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(54) **WELL BORE CLEANING**

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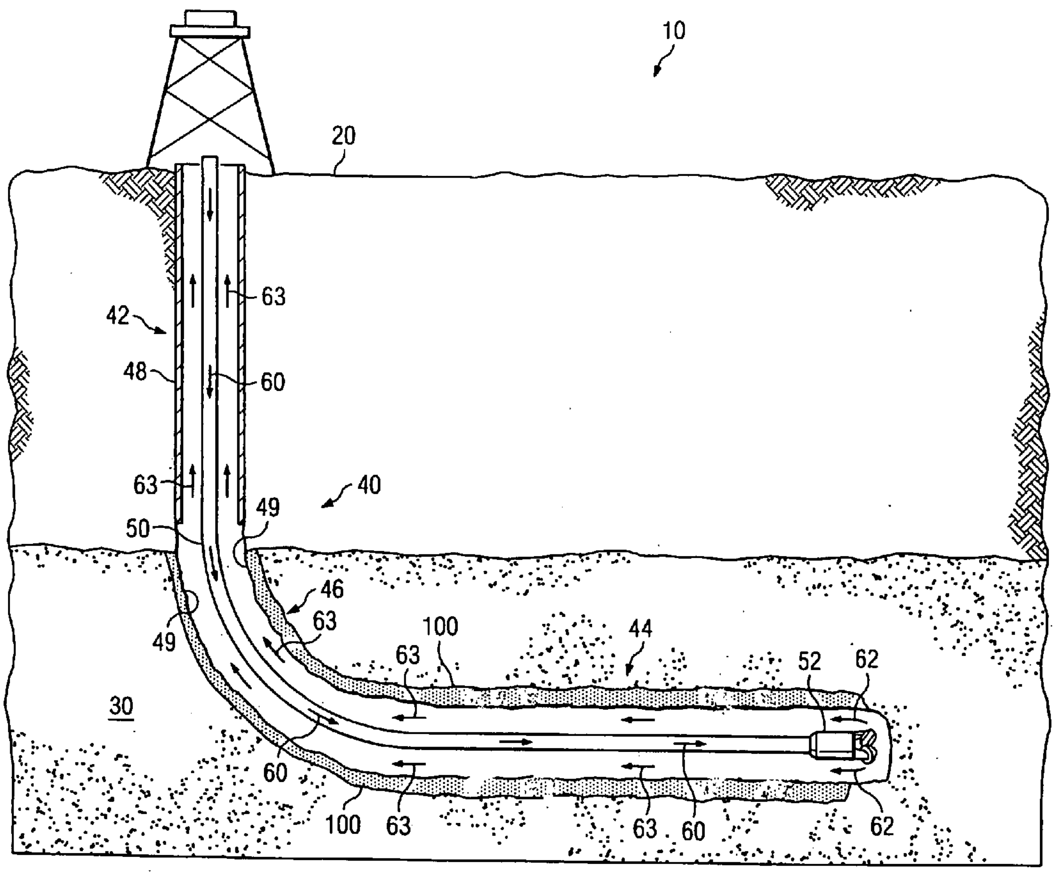
(52) **U.S. Cl.** **175/65**; 175/339

(57) **ABSTRACT**

A system and method for drilling a substantially horizontal well bore in a normally to sub-normally pressured formation. The normally to sub-normally pressured formation is an unconventional reservoir. The well bore is drilled over-balanced with a drilling fluid having a density at least about the density of the cuttings produced by drilling the well bore.



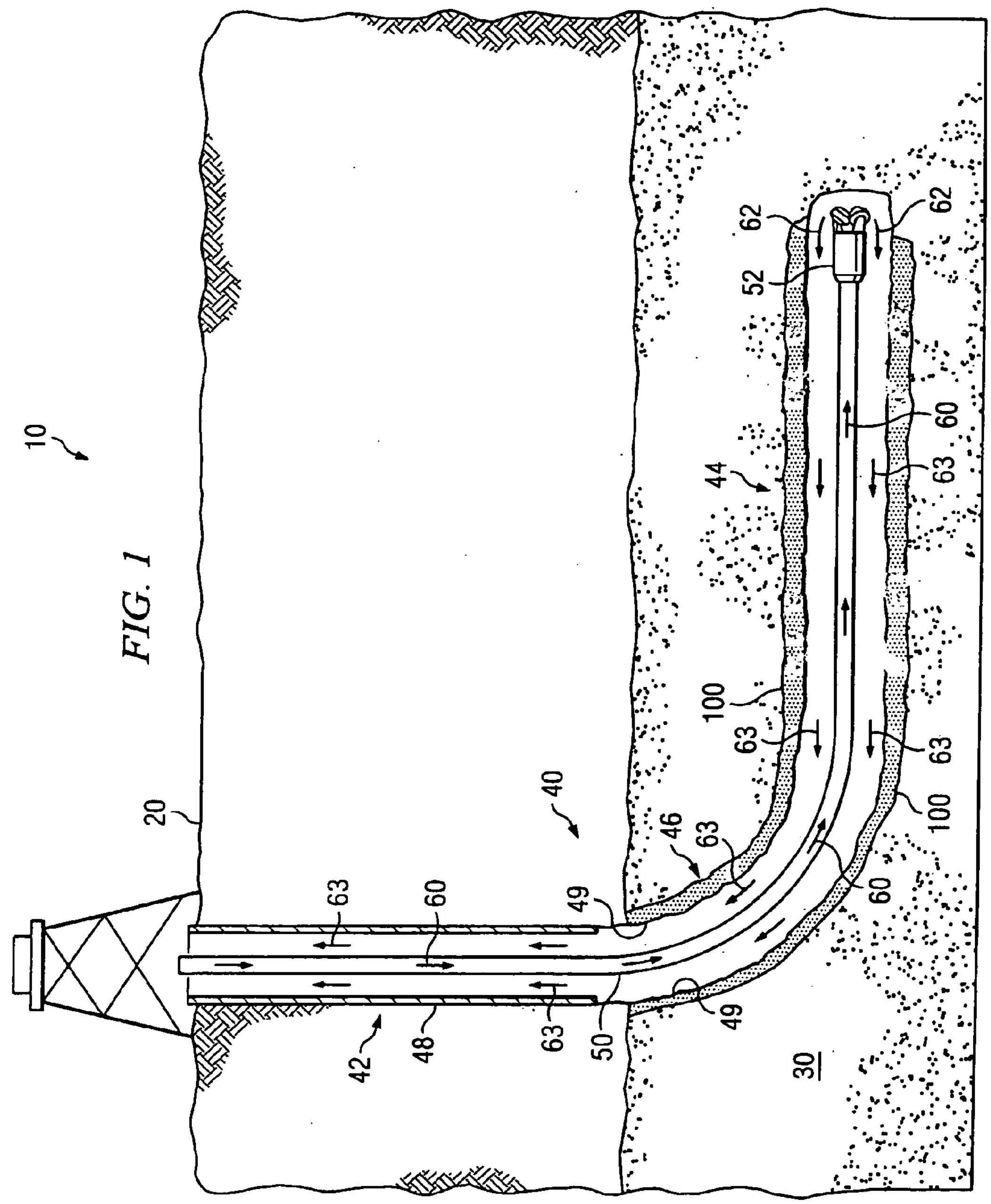
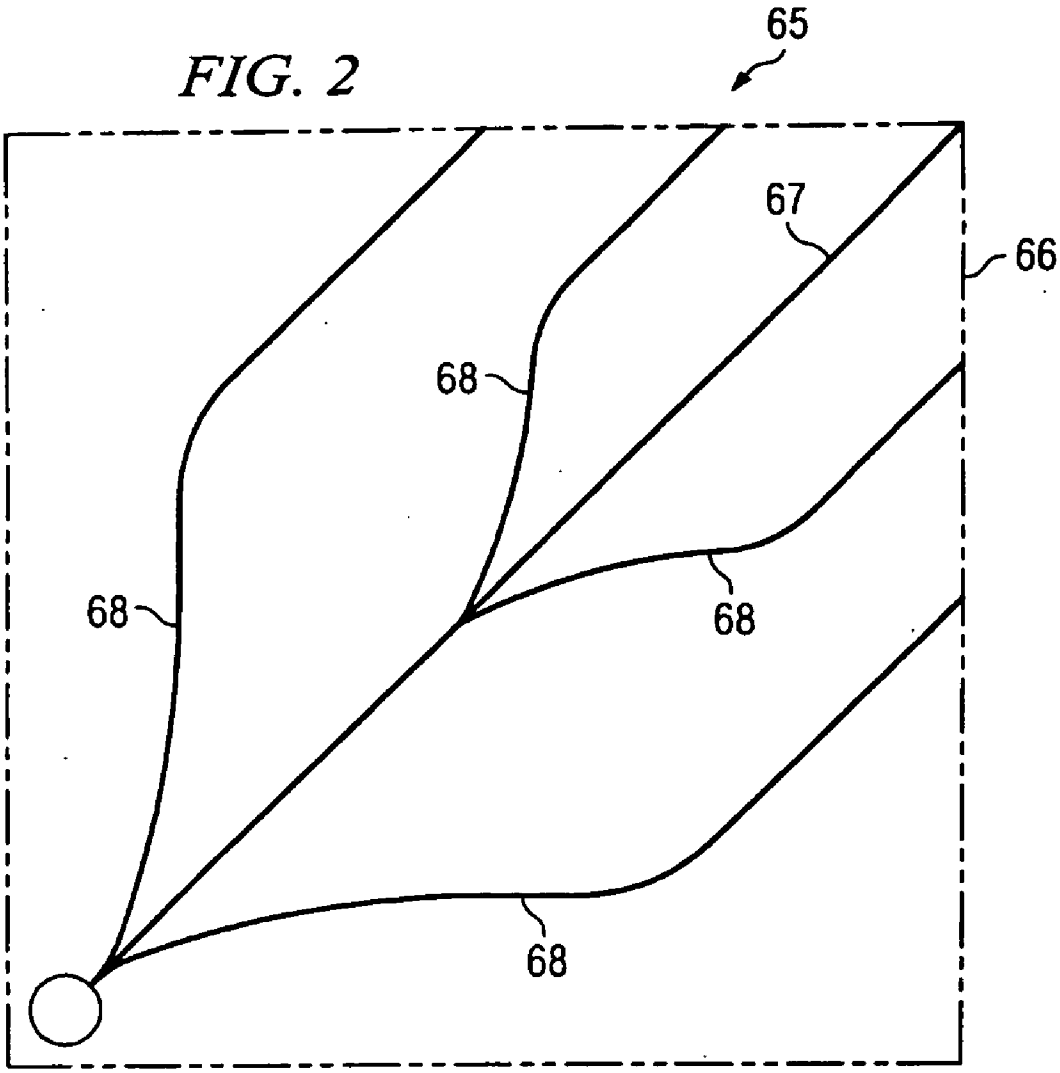


