

18/15

Señor

SUPERINTENDENTE DE INDUSTRIA Y COM
DIVISION DE NUEVAS CREACIONES

SUPERINDUSTRIA Y COMERCIO
Radicación : 01011417 00000002 Folios: 146
Fecha (AMD): 2001-05-30 16:49:20
Trámite : 002 PATENTES D 1 REGISTRO/ 444 RESPUESTA
Dependencia: 2020 DIVISION DE NUEVAS CREACIONES

E. _____ S. _____ D. _____

Re: **P1.-EXXONMOBIL UPSTREAM RESEARCH COMPANY.-**
Solicitud de Patente de Invención para "METODO Y APARATO
PARA LA ESTIMULACION DE MULTIPLES INTERVALOS DE
FORMACIÓN".-Clase C. 10-Expediente número 01-011.417.-

1. Me refiero a la solicitud de patente arriba nombrada de 14 de Febrero de 2001 y al requerimiento hecho por ese Despacho notificado por fijación en lista de fecha 5 de Abril del mismo año.

2. Anexos me permito presentar a usted:

(1) En original y dos copias, una de ellas de 6cm x 6cm, Arte Final de la figura característica de la Invención para la publicación en la Gaceta de la Propiedad Industrial;

(2) Copias auténticas dos (2) de las primeras solicitudes de patente presentadas para el invento arriba nombrado, **respecto de las cuales reclamo prioridad**, a saber:

(a) Copia auténtica debidamente certificada de la solicitud estadounidense número 60/182.687 de 15 de Febrero de 2000, junto con su traducción correspondiente a las legalizaciones y reivindicaciones de dicho documento; y

(b) Copia auténtica debidamente certificada de la solicitud estadounidense número 60/244.258 de 30 de Octubre de

2000, junto con su traducción correspondiente a las legalizaciones y reivindicaciones de dicho documento.

- (3) Documento que acredita el traspaso que los autores del invento de la referencia hacen a favor de mi representando, de sus derechos sobre el mismo, debidamente apostillado, junto con su traducción oficial número 8259, debidamente legalizada hasta por el Ministerio de Relaciones Exteriores de Colombia bajo los números 131566, 131568 y 131565 de 4 de Mayo de 2001 correspondiente a las legalizaciones y partes pertinentes de dicho documento de traspaso.

3. Anexa también me permito presentar copia debidamente autenticada por el Notario Sexto del Circulo de Bogotá, de los documentos que acreditan la calidad de Traductor Oficial del señor Gabriel Rueda Chadid quien elaboró las traducciones de las legalizaciones y las reivindicaciones de las solicitudes estadinenses número 60/182.687 y 60/244.258 de 15 de Febrero y 30 de Octubre de 2000.

4. Anexa también me permito presentar fotocopia, debidamente autenticada por el Notario Sexto del Circulo de Bogotá, del documento que acredita al suscrito y/o al doctor JOSE LLOREDA CAMACHO y/o a la doctora AURA DUEÑAS RODRIGUEZ, y/o al doctor GUSTAVO TAMAYO y/o a la doctora ANGELA MARIA RESTREPO y/o a la doctora ALICIA LLOREDA, en los términos del Párrafo 1º del Artículo 543 del Decreto-Ley 410 de 1971, como Representantes Legales en Bogotá para todos los asuntos relacionados con la Propiedad Industrial de la sociedad EXXONMOBIL UPSTREAM RESEARCH COMPANY, organizada y existente de conformidad con las Leyes del Estado de Delaware, Estados Unidos de América y domiciliada en Houston, Estado de Texas, Estados Unidos de América.

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5. Con el texto del documento mencionado presento, asimismo, fotocopias, debidamente autenticadas por el Notario Sexto del Circulo de Bogotá, de:

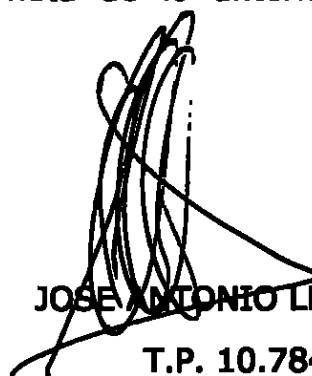
- (a) Certificado Notarial, expedido el 15 de Marzo de 2000, que acredita la existencia y representación de mi representando en los términos del Artículo 64 del Decreto 1400 de 1970 y 480 del Decreto Ley 410 de 1971;
- (b) Autenticación del anterior Certificado Notarial por el Secretario de Estado del Estado de Texas, Estados Unidos de América, de 17 de Marzo de 2000;
- (c) Autenticación del anterior documento por el Cónsul de Colombia en Houston, Estado de Texas, Estados Unidos de América, de fecha 23 de Marzo de 2000;
- (d) Autenticación del anterior certificado expedido por el Cónsul de Colombia en Houston, Estado de Texas, Estados Unidos de América, nombrado por el Ministerio de Relaciones Exteriores de Colombia, bajo el número 240730 de 29 de Marzo de 2000; y
- (e) Traducción Oficial No. 007 de las partes pertinentes del documento anterior, también debidamente legalizada hasta por el Ministerio de Relaciones Exteriores de Colombia bajo el número 037113 de 29 de Marzo de 2000.

6. En consecuencia, ruego a usted reconocer mi calidad de Representante Legal respecto de la sociedad EXXONMOBIL UPSTREAM RESEARCH COMPANY, toda vez que se ha allegado a esa División el poder necesario y se ha acreditado su existencia y representación dentro de los términos legales (Artículos 26 y 39 de la Decisión 486).

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7. Ruego a usted tomar atenta nota de lo anterior y proceder de conformidad.

Señor SuperIntendente,



JOSE ANTONIO LLORED A
T.P. 10.784
Código 231



FORMATO DE DIGITALIZACION
RELACION DE ANEXOS



Royal
Technologies S.A.
Incorporated in the United States of America

Expediente No		No de Folio
Item	No de unidades	
1 CD		
2 DVD		
3 REVISTA		
4 LIBRO		
5 PERIODICO		
6 DISQUETES		
7 SOBRE DE MANILA	1	
8 SOBRE BLANCO TAMAÑO CARTA		
9 SOBRE BLANCO TAMAÑO OFICIO		
10 OTROS:		

Observaciones: Ate Fiml

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EL SUSCRITO JEFE DEL AREA DE
LEGALIZACIONES DE MINISTERIO DE
RELACIONES EXTERIORES.

HACE CONSTAR

COMO NOTARIO SEXTO DE
SANTAFE DE BOGOTA
HAGO CONSTAR
QUE LA FOTOCOPIA CON LA FOTOCOPIA
AUTENTICA QUE HE TENIDO A LA VISTA
SANTAFE DE BOGOTA 13 DIC 2000
JUAN PABLO MENDOZA

Que el señor Gabriel Rueda, se encuentra debidamente
registrado ante este Ministerio, como traductor e
intérprete oficial para los idiomas INGLES -ESPAÑOL,
ESPAÑOL - INGLES.

Para efectos de ésta certificación el interesado presenta
copia autenticada de la certificación del Ministerio de
Justicia acerca de la vigencia de la resolución
1982.

Dada en Santafé de Bogotá, D.C. a 19 de diciembre de 1998 y nueve días
(19) del mes de diciembre de 1998

COMO NOTARIO SEXTO ENCARGADO
DE SANTAFE DE BOGOTA
HAGO CONSTAR
QUE LA FOTOCOPIA CON LA FOTOCOPIA
AUTENTICA QUE HE TENIDO A LA VISTA
SANTAFE DE BOGOTA
PABLO MENDOZA BARAJAS

Neibón Sánchez Torres
Jefe Área de Legalizaciones

COMO NOTARIO SEXTO ENCARGADO DEL CIRCULO
DE SANTAFE DE BOGOTA, HAGO CONSTAR QUE
ESTA COPIA POTESTATIVA CONCORDA CON EL ORIGINAL
QUE HE TENIDO A LA VISTA
01 JUL 1998
PABLO MENDOZA

COMO NOTARIO SEXTO DE
SANTAFE DE BOGOTA
HAGO CONSTAR
QUE LA FOTOCOPIA CON LA FOTOCOPIA
AUTENTICA QUE HE TENIDO A LA VISTA
SANTAFE DE BOGOTA 01 JUL 2000
JUAN PABLO MENDOZA

NST/gtm.



Ministerio de Justicia y del Derecho

EL SECRETARIO GENERAL DEL MINISTERIO DE
JUSTICIA Y DEL DERECHO

CERTIFICA:

Que por Resolución 5996 del 29 de noviembre de 1982, le fue expedida licencia para ejercer funciones de Traductor e Intérprete Oficial en los idiomas INGLÉS-ESPAÑOL, ESPAÑOL-INGLÉS a GABRIEL RUEDA CHADID, identificado con la cédula de ciudadanía No. 7.124.145 expedida en Bogotá. Que dicha resolución se encuentra vigente en la fecha.

A solicitud del interesado, en Santa Fe de Bogotá, D.C., a los 17 meses de noviembre de 1994.

JORGE LEIS SABOGAL SABOGAL

COMO NOTARIO SEXTO DE
SANTAFE DE BOGOTA
HAGO CONSTAR
QUE LA FOTOCOPIA CONIENE CON LA FOTOCOPIA
AUTENTICA QUE HE TENIDO A LA VISTA
SANTAFE DE BOGOTA, 13 JUL 2000

COMO NOTARIO SEXTO DE BOGOTA
HAGO CONSTAR
QUE LA FOTOCOPIA CONIENE CON LA FOTOCOPIA
AUTENTICA QUE HE TENIDO A LA VISTA
SANTAFE DE BOGOTA, 21 FEB 2001
PAULO MENDEZ BARANAS

COMO NOTARIO SEXTO DE BOGOTA
HAGO CONSTAR
QUE LA FOTOCOPIA CONIENE CON LA FOTOCOPIA
AUTENTICA QUE HE TENIDO A LA VISTA
SANTAFE DE BOGOTA, 21 AGO 1998

SECRETARIO
GENERAL
REPUBLICA DE COLOMBIA

HAGO CONSTAR
QUE LA FOTOCOPIA CONIENE CON LA FOTOCOPIA
AUTENTICA QUE HE TENIDO A LA VISTA
SANTAFE DE BOGOTA, 01 SET 2000

COMO NOTARIO SEXTO DE
SANTAFE DE BOGOTA
HAGO CONSTAR
QUE LA FOTOCOPIA CONIENE CON LA FOTOCOPIA
AUTENTICA QUE HE TENIDO A LA VISTA
SANTAFE DE BOGOTA, 01 JUL 1998

W/R/unc

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TRIBUNAL SUPERIOR DEL DISTRITO JUDICIAL DE SANTAFE DE BOGOTA
SECRETARIA GENERAL

LA SUSCRITA SECRETARIA DEL H. TRIBUNAL SUPERIOR DEL DISTRITO JUDICIAL
DE SANTAFE DE BOGOTA,

COMO NOTARIO SEXTO DE
SANTAFE DE BOGOTA
HAGO CONSTAR
QUE LA FOTOCOPIA CONCORDA CON LA FOTOCOPIA
AUTENTICA QUE HE TENIDO A LA VISTA
SANTAFE DE BOGOTA
13 DIC 2000
JUAN MANUEL SUTERO MEDINA
NOTARIO

CERTIFICA:

Que el Acuerdo No. 183 de diciembre 3 de 1982 emanado de esta Corporación, por medio del cual dió posesión al señor GABRIEL RUEDA CHADID identificado con Cédula de Ciudadanía No. 9.999.999 de Bogotá como TRADUCTOR E INTERPRETE OFICIAL de los HABLA ESPAÑOL-INGLES, en virtud de la Resolución No. 1000 de 1998 VIGENTE.

COMO NOTARIO SEXTO DE
SANTAFE DE BOGOTA
HAGO CONSTAR
QUE LA FOTOCOPIA CONCORDA CON LA FOTOCOPIA
AUTENTICA QUE HE TENIDO A LA VISTA
SANTAFE DE BOGOTA
01 SET 2000
JUAN MANUEL SUTERO MEDINA
NOTARIO

Se expide en Santafé de Bogotá D.C., dieciséis (16) de noviembre
mil novecientos noventa y cuatro (1994).

MARIA INES RODRIGUEZ TORRES
SECRETARIA
COMO NOTARIO SEXTO DE
SANTAFE DE BOGOTA
HAGO CONSTAR
QUE LA FOTOCOPIA CONCORDA CON LA FOTOCOPIA
AUTENTICA QUE HE TENIDO A LA VISTA
SANTAFE DE BOGOTA
08 SET 1998
PABLO MENDEZ BARAJAS

COMO NOTARIO SEXTO DE
SANTAFE DE BOGOTA
HAGO CONSTAR
QUE LA FOTOCOPIA CONCORDA CON LA FOTOCOPIA
AUTENTICA QUE HE TENIDO A LA VISTA
SANTAFE DE BOGOTA
01 JUL 1998
JUAN MANUEL SUTERO MEDINA
NOTARIO
COMO NOTARIO SEXTO DE
SANTAFE DE BOGOTA
HAGO CONSTAR
QUE LA FOTOCOPIA CONCORDA CON LA FOTOCOPIA
AUTENTICA QUE HE TENIDO A LA VISTA
SANTAFE DE BOGOTA
01 JUL 1998
JUAN MANUEL SUTERO MEDINA
NOTARIO

CRM./

125
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Exxonmobil Upstream Research Company. 01.011.417

REF: LLC-0035-2001. La presente es Traducción Oficial de un documento presentado originalmente en inglés. Esta traducción es elaborada por Gabriel Rueda Chadid (Traductor Oficial).

ESTADOS UNIDOS DE AMERICA

A TODOS AQUELLOS QUE LLEGAREN A LEER EL CONTENIDO DEL

PRESENTE DOCUMENTO LES CERTIFICAMOS:

DEPARTAMENTO DE COMERCIO DE LOS ESTADOS UNIDOS

Oficina de Marcas y Patentes de los Estados Unidos

Enero 22 del 2001

Se certifica que anexo se encuentra fiel copia de los Registros de la Oficina de Marcas y Patentes de los Estados Unidos correspondientes a los documentos de la patente solicitada y cuya identificación aparece más adelante, la cual cumplió con los requerimientos exigidos para que se otorgue una fecha de presentación de acuerdo con los dispuesto en la Sección 35 USC 111.

Número de Solicitud: 60/182.687

Fecha de presentación: Febrero 15, 2000

Por autorización del

COMISIONADO DE MARCAS REGISTRADAS Y PATENTES

L. EDELEN

Funcionario Encargado de Certificaciones (Hay firma y sello)

**GABRIEL RUEDA CHADID
TRADUCTOR OFICIAL
RESOLUCION 1996 DE NOV. 29-83
MINISTERIO DE JUSTICIA**

Indicar con un signo (+) dentro de esta casilla --> +

Expediente No.: 2000.008

PORTADA PARA LA SOLICITUD PROVISIONAL DE PATENTES

La presente solicitud de presentación de solicitud provisional de acuerdo con 37 CFR 1.53 (c)

INVENTOR(ES)/SOLICITUD(ES)

Apellido	Primer Nombre	Lugar de Residencia (Ciudad y Estado o País)
Randy C.	Tolman	
Lawrence O.	Carlson	
David A.	Klnison	3326 Three Pines Drive, Kingwood, Texas 77339
Kris J.	Nygaard	4019 Tartan, Houston, Texas 77025

TITULO DEL INVENTO (280 caracteres máximo)

**METODO Y APARATO PARA ESTIMULACION DE INTERVALOS DE
FORMACIONES MULTIPLES**

DIRECCION DE CORRESPONDENCIA

[X] Nombre: Mr. Salvatore J. Casamassima; Ms. Linda A. Kubena

Dirección: ExxonMobil Upstream Research Company

Dirección: P.O. Box 2189

Ciudad: Houston Estado: Texas Código: 77252-2189

País: Estados Unidos Tel: 713-431-4577 Fax: 713-431-4664

PARTES ADJUNTAS DE LA SOLICITUD (indicar lo que se aplica)

X Especificaciones Número de Páginas: 22

128.
125

1 Dibujos

Número de Láminas: 1

FORMA DE PAGO (Indicar)

X El Comisionado queda autorizado para cobrar los derechos de presentación y acreditar la cuenta No. 05-1328

DERECHOS PROVISIONALES DE PRESENTACION: \$ 150.00

Fue elaborado por una entidad del Gobierno de los Estados Unidos, o bajo contrato con entidades del Gobierno de dicho país

X No.

Firmado, Fecha: Febrero 15, 2000

NOMBRE: LINDA A. KUBENA No. de Registro: 42.772

TELONO: 713-431-4577

SOLICITUD PROVISIONAL DE PATENTES (PAGINA ADICIONAL)

La presente solicitud de presentación de solicitud provisional de acuerdo con 37 CFR 1.53 (c)

INVENTOR(ES)/SOLICITUD(ES)

Primer Nombre	Apellido	Lugar de Residencia
		(Ciudad y Estado o País)
Gleen S.	Goss	1630 Scenic Mountain Court, Kingwood, Texas 77345
William A.	Soren	20606 Fawbrook Court, Katy, Texas 77450
Lee L.	Shafer	

fr 9
GABRIEL RUEDA CHADID
TRADUCTOR OFICIAL
RESOLUCION 5996 DE NOV. 29-81
MINISTERIO DE JUSTICIA

REIVINDICACIONES

1. Un método para perforar y tratar por lo menos un intervalo de una perforación de pozo que penetra una formación subterránea que corresponde sustancialmente a la que se describe y reivindica en el presente documento.

2. Un conjunto de "bottom" para perforar y tratar por lo menos un intervalo de una perforación de pozo que penetra una formación subterránea que es sustancialmente como se describe y reivindica en el presente documento.

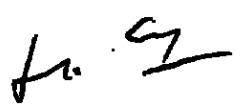
3. Un método para perforar y tratar por lo menos un intervalo de una perforación de pozo que penetra una formación subterránea, donde el método comprende los siguientes pasos:

- (a) suspender un mecanismo de perforación y un dispositivo de sellado reconfigurable en el mencionado perforador de pozo;
- (b) perforar un primer intervalo utilizando el mencionado mecanismo de perforación, con el fin de crear perforaciones que permitan la comunicación entre la mencionada formación subterránea y la mencionada perforación de pozo;
- (c) posicionar el mencionado dispositivo de sellado reconfigurable por debajo del mencionado intervalo perforado;

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- (d) bombear un fluido de tratamiento a través de la mencionada perforación de pozo ubicándose dentro de las mencionadas perforaciones;
 - (e) liberar el mencionado dispositivo de sellado reconfigurable; y
 - (f) repetir los pasos (b) hasta (e) durante los intervalos deseados.

La anterior es Traducción Oficial de un documento presentado originalmente en inglés. Esta traducción fue realizada por **GABRIEL RUEDA CHADID** (Traductor Oficial). Resolución 5996 del Minjusticia, por lo cual estampo mi Sello y Firmo.

Bogotá D.C., Mayo 4 del 2001.


GABRIEL RUEDA CHADID
TRADUCTOR OFICIAL
RESOLUCION 5996 DE NOV. 29-01
MINISTERIO DE JUSTICIA

FOR L. EDLEN
60/182,687
01.01.4/17
125
100

PA 351929



THE UNITED STATES OF AMERICA

TO ALL TO WHOM THESE PRESENTS SHALL COME:

UNITED STATES DEPARTMENT OF COMMERCE

United States Patent and Trademark Office

January 22, 2001

THIS IS TO CERTIFY THAT ANNEXED HERETO IS A TRUE COPY FROM THE RECORDS OF THE UNITED STATES PATENT AND TRADEMARK OFFICE OF THOSE PAPERS OF THE BELOW IDENTIFIED PATENT APPLICATION THAT MET THE REQUIREMENTS TO BE GRANTED A FILING DATE UNDER 35 USC 111.

APPLICATION NUMBER: 60/182,687

FILING DATE: February 15, 2000



**By Authority of the
COMMISSIONER OF PATENTS AND TRADEMARKS**

L. Edelen

**L. EDELEN
Certifying Officer**

EXPRESS MAIL LABEL # EJ 201462526 US

Please type a plus sign (+) inside this box →

02.16.00

Docket Number:

2008.008

A 129

PROVISIONAL APPLICATION FOR PATENT COVER SHEET (Large Entity)

This is a request for filing a PROVISIONAL APPLICATION FOR PATENT under 37 CFR 1.53 (c).

INVENTOR(S)/APPLICANT(S)

Given Name (first and middle (if any))	Family Name or Surname	Residence (City and either State or Foreign Country)
Randy C. Lawrence O. David A. Kris J.	Telmer Carlson Kilson Nygaard	2328 Three Pines Drive, Kingwood, Texas 77339 4819 Tartan, Houston, Texas 77025

☒ Additional inventors are being named on page 2 attached hereto

TITLE OF THE INVENTION (200 characters max)

METHOD AND APPARATUS FOR STIMULATION OF MULTIPLE FORMATION INTERVALS

Direct all correspondence to:

CORRESPONDENCE ADDRESS

☐ Customer Number

Place Customer Number
Bar Code Label here

OR

☒ Firm or Individual Name Mr. Salvatore J. Casarrese; Ms. Linda A. Kubena

Address ExxonMobil Upstream Research Company

Address P. O. Box 2189

City Houston State Texas ZIP 77262-2189

Country United States Telephone 713-431-4577 Fax 713-431-4684

ENCLOSED APPLICATION PARTS (check all that apply)

☒ Specification Number of Pages 22

☒ Drawing(s) Number of Sheets 1 ☐ Other (specify)

METHOD OF PAYMENT OF FILING FEES FOR THIS PROVISIONAL APPLICATION FOR PATENT (check one)

☐ A check or money order is enclosed to cover the filing fees

FILING FEE
AMOUNT (\$)

☒ The Commissioner is hereby authorized to charge filing fees or credit any overpayment to Deposit Account Number:

05-1328

\$150.00

The invention was made by an agency of the United States Government or under a contract with an agency of the United States Government.

☒ No

☐ Yes, the name of the U.S. Government agency and the Government contract number are:

Respectfully submitted,

SIGNATURE

DATE

February 15, 2000

TYPED or PRINTED NAME Linda A. Kubena

REGISTRATION NO.
(if appropriate)

42,772

TELEPHONE

713-431-4577

USE ONLY FOR FILING A PROVISIONAL APPLICATION FOR PATENT

SEND TO: Box Provisional Application, Assistant Commissioner for Patents, Washington, DC 20231

**METHOD AND APPARATUS FOR STIMULATION OF MULTIPLE
FORMATION INTERVALS**

5

FIELD OF THE INVENTION

This invention relates generally to the field of perforating and treating
subterranean formations to increase the production of oil and gas therefrom. More
specifically, the invention provides an apparatus and a method for perforating and
treating multiple intervals without the necessity of removing equipment from the
10 wellbore between steps or stages.

BACKGROUND OF THE INVENTION

When multiple hydrocarbon-bearing zones are stimulated by hydraulic
fracturing or acid stimulation treatments, economic and technical gains are realized by
injecting multiple treatment stages that can be diverted (or separated) by various
15 devices such as mechanical plugs, ball sealers, or chemical agents.

In mechanical diversion, the deepest interval is first perforated and fracture
stimulated, then the interval is isolated mechanically and the process is repeated in the
next interval up. For example, the deepest 30 meters (about 100 feet) of formation
thickness might be perforated, fractured, and propped with sand. A mechanical bridge
20 plug would then be placed within the casing just above the treated interval and the
process repeated on the next 30 meters (about 100 feet). To treat 300 meters (about
1,000 feet) of formation in this manner would require ten jobs over a time interval of
ten days to two weeks with not only multiple fracture treatments, but also multiple
perforating and bridge plug running operations. At the end of the treatment process, a
25 wellbore clean-out operation would be required to remove the bridge plugs and put
the well on production. The major advantage of using mechanical separation is high
confidence that the entire target zone is treated. The major disadvantages are the high

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cost of treatment and the risk of complications resulting from so many operations on the well. For example, a bridge plug can become stuck in the casing and need to be drilled out at great expense. A further disadvantage is that the required wellbore clean-out operation often damages some of the successfully fractured intervals.

- 5 One alternative to using bridge plugs is filling the just fractured interval of the wellbore with fracturing sand, commonly referred to as the Pine Island technique. The sand column essentially plugs off the already fractured interval and allows the next interval to be perforated and fractured independently. The primary advantage is elimination of the problems and risks associated with bridge plugs. The
- 10 disadvantages are that the sand plug does not give a perfect hydraulic seal and it can be difficult to remove from the wellbore at the end of all the fracture stimulations. Unless the well's fluid production is strong enough to carry the sand from the wellbore, the well may still need to be cleaned out with a work-over rig or coiled tubing unit. As before, additional wellbore operations increase costs, mechanical
- 15 risks, and risks of damage to the fractured intervals.

- Another possible process is limited entry diversion in which the entire target zone of the formation to be treated is perforated with a very small number of perforations, generally of small diameter, so that the pressure loss across those perforations during pumping promotes a high, internal wellbore pressure. The
- 20 internal wellbore pressure is designed to be high enough to cause all of the perforated intervals to fracture at the same time. If the pressure were too low, only the weakest portions of the formation would fracture. The primary advantage is that there are no inside-the-casing obstructions like bridge plugs or sand to cause problems later. The disadvantage is that limited entry fracturing often does not work well for thick
- 25 intervals because the resulting fracture is frequently too narrow (the proppant cannot all be pumped away into the narrow fracture and remains in the wellbore), and the initial, high wellbore pressure does not last. As the proppant material is pumped, the perforation diameters are eroded to larger sizes that quickly reduce the internal wellbore pressure. The net result can be that not all of the target zone is stimulated.

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The problem with failure to stimulate the entire target zone can be addressed by using limited, concentrated perforated intervals diverted by ball sealers. The zone to be treated could be divided into sub-zones with perforations at approximately the center of each of those sub-zones. The fracture stages would then be pumped with diversion by ball sealers at the end of each stage. Specifically, 300 meters (about 1,000 feet) of gross formation might be divided into ten sub-zones of about 30 meters (about 100 feet) each. At the center of each 30 meter (about 100 foot) sub-zone, ten perforations might be shot at a density of three shots per meter (one shot per foot) of casing. A fracture stage would then be pumped with sand-laden fluid followed by at least ten ball sealers, one for each open perforation in a single perforation set or interval. The process would be repeated until all of the perforation sets were fractured. This technique presumes that each perforation interval or sub-zone would break down and fracture at sufficiently different pressure that each stage of treatment would enter only one set of perforations. Even though the job could be designed such that fracture stresses were sufficiently different that only one sub-zone should break down at a time, based on the currently available data quality it is difficult to be certain that only one sub-zone will be treated in each stage.

The primary advantages of ball sealer diversion are low cost and low risk of mechanical problems. Costs are low because the process can be completed in one continuous operation, usually during just a few hours of a single day. Only the ball sealers are left in the wellbore to either flow out with produced hydrocarbons or drop to the bottom of the well in an area known as the rat (or junk) hole. The primary disadvantage is the inability to be certain that only one set of perforations will fracture at a time so that the correct number of ball sealers are dropped at the end of each stage. Further disadvantages are lack of certainty that all of the perforated intervals will be treated and lack of knowledge of the order in which these intervals are treated while the job is in progress.

An alternative method that has been developed by several service companies involves the use of a coiled tubing stimulation system to sequentially stimulate

multiple zones. The coiled tubing system has a mechanical "straddle-packer-like" diversion tool attached to the end of the coiled tubing that when properly placed and actuated across the perforations allows hydraulic isolation to be achieved above and below the diversion tool. Stimulation fluid is then pumped down the interior of the coiled tubing and exits flow ports placed in the diversion tool between the upper and lower sealing elements. Various service companies offer this general stimulation method as part of their stimulation product/service line and specific details may be found in service companies' product brochures and industry publications.

As a general overview, existing coiled tubing stimulation systems are typically implemented as follows:

1. The well is drilled and casing cemented across the interval to be completed;
2. The target zones within the completion interval are selected (typically zones containing hydrocarbon-bearing sands as identified by a combination of open-hole and cased-hole logs);
3. All target zones to be stimulated are perforated by a perforating crew that rigs-up on the well, shoots the target zones (possibly in multiple gun trips into the well), and then rigs-down and moves off-site;
4. The coiled tubing stimulation system and crew is mobilized to the well-site and rigged-up for the stimulation job;
5. The coiled tubing with straddle-packer-like diversion tool is run into the well, with the diversion tool placed across the deepest set of perforations such that the upper and lower sealing elements of the diversion tool straddle the perforated interval;

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6. The upper and lower sealing elements of the diversion tool are activated or engaged to obtain hydraulic isolation above and below the diversion tool;

5 7. The "first stage" of the stimulation treatment is pumped down the interior of the coiled tubing string and into the deepest set of perforations;

8. Upon completion of this first stage, the sealing elements are deactivated or disengaged and the coiled tubing pulled upward to place the diversion tool across the second deepest set of perforations and the second stage stimulation is performed;

10 9. This process is continued until either all of the successive targeted sands have been stimulated or the process is aborted due to operational upset.

15 Based on service company documentation, this coiled tubing system has been used to stimulate multiple zones in wells with depths on the order of 7,500 to 8,000 feet. However, the existing coiled tubing systems as currently offered by the service companies are not readily deployable for deeper well conditions due to technical obstacles including the following:

20 1. Excess friction pressure is generated when pumping stimulation fluids, particularly proppant-laden and/or high viscosity fluids, at high rates through longer lengths of coiled tubing. Depending on the size of the coiled tubing and the maximum allowable surface hardware working pressures, pump rates could be limited to just a few barrels per minute; which, for example, would not allow effective placement of proppant during hydraulic fracture treatments.

