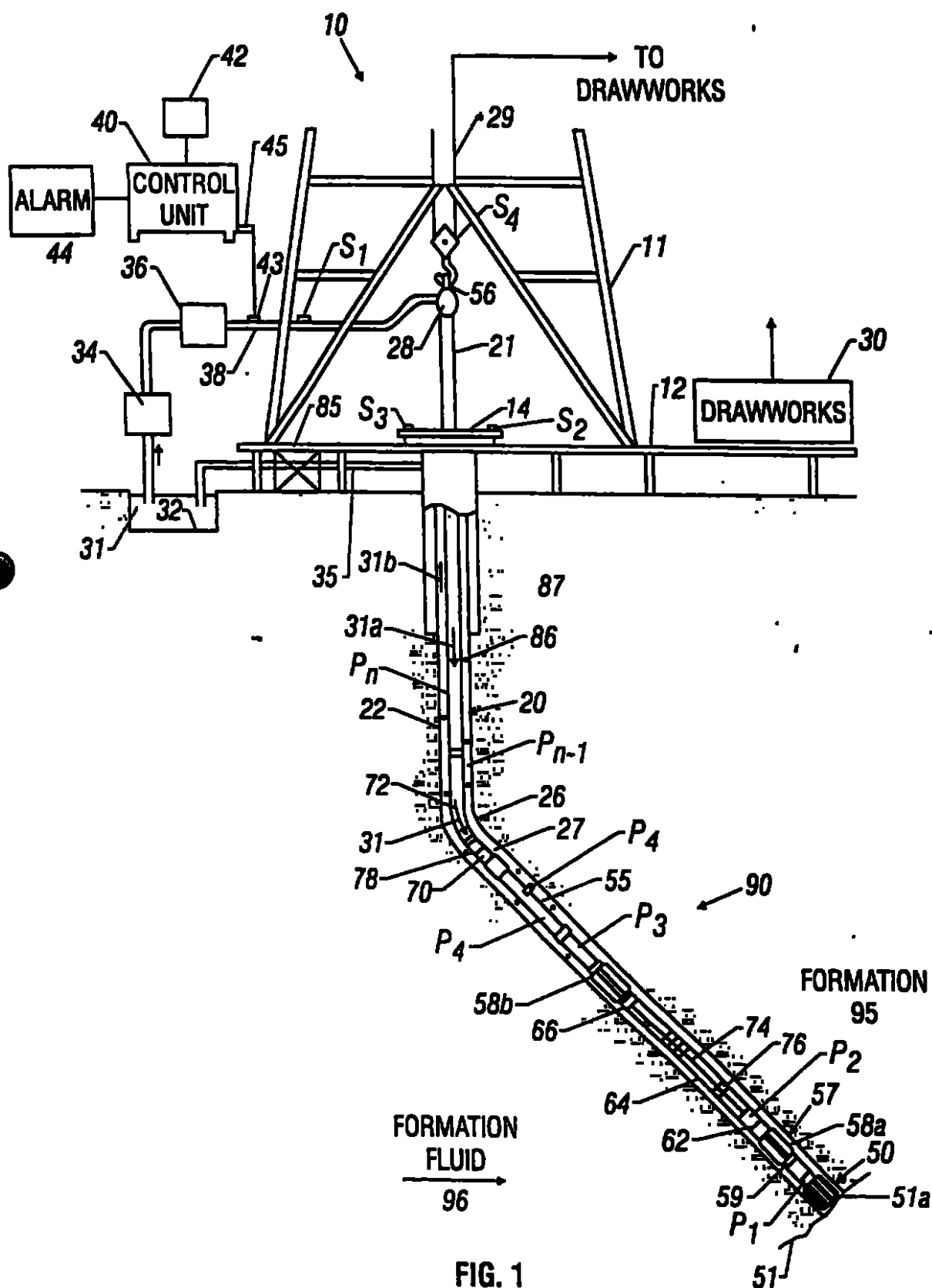
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2 through the wellbore during drilling of said wellbore, comprising:

3 (a) a bottomhole assembly carrying a plurality of sensors; and

4 (b) a fluid viscosity measuring device carried by the bottomhole assembly,
5 said viscosity measuring device providing measurements indicative of
6 the viscosity of the drilling fluid during drilling of the wellbore.

1 21. The downhole tool of claim 20 wherein the viscosity measuring device includes
2 a pair of plates that receive a sample of the drilling fluid therebetween and provide a
3 measure of the viscosity when said plates are moved relative to each other.



SUBSTITUTE SHEET (RULE 26)

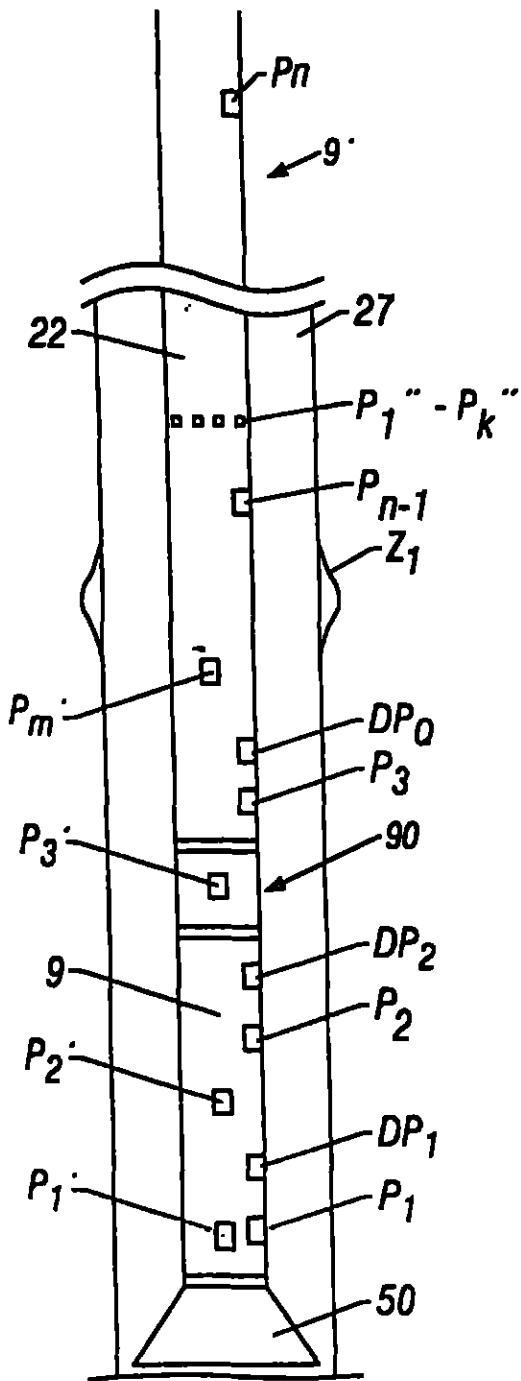


FIG. 2A

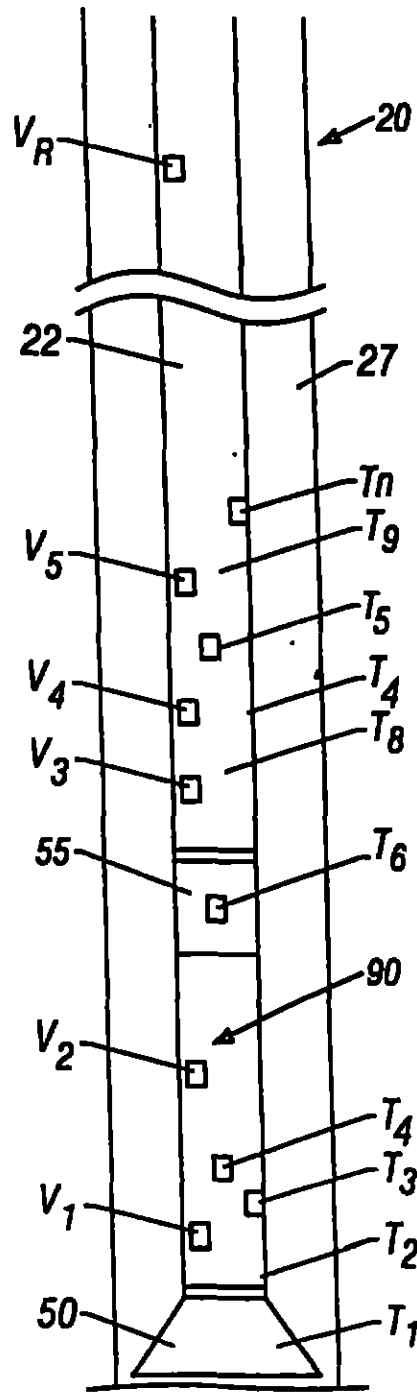


FIG. 2B

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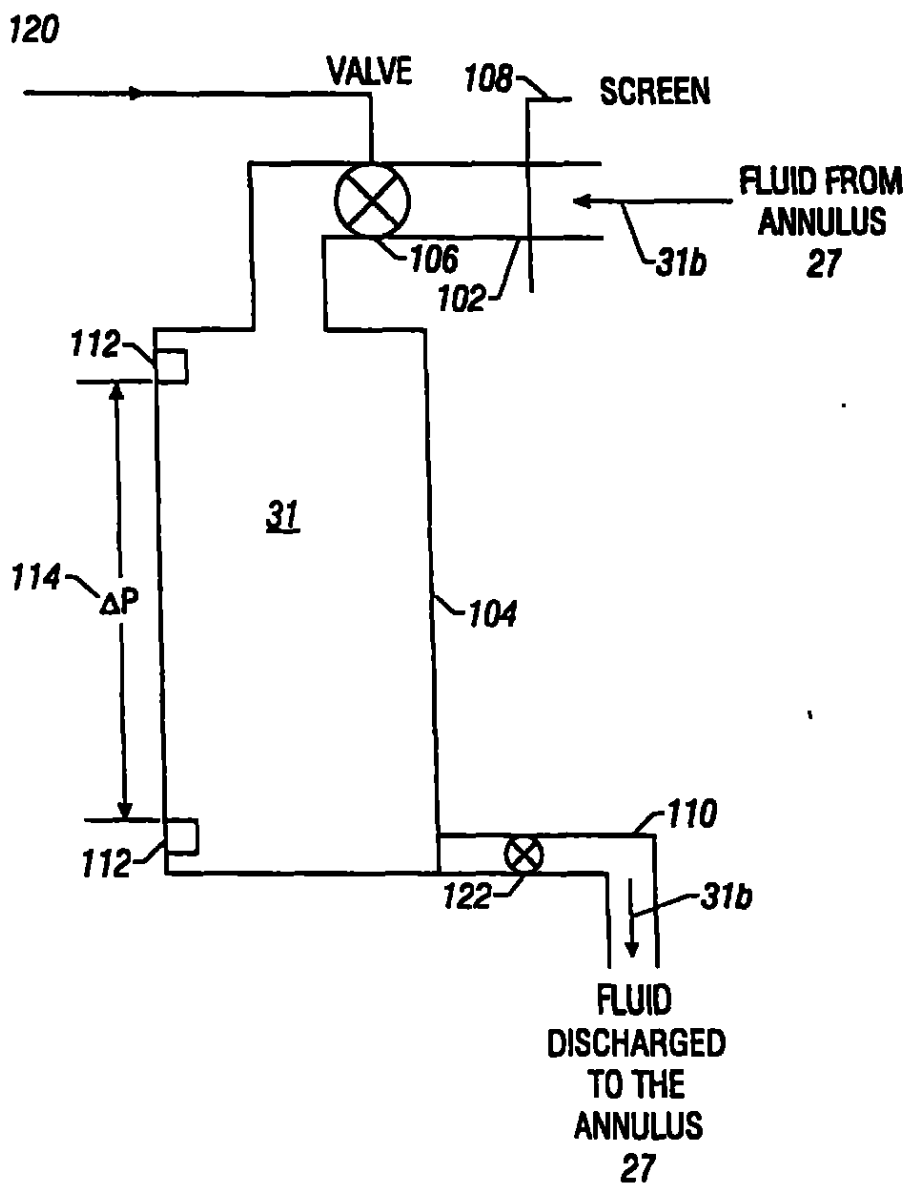


FIG. 3

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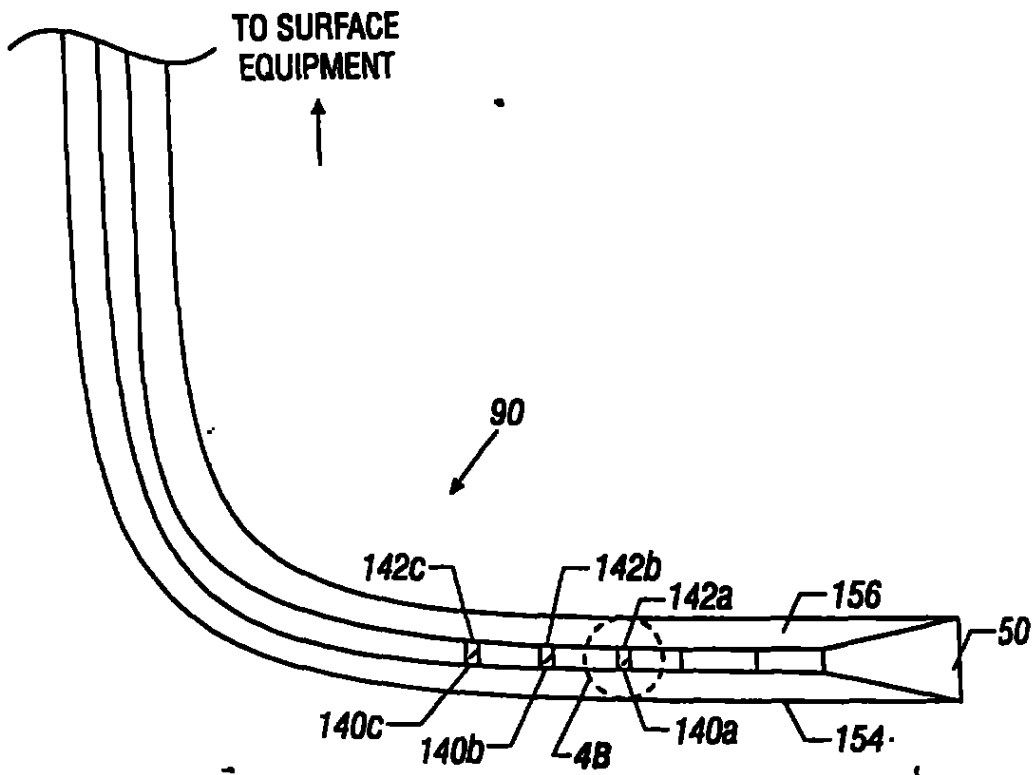


FIG. 4

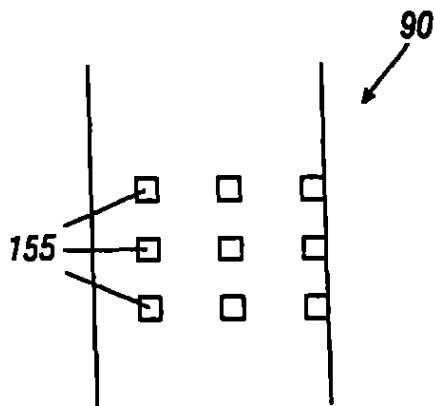


FIG. 4A

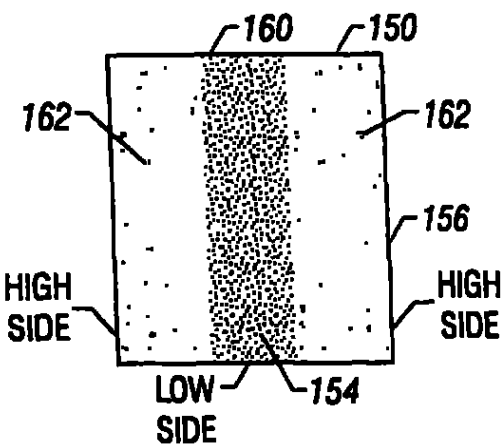


FIG. 4B

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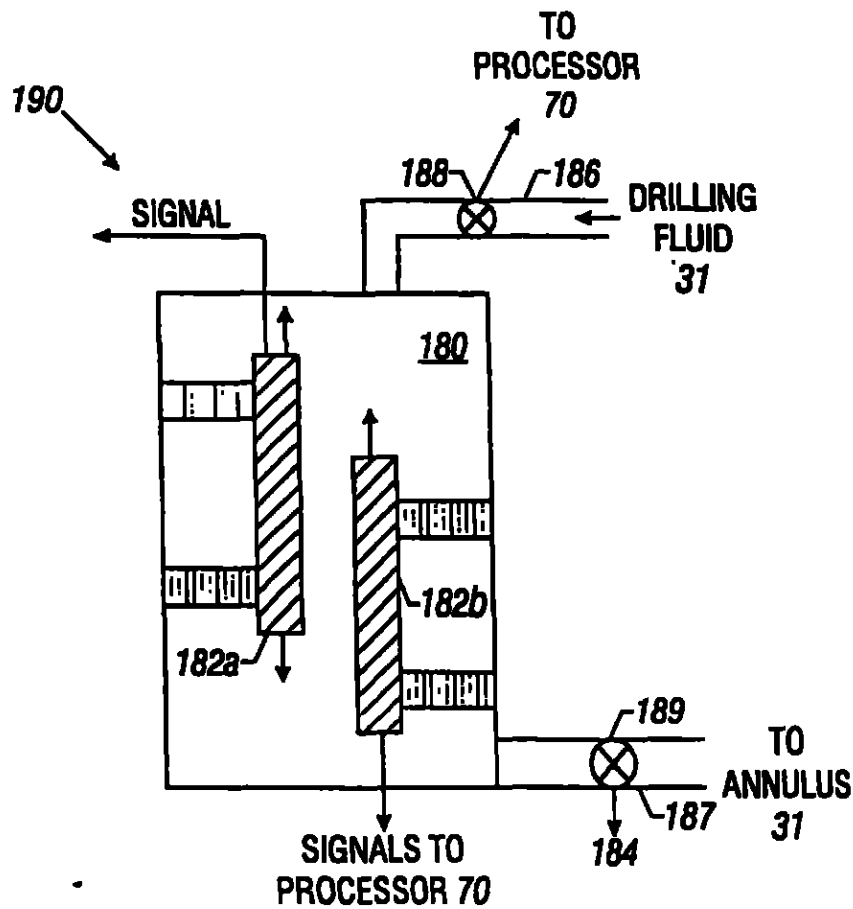


