METHOD AND COMPOSITION FOR CEMENTING A CASING IN A WELLBORE

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Filed: Nov. 16, 2012

Related U.S. Application Data

Provisional application No. 61/561,628, filed on Nov. 18, 2011.

ABSTRACT

Methods and compositions for treating a formation, proximate a wellbore, prior to primary cementing, by reacting an activating agent and a silicate to provide a barrier between the wellbore and the formation to reduce the contamination of cement by ingress of formation fluids or leakage of cement from the wellbore during cement transitional phases. The activating agent may be provided while the wellbore is being drilled or may be provided subsequent to drilling or may be at least partially naturally occurring in the formation prior to drilling. The silicate may be provided during or subsequent to drilling.
FIG. 6

TREATED WITH ACTIVATING AGENT AND SILICATE

DEPTH

200

230

230

220

210

Gamma Ray Attenuation Curves

Interpreted Cement Map

Attenuation Difference Curves
FIG. 7
METHOD AND COMPOSITION FOR CEMENTING A CASING IN A WELLBORE

CROSS REFERENCE TO RELATED APPLICATIONS

[0001] This application claims the benefit of priority of U.S. Provisional Patent Application No. 61/561,628 filed Nov. 18, 2011, which is incorporated herein by reference in its entirety.

FIELD

[0002] The present disclosure relates generally to methods and compositions for cementing. More particularly, the present disclosure relates to methods and compositions for preparing and conducting primary cementing of a tubular, such as casing, in a subterranean formation penetrated by the wellbore.

BACKGROUND

[0003] In oil and gas well operations the primary purpose of cement is to support wellbore casing and to isolate downhole fluids between and within subterranean formations.

[0004] One problem encountered in the prior art is that mixture between drilling fluids, spacer fluids, or formation fluids and cement results in poor cement quality. This includes cement being lost to the formation, leaving voids and channels, and wellbore fluid influx diluting the cement.

[0005] cementing in shallow formations may present special problems. Shallow formations generally have limited cohesion or compressive strength, and often react poorly with the fluids used in drilling and cementing, which further reduce these properties. These shallow cementing challenges result in significant well problems such as gas migration, casing vent flows, and the inability to detect or demonstrate adequate cement quality or zonal isolation.

[0006] Thermal wells exacerbate these conditions described above, and subject the well to additional issues such as HS&E (health, safety, and the environment), wellbore integrity, casing collapse or failure, and fluid migration.

[0007] As used herein, primary cementing operations refer to cementing operations as part of the original drilling of a well, or subsequent drilling operations where new intervals of a well are drilled, such as deepening or sidetracking of an existing well. As used herein, primary cementing operations do not refer to subsequent, remedial workover operations.

[0008] As used herein, the formation “matrix” refers to the portion of a subterranean stratigraphic formation with a structure of supporting rock and interconnected voids (pore spaces, fractures, etc.) through which fluids can move. This matrix has certain porosity and permeability characteristics, which affect the mobility of fluids (water, gas, oil, etc.) to flow within this matrix, and varies by interval within a formation, and varies by well within an area.

[0009] In addition to commonly known primary cementing challenges such as ineffective removal of drilling fluids and drilling fluid filter cake, mechanisms with potential to adversely affect the effectiveness of the cement within the casing and formation annulus include:

[0010] Porous and permeable sands, carbonates, or formation fractures, may be filled with mobile water. This water can flow through the formation matrix (and into the wellbore) as part of regional aquifers, through formation ballooning, or through cross flow to adjacent formations with different pressure regimes, among other water mobilization mechanisms.

[0011] Porous and permeable sands, carbonates, or formation fractures may contain hydrocarbons such as natural gas, condensate, or oil. These hydrocarbons can flow through the formation matrix, (and into the wellbore), through formation ballooning, or through cross flow to adjacent formations with different pressure regimes, among other water mobilization mechanisms.

[0012] As cement transitions from liquid to solid, it loses its thixotropic nature, gradually from being a liquid, exerting hydrostatic pressure, to liquid with suspended solids, to a matrix of suspended solids filled with liquid, and finally to a solid. During the phase when the solids contact each other the cement becomes self supporting. During this transition phase the column of cement is unable to transmit hydrostatic pressure on the formation.

[0013] During this phase of hydrostatic pressure and cement solids transition, the cement fluid is capable of being diluted by water or hydrocarbons or both flowing into the wellbore, being displaced by formation cross flow, and other manners of undesirable fluid interactions.

[0014] Cement contamination due to dilution results in a lower quality cement with reduced compressive strength, which is less effective in providing wellbore integrity and hydraulic isolation between adjacent formations within the wellbore.

[0015] Contamination of the cement with the introduction of gas into the wellbore during this transition phase through liberation of overpressure of a formation (e.g. decrease in pressure) relative to the well annulus pressure may result in gas migrating into the wellbore and gas migration up the annulus, creating such problems as surface casing vent flows, and poor aquifer or bottom water isolation.

[0016] The feeding of cement into low pressure porous or fractured zones can result in the cement moving away from the casing, creating micro-annulus issues adjacent to the casing/tubing. Cement fallback can also result, creating an interval near surface without cement.

[0017] Attempts to resolve these issues have included using improved cement blends, faster setting cement, self-expanding cement, lighter and heavier cement blends, bridging additives, better fluid displacement methods such as high displacement pump rates, hesitation squeezes, casing rotation, open hole packers, application of surface applied annular pressure following cementing operations enhanced casing centralization within the wellbore, larger pre-flush treatments, and a variety of pre-flush and scavenger treatments including scouring sand.

[0018] A relatively effective treatment for hole stability has been found using silicate, either as the primary drilling fluid or as a wash prior to cementing. Shale stability is improved with the reaction of silicate with positive ions on the edge of shale and clay platelets along the formation to wellbore interface. This adhesion to the shale limits the hydration of the shale and/or clay, which creates shale swelling and degradation, leading to tight hole or formation sloughing into the wellbore.

[0019] However, silicate alone has not proven effective to improve the cement quality across certain sand zones, including the Grand Rapids and Clearwater zones of Alberta. Sand zones, notably those sands with water aquifers washing the sands, are effectively inert, having no ionic activity to activate the silicate.
It is, therefore, desirable to provide improved methods and compositions for cementing.

SUMMARY DESCRIPTION

It is an object of the present disclosure to obviate or mitigate at least one disadvantage of previous methods and compositions for cementing a well.

The disclosed methods and compositions relate to primary cementing for oil, gas, or water related wells. For example, primary cementing of casing within a wellbore bored into a subterranean formation for recovery of oil or gas or injection of oil, gas, water related fluids or various enhanced recovery materials. Wells with various other purposes may include evaluation, monitoring and observation wells.