25 2. Most seal elements (e.g., cup technology) currently used in the operations described above may experience sealing problems or seal failure in

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deeper wells as the seals are run past a large number of perforations at increased well temperatures associated with deeper well depths. Since the seals run in contact with or at a minimal clearance from the pipe wall, rough interior pipe surfaces and/or perforation burrs can damage the sealing elements. Seals currently available in straddle-packer-like diversion tools are also constructed from elastomers which are unable to withstand the higher temperatures often associated with deeper wells.

3. Depth control of the coiled tubing system and straddle-packer-like diversion tool becomes more difficult as depth increases. This problem is compounded by shooting the perforations before running the coiled tubing system in the hole. The perforating operation uses a different depth measurement device (usually a casing collar locator system) than is generally used in the coiled tubing system.

4. Running speed of the existing systems with cup seals is generally on the order of 15 feet-per-minute running downhole to 30 feet-per-minute coming uphole. For example, at the lower running speed, approximately 13 hours would be required to reach a depth of 12,000 feet prior to beginning the stimulation. Given safety issues surrounding nighttime operations, this slow running speed may result in multiple days being required to complete a stimulation job. If any problems are encountered during the job, tripping in and out of the hole may become very costly because of the total operation times associated with the slow running speeds.

Accordingly, there is a need for an improved apparatus and method for perforating and stimulating multiple zones of a subterranean formation.

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SUMMARY OF THE INVENTION

This invention provides a method for perforating and treating at least one interval of a wellbore penetrating a subterranean formation, by suspending a perforating means and a resettable sealing device in the wellbore, perforating a first interval, positioning the sealing device below the perforated interval, pumping a treatment fluid through the wellbore into the perforations, releasing the sealing device; and repeating these steps for as many intervals as desired.

BRIEF DESCRIPTION OF THE DRAWINGS

The present invention and its advantages will be better understood by referring to the following detailed description and the attached drawings in which:

Figure 1 is an illustration of one possible configuration for the bottomhole assembly apparatus.

Figure 2 is an illustration of one variation of the method.

DETAILED DESCRIPTION OF THE INVENTION

The present invention will be described in connection with its preferred embodiments. However, to the extent that the following description is specific to a particular embodiment or a particular use of the invention, this is intended to be illustrative only, and is not to be construed as limiting the scope of the invention. On the contrary, it is intended to cover all alternatives, modifications, and equivalents that are included within the spirit and scope of the invention, as defined by the appended claims.

The present invention provides both a new method and a new apparatus for multi-stage stimulation treatments and will provide significant economic and technical benefits over currently existing methods. The new apparatus consists of a suspension system (e.g., coiled tubing, jointed tubing, electric line, wireline, etc.) with a

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bottomhole assembly comprised of a select-fire perforating gun system and a re-settable packer sealing element as shown conceptually in Figure 1 and designed for the anticipated wellbore environment and loading conditions. As shown conceptually in Figure 2, the new method involves sequentially select-fire perforating and then stimulating the individual zones from bottom to top of the completion interval, with the stimulation fluid pumped down the annular space between the production casing and the suspension system. As discussed further below, this new apparatus and method offer substantial improvements over existing coiled-tubing and jointed tubing stimulation technology and are applicable over a wide range of wellbore architectures and stimulation treatment designs.

The present invention provides a new method for perforating and stimulating multiple formation intervals, which allows each single zone to be treated with an individual treatment stage while eliminating or minimizing the problems with existing coiled tubing systems as identified above. The invention involves individually and sequentially perforating and treating each of the desired multiple zones while pumping the multiple stages of the stimulation treatment and deploying a mechanical re-settable diversion device to provide controlled diversion of each individual treatment stage.

Specifically, a preferred embodiment of the new method involves the following steps, where the stimulation job is chosen, for descriptive purposes, to be a multi-stage hydraulic proppant fracture stimulation:

1. The well is drilled and casing cemented across the interval to be completed;
2. The target zones within the completion interval are identified (typically by a combination of open-hole and cased-hole logs);

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3. A reel of coiled tubing is made-up with a special bottom-hole assembly (BHA);

5 4. The BHA consists of a select-fire perforating gun system with casing-collar-locator, flow ports, and a mechanical re-settable sealing device where the perforating gun system has been designed based on knowledge of the number, location, and thickness of the hydrocarbon-bearing sands within the target zones;

10 5. The coiled tubing with BHA is run into the well via a lubricator system and the coiled tubing injection head is suspended by crane or rig above the wellhead;

15 6. The coiled tubing/BHA is run to the bottom-most target zone such that the first set of perforation charges contained on the select-fire perforating gun system are located directly across the bottom-most target zone where precise depth control is established based on readings from the casing-collar-locator and coiled tubing odometer systems;

7. The first set of perforation charges are selectively-fired by remote actuation and penetrate the casing and cement sheath to establish hydraulic communication with the formation;

20 8. The coiled tubing may be moved to position the top of the re-settable mechanical sealing device directly below the deepest perforation of this first target zone (to minimize potential for proppant fill above the sealing device);

9. The re-settable mechanical sealing device is actuated to effect a hydraulic seal above and below the sealing device;

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10. The first stage of the fracture stimulation treatment is initiated with fluid pumped down the annulus between the coiled-tubing and production casing at fracture stimulation rates; also, static hydraulic pressure can be maintained inside the coiled tubing to resist its collapse.

5 11. At the end of the first stage of the stimulation treatment, the sealing device is actuated to disengage the seal and allow the coiled tubing/BHA to be moved. Should proppant fill above the sealing device occur that prevents the coiled tubing/BHA from immediate movement; fluid can be either reverse-circulated or forward-circulated to wash-over and clean-out the proppant to free the coiled tubing/BHA and allow movement;

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12. The coiled tubing/BHA is then pulled uphole to the second deepest target zone such that the second set of perforation charges contained on the select-fire perforating gun system are located directly across the second deepest target zone where again precise depth control is established based on readings from the casing-collar-locator and coiled tubing odometer systems;

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13. The second set of perforation charges are selectively-fired by remote actuation and penetrate the casing and cement sheath to establish hydraulic communication with the formation; The coiled tubing may be moved to position the top of the re-settable mechanical sealing device directly below the deepest perforation of this second target zone (to minimize potential for proppant fill above the sealing device);

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14. The re-settable mechanical sealing device is actuated to effect a hydraulic seal above and below the sealing device;

15. The second stage of the fracture stimulation treatment is initiated with fluid pumped down the annulus between the coiled-tubing and production casing at fracture stimulation rates;

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16. The entire process as described in Step 11 through Step 15 is repeated until all of the zones are individually-stimulated;

17. Upon completion of the stimulation process, the coiled tubing/BHA assembly is removed from the wellbore;

5 18. The well can be immediately placed on production with the hydrocarbon stream turned to sales.

It will be recognized by those skilled in the art that the preferred suspension method when proppant-laden fluids are involved would be conventional tubing or coiled tubing, preferably with one or more circulation ports so that proppant settling
10 in the wellbore could easily be circulated out of the wellbore. Treatments such as acid fracturing or matrix acidizing may not require such a capability and could generally be performed with a suspension system based on electric line or wireline.

Depending on the suspension system used and the objectives of a particular job, perforating guns and any other desired equipment may be positioned either above
15 or below the resettable sealing device. The suspension system itself, whether it be wireline, electric line, coiled tubing, or conventional tubing may be used to convey signals to activate the sealing device and/or perforating device. It would also be possible to suspend such signaling means within conventional or coiled tubing used to suspend the sealing and perforating devices themselves. Alternatively, the signaling
20 means, whether it be electric, hydraulic, or other means, could be run in the hole externally to the suspension means or even housed in or comprised of one or more separate strings of coiled or conventional tubing.

Several major technological and economic benefits are immediately derived from application of this new invention. Reducing the friction pressure limitations
25 allows treatment of deeper wells and reduces the requirement for special fracture fluid formulations. Friction pressure limitations are reduced or eliminated since the fluid is

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pumped down the annulus between the coiled tubing or other suspension means and production casing. Since friction pressure is drastically reduced from that experienced with pumping down coiled tubing, well depths where this technique can be applied are substantially increased. For example, assuming 1-1/2 inch coiled tubing deployed in a
5 5-1/2 inch outer diameter 17 pound per foot casing, the effective cross-sectional flow area is approximately equivalent to a 5 inch outer diameter casing string. With this effective cross-sectional flow area, well depths on the order of 20,000 feet or greater could be readily treated and higher pump rates (e.g., on the order of 10 to 30 barrels per minute or more) can be achieved for effective proppant transport and hydraulic
10 fracturing.

Since the fluid is pumped down the annulus (the flow path possesses greater equivalent flow area) conventional fracturing fluids can be used, as opposed to special low-viscosity fluids such as Dowell-Schlumberger's ClearFrac™ fluid (used to reduce friction pressure drop through coiled tubing). The use of conventional fracturing fluid
15 technology then enables treatment of formations with temperatures greater than 250 °F, which is currently the degradation limit for ClearFrac™ fluid.

The sealing device used could be an inflatable device or a currently available mechanical re-settable packer. Mechanical re-settable packers exist that provide substantial clearance between seals and casing wall (i.e., on the order of 0.10 - 0.20
20 inches) such that seal wear and tear will be drastically reduced or eliminated altogether. In preferred embodiments of this invention, there would be sufficient clearance between the sealing device in its deactivated state and the casing wall to allow rapid movement into and out of the wellbore without significant damage to the sealing device. The seal technology using mechanical re-settable packers that
25 provides clearance between the seal surface and the casing wall (when the seal is not actuated) would also allow the coiled tubing/BHA to be tripped in and out of the hole at much faster speeds than currently existing coiled tubing systems.

Other advantages of the inventive apparatus are as follow:

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1. Since the perforating gun is deployed simultaneously with the coiled tubing and resettable sealing device all components can be depth controlled at the same time by the same measurement standard. This eliminates depth control problems that existing coiled tubing systems possess when perforation operations and stimulation operations are performed using two different measurement systems at two different times and wellbore trips. Very precise depth control can be achieved by use of a casing-collar-locator, which is the preferred method of depth control.
2. The gross height of each of the individual perforated target intervals is not limited. This is in contrast to the problem that existing coiled tubing systems possess using a straddle-packer like device that limits application to 15 - 30 feet of perforated interval height.
3. Since permanent bridge plugs are not used, the incremental cost and wellbore risk associated with bridge plug drill-out operations is eliminated.
4. It is possible that the coiled tubing string used for the stimulation job could be hung-off in the wellhead and used as the production tubing string, which would result in significant cost savings by eliminating the need for rig mobilization to the well-site.
5. The sequence of zones to be treated can be precisely controlled. As a result, prior to pumping the treatment, the design of individual treatment stages can be optimized based on the characteristics of each individual zone. For example, in the case of hydraulic fracturing, the size of the fracture job and various treatment parameters can be modified to provide the most optimal stimulation of that zone.

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5 6. The potential for sub-optimal stimulation because multiple zones are treated simultaneously is essentially eliminated by having only one open set of perforations above the re-settable packer. For example, in the case of hydraulic fracturing, this invention may minimize the potential for overflush or sub-optimal placement of proppant into the fracture.

7. The entire treatment can be pumped in a single trip, resulting in significant cost savings over other techniques that require wireline or rig work to trip in and out of the hole in between treatment stages.

10 8. The invention can be applied to multi-stage treatments in deviated and horizontal wellbores. Typically, other conventional diversion technology in deviated and horizontal wellbores is more challenging because of the nature of the fluid transport of the diverter material over the long intervals typically associated with deviated or horizontal wellbores.

15 9. Should a screen-out occur during the fracture treatment, the invention provides a method for sand-laden fluid in the annulus to be immediately circulated out of the hole such that stimulation operations can be recommenced without having to trip the coiled tubing/BHA out of the hole.

20 10. Should a problem occur such that the treatment must be terminated, the up-hole zones to be stimulated have not been compromised, since they have yet to be perforated. This is in contrast to conventional coiled tubing stimulation methods, where all perforations must be shot prior to the job. Should the conventional coiled tubing job fail, it may be extremely difficult to effectively divert and stimulate over a
25 long completion interval.

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5 11. Since only one set of perforations would be open above the sealing element in this invention, fluid can be forward-circulated or reverse-circulated without the possibility of breaking down the other multiple sets of open perforations above the top sealing element as could occur in the conventional coiled tubing job. This can minimize or eliminate fluid loss and damage to the formation when the bottomhole circulation pressure would otherwise exceed the formation pore pressure.

10 12. The presence of the coiled tubing system provides a means to measure bottomhole pressure after perforating or during stimulation operations based on pressure calculations involving the coiled tubing string under shut-in (or low-flow-rate) conditions.

15 13. The presence of the coiled tubing system provides a means to inject fluid downhole independently from the fluid injected in the annulus. This may be useful, for example, in applications such as: (a) keeping the BHA sealing device and flow ports clean of proppant accumulation (that could possibly cause tool sticking) by pumping fluid downhole at a nominal rate to clean off the sealing device and flow ports; (b) downhole mixing applications (as discussed further below under "Technology Extensions"); and (c) spotting of acid downhole during perforating to aid perforation hole clean-up and communication with the formation.

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14. The coiled tubing system can allow controlled flowback of individual treatment stages to aid clean up and proppant placement by providing the ability to obtain "forced-closure" of the fracture.

25 15. Operational safety may be improved over other techniques that involve direct personnel exposure to live perforating charges and

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wellhead/lubricator assembly/disassembly operations during high-pressure pumping operations.

5 The perforating gun system may be comprised of commercially-available gun systems. These gun systems could include what will be referred to herein as a "select-fire" system such that a single perforation gun assembly is comprised of multiple charges or sets of perforation charges in which each individual charge or set of perforation charges can be remotely controlled and fired from the surface by use of an electric, hydraulic, or other signal. Each set of perforation charges can be designed (number of charges, number of shots per foot, hole size, penetration characteristics) for optimal perforation of the individual zone that is to be treated with an individual stage. With current select-fire gun technology, commercial gun systems exist that could allow on the order of 30 to 40 intervals to be perforated sequentially in a single downhole trip. Guns can be pre-sized and designed to provide for firing of multiple sets of perforations.

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15 In order to minimize the total length of the gun system and BHA, it may be desirable to use multiple (two or more) charge carriers uniformly distributed around and strapped, welded, or otherwise attached to the coiled tubing. For example, if it were desired to stimulate 30 zones, where each zone is perforated with a 4-ft gun, a single gun assembly would result in a total length of approximately 150 feet, which
20 may be impractical to handle at the surface. Alternatively, two gun assemblies located opposite one another on the coiled tubing could be deployed, where each assembly could contain 15 guns, and total length could be approximately 75-feet, which can readily be handled at the surface with existing lubricator and crane systems.

25 An example of the type of surface equipment that could be utilized in the proposed operation would be a rig up that used a very long lubricator with the coiled tubing injector head high in the air and supported by a crane and multiple guy lines. The height to the top of the injector head could be approximately 90 feet with the "goose-neck" (where the coil is bent over to go down vertically into the well)

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approaching approximately 105 feet above the ground. The crane would support the load of the injector head, the coil, and any necessary fishing operations (jarring and pulling). In the present invention, the coiled tubing/BHA assembly could be run into the hole using a similar surface equipment rig-up. The stimulation fluid would be
5 pumped into the coiled tubing by production casing annulus by hooking up the stimulation piping to the side outlet valves of the wellhead.

An alternative arrangement for the perforating gun or guns would be to hang one or more guns below the coiled tubing. There could be two or more separate gun assemblies attached in such a way that the charges were oriented away from the other
10 assembly or assemblies. It could also be a single assembly with charges loaded more densely and firing mechanisms designed to simultaneously fire only a subset of the charges within a given interval, perhaps all at a given phase orientation.

Alternative embodiments for application of this invention include, but are not limited to, the following:

- 15 1. Abrasive water-jet cutting technology could be deployed as the perforating device. The use of coiled tubing or jointed tubing provides a flow conduit down the center of the tubing. Abrasive water-jet cutting technology could be applied with water-jet cutting nozzles installed in the bottom-hole portion of the coiled tubing. High-pressure high-velocity
20 abrasive fluid would be pumped downhole through the coiled tubing and through the nozzles. The abrasive fluid would then cut through the casing wall, cement sheath, and penetrate the formation to provide flow path communication to the formation. Arbitrary distributions of holes and slots could be placed using this method throughout the completion interval
25 during the stimulation job. This technology extension would replace the select-fire perforating gun system using conventional charge technology. Elimination of the conventional perforating gun system would

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substantially reduce the height requirement for the surface lubricator system.

5 2. Sealing devices could include mechanical re-settable packer devices, inflatable packers, cups, or other mechanical devices that provide effective hydraulic isolation and are re-settable. Alternatively, the device could be used with a mechanical device that does not provide perfect hydraulic seal and retains a small gap around the circumference of the device. This small gap could be sized to provide a sealing mechanism (if desired) whereby proppant bridges across the small gap and provides a seal (if desired) that can be removed by fluid circulation.

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3. Shallow offset wells with surface slips could be drilled to provide a vehicle whereby additional BHA's can be made-up in the vertical position, and thus be safely and rapidly picked-up for continuous stimulation operations with minimal downtime;

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4. The BHA could contain a downhole motor to provide rotation/torque to accommodate actuation of mechanical sealing devices requiring rotation/torque for actuation. In addition, this motor, in conjunction with an orienting device (e.g., gyroscope or compass) could allow oriented perforating such that perforation holes are placed in a preferred compass direction.

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5. Downhole instrumentation gauges for measurement of well conditions (casing collar locator, pressure, temperature, and other measurement gauges) for real-time downhole monitoring of stimulation job parameters, reservoir properties, and/or well performance could be deployed as part of the BHA.

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5 6. In addition to the re-settable mechanical diversion device, other diversion material/devices could be pumped downhole in the tubing-by-casing annulus during the treatment including, for example, gel systems, organic compounds, inorganic compounds, and ball sealers. The additional diversion material could be used to help minimize the duration of the stimulation treatment as some time savings could be realized by reducing the number of times the mechanical diversion device is set, while still achieving diversion capabilities over the multiple zones. For example in a 3,000 foot interval where individual zones nominally 100 feet apart are to be treated, it may be desirable to use the resettable mechanical diversion device working in 500 foot increments uphole, and then divert each of the six stages with a diverting agent carried in the treating fluid. Alternatively, limited entry techniques could be used for multiple intervals as a subset of the gross interval desired to be treated. Either of these variations would decrease the number of mechanical sets of the mechanical diversion device and may extend its effective life.

20 7. The presence of the coiled tubing string allows for deployment of downhole mixing devices and application of downhole mixing technology. Specifically, the coiled tubing string can be used to pump chemicals downhole and through the flow ports in the BHA to subsequently mix with the fluid pumped in the coiled tubing by production casing annulus. For example, during a hydraulic fracturing treatment, it may be desirable to pump nitrogen downhole in the coiled tubing and have it mix with the treatment fluid downhole, such that nitrogen-assisted flowback can be accommodated.

8. Multiple stage hydraulic fracturing of multiple zones.

9. Multiple stage acid fracturing of multiple zones.

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10. Multiple stage matrix acidizing of multiple zones.

11. Treatments of vertical, deviated, or horizontal wellbores. For example, the invention provides a method to generate multiple vertical (or somewhat vertical) fractures to intersect horizontal or deviated wellbores. Such a technique may enable economic completion of multiple wells from a single pad location, in fields that would otherwise be uneconomic to develop.

12. Treatment of a multi-lateral well could be performed wherein the deepest lateral is treated first; then a plug is set or sleeve actuated to isolate this lowest lateral; the next up-hole lateral is then treated; another plug is set or sleeve actuated to isolate this lateral; and the process repeated to treat the desired number of laterals within a single wellbore.

Although the embodiments discussed above are primarily related to the beneficial effects of the inventive process when applied to hydraulic fracturing processes, this should not be interpreted to limit the claimed invention which is applicable to any situation in which perforating and performing other wellbore operations in a single trip is beneficial. Those skilled in the art will recognize that many variations not specifically mentioned in the examples will be equivalent in function for the purposes of this invention.

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What we claim is:

1. A method for perforating and treating at least one interval of a wellbore penetrating a subterranean formation substantially as is described and claimed herein.
2. A bottom-hole assembly for perforating and treating at least one interval of a wellbore penetrating a subterranean formation substantially as is described and claimed herein.
3. A method for perforating and treating at least one interval of a wellbore penetrating a subterranean formation, said method comprising the steps of:
 - a) suspending a perforating means and a resettable sealing device in said wellbore;
 - b) perforating a first interval using said perforating means to create perforations allowing communication between said subterranean formation and said wellbore;
 - c) positioning said resettable sealing device below said perforated interval;
 - d) pumping a treatment fluid through said wellbore into said perforations;
 - e) releasing said resettable sealing device; and
 - f) repeating steps b through e for as many intervals as desired.

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ABSTRACT

This invention provides a method for perforating and treating at least one interval of a wellbore penetrating a subterranean formation, by suspending a
5 perforating means and a resettable sealing device in the wellbore, perforating a first interval, positioning the sealing device below the perforated interval, pumping a treatment fluid through the wellbore into the perforations, releasing the sealing device; and repeating these steps for as many intervals as desired.

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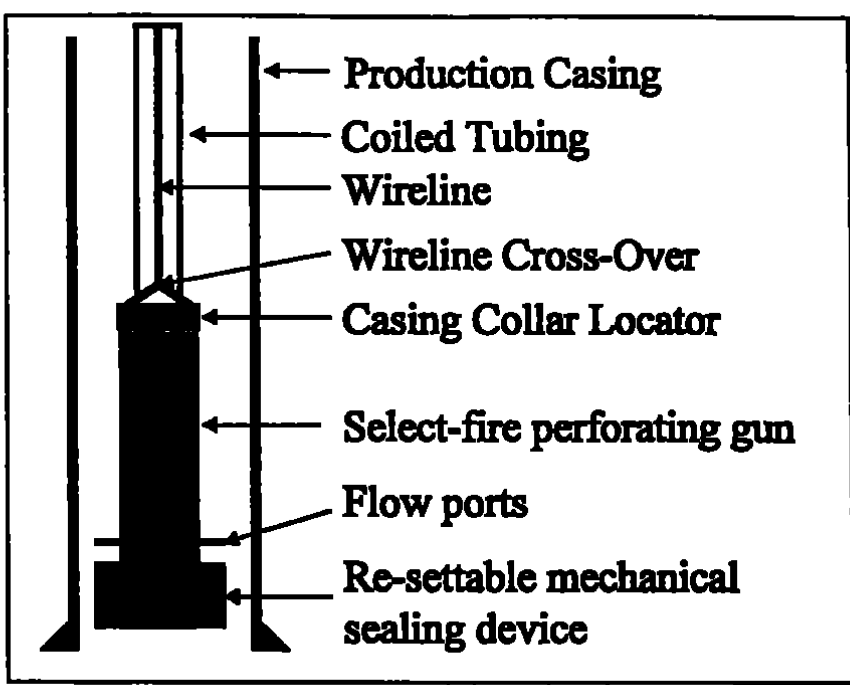


Figure 1

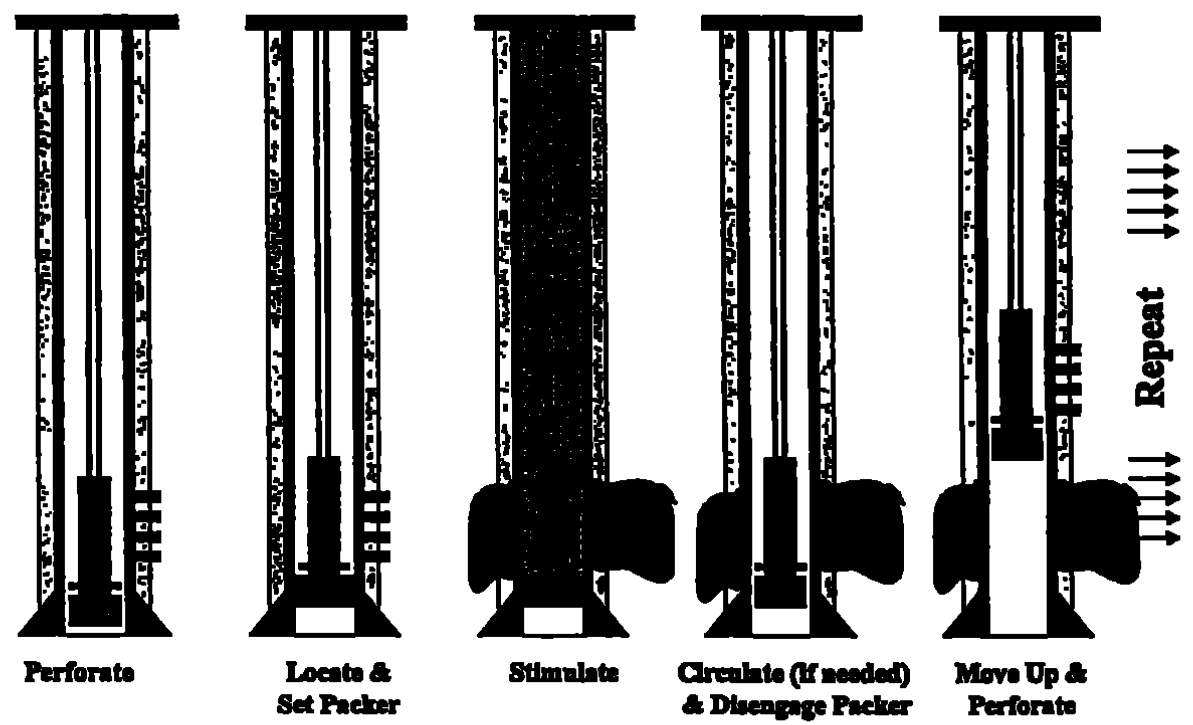


Figure 2

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Exxonmobil Upstream Research Company. 01.011.417

REF: LLC-0036-2001. La presente es Traducción Oficial de un documento presentado originalmente en inglés. Esta traducción es elaborada por Gabriel Rueda Chadid (Traductor Oficial).

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A TODOS AQUELLOS QUE LLEGAREN A LEER EL CONTENIDO DEL
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DEPARTAMENTO DE COMERCIO DE LOS ESTADOS UNIDOS**

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Enero 22 del 2001

Se certifica que anexo se encuentra fiel copia de los Registros de la Oficina de Marcas y Patentes de los Estados Unidos correspondientes a los documentos de la patente solicitada y cuya identificación aparece más adelante, la cual cumplió con los requerimientos exigidos para que se otorgue una fecha de presentación de acuerdo con los dispuesto en la Sección 35 USC 111.

**Número de Solicitud: 60/244.258
Fecha de presentación: Octubre 30, 2000**

**Por autorización del
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L. EDELEN

Funcionario Encargado de Certificaciones (Hay firma y sello)

**GABRIEL RUEDA CHADID
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DEPARTAMENTO DE COMERCIO DE LOS ESTADOS UNIDOS

PORTADA PARA LA SOLICITUD PROVISIONAL DE PATENTES

La presente solicitud de presentación de solicitud provisional de acuerdo con 37 CFR 1.53 (c)

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TITULO DEL INVENTO (280 caracteres máximo)
METODO Y APARATO PARA ESTIMULACION DE INTERVALOS DE
FORMACIONES MULTIPLES

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FORMA DE PAGO (Indicar)

X El Comisionado queda autorizado para cobrar los derechos de presentación y acreditar la cuenta No. 05-1328

DERECHOS PROVISIONALES DE PRESENTACION: \$ 150.00

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NOMBRE: KELLY A. MORGAN **No. de Registro:** 35.620

TELEFONO: 713-431-4462 Expediente No.: 2000.008

SOLICITUD PROVISIONAL DE PATENTES (PAGINA ADICIONAL)

La presente solicitud de presentación de solicitud provisional de acuerdo con 37 CFR 1.53 (c)

Expediente No.: 2000.008

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Expediente No. PM 2000.008

**SOLICITUD PROVISIONAL DE PATENTE EN LOS
ESTADOS UNIDOS**

TITULO: "Método y Aparato para Estimular Intervalos de
Formaciones Múltiples"

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Etiqueta de Correo Expreso: EF049363252US

Fecha: Octubre 30, 2000

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REIVINDICACIONES

1. Un método para perforar y tratar intervalos múltiples de una o mas formaciones subterráneas interceptadas por una perforación de pozo, donde el método comprende:

- (a) Despliegue de un bottom-hole assembly ("BHA") a partir de una sarta de entubamiento dentro de las mencionadas perforaciones de pozo, donde el mencionado conjunto BHA tiene un dispositivo de perforación y un mecanismo de sellado;
- (b) el uso del mencionado dispositivo de perforación para perforar por lo menos un intervalo de una o mas de las formaciones subterráneas;
- (c) posicionamiento del BHA mencionado dentro de las perforaciones mencionadas de pozo y activación del mecanismo de sellado, con el fin de establecer un sello hidráulico por debajo del mencionado intervalo perforado;
- (d) bombeo de un fluido de tratamiento por debajo del anillo ubicado entre la sarta de entubamiento y la perforación de pozo y dentro de las perforaciones creadas por el mencionado dispositivo de perforación, sin retirar dicho dispositivo que se encuentra unido a la mencionada perforación del pozo;
- (e) liberación del mecanismo de sellado; y

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(f) repetición de los pasos (b) hasta (e) por espacio de un intervalo adicional como mínimo de la mencionada formación subterránea o de varias de éstas.

2. El método descrito en la Reivindicación 1 donde la sarta de entubamiento se presenta en forma embobinada.

3. El método descrito en la Reivindicación 1 donde la sarta de entubamiento es un entubado unido.

4. El método descrito en la Reivindicación 1 donde el ensamble mencionado BHA comprende además un localizador de cuello de casing.