FIG. 5

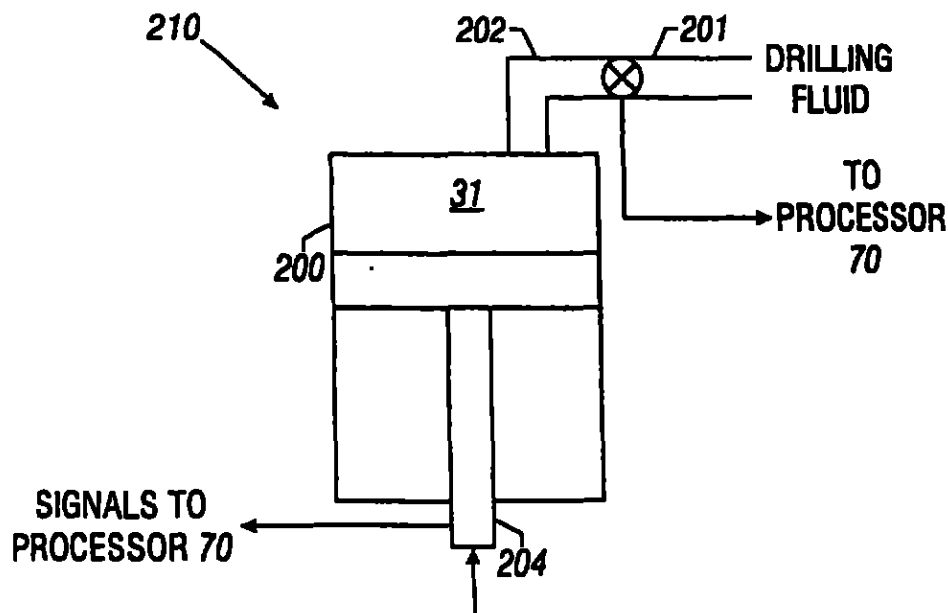
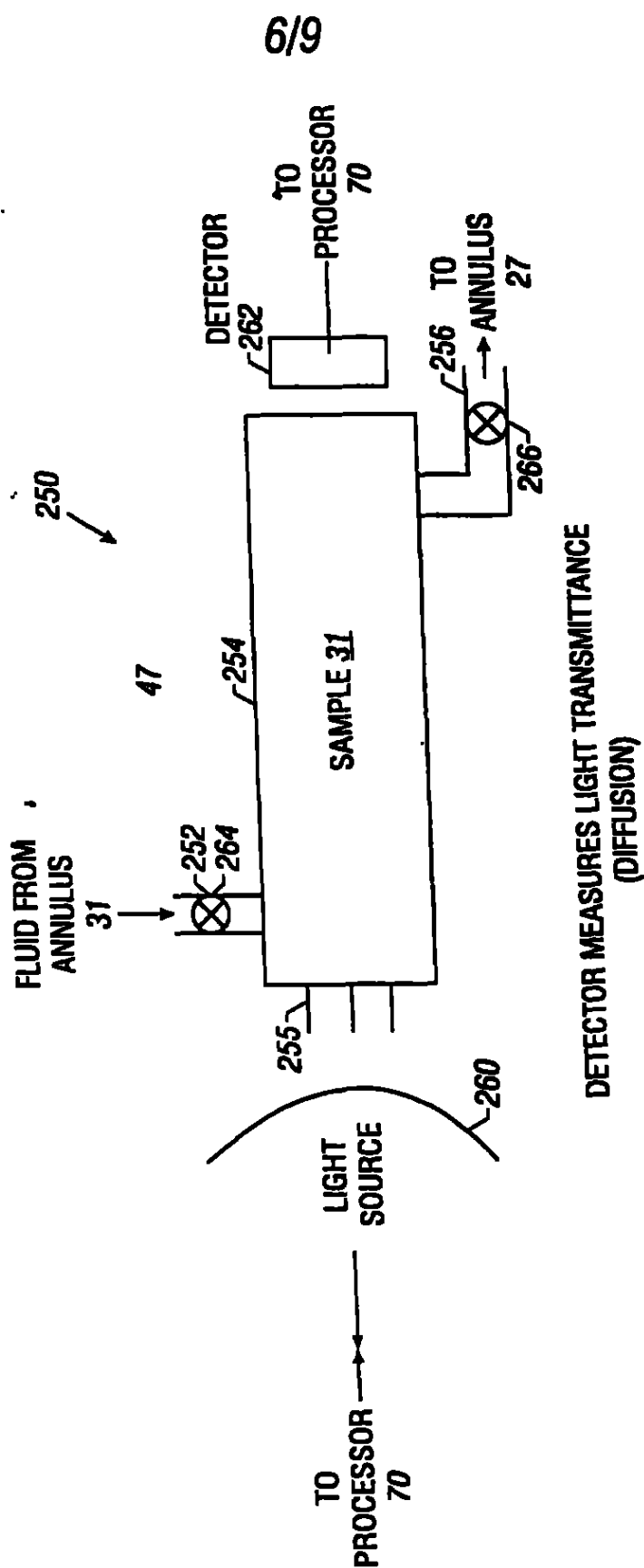


FIG. 6
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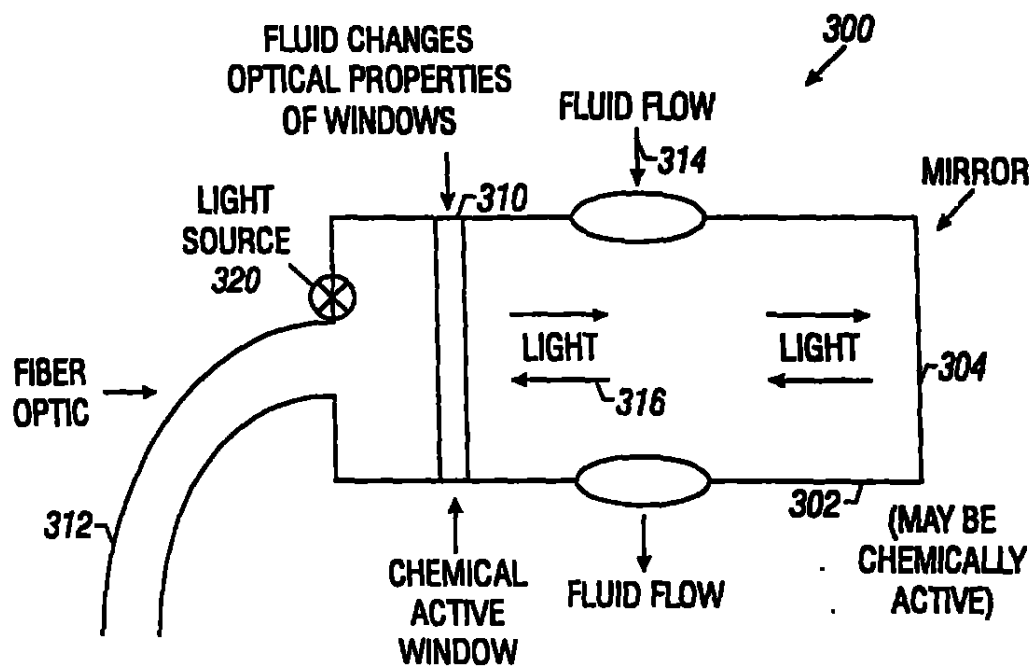


FIG. 8

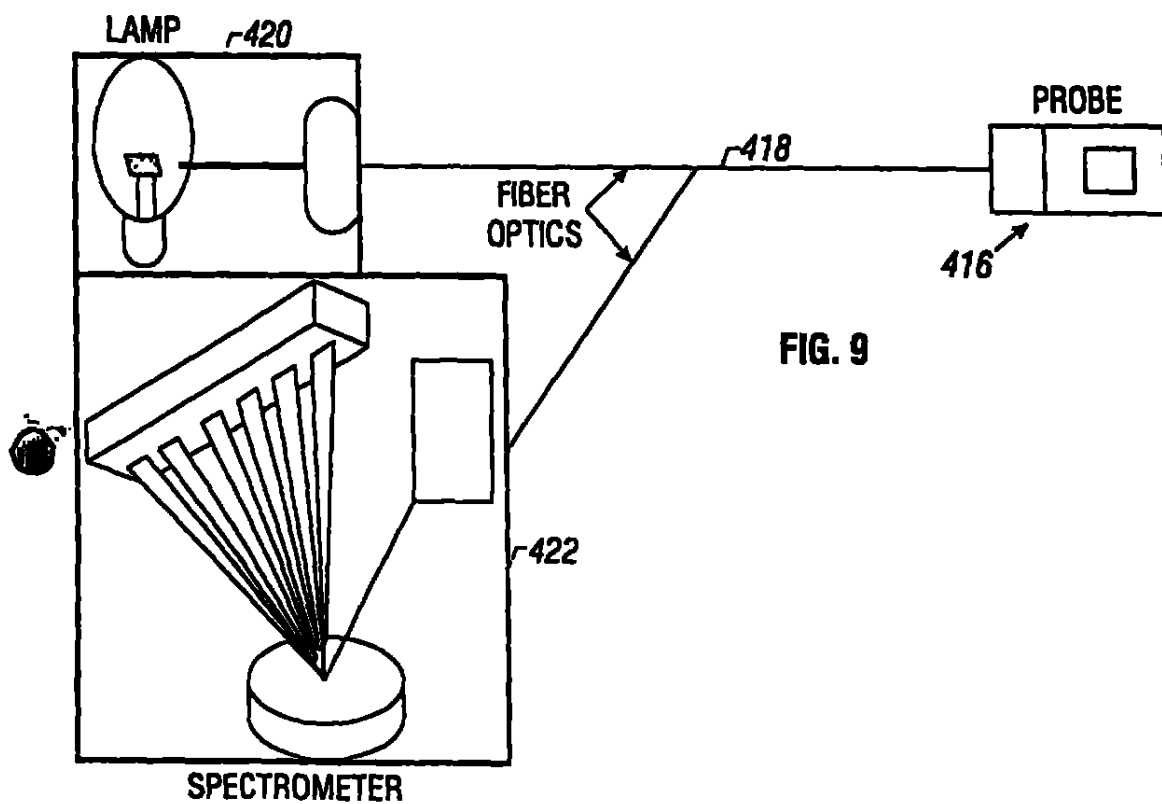


FIG. 9

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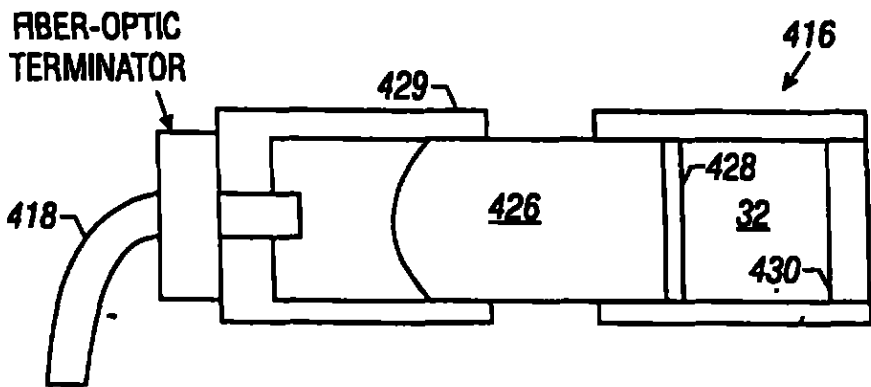


FIG. 10

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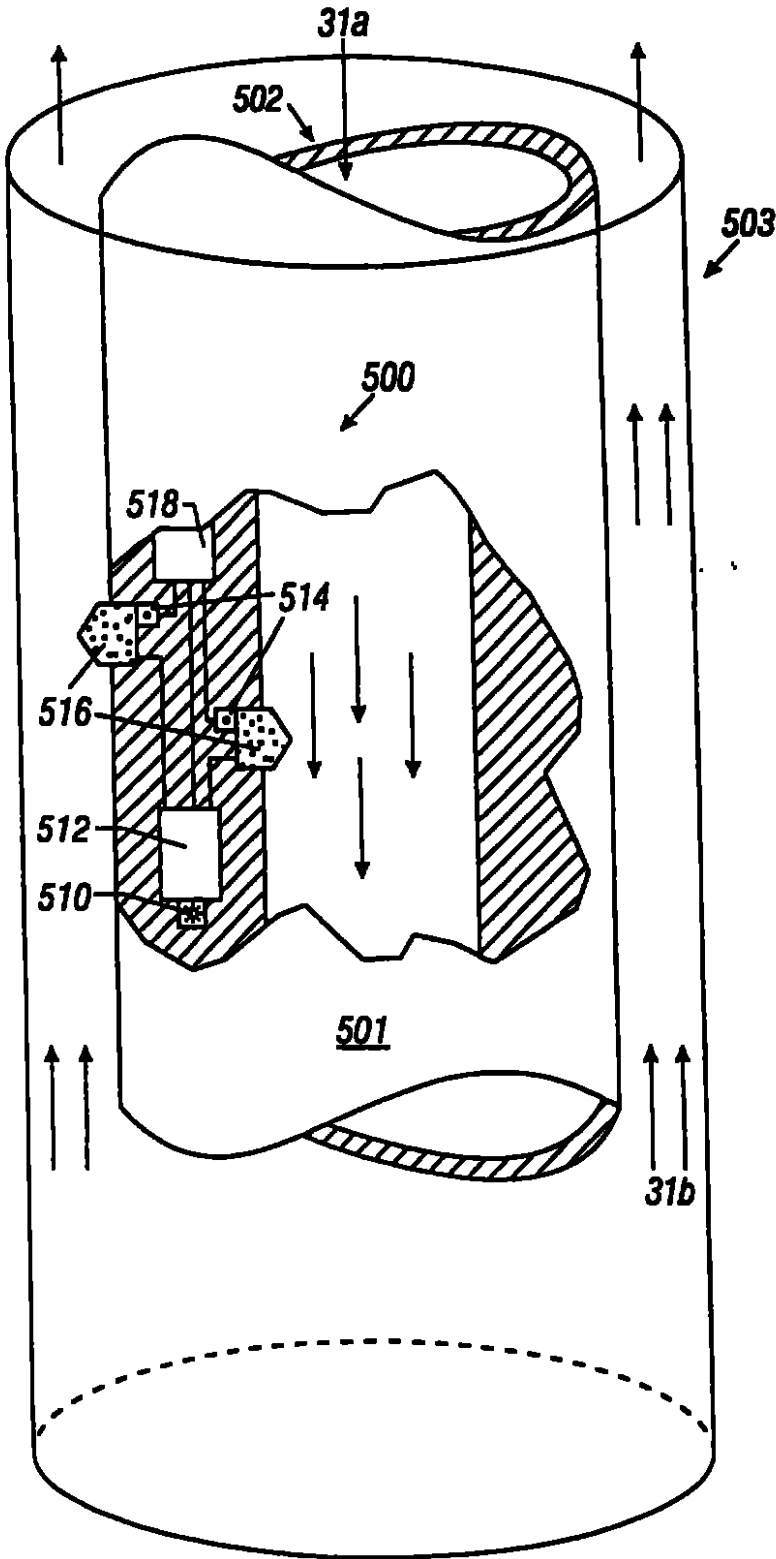


FIG. 11

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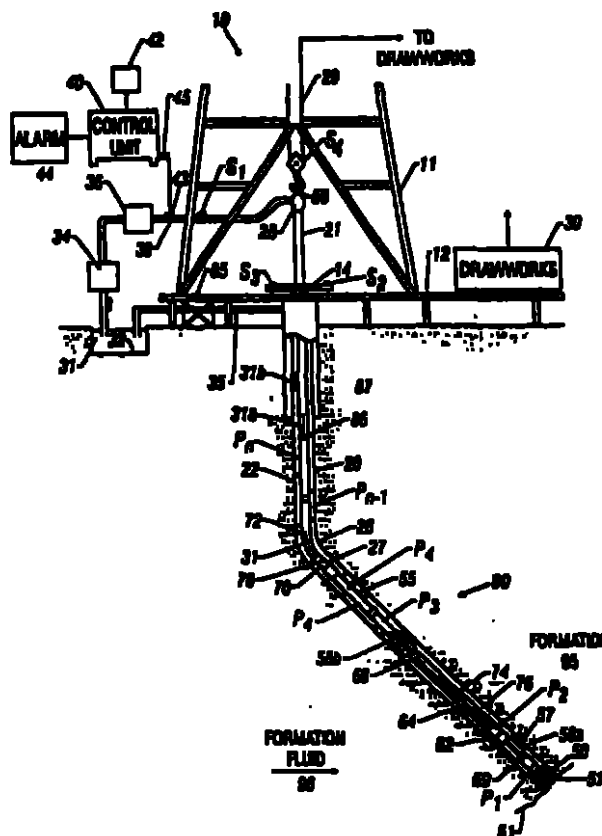
INTERNATIONAL APPLICATION PUBLISHED UNDER THE PATENT COOPERATION TREATY (PCT)

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(22) International Filing Date: 26 June 1998 (26.06.98)		Published With international search report.	
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(74) Agents: ROWOLD, Carl, A. et al.; Baker Hughes Incorporated, Suite 1200, 3900 Essex Lane, Houston, TX 77027 (US).			