The disclosed methods and compositions may be used for well types known to one skilled in the art, including vertical, directional, or horizontal wells associated with the recovery of oil or gas from subterranean formations. Thermally stimulated wells associated with Cyclic Steam Stimulation (CSS), Toe Heel Air Injection (Thai), or horizontal wells of the type use in steam assisted gravity drainage (SAGD) recovery of bitumen from oil sands formations are of particular interest due to importance of wellbore integrity and subterranean hydraulic isolation.

In the methods and compositions disclosed, the wellbore is treated while drilling or subsequent to drilling, prior to cementing, by reacting an activating agent and a silicate to mitigate the mixture of formation fluids and cement.

In an embodiment disclosed, the activating agent is applied to the wellbore interface, and subsequently the silicate is applied to the wellbore interface. In an embodiment disclosed the silicate is applied to the wellbore interface, and subsequently the activating agent is applied to the wellbore interface. In an embodiment disclosed, the silicate is applied to the wellbore interface to react with activating agent pre-existing in the formation (for example if water in the formation contains activating agent, such as Ca(II)).

In an oilfield downhole application, silicate is activated to precipitate or create a silicate gel by several methods which include a reduction in pH, or with contact with light metal ions (cations) as activating agents. Reduction of pH can be achieved through dilution, or through addition of an acidic fluid. Acids common to oilfield applications include citric acid, hydrochloric acid, sulphamic acid, hydrofluoric acid, organic acids, among others.

In shale zones there is often adequate cations (common examples Ca(II), Mg(II) Na(II), KO(II), or other cations) which react with the silicate (for example, calcium cation Ca(II) reacts with silicate (SiO4)4− to form Ca9SiO4).

Sandstone formations typically do not have an abundance of these cations. In these sands the silicate is only activated if there is sufficient dilution to drop the pH below approximately 11.3, or if the connate water has sufficient cations to activate the silicate.

Dilution of the silicate with formation fluids to reduce the pH of the fluid to precipitate the silicate has not proven effective in affecting the formation properties to mitigate the movement of fluids within these formations.

In the present disclosure, the near wellbore area within the formation(s) of interest is/are flushed or otherwise contacted with cations, introducing an activating agent for silicate. Silicate is then introduced into the wellbore and near wellbore formation matrix (via porosity or fractures both), precipitating or gelling the silicate within this matrix or fracture.

In an embodiment disclosed, calcium, for example Ca(II) has proven effective as an activating agent. In an embodiment disclosed, calcium chloride, calcium nitrate, lime, or slaked lime (calcium hydroxide) are effective sources of the calcium cation.

The process of flushing the near wellbore area within the formations of interest with silicate, followed by the introduction of cations (Ca(II) most commonly used) into the wellbore and near wellbore formation matrix (porosity or fractures), is also effective in precipitating or gelling the silicate (previously introduced in the formation matrix or fractures) within this matrix.

The disclosed methods and compositions provide an improved cement quality by mitigating cement contamination from formation, providing hydraulic isolation, casing support, and wellbore integrity. They are unique in that they address and alter the formation properties to create an improvement in the quality of the cement job, rather than addressing the cement blend or placement techniques.

In methods and formulations disclosed, the process of using sodium silicate or potassium silicate (silicates) with an activating agent (light metal cations, sourced from common oilfield products such as CaCl2, Ca(NO3)2, lime, etc.) to mitigate cement contamination from the fluids found in formations containing adequate porosity, permeability, and fractures which could allow the exchange of wellbore and formation fluids during primary cementing operations of tubular products in wellbore applications.

Water aquifers and other water or hydrocarbon bearing formations with adequate permeability to degrade the quality or effectiveness of the cement are of primary interest. “Tubular products” include casing, tubing, and other means of accessing downhole intervals within a wellbore (typically referred to as casing below). The matrix with characteristics of interest are primarily sandstone reservoirs in the discussed area of interest.

Silicates’ interaction with shales is well known, and silicates are commonly used to stabilize shales in drilling fluids. Shales have sufficient cations to activate the silicates, creating a gelation and precipitation of the silicates on the surface of the shales to create effective inhibition. The most effective silicate gelation and precipitation mechanism is a reaction with light metal cations, such as calcium or magnesium. Silicates are not effective in formations such as sands, limestone, dolomite, or within the fractures of shales, where such cations may be scarce. In the present disclosure, fluids within the formation’s matrix (sand, limestone or dolomite pore space, or fractures) are flushed or otherwise contacted with light metal cations, to allow them to penetrate the matrix as an activating agent, and then followed with either sodium or potassium silicate.

Sources of cationic activating agents include calcium chloride, lime, calcium nitrate, calcium hydroxide, calcium sulfate, or a similar cation source. The silicate forms a precipitate and effectively reduces the formations permeability (locally at or near the interface), mitigating the exchange of formation fluids with the annulus during the primary cementing process.

In an embodiment disclosed, a silicate and an activating agent react within the formation porosity matrix, within formation fractures, or on a formation to wellbore
interface to form a precipitate or gel which reduces the local permeability of the formation, thereby reducing the exchange of fluid between a wellbore and the formation, thereby improving the cementing of the well by mitigating cement contamination within the annulus throughout the primary cementing process.

[0039] Silicate and Activating Agent
[0040] A suitable silicate may include sodium silicate or potassium silicate. A suitable activating agent may include light metal cations, such as Ca²⁺, from CaCl₂, Ca(NO₃)₂, lime etc. Other suitable cations may include Mg²⁺ (magnesium), Na⁺ (sodium), or K⁺ (potassium). In an embodiment disclosed, caustic soda (sodium hydroxide) is a source for Na⁺ cations.

[0041] Reaction
[0042] The reaction between the activating agent and the silicate results in a precipitation or gelation reaction (or both), (for example 2 [Ca]⁺ with [SiO₄]⁴⁻ produces Ca₂SiO₄), locally reducing the formation permeability so that there is a reduction in fluid exchange between formation fluids and cement within the wellbore. Therefore when the cement cures, it provides a better cement quality and more effective cement sheath between the wellbore and the casing, i.e. less contamination of cement by influx of wellbore fluids (water, oil, gas), less escape of cement to the formation, and less displacement of cement by the wellbore fluids during the cement transitional phases.

[0043] Squeeze
[0044] In an embodiment disclosed, the wellbore annulus is pressurized to "squeeze" the silicate or the activating agent or both into the formation matrix to improve the degree of penetration into the matrix and thus a more effective barrier is formed by the precipitate or gel within the formation matrix. In an embodiment disclosed, the squeeze pressure is less than a formation fracture pressure. In an embodiment disclosed, the squeeze may be repeated.