5. El método descrito en la Reivindicación 1 donde el dispositivo de perforación es una pistola de perforado de selección de fuego que contiene múltiples sets de una o varias cargas de perforación moldeadas, donde cada una de estas materias o sets correspondientes a una o varias cargas de perforación moldeadas son controladas y activadas individualmente por una señal óptica o eléctrica transmitida por medio de un cable que se instala en la perforación del pozo.

6. El método descrito en la Reivindicación 1 donde el mencionado dispositivo de perforación es un elemento de corte a chorro que utiliza un fluido bombeado hacia abajo de la mencionada sarta de entubamiento con el fin de establecer una comunicación hidráulica entre la mencionada perforación del pozo y el intervalo o intervalos de tales formaciones

subterráneas.

7. El método descrito en la Reivindicación 1 donde el fluido de tratamiento también se bombea hacia la mencionada sarta de entubado, a través de los puertos de flujo de dicho conjunto BHA, y hacia el interior de tales perforaciones.

8. El método descrito en la Reivindicación 1 donde hay un segundo fluido de tratamiento que se bombea hacia abajo de la mencionada sarta de entubamiento, a través de los puertos de flujo en el conjunto mencionado BHA, y hasta colocarse dentro de las perforaciones.

9. El método descrito en la Reivindicación 8 donde este segundo fluido de tratamiento es nitrógeno.

10. El método descrito en la Reivindicación 1 donde este mecanismo de sellado es un empaque re-acondicionable.

11. El método descrito en la Reivindicación 1 donde el mencionado fluido de tratamiento es un compuesto acuoso de material propulsor "proppant" líquido portador.

12. El método descrito en la Reivindicación 1 donde este fluido de tratamiento no contiene el mencionado material propulsor "proppant".

13. El método descrito en la Reivindicación 1 donde el mencionado fluido de tratamiento es una solución ácida.

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14. El método descrito en la Reivindicación 1 donde este fluido de tratamiento es un solvente orgánico.

15. El método descrito en la Reivindicación 1 donde el mencionado método comprende además el paso de desplegar por lo menos un agente de diversificación antes de liberar el mecanismo de sellado que se menciona, dentro la perforación del pozo con el fin de bloquear algún flujo posterior del fluido de tratamiento dentro de las mencionadas perforaciones.

16. El método descrito en la Reivindicación 15 donde dicho agente de dispersión aplicado en la perforación del pozo se selecciona a partir del grupo conformado por partículas, gels, fluidos viscosos, espumas y sellantes de cola.

17. El método descrito en la Reivindicación 1 donde este mecanismo de sellado es accionado por presión hidráulica que se transmite desde la superficie a través de un umbilical.

18. El método descrito en la Reivindicación 1 donde este dispositivo de perforación es accionado por presión hidráulica que se transmite desde la superficie a través de un umbilical.

19. El método descrito en la Reivindicación 1 donde el mencionado dispositivo de perforación es accionado por presión hidráulica que se transmite desde la superficie a

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través de la mencionada perforación del pozo.

20. El método descrito en la Reivindicación 1 donde el mencionado dispositivo de perforación es accionado por presión hidráulica que se transmite desde la superficie a través de la mencionada sarta de entubado.

21. Un método para perforar y tratar intervalos múltiples de una o mas formaciones subterráneas interceptadas por una perforación de pozo, donde el método comprende:

- (a) Despliegue de un bottom-hole assembly ("BHA") que utiliza un medio de despliegue dentro de las mencionadas perforaciones de pozo, donde el mencionado conjunto BHA tiene un dispositivo de perforación y un mecanismo de sellado;
- (b) el posicionamiento del mencionado dispositivo de perforación adyacente al intervalo que deba perforarse y el uso de este dispositivo de perforación con el fin de perforar el intervalo mencionado;
- (c) posicionamiento del BHA mencionado dentro de las perforaciones mencionadas de pozo y el accionamiento del mecanismo de sellado, con el fin de establecer un sello hidráulico por debajo del mencionado intervalo perforado;
- (d) el bombeo de un fluido de tratamiento hacia abajo del mencionado anillo entre los medios de suspensión y la

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perforación de pozo y dentro de las perforaciones creadas por el mencionado dispositivo de perforación, sin retirar dicho dispositivo que se encuentra unido a la mencionada perforación del pozo;

(e) liberación del mecanismo de sellado; y

(f) repetición de los pasos (b) hasta (e) por espacio de un intervalo adicional como mínimo de la mencionada formación subterránea o de varias de éstas.

22. El método descrito en la Reivindicación 21 donde el mencionado mecanismo de despliegue se selecciona a partir del grupo conformado por un cable de perforación "wireline", una línea resbaladiza "slickline" y un cable.

23. El método descrito en la Reivindicación 21 donde dicho mecanismo de despliegue es una sarta de entubado.

24. El método descrito en la Reivindicación 23 donde esta sarta de entubado es de forma de espiral.

25. El método descrito en la Reivindicación 23 donde esta sarta de entubado consiste en una unión de tubos.

26. El método descrito en la Reivindicación 23 donde este fluido de tratamiento es bombeado hacia la sarta de entuba. a través de los puertos de flujo en el BHA, hasta ubicarse dentro de las perforaciones.

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27. El método descrito en la Reivindicación 26 donde este fluido de tratamiento también es bombeado hacia el anillo que está ubicado entre la mencionada sarta de entubado y la mencionada perforación del pozo.

28. El método descrito en la Reivindicación 24 donde este fluido de tratamiento es bombeado hacia el anillo que está ubicado entre la mencionada sarta de entubado y la perforación del pozo.

29. El método descrito en la Reivindicación 21 donde este mecanismo de sellado es un empaque reconfigurable.

30. El método descrito en la Reivindicación 21 donde este fluido de tratamiento es una solución acuosa de un material propulsor "proppant" y un fluido portador.

31. El método descrito en la Reivindicación 21 donde este fluido de tratamiento no contiene el mencionado material propulsor "proppant".

32. El método descrito en la Reivindicación 21 donde este fluido de tratamiento es una solución ácida.

33. El método descrito en la Reivindicación 21 donde este fluido de tratamiento es un solvente orgánico.

34. El método descrito en la Reivindicación 21 donde el mencionado dispositivo de perforación es una pistola de perforación de selección de disparo que contiene múltiples

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sets de una o mas cargas conformadas de perforación, donde cada uno de estos sets de una o mas cargas conformadas de perforación es controlada y activada individualmente por una señal eléctrica u óptica transmitida a través de un cable instalado en la perforación del pozo.

35. El método descrito en la Reivindicación 21 donde este dispositivo de perforación es accionado por presión hidráulica que se transmite desde la superficie a través de la mencionada perforación del pozo.

36. El método descrito en la Reivindicación 23 donde este dispositivo de perforación es accionado por presión hidráulica que se transmite desde la superficie a través de la mencionada sarta de entubado.

37. El método descrito en la Reivindicación 23 donde este dispositivo de perforación es un mecanismo de corte a chorro que utiliza el fluido bombeado hacia abajo de la mencionada sarta de entubamiento, con el fin de establecer comunicación hidráulica entre la mencionada perforación de pozo y el intervalo o intervalos de tales formaciones subterráneas.

38. El método descrito en la Reivindicación 21 donde dicho método comprende el paso de desplegar antes de liberar el mecanismo de sellado, por lo menos un agente de dispersión dentro de la mencionada perforación del pozo con el fin de bloquear aun mas el flujo del líquido de tratamiento dentro de tales perforaciones.

39. El método descrito en la Reivindicación 38 donde este agente de dispersión desplegado dentro del mencionado pozo perforado se selecciona a partir del grupo conformado por partículas, gels, fluidos viscosos, espumas y selladores de bola.

40. Un sistema para tratamiento de estimulación que se utiliza en la perforación y tratamiento de intervalos múltiples de una o varias formaciones subterráneas interceptadas por una perforación de pozo, donde dicho sistema comprende:

- (a) un líquido de tratamiento;
- (b) una sarta de entubado desplegada al interior de dicha perforación de pozo;
- (c) un conjunto de bottom-hole assembly (BHA) que se instala con dicha sarta de entubado, donde el BHA tiene por lo menos un dispositivo de perforación, con el fin de perforar secuencialmente tales intervalos múltiples, mas un mecanismo de sellado, donde el BHA es capaz de posicionarse dentro de la mencionada perforación del pozo, con el fin de permitir el accionamiento de tal mecanismo de perforación y del mecanismo de sellado;
- (d) el mecanismo de sellado capaz de establecer un sello hidráulico por encima y por debajo del mecanismo de sellado, y que además es capaz de liberar dicho sello hidráulico con el fin de permitir que el mencionado

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conjunto BHA se desplace hacia un sitio distinto dentro del pozo perforado, permitiendo de esta manera que cada uno de los intervalos del tratamiento múltiple mencionado se trate con el líquido de tratamiento ya mencionado en forma separada de los demás intervalos de tratamiento.

41. El sistema descrito en la Reivindicación 40 donde esta sarta de entubado tiene forma de espiral.

42. El sistema descrito en la Reivindicación 40 donde esta sarta de entubado consiste en una unión de tubos.

43. El sistema descrito en la Reivindicación 40 donde el mencionado sistema BHA comprende además un localizador de cuello de casing.

44. El sistema descrito en la Reivindicación 40 donde este dispositivo de perforación es una pistola de selección de disparo que contiene múltiples sets de una o mas cargas conformadas de perforación, cada una de las cuales es controlada y activada individualmente por una señal óptica o eléctrica que se transmite a través de un cable instalado dentro del pozo perforado.

45. El sistema descrito en la Reivindicación 40 donde este dispositivo de perforación es accionado por presión hidráulica que se transmite desde la superficie hasta la mencionada perforación del pozo.

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46. El sistema descrito en la Reivindicación 40 donde este dispositivo de perforación es accionado por presión hidráulica que se transmite desde la superficie a través de la mencionada sarta de entubado.

47. El sistema de la Reivindicación 44 donde este dispositivo de perforación es un elemento de corte por chorro que utiliza fluido que se bombea hacia la sarta de entubado con el fin de establecer una comunicación hidráulica entre el pozo perforado y uno o varios de los intervalos de las formaciones subterráneas antes mencionadas.

48. El sistema descrito en la Reivindicación 40 donde este mecanismo de sellado es un empaque reconfigurable.

49. El sistema descrito en la Reivindicación 40 donde este fluido de tratamiento es una solución acuosa de un material propulsor "proppant" y un fluido portador.

50. El sistema descrito en la Reivindicación 40 donde este fluido de tratamiento es un líquido que no contiene material propulsor "proppant".

51. El sistema descrito en la Reivindicación 40 donde este fluido de tratamiento es una solución ácida.

52. El sistema descrito en la Reivindicación 40 donde este fluido de tratamiento es un solvente orgánico.

53. Un aparato que se utiliza en perforación y tratamiento de intervalos múltiples de una o mas formaciones subterráneas interceptadas por un pozo perforado, donde el aparato comprende:

- (a) un conjunto de bottom-hole assembly (BHA), adaptado para que se instale dentro de la perforación del pozo mediante un elemento de despliegue, donde el BHA tiene por lo menos un dispositivo de perforación para perforar en forma secuencial los mencionados intervalos múltiples y por lo menos un mecanismo de sellado; y
- (b) el mecanismo de sellado mencionado que es capaz de establecer un sello hidráulico dentro de la mencionada perforación del pozo, y que es además capaz de liberar este sello hidráulico con el fin de permitir que dicho BHA se desplace hacia un sitio distinto al interior del pozo perforado, permitiendo así que cada uno de los intervalos múltiples de tratamiento sean separadamente tratados con respecto de los demás intervalos de tratamiento.

54. El aparato descrito en la Reivindicación 53 donde tal mecanismo de suspensión es una sarta de entubado.

55. El aparato descrito en la Reivindicación 54 donde esta sarta de entubado tiene forma de espiral.

56. El aparato descrito en la Reivindicación 54 donde esta sarta de entubado consiste en unión de tubos.

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57. El aparato descrito en la Reivindicación 53 donde este mecanismo de suspensión se selecciona a partir del grupo conformado por un cable de perforación "wireline", línea resbaladiza "slickline" y cable.

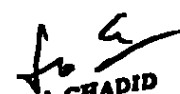
58. El aparato descrito en la Reivindicación 53 donde el BHA comprende además un localizador de cuello casing.

59. El aparato descrito en la Reivindicación 53 donde este mecanismo de sellado es un empaque reconfigurable.

60. El aparato de la Reivindicación 53 donde este dispositivo de perforación es una pistola de selección de disparo que contiene múltiples sets de una o varias cargas de perforación conformadas, donde cada uno de los sets de una de estas cargas es controlada y activada individualmente por una señal eléctrica que se transmite por medio de un cable de perforación "wireline" instalado en el pozo perforado.

61. El aparato descrito en la Reivindicación 53 donde este dispositivo de perforación es accionado por presión hidráulica que se transmite desde la superficie a través de la mencionada perforación del pozo.

62. El aparato descrito en la Reivindicación 54 donde dicho dispositivo de perforación es accionado por presión hidráulica se transmite desde la superficie a través de la mencionada sarta de entubado.


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63. El aparato descrito en la Reivindicación 54 donde el mencionado dispositivo de perforación es un elemento de corte por chorro que utiliza el fluido bombeado hacia dicha sarta de entubado, con el fin de establecer comunicación hidráulica entre el pozo perforado y uno o varios de los intervalos de tales formaciones subterráneas.

64. Un aparato que se utiliza en la perforación y tratamiento de intervalos múltiples de una o varias formaciones subterráneas que se interceptan por medio de una perforación de pozo, donde el aparato comprende:

- (a) un conjunto de bottom-hole assembly, que tiene por lo menos un dispositivo de perforación para perforar secuencialmente tales intervalos múltiples, y por lo menos un mecanismo de sellado, y al menos un dispositivo de transacción;
- (b) este dispositivo de transacción es capaz de posicionar el mencionado BHA en diferentes posiciones dentro del pozo perforado; y
- (c) el mencionado dispositivo de sellado que es capaz de establecer un sello hidráulico dentro de dicha perforación de pozo, y que además está en condiciones de liberar tal sello hidráulico con el fin de permitir que el BHA se desplace a una posición distinta al interior de la mencionada perforación, permitiendo de esta manera que cada uno de estos intervalos múltiples de tratamiento sean tratados por separado con respecto de

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los demás intervalos de tratamiento.

65. El aparato de la Reivindicación 64 donde el BHA comprende además un localizador de cuello de casing.

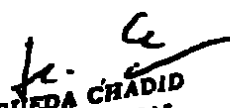
66. El aparato descrito en la Reivindicación 64 donde este mecanismo de sellado es un empaque reconfigurable.

67. El aparato descrito en la Reivindicación 64 donde este dispositivo de perforación es una pistola de selección de disparo que contiene múltiples sets de una o varias cargas de perforación, donde cada uno de estos sets se controla y activa individualmente por medio de señal eléctrica transmitida por un cable de perforación "wireline" que se despliega en el pozo perforado.

68. El aparato descrito en la Reivindicación 64 donde este dispositivo de perforación es accionado por presión hidráulica que se transmite desde la superficie a través de la perforación del pozo.

La anterior es Traducción Oficial de un documento presentado originalmente en inglés. Esta traducción fue realizada por GABRIEL RUEDA CHADID (Traductor Oficial). Resolución 5996 del Minjusticia, por lo cual estampo mi Sello y Firmo.

Bogotá D.C., Mayo 3 del 2001.


GABRIEL RUEDA CHADID
TRADUCTOR OFICIAL
RESOLUCION 5996 DE NOV. 29-89
MINISTERIO DE JUSTICIA

PA 381929

THE UNITED STATES OF AMERICA

TO ALL TO WHOM THESE PRESENTS SHALL COME:

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United States Patent and Trademark Office

January 22, 2001

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APPLICATION NUMBER: 60/244,258

FILING DATE: October 30, 2000



**By Authority of the
COMMISSIONER OF PATENTS AND TRADEMARKS**

L. Edelen

**L. EDELEN
Certifying Officer**

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PROVISIONAL APPLICATION FOR PATENT COVER SHEET

This is a request for filing a PROVISIONAL APPLICATION FOR PATENT under 37 CFR 1.63(e).

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☒ Additional inventors are being named on the _____ separately numbered sheets attached hereto					
TITLE OF THE INVENTION (250 characters max)					
METHOD AND APPARATUS FOR STIMULATION OF MULTIPLE FORMATION INTERVALS					
Direct all correspondence to: CORRESPONDENCE ADDRESS					
☐ Customer Number				Place Customer Number Bar Code Label here	
OR Type Customer Number here					
☒ Firm or Individual Name		Kelly A. Morgan			
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ENCLOSED APPLICATION PARTS (check all that apply)					
☒ Specification		Number of Pages 53		☐ CD(s), Number	
☒ Drawing(s)		Number of Sheets 17		☒ Other (specify)	
☐ Application Data Sheet. See 37 CFR 1.78		EXPRESS MAIL NO. EP04836328US and postcard			
METHOD OF PAYMENT OF FILING FEES FOR THIS PROVISIONAL APPLICATION FOR PATENT (check one)					
☐ A check or money order is enclosed to cover the filing fees				FILING FEE AMOUNT (\$)	
☒ The Commissioner is hereby authorized to charge filing fees or credit any overpayment to Deposit Account Number:		05-1328		\$150.00	
☐ Payment by credit card. Form PTO-2038 is attached.					
The invention was made by an agency of the United States Government or under a contract with an agency of the United States Government.					
☒ No.					
☐ Yes, the name of the U.S. Government agency and the Government contract number are: _____					

Respectfully submitted,

SIGNATURE

Kelly A. Morgan

Date 10/30/00

TYPED or PRINTED NAME Kelly A. Morgan

REGISTRATION NO.

35,820

(if appropriate)

TELEPHONE 713/431-4462

Doctet Number:

2000.008

USE ONLY FOR FILING A PROVISIONAL APPLICATION FOR PATENT

This collection of information is required by 37 CFR 1.61. The information is used by the public to file (and by the PTO to process) a provisional application. Confidentiality is governed by 35 U.S.C. 122 and 37 CFR 1.14. This collection is estimated to take 6 hours to complete, including gathering, preparing, and submitting the complete provisional application to the PTO. Time will vary depending upon the individual case. Any comments on the amount of time you require to complete this form and/or suggestions for reducing this burden, should be sent to the Chief Information Officer, U.S. Patent and Trademark Office, U.S. Department of Commerce, Washington, D.C. 20231. DO NOT SEND FEES OR COMPLETED FORMS TO THIS ADDRESS. SEND TO: Box Provisional Application, Assistant Commissioner for Patents, Washington, D.C. 20231.

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Additional Page

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Docket Number	2000.088	Type a plus sign (+) inside this box →	+
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60244258-103000

Number 2 of 2

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U. S. PROVISIONAL PATENT APPLICATION

Title : "Method And Apparatus For Stimulation Of Multiple Formation Intervals"

Inv ntors: Randy C. Tolman
Lawrence O. Carlson
David A. Kinison
Kris J. Nygaard
Glenn S. Goss
William A. Sorem
Lee L. Shafer

Express Mail Mailing Label No.: EF048363252US

Date: October 30, 2000

000001-85244209

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PATENT APPLICATION UNDER SERIAL NO. 103000

METHOD AND APPARATUS FOR STIMULATION OF MULTIPLE FORMATION INTERVALS

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FIELD OF THE INVENTION

This invention relates generally to the field of perforating and treating subterranean formations to increase the production of oil and gas therefrom. More specifically, the invention provides an apparatus and a method for perforating and treating multiple intervals without the necessity of removing equipment from the wellbore between steps or stages.

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BACKGROUND OF THE INVENTION

When a hydrocarbon-bearing, subterranean reservoir formation does not have enough permeability or flow capacity for the hydrocarbons to flow to the surface in economic quantities or at optimum rates, hydraulic fracturing or chemical (usually acid) stimulation is often used to increase the flow capacity. A wellbore penetrating a subterranean formation typically consists of a metal pipe (casing) cemented into the original drill hole. Holes (perforations) are placed to penetrate through the casing and the cement sheath surrounding the casing to allow hydrocarbon flow into the wellbore and, if necessary, to allow treatment fluids to flow from the wellbore into the formation.

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Hydraulic fracturing consists of injecting fluids (usually viscous shear thinning, non-Newtonian gels or emulsions) into a formation at such high pressures and rates that the reservoir rock fails and forms a plane, typically vertical, fracture (or fracture network) much like the fracture that extends through a wooden log as a wedge is driven into it. Granular proppant material, such as sand, ceramic beads, or other materials, is generally injected with the later portion of the fracturing fluid to hold the fracture(s) open after the pressure is released. Increased flow capacity from the reservoir results from the easier flow path left between grains of the proppant material within the fracture(s). In chemical stimulation treatments, flow capacity is improved by dissolving materials in the formation or otherwise changing formation properties.

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Application of hydraulic fracturing as described above is a routine part of petroleum industry operations as applied to individual target zones of up to about 60 meters (200 feet) of gross, vertical thickness of subterranean formation. When there are multiple or layered reservoirs to be hydraulically fractured, or a very thick hydrocarbon-bearing formation (over about 60 meters), then alternate treatment techniques are required to obtain treatment of the entire target zone. The methods for improving treatment coverage are commonly known as "diversion" methods in petroleum industry terminology.

When multiple hydrocarbon-bearing zones are stimulated by hydraulic fracturing or chemical stimulation treatments, economic and technical gains are realized by injecting multiple treatment stages that can be diverted (or separated) by various means, including mechanical devices such as bridge plugs, packers, downhole valves, sliding sleeves, and baffle/plug combinations; ball sealers; particulates such as sand, ceramic material, proppant, salt, waxes, resins, or other compounds; or by alternative fluid systems such as viscosified fluids, gelled fluids, foams, or other chemically formulated fluids; or using limited entry methods. These and all other methods and devices for temporarily blocking the flow of fluids into or out of a given set of perforations will be referred to herein as "diversion agents."

In mechanical bridge plug diversion, for example, the deepest interval is first perforated and fracture stimulated, then the interval is typically isolated by a wireline-set bridge plug, and the process is repeated in the next interval up. Assuming ten target perforation intervals, treating 300 meters (1,000 feet) of formation in this manner would typically require ten jobs over a time interval of ten days to two weeks with not only multiple fracture treatments, but also multiple perforating and bridge plug running operations. At the end of the treatment process, a wellbore clean-out operation would be required to remove the bridge plugs and put the well on production. The major advantage of using bridge plugs or other mechanical diversion agents is high confidence that the entire target zone is treated. The major disadvantages are the high cost of treatment resulting from multiple trips into and out of the wellbore and the risk of complications resulting from so many operations on the well. For example, a bridge plug can become stuck in the casing and need to be drilled

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out at great expense. A further disadvantage is that the required wellbore clean-out operation may damage some of the successfully fractured intervals.

One alternative to using bridge plugs is filling the portion of wellbore associated with the just fractured interval with fracturing sand, commonly referred to as the Pine Island technique. The sand column in the wellbore essentially plugs off the already fractured interval and allows the next interval to be perforated and fractured independently. The primary advantage is elimination of the problems and risks associated with bridge plugs. The disadvantages are that the sand plug does not give a perfect hydraulic seal and it can be difficult to remove from the wellbore at the end of all the fracture stimulations. Unless the well's fluid production is strong enough to carry the sand from the wellbore, the well may still need to be cleaned out with a work-over rig or coiled tubing unit. As before, additional wellbore operations increase costs, mechanical risks, and risks of damage to the fractured intervals.

Another method of diversion involves the use of particulate materials, granular solids that are placed in the treating fluid to aid diversion. As the fluid is pumped, and the particulates enter the perforations, a temporary block forms in the zone accepting the fluid if a sufficiently high concentration of particulates is deployed in the flow stream. The flow restriction then diverts fluid to the other zones. After the treatment, the particulate is removed by produced formation fluids or by injected wash fluid, either by fluid transport or by dissolution. Commonly available particulate diverter materials include benzoic acid, naphthalene, rock salt (sodium chloride), resin materials, waxes, and polymers. Alternatively, sand, proppant, and ceramic materials, could be used as particulate diverters. Other specialty particulates can be designed to precipitate and form during the treatment.

Another method for diverting involves using viscosified fluids, viscous gels, or foams as diverting agents. This method involves pumping the diverting fluid across and/or into the perforated interval. These fluid systems are formulated to temporarily obstruct flow to the perforations due to viscosity or formation relative permeability decreases; and are also designed so that at the desired time, the fluid system breaks down, degrades, or dissolves (with or without adding chemicals or other additives to trigger such breakdown or dissolution) such that flow can be restored to or from the

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perforations. These fluid systems can be used for diversion of matrix chemical stimulation treatments and fracture treatments. Particulate diverters and/or ball sealers are sometimes incorporated into these fluid systems in efforts to enhance diversion.

Another possible process is limited entry diversion in which the entire target zone of the formation to be treated is perforated with a very small number of perforations, generally of small diameter, so that the pressure loss across those perforations during pumping promotes a high, internal wellbore pressure. The internal wellbore pressure is designed to be high enough to cause all of the perforated intervals to fracture simultaneously. If the pressure were too low, only the weakest portions of the formation would fracture. The primary advantage of limited entry diversion is that there are no inside-the-casing obstructions like bridge plugs or sand to cause problems later. The disadvantage is that limited entry fracturing often does not work well for thick intervals because the resulting fracture is frequently too narrow (the proppant cannot all be pumped away into the narrow fracture and remains in the wellbore), and the initial, high wellbore pressure may not last. As the sand material is pumped, the perforation diameters are often quickly eroded to larger sizes that reduce the internal wellbore pressure. The net result can be that not all of the target zone is stimulated. An additional concern is the potential for flow capacity into the wellbore to be limited by the small number of perforations.

Some of the problems resulting from failure to stimulate the entire target zone or using mechanical methods that require multiple wellbore operations and wellbore entries that pose greater risk and cost as described above may be alleviated by using limited, concentrated perforated intervals diverted by ball sealers. The zone to be treated could be divided into sub-zones with perforations at approximately the center of each of those sub-zones, or sub-zones could be selected based on analysis of the formation to target desired fracture locations. The fracture stages would then be pumped with diversion by ball sealers at the end of each stage. Specifically, 300 meters (1,000 feet) of gross formation might be divided into ten sub-zones of about 30 meters (about 100 feet) each. At the center of each 30 meter (100 foot) sub-zone, ten perforations might be shot at a density of three shots per meter (one shot per foot) of casing. A fracture stage would then be pumped with proppant-laden fluid followed by

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ten or more ball sealers, at least one for each open perforation in a single perforation set or interval. The process would be repeated until all of the perforation sets were fractured. Such a system is described in more detail in U.S. Patent No. 5,890,536, issued April 6, 1999.

5 Historically, all zones to be treated in a particular job that uses ball sealers as the diversion agent have been perforated prior to pumping treatment fluids, and ball sealers have been employed to divert treatment fluids from zones already broken down or otherwise taking the greatest flow of fluid to other zones taking less, or no, fluid prior to the release of ball sealers. Treatment and sealing theoretically proceeded zone
10 by zone depending on relative breakdown pressures or permeabilities, but problems were frequently encountered with balls prematurely seating on one or more of the open perforations outside the targeted interval and with two or more zones being treated simultaneously. Furthermore, this technique preumes that each perforation interval or sub-zone would break down and fracture at sufficiently different pressure so that each
15 stage of treatment would enter only one set of perforations.

 The primary advantages of ball sealer diversion are low cost and low risk of mechanical problems. Costs are low because the process can typically be completed in one continuous operation, usually during just a few hours of a single day. Only the ball sealers are left in the wellbore to either flow out with produced hydrocarbons or drop
20 to the bottom of the well in an area known as the rat (or junk) hole. The primary disadvantage is the inability to be certain that only one set of perforations will fracture at a time so that the correct number of ball sealers are dropped at the end of each treatment stage. In fact, optimal benefit of the process depends on one fracture stage entering the formation through only one perforation set and all other open perforations
25 remaining substantially unaffected during that stage of treatment. Further disadvantages are lack of certainty that all of the perforated intervals will be treated and of the order in which these intervals are treated while the job is in progress. When the order of zone treatment is not known or controlled, it is not possible to ensure that each individual zone is treated or that an individual stimulation treatment stage has
30 been optimally designed for the targeted zone. In some instances, it may not be

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possible to control the treatment such that individual zones are treated with single treatment stages.

To overcome some of the disadvantages that may occur during stimulation treatments when multiple zones are perforated prior to pumping treatment fluids, an alternative mechanical diversion method has been developed that involves the use of a coiled tubing stimulation system to sequentially stimulate multiple intervals with separate treatment. As with conventional ball sealer diversion, all intervals to be treated are perforated prior to pumping the stimulation treatment. Then coiled tubing is run into the wellbore with a mechanical "straddle-packer-like" diversion tool attached to the end. This diversion tool, when properly placed and actuated across the perforations, allows hydraulic isolation to be achieved above and below the diversion tool. After the diversion tool is placed and actuated to isolate the deepest set of perforations, stimulation fluid is pumped down the interior of the coiled tubing and exits flow ports placed in the diversion tool between the upper and lower sealing elements. Upon completion of the first stage of treatment, the sealing elements contained on the diversion tool are deactivated or disengaged, and the coiled tubing is pulled upward to place the diversion tool across the second deepest set of perforations and the process is continued until all of the targeted intervals have been stimulated or the process is aborted due to operational upsets.

This type of coiled tubing stimulation apparatus and method have been used to hydraulically fracture multiple zones in wells with depths up to about 8,000 feet. However, various technical obstacles, including friction pressure losses, damage to sealing elements, depth control, running speed, and potential erosion of coiled tubing, currently limit deployment in deeper wells.