(54) Title: DRILLING SYSTEM WITH SENSORS FOR DETERMINING PROPERTIES OF DRILLING FLUID DOWNHOLE

(57) Abstract

The present invention provides a drilling system for drilling oilfield boreholes or wellbores utilizing a drill string having a drilling assembly conveyed downhole by a tubing (usually a drill pipe or coiled tubing). The drilling assembly includes a bottom hole assembly (BHA) and a drill bit. The bottom hole assembly preferably contains commonly used measurement-while-drilling sensors. The drill string also contains a variety of sensors for determining downhole various properties of the drilling fluid. Sensors are provided to determine density, viscosity, flow rate, clarity, compressibility, pressure and temperature of the drilling fluid at one or more downhole locations. Chemical detection sensors for detecting the presence of gas (methane) and H_2S are disposed in the drilling assembly. Sensors for determining fluid density, viscosity, pH, solid content, fluid clarity, fluid compressibility, and a spectroscopy sensor are also disposed in the BHA. Data from such sensors may be processed downhole and/or at the surface. Corrective actions are taken based upon the downhole measurements at the surface which may require altering the drilling fluid composition, altering the drilling fluid pump rate or shutting down the operation to clean wellbore. The drilling system contains one or more models, which may be stored in memory downhole or at the surface. These models are utilized by the downhole processor and the surface computer to determine desired fluid parameters for continued drilling. The drilling system is dynamic, in that the downhole fluid sensor data is utilized to update models and algorithms during drilling of the wellbore and the updated models are then utilized for continued drilling operations.



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INTERNATIONAL SEARCH REPORT

International Application No

PCT/US 98/13119

A. CLASSIFICATION OF SUBJECT MATTER

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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 6 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)

C. DOCUMENTS CONSIDERED TO BE RELEVANT

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☒ Further documents are listed in the continuation of box C☒ Patent family members are listed in annex

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Date of the actual completion of the international search

4 February 1999

Date of mailing of the international search report

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Internat'l Application No.

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INTERNATIONAL SEARCH REPORT

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FURTHER INFORMATION CONTINUED FROM PCT/ISA/ 210

This International Searching Authority found multiple (groups of) inventions in this international application, as follows:

1. Claims: 1-6

Drilling system comprising a plurality of pressure sensors, further a drilling system comprising a plurality of temperature sensors.

2. Claims: 7,8,18,19

Drilling system comprising one or plural sensors providing flow rate measurement, further a drilling system including a fiber optic sensor.

3. Claims: 9-13

Method of determining the relative amount of a component material of a drilling fluid, comprising tagging said component.

4. Claims: 14-17

System for monitoring a parameter of interest of a drilling fluid, comprising a spectrometric device.

5. Claims: 20,21

Downhole drilling tool comprising a fluid viscosity measuring device.

INTERNATIONAL SEARCH REPORT

Information on patent family members

Int. Application No.
PCT/US 98/13119

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12 April 2001 (12.04.2001)

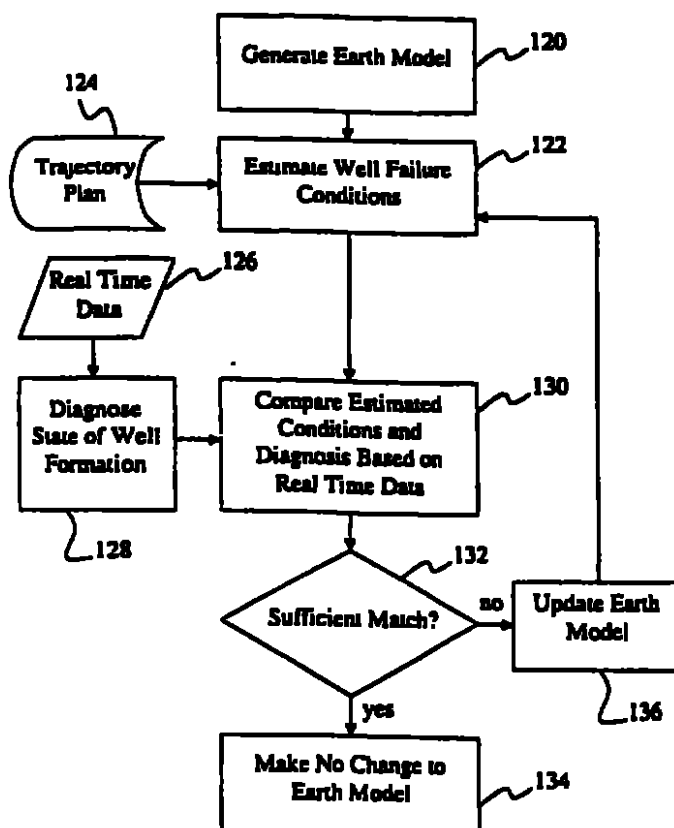
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- (51) International Patent Classification⁷: G01V 11/00 (71) Applicant (for CA only): SCHLUMBERGER CANADA LIMITED [CA/CA]: Monrovia Place, 24th Floor, 801 6th Avenue, S.W., Calgary, Alberta T2P 3W2 (CA).
- (21) International Application Number: PCT/GB00/03704
- (22) International Filing Date: 27 September 2000 (27.09.2000) (71) Applicant (for FR only): SERVICES PETROLIERS SCHLUMBERGER [FR/FR]: 42, rue Saint Dominique, F-75007 Paris (FR).
- (23) Filing Language: English (71) Applicant (for NL only): SCHLUMBERGER TECHNOLOGY B.V. [NL/NL]: Parkstraat 83-89, NL-2514 JG The Hague (NL).
- (26) Publication Language: English
- (30) Priority Data: 9923290.2 1 October 1999 (01.10.1999) GB (72) Inventors; and (75) Inventors/Applicants (for US only): BRADFORD, Ian [GB/GB]; 66 Caribou Way, Cherry Hinton, Cambridge, Cambridgeshire CB1 9XG (GB). COOK, John, Mervyn [GB/GB]; 4 Ginton Road, Cambridge CB3 0LJ (GB). FULLER, John [GB/GB]; School House, Bentley, Farnham, Surrey GU10 5JP (GB). ALDRED, Walter, David
- (71) Applicant (for all designated States except CA, FR, MX, US): SCHLUMBERGER HOLDINGS LIMITED (—/—): Craigmuir Chambers, Road Town, P.O. Box 71, Tortola (VG).

[Continued on next page]

(54) Title: METHOD FOR UPDATING AN EARTH MODEL USING MEASUREMENTS GATHERED DURING BOREHOLE CONSTRUCTION



(57) Abstract: A method and system for real time updating of an earth model are disclosed. The efficiency with which an oil or gas well is constructed can be enhanced by updating the relevant earth model using real-time measurements of the effective density of the drilling fluid and other parameters. The disclosed method includes generating an earth model used for predicting potential problems in drilling of a borehole having a predetermined trajectory. Evaluations of the state of the borehole and local geological features are obtained which are based on the earth model. Real time data is used to create a diagnosis of the state of the borehole and local geological features. The evaluations are compared with a diagnosis to identify inconsistencies. A component of the earth model is identified that is both related to the identified inconsistency and has a high degree of uncertainty. The selected component of the earth model is then updated prior to completing construction of the borehole using the received data.

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Method for Updating an Earth Model Using
Measurements Gathered During Borehole Construction

FIELD OF THE INVENTION:

- 5 The present invention relates to the field of drilling oil and gas wells. In particular, the invention relates to a method for updating an earth model during construction of the well.

10 BACKGROUND OF THE INVENTION:

- Earth models contain data which characterise the properties of, and surfaces bounding, the geological features which form the earth's sub-surface, such as rock formations and faults. They are used to
15 assist operations occurring in the earth's sub-surface, such as the drilling of an oil or gas well, or the development of a mine.

- The domain of applicability of an earth model varies greatly and should be considered on a case by
20 case basis. Some earth models are applicable only in the near vicinity of a particular oil or gas well, or mine. Others may be valid for an entire oil or gas field, or perhaps even over a region such as the North Sea or Gulf of Mexico.

- 25 The data in an earth model consists of measurements gathered during activities such as the seismic, logging or drilling operations of the oil and gas industry, and of interpretations made from these measurements. The data may be gathered above, on, or
30 below the earth's surface.

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As the duration or number of sub-surface operations increases, more data is gathered. This data can be used to amend the relevant earth model, with the aim that it should characterise the geology and properties ever more accurately. Clearly, it will be conducive to the efficiency of these operations if amendments which enhance the accuracy of the earth model are made as quickly as possible, or appropriate.

The oil and gas industry's traditional approach to amending earth models has not had a real-time element, apart from using formation integrity, leak-off or extended leak-off tests, or equivalent circulating density (ECD) data in the case of drilling fluid (commonly referred to as 'mud') loss while drilling, to constrain the minimum principal in-situ stress. See e.g., Addis et al., 'A comparison of leak-off test and extended leak-off test data for stress estimation', paper SPE/ISRM 47235 presented at the 1998 Eurock Rock Mechanics in Petroleum Engineering Conference, Trondheim, July 8-10 (hereinafter 'Addis et al., 1998'). Measurement-while drilling (MWD) data, logging-while drilling (LWD) data, wireline logs, results from tests performed on core, drilling experience and perhaps other information are used to amend the relevant earth model using techniques identical to those used to generate the original version of the earth model. An example of these conventional techniques are described in a publication by Schlumberger Educational Services entitled 'Log interpretation principles/applications', Houston, Texas

(1987), incorporated herein by reference and hereinafter referred to as "(Schlumberger, 1987)".

This traditional approach has been enhanced in order to improve the handling of very severe wellbore instability problems in the Cusiana field in Colombia. See, Last, N., Plumb, R.A., Harkness, R., Charlez, P., Alsen, J. and McLean, M.: 'An integrated approach to evaluating and managing wellbore instability in the Cusiana field, Colombia, South America', paper SPE 30464 presented at the 1995 Annual SPE Technical Conference, Dallas Oct. 22-25, incorporated herein by reference and hereinafter "Last et al. (1995)". Last describes an integrated approach to evaluating and managing wellbore instability. An earth model was constructed using data from existing wells, together with results obtained using a computational analysis tool which modelled the geological structure and the in-situ stress state. This allowed the upper and lower bounds to the drilling fluid density to be estimated, provided that the well trajectory was specified, using standard techniques.

As a well was drilled, a data acquisition programme which included cavings monitoring and measurements-while-drilling allowed the failure mechanisms of the rock formations to be characterised and as well as the identification and implementation of appropriate drilling practices. This led to faster, more efficient, well construction. The earth model was updated after a well or hole section had been completed using all available data, particularly (a) downhole images of borehole geometry, fractures, faults and

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bedding, (b) stress measurements such as extended leak-off tests, (c) results from tests made on core, and (d) four-arm calliper logs, where available. Measurement-while-drilling techniques were used to characterise
5 time-dependent hole geometry in particular hole intervals.

The approach of Last et al. (1995) enhanced the analysis of formation instability that can be made while drilling, with the minimum horizontal stress also
10 being updated in real-time. The understanding of the nature of the formation instability led to improved drilling practices allowing the wells they studied to be constructed much more efficiently.

However, the approach of Last et al. (1995)
15 has many limitations, including the following. First, no constitutive parameter or component of the in-situ stress state, other than the minimum principal stress, was updated in real-time. Such parameters were updated after drilling had been completed, using measurements
20 made by wireline tools, in addition to the data gathered in real-time. Second, LWD measurements, such as resistivity and sonic, were not extensively used. This inhibited the diagnosis of the instability mechanisms. Due to these limitations, it was not
25 possible to quantify amendments to drilling practices, apart from updating the value of ECD above which drilling fluid is lost to the formation.

SUMMARY OF THE INVENTION:

30 Thus, it is an object of the present invention to provide a method to increase the

efficiency with which an oil or gas well can be constructed.

It is a further object of the present invention to provide a method in which amendments that
5 enhance the accuracy of the earth model are made quickly and efficiently.

It is a further object of the present invention where one or more inconsistencies are identified to provide a method of selecting which
10 component or components of an earth model to update.

According to the present invention the efficiency with which an oil or gas well is constructed can be enhanced by updating the relevant earth model using real-time measurements of the effective density
15 of the drilling fluid and at least one other parameter. Updating the earth model need not occur on a continuous basis, but on a timescale appropriate to this construction process. As used herein the term "real-time" is defined to mean as the well or borehole is
20 being constructed. That is, the data acquisition can occur continuously (e.g. measurement while drilling data), or at discrete times (e.g. palaeontological analysis of rock carried by the drilling fluid from the wellbore) and still be considered "real-time".

25 A method for updating an earth model is provided that includes obtaining an earth model used for predicting potential problems in drilling of a borehole having a predetermined trajectory. Evaluations of the state of the borehole and local
30 geological features are obtained which are based on the earth model. Data is received that has been gathered

during the construction of the borehole. The evaluations are compared with a diagnosis of the state of the borehole and local geological features to identify at least one inconsistency. A component of the earth model is identified that is both related to the identified inconsistency and has a high degree of uncertainty. The selected component of the earth model is then updated prior to completing construction of the borehole using the received data.

10 Preferably, the evaluations of the state of the borehole and local geological features are predictions of one or more conditions under which the borehole will fail, and they are obtained by combining the earth model with the predetermined trajectory of the borehole.

15 Preferably, the process is repeated until a sufficient match exists between the predicted failure conditions and the diagnoses of the borehole.

20 Preferably, the earth model component that will be updated is selected by first identifying components of the earth model that are relevant to the identified inconsistency and then ranking the identified components according to the degree of uncertainty. The component selected is preferably updated using the minimum changes needed to eliminate an identified inconsistency.

25 Preferably, the received data includes the effective density of the drilling fluid used in the construction of the borehole and one at least other parameter, and the selected component is updated by

using the effective density and at least one other parameter.

The invention is also embodied in a method for drilling a borehole using an earth model that is updated according to the invention. The invention is also embodied in a computer readable medium that is capable of causing a computer to update the earth model according to the invention.

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BRIEF DESCRIPTION OF THE DRAWINGS:

Figure 1 illustrates the construction of a borehole according to a preferred embodiment of the invention;

Figure 2 shows a flow chart of a method of updating an earth model, according to a preferred embodiment of the invention;

Figures 3a and 3b show examples of angular cavings that have become detached from the wellbore wall when breakouts occur;

Figure 4 is a schematic representation of breakouts and drilling induced fractures in a vertical well embedded in an isotropic rock formation;

Figure 5 is a flow chart illustrating in greater detail the preferred method of updating the earth model according to the present invention;

Figure 6 illustrates an example of the minimum principal in-situ stress in an earth model;

Figure 7 illustrates an example of the mud window estimated prior to drilling a well;

Figure 8 illustrates an example of drilling hazards derived from an analysis of experience drilling offset wells and the well trajectory shown in Figure 9;

Figure 9 illustrates the trajectory of the
5 well used in the examples of Figures 6-11;

Figure 10 illustrates the in-situ stress state prior to drilling the well used in Figures 6-11; and

Figure 11 illustrates an example of the
10 formation strength in the example of figure 6-11.

DETAILED DESCRIPTION OF THE INVENTION:

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The present invention advantageously increases efficiency with which an oil or gas well is constructed by updating the relevant earth model using real-time measurements. Preferably, the real-time
20 measurements are ECD and at least one other parameter, which can gathered using common commercially available methods. For example, the ECD data may be obtained using such as Schlumberger's Annular Pressure While Drilling APWD measurements. See e.g., Schlumberger
25 Oilfield Review: 'Using Downhole Annular Pressure Measurements to Improve Drilling Performance', Sugar-Land, Texas, Winter 1998 incorporated herein by reference and hereinafter referred to as "Schlumberger (1998)".

30

Figure 1 illustrates the construction of a borehole according to a preferred embodiment of the

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invention. Borehole 102 is being drilled into Earth 100. Rig 104 is located at the surface and is used to support the drilling operation. Drill bit 110 is located at the bottom of the borehole and is connected to the rig via drill string 106. Also shown is a LWD or MWD tool 108 that is capable of making measurements during the drilling operation. The dashed line 114 shows the planned borehole trajectory. Offset well 116 is also shown, along with rig 118. Although in the example of Figure 1 the boreholes are shown being drilled on land, the invention is also applicable to offshore drilling operations. Control station 112 is shown schematically, and contains one or more computers that are used to store the earth model, receive measurements from the downhole tools, and update the earth model according to the preferred embodiments described herein. The control station 112 is shown to be located near the rig 104, however in general the control station can be located remotely. Alternatively, some portions of the control station could be located remotely while other portions are located near to the borehole.