[0045] Remaining Cations
[0046] Any cations, for example Ca²⁺ etc., not consumed by reaction with the silicate act as a cement curing accelerator at the formation to annulus interface, acting to further reduce the cement to wellbore fluid interaction at the formulation to annulus interface, by accelerating the curing of the cement at that interface, further reducing the cement contamination within the annulus.

[0047] Quality of Primary Cementing
[0048] A quality primary cementing operation provides a hydraulic seal in the wellbore annulus, along (for example) the casing providing hydraulic isolation between subterranean formations. In addition, quality cementing provides corrosion protection of the casing. In addition, quality cementing provides reduced casing movement (for example) during thermal cycles (expansion and contraction) reducing potential for casing collapse, separation, and/or failure due to related thermal stresses. In addition, quality cementing provides casing support and wellbore integrity. In addition, quality cementing reduces the ability of gas and/or hydrocarbons to enter the wellbore and therefore reduces the potential for gas migration within the cement column. Further, as gas migration is a common cause of surface casing vent flows, quality cementing reduces the occurrence of surface casing vent flows. In addition, quality cementing reduces the occurrence of channeling and communication between different formations or intervals within a formation. In addition, quality cementing provides the ability to assess and confirm (for example by cement bond log interpretation) to determine the cement quality, ability to provide hydraulic isolation between formations, and to provide wellbore integrity supporting the casing.

[0049] In a first aspect, the present disclosure provides a method of primary cementing of a casing in a wellbore drilled in a formation including treating the formation, proximate the wellbore, with an activating agent, and treating the formation, proximate the wellbore, with a silicate, prior to the primary cementing of the casing in the wellbore.

[0050] In an embodiment disclosed, a reaction between the activating agent and the silicate forms a gel or precipitate substantially within the formation. In an embodiment disclosed, the gel or precipitate forms a region of reduced permeability within the formation, proximate the wellbore.

[0051] In an embodiment disclosed, the pressure in the wellbore is increased by a squeeze pressure, to squeeze at least a portion of the activating agent or the silicate or both into the formation. In an embodiment disclosed, the squeeze pressure is less than a formation fracture pressure.

[0052] In an embodiment disclosed, the squeeze pressure is held for a squeeze time. In an embodiment disclosed, the squeeze time is between 1 min. and 30 min. In an embodiment disclosed, the squeeze time is between 5 min. and 20 min.

[0053] In an embodiment disclosed, the activating agent is provided in a drilling fluid during drilling of the wellbore.

[0054] In an embodiment disclosed, the method is performed after the wellbore has been drilled to a selected total depth (TD), the wellbore cleaned, and the casing ran into the wellbore.

[0055] In an embodiment disclosed, an annulus is formed in the wellbore between the casing and the formation, wherein the pressure of the annulus is increased by a squeeze pressure, to squeeze at least a portion of the silicate or the activating agent or both into the formation. In an embodiment disclosed, the squeeze pressure is less than a formation fracture pressure.

[0056] In an embodiment disclosed, the squeeze pressure is held for a squeeze time. In an embodiment disclosed, the squeeze time is between 1 min. and 30 min. In an embodiment disclosed, the squeeze time is between 5 min. and 20 min.

[0057] In an embodiment disclosed, the activating agent comprising one or more light metal cations. In an embodiment disclosed, the light metal cations are selected from the group consisting of Ca²⁺, Mg²⁺, Na⁺, and K⁺. In an embodiment disclosed, the activating agent includes Ca²⁺ ions. In an embodiment disclosed, an activating agent concentration of the Ca²⁺ ions is between 500 mg/L and 50,000 mg/L. In an embodiment disclosed, the activating agent concentration is between 2,000 mg/L and 50,000 mg/L. In an embodiment disclosed, the activating agent concentration is between 20,000 mg/L and 40,000 mg/L. In an embodiment disclosed, the volume of activating agent solution is between 2 m³ and 40 m³.

[0058] In an embodiment disclosed, the activating agent contacts the formation for a contact time. In an embodiment disclosed, the contact time is between 1 min. and 30 min. In an embodiment disclosed, the contact time is between 5 min. and 20 min.

[0059] In an embodiment disclosed, a silicate concentration is between 4 percent and 50 percent. In an embodiment disclosed, the silicate concentration is between 5 percent and 30 percent. In an embodiment disclosed, the volume of silicate solution is between 2 m³ and 40 m³.
In an embodiment disclosed, the silicate contacts the formation for a contact time. In an embodiment disclosed, the contact time is between 1 min. and 30 min. In an embodiment disclosed, the contact time is between 5 min. and 20 min.

In an embodiment disclosed, the formation is treated with a further activating agent or a further silicate or both. For example, if a silicate is provided and then an activating agent is provided, then a further treatment of silicate is provided. If an activating agent is provided and then a silicate, then a further treatment of activating agent is provided.

In an embodiment disclosed, the method includes monitoring returns in order to estimate the placement of the activating agent or the silicate or both in the formation.

In a further aspect, the present disclose provides a method of primary cementing of a casing in a wellbore, including drilling the wellbore in a subterranean formation, providing a casing in the wellbore, providing a first fluid spacer into an annulus between the casing and the formation, providing an activating agent into the formation, providing a second fluid spacer into the annulus, providing a silicate into the formation, providing a third fluid spacer into the annulus, and conducting the primary cementing of the casing in the wellbore.

In a further aspect, the present disclosure provides a method of primary cementing of a casing in a wellbore, including providing a drill bit on a drill-string for drilling a wellbore in a subterranean formation, drilling the wellbore in the formation, passing above a zone of interest, drilling the wellbore through the zone of interest with a drilling fluid laden with activating agent and passing drilling shortly thereafter, providing a first fluid spacer into an annulus between the drill-string and the formation, providing a silicate into the formation, providing a second fluid spacer into the annulus, continuing drilling the wellbore, installing the casing, and conducting the primary cementing of the casing.

Other aspects and features of the present disclosure will become apparent to those ordinarily skilled in the art upon review of the following description of specific embodiments in conjunction with the accompanying figures.

BRIEF DESCRIPTION OF THE DRAWINGS

Embodiments of the present disclosure will now be described, by way of example only, with reference to the attached Figures.