Excess friction pressure is generated when pumping stimulation fluids, particularly proppant-laden and/or high viscosity fluids, at high rates through longer lengths of coiled tubing. Depending on the length and diameter of the coiled tubing, the fluid viscosity, and the maximum allowable surface hardware working pressures, pump rates could be limited to just a few barrels per minute; which, depending on the characteristics of a specific subterranean formation, may not allow effective placement

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of proppant during hydraulic fracture treatments or effective dissolution of formation materials during acid stimulation treatments

Erosion of the coiled tubing could also be a problem as proppant-laden fluid is pumped down the interior of the coiled tubing at high velocity, including the portion of the coiled tubing that remains wound on the surface reel. The erosion concerns are exacerbated as the proppant-laden fluid impinges on the "continuous bend" associated with the portion of the coiled tubing placed on the surface reel.

Most seal elements (e.g., "cup" seal technology) currently used in the coiled tubing stimulation operations described above could experience sealing problems or seal failure in deeper wells as the seals are run past a large number of perforations at the higher well temperatures associated with deeper wells. Since the seals run in contact with or at a minimal clearance from the pipe wall, rough interior pipe surfaces and/or perforation burrs can damage the sealing elements. Seals currently available in straddle-packer-like diversion tools are also constructed from elastomers which may be unable to withstand the higher temperatures often associated with deeper wells.

Running speed of the existing systems with cup seals is generally on the order of 15 to 30 feet-per-minute running downhole to 30 to 60 feet-per-minute coming uphole. For example, at the lower running speed, approximately 13 hours would be required to reach a depth of 12,000 feet before beginning the stimulation. Given safety issues surrounding nighttime operations, this slow running speed could result in multiple days being required to complete a stimulation job. If any problems are encountered during the job, tripping in and out of the hole could be very costly because of the total operation times associated with the slow running speeds.

Depth control of the coiled tubing system and straddle-packer-like diversion tool also becomes more difficult as depth increases, such that placing the tool at the correct depth to successfully execute the stimulation operation may be difficult. This problem is compounded by shooting the perforations before running the coiled tubing system in the hole. The perforating operation uses a different depth measurement device (usually a casing collar locator system) than is generally used in the coiled tubing system.

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In addition, the coiled tubing method described above requires that all of the perforations be placed in the wellbore in a separate perforating operation prior to pumping the stimulation job. The presence of multiple perforation sets open above the diversion tool can cause operational difficulties. For example, if the proppant fracture
5 from the current zone were to grow vertically and/or poor quality cement is present behind pipe, the fracture could intersect the perforation sets above the diversion tool such that proppant could "dump" back into the wellbore on top of the diversion tool and prevent further tool movement. Also, it could be difficult to execute circulation operations if multiple perforation sets are open above the diversion tool. For example,
10 if the circulation pressures exceed the breakdown pressures associated with the perforations open above the diversion tool, the circulation may not be maintained with circulation fluid unintentionally lost to the formation.

A similar type of stimulation operation may also be performed using jointed tubing and a workover rig rather than a coiled tubing system. Using a diversion tool
15 deployed on jointed tubing may allow for larger diameter tubing to reduce friction pressure losses and allow for increased pump rates. Also, concerns over erosion and tubing integrity may be reduced when compared to coiled tubing since heavier wall thickness jointed tubing pipe may be used and jointed tubing would not be exposed to plastic deformation when run in the wellbore. However, using this approach would
20 likely increase the time and cost associated with the operations because of slower pipe running speeds than those possible with coiled tubing.

To overcome some of the limitations associated with completion operations that require multiple trips of hardware into and out of the wellbore to perforate and stimulate subterranean formations, methods have been proposed for "single-trip"
25 deployment of a downhole tool string to allow for fracture stimulation of zones in conjunction with perforating. Specifically, these methods propose operations that may minimize the number of required wellbore operations and time required to complete these operations, thereby reducing the stimulation treatment cost. These proposals include 1) having a sand slurry in the wellbore while perforating with overbalanced
30 pressure, 2) dumping sand from a bailer simultaneously with firing the perforating charges, and 3) including sand in a separate explosively released container. These

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proposals all allow for only minimal fracture penetration surrounding the wellbore and are not adaptable to the needs of multi-stage hydraulic fracturing as described herein.

Accordingly, there is a need for an improved method and apparatus for individually treating each of multiple intervals of a subterranean formation penetrated by a wellbore while maintaining the economic benefits of multi-stage treatment. There is also a need for a method and apparatus that can economically reduce the risks inherent in the currently available stimulation treatment options for hydrocarbon-bearing formations with multiple or layered reservoirs or with thickness exceeding about 60 meters (200 feet) while ensuring that optimal treatment placement is performed with a mechanical diversion agent that positively directs treatment stages to the desired location.

SUMMARY OF THE INVENTION

This invention provides an apparatus and method for perforating and treating multiple intervals of one or more subterranean formations intersected by a wellbore.

The apparatus consists of a deployment means (e.g., coiled tubing, jointed tubing, electric line, wireline, downhole tractor, etc.) with a bottomhole assembly ("BHA") comprised of at least a perforating device and a re-settable mechanical sealing mechanism that may be independently actuated from the surface via one or more signaling means (e.g., electronic signals transmitted via wireline; hydraulic signals transmitted via tubing, annulus, umbilicals; tension or compression loads; radio transmission; fiber-optic transmission; etc.).

The method includes the steps of deploying the BHA within the wellbore using a deployment means where the deployment means may be a tubing-string, cable, or downhole tractor. The perforating device is positioned adjacent to the interval to be perforated and is used to perforate the interval. The BHA is positioned within the wellbore using the deployment means, and the sealing mechanism is actuated so as to establish a hydraulic seal that positively directs fluid pumped down the wellbore to enter the perforated interval. The sealing mechanism is released. The process can then be repeated, without removing the BHA from the wellbore, for at least one additional interval of the one or more subterranean formations.

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The deployment means can be a tubing string, including a coiled tubing or standard jointed tubing, a wireline, a slickline, or a cable. Rather than tubing or cable deployment, the deployment means could also be a tractor system attached to the BHA. The tractor system may be a self-propelled, computer-controlled, and carry on-board signaling systems such that it is not necessary to attach cable or tubing to control and actuate the BHA and/or tractor system. Alternatively, the tractor system could be controlled and energized by cable or tubing umbilicals such the tractor system and BHA are controlled and actuated via signals transmitted downhole using the umbilicals. Many different embodiments to the invention can exist depending on the suspension means and specific components of the BHA.

In the first embodiment of the invention, when the deployment means is a tubing string, once an interval has been perforated the BHA can be moved and the sealing mechanism actuated to establish a hydraulic seal below the perforated interval. Then treating fluid can be pumped down the annulus between the tubing string and the wellbore and into the perforated interval. And a second treating fluid, such as nitrogen, could also be pumped down the tubing string at the same time that the first treating fluid is pumped down the annulus between the tubing string and the wellbore.

In the second embodiment, when the suspension means is a tubing string, once an interval has been perforated the BHA can be moved and the sealing mechanism actuated to establish a hydraulic seal above the perforated interval. Then treating fluid can be pumped down the tubing string and into the perforated interval.

In the third embodiment, when the deployment means is a tubing string, the BHA can be moved and the sealing mechanism actuated to establish a hydraulic seal above and below the perforated interval (where the sealing mechanism consists of two seal elements spaced sufficient distance apart to straddle the perforated interval). In this third embodiment, treating fluid can be pumped down the tubing string itself, through a flow port placed in-between the two seal elements of the sealing mechanism and into the perforated interval.

In a fourth embodiment of the invention, when the BHA is deployed in the wellbore using a wireline, slickline or cable, the BHA would be moved and the sealing mechanism actuated to establish a hydraulic seal below the perforated interval to be

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treated, and the treating fluid would be pumped down the annulus between the wireline, slickline, or cable, and the wellbore.

In a fifth embodiment of the invention, an "umbilical" is deployed as an additional means to actuate a BHA component. In the most general sense, the
5 umbilical could take the form of a small diameter tubing or multiple tubing to provide hydraulic communication with BHA components; and/or the umbilical could take the form of a cable or multiple cables to provide electrical or electro-optical communication with BHA components.

In a sixth embodiment of the invention, when the deployment means is a tractor
10 system attached to the BHA, the BHA can be moved and the sealing mechanism actuated to establish a hydraulic seal below the perforated interval. The treating fluid can be pumped down the wellbore and into the perforated interval.

One of the primary advantages of this apparatus and method is that the BHA,
15 including the sealing mechanism and the perforating device, does not need to be removed from the wellbore prior to treatment with the treating fluid and between treatment of multiple formation zones or intervals. Another primary advantage of this apparatus and method is that each treatment stage is diverted using a mechanical diversion agent such that precise control of the treatment diversion process is achieved and each zone can be optimally stimulated. As a result, there are significant costs
20 savings associated with reduction in the time required to perforate and treat multiple intervals within a wellbore. In addition, there are production improvements associated with using a mechanical diversion agent to provide precisely-controlled treatment diversion when stimulating multiple formation interval within a wellbore. As such, the inventive method and apparatus provide significant economic advantages over existing
25 methods and equipment since the inventive method and apparatus allow for perforating and stimulating multiple zones with a single wellbore entry, and subsequent withdrawal, of a bottomhole assembly that provides dual functionality as both a mechanical diversion agent and perforating device.

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BRIEF DESCRIPTION OF THE DRAWINGS

The present invention and its advantages will be better understood by referring to the following detailed description and the attached drawings in which:

5 Figure 1 illustrates one possible representative wellbore configuration with peripheral equipment that could be used to support the bottomhole assembly used in the present invention. Figure 1 also illustrates representative bottomhole assembly storage wellbores with surface slips that may be used for storage of spare or contingency bottomhole assemblies.

10 Figure 2A illustrates the first embodiment of the bottomhole assembly deployed using coiled tubing in an unperforated wellbore and positioned at the depth location to be perforated by the first set of selectively-fired perforating charges. Figure 2A further illustrates that the bottomhole assembly consists of a perforating device, an inflatable, re-settable packer, a re-settable axial slip device, and ancillary components.

15 Figure 2B represents the bottomhole assembly, coiled tubing, and wellbore of Figure 2A after the first set of selectively-fired perforating charges are fired resulting in perforation holes through the production casing and cement sheath and into the first formation zone such that hydraulic communication is established between the wellbore and the first formation zone.

20 Figure 2C represents the bottomhole assembly, coiled tubing, and wellbore of Figure 2B after the bottomhole assembly has been re-positioned and the first formation zone stimulated with the first stage of the multiple-stage, hydraulic, proppant fracture treatment where the first stage of the fracture treatment was pumped downhole in the wellbore annulus existing between the coiled tubing and production casing. In Figure 2C, the sealing mechanism is shown in a de-activated position since, for illustration purposes only, it is assumed that no other perforations besides those associated with the first zone are present, and as such, isolation is not necessary for treatment of the first zone.

25 Figure 3A represents the bottomhole assembly, coiled tubing, and wellbore of Figure 2C after the bottomhole assembly has been re-positioned and the second set of selectively-fired perforating charges have been fired resulting in perforation holes

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through the production casing and cement sheath and into the second formation zone such that hydraulic communication is established between the wellbore and the second formation zone.

Figure 3B represents the bottomhole assembly, coiled tubing, and wellbore of Figure 3A after the bottomhole assembly has been re-positioned a sufficient distance below the deepest perforation of the second perforation set to allow slight movement upward of the BHA to set the re-settable axial slip device while keeping the location of the circulation port below the bottom-most perforation of the second perforation set.

Figure 3C represents the bottomhole assembly, coiled tubing and wellbore of Figure 3B after the re-settable mechanical slip device has been actuated to provide resistance to downward axial movement ensuring that the inflatable, re-settable packer and re-settable mechanical slip device are located between the first zone and second zone perforations.

Figure 3D represents the bottomhole assembly, coiled tubing and wellbore of Figure 3C after the inflatable, re-settable packer has been actuated to provide a barrier to flow between the portion of the wellbore directly above the inflatable, re-settable packer and the portion of the wellbore directly below the inflatable, re-settable packer.

Figure 3E represents the bottomhole assembly, coiled tubing, and wellbore of Figure 3D after the second formation zone has been stimulated with the second stage of the multiple stage hydraulic proppant fracture treatment where the second stage of the fracture treatment was pumped downhole in the wellbore annulus existing between the coiled tubing and production casing.

Figure 3F represents the bottomhole assembly, coiled tubing, and wellbore of Figure 3E after the inflatable, re-settable packer has been de-activated thereby re-establishing pressure communication between the portion of the wellbore directly above the inflatable, re-settable packer and the portion of the wellbore directly below the inflatable, re-settable packer. The re-settable mechanical slip device is still energized and continues to prevent movement of the coiled tubing and bottomhole assembly down the wellbore.

Figure 4A represents a modified bottomhole assembly, similar to the bottomhole assembly described in Figures 2A through 2C and Figures 3A through

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3F, but with the addition of a mechanical-plug, settable with a select-fire charge setting system, located below the string of perforating guns. Figure 4A also represents the coiled tubing, and wellbore of Figure 3F after an additional, third perforating and fracture stimulation operation has been performed. In Figure 4A, it is noted that only
5 the second and third fractures and perforation sets are shown. In Figure 4A, the modified bottomhole assembly is shown suspended by coiled tubing such that the location of the bridge-plug is located above the last perforated interval and below the next interval to be perforated.

Figure 4B represents the bottomhole assembly, coiled tubing, and wellbore of
10 Figure 4A after the mechanical-plug has been select-fire-charge-set in the well and after the bottomhole assembly has been re-positioned and the first set of selectively-fired perforating charges have been fired and result in perforation holes through the production casing and cement sheath and into the fourth formation zone such that hydraulic communication is established between the wellbore and the fourth formation
15 zone.

Figure 5 represents a second embodiment of the invention. In this embodiment, the suspension means is a tubing string, and once an interval has been perforated, the BHA can be moved and the sealing mechanism actuated to establish a hydraulic seal above the perforated interval. Then treating fluid can be pumped down
20 the tubing string and into the perforated interval.

Figure 6 represents a third embodiment of the invention. The suspension means is a tubing string, and the BHA can be moved and the sealing mechanism actuated to establish a hydraulic seal above and below the perforated interval (where the sealing mechanism consists of two seal elements spaced sufficient distance apart to
25 straddle the perforated interval). In this third embodiment, treating fluid can be pumped down the tubing string itself, through a flow port placed in-between the two seal elements of the sealing mechanism and into the perforated interval.

Figure 7 represents a fourth embodiment of the invention. The BHA is suspended in the wellbore using a wireline (or slickline or cable). The BHA would be
30 moved and the sealing mechanism actuated to establish a hydraulic seal below the

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perforated interval to be treated, and the treating fluid would be pumped down the annulus between the wireline, slickline, or cable, and the wellbore.

Figures 8A and 8B represent a fifth embodiment of the invention that utilizes an umbilical tubing, deployed interior to the tubing used as the deployment means, for
5 actuation of the re-settable sealing mechanism.

Figure 9 represents a sixth embodiment of the invention that utilizes a tractor system attached to the BHA such that BHA can be moved and the sealing mechanism actuated to establish a hydraulic seal below the perforated interval. The treating fluid can be pumped down the wellbore and into the perforated interval.

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DETAILED DESCRIPTION OF THE INVENTION

The present invention will be described in connection with its preferred embodiments. However, to the extent that the following description is specific to a particular embodiment or a particular use of the invention, this is intended to be
15 illustrative only, and is not to be construed as limiting the scope of the invention. On the contrary, the description is intended to cover all alternatives, modifications, and equivalents that are included within the spirit and scope of the invention, as defined by the appended claims.

The present invention provides a new method and a new apparatus for
20 perforating and stimulating multiple formation intervals, which allows each single zone to be treated with an individual treatment stage while eliminating or minimizing the problems that are associated with existing coiled tubing or jointed tubing stimulation methods and hence providing significant economic and technical benefit over existing methods.

Specifically, the invention involves suspending a bottomhole assembly in the
25 wellbore to individually and sequentially perforate and treat each of the desired multiple zones while pumping the multiple stages of the stimulation treatment and to deploy a mechanical re-settable sealing mechanism to provide controlled diversion of each individual treatment stage. For the purposes of this application, "wellbore" will
30 be understood to include below ground sealed components of the well and also all

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5 sealed equipment above ground level, such as the wellhead, spool pieces, blowout preventers, and lubricator. The new apparatus consists of a deployment means (e.g., coiled tubing, jointed tubing, electric line, wireline, tractor system, etc.) with a bottomhole assembly comprised of at least a perforating device and a re-settable mechanical sealing mechanism that may be independently actuated from the surface via one or more signaling means (e.g., electronic signals transmitted via wireline; hydraulic signals transmitted via tubing, annulus, umbilicals; tension or compression loads; radio transmission; fiber-optic transmission; etc.) and designed for the anticipated wellbore environment and loading conditions. In the most general sense, the term "bottomhole assembly" is used to denote a string of components consisting of at least a perforating device and a re-settable sealing mechanism. Additional components including, but not limited to, fishing necks, shear subs, wash tools, circulation port subs, flow port subs, pressure equalization port subs, temperature gauges, pressure gauges, wireline connection subs, re-settable mechanical slips, casing collar locators, centralizer subs and/or connector subs may also be placed on the bottomhole assembly to facilitate other anticipated auxiliary or ancillary operations and measurements that may be desirable during the stimulation treatment.

10 In the most general sense, the re-settable mechanical sealing mechanism performs the function of providing a "hydraulic seal", where hydraulic seal is defined as sufficient flow restriction or blockage such that fluid is forced to be directed to a different location than the location it would otherwise be directed to if the flow restriction were not present. Specifically, this broad definition for "hydraulic seal" is meant to include a "perfect hydraulic seal" such that all flow is directed to a location different from the location the flow would be directed to if the flow restriction were not present; and an "imperfect hydraulic seal" such that an appreciable portion of flow is directed to a location different from the location the flow would be directed to if the flow restriction were not present. Although it would generally be preferable to use a re-settable mechanical sealing that provides a perfect hydraulic seal to achieve optimal stimulation; a sealing mechanism that provides an imperfect hydraulic seal could be used and an economic treatment achieved even though the stimulation treatment may not be perfectly diverted.

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5 In the first preferred embodiment of the invention, coiled tubing is used as the deployment means and the new method involves sequentially perforating and then stimulating the individual zones from bottom to top of the completion interval, with the stimulation fluid pumped down the annular space between the production casing and the coiled tubing. As discussed further below, this embodiment of the new apparatus and method offer substantial improvements over existing coiled tubing and jointed tubing stimulation technology and are applicable over a wide range of wellbore architectures and stimulation treatment designs.

10 Specifically, the first preferred embodiment of the new method and apparatus involves the deployment system, signaling means, bottomhole assembly, and operations as described in detail below, where the various components, their orientation, and operational steps are chosen, for descriptive purposes only, to correspond to components and operations that could be used to accommodate hydraulic proppant fracture stimulation of multiple intervals.

15 In the first preferred embodiment for a hydraulic proppant fracture stimulation treatment, the apparatus would consist of the BHA deployed in the wellbore by coiled tubing. The BHA would include a perforating device; re-settable mechanical sealing mechanism; casing-collar-locator; circulation ports; and other ancillary components (as described in more detail below).

20 Furthermore, in this first preferred embodiment, the perforating device would consist of a select-fire perforating gun system (using shaped-charge perforating charges); and the re-settable mechanical sealing mechanism would consist of an inflatable, re-settable packer, a mechanical re-settable slip device to prevent downward axial movement of the bottomhole assembly when set; and pressure equalization ports
25 located above and below the inflatable re-settable packer.

In addition, in this first preferred embodiment, a wireline would be placed interior to the coiled tubing and used to provide a signaling means for actuation of select-fire perforation charges and for transmission of electric signals associated with the casing-collar-locator used for BHA depth measurement.

30 Referring now to Figure 1, an example of the type of surface equipment that could be utilized in the first preferred embodiment would be a rig up that used a very

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long lubricator 2 with the coiled tubing injector head 4 suspended high in the air by crane arm 6 attached to crane base 8. The wellbore would typically comprise a length of a surface casing 78 partially or wholly within a cement sheath 80 and a production casing 82 partially or wholly within a cement sheath 84 where the interior wall of the wellbore is composed of the production casing 82. The depth of the wellbore would preferably extend some distance below the lowest interval to be stimulated to accommodate the length of the bottomhole assembly that would be attached to the end of the coiled tubing 106. Coiled tubing 106 is inserted into the wellbore using the coiled tubing injection head 4 and lubricator 2. Also installed to the lubricator 2 are blow-out-preventors 10 that could be remotely actuated in the event of operational upsets. The crane base 8, crane arm 6, coiled tubing injection head 4, lubricator 2, blow-out-preventors 10 (and their associated ancillary control and/or actuation components) are standard equipment components well known to those skilled in the art that will accommodate methods and procedures for safely installing a coiled tubing bottomhole assembly in a well under pressure, and subsequently removing the coiled-tubing bottomhole assembly from a well under pressure.

With readily-available existing equipment, the height to the top of the coiled tubing injection head 4 could be approximately 90 feet from ground level with the "goose-neck" 12 (where the coil is bent over to go down vertically into the well) approaching approximately 105 feet above the ground. The crane arm 6 and crane base 8 would support the load of the injector head 4, the coiled tubing 106, and any load requirements anticipated for potential fishing operations (jarring and pulling).

In general, the lubricator 2 must be of length greater than the length of the bottomhole assembly to allow the bottomhole assembly to be safely deployed in a wellbore under pressure. Depending on the overall length requirements and as determined prudent based on engineering design calculations for a specific application, to provide for stability of the coiled tubing injection head 4 and lubricator 2, guy-wires 14 could be attached at various locations on the coiled tubing injection head 4 and lubricator 2. The guy wires 14 would be firmly anchored to the ground to prevent undue motion of the coiled tubing injection head 4 and lubricator 2 such that the integrity of the surface components to hold pressure would not be compromised.

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Depending on the overall length requirements, alternative injection head/lubricator system suspension systems (coiled tubing rigs or fit-for-purpose workover rigs) could also be used.

Also shown in Figure 1 are several different wellhead spool pieces which may be used for flow control and hydraulic isolation during rig-up operations, stimulation operations, and rig-down operations. The crown valve 16 provides a device for isolating the portion of the wellbore above the crown valve 16 from the portion of the wellbore below the crown valve 16. The upper master fracture valve 18 and lower master fracture valve 20 also provide valve systems for isolation of wellbore pressures above and below their respective locations. Depending on site-specific practices and stimulation job design, it is possible that not all of these isolation-type valves may actually be required or used.

The side outlet injection valves 22 shown in Figure 1 provide a location for injection of stimulation fluids into the wellbore. The piping from the surface pumps and tanks used for injection of the stimulation fluids would be attached with appropriate fittings and/or couplings to the side outlet injection valves 22. The stimulation fluids would then be pumped into the wellbore via this flow path. With installation of other appropriate flow control equipment, fluid may also be produced from the wellbore using the side outlet injection valves 22. It is noted that the interior of the coiled tubing 106 can also be used as a flow conduit for fluid injection into the wellbore.

The bottomhole assembly storage wellbores 24 shown in Figure 1 provide a location for storage of spare or contingency bottom-hole assemblies 27, or for storage of bottomhole assemblies that have been used during previous operations. The bottomhole assembly storage wellbores 24 may be drilled to a shallow depth such that a bottomhole assembly that may contain perforating charges may be safely held in place with surface slips 26 such that the perforating charges are located below ground level until the bottomhole assembly is ready to be attached to the coiled tubing 106. The bottomhole assembly storage wellbores 24 may be drilled to accommodate placement of either cemented or uncemented casing string, or may be left uncased altogether. The actual number of bottomhole assembly storage wellbores 24 required

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for a particular operation would depend on the overall job requirements. The bottomhole assembly storage wellbores 24 could be located within the reach of the crane arm 6 to accommodate rapid change-out of bottomhole assemblies during the course of the stimulation operation without the necessity of physically relocating the crane base 8 to another location.

Referring now to Figure 2A, coiled tubing 106 is equipped with a coiled tubing connection 110 which may be connected to a shear-release/fishing neck combination sub 112 that contains both a shear-release mechanism and a fishing neck and allows for the passage of pressurized fluids and wireline 102. The shear-release/fishing neck combination sub 112 may be connected to a sub containing a circulation port 114 that may provide a flow path to wash debris from above the inflatable, re-settable packer 120 or provide a flow path to inject fluid downhole using the coiled tubing 106. The circulation port sub 114 contains a valve assembly that actuates the circulation port 114 and the upper equalization port 116. The upper equalization port 116 may be connected to a lower equalization port 122 via tubing through the inflatable, re-settable packer 120. Both the circulation port 114 and the upper equalization port 116 would preferably be open in the "running position", thereby allowing pressure communication between the internal coiled-tubing pressure and the coiled tubing by casing annulus pressure. Within this document, "running position" refers to the situation where all components in the bottomhole assembly possess a configuration that permits unhindered axial movement up and down the wellbore. The lower equalization port 122 located below the inflatable, re-settable packer 120 is always open and flow through the equalization ports is controlled by the upper equalization port 116. The circulation and equalization ports can be closed simultaneously by placing a slight compressive load on the BHA. To prevent potential back-flow into the coiled tubing when the circulation port 114 is open in the running position, a surface pressure can be applied to the coiled tubing 106 such that the pressure inside the circulation port 114 exceeds the wellbore pressure directly outside the circulation port 114. The re-settable, inflatable packer is hydraulically isolated from the internal coiled tubing pressure in the running position. The inflatable, re-settable packer can gain pressure communication via internal valving with the internal coiled tubing pressure by placing a

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slight compressive load on the BHA. Mechanically actuated, re-settable axial position locking devices, or "slips," 124 may be placed below the inflatable, re-settable packer 120 to resist movement down the wellbore. The mechanical slips 124 may be actuated through a "continuous J" mechanism by cycling the axial load between compression and tension. A wireline connection sub 126 is located above the casing collar locator 128 and select-fire perforating gun system. The perforating gun system may be designed based on knowledge of the number, location, and thickness of the hydrocarbon-bearing sands within the target zones. The gun system will be composed of one gun assembly (e.g., 134) for each zone to be treated. The first (lowest) gun assembly will consist of a select-fire head 132 and a gun encasement 134 which will be loaded with perforating charges 136 and a select-fire detonating system.

Specifically, a preferred embodiment of the new method involves the following steps, where the stimulation job is chosen, for descriptive purposes, to be a multi-stage, hydraulic, proppant-fracture stimulation.

1. The well is drilled and casing is cemented across the interval to be completed, and if desired, one or more bottomhole assembly storage wellbores are drilled and completed.
2. The target zones within the completion interval are identified (typically by a combination of open-hole and cased-hole logs).
3. The bottomhole assemblies (BHA), and perforating gun assemblies to be deployed on each BHA anticipated to be used during the stimulation operation, are designed based on knowledge of the number, location, and thickness of the hydrocarbon-bearing sands within the target zones.
4. A reel of coiled tubing is made-up with a preferred embodiment BHA described above. The reel of coiled tubing would also be made-up to contain the wireline that is used to provide a signaling means for actuation of the perforating guns. Preferably, the desired quantity of appropriately configured spare or contingency BHA's would also be made-up and stored in the bottomhole assembly storage wellbore(s). The coiled tubing may be pre-loaded with fluid either before or after attaching the BHA to the coiled tubing.

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5. As shown in Figure 1, the coiled tubing 106 with BHA is run into the well via a lubricator 2 and the coiled tubing injection head 4 is suspended by crane arm 6.
6. The coiled tubing/BHA is run into the well while correlating the depth of the BHA with the casing collar locator 128 (Figure 2A).
7. The coiled tubing/BHA is run below the bottom-most target zone to ensure that there is sufficient wellbore depth below the bottom-most perforations to locate the BHA below the first set of perforations during fracturing operations. As shown in Figure 2A, the inflatable, re-settable packer 120 and re-settable mechanically actuated slips 124 are in the running position.
8. As shown in Figure 2B, the coiled tubing/BHA is then raised to a location within the wellbore such that the first (lowest) set of perforation charges 136 contained on the first gun assembly 134 of the select-fire perforating gun system are located directly across the bottom-most target zone where precise depth control may be established based on readings from the casing-collar-locator 128 and coiled tubing odometer systems (not shown). The action of moving the BHA up to the location of the first perforated interval will cycle the mechanical slip "continuous J" mechanism (not shown) into the pre-lock position where subsequent downward motion will force the re-settable mechanical slip 124 into the locked position thereby preventing further downward movement. It is noted that additional cycling of the coiled tubing axial load from compression to tension and back will return the re-settable mechanical slips to running position. In this manner, the mechanical slip continuous J mechanism coupled with the use of compression and tension loads transmitted via the suspension means (coiled tubing) are used to provide downhole actuation and de-actuation of the mechanical slips.
9. The first set of perforation charges 136 are selectively-fired by remote actuation via wireline 102 communication with the first select-fire head 132 to penetrate the casing 82 and cement sheath 84 and establish hydraulic communication with the formation 86 through the resultant perforations 230-231. It will be understood that any given set of perforations can, if desired, be a set of one, although generally multiple perforations would provide improved treatment results. It will also be understood that more than one segment of the gun assembly may be fired if desired

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to achieve the target number of perforations whether to remedy an actual or perceived misfire or simply to increase the number of perforations. It will also be understood that an interval is not necessarily limited to a single reservoir sand. Multiple sand intervals could be perforated and treated as a single stage using other diversion agents suitable for simultaneous deployment with this invention within a

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10. As shown in Figure 2C, the coiled tubing may be moved to position the circulation port 114 directly below the deepest perforation 231 of this first target zone to minimize potential for proppant fill above the inflatable, re-settable packer 120 and minimize high velocity proppant flow past the BHA.