Figure 2 shows a flow chart of a method of updating an earth model, according to a preferred embodiment of the invention. In step 120, prior to drilling a well and applying the invention, an earth model is generated with seismic, logging and offset well data using techniques which are publicly documented (See, e.g., Last et al. (1995), Schlumberger, 1987). The data contained in the earth model is defined herein as the "components" of the

earth model. The types of data or components contained in an earth model typically consists of: (1) Surfaces bounding geological features, (2) Constitutive parameters of the rock. These describe the mechanical response of rock under load, (3) Stress state and pore pressure, (4) Nature and severity of the drilling hazards associated with each geological feature and/or trajectory. The drilling hazards are categorised from a list which includes hole cleaning, sloughing, chemical activity, undergauge hole, interbedded sequences, faults, naturally fractured formations, formations with weak planes, mobile formations and permeable formations (this list is not exhaustive and further categories can be envisaged), and (5) Any other parameter that may prove to be useful for real-time analysis, such as gamma-ray measurements which characterise the radioactive nature of a formation.

In step 122, the earth model is combined with the planned well trajectory 124, in order to estimate the upper and lower bounds to the drilling fluid density, together with the drilling hazards and their severity at discrete points along the trajectory. Step 122 may be accomplished using standard techniques, such as those outlined in Fjaer, E., Holt, R.M., Horsrud, P., Raaen, A.M., and Risnes, R.: 'Petroleum Related Rock Mechanics', Elsevier, Amsterdam (1992), incorporated herein by reference and hereinafter referred to as "Fjaer et al. (1992)." More sophisticated analyses could also be used which may involve concepts such as elastoplastic modelling. See e.g. Bradford, I.D.R., Fuller, J.A., Thompson, P.J.,

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and Walsgrove, T.R.: 'Benefits of assessing the solids production risk in a North Sea reservoir using elastoplastic modelling', paper SPE/ISRM 47360 presented at the 1998 Eurock Rock Mechanics in
5 Petroleum Engineering Conference, Trondheim, July 8-10 Incorporated herein by reference and hereinafter referred to as "Bradford et al., (1998)." Although the earth model is shown to be generated in step 120 and the estimations performed in step 122, the earth model
10 and the estimates could be obtained through other means such as receiving them from an outside service provider.

As the well is being drilled, the nature and severity of instability mechanisms, together with the
15 conditions under which they occur, are identified, or diagnosed, in step 128. The extent of any instability, which is defined as the length of wellbore over which formation failure is occurring, may also be determined. The diagnosis of step 128 can be carried out by the
20 method disclosed in Last et al. (1995). However, a more extensive use of real-time MWD and LWD measurements is preferably used for the diagnosis.

According to a preferred embodiment, in step 128, diagnosing the nature, severity and extent of
25 wellbore instability mechanisms should include the following considerations.

1. There should be sufficient familiarity, prior to commencing operations, with the upper and lower bounds of the drilling fluid density (these
30 define the "mud window") and the anticipated severity of any instabilities.

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2. The mud density and ECD should be monitored continuously, particularly in relation to the mud window calculations in order to assess the likely degree of breakouts and the possibility of mud losses.

5 When the mud is stationary, as is the case during connections, the ECD equals the mud density. During drilling, or while circulating off bottom, the ECD typically exceeds the mud density by up to 0.5-1.0 lb/gal. During trips, when equipment is being pulled up
10 and down the well, the ECD below the bit is typically 0-0.5 lb/gal less and more, respectively, than the mud density.

3. The behaviour of the drillpipe and bottom hole assembly (BHA), hole cleaning, rate of penetration
15 (ROP), trajectory, cavings rate and morphology, mud losses/gains and chemistry, together with resistivity, gamma-ray, compressional slowness and caliper LWD measurements should also be continuously monitored. It is then possible to conduct the following evaluations:

20 (a) Cavings analysis can provide a signal that the borehole is failing and indicates the troublesome formations. Tabular, angular or splintered cavings indicate that the nature of the instability is natural fracturing or weak planes, breakouts and over-
25 pressure, respectively. The cavings rate indicates the level of failure. However, if the hole cleaning is inadequate, not all of the debris generated by any instability may be discharged from the well, thereby masking the severity of the problem. This issue is
30 discussed fully below.

(b) Mud losses occur in naturally fractured zones, faults or drilling induced fractures. Such an event indicates that the fluid pressure in the annulus has exceeded the minimum in-situ principal stress. Mud gains indicate the pore pressure has exceeded the mud pressure or that previously lost mud is being returned to the wellbore due to fracture closure. Such an event allows the pore pressure estimate to be refined. In areas where there is chemical instability, a more comprehensive mud analysis programme may be required.

(c) Gamma-ray data enables formation boundaries to be identified. Some characterisation of the formation may also be possible, if the data is combined with other measurements such as resistivity.

(d) Resistivity measurements allows fracture identification. Schlumberger's LWD tool measures the resistivity at various depths (See e.g., Schlumberger (1998)); the degree of oil based mud invasion into water filled fractures can therefore be determined.

(e) Compressional slowness characterises pore pressure and formation strength.

(f) Caliper measurements of hole enlargement, if available, will identify the unstable formations.

(g) The ROP and hole cleaning efficiency form the key links between wellbore instability and operations. Rock debris in the annulus, resulting from drilling and/or wall failure, will increase if hole cleaning is inadequate, raising the risk of pack-offs, stuck pipe and tools lost in hole. For an explanation of these terms, see Bourgoyne, A.T., Chenevert, M.E.,

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Millheim, K.K. and Young, F.S.: 'Applied Drilling Engineering, SPE Textbook Series, Vol. 2 (1991), incorporated herein by reference. The ability to clean the hole is also related to the ROP. At sufficiently high ROP's, the rate of influx of debris into the annulus, from drilling and newly exposed rock which may be failing, will exceed the rate at which material can be discharged from the well, leading to the consequences outlined above.

- 10 A reliable diagnosis of the instability mechanism preferably uses all available data. If tabular cavings, due to natural fracturing, are observed, then the resistivity log should be checked for evidence of mud invasion into fractures and the mud records require examining for losses. Similarly, if splintered cavings due to over-pressured formations are seen then high gas levels, kicks or mud gains may also be present. The observation of angular cavings due to breakouts requires the debris levels in the hole to be discerned. In all cases, the cavings volume should be compared to the ECD and the degrees of tight hole and restricted circulation to discern the effectiveness of the hole cleaning and the severity of instability.

- 25 In step 130, the states of the wellbore, and geological features adjacent to it, that are predicted using the earth model are compared with those diagnosed using real-time data. If differences exist between the predicted and diagnosed states then the earth model is updated. The comparison of the estimated conditions and the real time based diagnosis should be considered to "match" when the two conditions are within a

reasonable range. For example, according to a preferred embodiment, if the mud pressure at which moderately severe breakouts occurred is not within 2 percent of the value estimated in step 122, then they
5 considered inconsistent and a "sufficient match" in step 132 does not exist. However, the individual thresholds for each compared condition will have to be determined on a case-by-case basis.

According to a preferred embodiment, real-
10 time data 126 includes measurements of the ECD and at least one other parameter. Preferably, these measurements are used in the comparison of diagnosed states with predictions derived from the earth model in step 130, and in the updating of the earth model, which
15 discussed more fully below.

For example, in a vertical well, suppose the ECD exceeds the estimated lower bound of the drilling fluid density and that a steady stream of cavings is being carried from the hole. If the cavings have an
20 angular morphology, then breakouts have occurred, albeit at a higher than expected drilling fluid pressure, as indicated by the ECD data. As the pressure of the drilling fluid decreases, zones of shear failure develop that are centred about the line
25 of action of the minimum horizontal in-situ stress. The material in these zones eventually drops into the wellbore, leading to the cavings shown in Figures 3a and 3b. Conversely, as the drilling fluid pressure increases, fractures develop centred about the line of
30 action of the maximum horizontal in-situ stress.

According to a preferred embodiment, following are four examples of situations in which there would be an insufficient match in step 132 and the earth model would therefore be updated:

- 5 1. Breakouts occur, or the fluid is lost to the formation, at values of ECD that differ from those that are predicted;
2. The nature, severity or extent of the drilling hazards differ from their prognosis;
- 10 3. Geological characteristics (e.g. the location of formation tops with respect to the trajectory) differ from their prognoses; or
4. Fluid or gas unexpectedly enters the wellbore indicating that estimates of the pore pressure
- 15 are inaccurate.

Referring again to Figure 2, in this example a sufficient match would not exist in step 132. Accordingly, the earth model would be updated in step 136. In this example, the in-situ stress state, the

20 formation strength, or both of these quantities should be amended so that the predicted and actual states match adequately.

According to a preferred embodiment, the components of the earth model that are the most

25 uncertain should be given priority in the updating process. This advantageously allows for the most efficient and accurate updating of the earth model. Figure 5 is a flow chart illustrating in greater detail the preferred method of updating the earth model

30 according to the present invention. Steps 150, 152 and 154 correspond to step 136 in Figure 2, whereas steps

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122, 130, 132 and 134 correspond to the same steps in both figures 2 and 5.

In step 150 the components that are relevant to the inconsistency are determined. In cases where there are more than one inconsistency is identified in the comparison step 130, the most hazardous inconsistency is generally addressed first. In step 152 the relevant components identified in step 150 are ranked according to certainty. In other words, the earth model components that are most unreliable are identified, and preferably, ranked in order of reliability. Alternatively, step 150 can be skipped and the ranking step 152 applied to all or some predetermined number of most uncertain components. The goal of steps 150 and 152 are to identify the most unreliable or most uncertain components or parameters in the earth model so that the update can be focused on those components.

In step 154 the most uncertain components are updated. According to a preferred embodiment, the components that are updated are ideally altered by the smallest degree needed to allow matching of the predicted and measured components.

As discussed above, in steps 122, 130, 132, and 134 failure conditions are estimated, and comparison is made to determine if there is a sufficient match between the estimated conditions and the real time diagnosis. If there is a sufficient match, no further changes are made to the earth model. When a sufficient match is not found, steps 152, 154 122, 130 and 132 are repeated as shown in Figure 5.

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When step 152 is being repeated, the recently amended components are preferably re-ranked as being more certain due to their recent amendment. When step 122 is being repeated, the well failure conditions are re-estimated using the updated components.

Following is an example the process described in Figure 5. If real-time compressional slowness data is available through use of the appropriate LWD tool, then the formation strength estimate can be inferred from this measurement and the formation strength is assumed to be the most reliable component in step 154. In step 154, the minimum change to the in-situ stress state (actually the maximum principal in-situ stress, as the minimum principal in-situ stress is constrained using a combination of fluid loss and ECD data) should then be made which allows the predicted and measured pressures at which breakouts occur to adequately match, with the latter determined using ECD data. If real-time compressional slowness data is not available, then it is assumed that the formation strength is the most unreliable (or least certain) parameter or component in step 152. In step 154, the formation strength is updated until prediction and reality match adequately.

Following are further examples of how the earth model updating processes in steps 150, 152 and 154 could be carried out, according to the invention. In particular, if breakouts or fluid losses do not occur as anticipated then the in-situ stress state and formation strength predictions should be amended. More specific examples are as follows.

Suppose the ECD exceeds the anticipated minimum principal in-situ stress without fluid loss. The minimum principal in-situ stress should be amended to be equal to the maximum ECD encountered over the appropriate interval. The new estimate of the minimum principal in-situ stress will be a lower bound to the true value, but will be more accurate than the existing prediction.

Suppose fluid loss occurs at an ECD lower than the minimum principal in-situ stress. The minimum principal in-situ stress should be set to the ECD at which the fluid loss occurred. This will require a comparison of the time based ECD and drilling fluid volume logs.

Suppose breakouts occur at a value of the ECD higher than the minimum value predicted; it is then either in-situ stress state, the formation strength, or both of these quantities that should be amended. If the formation strength can be inferred from real-time measurements, such as compressional slowness data from the appropriate LWD tool or indentation tests on cuttings, then it may be assumed to be the most reliable parameter. The minimum change to the in-situ stress state (actually the maximum principal in-situ stress, as the minimum principal in-situ stress is constrained through fluid loss observations) is then made which allows prediction to match reality. If the formation strength cannot be inferred from real-time measurements, it should be assumed to be the most unreliable parameter and then amended until there is an adequate match between prediction and reality. The

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method of updating the in-situ stress or formation strength is identical in both cases: it requires that these parameters are amended until the output of the models that has used to estimate the bounds to the drilling fluid density agrees with the real-time measurement. This is an iterative process.

Breakouts occurring at values of ECD that are lower than the predicted minimum values are expected. No change is therefore made to the mechanical earth model.

Suppose the nature, severity or extent of the drilling hazards, or geological characteristics, differ from their prognoses, or fluid or gas unexpectedly enters the wellbore. The diagnostic techniques outlined in above could be used to detect these events and the earth model could then be directly updated without further computation, although the ECD should be used to assess the severity of the drilling hazard and the expectation of fluid or gas entry into the wellbore.

Other real-time information, such as palaeontological analysis of cavings or LWD resistivity data, should be used to assess the extent of any instability associated with the wellbore or adjacent geology.

The following example further illustrates how an earth model may be updated. After a well had been drilled to a depth of 2000m TVD (true vertical depth), it was decided to pull the drilling equipment out of the well. However, during this process 12 barrels of drilling fluid were lost to the formation. The real-time ECD measurement showed that this occurred at a pressure equivalent to 15.35 lb/gal. Figure 6

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illustrates an example of the minimum principal in-situ stress in an earth model, according to a preferred embodiment of the invention. As shown in Figure 6, the minimum principal in-situ stress was therefore revised
5 to be the equivalent of 15.35 lb/gal for the entire region above 2000m TVD.

As discussed, estimates along the trajectory of the upper and lower bounds of the drilling fluid density, together with the nature, severity and extent
10 of the drilling hazards, allow the states of the wellbore, and geological features adjacent to it, to be predicted while the well is constructed. Examples of these are shown in Figures 7 and 8 for a well drilled in the North Sea. Figure 7 illustrates an example of
15 the mud window (i.e. allowable drilling fluid densities) estimated prior to drilling the well. Drilling with a mud (i.e. fluid) whose density falls to the left of the solid line leads to breakouts. Conversely, drilling with a mud whose density falls to
20 the right of the thick broken line will cause fluid loss into the formation. The vertical axis denotes the length of wellbore below the drilling rig floor. Figure 8 illustrates an example of drilling hazards, derived from an analysis of experience drilling offset
25 wells, and the well trajectory shown in Figure 9. In figure 8, the severity of the hazard is shown as a "traffic light" classification. The vertical cross hatch indicates that the symptoms of the instability are present but insignificant: no remedial action is
30 necessary. The horizontal cross hatch indicates that remedial action should be taken because the instability

is significant and could become serious. The diagonal cross hatch indicates that the instability is likely to result in loss of the well. The problem should be avoided, otherwise immediate remedial action should be taken. Figure 9 illustrates the trajectory of the well used in the examples of Figures 6-11. The Northerly and westerly directions are annotated (N and W, respectively). The vertical scale is true vertical depth below the drilling rig floor. Figure 10 illustrates the in-situ stress state prior to drilling the well used in Figures 6-11. In Figure 10, the symbols σ_v , σ_h , and σ_H denote the vertical, minimum horizontal, maximum horizontal stresses, respectively and P_p is the pore pressure. TVD denotes true vertical depth with respect to the drilling rig floor. Figure 11 illustrates an example of the formation strength in the example of figure 6-11. The formation strength shown in Figure 11 is defined by the two parameters required to define the Mohr-Coulomb failure criterion. UCS and ϕ denote the uniaxial compressive strength and friction angle respectively.

The upper and lower bounds to the drilling fluid density may be derived by combining a prediction of the stress state around the wellbore embedded in an isotropic, homogeneous medium using an undrained linear elastic model with a Mohr-Coulomb failure criterion (Fjaer et al., 1992), or through use of other techniques. The lower bound represents the minimum ECD that is required in order to prevent breakouts. The upper limit represents the maximum ECD that is

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allowable before rock at the wellbore wall fractures or fluid is lost to the formation. These bounds may, however, have different physical interpretations if more sophisticated models (for example, the deformation of a salt formation) are used to derive them.

While preferred embodiments of the invention have been described, the descriptions and examples are merely illustrative and are not intended to limit the present invention.

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247CLAIMS

What is claimed is:

- 5 1. A method for updating an earth model
comprising the steps of:
- obtaining an earth model used for predicting
potential problems in drilling of a borehole
having a predetermined trajectory, the earth model
10 comprising a plurality of components;
- obtaining evaluations of the state of the
borehole and local geological features, the
evaluations being based on the earth model;
- receiving data gathered during the
15 construction of the borehole;
- comparing the evaluations with a diagnosis of
the state of the borehole and local geological
features to identify at least one inconsistency,
the diagnosis being based on the received data;
- 20 selecting a component of the earth model that
is related to the identified inconsistency and has
a high degree of uncertainty; and
- updating the selected component of the earth
model prior to completing construction of the
25 borehole using the received data.
2. The method of claim 1 wherein the
evaluations of the state of the borehole and local
30 geological features include predictions of one or more
conditions under which the borehole will fail.