FIG. 1 is a simplified depiction of a drilling operation to provide a wellbore within a subterranean formation;

FIG. 2 is a typical plot of downhole annulus pressure versus time before, during, and after primary cementing operations;

FIG. 3 is a cross-section of a wellbore depicting a formation and a casing within the wellbore;

FIG. 4 is an example of an Alberta SAGD well cement evaluation log (segmented bond tool (SBT) cement bond log (CBL)) subsequent to primary cementing not pre-treated with silicate or activating agent;

FIG. 5 is an example of an Alberta SAGD well cement evaluation log segmented bond tool (SBT) cement bond log (CBL) subsequent to primary cementing pre-treated with silicate (without activating agent);

FIG. 6 is an example of an Alberta SAGD well cement evaluation log (segmented bond tool (SBT) cement bond log (CBL)) subsequent to primary cementing pre-treated with silicate and with activating agent;

FIG. 7 is an example of an Alberta SAGD well cement evaluation log (segmented bond tool (SBT) cement bond log (CBL)) subsequent to primary cementing pre-treated with activating agent, followed by silicate treatment during drilling operations;

FIG. 8 is a simplified depiction of a SAGID horizontal well schematic with one example of well design and subterranean formation strata depicted;

FIG. 9 is a simplified depiction of a variety of well configurations for wellbores within a subterranean formation associated with Alberta SAGD oil and gas operations; and

FIG. 10 is an example of a particular cement blend and its compressive strength characteristics versus time at various cement blend densities.

DETAILED DESCRIPTION

Generally, the present disclosure provides a method and composition for cementing a well.

The disclosed method improves the cement quality and effectiveness by altering the characteristics and properties of the formation matrix adjacent to the wellbore. In one embodiment disclosed, the method may be used in cementing of a tubular (casing, tubing, etc.) in a wellbore within the annulus between the tubular and the formation as part of a primary well cementing processes.

Oil and Gas Well Drilling

Referring to FIG. 1, typical drilling operations involve rotating a drill bit 10 on a drill-string 20 by a drilling rig 30 to cut through the formation matrix 160 (see FIG. 3) (rock, shale, sand etc.) of the formation 40 to create a wellbore 50. As an example, the wellbore 50 is cut through several formations 40, 40A, 40B, 40C, 40D, 40E, 40F, 40G, and 40H. Drilling fluid 60 is circulated down the drill-string 20 across a cutting face of the drill bit 10 and drilling fluid and drill cuttings 70 circulate back up an annulus 80 in the wellbore 50 between the drill-string 20 and the formation 40-40H, to surface 90 for processing and re-use in the drilling fluid 60.

Once the wellbore 50 has been drilled to a selected target depth (TD), the drill-string 20 and drill bit 10 are removed from the wellbore 50, the wellbore 50 cleaned and conditioned and a tubular, such as a casing 110 (see FIGS. 3 and 8) is run into the wellbore 50 and cemented in place. Cementing the casing 110 in place typically involves pumping cement 100 as a slurry down the casing 110 and out a bottom end of the casing 110 at a casing shoe 120, and into the wellbore 50 up an annulus 165 in the wellbore 50 between the formation 40-40H and the casing 110. When the cement 100 sets, the casing 110 is secured in place within the wellbore 50.

FIG. 1 also shows a surface casing 130 having a surface casing shoe 140 cemented in the wellbore 50 with surface casing cement 150.

As is known to a person skilled in the art, the casing 110 may be monobore casing or several stages or sizes may be used along the wellbore 50, as the wellbore 50 is drilled. The methods and compositions of the present disclosure apply regardless.

FIG. 2, an example graph of the downhole pressure and downhole temperature within the annulus 165, in a vertical well, at an example depth within the formation 40-40H, shows the variance during the transitional phases of the cement 100. As the cement 100 transitions from liquid to solid, it loses its thixotropic nature, graduating from being a liquid, exerting hydrostatic pressure, to liquid with suspended solids, to a matrix of suspended solids filled with liquid, to...
finally a solid. The cement becomes self-supporting during the phase when the solids contact each other. During this transition phase the hydrostatic pressure of the column of the cement is relieved. Circulating pressures, followed by the cement placement pressures are shown. Subsequent to cementing operations, the cement hydrostatic pressure is observed, and a reduction in downhole pressure over time is demonstrated as the cement enters the transitional phases. In the example shown in FIG. 2, McMurray formation sensors at the depths indicated, the pressure falls to the static reservoir pressure over time.

During this phase of hydrostatic pressure and cement solids transition, the cement slurry is capable of feeding into low pressure zones of the formation along the wellbore, being diluted by water or hydrocarbons or both flowing into the wellbore from the formation, being displaced by formation fluid cross flow, and other manners of undesirable interactions between the fluids (formation fluids and cement slurry).

In the method and compositions of the present disclosure, wellbore fluid exchange such as washing away of the cement, dilution of the cement, formation fluid cross flow, dehydration of the cement, and other problems which may occur during the transition phase of the cement during primary cementing operations are reduced, improving the quality and effectiveness of the cement.

Referring to FIGS. 1, 3, and 8 the disclosed methods and compositions include the use of silicates precipitated or gelled or both within the formation matrix along an interface between the wellbore and the formation (one or more of the reduction of a region of the formation matrix to provide a region of reduced permeability thus reducing the exchange of fluids between the formation and the wellbore during the cementing process.

The use of a cationic activating agent enhances the effectiveness of the disclosed methods and compositions where fluids within the formation matrix do not have adequate silicate activation agents to create an effective gelation or precipitation process or both within the pore spaces or fractures of the formation matrix. The reaction between an activating agent and a silicate creates the region of reduced permeability, forming a barrier at the interface between the formation and the wellbore. The barrier impedes the inflow/influx of formation fluids into the wellbore or the outflow/eflux of cement or both, contributing to an improvement in the quality or integrity of the primary cementing.

The disclosed methods and composition is also effective if the formation is a porous formation, and is flushed with a silicate such as sodium or potassium silicate, the silicate allowed to penetrate the formation matrix to a matrix penetration region, which is then followed with a cationic activating agent which includes calcium chloride, lime, sodium chloride, or some similar cation source. The silicate forms a gel or precipitate or both and effectively reduces the permeability of the formation matrix to provide the region of reduced permeability or barrier or both, mitigating the exchange of formation fluids during the cementing process. As with the methods and compositions outlined above, the exchange of fluid between the wellbore and the formation, detrimental to the effectiveness of the cement, is mitigated.

Silicate

In an embodiment disclosed, potassium silicate (one of the most readily available and widely used of the silicate families) may be used. In an embodiment disclosed, sodium silicate (similarly effective) may be used.

In an embodiment disclosed, silicate concentrations of between 4% and 50% may be effective, depending on the formation porosity and permeability characteristics. In an embodiment disclosed, silicate concentrations of between 8% and 30% may be used. Concentrations have varied based on silicate consumption during the formation treatment process, and the surface mixing procedures and limitations, and the particular application procedure used.

Cation

In an embodiment disclosed, cation concentrations (calcium is most commonly used) of 500 mg/L to 50,000 mg/L may be effective, depending on the formation water properties, porosity and permeability characteristics. In an embodiment disclosed, calcium concentrations between 2,000 mg/L and 50,000 mg/L may be used. In an embodiment disclosed, calcium concentrations between 20,000 mg/L and 40,000 mg/L may be used. Concentrations used have varied based on calcium consumption during the formation treatment process, surface mixing procedures and limitations, and the particular application procedure used.