FIG. 1

FIG. 2



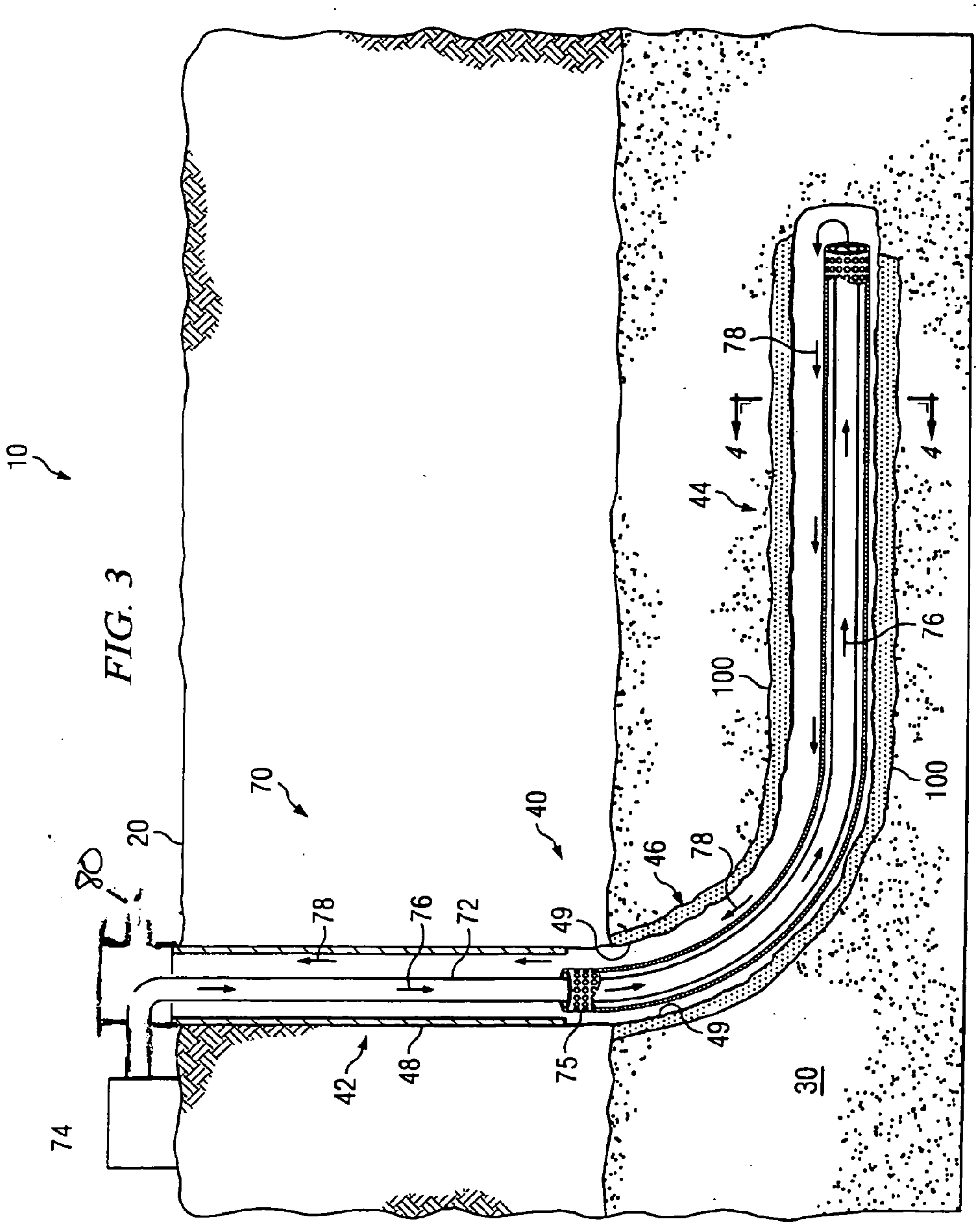


FIG. 3

FIG. 4

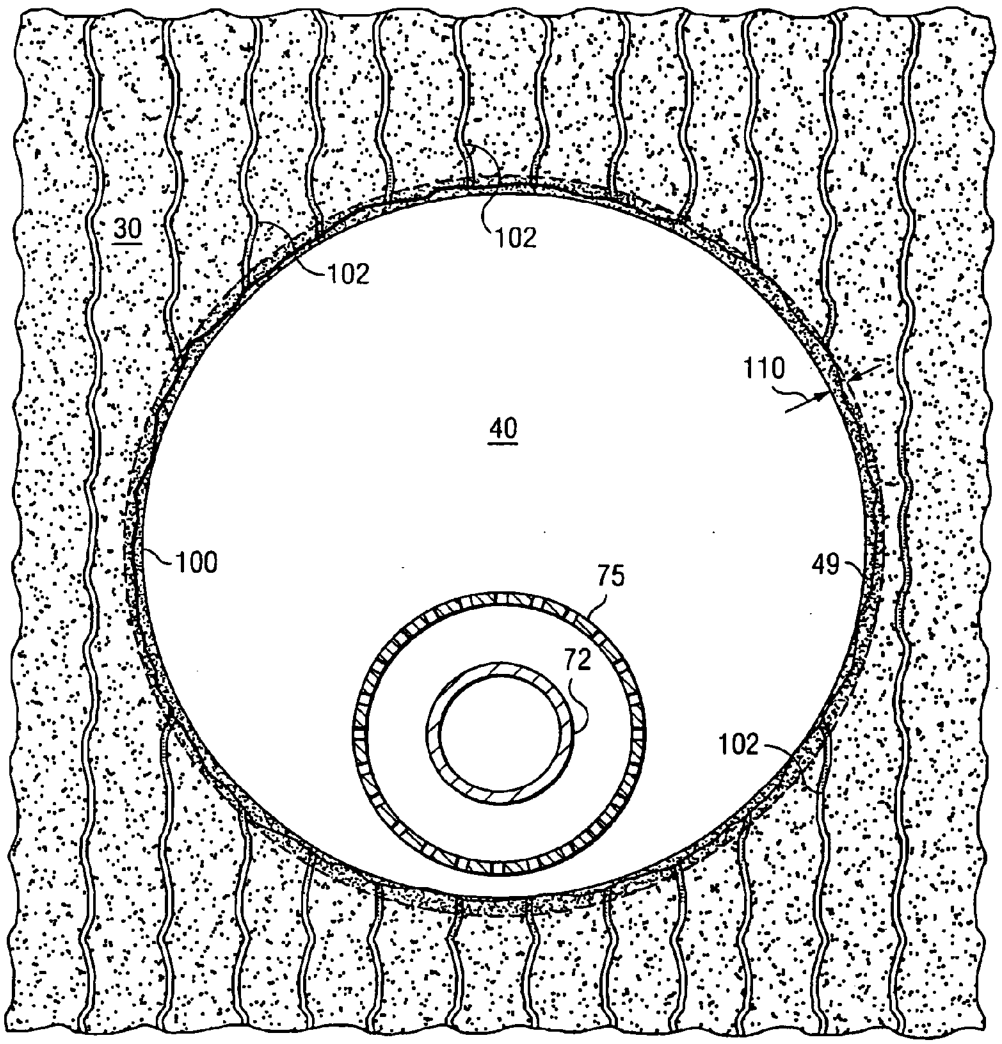


FIG. 5

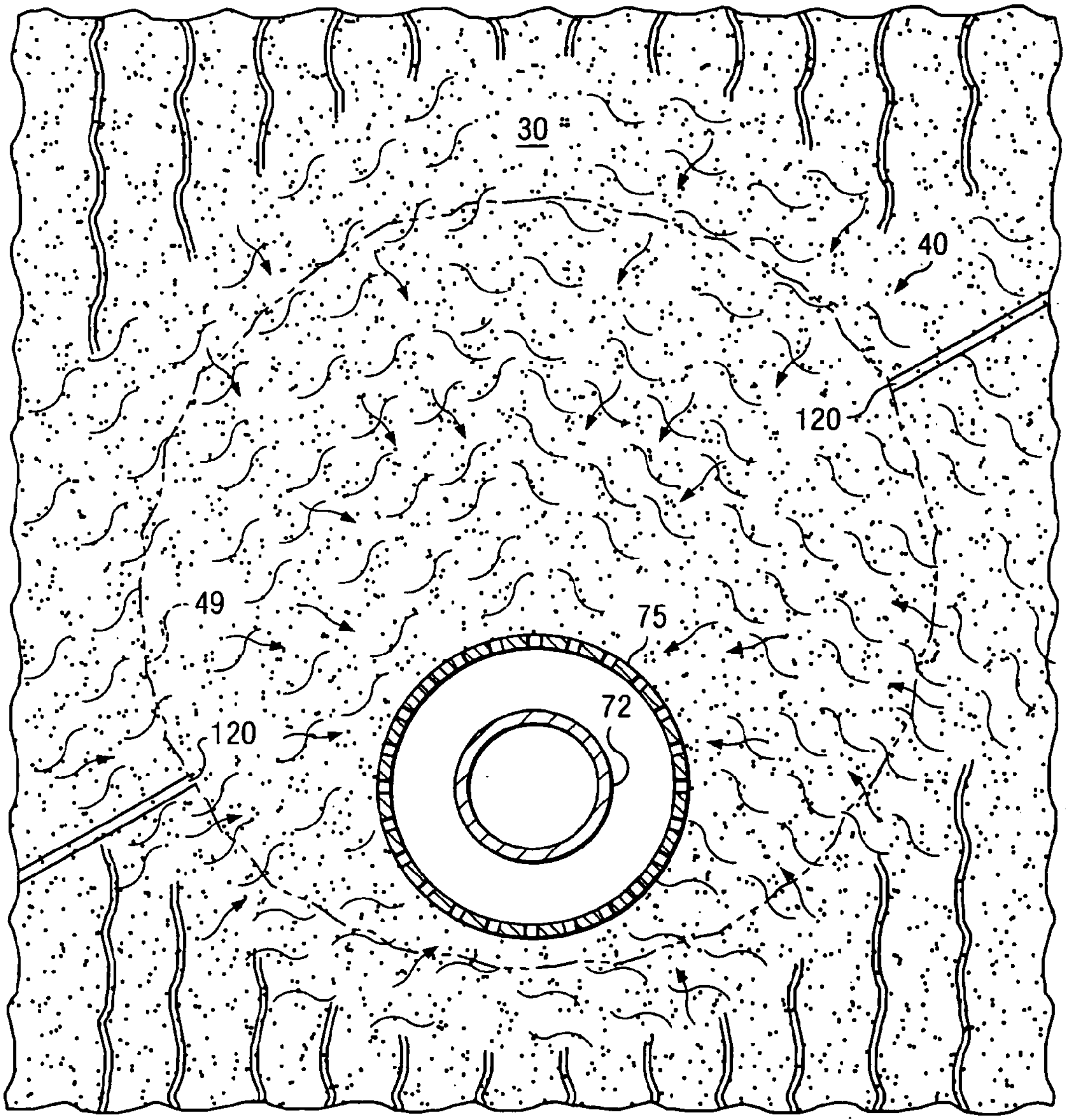
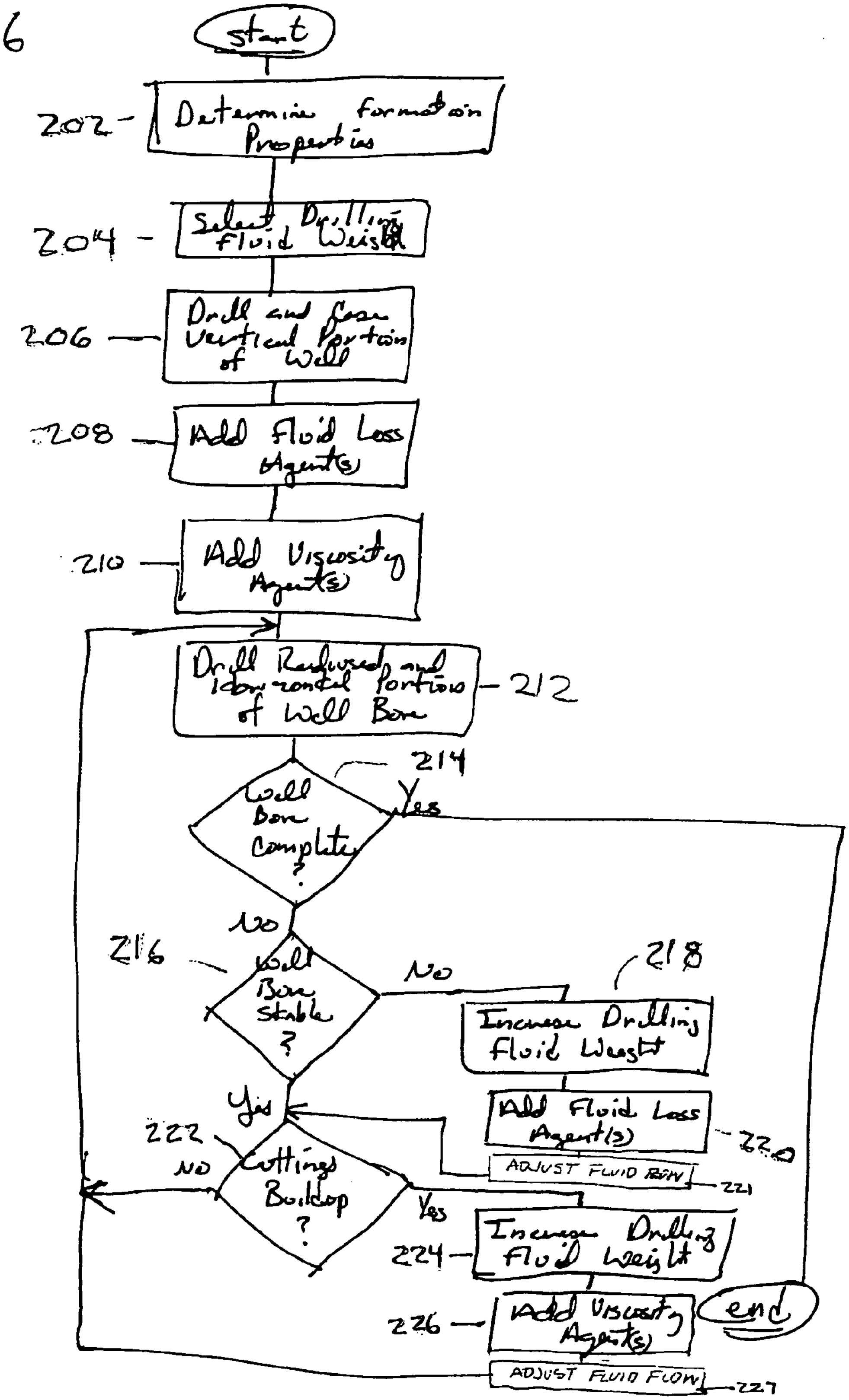


FIG. 6


start
202
Determine formation Properties
204
Select Drilling Fluid Weight
206
Drill and Case Vertical Portion of Well
208
Add Fluid Loss Agent(s)
210
Add Viscosity Agent(s)
Drill Radiused and Horizontal Portion of Well Bore
212
214
Well Bore Complete ?
Yes
No
216
Well Bore Stable ?
No
218
Increase Drilling Fluid Weight
Add Fluid Loss Agent(s)
220
ADJUST FLUID FLOW
221
Yes
222
Cuttings Buildup ?
No
Yes
Increase Drilling Fluid Weight
224
Add Viscosity Agent(s)
226
end
ADJUST FLUID FLOW
227