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11. The first stage of the fracture stimulation treatment is initiated by circulating a small volume of fluid down the coiled tubing 106 through the circulation port 114 (via a positive displacement pump). This is followed by initiating the pumping of stimulation fluid down the annulus between the coiled tubing 106 and production casing 82 at fracture stimulation rates. The small volume of fluid flowing down the coiled tubing 106 serves to keep a positive pressure inside the coiled tubing 106 to resist proppant-laden fluid backflow into the coiled tubing 106 and to resist coiled tubing collapse loading during fracturing operations. It is noted that as an alternative means to resist coiled tubing collapse, an internal valve mechanism may be used to maintain the circulation port 114 in the closed position and with positive pressure then applied to the coiled tubing 106 using a surface pump. As an illustrative example of the fracture treatment design for stimulation of a 15-acre size sand lens containing hydrocarbon gas, the first fracture stage could be comprised of "sub-stages" as follows: (a) 5,000 gallons of 2% KCl water; (b) 2,000 gallons of cross-linked gel containing 1 pound-per-gallon of proppant; (c) 3,000 gallons of cross-linked gel containing 2 pounds-per-gallon of proppant; (d) 5,000 gallons of cross-linked gel containing 3 pounds-per-gallon of proppant; and (e) 3,000 gallons of cross-linked gel containing 4 pound-per-gallon of proppant such that 35,000 pounds of proppant are placed into the first zone.

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12. As shown in Figure 2C, all sub-stages of the first fracture operation are completed with the creation of the first proppant fracture 232.

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13. At the end of the first stage of the stimulation treatment, should proppant in the wellbore prevent the coiled tubing/BHA from immediate movement; fluid can be circulated through the circulation port 114 to wash-over and clean-out the proppant to free the coiled tubing/BHA and allow movement.

5 14. As shown in Figure 3A, the coiled tubing/BHA is then pulled uphole to slightly above the second deepest target zone such that the second set of perforation charges 146 contained on the select-fire perforating gun system 144 are located slightly above the second deepest target zone where again precise depth control is established based on readings from the casing-collar-locator 128 and coiled tubing odometer systems. The action of moving the BHA upward (to slightly above the second interval to be perforated) will cycle the re-settable mechanical slip "continuous J" mechanism into the pre-lock position. Further cycling of compression/tension loads are performed to place the mechanical slip continuous J mechanism back into the running position. The coiled tubing/BHA is then moved
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15 downward to position the perforation charges 146 contained on the select-fire perforating gun system 144 directly across from the second deepest target zone where again precise depth control is established based on readings from the casing-collar-locator 128 and coiled tubing odometer systems.

15. The second set of perforation charges 146 are selectively-fired by remote actuation via the second select-fire head 142 to penetrate the casing 82 and cement sheath 84 and establish hydraulic communication with the formation 86 through the resultant perforations 240-241.
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16. As shown in Figure 3B, the coiled tubing may be moved down the wellbore to position the BHA several feet below the deepest perforation 241 of the second target zone. Subsequent movement of the BHA up the wellbore to position the circulation port 114 directly below the deepest perforation 241 of this second target zone will cycle the re-settable mechanical slips 124 into the pre-lock position, where subsequent downward motion will force the re-settable mechanical slip 124 into the locked position thereby preventing further downward movement.
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17. As shown in Figure 3C, downward movement engages the re-settable mechanical slips 124 with the casing wall 82 thereby preventing further downward movement
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of the BHA. A compression load on the coiled tubing is then applied and this load closes the circulation port 114 and upper equalization port 116, and creates pressure communication between the inflatable, re-settable packer 120 and the internal coiled tubing pressure. The compression load also locks the circulation port 114 into a position directly below the deepest perforation 241 of this second target zone (to minimize potential for proppant fill above the inflatable, re-settable packer 120 and minimize high velocity proppant flow past the BHA) and with the re-settable, inflatable packer 120 positioned between the first and second perforated intervals.

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- 10 18. A further compression load is set down on the coiled tubing/BHA to test the re-settable mechanical slips 124 and ensure that additional downward force does not translate into further movement of the BHA down the wellbore.
- 15 19. As shown in Figure 3D, the inflatable, re-settable packer 120 is actuated by pressurizing the coiled tubing 106 to effect a hydraulic seal above and below the inflatable, re-settable packer 120. A compression load is maintained on the BHA to maintain pressure communication between the internal coiled tubing pressure and the inflatable, re-settable packer 120, to keep the circulation port 114 and the upper equalization port 116 closed, and to keep the re-settable mechanical slips 124 in the locked and energized position. The inflatable, re-settable packer 120 is maintained in the actuated state by maintaining pressure in the coiled tubing 106 via a surface pump system (it is noted that alternatively, the inflatable, re-settable packer could be maintained in an actuated state by locking pressure in to the element using an internal valve remotely controlled from surface by a signaling means compatible with other BHA components and other present signaling means).
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- 25 20. The second stage of the fracture stimulation treatment is initiated with fluid pumped down the annulus between the coiled tubing 106 and production casing 82 at fracture stimulation rates while maintaining compression load on the BHA to keep the circulation port 114 and upper equalization port 116 closed, and maintaining coiled tubing pressure at a sufficient level to resist coiled tubing string collapse and to keep the inflatable, re-settable packer 120 inflated and serve as a hydraulic seal between the annular pressure above the packer before, during and
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after the fracture operation and the sealed wellbore pressure below the inflatable, re-settable packer.

5 21. All sub-stages of the fracture operation are pumped leaving a minimal under-flush of the proppant-laden last sub-stage in the wellbore so as not to over-displace the fracture treatment. If during the course of this treatment stage, the seal integrity of the inflatable, re-settable packer is believed to be compromised, the treatment stage could be temporarily suspended to test the packer seal integrity above the highest (shallowest) existing perforations (e.g., perforation 240 in Figure 3D) after setting the inflatable, re-settable packer 120 in blank pipe. If the seal integrity test were to be performed, it could be desirable to perform a circulation/washing operation to ensure any proppant that may be present in the wellbore is circulated out of the wellbore prior to conducting the test. The circulation/washing operation could be performed by opening the circulation port 114 and then pumping of circulation fluid down the coiled tubing 106 to circulate the proppant out of the wellbore.

10 22. As shown in Figure 3E, all sub-stages of the second fracture operation are completed with the creation of a second proppant fracture 242.

15 23. After completing the second stage fracture operation and ceasing injection of stimulation fluid down the annulus formed between the coiled tubing 106 and production casing 82, a small tension load is applied to the coiled tubing 106 while maintaining internal coiled tubing pressure. The small applied tension first isolates the inflatable, re-settable packer pressure from the coiled tubing pressure thereby locking pressure in the inflatable, re-settable packer 120 and thereby maintaining a positive pressure seal and imparting significant resistance to axial movement of the inflatable, re-settable packer 120. In the same motion, the applied tension may then open the circulation port 114 and equalization port 116 thereby allowing the coiled tubing pressure to bleed off into the annulus formed by the coiled tubing 106 and production casing 82 while simultaneously allowing the pressure above and below the inflatable, re-settable packer 120 to equilibrate. The surface system pump providing internal coiled tubing pressure may be stopped after equilibrating the downhole pressures.

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24. After the pressures inside the coiled tubing, in the annulus formed by the coiled tubing 106 and production casing 82 above the inflatable, re-settable packer 120, and in the annulus formed by the BHA and production casing 82 below the inflatable, re-settable packer 120 equilibrate, a compressive load placed on the coiled tubing will close the circulation port 114 and upper equalization port 116 before releasing the pressure trapped within the inflatable, re-settable packer 120 into the coiled tubing 106. This release of internal pressure from the inflatable, re-settable packer 120 will allow the inflatable, re-settable packer 120 to retract from the production casing wall, as shown in Figure 3F, in the absence of an external differential pressure across the inflatable, re-settable packer 120 which could otherwise result in forces and movement that could damage the coiled tubing 106 or BHA.
25. Once the inflatable, re-settable packer 120 is unset, as shown in Figure 3F, tension pulled on the coiled tubing / BHA could de-energize the re-settable mechanical slips 124 thereby allowing the BHA to be free to move and be repositioned up the wellbore.
26. If at the end of the second stage of the stimulation treatment, proppant in the wellbore prevents the coiled tubing/BHA from immediate movement, fluid may be circulated through the circulation port 114 to wash-over and clean-out the proppant to free the coiled tubing/BHA and allow upward movement of the BHA after releasing the inflatable, re-settable packer.
27. The process as described above is repeated until all planned zones are individually-stimulated (Figures 3A to 3F represent a BHA designed for a three zone stimulation).
28. Upon completion of the stimulation process, the components of the BHA are returned to running position and the coiled tubing/BHA assembly is removed from the wellbore.
29. If all the desired target zones have been stimulated, the well can be immediately placed on production.
30. If it is desirable to stimulate additional zones, a reel of coiled tubing may be made-up with a slightly modified bottomhole assembly as shown in Figure 4A. In this

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assembly, the only alteration to the BHA of the preferred embodiment described above may be the addition of a select-fire-set mechanical plug 164 or select-fire set bridge-plug 164 located below the lowest select-fire gun assembly as shown in Figure 4A. In general, the select-fire-set mechanical plug 164 can be either a bridge plug or a fracture baffle. A fracture baffle would generally be preferred if it is desirable to simultaneously produce zones separated by the plug immediately after the stimulation job.

31. The modified BHA, shown in Figure 4A, consists of a select-fire perforating gun system (Figure 4A depicts a gun system comprising perforating guns 174, 184 and 194 with associated charges 176, 186 and 196 and select-fire heads 172, 182 and 192), a casing-collar-locator 128, flow ports 114, 116 and 122, an inflatable, re-settable packer 120, a re-settable mechanical axial slip device 124 and select-fire bridge plug 164 set using select-fire head 162. The modified BHA is run into the well via a lubricator and the coiled tubing injection head suspended by crane or rig above the wellhead.

32. The coiled tubing/BHA is run into the well while correlating the depth with the casing collar locator.

33. As shown in Figure 4A, the coiled tubing/modified BHA is run into the wellbore to position the select-fire mechanical-plug 164 above the last previously stimulated zone 252.

34. As shown in Figure 4B the select-fire firing head 162 is fired to set the select-fire mechanical plug 164 above the last previously stimulated zone 252.

35. After the bridge-plug select-fire head 162 is activated to set the select-fire bridge-plug 164, the coiled tubing/modified BHA is then raised to a location within the wellbore such that the first (lowest) set of perforation charges 176 contained on the select-fire perforating gun system are located directly across the next, bottom-most target zone to be perforated where precise depth control may be established based on readings from the casing-collar-locator 128 and coiled tubing odometer systems located on the surface equipment. The action of moving the BHA up to the location of the first perforated interval will cycle the re-settable mechanical slips 124 into the locked position and will require cycling the coiled tubing axial load

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from compression to tension and back to return the re-settable mechanical slips to running position.

36. As shown in Figure 4B, the first set of perforation charges 176 on the modified BHA are selectively-fired by remote actuation via the second select-fire head 172 to penetrate the casing 82 and cement sheath 84 with perforations 270, 271 and establish hydraulic communication with the formation 86 through the resultant perforations 270-271.
37. If there is insufficient space between the last previously placed perforations 250, 251 and the location of the next set of perforations 270, 271 to be stimulated to enable appropriate placement of the BHA for perforation, isolation and stimulation of the next set of perforations 270, the select-fire bridge plug 164 may be set below the last previously stimulated perforations 250, 251, and the inflatable, re-settable packer may be employed during the first stimulation operation to isolate the uppermost perforations 270, 271 from the previously stimulated perforations 250, 251.
38. The entire process as described above is then repeated as appropriate until all planned zones are individually-stimulated (Figure 4A and Figure 4B represent a BHA designed for an additional three zone stimulation operation).

It will be recognized by those skilled in the art that the preferred suspension method when proppant-laden fluids are involved would be conventional jointed tubing or coiled tubing, preferably with one or more circulation ports so that proppant settling in the wellbore could easily be circulated out of the wellbore. Treatments such as acid fracturing or matrix acidizing may not require such a capability and could readily be performed with a deployment system based on cable such as slickline or wireline, or based on a downhole tractor system.

It will be recognized by those skilled in the art that depending on the objectives of a particular job, various pumping systems could be used and could involve the following arrangements: (a) pumping down the annulus created between the cable or tubing (if the deployment method uses cable or tubing) and the casing wall; (b) pumping down the interior of the coiled tubing or jointed tubing if the suspension method involves the use of coiled tubing or jointed tubing and excess friction and proppant erosion were not of concern for the well depths considered; or

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(c) simultaneously pumping down the annulus created between the tubing (if the deployment method involves tubing) and the casing wall and the interior of the tubing if excess friction and proppant erosion were not of concern for the well depths considered.

5 Figure 5 illustrates a second embodiment of the invention where coiled tubing is used as the deployment means and excess friction is not of concern and either proppant is not pumped during the job or use of proppant is not of concern. Figure 5 shows that coiled tubing 106 is used to suspend the BHA and BHA components. In this embodiment, the individual zones are treated in sequential order from shallower wellbore locations to deeper wellbore locations. In this embodiment, as shown in Figure 5, circulation port 114 is now placed below the inflatable, re-settable packer 120 such that treatment fluid may be pumped down the interior of coiled tubing 106, exit the circulation port 114, and be positively forced to enter the targeted perforations. As an illustration of the operations, Figure 5 shows that the inflatable, re-settable packer 120 has been actuated and set below perforations 241 that are associated with a previous zone hydraulic fracture 242. The inflatable, re-settable packer 120 provides hydraulic isolation such that when treatment fluid is subsequently pumped down the coiled tubing 106, the treating fluid is forced to enter previously placed perforations 230 and 231 and create new hydraulic fractures 232. The operations are then continued and repeated as appropriate for the desired number of formation zones and intervals.

25 Figure 6 illustrates a third embodiment of the invention where coiled tubing is used as the deployment means and excess friction is not of concern and either proppant is not pumped during the job or use of proppant is not of concern. Figure 6 shows that coiled tubing 106 is used to suspend the BHA and BHA components. In this embodiment, the individual zones may be treated in any order. In this embodiment, as shown in Figure 6, a straddle-packer inflatable sealing mechanism 125 is used as the re-settable sealing mechanism and the circulation port 114 is now placed between the upper inflatable sealing element 121 and the lower inflatable sealing element 123. When the upper inflatable sealing element 121 and the lower inflatable sealing element 123 are actuated, treatment fluid may be pumped down the interior of coiled tubing

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actuated via hydraulic pressure transmitted via the umbilical 104. In general, multiple umbilicals can be deployed either in the interior of the coiled tubing and/or in the annulus between the coiled tubing and production casing. In general, the umbilicals can be used to perform several different operations, including but not limited to, providing (a) hydraulic communication for actuation of individual BHA components including, but not limited to, the sealing mechanism and/or perforating device; (b) flow conduits for downhole injection or circulation of additional fluids; and (c) for data acquisition from downhole measurement devices. It is noted that as shown in Figure 8A, the BHA also includes centralizers 201, 203, and 205 that are used to keep the BHA centralized in the wellbore when BHA components are in the running position.

The use of an umbilical(s) can provide the ability to hydraulically engage and/or disengage the re-settable mechanical sealing mechanism independent of the hydraulic pressure condition within the coiled tubing. This then allows the method to be extended to use of re-settable mechanical sealing mechanisms requiring independent hydraulic actuation for operation. Perforating devices that require hydraulic pressure for selective-firing can be actuated via an umbilical. This may then allow the wireline, if deployed with the coiled tubing and BHA, to be used for transmission of an additional channel or channels of electrical signals, as may be desirable for acquisition of data from measurement gauges located on the bottomhole assembly, or actuation of other BHA components, for example, an electrical downhole motor-drive that could provide rotation/torque for BHA components. Alternatively, an umbilical could be used to operate a hydraulic motor for actuation of various downhole components (e.g., a hydraulic motor to engage or disengage the re-settable sealing mechanism).

The use of an umbilical(s) can provide the ability to inject or circulate any fluid downhole to multiple locations as desired with precise control. For example, to help mitigate proppant settling on the sealing mechanism during a hydraulic proppant fracture treatment, umbilical(s) could be deployed and used to provide independent continuous or intermittent washing and circulation to keep proppant from accumulating on the sealing mechanism. For example, one umbilical could run to just above the re-settable mechanical sealing mechanism while another is run just below the re-settable mechanical sealing mechanism. Then, as desired, fluid (e.g., nitrogen) could

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be circulated downhole to either or both locations to wash the proppant from the region surrounding the sealing mechanism and hence mitigate the potential for the BHA sticking due to proppant accumulation. In the case of fluid circulation, it is noted that the umbilical size and fluid would be selected to ensure the desired rate is achieved and is not unduly limited by friction pressure in the umbilical.

In addition to umbilicals comprised of tubing strings that provide hydraulic communication downhole as a signaling means for actuation of BHA components (or possibly as a signal transmission means for surface recording of downhole gauges), in general, one or more wireline or fiber-optic cables could be deployed in the wellbore to provide a electrical or electro-optical communication downhole as a signaling means for actuation of BHA components (or possibly as a signal transmission means for surface recording of downhole gauges).

Figure 9 illustrates a sixth embodiment of the invention where a tractor system, comprised of upper tractor drive unit 131 and lower tractor drive unit 133, is attached to the BHA and is used to deploy and position the BHA within the wellbore. In this embodiment, the individual zones are treated in sequential order from deeper wellbore locations to shallower wellbore locations. In this embodiment, the BHA also contains an internal electrical pump system 117, powered by electrical energy transmitted downhole via the wireline 102, to inflate or deflate the inflatable, re-settable packer 120 using wellbore fluid. In this embodiment, treatment fluid is pumped down the annulus between the wireline 102 and production casing wall 82 and is positively forced to enter the targeted perforations. Figure 9 shows that the inflatable, re-settable packer 120 has been actuated and set below the perforations 241 that are associated with the next zone to be fractured. The inflatable, re-settable packer 120 provides hydraulic isolation such that when treatment fluid is subsequently pumped down the annulus between the wireline 102 and production casing 82, the treating fluid is forced to enter perforations 240 and 241 and create new hydraulic fractures 242. The operations are then continued and repeated as appropriate for the desired number of formation zones and intervals.

As alternatives to this sixth embodiment, the tractor system could be

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self-propelled, controlled by on-board computer systems, and carry on-board signaling systems such that it would not be necessary to attach cable or tubing for positioning, control, and/or actuation of the tractor system. Furthermore, the various BHA components could also be controlled by on-board computer systems, and carry on-board signaling systems such that it is not necessary to attach cable or tubing for control and/or actuation of the components. For example, the tractor system and/or BHA components could carry on-board power sources (e.g., batteries), computer systems, and data transmission/reception systems such that the tractor and BHA components could either be remotely controlled from the surface by remote signaling means, or alternatively, the various on-board computer systems could be pre-programmed at the surface to execute the desired sequence of operations when the deployed in the wellbore.

It will be recognized by those skilled in the art that many different components can be deployed as part of the bottomhole assembly. The bottomhole assembly may be configured to contain instrumentation for measurement of reservoir, fluid, and wellbore properties as deemed desirable for a given application. For example, temperature and pressure gauges could be deployed to measure downhole fluid temperature and pressure conditions during the course of the treatment; a densitometer could be used to measure effective downhole fluid density (which would be particularly useful for determining the downhole distribution and location of proppant during the course of a hydraulic proppant fracture treatment); and a radioactive detector system (e.g., gamma-ray or neutron measurement systems) could be used for locating hydrocarbon bearing zones or identifying or locating radioactive material within the wellbore or formation.

Depending on the specific bottomhole assembly components and whether the perforating device creates perforation holes with burrs that may damage the sealing mechanism, the bottomhole assembly could be configured with a "perforation burr removal" tool that would act to scrape and remove perforation burrs from the casing wall.

Depending on the specific bottomhole assembly components and whether excessive wear of bottomhole assembly components may occur if the assembly is run in

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contact with the casing wall, centralizer subs could be deployed on the bottomhole assembly to provide positive mechanical positioning of the assembly and prevent or minimize the potential for damage due to the assembly running in contact with the casing wall.

5 Depending on the specific bottomhole assembly components and whether the perforation charges create severe shock waves and induce undue vibrations when fired, the bottomhole assembly may be configured with vibration/shock dampening subs that would eliminate or minimize any adverse effects on system performance due to perforation charge detonation.

10 Depending on the deployment system used and the objectives of a particular job, perforating devices and any other desired BHA components may be positioned either above or below the re-settable sealing mechanism and in any desired order relative to each other. The deployment system itself, whether it be wireline, electric line, coiled tubing, conventional jointed tubing, or downhole tractor may be used to
15 convey signals to activate the sealing mechanism and/or perforating device. It would also be possible to suspend such signaling means within conventional jointed tubing or coiled tubing used to suspend the sealing and perforating devices themselves. Alternatively, the signaling means, whether it be electric, hydraulic, or other means, could be run in the hole externally to the suspension means or even housed in or
20 comprised of one or more separate strings of coiled tubing or conventional jointed tubing.

 With respect to treatments that use high viscosity fluid systems in wells deeper than about 8,000 feet, several major technological and economic benefits are immediately derived from application of this new invention. Reducing the friction
25 pressure limitations allows treatment of deeper wells and reduces the requirement for special fracture fluid formulations. Friction pressure limitations are reduced or eliminated because the high viscosity fluid can be pumped down the annulus between the coiled tubing or other suspension means and production casing. Since friction pressure limitations can be reduced or eliminated from that experienced with pumping
30 high viscosity fluid systems down the interior of coiled tubing, well depths where this technique can be applied are substantially increased. For example, assuming 1-1/2-inch

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coiled tubing deployed in a 5-1/2-inch outer diameter 17-pound-per-foot casing, the effective cross-sectional flow area is approximately equivalent to a 5-inch outer diameter casing string. With this effective cross-sectional flow area, well depths on the order of 20,000 feet or greater could be treated and higher pump rates (e.g., on the order of 10 to 30-barrels-per-minute or more) could be achieved for effective proppant transport and hydraulic fracturing using high viscosity fluids.

Since the annulus typically may have greater equivalent flow area, conventional fracturing fluids can be used, as opposed to special low-viscosity fluids (such as Dowell-Schlumberger's ClearFrac™ fluid) used to reduce friction pressure drop through coiled tubing. The use of conventional fracturing fluid technology would then allow treatment of formations with temperatures greater than 250°F, above which currently available higher-cost specialty fluids may begin to degrade.

The sealing mechanism used could be an inflatable device, a mechanical compression-set re-settable packer, a mechanical compression-set straddle-packer design, cup-seal devices, or any other alternative device that may be deployed via a suspension means and provides a re-settable hydraulic sealing capability or equivalent function. Both inflatable and compression set devices exist that provide radial clearance between seals and casing wall (e.g., on the order of 0.25-inches to 1-inch for inflatable devices or 0.1 - 0.2 inches for compression-set devices) such that seal wear and tear would be drastically reduced or eliminated altogether. In a preferred embodiment of this invention, there would be sufficient clearance between the sealing mechanism in its deactivated state and the casing wall to allow rapid movement into and out of the wellbore without significant damage to the sealing mechanism or without pressure control issues related to surging/swabbing the well due to tool movement. The increased clearance between the seal surface and the casing wall (when the seal is not actuated) would also allow the coiled tubing/BHA to be tripped in and out of the hole at much faster speeds than are possible with currently available coiled tubing systems. In addition, to minimize potential undesirable seal wear and tear, in a preferred embodiment, the perforating device would accommodate perforating the casing wall such that a perforation hole with a relatively smooth edge would be achieved. Alternatively, the mechanical re-settable sealing mechanism may

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15 The gross height of each of the individual perforated target intervals is not limited. This is in contrast to the problem that existing coiled tubing systems possess using a straddle-packer like device that limits application to 15 - 30 feet of perforated interval height.

If coiled tubing is used as the deployment means, it is possible that the coiled tubing string used for the stimulation job could be hung-off in the wellhead and used as the production tubing string, which could result in significant cost savings by eliminating the need for rig mobilization to the well-site for installation of conventional production tubing string comprised of jointed tubing.

Controlling the sequence of zones to be treated allows the design of individual treatment stages to be optimized based on the characteristics of each individual zone. Furthermore, the potential for sub-optimal stimulation because multiple zones are treated simultaneously is essentially eliminated by having only one open set of perforations exposed to each stage of treatment. For example, in the case of hydraulic fracturing, this invention may minimize the potential for overflush or sub-optimal

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placement of proppant into the fracture. Also, if a problem occurs such that the treatment must be terminated, the up-hole zones to be stimulated have not been compromised, since they have yet to be perforated. This is in contrast to conventional ball sealer or coiled tubing stimulation methods, where all perforations must be shot prior to the job. Should the conventional coiled tubing job fail, it may be extremely difficult to effectively divert and stimulate over a long completion interval. Additionally, if only one set of perforations is open above the sealing element, fluid can be circulated without the possibility of breaking down the other multiple sets of open perforations above the top sealing element as could occur in the conventional coiled tubing job. This can minimize or eliminate fluid loss and damage to the formation when the bottomhole circulation pressure would otherwise exceed the formation pore pressure.

The entire treatment can be pumped in a single trip, resulting in significant cost savings over other techniques that require multiple wireline or rig work to trip in and out of the hole in between treatment stages.

The invention can be applied to multi-stage treatments in deviated and horizontal wellbores. Typically, other conventional diversion technology in deviated and horizontal wellbores is more challenging because of the nature of the fluid transport of the diverter material over the long intervals typically associated with deviated or horizontal wellbores.

Should a screen-out occur during the fracture treatment, the invention provides a method for sand-laden fluid in the annulus to be immediately circulated out of the hole such that stimulation operations can be recommenced without having to trip the coiled tubing/BHA out of the hole. The presence of the coiled tubing system provides a means to measure bottomhole pressure after perforating or during stimulation operations based on pressure calculations involving the coiled tubing string under shut-in (or low-flow-rate) conditions.

The presence of the coiled tubing or conventional jointed tubing system, if used as the deployment means, provides a means to inject fluid downhole independently from the fluid injected in the annulus. This may be useful, for example, in additional applications such as: (a) keeping the BHA sealing mechanism and flow ports clean of

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proppant accumulation (that could possibly cause tool sticking) by pumping fluid downhole at a nominal rate to clean off the sealing mechanism and flow ports; (b) downhole mixing applications (as discussed further below); (c) spotting of acid downhole during perforating to aid perforation hole clean-up and communication with the formation; and (d) independently stimulating two zones isolated from each other by the re-settable sealing mechanism. As such, if tubing is used as the deployment means, depending on the specific operations desired and the specific bottomhole assembly components, fluid could be circulated downhole at all times; or only when the sealing element is energized, or only when the sealing element is not energized; or while equalization ports are open or closed. Depending on the specific bottomhole assembly components and the specific design of downhole flow control valves, as may be used for example as integral components of equalization ports subs, circulation port subs or flow port subs, downhole flow control valves may be operated by wireline actuation, hydraulic actuation, flow actuation, "j-latch" actuated, sliding-sleeve actuated, or by many other means known to those skilled in the art of operation and actuation of downhole flow control valves.

The coiled tubing system still allows for controlled flowback of individual treatment stages to aid clean up and assist fracture closure. Flowback can be performed up the annulus between the coiled tubing and the production casing, or alternatively, flowback may even be performed up the coiled tubing string if excessive proppant flowback were not to be considered a problem.

The perforating device may be comprised of commercially-available gun systems. These gun systems could include what will be referred to herein as a "select-fire" system such that a single perforation gun assembly is comprised of multiple charges or sets of perforation charges. Each individual set of one or more perforation charges can be remotely controlled and fired from the surface using electric, radio, pressure, fiber-optic or other actuation signals. Each set of perforation charges can be designed (number of charges, number of shots per foot, hole size, penetration characteristics) for optimal perforation of the individual zone that is to be treated with an individual stage. With current select-fire gun technology, commercial gun systems exist that could allow on the order of 30 to 40 intervals to be perforated sequentially in

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a single downhole trip. Guns can be pre-sized and designed to provide for firing of multiple sets of perforations. Guns can be located at any location on the bottomhole assembly, including either above or below the mechanical re-settable sealing mechanism.

5 Intervals may be grouped for treatment based on reservoir properties, treatment design considerations, or equipment limitations. After each group of intervals (preferably 5 to approximately 20), at the end of a workday (often defined by lighting conditions), or if difficulties with sealing one or more zones are encountered, a bridge plug or other mechanical device would preferably be used to isolate the group
10 of intervals already treated from the next group to be treated. One or more select-fire set bridge plugs or fracture baffles could be run in conjunction with the bottomhole assembly and set as desired during the course of the completion operation to provide positive mechanical isolation between perforated intervals and eliminate the need for a separate wireline run to set mechanical isolation devices or diversion agents between
15 groups of fracture stages.

 In general, the inventive method can be readily employed in production casings of 4-1/2 inch diameter to 7-inch diameter with existing commercially available perforating gun systems and mechanical re-settable sealing mechanisms. The inventive method could be employed in smaller or larger casings with mechanical re-settable
20 sealing mechanisms appropriately designed for the smaller or larger casings.