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3. The method of claim 2 wherein the predictions are obtained by combining the earth model with the predetermined trajectory of the borehole.

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4. The method of claim 3 further comprising repeating the steps of combining, comparing, selecting and updating until a sufficient match exists between the predicted failure conditions and the diagnoses of the borehole.

5. The method of claim 4 wherein the step of combining when repeated uses the updated component of the earth model, and the step of selecting when being repeated, considers components that have been recently updated as having a lower degree of uncertainty.

6. The method of claim 1 wherein the step of selecting a component comprises:
identifying components of the earth model that are relevant to the identified inconsistency;
and
ranking the identified components according to the degree of uncertainty.

7. The method of claim 1 wherein the selected component is the component having the highest degree of uncertainty of the components that are related to the identified inconsistency.

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8. The method of claim 1 wherein the step of updating comprises effecting the minimum practical changes to the selected component that eliminates an identified inconsistency.

9. The method of claim 1 wherein the received data includes the effective density of the drilling fluid used in the construction of the borehole and one at least other parameter, and the step of updating comprises updating the selected component using the effective density and the at least one other parameter.

10. The method of claim 1 wherein the diagnosis of the borehole is generated by extensive use of real-time MWD and LWD measurements.

11. The method of claim 1 wherein the step of obtaining an earth model includes generating the earth model.

12. A method for drilling a borehole using an earth model comprising the steps of:

obtaining an earth model used for predicting potential problems in drilling of a borehole having a predetermined trajectory comprising a plurality of components;

predicting one or more conditions under which the borehole will fail based on the earth model and the predetermined trajectory;

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drilling part of the borehole substantially according to the predetermined trajectory;

receiving data gathered during the construction of the borehole;

5 comparing the predicted failure conditions with a diagnoses of the borehole based on the received data to identify at least one inconsistency;

10 selecting a component of the earth model that is related to the identified inconsistency and has a high degree of uncertainty;

updating the selected component of the earth model prior to completion of the borehole using the received data; and

15 thereafter drilling a further portion of the borehole using the earth model including the updated component.

13. The method of claim 12 further comprising repeating the steps of predicting, comparing, selecting and updating until a sufficient match exists between the predicted failure conditions and the diagnoses of the borehole.

25 14. The method of claim 13 wherein the step of combining when repeated uses the updated component of the earth model, and the step of selecting when being repeated, considers components that have been recently updated as having a lower degree of
30 uncertainty.

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15. The method of claim 12 wherein the step of selecting a component comprises:

identifying components of the earth model that are relevant to the identified inconsistency;

5 and

ranking the identified components according to the degree of uncertainty.

16. The method of claim 12 wherein the step of updating comprises effecting the minimum practical changes to the selected component that eliminates an identified inconsistency.

17. The method of claim 12 wherein the received data includes the effective density of the drilling fluid used in the construction of the borehole and one at least other parameter, and the step of updating comprises updating the selected component using the effective density and the at least one other parameter.

18. A computer readable medium that is capable of causing a computer to perform steps comprising:

25 obtaining an earth model used for predicting potential problems in drilling of a borehole having a predetermined trajectory, the earth model comprising a number of components;

obtaining evaluations of the state of the borehole and local geological features, the evaluations being based on the earth model;

receiving data gathered during the
construction of the borehole;

comparing the evaluations with a diagnosis of
the state of the borehole and local geological
5 features to identify at least one inconsistency,
the diagnosis being based on the received data;

selecting a component of the earth model that
is related to the identified inconsistency and has
a high degree of uncertainty; and

10 updating the selected component of the earth
model prior to completing construction of the
borehole using the received data.

19. The computer readable medium of claim 18
15 capable of causing a computer to perform steps further
comprising:

identifying components of the earth model
that are relevant to the identified inconsistency;
and

20 ranking the identified components according
to the degree of uncertainty.

20. The computer readable medium of claim 19
wherein the step of updating comprises effecting the
25 minimum practical changes to the selected component
that eliminates an identified inconsistency.

21. The computer readable medium of claim 20
wherein the received data includes the effective
30 density of the drilling fluid used in the construction
of the borehole and one at least other parameter, and

the step of updating comprises updating the selected component using the effective density and the at least one other parameter.

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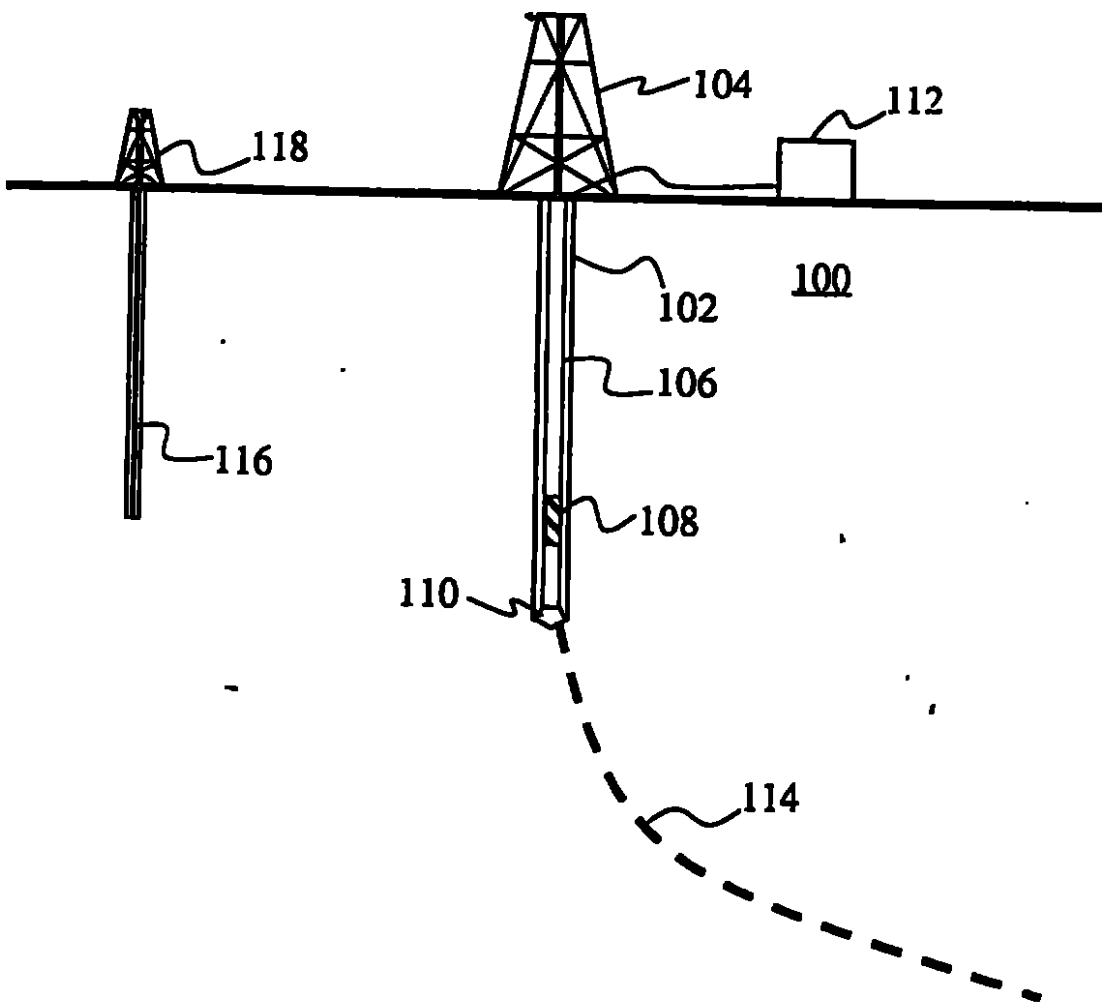


FIG. 1

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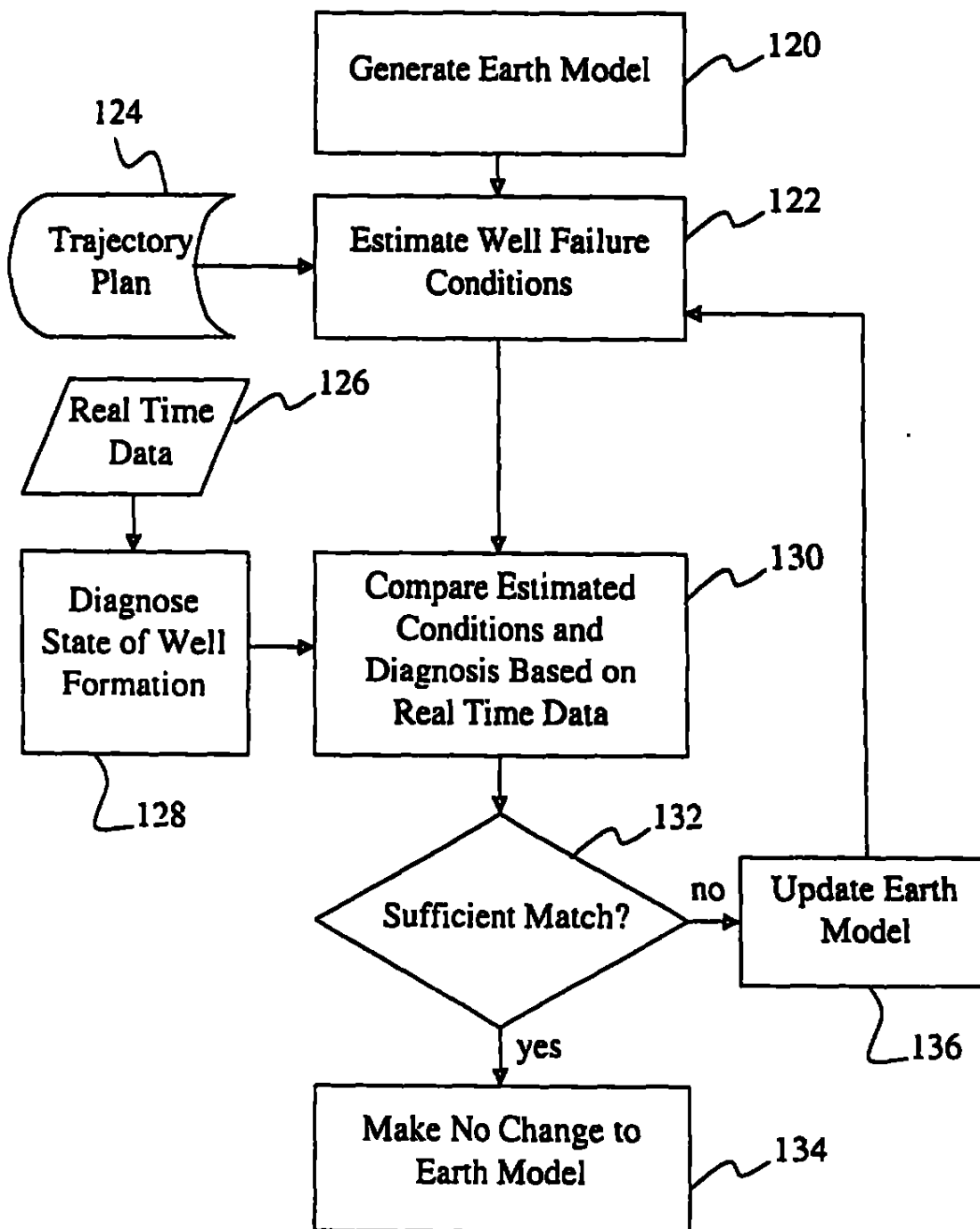
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FIG. 2

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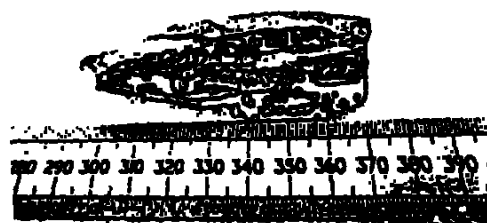


FIG. 3a



FIG. 3b

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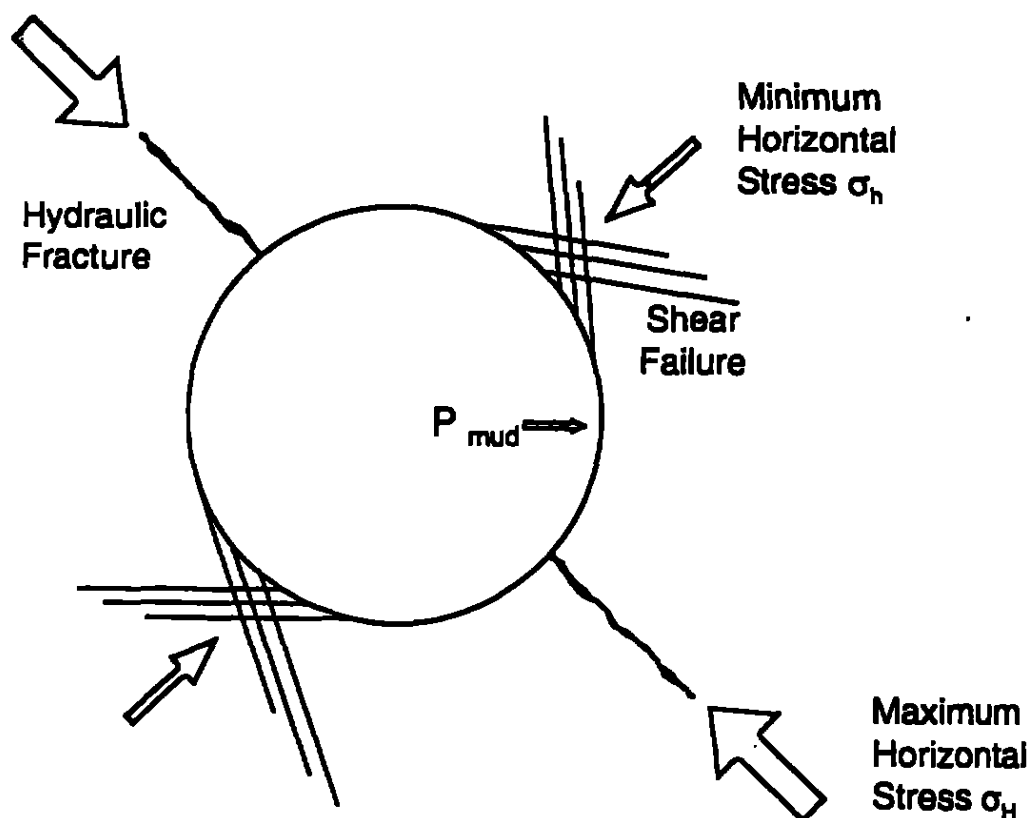


FIG. 4

SUBSTITUTE SHEET (RULE 26)

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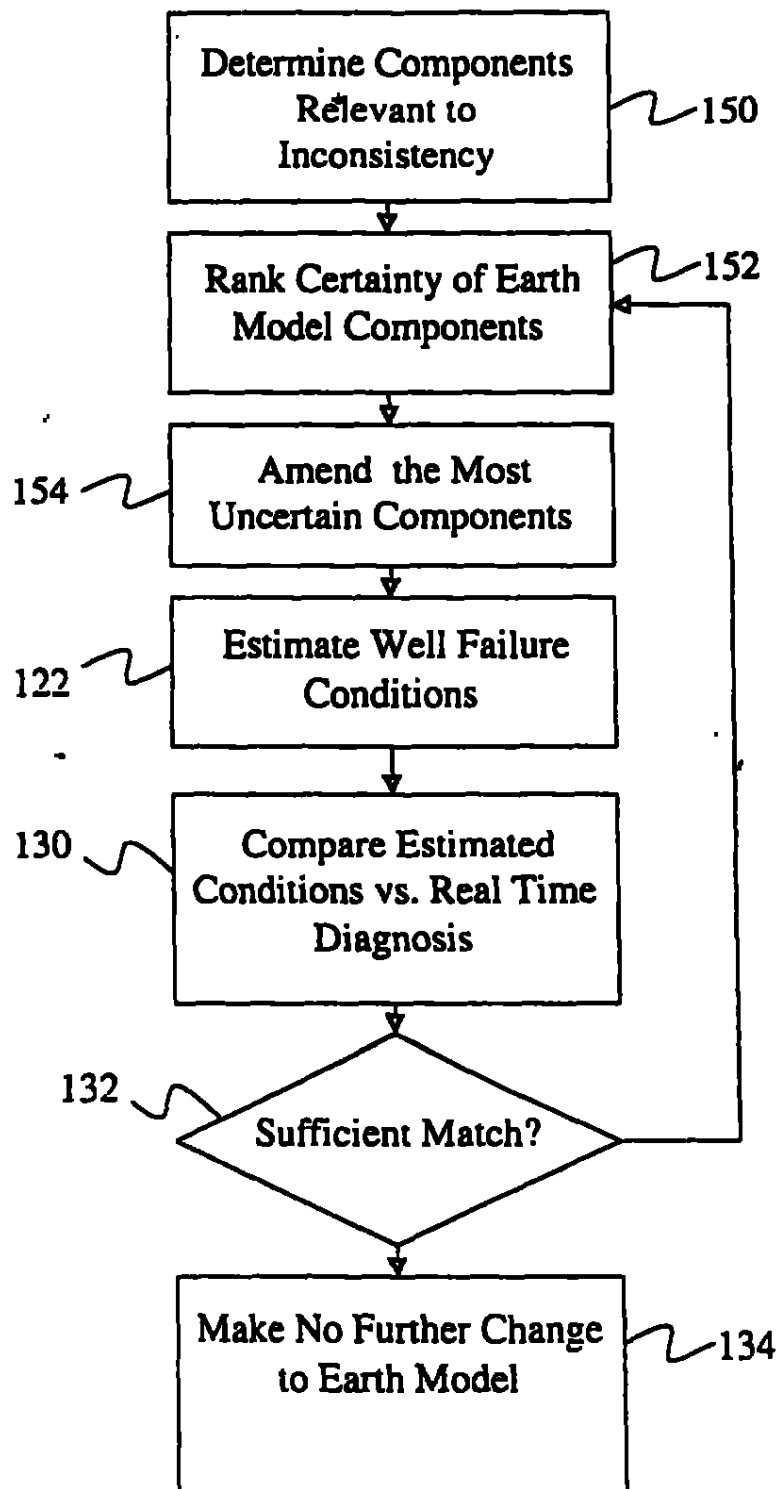