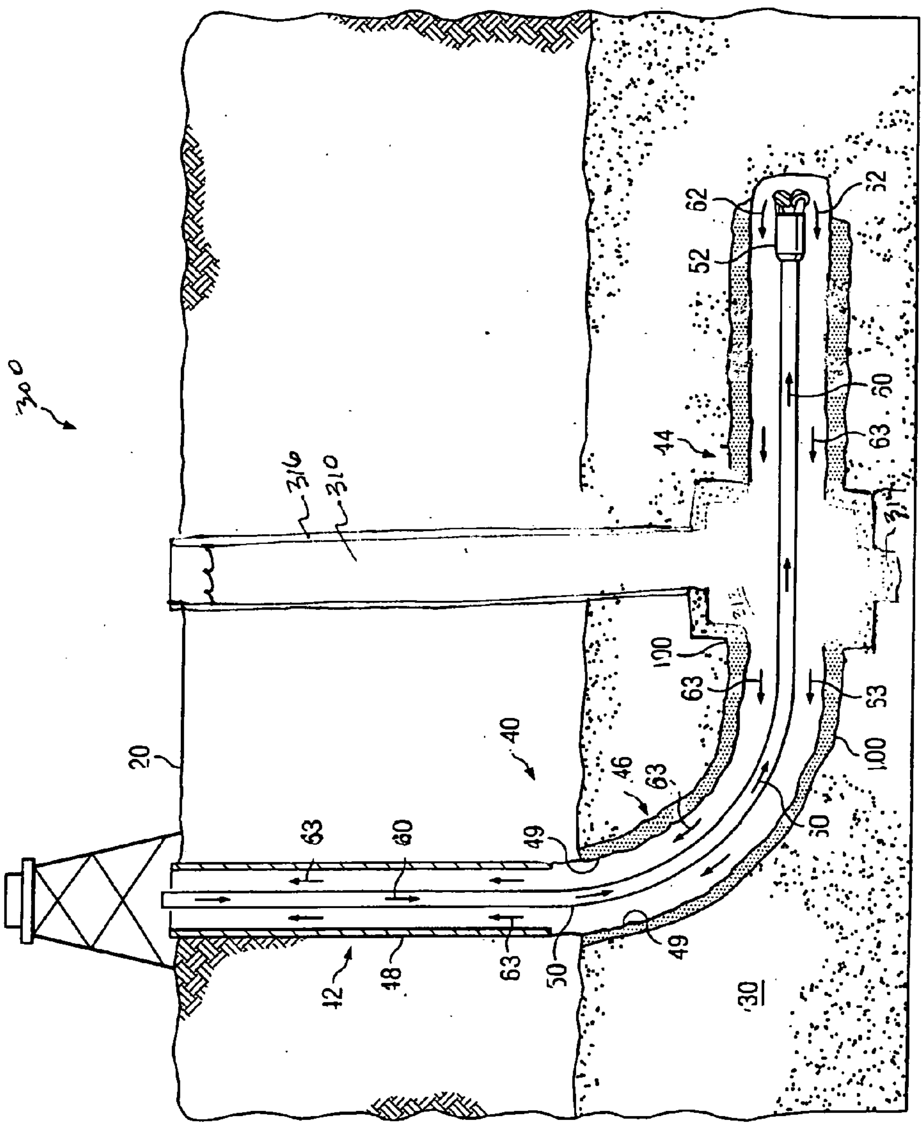


FIG 7

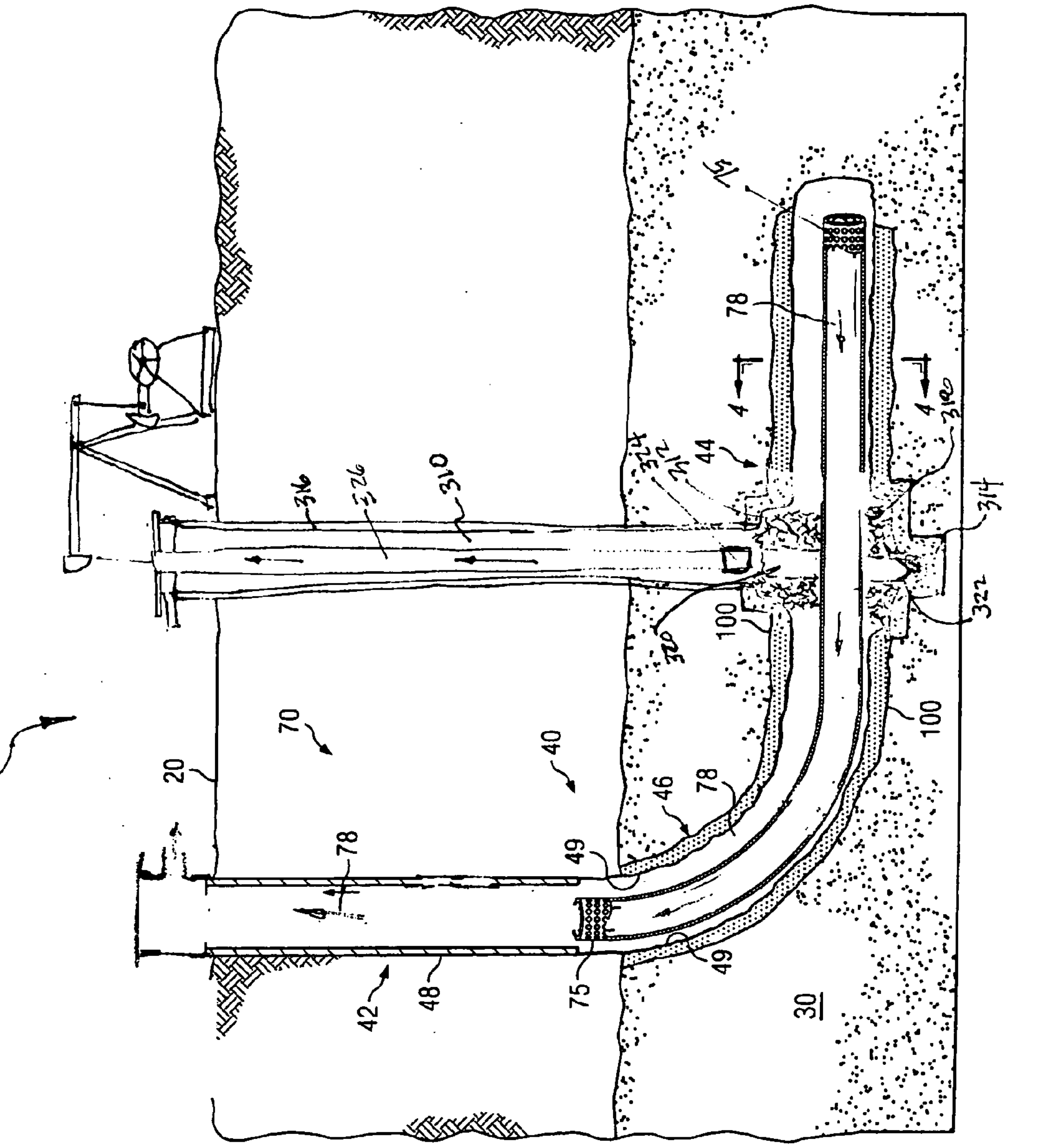


FIG 8

WELL BORE CLEANING

RELATED APPLICATIONS

[0001] This application is a continuation-in-part of, and therefore claims priority from, U.S. patent application Ser. No. 11/035,537 filed on Jan. 14, 2005, which is a continuation-in-part of, and therefore claims priority from, U.S. patent application Ser. No. 10/723,322, filed on Nov. 26, 2003. This application incorporates by reference the two applications noted above, as well as the application entitled Drilling Normally to Sub-Normally Pressured Formations filed May 31, 2005.

TECHNICAL FIELD

[0002] This disclosure relates generally to the field of recovery of subterranean resources, and more particularly to a system and method for well bore cleaning.

BACKGROUND

[0003] Reservoirs are subterranean formations of rock containing oil, gas, and/or water. Unconventional reservoirs include coal formations, shale formations and low permeability formations containing gas and, in some cases, water. A coal bed, for example, may contain natural gas and water.

[0004] Coal bed methane (CBM) is often produced using vertical wells drilled from the surface into a coal bed. Vertical wells drain a very small radius of methane gas in low permeability formations. As a result, after gas in the vicinity of the vertical well has been produced, further production from the coal seam through the vertical well is limited.

[0005] To enhance production through vertical wells, the wells have been fractured using conventional and/or other stimulation techniques. Horizontal patterns have also been formed in coal seams to increase and/or accelerate gas production.

SUMMARY

[0006] The invention encompasses a system and method for well bore cleaning. In one embodiment, the method includes drilling a substantially horizontal well bore in a normally to sub-normally pressured formation. The normally to sub-normally pressured formation is an unconventional reservoir. The well bore is drilled over-balanced with a drilling fluid including a fluid loss agent. The fluid loss agent is operable to form a filter cake on the well bore during drilling.

[0007] More specifically, in accordance with a particular embodiment, the unconventional reservoir may comprise a fractured formation, a coal bed and/or a shale. The fluid loss agent may comprise a non-invasive or low-invasive fluid such as micelles, aphrons or other agent operable to form a filter cake to limit fluid loss from the well bore to the formation. The drilling fluid may comprise a heavy fluid having a density of 9.5 pounds per gallon or greater, 10 pounds per gallon or greater and/or a density substantially equal to or greater than that of the cuttings generated during drilling of the well bore.

[0008] Technical advantages of certain embodiments include providing a system and method for drilling a normally to sub-normally pressured formation. In a particular embodiment, a fluid loss agent may be used to form a filter cake around the well bore to enhance well bore stability. For example, the filter cake may seal the well bore and prevent fluid loss to the formation that could destabilize the formation and lower productivity of the formation. In addition, the filter cake may allow a positive pressure differential to be maintained between the well bore and the formation during drilling to stabilize the well bore.

[0009] Another technical advantage of certain embodiments may include the use of a dense drilling fluid to enhance well bore stability and/or improve cutting removal efficiency. In a particular embodiment, a dense drilling fluid having a density greater than 9.5 pounds per gallon, may be used. In other embodiments, the density of the drilling fluid may be 10 pounds per gallon or greater and/or have a density substantially the same or greater than the cuttings in order to improve cuttings removal.