 Each individual gun may be on the order of 2 to 8 feet in length, and contain on the order of 8 to 20 perforating charges placed along the gun tube at shot density ranging between 1 and 6 shots per foot, but preferably 2 to 4 shots per foot. In a preferred embodiment, as many as 15 to 20 individual guns could be stacked one on
25 top of another such that the assembled gun system total length is preferably kept to less than approximately 80 to 100 feet. This total gun length can be run into the wellbore using a readily-available surface crane and lubricator system. Longer gun lengths could also be used, but may require additional or special surface equipment depending on the total number of guns that would make up the complete perforating
30 device. It is noted that in some unique applications, gun lengths, number of charges per gun, and shot density could be greater or less than as specified above as final

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perforating system design would be impacted by the specific formation characteristics present in the wellbore to stimulated

In order to minimize the total length of the gun system and BHA, it may be desirable to use multiple (two or more) charge carriers uniformly distributed around and strapped, welded, or otherwise attached to the coiled tubing or connected below the mechanical re-settable sealing mechanism. For example, if it were desired to stimulate 30 zones, where each zone is perforated with a 4-ft gun, a single gun assembly would result in a total length of approximately 150 feet, which may be impractical to handle at the surface. Alternatively, two gun assemblies located opposite one another on the coiled tubing could be deployed, where each assembly could contain 15 guns, and total length could be approximately 75-feet, which could readily be handled at the surface with existing lubricator and crane systems.

An alternative arrangement for the perforating gun or guns would be to locate one or more guns above the re-settable mechanical sealing mechanism. There could be two or more separate gun assemblies attached in such a way that the charges were oriented away from the components on the bottomhole assembly or the coiled tubing. It could also be a single assembly with charges loaded more densely and firing mechanisms designed to simultaneously fire only a subset of the charges within a given interval, perhaps all at a given phase orientation.

In an alternative embodiment of this invention, abrasive water-jet cutting technology could be deployed as the perforating device. The use of coiled tubing or jointed tubing provides a flow conduit down the center of the tubing. Abrasive water-jet cutting technology could be applied with water-jet cutting nozzles installed in the bottom-hole portion of the coiled tubing. High-pressure high-velocity abrasive fluid or slurries would be pumped downhole through the coiled tubing and through the nozzles. The abrasive fluid would then cut through the casing wall, cement sheath, and penetrate the formation to provide flow path communication to the formation. Arbitrary distributions of holes and slots could be placed using this method throughout the completion interval during the stimulation job. Elimination of the conventional select-fire perforating gun system and replacement with a much smaller length abrasive

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excessive proppant flowback may also be increased leading to reduced stimulation effectiveness. Flowback would preferably be performed at a controlled low-rate to limit potential proppant flowback. Depending on flowback results, resin-coated proppant or alternative gun configurations could be used to improve the stimulation effectiveness.

In addition, if tubing or cable are used as the deployment means to help mitigate potential undesirable proppant erosion on the tubing or cable from direct impingement of the proppant-laden fluid when pumped into the side-outlet injection ports, an "isolation device" can be rigged up on the wellhead. The isolation device may consists of a flange with a short length of tubing attached that runs down the center of the wellhead to a few feet below the injection ports. The bottomhole assembly and tubing or cable are run interior to the isolation device tubing. Thus the tubing of the isolation device deflects the proppant and isolates the tubing or cable from direct impingement of proppant. Such an isolation device would consist of an appropriate diameter tubing such that it would readily allow the largest outer diameter dimension associated with the tubing or cable and bottomhole assembly to pass through unhindered. The length of the isolation device would be sized such that in the event of damage, the lower master fracture valve could still be closed and the wellhead rigged down as necessary to remove the isolation tool. Depending on the stimulation fluids and the method of injection, an isolation device would not be needed if erosion concerns were not present. Although field tests of isolation devices have shown no erosion problems, depending on the job design, there could be some risk of erosion damage to the isolation tool tubing assembly resulting in difficulty removing it. If an isolation tool is used, preferred practices would be to maintain impingement velocity on the isolation tool substantially below typical erosional limits, preferably below about 180 ft/sec, and more preferably below about 60 ft/sec.

Another concern with this technique is that premature screen-out may occur if fluid displacement during pumping is not adequately measured as it may be difficult to initiate a fracture with proppant-laden fluid across the next zone to be perforated. It may be preferable to use a KCl fluid or some other non-gelled fluid or fluid system for the pad rather than a gelled pad fluid to better initiate fracturing of the next zone.

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Pumping the job at a higher rate with a non-gelled fluid between stages to achieve turbulent flush/sweep of the casing will minimize the risk of proppant screen-out. Also, contingency guns available on the tool string would allow continuing the job after an appropriate wait time.

- 5 Although the embodiments discussed above are primarily related to the beneficial effects of the inventive process when applied to hydraulic fracturing processes, this should not be interpreted to limit the claimed invention which is applicable to any situation in which perforating and performing other wellbore operations in a single trip is beneficial. Those skilled in the art will recognize that
- 10 many variations not specifically mentioned in the examples will be equivalent in function for the purposes of this invention.

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We Claim:

1. A method for perforating and treating multiple intervals of one or more subterranean formations intersected by a wellbore, said method comprising:
 - (a) deploying a bottom-hole assembly ("BHA") from a tubing string within said wellbore, said BHA having a perforating device and a sealing mechanism;
 - (b) using said perforating device to perforate at least one interval of said one or more subterranean formations;
 - (c) positioning said BHA within said wellbore and activating said sealing mechanism so as to establish a hydraulic seal below said at least one perforated interval;
 - (d) pumping a treating fluid down the annulus between said tubing string and said wellbore and into the perforations created by said perforating device, without removing said perforating device from said wellbore;
 - (e) releasing said sealing mechanism; and
 - (f) repeating steps (b) through (e) for at least one additional interval of said one or more subterranean formations.
2. The method of Claim 1 wherein said tubing string is a coiled tubing.
3. The method of Claim 1 wherein said tubing string is a jointed tubing.
4. The method of Claim 1 wherein said BHA further comprises a casing collar locator.
5. The method of Claim 1 wherein said perforating device is a select-fire perforating gun containing multiple sets of one or more shaped-charge perforating charges; each of said sets of one or more shaped-charge perforating charges individually controlled and activated by electric or optic signal transmitted via a cable deployed in the wellbore.
6. The method of Claim 1 wherein said perforating device is a jet cutting device that uses fluid pumped down said tubing string to establishing hydraulic communication between said wellbore and said one or more intervals of said one or more subterranean formations.

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7. The method of Claim 1 wherein said treating fluid is also pumped down said tubing string, through flow ports in said BHA , and into said perforations.
8. The method of Claim 1 wherein a second treating fluid is pumped down said tubing string, through flow ports in said BHA, and into said perforations.
- 5 9. The method of Claim 8 wherein said second treating fluid is nitrogen.
10. The method of Claim 1 wherein said sealing mechanism is a re-settable packer.
11. The method of Claim 1 wherein said treating fluid is a slurry of a proppant material and a carrier fluid.
12. The method of Claim 1 wherein said treating fluid is a fluid containing no proppant.
- 10 13. The method of Claim 1 wherein said treating fluid is an acid solution.
14. The method of Claim 1 wherein said treating fluid is an organic solvent.
15. The method of Claim 1 wherein said method further comprises the step of, prior to releasing said sealing mechanism, deploying at least one diversion agent in said wellbore to block further flow of treating fluid into said perforations.
- 15 16. The method of Claim 15 wherein said diversion agent deployed in said wellbore is selected from the group consisting of particulates, gels, viscous fluids, foams, and ball sealers.
- 20 17. The method of Claim 1 wherein said sealing mechanism is actuated by hydraulic pressure transmitted from the surface through an umbilical.
18. The method of Claim 1 wherein said perforating device is actuated by hydraulic pressure transmitted from the surface through an umbilical.
19. The method of Claim 1 wherein said perforating device is actuated by hydraulic pressure transmitted from the surface through said wellbore.
- 25 20. The method of Claim 1 wherein said perforating device is actuated by hydraulic pressure transmitted from the surface through said tubing string.
21. A method for perforating and treating multiple intervals of one or more subterranean formations intersected by a wellbore, said method comprising:

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- (a) deploying a bottom-hole assembly ("BHA") using a deployment means within said wellbore, said BHA having a perforating device and a sealing mechanism;
- 5 (b) positioning said perforating device adjacent the interval to be perforated and using said perforating device to perforate said interval;
- (c) positioning said BHA within said wellbore and actuating said sealing mechanism so as to establish a hydraulic seal below said at least one perforated interval;
- 10 (d) pumping a treating fluid down said annulus between said suspension means and said wellbore and into the perforations created by said perforating device, without removing said perforating device from said wellbore;
- (e) releasing said sealing mechanism; and
- 15 (f) repeating steps (b) through (e) for at least one additional interval of said one or more subterranean formations.
- 22. The method of Claim 21 wherein said deployment means is selected from the group consisting of a wireline, a slickline, and a cable.
- 23. The method of Claim 21 wherein said deployment means is a tubing string.
- 24. The method of Claim 23 wherein said tubing string is coiled tubing.
- 20 25. The method of Claim 23 wherein said tubing string is jointed tubing.
- 26. The method of Claim 23 wherein said treating fluid is pumped down said tubing string, through flow ports in said BHA, and into said perforations.
- 27. The method of Claim 26 wherein said treating fluid is also pumped down the annulus between said tubing string and said wellbore.
- 25 28. The method of Claim 24 wherein said treating fluid is pumped down the annulus between said tubing string and said wellbore.
- 29. The method of Claim 21 wherein said sealing mechanism is a re-settable packer.
- 30 30. The method of Claim 21 wherein said treating fluid is a slurry of a proppant material and a carrier fluid.

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31. The method of Claim 21 wherein said treating fluid is a fluid containing no proppant.
32. The method of Claim 21 wherein said treating fluid is an acid solution.
33. The method of Claim 21 wherein said treating fluid is an organic solvent.
- 5 34. The method of Claim 21 wherein said perforating device is a select-fire perforating gun containing multiple sets of one or more shaped-charge perforating charges; each of said sets of one or more shaped-charge perforating charges individually controlled and activated by an electric or optic signal transmitted via a cable deployed in the wellbore.
- 10 35. The method of Claim 21 wherein said perforating device is actuated by hydraulic pressure transmitted from the surface through the said wellbore.
36. The method of Claim 23 wherein said perforating device is actuated by hydraulic pressure transmitted from the surface through the said tubing string.
37. The method of Claim 23 wherein said perforating device is a jet cutting device
15 that uses fluid pumped down said tubing string to establishing hydraulic communication between said wellbore and said one or more intervals of said one or more subterranean formations.
38. The method of Claim 21 wherein said method further comprises the step of, prior to releasing said sealing mechanism, deploying at least one diversion
20 agent in said wellbore to block further flow of treating fluid into said perforations.
39. The method of Claim 38 wherein said diversion agent deployed in said wellbore is selected from the group consisting of particulates, gels, viscous fluids, foams, and ball sealers.
- 25 40. A stimulation treatment system for use in perforating and treating multiple intervals of one or more subterranean formations intersected by a wellbore, said system comprising:
- (a) a treating fluid;
 - (b) a tubing string deployed within said wellbore;
 - 30 (c) a bottom-hole assembly (BHA) deployed with said tubing string, said BHA having at least one perforating device, for sequentially perforating

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said multiple intervals, and one sealing mechanism, said BHA capable of being positioned within said wellbore, to allow actuation of said perforating device and said sealing mechanism;

(d) said sealing mechanism capable of establishing a hydraulic seal above and below said sealing mechanism, and further capable of releasing said hydraulic seal to allow said BHA to move to a different position within said wellbore, thereby allowing each of said multiple treatment intervals to be treated with said treating fluid separately from said other treatment intervals.

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- 10 41. The system of Claim 40 wherein said tubing string is coiled tubing.
42. The system of Claim 40 wherein said tubing string is jointed tubing.
43. The system of Claim 40 wherein said BHA further comprises a casing collar locator.
- 15 44. The system of Claim 40 wherein said perforating device is a select-fire perforating gun containing multiple sets of one or more shaped-charge perforating charges; each of said sets of one or more shaped-charge perforating charges individually controlled and activated by an electric or optic signal transmitted via a cable deployed in the wellbore.
- 20 45. The system of Claim 40 wherein said perforating device is actuated by hydraulic pressure transmitted from the surface through the said wellbore.
46. The system of Claim 40 wherein said perforating device is actuated by hydraulic pressure transmitted from the surface through the said tubing string.
- 25 47. The system of Claim 44 wherein said perforating device is a jet cutting device that uses fluid pumped down said tubing string to establishing hydraulic communication between said wellbore and said one or more intervals of said one or more subterranean formations.
48. The system of Claim 40 wherein said sealing mechanism is a re-settable packer.
49. The system of Claim 40 wherein said treating fluid is a slurry of a proppant material and a carrier fluid.
- 30 50. The system of Claim 40 wherein said treating fluid is a fluid containing no proppant.

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51. The system of Claim 40 wherein said treating fluid is an acid solution.
52. The system of Claim 40 wherein said treating fluid is an organic solvent.
53. An apparatus for use in perforating and treating multiple intervals of one or more subterranean formations intersected by a wellbore, said apparatus comprising:
- 5 (a) a bottom-hole assembly (BHA), adapted to be deployed in said wellbore by a deployment means, said BHA having at least one perforating device for sequentially perforating said multiple intervals and at least one sealing mechanism; and
- 10 (b) said sealing mechanism capable of establishing a hydraulic seal in said wellbore, and further capable of releasing said hydraulic seal to allow said BHA to move to a different position within said wellbore, thereby allowing each of said multiple treatment intervals to be treated separately from said other treatment intervals.
- 15 54. The apparatus of Claim 53 wherein said suspension means is a tubing string.
55. The apparatus of Claim 54 wherein said tubing string is a coiled tubing.
56. The apparatus of Claim 54 wherein said tubing string is jointed tubing.
57. The apparatus of Claim 53 wherein said suspension means is selected from the group consisting of a wireline, a slickline, and a cable.
- 20 58. The apparatus of Claim 53 wherein said BHA further comprises a casing collar locator.
59. The apparatus of Claim 53 wherein said sealing mechanism is a re-settable packer.
60. The apparatus of Claim 53 wherein said perforating device is a select-fire perforating gun containing multiple sets of one or more shaped-charge perforating charges; each of said sets of one or more shaped-charge perforating charges individually controlled and activated by an electric signal transmitted via a wireline deployed in the wellbore.
- 25 61. The apparatus of Claim 53 wherein said perforating device is actuated by hydraulic pressure transmitted from the surface through the said wellbore.
- 30

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62. The apparatus of Claim 54 wherein said perforating device is actuated by hydraulic pressure transmitted from the surface through the said tubing string.
63. The apparatus of Claim 54 wherein said perforating device is a jet cutting device that uses fluid pumped down said tubing string to establishing hydraulic communication between said wellbore and said one or more intervals of said one or more subterranean formations.
64. An apparatus for use in perforating and treating multiple intervals of one or more subterranean formations intersected by a wellbore, said apparatus comprising:
- (a) a bottom-hole assembly, having at least one perforating device for sequentially perforating said multiple intervals, at least one sealing mechanism; and at least one tractor device;
 - (b) said tractor device capable of positioning said BHA at different positions in said wellbore; and
 - (c) said sealing device capable of establishing a hydraulic seal in said wellbore, and further capable of releasing said hydraulic seal to allow said BHA to move to a different position within said wellbore, thereby allowing each of said multiple treatment intervals to be treated separately from said other treatment intervals.
65. The apparatus of Claim 64 wherein said BHA further comprises a casing collar locator.
66. The apparatus of Claim 64 wherein said sealing mechanism is a re-settable packer.
67. The apparatus of Claim 64 wherein said perforating device is a select-fire perforating gun containing multiple sets of one or more shaped-charge perforating charges; each of said sets of one or more shaped-charge perforating charges individually controlled and activated by an electric signal transmitted via a wireline deployed in the wellbore.
68. The apparatus of Claim 64 wherein said perforating device is actuated by hydraulic pressure transmitted from the surface through the said wellbore.

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ABSTRACT

The invention provides an apparatus and method for perforating and treating multiple intervals of one or more subterranean formations intersected by a wellbore by deploying a bottom-hole assembly ("BHA") having a perforating device and at least one sealing mechanism within said wellbore. The BHA may be suspended in the wellbore using a tubing string or cable; or alternatively, the BHA may be deployed using a tractor system attached directly to the BHA. The perforating device is used to perforate the first interval to be treated. Then the BHA is positioned within the wellbore such that the sealing mechanism, when actuated, establishes a hydraulic seal in the wellbore to positively force fluid to enter the perforations corresponding to the first interval to be treated. A treating fluid is then pumped down the wellbore and into the perforations created in the perforated interval. The sealing mechanism is released, and the steps are then repeated for as many intervals as desired, without removing the BHA from said wellbore.

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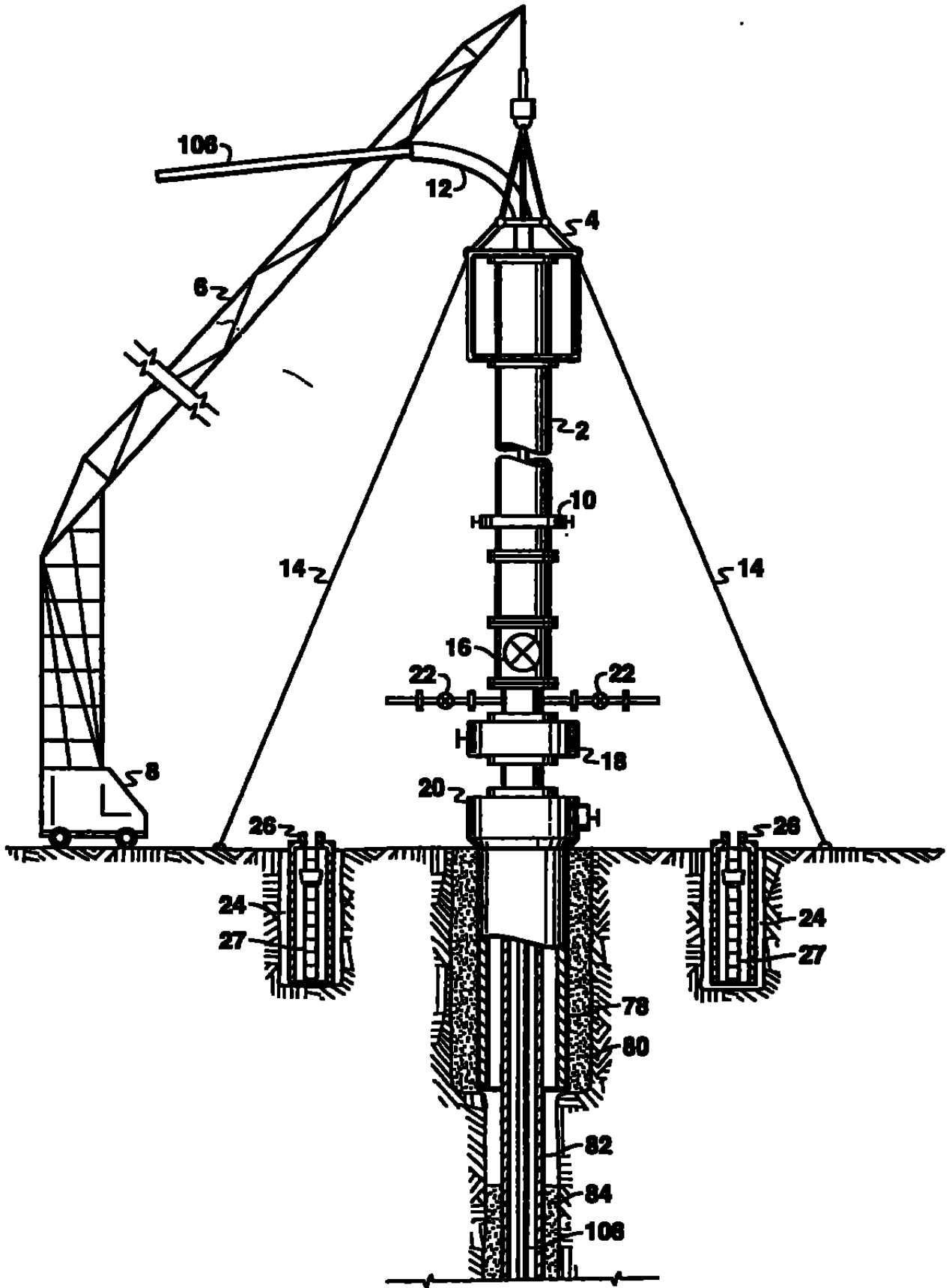


FIG. 1

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FIG. 2A

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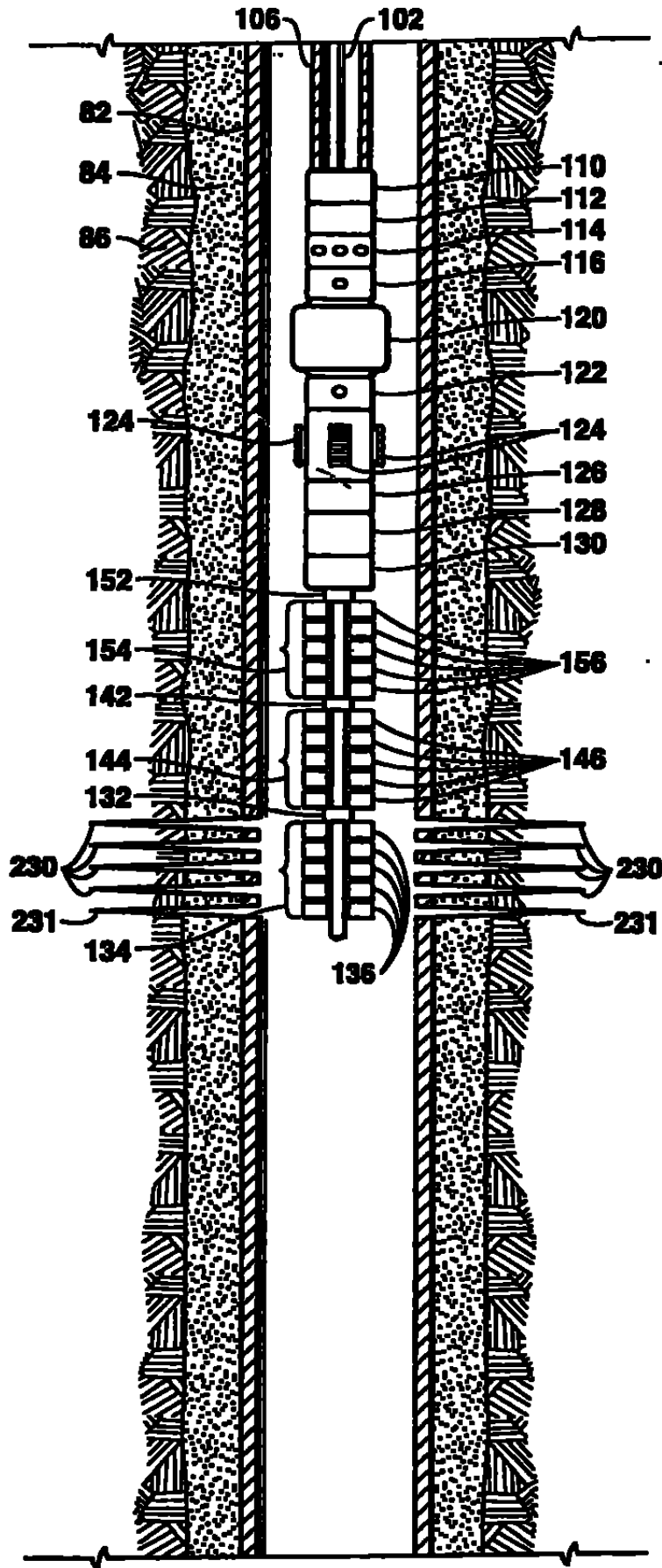


FIG. 2B

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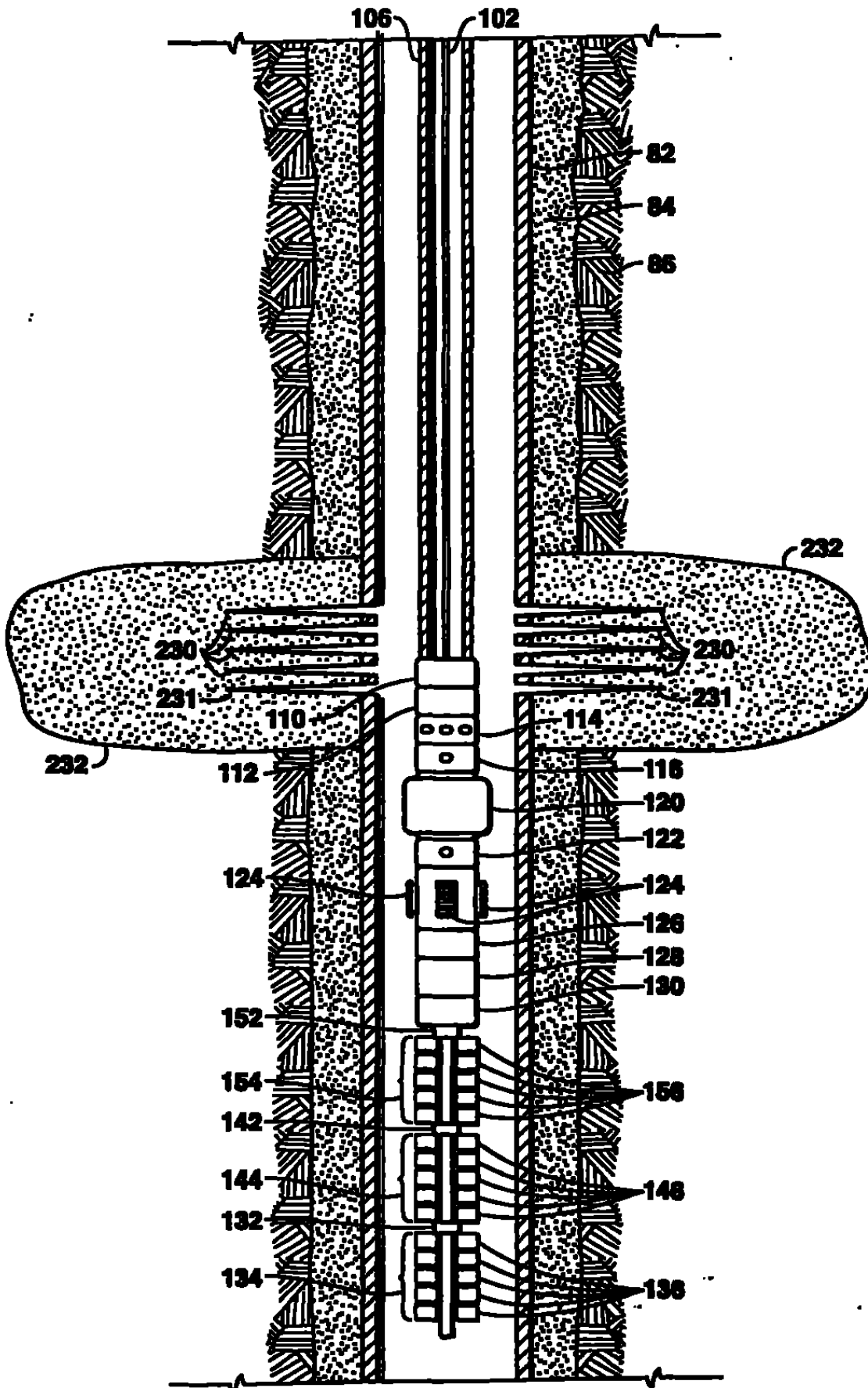


FIG. 2C

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FIG. 3A

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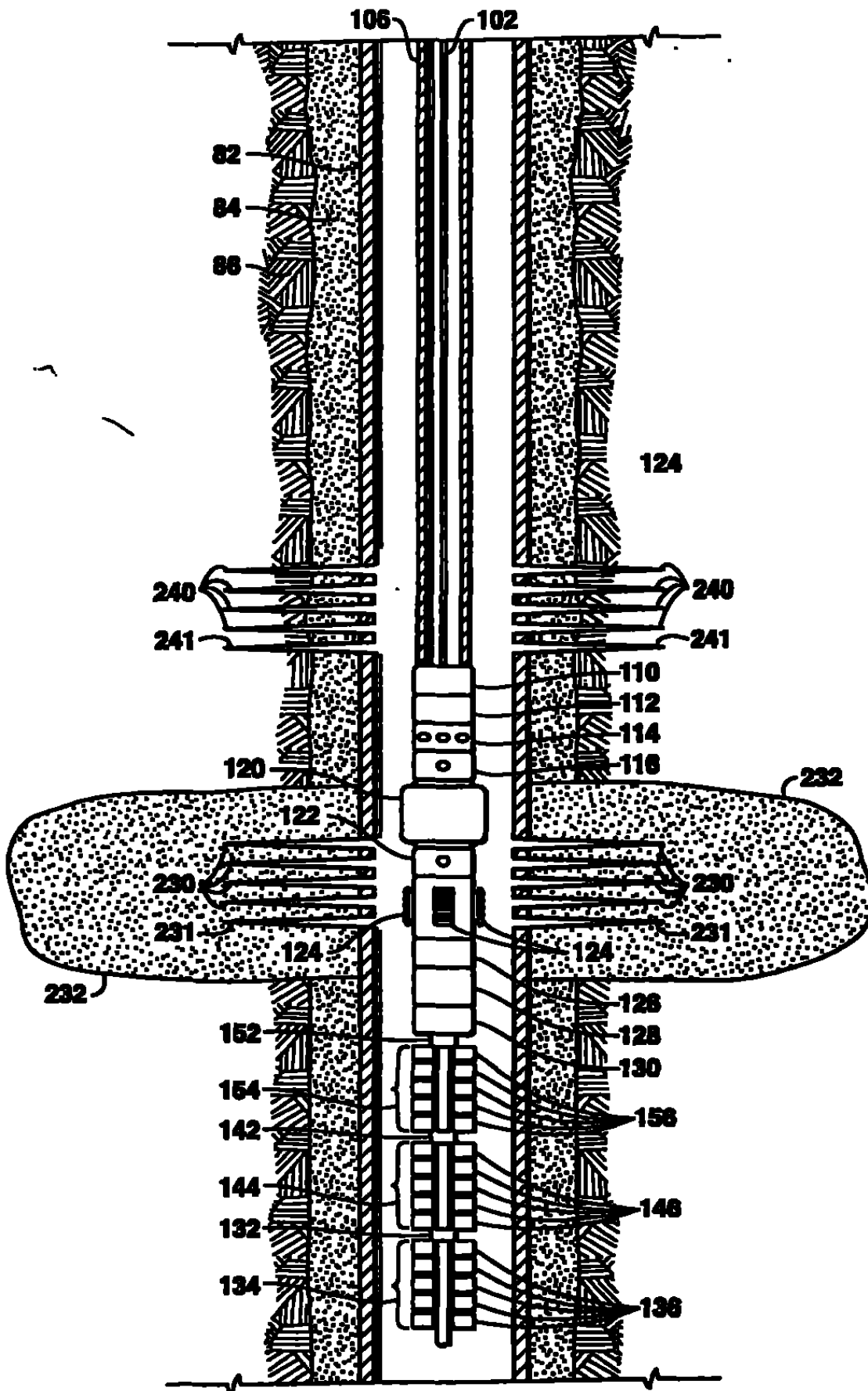