Referring to FIGS. 1 and 3, in embodiments of the present disclosure the activating agent or the silicate may be applied in a variety of manners and in a variety of sequences.

Treating After Drilling—Casing in Place

In an embodiment disclosed, the formation may be treated with the casing in place, subsequent to a drilling operation.

In an embodiment disclosed, the characteristics and properties of the formation matrix adjacent to the wellbore are altered before drilling the wellbore and running the casing. This method may use a single drilling fluid system to drill the intermediate interval of the well, or with the drilling fluid system historically in use in the application. The following treatment may be used once the entire interval of the wellbore is drilled to the interval total depth, followed by conditioning of the wellbore and running the casing into the wellbore.

That is, the wellbore may be drilled, conditioned, and casing run in conventionally, and the wellbore treated using methods and compositions of the present disclosure, before primary cementing.

A fluid spacer may be pumped into the annulus to separate the drilling fluid from a cationic treatment “pill”. The volume and displacement rate of the fluid spacer is dependent on the quality of the wellbore (bit gauge versus washouts, wellbore tortuosity), wellbore to casing annular volumes, type of drilling fluid used, and formation matrix porosity and permeability characteristics. In an embodiment disclosed, the fluid spacer may be water, viscousified water, drilling mud or combinations thereof.

Fluid spacer volumes of between about 2 m³ and 15 m³ may be required for adequate separation and displacement of the drilling fluid. Displacement rates with the fluid spacer in turbulent flow are most effective, but are often impractical and can be detrimental to the subsequent fluid placement. Displacement rates of about 0.5 m³/min and about 5 m³/min may be used, but displacement rates of between about 0.8 m³/min and about 2.4 m³/min are more typical.
[0103] Scouring Sand

[0104] A 0.5% to 4% (1% typical) scouring sand may be included in the fluid spacer to facilitate removal of drilling fluid filter cake. Depending on mixing, suspension characteristics, and pumping equipment available, a viscosifying polymer may be required to suspend the scouring sand in the fluid spacer during mixing and displacement.

[0105] Activating Agent

[0106] A fluid "pill" is then pumped containing a cationic activating agent. The volume and displacement rate of the cationic activating agent pill (calcium is most commonly used) is also dependent on the quality of the wellbore 50 (gauge versus washouts, tortuosity), wellbore to casing annular volumes, type of drilling fluid used, formation thickness, and formation matrix porosity and permeability characteristics.

[0107] Activating agent volumes of between about 2 m³ and about 40 m³ may be required for adequate coverage and treatment of the formations 40-401 targeted for treatment. Displacement rates with the solution in turbulent flow are most effective, but are often impractical and can be detrimental to the subsequent fluid placement. Rates of between about 0.2 m³/min and about 5 m³/min may be used, but displacement rates of between about 0.8 m³/min and 2.4 m³/min are more typical. Formation exposure time required will vary with porosity/permeability, differential pressure (overbalance), and the effectiveness of drilling fluid filter cake removal. In an embodiment disclosed, the activating agent is delivered at a displacement rate and total volume to provide a formation contact time of between 1 min. and 30 min. In an embodiment disclosed, the formation contact time is between 5 min. and 20 min. In an embodiment disclosed, the formation contact time is about 10 min.

[0108] Squeeze

[0109] In an embodiment disclosed, the most successful applications of the cationic activating agent may use a squeeze technique, where the activating agent fluid is pumped to a position adjacent to the formation 40-401 targeted, displacement is stopped, and a soaking and flushing period is commenced.

[0110] The near wellbore matrix flushing may be accelerated with pressure applied to the annulus. A diverter or blow out preventer (BOP) for the wellbore 50 is closed, and pressure applied to the annulus 165 between the casing 110 and the formation 40-401 within the wellbore 50. The pressure may be preselected to be sufficient to initiate or propagate penetration of the fluid into the formation matrix 160 into the matrix penetration region 175, but not so great as to induce or propagate fracture of the formation matrix 160. In an embodiment disclosed, a pressure less than a formation fracture pressure is used.

[0111] Squeeze volumes are designed to penetrate the formation matrix 160 based on the thickness of the formation 40-401, porosity or the formation 40-401, and potential differential pressure between formations (pressure regimes) and pressure regimes during cement transitional phases. Penetration of between about 2 mm and 20 cm may be obtained to create sufficient gel or precipitate or both to mitigate fluid flow or fluid transfer to the wellbore 50 or both, depending on pressure regimes during the desired cementing process. Current processes in wells of 500 m depth or less limit squeeze volumes over stratigraphic zones of interest or target zones of interest to approximately 10 m³, representing matrix penetration depths of approximately 6-8 cm (i.e. the matrix penetration region 175). In an embodiment disclosed, the squeeze is conducted for about 10 minutes. In an embodiment disclosed, the squeeze is repeated one or more times.

[0112] Fluid Spacer

[0113] A second fluid spacer is pumped out the casing shoe into the casing annulus to follow the activating agent to separate the activating agent fluid "pill" from the silicate fluids to follow. The volume and displacement rate of the fluid spacer is dependent on the quality of the wellbore 50 (bit gauge versus washouts, tortuosity), wellbore to casing annular volumes, and formation matrix porosity and permeability characteristics. Alternate means of placement into the formation 40-401 to annulus 80 include methods such as top down displacement.

[0114] Volumes of between about 2 m³ and about 15 m³ may be required for adequate separation and drilling fluid displacement. Displacement rates with the fluid in turbulent flow are most effective, but are often impractical and can be detrimental to the subsequent fluid placement. Rates of about 0.5 m³/min and about 5 m³/min may be used, but displacement rates of between about 0.8 m³/min and about 2.4 m³/min are more typical for commonly used well configurations. In an embodiment disclosed, the fluid spacer may be water, viscosified water, drilling mud or combinations thereof.

[0115] Silicate

[0116] A silicate solution (described above) is then displaced into the wellbore annulus. The volume and displacement rate of the silicate solution is also dependent on the quality of the wellbore 50 (drilled gauge versus washouts, tortuosity), wellbore to casing annular volumes, type of drilling fluid used, formation thickness, and formation matrix porosity/permeability characteristics.

[0117] Volumes of between about 2 m³ and about 40 m³ may be required for adequate coverage and treatment of the formation matrix targeted for treatment. Displacement rates with the solution in turbulent flow are most effective, but are often impractical and can be detrimental to the subsequent fluid placement. Rates of between about 0.5 m³/min and about 5 m³/min may be used, but displacement rates of between about 0.8 m³/min and about 2.4 m³/min are more typical. Formation exposure time required will vary with matrix porosity/permeability, differential pressure (overbalance), and the effectiveness of drilling fluid filter cake removal. In an embodiment disclosed, the silicate is delivered at a displacement rate and total volume to provide a formation contact time of between 1 min. and 30 min. In an embodiment disclosed, the formation contact time is between 5 min. and 20 min. In an embodiment disclosed, the formation contact time is about 10 min.