[0010] Other technical advantages will be readily apparent to one skilled in the art from the following figures, description, and claims. Moreover, while specific advantages have been enumerated above, various embodiments may include all, some, or none of the enumerated advantages.

DESCRIPTION OF DRAWINGS

[0011] **FIG. 1** illustrates one embodiment of drilling a well of drilling a well from the terranean surface to a subterranean zone;

[0012] **FIG. 2** illustrates one embodiment of a well bore pattern for the well of **FIG. 1**;

[0013] **FIG. 3** illustrates one embodiment of producing the well of **FIG. 1**;

[0014] **FIG. 4** is a cross sectional diagram along lines **4-4** of **FIG. 3** illustrating one embodiment of the well bore of **FIG. 3**;

[0015] **FIG. 5** is a cross-sectional diagram illustrating collapse of the well bore of **FIG. 4**;

[0016] **FIG. 6** is a flow chart illustrating an example method for drilling a normally to sub-normally pressured formation;

[0017] **FIG. 7** illustrates another embodiment of drilling a well from the terranean surface to a subterranean zone; and

[0018] **FIG. 8** illustrates one embodiment of producing the well of **FIG. 7**.

[0019] Like reference symbols in the various drawings indicate like elements.

DETAILED DESCRIPTION

[0020] **FIG. 1** illustrates an example system **10** for drilling a well bore **40** from the terranean surface **20** to a subterranean zone **30**. As described in more detail below, the well bore **40** may be drilled overbalanced using a low-loss and/or dense drilling fluid. The low-loss and/or dense drilling fluid may assist in sealing and stabilizing the well bore **40**.

[0021] In the illustrated embodiment, subterranean zone **30** is an unconventional reservoir, such as a coal seam, tight shale or low permeability formations. Subterranean zone **30** may be accessed to remove and/or produce water, hydrocarbons, and other fluids, to sequester carbon dioxide or other pollutants, and/or for other operations. Subterranean zone **30** may, in one embodiment, be naturally fractured.

[**0022**] For ease of reference and purposes of example, subterranean zone **30** will be referred to as coal seam **30**. The coal seam **30** may be a normally to sub-normally pressured formation. For a normally pressured formation, the pressure in the formation is equal or substantially equal to that of the water gradient at the depth of the formation. For a sub-normally pressured formation, the pressure in the formation is less than that of the water gradient at the depth of the formation. For example, a sub-normally pressured coal seam **30** may have a pressure that is 5 or more percent less than that of the water gradient at the depth of the coal seam **30**.

[**0023**] The well bore **40** can define a first portion **42** that extends from the surface **20**, a second portion **44** at least partially coinciding with the coal seam **30** and a curved or radiused portion **46** interconnecting the portions **42** and **44**. In one instance, the first portion **42** may be drilled to extend past the curved portion **46** to define a sump and/or to provide access to additional coal seams **30**, for example, by drilling additional curved portions **46** and second portions **44**. Additionally, although the first portion **42** is illustrated as being substantially vertical, the first portion **42** may be formed at any angle relative to the surface. For example, the first portion **42** may be slanted to reduce the radius of the curved portion **46**, to accommodate surface **20** geometric characteristics or other concerns such as nearby well bores. For example, the first portion **42** may be angled to accommodate an adjacent well bore **40** drilled from the same surface area or same drilling pad. The first portion **42** of well bore **40** may be lined with a suitable casing **48**. The casing **48** may also extend into or through the curved section **46**, and in some instances, into the second portion **44**.

[**0024**] The second portion **44** may be substantially horizontal and/or in the seam of coal seam **30**, may track the depth of the coal seam **30**, may undulate in the coal seam **30** or be otherwise suitably disposed in or about the coal seam **30**. The second portion **44** of the well bore **40** may include a well bore pattern with a plurality of lateral or other horizontal well bores, as it discussed in more detail with respect to **FIG. 2**. In another embodiment, the well bore **40** may be a single bore without laterals.

[**0025**] Although **FIG. 1** illustrates a single articulated well bore **40** that deviates to horizontal, system **10** may be implemented, as described in connection with **FIG. 7**, as dual or multi-well systems or any other suitable types of wells or well systems. Well bore **40** may be drilled to intersect more natural passages and other fractures, such as "cleats" of a coal seam **30**, that allow the flow of fluids from seam into well bore **40**, thereby increasing the productivity of the well.

[**0026**] Articulated well bore **40** is drilled using drill string **50** that includes a suitable down-hole motor and drill bit **52**. The drill string **50** may be driven by a rotary rig, top drive rig and/or coiled tubing rig. Accordingly, the drill string **50** may be coiled tubing, sectioned drill pipe or other suitable tubing. Other down hole drill and/or steering systems may be used. During the process of drilling well bore **40**, drilling fluid or mud is pumped down drill string **50**, as illustrated by arrows **60**, and circulated out of drill string **50** in the vicinity of drill bit **52**, as illustrated by arrows **62**. The drilling fluid flows into the annulus between drill string **50** and well bore walls **49** where the drilling fluid is used to remove formation cuttings and coal fines. The cuttings and coal fines (hereinafter referred to as "debris") are entrained in the drilling fluid, which circulates up through the annulus between the drill string **40** and the well bore walls **49**, as illustrated by arrows **63**, until it reaches surface **20**, where the debris is removed from the drilling fluid and the fluid is re-circulated through well bore **40**.

[**0027**] In certain embodiments, the drilling fluid may comprise water and one or more weighting agents, fluid loss agents, and/or viscosity agents. The weighting agents may be used to increase the density of the drilling fluid and thus the hydrostatic fluid pressure exerted on the coal seam **30** during drilling of the well bore **40**. The drilling operation produces a column of drilling fluid in the well bore **40** having a vertical height equal to the depth of the well bore **40** and produces a hydrostatic pressure on well bore **40** relating to the density of the drilling fluid and the vertical height of the column of fluid. In one embodiment, the well bore **40** is drilled over-balanced with the hydrostatic fluid pressure in well bore **40** exceeding the pressure in the coal seam **30**. For normally and sub-normally pressured coal seams **30**, the well bore **40** may be drilled with a drilling fluid having a density selected to be approximately equal to or greater than the density of the formation cuttings. In one instance, the well bore **40** may be drilled with a drilling fluid having a density of 9.5 pounds per gallon or higher, 10 pounds per gallon or higher, or a density close to or matching that of the coal cuttings, which may be 11.2 pounds per gallon. In this embodiment, the coal cuttings may be buoyant or nearly buoyant in the drilling fluid and efficiently removed from the well bore **40**. This would allow for extremely high rates of drilling and high hole cleaning efficiency, greater than could be achieved with drilling fluid having a lower density than the cuttings.

[**0028**] In one embodiment, a salt such as sodium chloride or calcium chloride may be used as a weighting agent. In particular, sodium chloride may provide a brine having a density of up to 9.9 pounds per gallon. Calcium chloride may provide a brine having a density up to 11.7 pounds per gallon. In other embodiments, potassium formate may be used as a weighting agent. Potassium formate may provide a drilling fluid having a density up to 14 pounds per gallon. Other suitable weighting agents may be used.

[**0029**] The density, or specific gravity, of the drilling fluid may be determined based on bore hole stability needs, fracture gradient of the coal seam **30**, and/or cutting removal needs. In this and other embodiments, bore hole stability needs may be initially determined based on the formation stress, formation pressure, and/or formation strength of the coal seam **30**. For example, drilling fluid density may be increased when the coal seam **30** has less rock stability, while the density of the drilling fluid may be reduced when the coal seam **30** has a greater rock stability. Other suitable criteria may be used in initially or otherwise determining the density of the drilling fluid.

[**0030**] The fluid loss agent may form a filter cake **100** along the walls of the well bore **40**. Filter cake **100** may prevent or significantly restrict drilling fluids from flowing into coal seam **30** from the well bore **40**. The filter cake **100** may also provide a pressure boundary or seal between coal seam **30** and well bore **40** which may allow hydrostatic pressure in the well bore **40** to be used to control stability of the well bore **40** to prevent collapse during drilling. For example, during drilling, the filter cake **100** may aid well bore stability by allowing the hydrostatic pressure to act against the walls of the well bore **40** and/or by preventing drilling fluid from entering the coal seam **30** and destabilizing the seam around the well bore **40**.

[0031] The depth of the filter cake **100** may be dependent upon many factors including the composition of the drilling fluid, the fluid loss agent, and/or the properties of the formation. The fluid loss agent may be selected or otherwise designed in connection with the drilling fluid based on rock mechanics, pressure and other characteristics of the coal seam **30** to form a filter cake that reduces or minimizes fluid loss during drilling and/or reduces or minimizes skin damage to the well bore **40**.