FIG. 3B

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FIG. 3C

**FIG. 3D**



FIG. 3E

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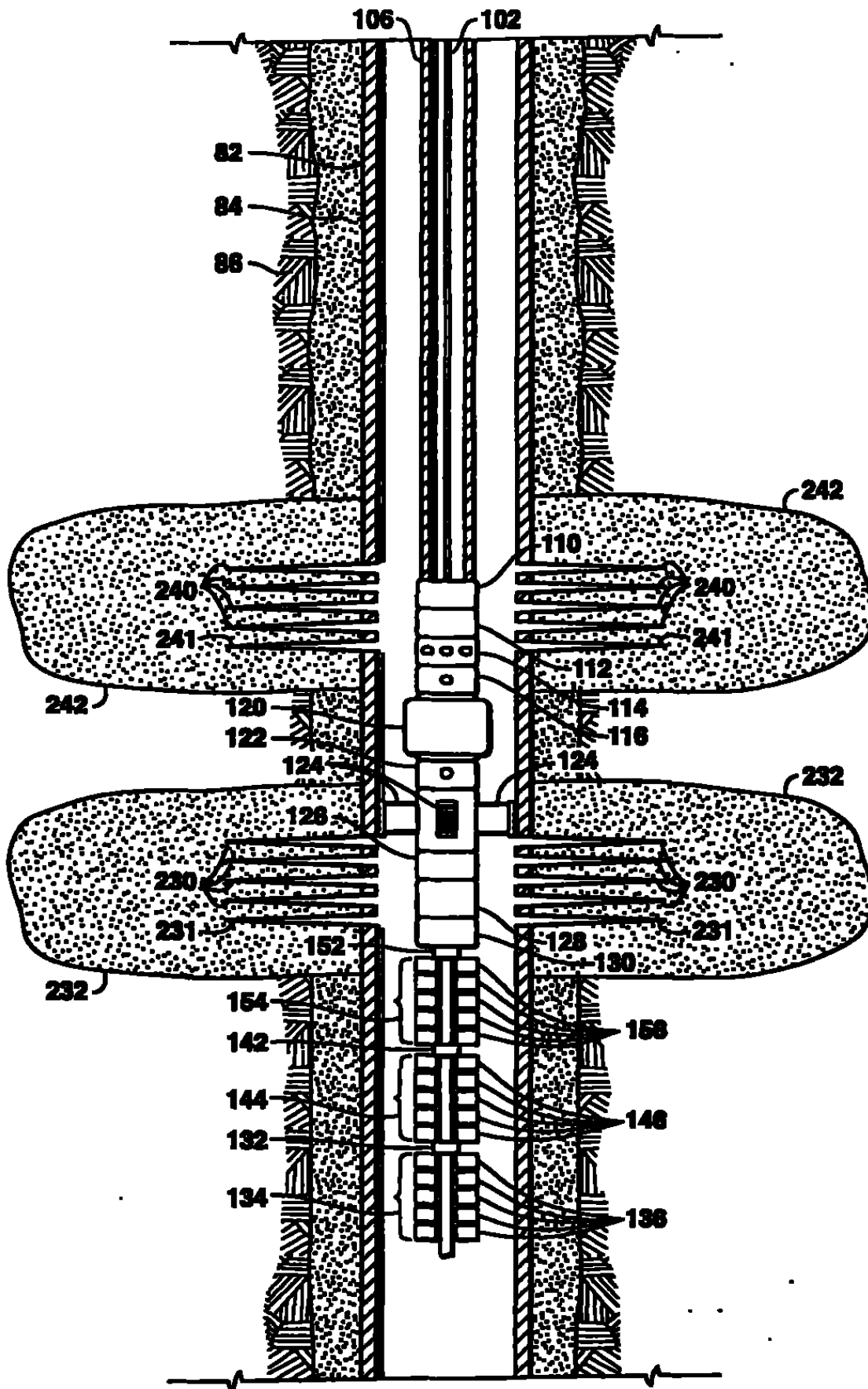


FIG. 3F

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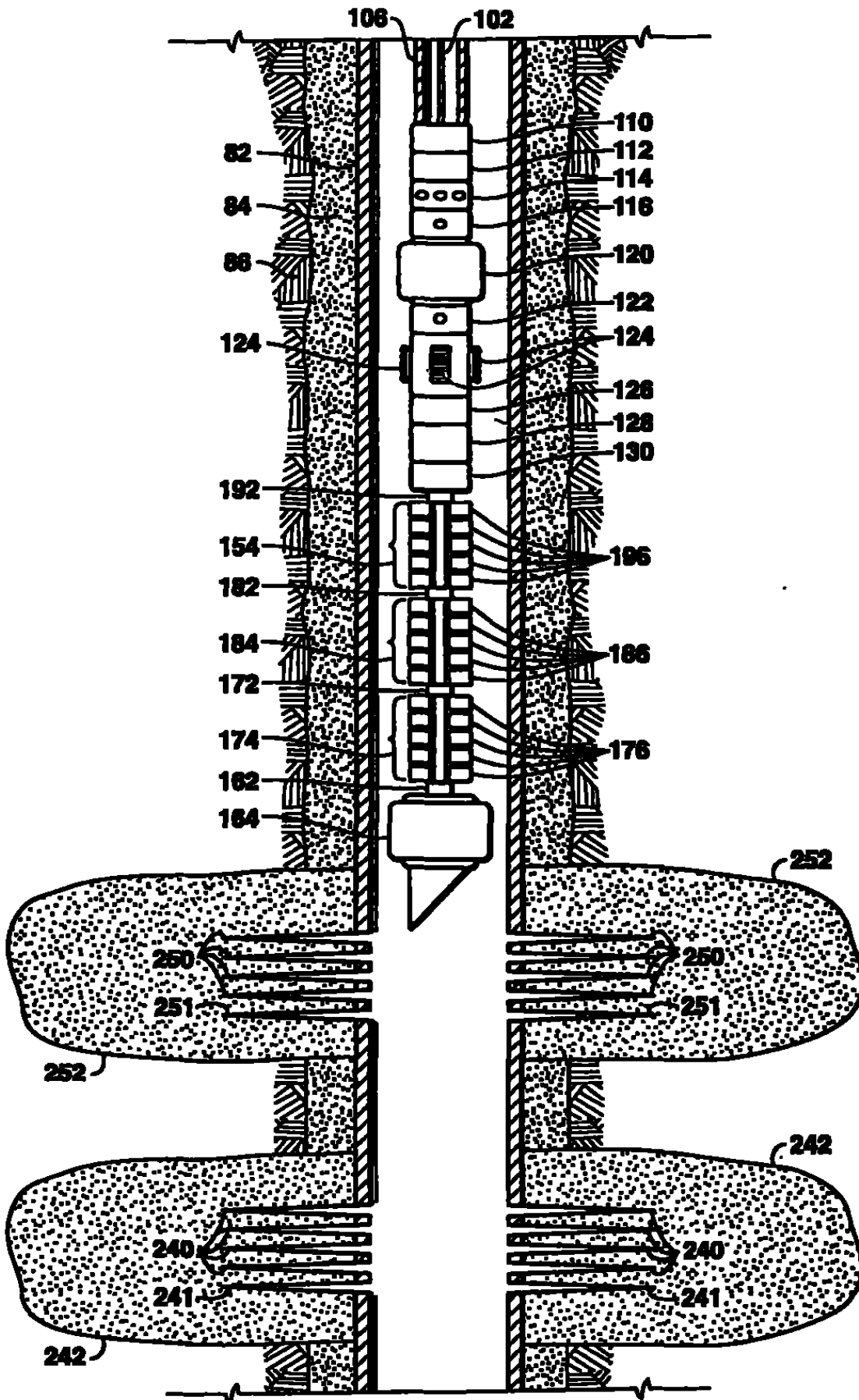


FIG. 4A

000001-85244209



FIG. 4B

246
242

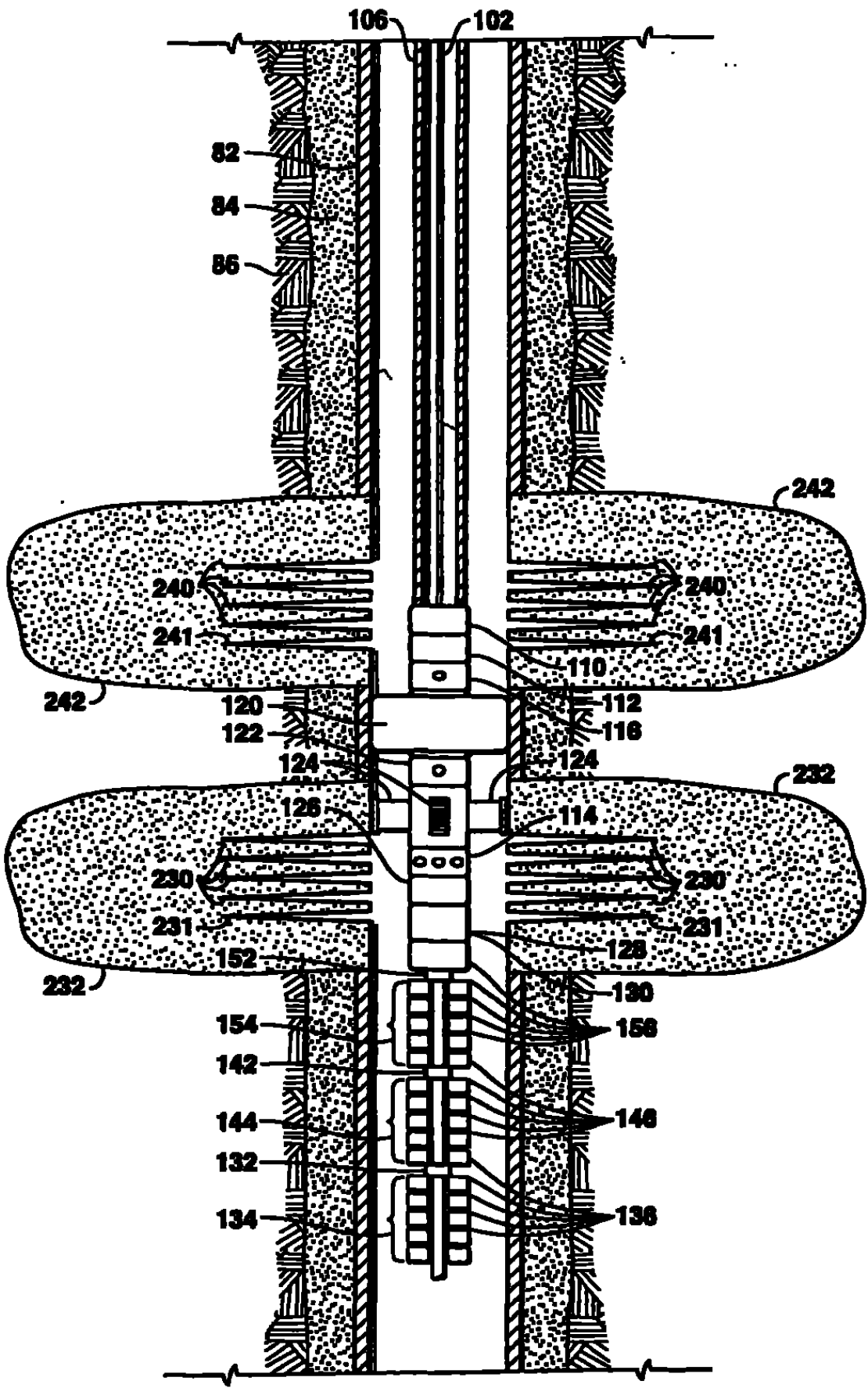


FIG. 5

000001-85244209



FIG. 6

248
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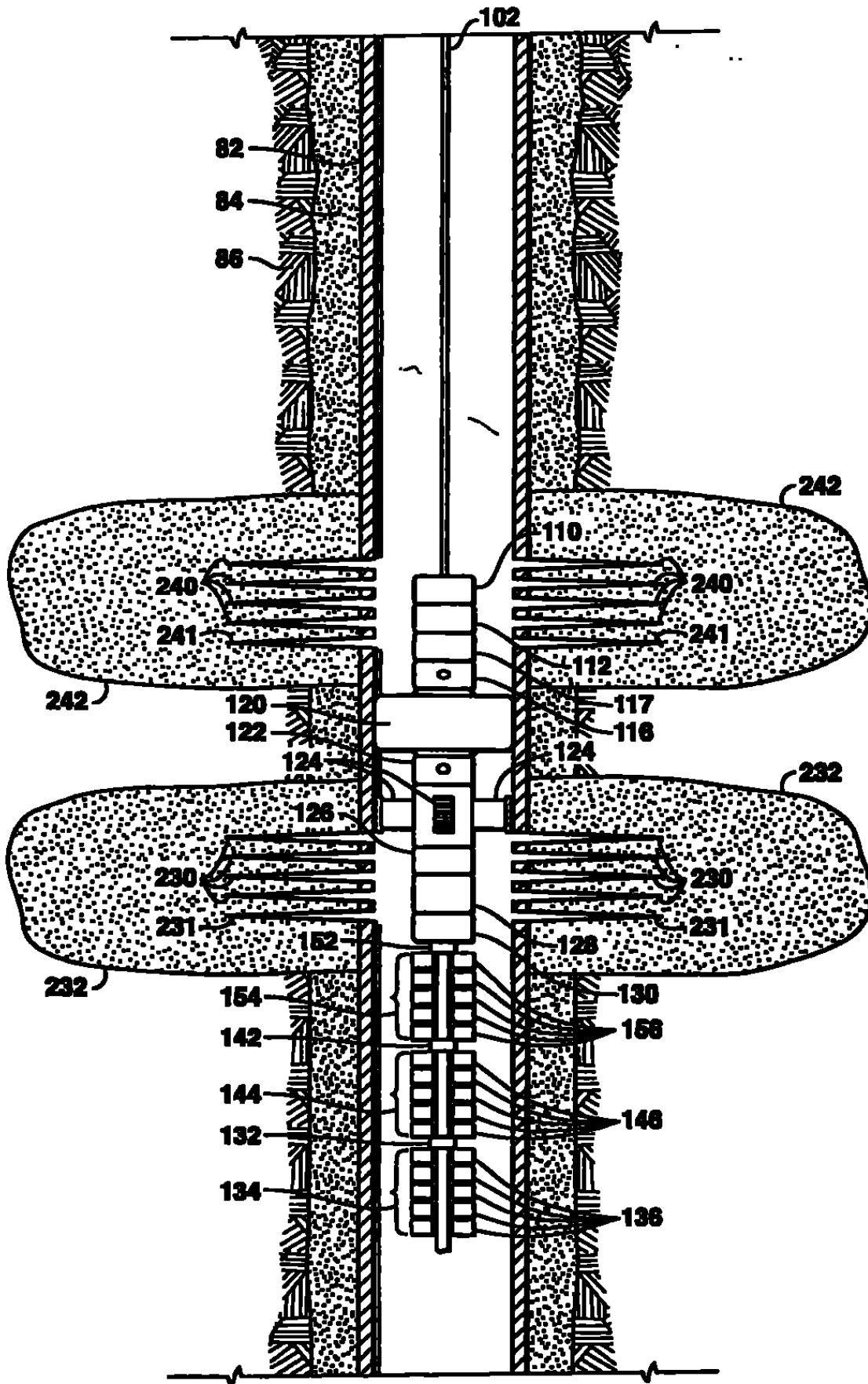


FIG. 7

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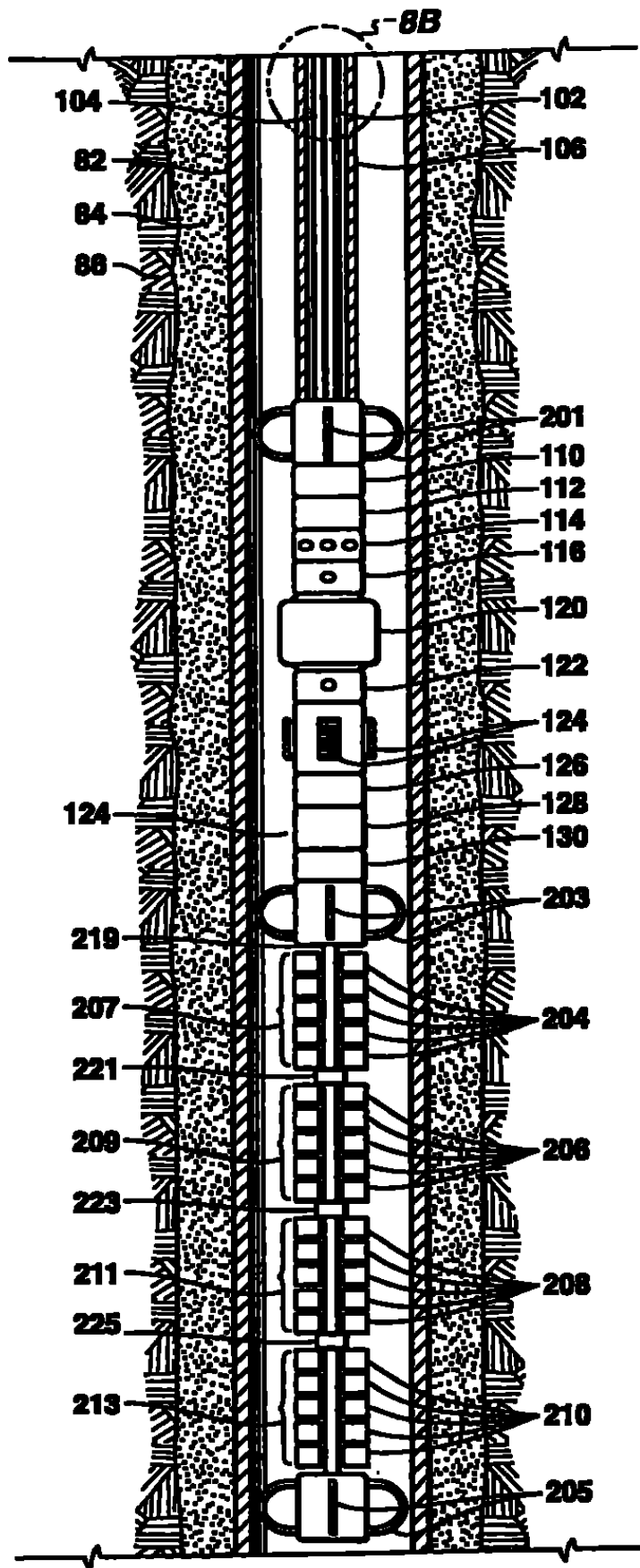


FIG. 8A

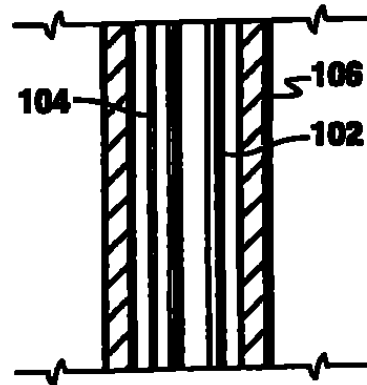
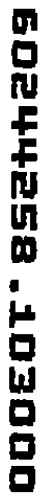


FIG. 8B

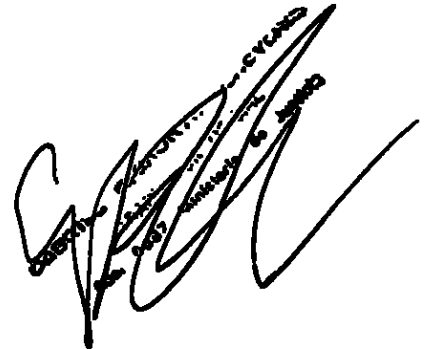
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**FIG. 9**

TRADUCCION OFICIAL NO. 8259

DE UN DOCUMENTO ESCRITO EN INGLES.

=====



Legalizaciones de un traspaso de patente de varios Inventores a EXXON MOBIL
UPSTREAM RESEARCH COMPANY con certificados notariales, escritos todos
simultáneamente en inglés y en español.

Los certificados notariales son los siguientes:

1. Auténtica la firma de Randy C. Tolman, con fecha Abril 2 de 2001, está firmado por
Susan Y. Hoffman y tiene el siguiente sello de caucho: Susan Y. Hoffman - Notario
Público, Estado de Wyoming, Condado de Sublette, Wyoming - La Comisión Expira
en Diciembre 3 de 2003. - A la izquierda el escudo del Estado de Wyoming.
2. Auténtica la firma de Lawrence O. Carlson, con fecha Abril 9 de 2001, está firmado
por Jane V. Moreau y tiene el siguiente sello de caucho: Jane V. Moreau - Notario
Público, Estado de Texas - Mi Comisión Expira 01-16-2003. - A la izquierda el escudo
de Texas con la leyenda Notario Público - Estado de Texas
3. Auténtica la firma de David A. Kinison, con fecha Abril 9 de 2001, está firmado por
Jane V. Moreau y tiene el siguiente sello de caucho: Jane V. Moreau - Notario
Público, Estado de Texas - Mi Comisión Expira 01-16-2003. - A la izquierda el escudo
de Texas con la leyenda Notario Público, Estado de Texas.

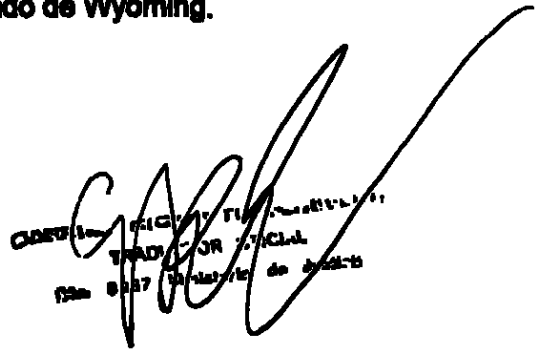
4. Auténtica la firma de Kris J. Nygaard, con fecha 14 de Abril de 2001, está firmado por Jacqueline West y tiene los siguientes sellos: de caucho: Jacqueline West – Notario Público, Estado de Texas – Mi Comisión Expira 4-26-2002 – Sello en relieve: Jacqueline West – Notario Público, Estado de Texas – Expira 4-26-2002.
5. Auténtica la firma de Glenn A. Goss, con fecha Abril 9 de 2001, está firmado por Jane V. Moreau y tiene el siguiente sello: de caucho: Jane V. Moreau - Notario Público, Estado de Texas – Mi Comisión Expira 01-16-2003. - A la izquierda el escudo de Texas con la leyenda: Notario Público Estado de Texas.
6. Auténtica la firma de William A. Sorem, con fecha 13 de Abril de 2001, está firmado por Jacqueline West y tiene los siguientes sellos: de caucho: Jacqueline West – Notario Público, Estado de Texas – Mi Comisión Expira 4-26-2002 – Sello en relieve: Jacqueline West – Notario Público, Estado de Texas – Expira 4-26-2002.
7. Auténtica la firma de Lee L. Shafer, con fecha Abril 2 de 2001, está firmado por Susan Y. Hoffman y tiene el siguiente sello de caucho: Susan Y. Hoffman - Notario Público, Estado de Wyoming, Condado de Sublette, Wyoming – La Comisión Expira en Diciembre 3 de 2003. - A la izquierda el escudo del Estado de Wyoming.

=====

ESTADO DE TEXAS
SECRETARÍA DE ESTADO

APOSTILLA

(Convención de La Haya de octubre 5 de 1961)


CORREO ELECTRONICO: [illegible]
TEL: 512-475-6000
FAX: 512-475-6001
www.sos.state.tx.us

258
249

1. País: Estados Unidos de América

Este documento público

2. ha sido firmado por JACQUELINE WEST

3. actuando en su condición de Notario Público, Estado de Texas

4. y tiene el sello/estampilla de JACQUELINE WEST, Notario Público, Estado de Texas, La Comisión Expira 06-02

CERTIFICADO

5. en Austin, Texas

6. en Abril 17 de 2001

7 por el Secretario del Estado de Texas

8 Certificado No. N-247900

9 Sello: El Estado de Texas

10. Firma: Firmado: Henry Cuellar

Secretario de Estado

=====

ESTADO DE TEXAS

SECRETARÍA DE ESTADO

APOSTILLA

MINISTERIO DE RELACIONES
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131595
GABRIEL RODRIGUEZ
CONFIRMA APARECE EN EL
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LAS FUNCIONES INDICADAS

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RESPONSABILIDAD DEL TEXTO.
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JEFE DE LEGALIZACIONES
SANTAFE DE BOGOTA D.C.

Tratado de Libre Comercio
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6/2000

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250

1

MINISTERIO DE RELACIONES
EXTERIORES
131568
Gibriel Kacivhe
CUYA FIRMA APARECE EN EL
DOCUMENTO DESEMPENA
LAS FUNCIONES INDICADAS

131568
Gabriel Kadiwe

Público, Estado de
01-16-03

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1003

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SAIAF DE BOBOTA D.C.**

1800

**JEFFREY GALZANO'S
SABOTEUR BOBOTA D.C.**

Secretario de Estado

[Handwritten signature]

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APOSTILLA

(Convención de La Haya de octubre 5 de 1961)

1. País: Estados Unidos de América

Este documento público

2. ha sido firmado por Susan Y. Hoffman

3. actuando en su condición de Notario Público, Estado de Wyoming

4. y tiene el sello/estampilla de Susan Y. Hoffman, Notario Público

CERTIFICADO

5. en Cheyene, Wyoming

6. en Abril 17 de 2001

7. por Kelly L. Dagostino, Asistente Administrativo, Estado de Wyoming

8. No. 17015

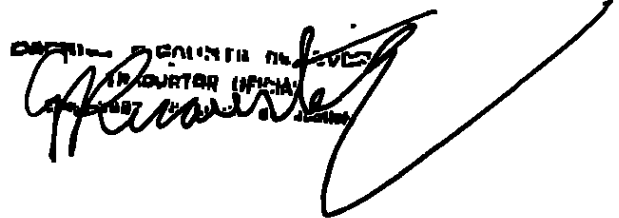
9. Sello en relieve, estampado sobre lámina de papel metalizado: Gran Sello del Estado de Wyoming.

10. Firma: Firmado: Kelly L. Dagostino

Es traducción fiel y competente, de la cual queda copia en el archivo de esta oficina de traducciones para su confrontación, a la cual me remito.

Derechos de traducción: \$40.000

Bogotá, D.C. 4 de mayo de 2001


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152
MINISTERIO DE RELACIONES EXTERIORES
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131566
GABRIEL AGUIRRE
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JEFE DE LEGALIZACIONES
SANTAFE DE BOGOTA D.C.

State of Wyoming



Office of the SECRETARY OF STATE

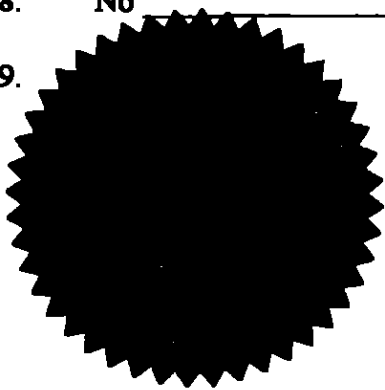
Apostille

(Convention de La Hague du 5 Octobre 1961)

1. Country: United States of America
This public document
2. has been signed by Susan Y. Hoffman
3. acting in the capacity of Notary Public, State of Wyoming
4. bears the seal/stamp of Susan Y. Hoffman, Notary Public/Wyoming

Certified

5. at Cheyenne, Wyoming
6. the 17th of April 2001
7. by Kelly L. Dagostino, Administrative Assistant, State of Wyoming
8. No 17015

9. 
10. Signature Kelly L Dagostino

ASSIGNMENT

The undersigned,

1. Randy C. Tolman
2. Lawrence O. Carlson
3. David A. Kinison
4. Kris J. Nygaard
5. Glenn S. Goss
5. William A. Sorem
7. Lee L. Shafer

domiciled in

1. P.O.Box 4097, 11 Meadow Canyon Dr., Marbleton Wyoming 83113 USA
2. 15018 Redbud Leaf Lane, Cypress Texas 77429 USA
3. 3326 Three Pines Drive, Kingwood, Texas 77339 USA
4. 4019 Tartan Lane, Houston, Texas 77025 USA
5. 1630 Scenic Mountain Court, Kingwood, Texas 77345 USA
6. 20606 Faunbrook Court, Katy, Texas 77450 USA
7. P.O.Box 680, 5 Gopher Ridge lane, Big Piney, Wyoming 83113 USA

hereby state under oath to be the sole and true inventor of

METHOD AND APPARATUS FOR STIMULATION OF MULTIPLE FORMATION INTERVALS

We state as well that we assign, without reservations or limitation, in favor of

EXXONMOBIL UPSTREAM RESEARCH COMPANY

a corporation organized and existing under the laws of

the State of Delaware, United States of America

domiciled in

the State of Texas, United States of America

all rights inherent to said invention, and that the above mentioned corporation hereby is enabled to apply, in its name, for the corresponding patent in the Republic of Colombia.