[0118] Squeeze

[0119] The most successful applications of the silicates have used a squeeze technique, where the fluid is pumped to a position adjacent to the targeted formation, displacement is stopped, and a soaking and flushing period is initiated. The near wellbore matrix flushing is accelerated with pressure applied to the annulus. The diverter or BOP is closed, and pressure applied to the wellbore to casing annulus.

[0120] Squeeze volumes are designed to penetrate the formation matrix 160 based on formation thickness, formation matrix porosity, and potential differential pressure between formations (pressure regimes) and pressure regimes during cement transitional phases. Penetration depths of between about 2 mm and about 20 cm may be required to create
sufficient gel or precipitate or both to mitigate fluid flow or fluid transfer or both into the wellbore 50, depending on pressure regimes during the described cementing process. Current processes limit squeeze volumes to about 10 m³, representing matrix penetration depths of approximately 6-8 cm over lithological zones of interest (an interval of approximately 500 mMD). Pressures of about 400 kPa and higher may be used, sufficient for the fluid to penetrate into the formation matrix, but below pressures that may induce fracture of the formation 40-40H.

0121] Multiple squeezes may be conducted to enhance the treatment of the formation matrix 160 prior to cementing. The most successful cementing operations have included a continuous silicate circulation, displacing the entire annulus to silicate. Exposure times in excess of 2 hours have proven most successful in the wellbore preparation, although this exposure time will vary with formation pressure (versus hydrostatic overbalance and ECD’s), formation pressure regimes, formation matrix porosity and permeability, and cement thickening times. Silicate concentrations are monitored during circulation, and additions of higher concentration silicate are added to maintain desired silicate levels within the formation to casing annulus.

0122] Fluid Spacer

0123] A third fluid spacer is pumped out the casing shoe into the casing annulus to separate the silicate agent fluid “pill” from the primary cementing operation to follow. The volume and displacement rate of the fluid spacer are dependent on hole quality (bit gauge versus washouts, tortuosity), wellbore to casing annular volumes, and formation matrix porosity/permeability characteristics. Alternate means of placement into the formation to casing annulus includes methods such as top down displacement.

0124] Volumes of between about 2 m³ and about 15 m³ may be required for adequate separation and drilling fluid displacement. Displacement rates with the fluid in turbulent flow are most effective, but are often impractical and can be detrimental to the subsequent fluid placement. Rates of between about 0.5 m³/min and about 5 m³/min may be used, but displacement rates of between 0.8 m³/min and 2.4 m³/min are more typical. In an embodiment disclosed, the fluid spacer may be water, viscosified water, drilling mud or combinations thereof.

0125] Primary Cementing

0126] The cementing operations are then commenced. The cementing sequence and blends will vary by region, temperature gradients, and numerous other cementing best practices considerations. Best cementing practices include, but are not limited to, scavenger cement blends of increasing density to ultimate cement density over incremental scavenger volumes and displacement rates. Casing movement including recirculation and or rotation is recommended as part of cementing best practices.

0127] Treating While Drilling—Activating Agent and Subsequent Silicate

0128] In an embodiment disclosed, the formation may be treated during drilling.

0129] In an embodiment disclosed, the activating agent is introduced during the drilling operations, and alters the characteristics and properties of the formation matrix 160 adjacent to the wellbore once an interval of interest has been drilled (prior to drilling the wellbore 50 to interval total depth).

0130] In this case, a second drilling fluid system can be used to drill formations containing the hydrocarbons or where a fluid system laden with activating agent is less appropriate.

0131] In this scenario, described below, the wellbore is drilled conventionally prior to reaching an interval of interest or target formation. The intervals of interest are drilled with a drilling fluid laden with an activating agent. The drilling fluid is high in concentrations of cations sufficient to activate the subsequent silicate treatment and mitigate fluid transfer between formation and annulus during the primary cementing process.

0132] Drilling Fluid with Activating Agent

0133] Typical drilling fluids, common to drilling practices, including calcium based “floc water” fluid systems, may be appropriate. However, standard “floc water” system typically contain calcium concentrations of between about 300 and about 1000 mg/L. Calcium concentrations significantly higher than these “standard” concentrations may be used to activate subsequent silicate treatments relative to the activation of the silicate to prevent wellbore fluid interaction during primary cementing. In an embodiment disclosed, cationic concentrations of between about 500 mg/L and about 50,000 mg/L may be used to activate the silicate to sufficient levels to create an effective barrier 190 as described herein.

0134] In an embodiment disclosed, current practices of “floc water” calcium content of between about 2,000 mg/L and about 3,000 mg/L from sources including lime and calcium nitrate may be used to provide an effective region of reduced permeability 180 or gel/precipitate silicate cation barrier 190 within the formation matrix 160 to facilitate an effective cement job as described above.

0135] Fluid Spacer

0136] Following drilling of the formation interval of interest with the drilling fluid laden with activating agent, a fluid spacer is pumped out the casing shoe and into the wellbore to separate the activating agent and the drilling fluid, for example floc water drilling system, from the silicate fluids to follow. The volume and displacement rate of the fluid spacer is dependent on quality of the wellbore 50 (bit gauge versus washouts, tortuosity), wellbore to casing annular volumes, and formation porosity/permeability characteristics. Alternate means of placement into the formation to casing annulus includes methods such as top down displacement.

0137] Volumes of between about 2 m³ and about 15 m³ may be required for adequate separation and drilling fluid displacement. Displacement rates with the fluid in turbulent flow are most effective, but are often impractical and can be detrimental to the subsequent fluid placement. Rates of between about 0.5 m³/min and about 5 m³/min may be used, but displacement rates of between 0.8 m³/min and 2.4 m³/min are more typical. Current application specific practices use about a 10 m³ spacer with displacement rates consistent with drilling pump rates. In an embodiment disclosed, the fluid spacer may be water, viscosified water, drilling mud or combinations thereof.

0138] Silicate

0139] A silicate solution (described above) is then pumped out the casing shoe and into the wellbore 50. The volume and displacement rate of the silicate solution is also dependent on hole quality (drilled gauge versus washouts, tortuosity), wellbore to casing annular volumes, type of drilling fluid used, formation thickness, and porosity/permeability characteristics of the formation matrix 160. Alternate means of place-
ment into the formation to casing annulus includes methods such as top down displacement.  