[0032] The filter cake **100** may be formed with low-loss, ultra low-loss, non-invasive, low-invasive or other suitable drilling fluids. In one embodiment, fluid loss agent may comprise solid micelles that form microscopic spheres, rods, and/or plates in solutions. The micelles may comprise polymers with a range of water and oil solubilities. The micelles form a low permeability seal over pore throats of the coal seam **30** to greatly limit further fluid invasion or otherwise seal the coal seam boundary. In a particular embodiment, the fluid loss agent may comprise FLC 2000 available from IMPACT SOLUTIONS GROUP which may create a shallow filter cake **100** having a depth of invasion into the formation approximately two to four centimeters with a structural integrity operable to seal the well bore **40**. In some instances, the fluid invasion rate of FLC 2000 may be 0.17 cubic meters of fluid lost to the formation per square meter of exposed formation in a day ($m^3/m^2 \cdot day$), as compared to 0.6 $m^3/m^2 \cdot day$ for other conventional drilling fluids. FLC 2000 may provide a high return permeability after drilling during production. Starch and/or other fluid loss agents may be used in connection with the FLC 2000. In a particular embodiment, starch may be used to increase the sealing effect of the filter cake **100** formed by the FLC 2000. In another embodiment, aphrons, for example may be used as the fluid loss agent.

[0033] The viscosity agents may increase lifting capacity of the drilling fluid. In a particular embodiment, the viscosity agents may comprise carboxyl methyl cellulose (CMC), hydroxyl ethyl cellulose (HEC), polyanionic cellulose (PAC), and/or xanthan gum (XG polymer). Other suitable viscosity agents may be used. In addition, the viscosity agents may be omitted when not needed.

[0034] During drilling, the first portion **42** of the well bore **40** may be drilled overbalanced with a dense drilling fluid, but without the fluid loss and viscosity agents. The density of the drilling fluid may initially be between 8.3 and 9.0 pounds per gallon. After casing the first portion **42** of the well bore **40**, and, in one embodiment, prior to entering the coal seam **30**, the fluid loss and viscosity agents may be added to the drilling fluid. In the embodiment in which FLC 2000 is used as the fluid loss agent, FLC 2000 may initially be added to the drilling fluid in concentrations of up to 6-10 kilograms per cubic meter. If additional stability is needed, the concentration of FLC 2000 may be increased up to about 15 kilograms per cubic meter. Similarly, the density of the drilling fluid may be increased up to, for example, 9.5 pounds per gallon or greater to control bore hole **40** stability and/or assist in cuttings removal. For example, the density of the drilling fluid may be increased up to the density of the coal to suspend the cuttings in the drilling fluid and increase hole cleaning efficiency. However, the density of the drilling fluid may be limited due to the fracture gradient of the coal seam **30**. In this case, additional viscofiers may be used. Additionally, the velocity and/or pump rate of the drilling fluid may be increased in the bore hole **40** to assist with cutting cleanout and removal

[0035] **FIG. 2** illustrates an example of horizontal well bore pattern **65** for use in connection with well bore **40**. In this embodiment, the pattern **65** may include a main horizontal well bore **67** extending diagonally across the coverage area **66**. A plurality of lateral or other horizontal well bores **68** may extend from the main bore **67**. The lateral bore **68** may mirror each other on opposite sides of the main bore **67** or may be offset from each other along the main bore **67**. Each of the laterals **68** may be drilled at a radius off the main bore **67**. The horizontal pattern **65** may be otherwise formed, may otherwise include a plurality of horizontal bores or may be omitted. For example, the pattern **65** may comprise a pinnate pattern having a main horizontal bore extending diagonally across the coverage area **66** and two, three four or more laterals extending from and on each side of the main horizontal bore **67** to the periphery of the coverage area **66**. The horizontal bores may be bores that are fully or substantially in the coal seam **30**, or horizontal and/or substantially horizontal.

[0036] **FIG. 3** illustrates production from well bore **40**. Drill string **50** has been removed and a fluid extraction system **70** inserted into well bore **40**. Fluid extraction system **70** may include any appropriate components capable of circulating and/or removing fluid from well bore **40** and lowering the pressure within well bore **40**. For example, fluid extraction system **70** may comprise a tubing string **72** coupled to an artificial lift apparatus **74**. Artificial lift apparatus **74** may comprise any appropriate device for circulating and/or removing fluid from well bore **40**, such as a pump or a fluid injector. Although artificial lift apparatus **74** is illustrated as being located on surface **20**, in certain embodiments, artificial lift apparatus **74** may be located within well bore **40**, such as would be the case if artificial lift apparatus **74** comprised a down-hole pump. The fluid may be a liquid and/or a gas. Artificial lift apparatus **74** may be omitted where, for example, water produced is limited and/or gas pressure in the coal seam is high enough to lift produced water to the surface **20**.

[0037] In certain embodiments, artificial lift apparatus **74** may comprise a pump coupled to tubing string **72** that is operable to draw fluid from well bore **40** through tubing string **72** to surface **20** and reduce the pressure within well bore **40**. In the illustrated embodiment, artificial lift apparatus **74** comprises a fluid injector, which may inject gas, liquid, or foam into well bore **40**. Any suitable type of injection fluid may be used in conjunction with system **70**. Examples of injection fluid may include, for example: (1) production gas, such as natural gas, (2) water, (3) air, and (4) any combination of production gas, water, air and/or treating foam. In particular embodiments, production gas, water, air, or any combination of these may be provided from a source outside of well bore **40**. In other embodiments, gas recovered from well bore **40** may be used as the injection fluid by re-circulating the gas back into well bore **40**. Rod, positive displacement and other pumps may be used. In these and other embodiments, as illustrated in **FIG. 8**, a cavity may be formed in the well bore **40** with the pump inlet positioned in the cavity. The cavity may form a junction with a vertical or other well in which the pump and/or pump inlet is disposed.

[0038] The fluid extraction system **70** may also include a liner **75**. The liner **75** may have a plurality of apertures and may be loose in the well bore or otherwise uncemented. The apertures may be holes, slots, or openings of any other suitable size and shape. The apertures may allow water and gas to enter into the liner **75** from the coal seal **30** for production to the surface. The liner **75** may have apertures when installed or may be perforated after installation. For example, the liner **75** may comprise a drill or other string perforated after another use in well bore **40**.

[0039] The size and/or shape of apertures in the liner **75** may in one embodiment be determined based on rock mechanics of the coal seam. In this embodiment, for example, a representative formation sample may be taken and tested in a tri-axial cell with pressures on all sides. During testing, pressure may be adjusted to simulate pressure in down-hole conditions. For example, pressure may be changed to simulate drilling conditions by increasing hydrostatic pressure on one side of the sample. Pressure may also be adjusted to simulate production conditions. During testing, water may be flowed through the formation sample to determine changes in permeability of the coal at the well bore in different conditions. The tests may provide permeability, solids flow and solids bridging information which may be used in sizing the apertures, determining the periodicity of the apertures, and determining the shape of the apertures. Based on testing, if the coal fails in blocks without generating a large number of fines that can flow into the well bore, large perforations and/or high clearance liners with a loose fit may be used. High clearance liners may comprise liners one or more casing sizes smaller than a conventional liner for the hole size. The apertures may, in a particular embodiment, for example, be holes that are ½ inch in size.

[0040] In operation of the illustrated embodiment, fluid injector **74** injects a fluid, such as water or natural gas, into tubing string **72**, as illustrated by arrows **76**. The injection fluid travels through tubing string **72** and is injected into the liner **75** in the well bore **40**, as illustrated by arrows **78**. As the injection fluid flows through the liner **75** and annulus between liner **75** and tubing string **72**, the injection fluid mixes with water, debris, and resources, such as natural gas, in well bore **40**. Thus, the flow of injection fluid removes water and coal fines in conjunction with the resources. The mixture **80** of injection fluid, water, debris, and resources is collected at a separator (not illustrated) that separates the resource from the injection fluid carrying the resource. Tubing string **72** and fuel injector **74** may be omitted in some embodiments. For example, if coal fines or other debris are not produced from the coal seam **30** into the liner **75**, fluid injection may be omitted.

[0041] In certain embodiments, the separated fluid is re-circulated into well bore **40**. In a particular embodiment, liquid, such as water, may be injected into well bore **40**. Because liquid has a higher viscosity than air, liquid may pick up any potential obstructive material, such as debris in well bore **40**, and remove such obstructive material from well bore **40**. In another particular embodiment, gas may be injected into well bore **40**. Although certain types of injection fluids are described, any combination of air, water, and/or gas that are provided from an outside source and/or re-circulated from the separator may be injected back into well bore **40**.

[0042] Also in certain embodiments, after drilling is completed, the drilling fluid may be left in well bore **40** while drill string **50** is removed and tubing string **72** and liner **75** are inserted. The drilling fluid, and possibly other fluids flowing from the coal seam **30**, may be pumped or gas lifted (for example, using a fluid injector) to surface **20** to reduce, or "draw down," the pressure within well bore **40**. As pressure is drawn down below reservoir pressure, fluid from the coal seam **30** may begin to flow into the well bore **40**. This flow may wash out the filter cake **100** when non-invasive or other suitable drilling fluids are used. In other embodiments, the filter cake **100** or a portion thereof may remain. In response to the initial reduction in pressure and/or friction reduction in pressure, the well bore **40** may collapse, as described below.