FIG. 5

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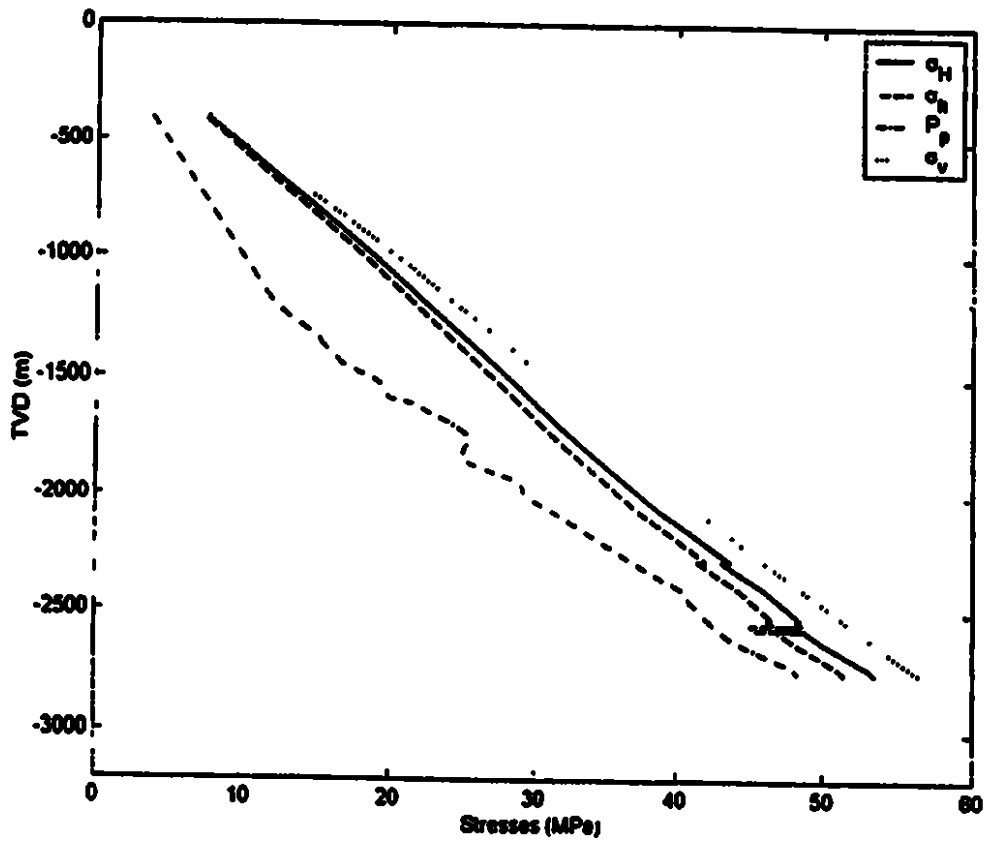


FIG. 6

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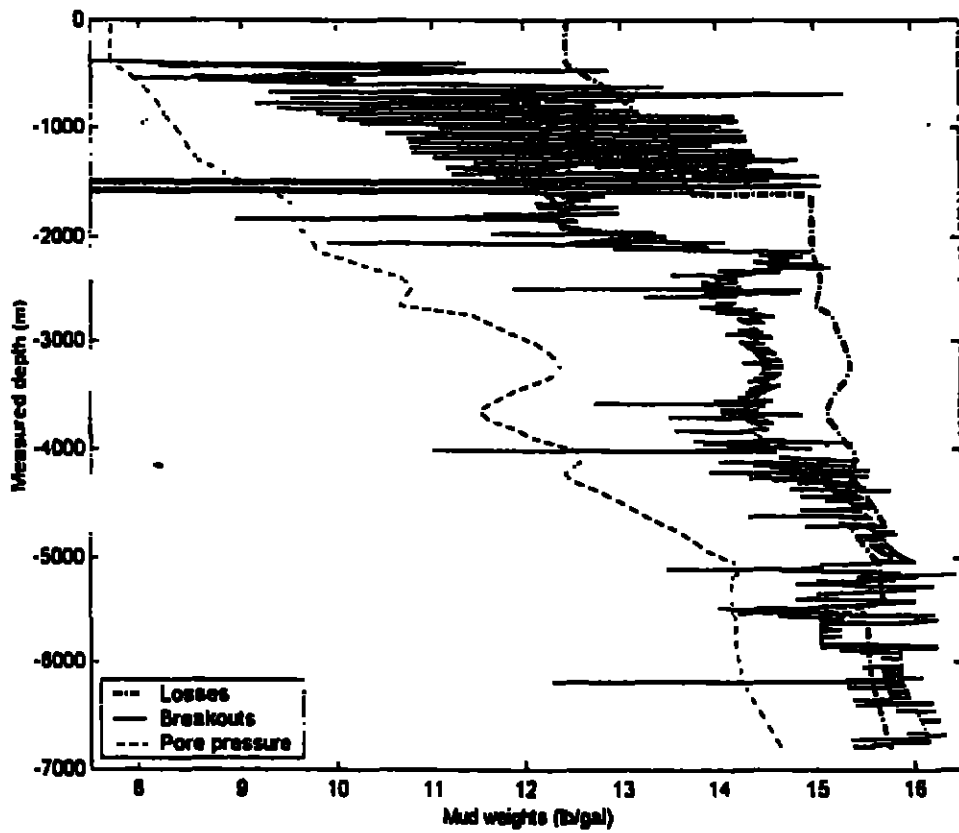


FIG. 7

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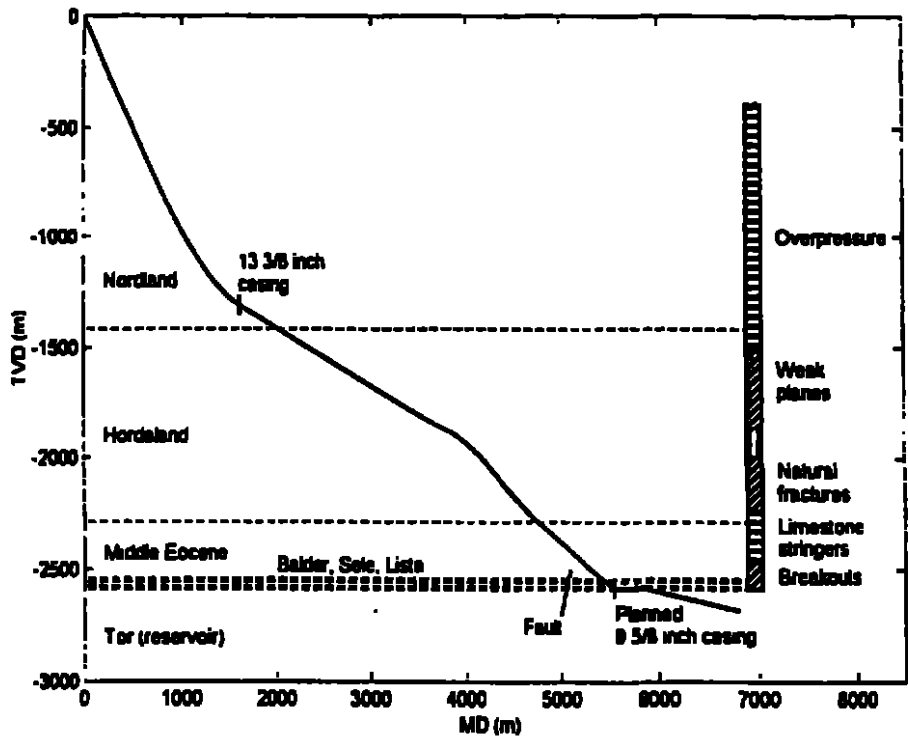


FIG. 8

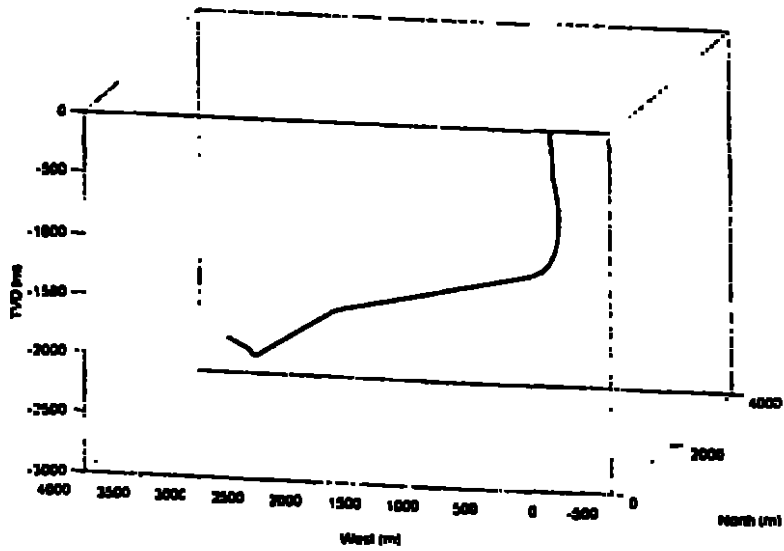


FIG. 9

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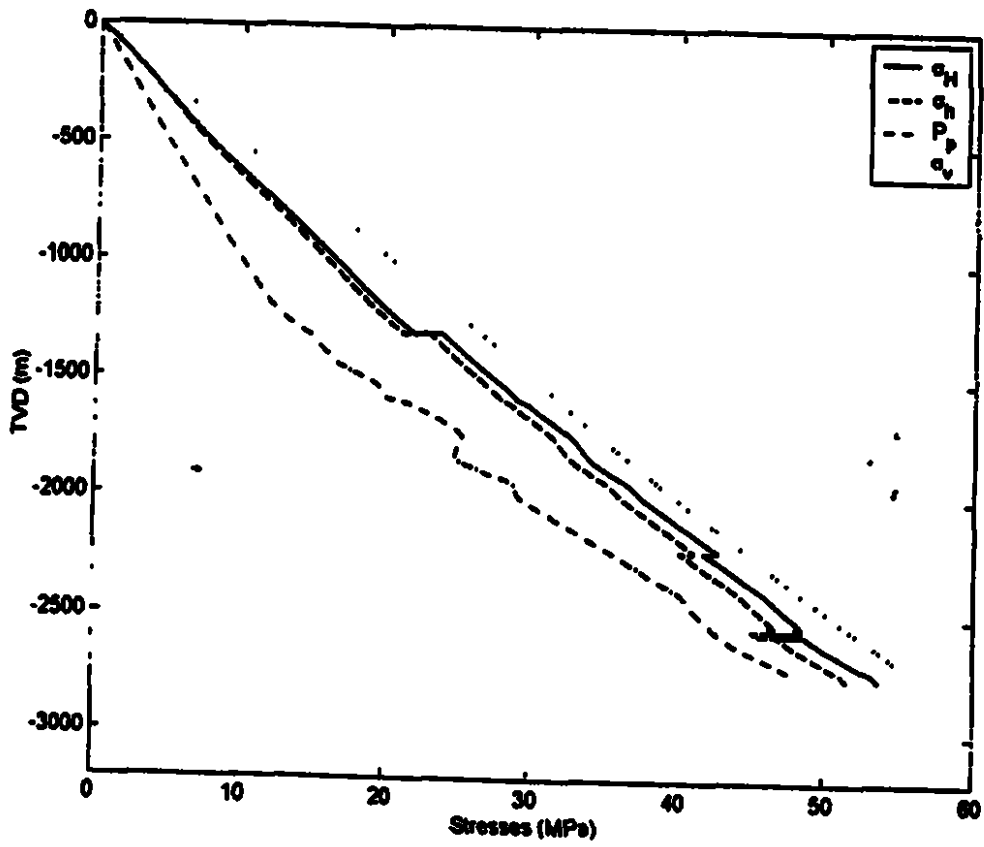


FIG. 10

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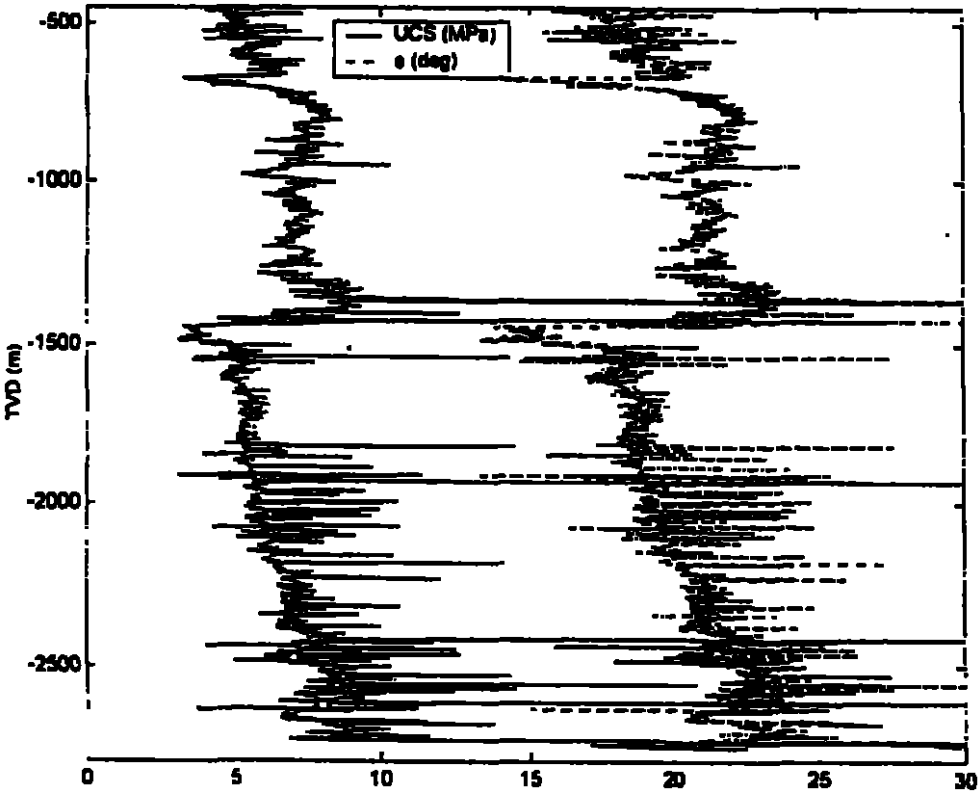


FIG. 11

INTERNATIONAL SEARCH REPORT

Intern. Patent Application No.

PCT/GB 00/03704

A. CLASSIFICATION OF SUBJECT MATTER
IPC 7 601V11/00

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 601V

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, WPI Data, COMPENDEX, INSPEC

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category *	Citation of document, with indication where appropriate, of the relevant passages	Relevant to claim No
P.X	US 5 995 446 A (MEYER JOERG H ET AL) 30 November 1999 (1999-11-30) column 3, line 23 - line 45 column 4, line 12 - line 50 column 4, line 62 - column 5, line 6; claim 1	1,12,18
A	WO 97 27502 A (BAKER HUGHES INC) 31 July 1997 (1997-07-31) page 1, line 9 - line 16 page 8, line 13 - line 16 page 13, line 10 - line 14 page 38, line 21 - page 39, line 9	1,12,18
A	US 5 838 634 A (HELWICK JR STERLING J ET AL) 17 November 1998 (1998-11-17) column 6, line 48 - column 7, line 67 -/--	1,12,18

☒ 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
- *I* document which may throw doubts on priority claims; or which is cited to establish the publication date of another claim or other special reason (as specified)
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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

Z document member of the same patent family

Date of the actual completion of the international search

13 December 2000

Date of making of the international search report

20/12/2000

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Lorne, B

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page 1 of 2

INTERNATIONAL SEARCH REPORT

Int. Application No
PCT/GB 00/03704

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265

C.(Continuation) 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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INTERNATIONAL SEARCH REPORT

Information on patent family members

International Application No

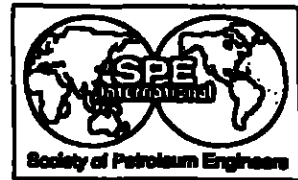
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Cost effective and successful drilling, in chemically inert formations, require that the drilling fluid pressure be maintained within a tight mud-weight window dictated by the stress and pressure analyses in and around the wellbore. When drilling in chemically active formations such as shale, fluid mud salinity and the formation exposure time also add a challenging task and increase the level of complexity in predicting the mud-weight window when using a Water Based Mud (WBM). The problems encountered in wellbore drilling operations, i.e., borehole collapse or formation breakdown, are

Although drilling fluid muds and time of exposure to mud/formation interface as well as the pressure buildup/depletion are time-dependent phenomena, the existing analytical and published solutions for the inclined wellbore analyses do not account for the time as an integral part of the solutions. Only the recently-developed analytical solution³ takes into account the coupled phenomena of time-dependent pore fluid diffusion and formation stress variation. These solutions are based on the well-established theory of poroelasticity.⁴ The poroelasticity theory is the only existing theory for which the four mechanical formation parameters are by now fully identified and measurable in the oil and gas industry practices.^{5, 6, 7} These parameters are defined as Biot's effective stress coefficient, α , Skempton's pore pressure coefficient, B , shear modulus, G , and the drained Poisson's ratio, ν . These four parameters with the formation permeability are the necessary independent properties for which a poroelastic analysis in homogeneous, isotropic and chemically inert formations can be complete. In shale formations the chemical potential coupled with the fluid salinity can also be formulated within the theory of poroelasticity.^{8, 9} In this work the solutions for time-dependent stresses and failure analyses for the inclined wellbore drilled in chemically active shales, have been derived and implemented in the PBORE-3D software^{10, 11}.