Volumes of between about 2 m$^3$ and about 40 m$^3$ may be required for adequate coverage and treatment of the formation matrix targeted for treatment. Displacement rates with the solution in turbulent flow are most effective, but are often impractical and can be detrimental to the subsequent fluid placement. Rates of about 0.2 m$^3$/min and about 5 m$^3$/min may be used, but displacement rates of between about 0.8 m$^3$/min and about 2.4 m$^3$/min are more typical. Formation exposure time required will vary with matrix porosity/permeability, differential pressure (overbalance), and the effectiveness of drilling fluid filter cake removal.

Squeeze

The most successful applications of the silicates have included the use of a squeeze technique, where the fluid is pumped to a position adjacent to the targeted formation, displacement is stopped, and a soaking and flushing period is initiated. The near wellbore matrix flushing is accelerated with pressure applied to the annulus. The diverter or BOP is closed, and pressure applied to the wellbore to casing annulus. Squeeze volumes are designed to penetrate the formation matrix based on formation thickness, formation matrix porosity, and potential differential pressure between formations (pressure regimes) and pressure regimes during cement transitional phases.

Matrix penetration depths of between about 2 mm and about 20 cm may be required to create sufficient gel and/or precipitate to mitigate fluid flow and/or fluid transfer to the wellbore, depending on pressure regimes during the described cementing process. Current processes in these wells with zones of interest less than about 500 m limit squeeze volumes over stratigraphic zones of interest to approximately 10 m$^3$, representing matrix penetration depths of approximately 6-8 cm. Pressures of 400 KPa and higher are used, sufficient to initiate penetration of the fluid into the formation matrix, but below pressures that may induce fracture of the formation.

Multiple squeezes may be conducted to enhance the treatment of the formation matrix prior to cementing. The most successful cementing operations have included a continuous silicate circulation, displacing the entire annulus to silicate. Successive exposure periods of 10 minutes each, over 1 to 3 squeezes have proven most successful in the matrix preparation, although this exposure time will vary with formation pressure (versus hydrostatic overbalance and equivalent circulating densities, formation pressure regimes, formation matrix porosity/permeability, and cement thickening times. Silicate concentrations are monitored during silicate fluid returns, with adjustments to displacement and squeeze volumes, concentrations, and silicate additions based on observed results from historical and/or offset results.

Fluid Spacer

A second fluid spacer is pumped into the drilling assembly/open hole annulus to separate the silicate "pill" from the subsequent drilling fluid used to drill the wellbore 50 to total depth. The volume and displacement rate of the fluid spacer is dependent on the quality of the wellbore 50 (bit gauge versus washouts, tortuosity), wellbore to casing annular volumes, and formation matrix porosity and permeability characteristics.

Volumes of between about 2 m$^3$ and about 15 m$^3$ may be required for adequate separation and drilling fluid displacement. Displacement rates with the fluid in turbulent flow are most effective, but are often impractical and can be detrimental to the subsequent fluid placement. Rates of between about 0.5 m$^3$/min and about 5 m$^3$/min may be used, but displacement rates of between about 0.8 m$^3$/min and about 2.4 m$^3$/min are more typical. In an embodiment disclosed, the fluid spacer may be water, viscosified water, drilling mud or combinations thereof.

Drilling Continued to Total Depth

The wellbore 50 is then drilled to total depth of the interval using the drilling fluid system of choice. Following circulating and conditioning the hole, the casing 110 is run and cemented per best cementing practices for the drilling area and application. In this process, the exchange of wellbore fluids as described above are mitigated by the introduction of the activating agent and the silicate into the formation matrix, thereby altering the formation permeability characteristics near the wellbore prior to the casing and cementing operations.

Treating While Drilling—Activating Agent and Subsequent Activating Agent and Silicate

In an embodiment disclosed, the method is a combination of the two processes described above. In an embodiment disclosed, activating agent is introduced during the drilling operations, and the characteristics and properties of the formation matrix adjacent to the wellbore 50 are altered after drilling the wellbore 50 and running the casing 110.

Additional activating agent followed by the silicate treatment are conducted, altering the characteristics and properties of the formation matrix 160 adjacent to the wellbore 50 once casing 110 is run at the end of the wellbore 50 interval. In this case, a second drilling fluid system may be used while drilling formations containing the hydrocarbons or where a fluid system laden with activating agent is less appropriate.

Drilling Fluid with Activating Agent

In this embodiment, the intervals of interest are drilled with a drilling fluid 60 laden with activating agent. The drilling fluid 60 is high in concentrations of cations sufficient to activate the subsequent silicate treatment and mitigate fluid transfer between the formation matrix 160 and the annulus 165 during the primary cementing process.

Typical drilling fluids, common to drilling practices may be appropriate, including calcium based "floc water" fluid systems. However, standard "floc water" systems typically contain calcium concentrations of between about 300 mg/L and about 1000 mg/L. Calcium concentrations significantly higher than these "standard" concentrations may be required to activate subsequent silicate treatments relative to the activation of the silicate to prevent wellbore fluid interaction during primary cementing. Cationic concentrations of between about 500 mg/L and about 50,000 mg/L may be required to activate the silicate to required levels to create an effective cement job as described above.

Current practices of "floc water" calcium content of between about 2,000 mg/L and about 3,000 mg/L from sources including lime and Calcium nitrate have proven effective in providing an effective cement job as described above.

 Fluid Spacer

Following drilling of the formation interval of interest, a fluid spacer is pumped into the casing annulus to separate the "floc water" drilling system from the subsequent drilling fluids to follow. The fluid spacer is recommended as
the high cationic content of the “floc water” system may be detrimental to the fluids properties of the drilling fluids to follow. In an embodiment disclosed, the fluid spacer may be water, viscosified water, drilling mud or combinations thereof.

[0159] Drilling Continued

[0160] The remainder of the wellbore 50 interval is drilled to the interval total depth, at which point the wellbore 50 is conditioned and the casing 110 is run.

[0161] Fluid Spacer

[0162] A fluid spacer is pumped into the casing annulus to separate the drilling fluid 60 from the cationic treatment “pill.” The volume and displacement rate of the fluid spacer is dependant on hole quality (bit gauge versus hole washouts, wellbore tortuosity), wellbore to casing annular volumes, type of drilling fluid used, and formation porosity/permeability characteristics.

[0163] Fluid spacer volumes of between about 2 m³ and about 15 m³ may be required for adequate separation and drilling fluid displacement. Displacement rates with the fluid in turbulent flow are most effective, but are often impractical and can be detrimental to the subsequent fluid placement. Rates of between about 0.5 m³/min and about 5 m³/min may be used, but displacement rates of between about 0.8 m³/min and about 2.4 m³/min are more typical. In an embodiment disclosed, the fluid spacer may be water, viscosified water, drilling mud or combinations thereof.