[0043] Collapse may, in certain embodiments, improve the efficiency of gas production from coal seam **30** by, for example, increasing the localized permeability of the coal seam **30**. The localized permeability is a permeability of all or part of an area around, otherwise about, or local to the well bore **40**. The localized permeability may be enhanced, in one embodiment, by spalling or cleaving the subterranean zone **30** around the well bore and/or otherwise collapsing the well bore **40**. Cleaving refers to splitting or separating portions of the subterranean zone **30**. Spalling refers to breaking portions of the subterranean zone **30** into fragments and may be localized collapsed, fracturing, splitting and/or shearing. The increased localized permeability provides more drainage surface area without hydraulically fracturing the coal seam **30**. Hydraulic fracturing comprises pumping a fracturing fluid down-hole under high pressure, for example, 1000 psi, 5000 psi, 10,000 psi or more.

[0044] Collapse may occur before or after production begins. Collapse may be beneficial in situations where coal seam **30** has low permeability, such as below 3 millidarcies. However, coal seams **30** having other levels of permeability may also benefit from collapse. In certain embodiments, the drilling fluid may be removed before the pressure drop in well bore **40**. In other embodiments, the pressure within well bore **40** may be reduced by removing the drilling fluid.

[0045] **FIG. 4** is a cross sectional diagram along lines **4-4** of **FIG. 3** illustrating well bore **40** in the subterranean zone **30**. Filter cake **100** is formed along walls **49** of the well bore **40**. As discussed above, filter cake **100** may occur in over-balanced drilling conditions where the drilling fluid pressure is greater that of the coal seam **30**. Filter cake **100** may be otherwise suitably generated and may comprise any partial or full blockage of pores, cleats **102** or fractures in order to seal the well bore **40** by substantially limiting or reducing fluid flow between the coal seam **30** and well bore **40**.

[0046] As previously described, use of a fluid loss agent, or non-invasive fluid, may create a relatively shallow invasion filter cake **100**, resulting in a relatively low amount of drilling fluid lost into the cleats **102** of the coal seam **30**. In certain embodiments, a filter cake **100** may have an invasion depth **110** between two and four centimeters thick. A thin filter cake **100** may be advantageous when it will not cause a permanent blockage but is strong enough to form a seal between coal seam **30** and well bore **40** to facilitate stability of the well bore **40** during drilling.

[0047] **FIG. 5** is a cross-sectional diagram illustrating collapse of the well bore **40**. Collapse may be initiated in response to the pressure reduction in the well bore **40**. As used herein, in response to means in response to at least the identified event. Thus, one or more events may intervene, be needed, or also be present. In one embodiment, the well bore **40** may collapse when the mechanical strength of the coal cannot support the overburden at the hydrostatic pressure in the well bore **40**. The well bore **40** may collapse, for example, when fluid pressure is reduced in the well bore **40**.

[0048] During collapse, a shear plane **120** may be formed along the sides of the well bore **40**. The shear planes **120** may extend into the coal seam **30** and form high permeability pathways connected to cleats **102**. In some embodiments, multiple shear planes **120** may be formed during spalling. Each shear plane **120** may extend about the well bore **40**.

[0049] Collapse may generate an area of high permeability within and around the pre-existing walls **49** of the well bore **40**. This enhancement and localized permeability may permit a substantially improved flow of gas or other resources from the coal seam **30** into liner **75** than would have occurred without collapse. In an embodiment where the well bore **40** includes a multi-lateral pattern, the main horizontal bore and lateral bores may each be lined with liner **75** and collapsed by reducing hydrostatic pressure in the well bores.

[0050] **FIG. 6** is a flow chart illustrating an example method for drilling normally and sub-normally pressured coal seams **30**. In this embodiment, well bore **40** comprises an articulated well bore in which the first portion **42** is vertical, the second portion **44** is horizontal and the curved portion **46** deviates from vertical to horizontal. As previously described, the well bore **40** may be otherwise suitably configured.

[0051] Referring to **FIG. 6**, the method begins at step **202**, in which formation properties are determined. For the coal seam **30**, formation stress, formation pressure and/or formation strength may be determined from core samples, reference databases, other well wells and/or other resources. At step **204**, drilling fluid density is selected based on well bore **40** stability and/or other formation properties. For overbalanced drilling, the drilling fluid density is selected such that the hydrostatic pressure of the drilling fluid at the depth of the coal seam **30** is greater than the pressure of the coal seam **30**. As previously described, sodium chloride, calcium chloride, potassium formate and/or other weighting agents may be used to raise the density of the drilling fluid to the desired density.

[0052] Proceeding to step **206**, the vertical portion **42** of the well bore **40** is drilled and cased. At step **208**, and, in one embodiment, prior to drilling into the coal seam **30**, one or more fluid loss agents are added to the drilling fluid. In one embodiment, the fluid loss agents include at least one of aphrons and micelles. As previously described, the fluid loss agents may form a filter cake **100** on the walls **49** of the well bore **40**. The filter cake **100** may stabilize the well bore **40** during drilling and may, in one embodiment, reduce differential sticking and provide lubrication to reduce friction of the drill string **50** in the well bore **40**. The fluid loss agents may, for example, comprise FLC 2000, other micelle, and/or aphrons.

[0053] At step **210**, one or more viscosity agents may be added to the drilling fluid. As previously described, the viscosity agents may comprise, for example, CMC, HEC, PAC and/or XG polymer. The viscosity agents may increase the viscosity of the drilling fluid and may thereby enhance cutting removal from the well bore **40**.

[0054] Proceeding to step **212**, the radiused portion **46** and horizontal portion **44** of the well bore **40** are drilled overbalance using the drilling fluid with the fluid loss agents and/or viscosity agents. Step **212** leads to decisional step **214** where during ongoing drilling operations, the No branch leads to decisional step **216**. At decisional step **216**, well bore **40** stability is determined. Well bore **40** stability may be determined based on, for example, the size and/or amount of cuttings being returned to the surface **20** during drilling. Large and/or a large number of cuttings may indicate instability of the well bore **40**.

[0055] If the well bore is not stable, the No branch of decisional step **216** leads to step **218**. At step **218**, density of the drilling fluid may be increased to increase pressure on the walls **49** of the well bore **40** and stabilize the well bore **40**. In one embodiment, care may be taken to avoid increasing drilling fluid density up to or beyond the fracture gradient of the coal seam **30**. Also, at step **220**, additional fluid loss agents may be added to the drilling fluid to enhance the filter cake **100** and reduce loss of drilling fluid into the coal seam **30**. In a particular embodiment, starch may be added to enhance the sealability of the filter cake **100**. In another embodiment, the additional amounts of fluid loss agents (aphrons, micelles, or other fluid loss agents) may be added to enhance the filter cake **100**. Also, at step **221**, the flow rate of the drilling fluid can be adjusted.

[0056] Step **221** leads to decisional step **222**. The Yes branch of decisional step **216** also leads to step **222**. At decisional step **222**, it is determined if cuttings are building up in the well bore **40**. Cutting buildup may be determined by the volume of cuttings recovered at the surface from the drilling fluid. For example, a low volume of cuttings may indicate buildup in the well bore **40**. If cuttings are building up in the well bore **40**, the Yes branch of decisional step **222** leads to step **224**. At step **224**, the density of the drilling fluid may be increased to enhance the ability of the drilling fluid to remove cuttings from the well bore **40**. The density of the drilling fluid may be increased to a specific gravity toward, up to, at, near or above that of the coal cuttings in order to increase buoyancy of cuttings in the drilling fluid and increase cutting removal. As previously described, in one embodiment, care may be taken to avoid reaching the fracture gradient of the coal seam **30** and causing fractures in the seam. Next, at step **226**, additional viscosity agents may be added to enhance cutting removal. At step **227**, the flow of drilling fluid may be adjusted. In one instance, the flow can be increased to increase cuttings removal.

[0057] Step **227** returns to step **212**. The No branch of decisional step **222** also returns to step **212**. At step **212**, drilling of the radiused and/or horizontal portions **46** and **44** of the well bore **40** is continued with adjustments for fluid density, fluid loss, and/or viscosity made as need for well bore stability and cuttings removal of the well bore **40**. Upon completion of the well bore **40**, the Yes branch of decisional step **214** leads to the end of the process.

[0058] **FIG. 7** illustrates another example system **300** of drilling a well bore **40** from the terranean surface **20** to a subterranean zone (coal seam **30**). The example system **300** is similar to the example system **10** described above with respect to **FIGS. 1-6** above, but further includes a surface bore **310** coupled to the terranean surface **20** and a cavity **312**. The surface bore **310** extends from the surface **20**, directly, through an entry bore (not shown), or from a location about the surface to at least partially coincide with the coal seam **30**. In some instances, the surface bore **310** may extend through and/or below the coal seam **30** to define a sump **314**. A casing **316** may be provided through all or part of the surface bore **310**, and in one instance terminates above the cavity **312**.

[0059] The surface bore **310** may be horizontally offset from the first portion **42** of the well bore **40** proximate the coal seam **30** a sufficient distance to permit the curved portion **46** and any desired length of second portion **44** to be drilled before intersecting the cavity **312**. The amount of the offset can be selected so the radius of the curved portion **46** can be large. A large radius of curvature reduces friction in the well bore **40** during drilling operations, and as a result, increases the reach of the drill string (as limited by friction) over well bores drilled with tighter radiuses.