PBORE-3D software allows the design of a wellbore-drilling program for mud-weight pressure window, mud salinity, and wellbore depth-gradient analysis. All these analyses are a function of time. PBORE-3D is a user-friendly software with a graphical user interface, which includes

features such as routines for data editing, graphical presentations of results, and convenient on-line help capabilities. The required poroelastic parameters are expressed in engineering terms with compatibility analysis implicitly included.

Phase one in the development of the PBORE-3D software for time-dependent stability analyses of inclined boreholes has been completed. The time-dependent processes and solutions that were analytically derived and implemented are the viscosity of rock formation, creep, thermal gradient, heating/cooling of mud, and the pore fluid diffusion effects within the framework of the theory of poroelasticity and the coupled stress-strain phenomenon. The extension of the time-dependent analytical solutions to chemically active shale formations and the analysis of mud weight and salinity in an inclined borehole drilled and completed in the most general three-dimensional state of stress, renders PBORE-3D a unique tool for wellbore drilling programs given the accuracy of the solutions and the savings on the personal computer's central processing unit (CPU) time. The solutions of theories of poroelasticity, porochemoelasticity, porothermoelasticity, and poroviscoelasticity, as well as their elastic, chemoelastic, thermoelastic, and viscoelastic counterparts, are all included in PBORE-3D. These recently-developed solutions corresponding to the poromechanics aspect of the rock formation and drilling fluid with their solid mechanics equivalents, will allow the drilling engineers to make the necessary decisions on potential critical time effects in the drilling as well as completion, e.g., time of casing placement and/or cementing.

Inclined Poroelastic Wellbore Problem

The inclined wellbore is defined as a wellbore drilled with its axis inclined to the far-field principal stress axes $x'y'z'$ (Figure 1(a)). The solution for the inclined wellbore was first presented by Bradley² in an elastic medium neglecting the coupled poroelastic effects in fluid saturated formation. Poroelasticity, pioneered by Biot,⁴ takes into account the interaction between the rock matrix deformation and pore fluid coupling. In poroelasticity the total stress components satisfy the same equilibrium equations as in solid mechanics; and the pore fluid flow is governed by Darcy's law. The coupling of solid matrix/grain deformation and pore fluid flow is governed by the following constitutive equations:

$$\sigma_{ij} = D_{ijkl} \epsilon_{kl} + \alpha_{ij} p \quad (1)$$

$$p = M(\zeta + \alpha_{ij} \epsilon_{ij}) \quad (2)$$

where the Einstein summation index convention is applied. Eq. (1) describes how the overall strains of the porous rock rely on the applied total stresses and pore pressure weighted by Biot's effective stress parameter, α_{ij} , where the tensor

notation implies a general anisotropic rock¹²; and, Eq. (2) indicates that the pore pressure is not only related to the pore fluid content variation, ζ , but also affected by the deformation of the porous body. The foregoing constitutive equations show that: the variation of pore pressure affects both pore pressure and total stresses in the effective stress law, hence the magnitude of the effective stresses; and, the deformation of the porous rock modifies the pore pressure, hence affecting the pore fluid flow. The analytical poroelastic solutions for inclined boreholes were derived by Cui *et al.*³

However, in the conventional analytical approaches based on Bradley's model², the aforementioned coupling effects are totally unaccounted for. Although these models include the pore pressure diffusion in an ad hoc fashion,¹ the coupling effects of fluid pore pressure and rock deformation do not exist. Therefore, their solutions predict a time-independent drilling mud-weight window and stress analyses at the wellbore wall.

The pseudo-three-dimensional poroelastic models were developed for inclined boreholes under both penetrating and impermeable conditions at the wellbore walls.^{1,13,14} These two pressure/flow boundary conditions are the most commonly used in wellbore stability analyses. In the swabbing and surging in a wellbore, time-dependent pressure/flow boundary conditions may be more realistic¹⁵; and these solutions were also derived and implemented. The poroelastic models predicted not only significantly different magnitudes of stresses and pore pressures around the wellbore compared to the conventional models, but also time-delayed failure phenomena similar to the ones observed in the field¹⁶ and which cannot be predicted by other existing models. In addition, the poroelastic models can predict the initiation of failures inside the walls, which contributes to wellbore breakouts.

Inclined Porochemoelastic Wellbore Problem:

In the past Oil-Based Muds (OBM) have been the drilling fluid of choice by the industry in shaley and difficult formations. However, environmental concerns and regulations have limited the use of OBM.¹⁷

The inclined wellbore geometry as defined earlier (Figure 1(a)) is the subject of the following solutions and analyses. Within the consistent framework of the theory of poroelasticity, the porochemoelastic solutions for the inclined wellbore are derived. Porochemoelasticity, quoted here for the first time, indicates that a chemical potential exists between the drilling fluid mud and the shale formation.¹⁷ The shale is assumed to behave as an isotropic ion exclusion membrane, and a modified Biot's theory is applied to the stress and pore pressure analyses of the swelling shale surrounding the wellbore.^{1,9}

Modified Biot's Theory

The theory of poroelasticity was first derived by Biot⁴ in 1941. The governing equations are presented here following Rice and Cleary.¹³

• **Equilibrium equations:**

$$\sigma_{ij,j} = 0 \quad \dots\dots\dots(3)$$

• **Compatibility condition:**

$$\nabla^2 \sigma_{ij} + \frac{1}{1+\nu} \sigma_{kk,j} + 2\eta \left(\delta_{ij} \nabla^2 p + \frac{1-\nu}{1+\nu} p_{,j} \right) = 0 \quad \dots\dots\dots(4)$$

• **Diffusion equation:**

$$\nabla^2 \left(\sigma_{kk} + \frac{3}{B} p \right) = \frac{1}{c} \frac{\partial p}{\partial t} \quad \dots\dots\dots(5)$$

The analytical solution for an inclined, circular, and infinitely long borehole, embedded in a linear, poroelastic, homogeneous, and isotropic formation of infinite extent subjected to an anisotropic far-field stress state, and a constant in-situ fluid pore pressure have been derived.³ The present modifications to the solutions stem from the fact that a chemical potential exists between the fluid in the wellbore and the shale rock formation. Following Sherwood,⁹ the chemical potential of water is defined by the following equation:

$$\mu_w = pV_w + RT \ln(a_w) \quad \dots\dots\dots(6)$$

The chemical potential calculated in the above equation is a function of the activity. For the drilling mud fluid the activity depends on the type of salt used. For example, in a mud where calcium chloride is used as a stabilizing agent the activity can be calculated from the salt concentration.

As indicated,^{1,9} μ_w/V_w plays the role of a modified pressure. The constitutive and governing equations can therefore be written in terms of the chemical potential.

The constitutive equations and governing equations are thus modified incorporating the effect of the chemical potential. Solution for the inclined borehole problem can therefore be obtained.

As shown in Figure 1(a) the formation is characterized by existence of far-field in-situ stresses S_x , S_y , and S_z and a chemical potential μ_w . The borehole inclination is defined by two angles ϕ_i and ϕ_r as shown in the figure. To ease the procedure to obtain solutions, a local coordinate system xyz is defined with the z -axis coinciding with the borehole axis. The far-field stresses S_x , S_y , and S_z are obtained in the local coordinate system following a simple stress transformation:

$$\begin{Bmatrix} S_x \\ S_y \\ S_z \\ S_{xy} \\ S_{yz} \\ S_{zx} \end{Bmatrix} = \begin{bmatrix} l_{xx}^2 & l_{xy}^2 & l_{xz}^2 \\ l_{yx}^2 & l_{yy}^2 & l_{yz}^2 \\ l_{zx}^2 & l_{zy}^2 & l_{zz}^2 \\ l_{xy}l_{xx} & l_{yy}l_{xx} & l_{yz}l_{xx} \\ l_{xy}l_{yx} & l_{yy}l_{yy} & l_{yz}l_{yy} \\ l_{xy}l_{zx} & l_{yy}l_{zy} & l_{yz}l_{zz} \end{bmatrix} \begin{Bmatrix} S_x \\ S_y \\ S_z \end{Bmatrix} \quad \dots\dots\dots(7)$$

where

$$\begin{bmatrix} l_{xx} & l_{xy} & l_{xz} \\ l_{yx} & l_{yy} & l_{yz} \\ l_{zx} & l_{zy} & l_{zz} \end{bmatrix} = \begin{bmatrix} \cos \phi_i \cos \phi_r & \sin \phi_i \cos \phi_r & \sin \phi_i \\ -\sin \phi_i \cos \phi_r & \cos \phi_i \cos \phi_r & 0 \\ \cos \phi_i \sin \phi_r & \sin \phi_i \sin \phi_r & \cos \phi_r \end{bmatrix} \quad \dots\dots\dots(8)$$

With the stresses obtained in the local coordinate system, the boundary conditions at the far-field and the borehole wall can be written as follows:

At far-field:

$$\begin{aligned} \sigma_{xx} &= -S_x \\ \sigma_{yy} &= -S_y \\ \sigma_{zz} &= -S_z \\ \sigma_{xy} &= -S_{xy} \\ \sigma_{yz} &= -S_{yz} \\ \sigma_{zx} &= -S_{zx} \end{aligned} \quad \dots\dots\dots(9)$$

At the borehole wall:

$$\begin{aligned} \sigma_{rr} &= -S_r H(-r) \\ \sigma_{\theta\theta} &= -S_{\theta\theta} H(-r) \\ \sigma_{zz} &= -S_z H(-r) \\ \mu &= \mu_w H(-r) \end{aligned} \quad \dots\dots\dots(10)$$

Owing to the linearity of the above equations, the boundary conditions can be decomposed into three problems.³ The final solution is obtained by a superposition of the solutions of the individual problems.

Inclined Poroviscoelastic Wellbore Problem

As we have seen, the theory of poroelasticity captures the coupling effects between pore pressure diffusion and the poromechanics matrix deformation in fluid saturated rocks giving rise to a variety of time-dependent phenomena. However, in addition to the effect of the viscous fluid diffusion, the rock matrix itself may exhibit a viscoelastic behavior. The time-dependent viscoelastic characteristics may be attributed to the intergranular frictional sliding, the intrinsic solid grain creep deformation, and even the solid-fluid interactions in fissures and micro-cracks at the granular or subgranular scales.^{19,20}

With the simultaneous existence of poro- and viscoelasticity, the response of the rock formation displays two time scales. The characteristic time of a viscoelastic response is an apparent material property while that for poroelasticity is dependent not only on the material property itself, but also on a global geometry length scale; namely the average distance to the drainage surface.

Following the spirit of the generalized Hooke's law, the poroviscoelastic model can be established by correlating the stress and the rate of stress to the strain and rate of strain. Using the hereditary integrals^{21,22} and with the application of the Laplace transform the correspondence of Biot's constitutive relations (1) and (2) are now expressed in the poroviscoelastic forms:

$$\bar{\sigma}_{ij} = \bar{D}_{ijm} \bar{\epsilon}_{ij} + \bar{\alpha}_{ij} \bar{p} \quad \text{.....(11)}$$

$$\bar{p} = \bar{M}(\bar{\zeta} - \bar{\alpha}_{ij} \bar{\epsilon}_{ij}) \quad \text{.....(12)}$$

The new various material coefficients of the poroviscoelasticity are the correspondence coefficients for those of poroelasticity. Based on this correspondence principle, all equations of poroviscoelasticity in the Laplace transform domain are formally the same as those of poroelasticity. However, the material coefficients for poroviscoelasticity carry different meanings. They are quotients of polynomials of the Laplace transform parameter. Their exact forms are determined from the specific spring-dashpot rheological model imposed from laboratory observations and measurements for various viscoelastic rock behaviors.

Since all equations of poroviscoelasticity in the Laplace transform domain are formally the same as those of poroelasticity, the solution to the inclined poroviscoelastic wellbore problem is formally the same as for the inclined poroelastic wellbore.²³

Inclined Porothermoelastic Wellbore Problem

The gradient of temperature between the drilling mud and the rock formation is also an important issue in wellbore stability

analysis. The temperature gradient will significantly affect the time-dependent stresses and pore pressure distributions in and around the wellbore. Within the framework of the theory of poroelasticity the solution of the inclined porothermoelastic wellbore problem has also been derived.^{24,25} These coupled solutions take into account the time-dependent variations of stresses and the mud-weight window in drilling operations. This model is unlike the one implemented by Coussy²⁶ and Wang and Papamichos²⁷ where the fully coupled phenomena do not exist. Although, numerical schemes that account for the porothermoelastic analyses, e.g., finite element, are existing.²⁸ These solutions inherit the shortcomings of numerical approaches to model diffusive phenomena.

The constitutive equations for a porothermoelastic system are given as follows.²⁹

$$\sigma_{ij} = 2G\epsilon_{ij} + \frac{2G\nu}{1-2\nu} - \alpha p \delta_{ij} - \frac{2G(1+\nu)\alpha^T}{3(1-2\nu)} T \delta_{ij} \quad \text{.....(13)}$$

$$\zeta = \frac{\alpha(1-2\nu)}{2G(1+\nu)} \left(\sigma_{kk} + \frac{3}{B} p \right) + (\alpha_m^T - \alpha_f^T) \phi_s \quad \text{.....(14)}$$

The corresponding solutions of the inclined wellbore in a porothermoelastic fluid saturated rock were also implemented in PBORE-3D.

Problems, Discussions and Graphs Evaluation

The capabilities of PBORE-3D to model poroelastic, porochemoelastic, poroviscoelastic, and porothermoelastic with their equivalent solid mechanics counterparts i.e., elastic, chemoelastic, viscoelastic and thermoelastic are illustrated here.

Figures 2 and 3 are the input dialog boxes. In Figure 2 a set of parameters which is usually provided by the industry standards, such as in-situ stress and formation pore pressure gradient, wellbore radius, wellbore depth and orientation, rock strength parameters, are inputted. Also the type of analysis should be defined, e.g., porochemoelastic. Figure 3 shows the input dialog box for the poroelastic parameters, the shale formation and mud activities, and finally the time intervals to conduct the porochemoelastic analyses.

Figures 4 and 5 show the tangential stresses varying with time at the wellbore wall. The figures compare the time-dependent stresses between the purely poroelastic and the porochemoelastic approaches. Similarly, Figures 6 and 7 show the mud-weight windows after 14.4 minutes of formation exposure to the drilling mud for the two cases. While Figures 8 and 9 illustrate for that same time, the various stability regions for the inclined wellbore with respect to the maximum direction of the maximum in-situ stress and the various angles of inclinations.

In Figure 10 the pore pressure variation from the instant of fluid exposure to the rock formation up to roughly 15 minutes of exposure is presented. At early times, and due to the Skempton effects, the pore pressure rises above the formation initial pressure, and, as time progresses, the pore pressure reaches equilibrium. Finally, and only for illustration, a porothermoelastic and a poroviscoelastic pore pressure time variation and mud-weight window snapshot, respectively, are shown in Figures 11 and 12.

Conclusions

The porothermoelastic solution of the inclined wellbore was formulated within Biot's theory of poroelasticity. The solutions for stresses and pore pressures were derived and implemented in PBORE-3D. Also, for completion, analyses have been conducted and mud-weight windows have been calculated. The above-derived solutions were implemented in the PBORE-3D software.

Within PBORE-3D various poromechanics and classical solid mechanics approaches and solutions have been implemented. The solutions are all in the analytical forms making PBORE-3D a very efficient software for drilling engineers to simulate "real time" analyses. With PBORE-3D various poroelastic, porothermoelastic, poroviscoelastic, and porothermoelastic effects on time-dependent analyses of stresses and pore pressure distributions in and around the wellbore, as well as wellbore stability and the mud-weight windows for drilling design programs can be calculated. It is clear that the coupling of rock deformation and pore fluid flow, compiled with viscoelastic rock properties, chemical potential, and thermal gradient, cause: time-dependent stresses and pore pressure; unusual pore pressure profiles; tensile effective radial stresses into the near wellbore rock formation; time delayed wellbore failure; and the initiation of the wellbore failure inside the wellbore walls. All the aforementioned phenomena have also been observed in the field; and all or most of them cannot be predicted by any of the existing conventional approaches for the inclined wellbore, since the cornerstone of these solutions take only account of the elastic theory and superpose the diffusion equation without any coupling effects.