TRASPASO

abajo firmado

1. Randy C. Tolman
2. Lawrence O. Carlson
3. David A. Kinison
4. Kris J. Nygaard
5. Glenn S. Goss
6. William A. Sorem
7. Lee L. Shafer

domiciliado en

1. P.O.Box 4097, 11 Meadow Canyon Dr., Marbleton Wyoming 83113 USA
2. 15018 Redbud Leaf Lane, Cypress Texas 77429 USA
3. 3326 Three Pines Drive, Kingwood, Texas 77339 USA
4. 4019 Tartan Lane, Houston, Texas 77025 USA
5. 1630 Scenic Mountain Court, Kingwood, Texas 77345 USA
6. 20606 Faunbrook Court, Katy, Texas 77450 USA
7. P.O.Box 680, 5 Gopher Ridge lane, Big Piney, Wyoming 83113 USA

decla bajo juramento ser único y verdadero inventor de

MEIODO Y APARATO PARA LA ESTIMULACION DE MULTIPLES INTERVALOS DE FORMACION

Declar asimismo que cedamos y transf sin reserva ni limitación, a favor de la sociedad

EXXONMOBIL UPSTREAM RESEARCH COMPANY

organizada y existente de conformidad con las leyes de

Estado de Delaware, Estados Unidos de América

domiciliada en

Estado de Texas, Estados Unidos de América

todos los derechos inherentes a dicha invención y que la citada sociedad queda facultada para solicitar en su nombre la patente correspondiente en la República de Colombia.

Signed on:

By Inventor:

Randy C. Tolman

Signed on:

By Inventor:

Lawrence O. Carlson

Signed on:

By Inventor:

David A. Kinison

Signed on:

By Inventor:

Kris J. Nygaard

Signed on:

By Inventor:

Glenn S. Goss

Signed on:

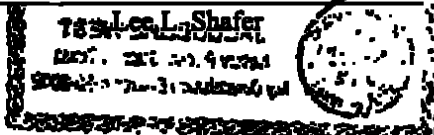
By Inventor:

William A. Sorem

Signed on:

By Inventor:

Lee L. Shafer



140

(1)

CERTIFICADO NOTARIAL (INDIVIDUO)

A los 2 días del mes de Abril
de 192001, compareci personalmente ante mi,
Notario Público,

Randy C. Tolman
a quien doy fé de conocer y me consta que
la persona descrita y firmante
del documento que precede, declarando ante mí
que otorga el mismo para los fines y propósitos
que en él se expresan.

NOTARY PUBLIC (Notario Público)

(2)

CERTIFICADO NOTARIAL (INDIVIDUO)

A los 9 días del mes de Abril
de 192001, compareci personalmente ante mi,
Notario Público,

LAWRENCE O. CARLSON
a quien doy fé de conocer y me consta que
la persona descrita y firmante
del documento que precede, declarando ante mí
que otorga el mismo para los fines y propósitos
que en él se expresan.

NOTARY PUBLIC (Notario Público)

(3)

CERTIFICADO NOTARIAL (INDIVIDUO)

A los 9 días del mes de Abril
de 192001, compareci personalmente ante mi,
Notario Público,

DAVID A. KINISON
a quien doy fé de conocer y me consta que
la persona descrita y firmante
del documento que precede, declarando ante mí
que otorga el mismo para los fines y propósitos
que en él se expresan.

NOTARY PUBLIC (Notario Público)

(4)

CERTIFICADO NOTARIAL (INDIVIDUO)

A los 13 días del mes de Abril
de 19 , compareci personalmente ante mi,
Notario Público,

KRIS J. NYGAARD
a quien doy fé de conocer y me consta que
la persona descrita y firmante
del documento que precede, declarando ante mí
que otorga el mismo para los fines y propósitos
que en él se expresan.

NOTARY PUBLIC (Notario Público)

NOTARIAL CERTIFICATE (INDIVIDUAL)

2001 On this 2nd day of April
19 personally appeared before me, a Notary
Public, **Randy C. Tolman**

to me known and known to me to be the person
described in and who executed the foregoing
document, and duly acknowledged to me
that he executed the same for the uses and
purposes therein expressed.



SUSAN Y. HOFFMAN
Notary Public - State of Wyoming
Sublette County, Wyoming
Commission Expires 3 Dec. 2003

NOTARIAL CERTIFICATE (INDIVIDUAL)

2001 On this 9th day of APRIL
19 personally appeared before me, a Notary
Public, **LAWRENCE O. CARLSON**

to me known and known to me to be the person
described in and who executed the foregoing
document, and duly acknowledged to
me that he
executed the same for the uses and purposes
therein expressed.



JANE V. MOREAU
Notary Public, State of Texas
My Commission Expires 01-10-2002

NOTARIAL CERTIFICATE (INDIVIDUAL)

2001 On this 9th day of April
19 personally appeared before me, a Notary
Public,

David A. Kinison
to me known and known to me to be the person
described in and who executed the foregoing
document, and duly acknowledged to
me that he
executed the same for the uses and purposes
therein expressed.



JANE V. MOREAU
Notary Public, State of Texas
My Commission Expires 01-10-2002

NOTARIAL CERTIFICATE (INDIVIDUAL)

2001 On this 13 day of April
19 personally appeared before me, a Notary
Public, **Kris J. Nygaard**

to me known and known to me to be the person
described in and who executed the foregoing
document, and he duly acknowledged to
me that he
executed the same for the uses and purposes
therein expressed.

Jacqueline West



JACQUELINE WEST
Notary Public, State of Texas
My Commission Expires 4-29-2002

3009
64

CERTIFICADO NOTARIAL (INDIVIDUO)

A los 10 días del mes de Abril
de 19~~90~~2001, comparecí personalmente ante mí,
Notario Público,

GLENN S. GOSS
a quien doy fé de conocer y me consta que
la persona descrita y firmante
del documento que precede, declarando ante mí
que otorga el mismo para los fines y propósitos
que en él se expresan.

NOTARY PUBLIC (Notario Público)

CERTIFICADO NOTARIAL (INDIVIDUO)

A los 13 días del mes de Abril
de 19~~90~~2001, comparecí personalmente ante mí,
Notario Público,

WILLIAM A. SOREM
a quien doy fé de conocer y me consta que
la persona descrita y firmante
del documento que precede, declarando ante mí
que otorga el mismo para los fines y propósitos
que en él se expresan.

NOTARY PUBLIC (Notario Público)

CERTIFICADO NOTARIAL (INDIVIDUO)

A los 2 días del mes de Abril
de 19~~90~~2001, comparecí personalmente ante mí,
Notario Público,

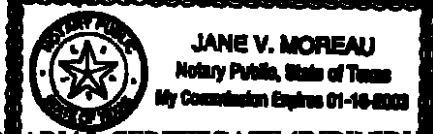
LEE L. SHAFFER
a quien doy fé de conocer y me consta que
la persona descrita y firmante
del documento que precede, declarando ante mí
que otorga el mismo para los fines y propósitos
que en él se expresan.

NOTARY PUBLIC (Notario Público)

NOTARIAL CERTIFICATE (INDIVIDUAL)

On this 10th day of April, 2001
I personally appeared before me, a Notary
Public, *Glenn S. Goss*

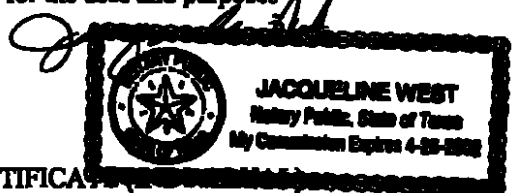
to me known and known to me to be the person
described in and who executed the foregoing
document, and *he* duly acknowledged to
me that *he*
executed the same for the uses and purposes
therein expressed.



NOTARIAL CERTIFICATE (INDIVIDUAL)

On this 13 day of April
I personally appeared before me, a Notary
Public, *William A. Sorem*

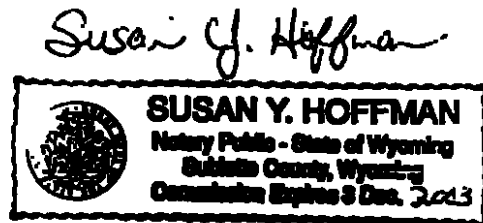
to me known and known to me to be the person
described in and who executed the foregoing
document, and *he* duly acknowledged to
me that *he*
executed the same for the uses and purposes
therein expressed.



NOTARIAL CERTIFICATE (INDIVIDUAL)

On this 2nd day of April
I personally appeared before me, a Notary
Public, *Lee L. Shafer*

to me known and known to me to be the person
described in and who executed the foregoing
document, and duly acknowledged to
me that *he*
executed the same for the uses and purposes
therein expressed.





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**

JACQUELINE WEST

3. **acting in the capacity of** **Notary Public, State of Texas**

4. **and bears the seal/stamp of** **JACQUELINE WEST, Notary Public, State of Texas, Commission Expires: 04-26-02**

CERTIFIED

5. **at Austin, Texas**

6. **on April 17, 2001**

7. **by the Secretary of State of Texas**

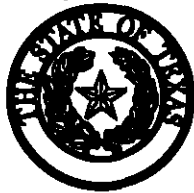
8. **Certificate No. N-247900**

9. **Seal**

10. **Signature:**




Henry Cuellar
Secretary of State
ST/sjs



287
256

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 **JANE V MOREAU**

3. acting in the capacity of **Notary Public, State of Texas**

4. and bears the seal/stamp of **JANE V MOREAU, Notary Public, State of Texas, Commission Expires: 01-16-03**

CERTIFIED

5. at Austin, Texas

6. on April 17, 2001

7. by the Secretary of State of Texas

8. Certificate No. N-247901

9. Seal

10. Signature:




Henry Cuellar
Secretary of State
ST/sjs

257-362

TRADUCCION OFICIAL No. 007

EL ESTADO DE TEXAS

SECRETARIO DE ESTADO

JACQUELINE WEST
Notario Público, Estado de Texas
Mi comisión expira 4-26-2002

YO, ELTON BOMER, Secretario de Estado del Estado de Texas, POR EL
PRESENTE CERTIFICO que de acuerdo con los registros de esta oficina

JACQUELINE WEST

está calificada como Notario Público para el Estado de Texas en abril 26, 1998,
por un periodo que termina en abril 26, 2002.

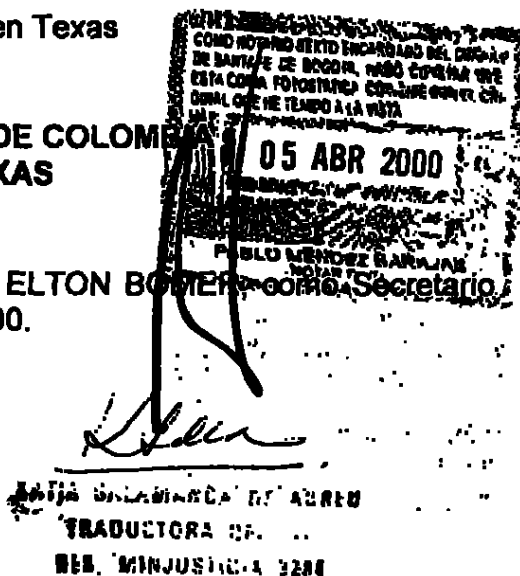
Fecha: marzo 17, 2000

Firmado: Elton Bomer
Secretario de Estado

Hay sello del Consulado General de Colombia en Texas

CONSULADO GENERAL DE COLOMBIA
HOUSTON, TEXAS
N° 750

CERTIFICA la firma y las funciones de Señor ELTON BOMER, como Secretario
de Estado de Texas, el día 23 de marzo del 2000.



Firmado: JOSE DAVID RUEDA VISBAL

Cónsul de Colombia

Hay sello del Consulado General de Colombia en Texas

MINISTERIO DE RELACIONES EXTERIORES

SANTA FE DE BOGOTA

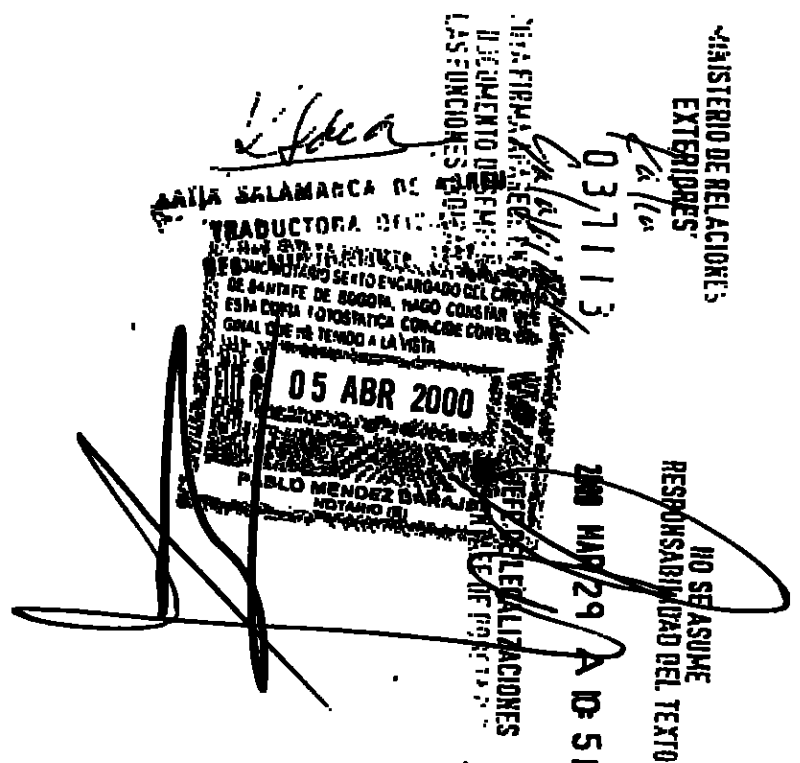
N° 240730

CERTIFICA la firma y el cargo del funcionario consular JOSE DAVID RUEDA VISBAL, el día 29 de marzo, 2000.

Hay sello del Consulado General de Colombia en Texas

(Firma) Ilegible

JEFE DE LEGALIZACIONES



HOUSTON, TEXAS
259

CONSULADO GENERAL DE COLOMBIA

Houston, Texas

MAR 23 2000

No.

750

El suscrito Cónsul de Colombia certifica que

ELTON BOMER

quien autoriza el presente documento, ejerce en la
fecha allí expresada las funciones de

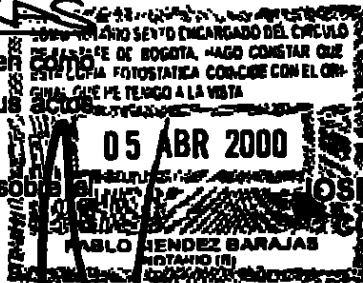
SECRETARIO DE
ESTADO DE TEXAS

y que la firma y sello que en el documento aparece como
suyos son los que usa y acostumbra a usar en sus
oficiales.

El Consulado no asume responsabilidad alguna sobre el
contenido del documento.

CONSULADO GENERAL DE COLOMBIA
EN HOUSTON, TEXAS

Pagado Impuesto de Timbre	US\$ 7.00
Pagado Derecho Consular	US\$ 15.00
Total Pagado	US\$ 22.00



JOSE DAVID RUEDA VISBAL
CONSUL DE COLOMBIA



146

NO SE ASUME
RESPONSABILIDAD DEL TEXTO

2000 MAR 29

OFICINA DE LEGALIZACIONES
SANTAFE DE BOGOTA

MINISTERIO DE RELACIONES
EXTERIORES

240730

DAVID RUCOA

NOTARIO

COMO NOTARIO SEYTO ENCARGADO DEL CIRCULO
DE SANTAFE DE BOGOTA, HAGO CONSTAR QUE
LA COPIA FOTOSTATICA CONCORDA CON EL ORIGINAL
QUE HE TENIDO A LA VISTA

05 ABR 2000

PABLO MENDEZ BARAJAS

NOTARIO





The State of Texas
Secretary of State

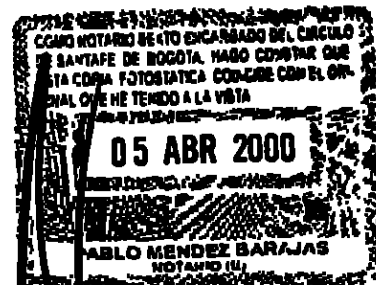
368
260

I, ELTON BOMER, Secretary of State of the State of Texas
DO HEREBY CERTIFY that according to the records of the State of Texas



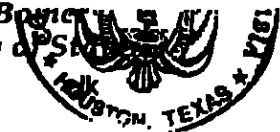
JACQUELINE WEST

qualified as a Notary Public for the State of Texas on April 26, 1998,
for a term ending on April 26, 2002.



March 17, 2000

Elton Bomer
Secretary of State



Los abajo firmados, Gary D. Lawson, Secretario Asistente

con domicilio en EXXONMOBIL UPSTREAM RESEARCH COMPANY
3120 Buffalo Speedway
P. O. Box 2189
Houston, Texas 77252-2189

organizada y existente de conformidad con las leyes del Estado de Delaware, E.U.A., nombramos por el presente a JOSE LLOREDA CAMACHO, y/o JOSE ANTONIO LLOREDA, y/o AURA DUEÑAS RODRIGUEZ, y/o GUSTAVO TAMAYO, y/o ANGELA MARIA RESTREPO y/o ALICIA LLOREDA, domiciliados en Bogotá, Colombia, con oficinas en dicha ciudad, Calle 72 No. 5-83, piso 6o., nuestros representantes legales y verdaderos en Bogotá, con facultades para recibir notificaciones y nombrar apoderados judiciales o extrajudiciales, con el fin de dar cumplimiento al parágrafo 1o. del artículo 543 del decreto 410 de 1971.

Los doctores JOSE LLOREDA CAMACHO, y/o JOSE ANTONIO LLOREDA, y/o AURA DUEÑAS RODRIGUEZ, y/o GUSTAVO TAMAYO, y/o ANGELA MARIA RESTREPO y/o ALICIA LLOREDA, o los apoderados que cualquiera de ellos designe, quedan especialmente facultados para presentarnos ante las autoridades colombianas, administrativas, judiciales o de policía, en todos los trámites relativos a la propiedad industrial, a cuyo efecto les facultamos para dar ante dichas autoridades todos los pasos necesarios al objeto indicado; elevar solicitudes, declaraciones y reclamos; formular descripciones, enmiendas, oposiciones y apelaciones; instaurar cancelaciones y amparos administrativos; abonar todos los impuestos y cuotas y efectuar todo otro pago determinado por la ley; recibir todos los documentos y valores, dando el descargo respectivo; llenar cualesquiera otros requisitos y tomar, en fin, todas las medidas que creyeren conducentes al resguardo de nuestros intereses; y en caso de producirse oposición, pasando los antecedentes a los tribunales, quedan facultados para tomar intervención como demandantes o demandados ante los jueces que sean competentes, pudiendo transar, someter a árbitros, desistirse, perdir y apelar, con todas las demás facultades que resulten necesarias; y por el presente declaramos desde ahora válido y bueno cuanto dichos representantes y/o los apoderados que cualquiera de ellos nombre hicieren en nuestro beneficio.

Asimismo, facultamos a los doctores JOSE LLOREDA CAMACHO, y/o JOSE ANTONIO LLOREDA, y/o AURA DUEÑAS RODRIGUEZ, y/o GUSTAVO TAMAYO, y/o ANGELA MARIA RESTREPO y/o ALICIA LLOREDA, para solicitar en la Oficina de Propiedad Industrial la protocolización de este documento y de cualquier poder que cualquiera de ellos otorgue a nombre nuestro, así como para sustituir el presente.

Dado y firmado a 15 días de Marzo 2000.

The undersigned, Gary D. Lawson, Assistant Secretary

of EXXONMOBIL UPSTREAM RESEARCH COMPANY
3120 Buffalo Speedway
P. O. Box 2189
Houston, Texas 77252-2189, organized and existing under the laws of the State of Delaware, United States of America, hereby appoint JOSE LLOREDA CAMACHO, and/or JOSE ANTONIO LLOREDA, and/or AURA DUEÑAS RODRIGUEZ, and/or GUSTAVO TAMAYO, and/or ANGELA MARIA RESTREPO and/or ALICIA LLOREDA, of Bogotá, Colombia, with offices in said town, Calle 72 No. 5-83, Sixth Floor, our true and legal representatives in Bogotá, with power to receive notifications and to appoint judicial or extrajudicial agents, so as to comply with paragraph 1 of article 543 of decree 410 of 1971.

Doctors JOSE LLOREDA CAMACHO, and/or JOSE ANTONIO LLOREDA, and/or AURA DUEÑAS RODRIGUEZ, and/or GUSTAVO TAMAYO, and/or ANGELA MARIA RESTREPO and/or ALICIA LLOREDA, or the agents by any one of them appointed, are especially empowered to represent us before the administrative, judicial or police authorities of Colombia, in all proceedings pertaining to industrial property, for which purpose we authorize them to take before the said authorities all the necessary steps to the said end; to file petitions, declarations, claims, cancellations and administrative injunction proceedings; to draw up specifications; to make amendments, oppositions and appeals, to pay all installments and effect all other payments prescribed by law; to receive proper receipts, to comply with all other requirements and, in short, to take all those measures which they may deem fit for the protection of our interests; and in case of opposition, where the proceedings be passed over to the courts, we authorize said agents to act on our behalf, as complainants as well as defendants, before the competent judges, with full powers to make arrangements, to submit to arbitrators, to desist, to collect, to appeal and, in short, with all such further powers as may be required; and we hereby declare from now on valid and good all that said representatives and/or the agents by any one of them appointed may do for our benefit.

We also authorize doctors JOSE LLOREDA CAMACHO, and/or JOSE ANTONIO LLOREDA, and/or AURA DUEÑAS RODRIGUEZ, and/or GUSTAVO TAMAYO, and/or ANGELA MARIA RESTREPO, and/or ALICIA LLOREDA, to apply for protocolization of this document, and of any power of attorney by any one of them appointed, in our name, before the Office of Industrial Property, as well as to substitute these presents.

Given and signed this 15th day of March 2000.

Gary D. Lawson, Assistant Secretary

NOTARY SHOULD EXECUTE OTHER SIDE



CERTIFICADO NOTARIAL (INDIVIDUO)

Estados Unidos de América
Estado de { ss
Condado de
A los días del mes de de 19
comparecí personalmente ante mí, Notario Público
en y por el condado antes citado,

a quien doy fe de conocer y me consta que es/son
la persona descrita y firmante del documento que precede,
declarando ante mí que otorga el mismo para los fines y
propósitos que en él se expresan.

Notary Public (Notario Público).

CERTIFICADO NOTARIAL (INDIVIDUO)

Estados Unidos de América
Estado de { ss
Condado de
A los días del mes de de 19
comparecí personalmente ante mí, Notario Público
en y por el condado antes citado,

a quien doy fe de conocer y me consta que es/son
la persona descrita y firmante del documento que precede,
declarando ante mí que otorga el mismo para los fines y
propósitos que en él se expresan.

Notary Public (Notario Público).

CERTIFICADO NOTARIAL (SOCIEDAD)

Estados Unidos de América
Estado de Texas { ss
Condado de Harris
Hoy 15 días de Marzo de 19 2000, compareció
Gary D. Lawson, a quien conozco y de
quien me consta que firmó el anterior documento, y quien
debidamente juramentado declaró y dijo que él es
Secretario Asistente de ExxonMobil
Upstream Research Company
la compañía nombrada en el documento, que antecede, una
sociedad debidamente organizada y existente conforme a las
leyes del Estado de Delaware
Estados Unidos de América, domiciliada en la ciudad de
Houston, Texas, Condado de Harris
Estado de Texas, Estados
Unidos de América y legalmente constituida para un período de
duración que aún no ha determinado, que el deponente es el
autorizado por dicha Compañía para conferir este poder, que el
sello estampado por él al pie de tal poder, que el deponente y en
representación de la expresada Compañía, el sello oficial de
ella; y que el objeto para el cual se confiere este poder, que el
está comprendido dentro del de la sociedad.

El suscrito Notario ha visto los Estatutos de Incorporación
firmados en Houston, Estado de Texas, y certifica que la
on fecha Noviembre 12, 1964, y certifica que la anterior declaración
uramentada es prueba suficiente de que los hechos sobre que
lla versa son ciertos o verdaderos, de lo cual se.

Notary Public (Notario Público).

NOTARIAL CERTIFICATE (INDIVIDUAL)

United States of America
State of { ss
County of
On this day of , 19 , personally
appeared before me, a Notary Public, in and for the above
mentioned county,

to me known to be the person described in and who
executed the foregoing document, and who duly acknowledged
to me that executed same for the uses and purposes
therein expressed.

NOTARIAL CERTIFICATE (INDIVIDUAL)

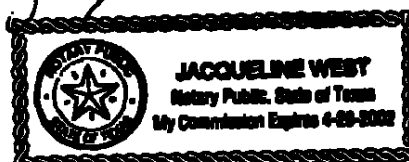
United States of America
State of { ss
County of
On this day of , 19 , personally
appeared before me, a Notary Public, in and for the above
mentioned county,

to me known to be the person described in and who
executed the foregoing document, and who duly acknowledged
to me that executed same for the uses and purposes
therein expressed.

NOTARIAL CERTIFICATE (CORPORATION)

United States of America
State of Texas { ss
County of Harris
On this 15 day of March of , 19 2000 , personally
came Gary D. Lawson
to me known, and known to me to be the person who signed the
foregoing instrument, who being by me duly sworn did depose
and say that he is the
Assistant Secretary of ExxonMobil Upstream
Research Company
the company named within, a
a Corporation organized and existing under the laws of the
State of Delaware, United States of
America, domiciled at the City of Houston, Texas
County of Harris, State of Texas
United States of America, and legally constituted for a period of
duration not yet expired; that the deponent is authorized by said
Company to confer this power of attorney; that the seal affixed
hereunto by the deponent in the name and on behalf of said
Corporation is the corporate seal thereof; and that the purpose
for which this instrument is granted is included within the
corporate purposes of the Company.

The undersigned Notary Public has seen the articles of
Incorporation of said Corporation executed at Houston,
State of Texas, under date of November 12, 1964
and hereby certifies that under the laws of said State the
foregoing acknowledgment is sufficient proof that the facts
therein contained are true, which he attests.





2do. EXAMEN DE FORMA PATENTE DE INVENCION

Folio 267

Radicación no 01-11417

Concepto Técnico no 426

Clasificación Internacional de Patentes: E21D 1/06; E21B 23/00

Practicado el examen de acuerdo a lo establecido en el Art. 38 de la Decisión 486 se determinó que esta solicitud de Patente de Invención:

- SI ☒ NO ☐ Contiene un resumen de la invención (Art.26-e).
- SI ☒ NO ☐ Contiene el título o nombre de la invención (Art.27-d).
- SI ☒ NO ☐ Contiene la descripción de la invención (Art.26-b).
- SI ☒ NO ☐ NO ES APLICABLE ☐ Contiene los dibujos necesarios para comprender la invención (Art.26-d)
- SI ☒ NO ☐ Contiene una o más reivindicaciones. (Art.26-c).
- SI ☐ NO ☐ NO ES APLICABLE ☒ Han sido desarrollados los productos y/o procedimientos a partir de recursos genéticos o de sus productos derivados de los que cualquiera de los Países Miembros es país de origen. (Art. 26- h).
- SI ☐ NO ☐ NO ES APLICABLE ☒ Los productos y/o procedimientos han sido obtenidos o desarrollados a partir de los conocimientos tradicionales de las comunidades indígenas, afroamericanas, o locales de los países miembros, de acuerdo a lo establecido en la Decisión 391 y sus modificaciones y reglamentaciones vigentes.(Art.26-i).
- SI ☐ NO ☒ La invención se refiere a un producto relativo a un material biológico. (Art.26-J).
- SI ☒ NO ☐ NO ES APLICABLE ☐ La prioridad coincide con la materia reivindicada.
- SI ☒ NO ☐ CUMPLE LOS REQUISITOS TÉCNICOS

OBSERVACIONES Y OTROS: SI ☐ NO ☐ ver hoja(s) anexa(s)

□

EXAMINADOR TÉCNICO
202051

Bogotá D. C., febrero 14 de 2003



Folio 268

2020
Bogotá DC

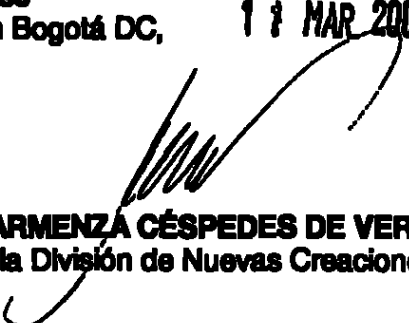
Doctor(a)
JOSE ANTONIO LLOREDA
Apoderado(a)

REFERENCIA:	Radicación No.	01-11417
	Trámite	002
	Evento	001
	Actuación	416
	Oficio No.	529
	Folios	001

Teniendo en cuenta que la solicitud de privilegio de patente que se tramita bajo el expediente indicado en la referencia, reúne los requisitos de forma establecidos en los artículos 26 y 27 de la Decisión 486 de la Comisión de la Comunidad Andina, y en las demás disposiciones vigentes sobre la materia, se envía el extracto de la solicitud a la Oficina de Comunicaciones para efecto de su publicación en la Gaceta de Propiedad Industrial, conforme lo establece el artículo 40 de la misma Decisión.

Cúmplase
Dado en Bogotá DC,

11 MAR 2003


ALIX CARMENZA CÉSPEDES DE VERGEL
Jefe de la División de Nuevas Creaciones

202051