[0060] **FIG. 7** depicts the surface bore **310** extending substantially vertically; however, the surface bore **310** may be formed at any angle relative to the surface **20**. For example, the surface bore **310** may be slanted or include a slanted portion. By slanting the surface bore **310**, the location of the surface bore **310** at the surface **20** can be positioned closer to the location of the first portion **42**, and in some instances can be drilled from the same drilling location, drilling pad, or both bores (bore **310**, bore **42**) can be drilled through a common entry bore. The surface bore **310** may also, or alternatively, be slanted to accommodate surface **20** geometric characteristics or other concerns such as nearby well bores.

[0061] Cavity **312** is formed proximate the coal seam **30**. As used herein, proximate is intended to encompass the case where the cavity **312** is partly or wholly within the coal seam **30**. The cavity **312** can be formed though the surface bore **310**, for example, with an under reamer device, by hydro-jetting, or other cavity forming device. Many cavity forming devices will form a cavity **312** with a substantially cylindrical portion, whereas natural occurring cracks or crevices are not cylindrical. The cavity **312** can be an enlarged cavity having a transverse dimension greater than the transverse dimension of the surface bore **310**. Alternately the cavity **312** can have a transverse dimension equal to or smaller than the transverse dimension of the surface bore **310**. The vertical dimension of the cavity **312**, may be smaller than the vertical thickness of the coal seam **30**, approximately the same as the vertical thickness of the coal seam **30**, or may be larger than the vertical thickness of the coal seam **30**.

[0062] The well bore **40** is drilled similarly to that described above, but the surface bore **310** and the cavity **312** are typically (although not necessarily) formed first. Also, the drilling of well bore **40** is controlled so that the bore intersects the cavity **312**. In certain embodiments, the cavity **312** provides an enlarged target for intersection, and reduces the precision to which drilling well bore **40** must be controlled. After the cavity **312** has been successfully intersected, drilling may continue through the cavity **312** and into the coal seam **30**. As discussed above, drilling fluid or mud is circulated down through the interior of drilling string **50** and up the annulus between drilling string **50** and well bore walls **49** where the drilling fluid is used to remove debris. While drilling the well bore **40**, additional fluids, for example additional drilling fluid with the same or different characteristics and/or amounts and types of weighting agents, fluid loss agents, and/or viscosity agents as that pumped down the drilling string **50**, or other suitable fluids, can be pumped down the surface bore **310** into the annulus between the drilling string **50** and the well bore walls **49**. The additional fluids can be flowed to increase the flow rate in the annulus and aid in removing debris that may otherwise traversing the curved portion **42** and traveling up the first portion **42** to the surface **20**.

[0063] As above, the well bore **40** may be a single bore without laterals, or may include a well bore pattern with a plurality of lateral or other horizontal well bores. If desired, all or part of the well bore pattern can be lined. For example, liners may be provided in the lateral or other horizontal well bores and tied back to casing or liners in the well bore **40**. Where the well bore **40** includes a well bore pattern, the cavity **312** can act as a junction for multiple lined bores. If two or more of the liners communicate with the cavity **312**, production from the bores can centrally collected in the cavity **312** and withdrawn.

[0064] **FIG. 8** illustrates producing the well bore **40** of the system **300**. In certain embodiments, the cavity **312** can be filled with gravel **318** (i.e. gravel packed). The gravel **318** helps support the cavity **312** and also acts to filter coal fragments out of fluid before it enters the surface bore **310**. In some embodiments, gravel that is coarse may be used because, for example, coal fragments breaking off from the coal seam tend to be larger than sands, silts and clays that are typically produced in other formations. In one example, gravel with a mean diameter of between about 20 and about 30 mm is used. Coarse gravel is different from finer gravel (i.e. gravel with a smaller mean diameter) used when producing from a sandy formation. The gravel **318**, typically contained in a slurry, may be introduced through the surface bore **310**, for example, through the interior of a tubing extending into the cavity or in an annulus between a tubing and the wall of the surface bore **310**.

[0065] In certain embodiments, the cavity **312** can be provided with a apertured liner **320** positioned to communicate with the surface bore **310**. The apertured liner **320** can be provided in the cavity **312** prior to gravel packing. Alternatively, the cavity **312** can be gravel packed and the apertured liner **320** provided with a conical or other suitable tip **322** and subsequently driven through the gravel **318** into position in the cavity **312**.

[0066] In this embodiment, the inlet **324** of a pump, such as a sucker rod pump, electric submersible pump, or other type of pump, is installed in the surface bore **310** to withdraw fluids collected in the cavity **312** to the surface **20** through a pump string **326**. The pump inlet **324** can be positioned within the surface bore **310** or within the apertured liner **320** in the cavity **312**. Other artificial lift techniques or the natural flow from the formation can be used in combination with or as an alternative to a pump.

[0067] In operation of the illustrative embodiment, water, debris, and resources, such as gas from the coal seam **30**, flow along the well bore **40**. The water and debris collect and the cavity **312**, and, if provided, also in the sump **314**. The water is removed from the cavity **312** to the surface **20** by the inlet **324** of the pump, or by other artificial lift or natural flow from the formation. Gas may flow through the well bore **40** to the surface **20**, through the surface bore **310** (in the annulus between the pump string **326** and the wall of the surface bore **310**) to the surface **20**, or through both.

[0068] Although the present disclosure has been described with several embodiments, various changes and modifications may be suggested to one skilled in the art. It is intended that the present invention encompasses such changes and modifications as fall within the scope of the appended claims.

What is claimed is:

1. A method for drilling a well bore, comprising:

drilling a substantially horizontal well bore in a normally to sub-normally pressured formation, the normally to sub-normally pressured formation comprising an unconventional reservoir; and

drilling the well bore over-balanced with a drilling fluid comprising a density greater than 9.5 pounds per gallon.

2. The method of claim 1, wherein the drilling fluid comprises a density at or greater than 10 pounds per gallon.

3. The method of claim 1, the drilling fluid comprising a density substantially at that of the cuttings produced by drilling the well bore.

4. The method of claim 3, wherein drilling the substantially horizontal well bore is performed at a rate that is greater than if the drilling fluid had a density substantially less than that of the cuttings produced by drilling the well bore.

5. The method of claim 1, further comprising adjusting at least one of the flow rate and the properties of the drilling fluid based at least in part on a difference between an actual amount of cuttings recovery per unit time and an expected amount of cuttings recovery per unit time.

6. The method of claim 1, wherein the unconventional reservoir comprises a coal bed.

7. The method of claim 1, wherein the unconventional reservoir comprises a shale.

8. The method of claim 1, wherein the unconventional reservoir comprises at least one of naturally occurring fractures and cleats.

9. A system for drilling a well bore, comprising:

a drill bit coupled by a drill string to a rig at a surface, the drill bit operable to drill a horizontal well bore in a normally to sub-normally pressured formation, the normally to sub-normally pressured formation comprising an unconventional reservoir; and

a drilling fluid pumped through the drill string to the drill bit and recirculated to the surface through the well bore, the drilling fluid comprising a density greater than 9.5 pounds per gallon.

10. The system of claim 9, wherein the drilling fluid comprises a density at least **10** pounds per gallon.

11. The system of claim 9, wherein the drilling fluid comprises a density substantially at that of the cuttings produced by drilling the well bore.

12. The system of claim 9, wherein the drilling fluid further comprises a viscosity agent.

13. The system of claim 9, wherein the drilling fluid further comprises at least one of micelles and aphrons.

14. The system of claim 9, wherein the unconventional reservoir comprises a coal seam.

15. The system of claim 9, wherein the unconventional reservoir comprises a shale.

16. The system of claim 9, wherein the unconventional reservoir comprises at least one of naturally occurring fractures and cleats.

17. The system of claim 9, wherein the drilling fluid comprises FLC 2000.

18. The system of claim 17, wherein the drilling fluid further comprises starch.

19. The system of claim 9, wherein the drilling fluid is adapted to form a filter cake to seal the well bore in the normally to sub-normally pressured formation during drilling.

20. A method for drilling a well bore, comprising:

drilling a substantially horizontal well bore in a normally to sub-normally pressured formation, the normally to sub-normally pressured formation comprising an unconventional reservoir; and

drilling the well bore over-balanced with a drilling fluid comprising a density at least about the density of the cuttings produced by drilling the well bore.

21. The method of claim 20, wherein the drilling fluid comprises a density greater than 9.5 pounds per gallon.

22. The method of claim 20, wherein the drilling fluid comprises a density at or greater than 10 pounds per gallon.

23. The method of claim 20, wherein the reservoir comprises a coal seam.

24. The method of claim 20, wherein drilling the substantially horizontal well bore is performed at a rate that is greater than if the drilling fluid had a density substantially less than that of the cuttings produced by drilling the well bore.

25. The method of claim 20, further comprising adjusting at least one of the flow rate and the properties of the drilling fluid based at least in part on a difference between an actual amount of cuttings recovery per unit time and an expected amount of cuttings recovery per unit time.

26. The method of claim 20, wherein the unconventional reservoir comprises at least one of naturally occurring fractures and cleats.

27. The method of claim 20, wherein the drilling fluid comprises FLC 2000.

28. The method of claim 1, wherein the drilling fluid comprises FLC 2000.

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