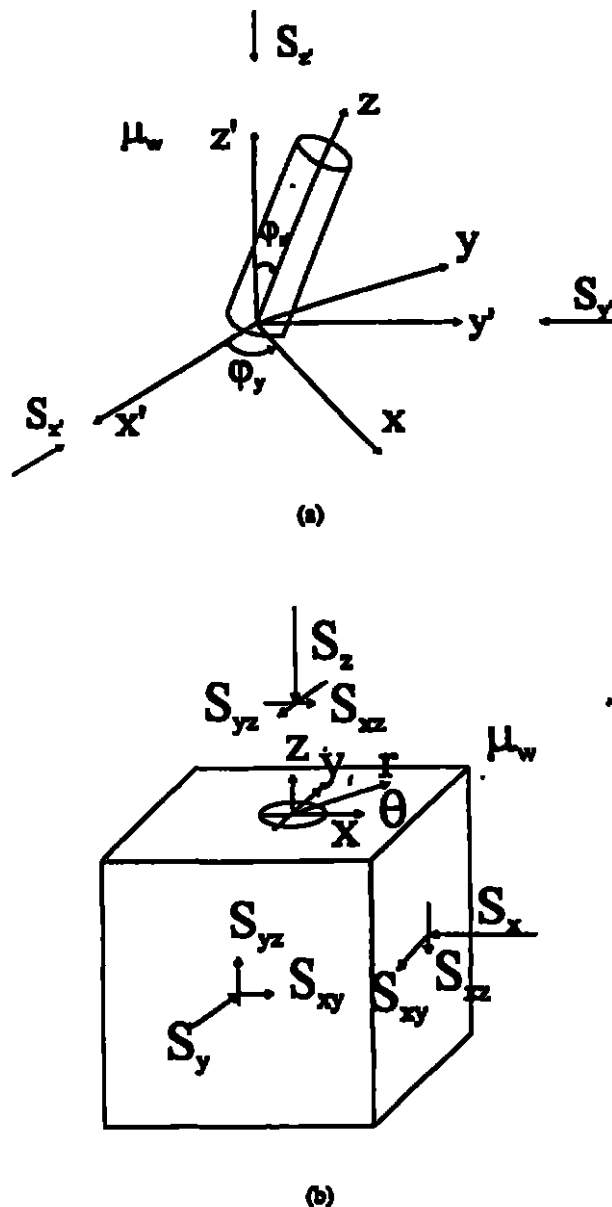


Fig. 1 - Geometry of an inclined borehole. Figure 1(a) shows a borehole drilled inclined to the far-field principal stresses. The inclined borehole is defined by two angles as shown. Figure 1(b) shows the anisotropic state of stress in the local coordinate system.

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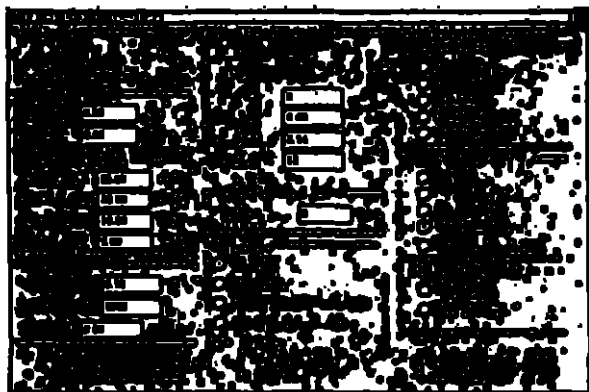


Fig. 2 - Geometric properties input box in FBORE-3D. The input is in a user-friendly dialog box and requires the user to enter data for the wellbore like the inclination angles, in-situ stresses, failure criterion, depth, etc. Within this dialog box the user can also select analysis type and the pore fluid condition to be used. Depending on the analysis type used the appropriate material properties dialog box will appear.



Fig. 3 - Material properties input dialog. The figure shows the input dialog for the material properties for the porochemoelastic analysis. The input required is the elastic parameters (Young's Modulus, Poisson's ratio), the poroelastic parameters (Skempton's Coefficient, Undrained Poisson's ratio, etc.), the chemical properties (formation activity, mud activity, reflection coefficient, etc.) and the time intervals at which the analysis is desired.

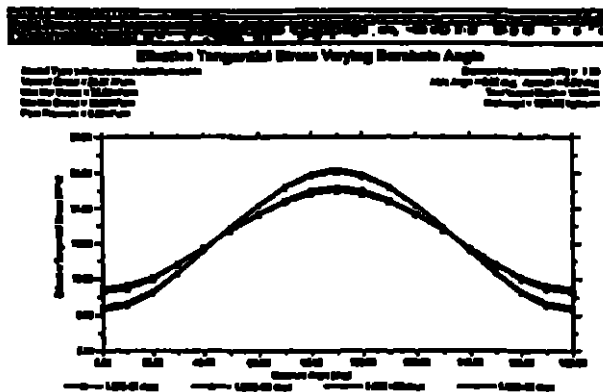


Fig. 4 - Effective tangential stress varying angle around borehole. This figure shows the effective tangential stress distribution at the borehole wall varying the angle around the borehole. The computations are performed for a porochemoelastic analysis type. However the formation activity and the mud activity are assumed to be the same and resulting in no chemical potential gradient. Therefore results are the same as would be seen from a poroelastic analysis. The variation of the effective tangential stress with time is significant.

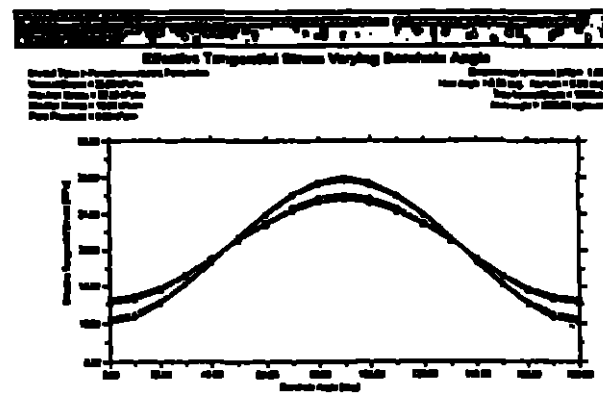


Fig. 5 - Effective tangential stress varying angle around the borehole. This figure shows the effective tangential stresses at the borehole wall for the porochemoelastic case. The formation and mud activities are different while other properties are the same as in Fig. 4. A chemical potential gradient exists and results in a substantial variation of the effective tangential stress field as compared to that in Fig. 4

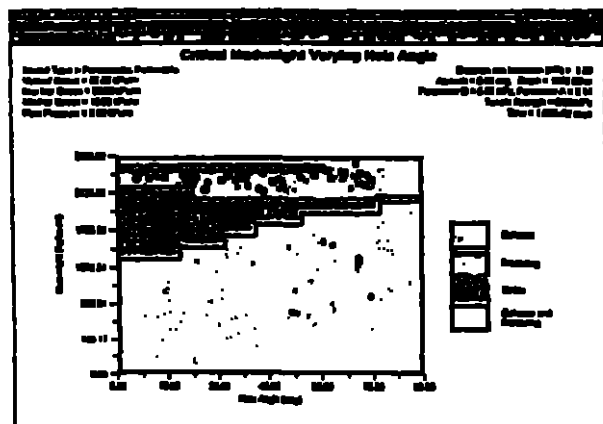


Fig. 6 - Mudweight varying hole angle. This figure shows the mudweight varying with the hole angle for the porochemoelastic analysis. The formation and mud activities are assumed to be the same as a result of which no chemical potential gradient exists and the results are the same as obtained from a poroelastic analysis. Significant collapse and fracturing regions are seen in the plot.

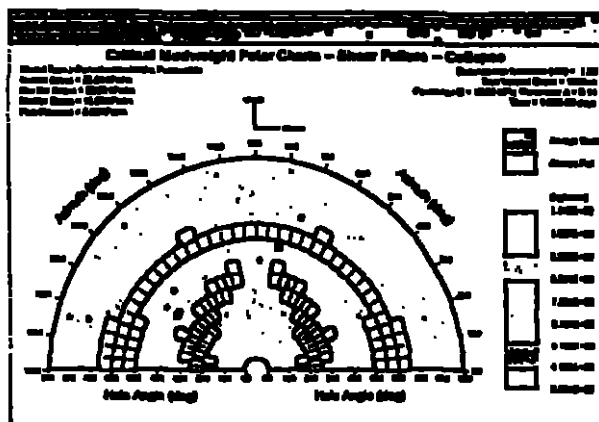


Fig. 8 - Critical mudweight polar charts for shear collapse. This figure shows the critical mudweight polar charts for a porochemoelastic material. The formation and mud activities however are assumed to be the same indicating that no chemical potential gradient exists and that the results are the same as seen from a poroelastic analysis. The polar charts vary the hole angle and the azimuth and color code the critical mudweights for various hole angles and azimuths according to legend. Critical mudweight polar charts for a shear collapse condition with a Drucker-Prager criteria are shown here.

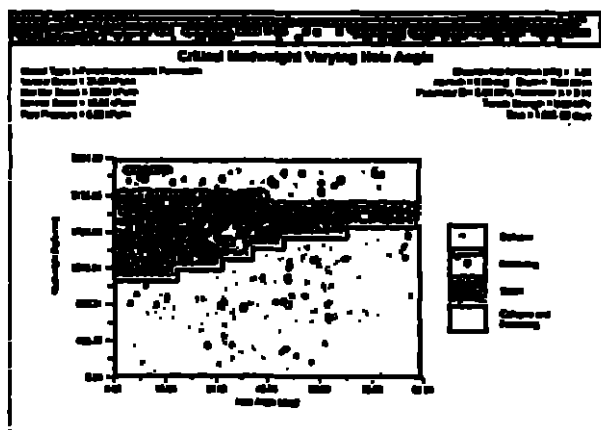


Fig. 7 - Mudweight varying the hole angle. This figure shows the mudweight varying with hole angle for the porochemoelastic analysis. The formation and mud activities are assumed to be different as a result of which a chemical potential gradient exists which will alter the stress distributions around the wellbore. As compared to the results shown in Fig. 6, keeping the formation and mud activities different can lead to a better mud window as is seen in this figure. The collapse and fracturing regions are significantly reduced indicating that the chemical potential gradient has a positive effect in this case.

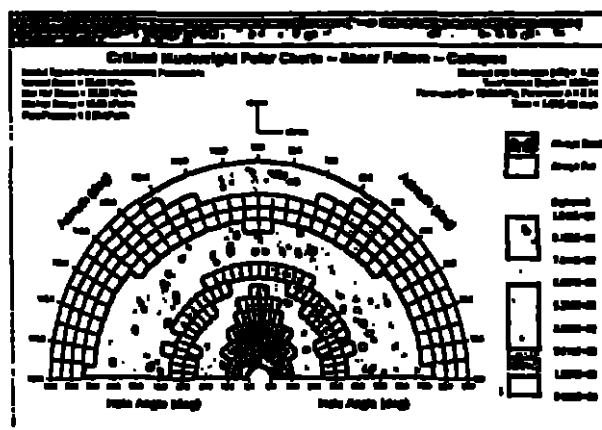


Fig. 9 - Critical mudweight polar charts for shear collapse. This figure shows the critical mudweight polar charts for the porochemoelastic case where the formation and mud activities are assumed to be different. A chemical potential gradient exists and results are different from those predicted by a poroelastic analysis. Compared to the results shown in Fig. 8 the critical mudweight distributions for this case are significantly different.

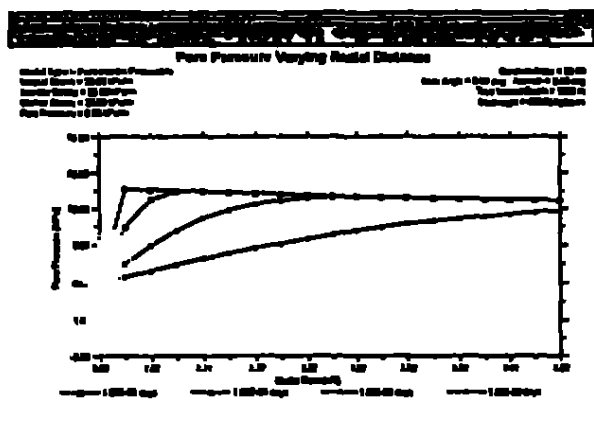


Fig. 10 – Pore pressure varying radial distance. This figure shows the pore pressure distribution varying radial distance from the borehole along the minimum horizontal stress direction for the poroelastic analysis type. An increase in the pore pressure close to the borehole is observed due to the Skempton effect.

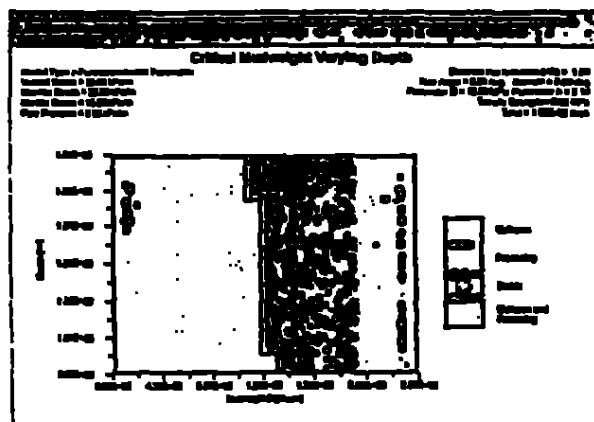


Fig. 12 – Critical mudweight varying with depth. This figure shows the mud window varying with depth for the poroelastoelastic analysis. It can be seen that as the depth increases the mud window reduces in size.

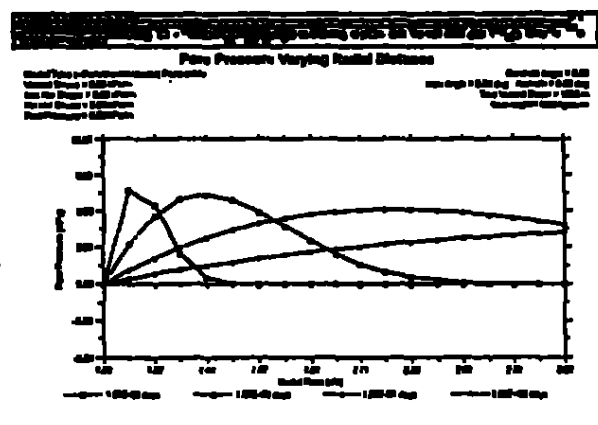


Fig. 11 – Pore pressure varying radial distance. This figure shows the pore pressure profile varying the radial distance into the formation. The in-situ stresses and virgin formation pore pressure have been assumed to be trivial so that the induced pore pressure is only due to the existence of a thermal gradient. It can be seen that only a thermal gradient can also induce a significant magnitude of pore pressure (Li 1988).

Nomenclature

- σ_{ij} = total stress tensor components, m/L^2 , MPa
 D_{ij} = drained elastic modulus tensor components, m/L^2 , MPa
 α_{ij} = Biot's effective stress coefficient tensor components
 p = pore pressure, m/L^2 , MPa
 M = Biot's modulus, m/L^2 , MPa
 ζ = pore fluid content variation
 ϵ_{ij} = overall strain tensor components
 E = drained Young's modulus, m/L^2 , MPa
 ν = drained Poisson's ratio
 ν_u = Undrained Poisson's ratio
 B = Skempton's pore pressure coefficient
 α = Biot's effective stress coefficient
 η = Poroelastic stress coefficient
 c = Diffusivity, L^2
 k = Permeability, L^2 , md
 μ = Chemical potential, ML^2/K^2 , N.m
 V_w = Partial molar volume of water, L^3 , m^3
 a_w = Activity
 R = Universal Gas Constant
 T = Temperature, deg C
 θ, ϕ_r = Inclination and Azimuth angles of the borehole, degrees
 S_x, S_y, S_z = Far-field stresses in $x'y'z'$ coordinate system, m/L^2 , MPa
 S_x, S_y, S_z = Far-field stresses in xyz coordinate system,

- $S_{xx} S_{yy} = m/L^2$, MPa
 $H(t) =$ Heaviside unit step function
 $l_{xy}, l_{yz}, \text{etc} =$ Direction cosines between $x'y'z'$ and xyz coordinate system
 $\bar{\sigma}_{ij} =$ Total stress tensor components in Laplace Transform Domain
 $\bar{D}_{ijkl} =$ Drained correspondence elastic modulus tensor components
 $\bar{\alpha}_{ij} =$ Biot's correspondence effective stress coefficient tensor components
 $\bar{p} =$ Pore pressure in Laplace Transform Domain
 $\bar{M} =$ Correspondence Biot's modulus
 $\bar{\zeta} =$ pore fluid content variation in Laplace Transform Domain
 $\bar{\epsilon}_{ij} =$ overall strain tensor components in Laplace transform domain
 $\alpha_v^T =$ Coefficient of volumetric expansion for formation material, per deg C
 $\alpha_f^T =$ Coefficient of Volumetric expansion for fluid, per deg C
 $\phi_0 =$ Porosity

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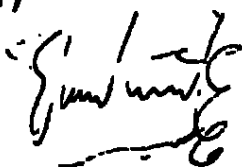
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