[0164] Scouring Sand

[0165] In an embodiment disclosed, scouring sand of between about 0.5% and about 4% (1% typical) may be included in the fluid spacer to facilitate removal of drilling fluid filter cake. Depending on mixing, suspension characteristics, and pumping equipment available, a viscosifying polymer may be required to suspend the scouring sand in the fluid spacer during mixing and displacement.

[0166] Activating Agent

[0167] A fluid “pill” is then pumped containing the cationic activating agent. The volume and displacement rate of the cationic activating agent pill (calcium most commonly used) is also dependant on the quality of the hold (bit gauge versus washouts, tortuosity), wellbore to casing annular volumes, type of drilling fluid used, formation thickness, and formation matrix porosity/permeability characteristics.

[0168] Volumes of between about 2 m³ and about 40 m³ may be required for adequate coverage and treatment of the formation matrix targeted for treatment. Displacement rates with the solution in turbulent flow are most effective, but are often impractical and can be detrimental to the subsequent fluid placement. Rates of between about 0.5 m³/min and about 5 m³/min may be used, but displacement rates of between about 0.8 m³/min and about 2.4 m³/min are more typical. Formation exposure time required will vary with matrix porosity/permeability, differential pressure (overbalance), and the effectiveness of drilling fluid filter cake removal.

[0169] Squeeze

[0170] The most successful applications of the cationic activating agent have utilized a squeeze technique, where the fluid is pumped to a position adjacent to the targeted formation, displacement is stopped, and a soaking and matrix flushing period is initiated. The near wellbore matrix flushing is accelerated with pressure applied to the annulus. The diverter or BOP is closed, and pressure applied to the wellbore to casing annulus. Pressures of 400 kPa and higher are used, sufficient to initiate penetration of the fluid into the formation matrix, but below pressures that may induce formation fracture. Squeeze volumes are designed to penetrate the formation matrix based on formation thickness, formation matrix porosity, and potential differential pressure between formations (pressure regimes) and pressure regimes during cement transitional phases. Matrix penetration depths of between about 2 mm and about 20 cm may be required to create sufficient gel and/or precipitate to mitigate fluid flow and/or fluid transfer to the wellbore, depending on pressure regimes during the described cementing process. Current processes in these wells with zones of interest less than 500 m limit squeeze volumes over lithological zones of interest to approximately 10 m³, representing matrix penetration depths of approximately 6-8 cm.

[0171] Fluid Spacer

[0172] A fluid spacer is pumped into the casing annulus to separate the activating agent fluid “pill” from the silicate fluids to follow. The volume and displacement rate of the fluid spacer is dependant on the quality of the wellbore 50 (bit gauge versus washouts, tortuosity), wellbore to casing annular volumes, and formation matrix porosity/permeability characteristics. Volumes of between about 2 m³ and about 15 m³ may be required for adequate separation and drilling fluid displacement. Displacement rates with the fluid in turbulent flow are most effective, but are often impractical and can be detrimental to the subsequent fluid placement. Rates of between about 0.5 m³/min and about 5 m³/min may be used, but displacement rates of between about 0.8 m³/min and 2.4 m³/min are more typical. In an embodiment disclosed, the fluid spacer may be water, viscosified water, drilling mud or combinations thereof.

[0173] Silicate

[0174] A silicate solution (described above) is then displaced into the wellbore annulus. The volume and displacement rate of the silicate solution is also dependant on the quality of the wellbore 50 (drilled gauge versus washouts, tortuosity), wellbore to casing annular volumes, type of drilling fluid used, formation thickness, and formation matrix porosity/permeability characteristics. Volumes of between about 2 m³ and about 40 m³ may be required for adequate coverage and treatment of the formation matrix targeted for treatment. Displacement rates with the solution in turbulent flow are most effective, but are often impractical and can be detrimental to the subsequent fluid placement. Rates of between about 0.2 m³/min and about 5 m³/min may be used, but displacement rates of between about 0.8 m³/min and about 2.4 m³/min are more typical. Formation exposure time required will vary with matrix porosity/permeability, differential pressure (overbalance), and the effectiveness of drilling fluid filter cake removal.

[0175] Squeeze

[0176] The most successful applications of the silicates utilize a squeeze technique, where the fluid is pumped to a position adjacent to the targeted formation, displacement is stopped, and a soaking and matrix flushing period is initiated. The near wellbore matrix flushing is accelerated with pressure applied to the annulus. The diverter or BOP is closed, and pressure applied to the wellbore to casing annulus. Pressures of 400 kPa and higher are used, sufficient to initiate penetration of the fluid into the formation matrix, but below pressures that may induce formation fracture. Squeeze volumes are designed to penetrate the formation matrix based on formation thickness, formation matrix porosity, and potential differential pressure between formations (pressure regimes) and pressure regimes during cement transitional phases. Matrix penetration depths of between about 2 mm and
about 20 cm may be required to create sufficient gel and/or precipitate to mitigate fluid flow and/or fluid transfer to the wellbore, depending on pressure regimes during the described cementing process. Current processes in these wells with zones of interest less than 500 m limit squeeze volumes over lithological zones of interest to approximately 10 m³, representing matrix penetration depths of approximately 6–8 cm. Pressures of 400 kPa and higher are used, sufficient to initiate penetration of the fluid into the formation matrix, but below pressures that may induce formation fracture.

[0177] Multiple squeezes may be conducted to enhance the treatment of the formation prior to cementing. The most successful cementing operations have included a continuous silicate circulation, displacing the entire annulus to silicate. Exposure times in excess of 2 hours have proven most successful in the wellbore preparation, although this exposure time will vary with formation pressure (versus hydrostatic overbalance and ECD’s), formation pressure regimes, formation matrix porosity/permeability, and cement thickening times. Silicate concentrations are monitored during circulation, and additions of higher concentration silicate are added to maintain desirable silicate levels within the formation to casing annulus.

[0178] Fluid Spacer

[0179] A fluid spacer is pumped into the casing annulus to separate the silicate agent fluid “pill” from the cementing sequence to follow. The volume and displacement rate of the fluid spacer is dependent on the quality of the wellbore 50 (bit gauge versus washouts, tortuosity), the wellbore casing annular volumes, and formation matrix porosity/permeability characteristics.

[0180] Volumes of between about 2 m³ and about 15 m³ may be required for adequate separation and drilling fluid displacement. Displacement rates with the fluid in turbulent flow are most effective, but are often impractical and can be detrimental to the subsequent fluid placement. Rates of between about 0.5 m³/min and about 5 m³/min may be used, but displacement rates of between about 0.8 m³/min and about 2.4 m³/min are more typical. In an embodiment disclosed, the fluid spacer may be water, viscosified water, drilling mud or combinations thereof.

[0181] Primary Cementing

[0182] Regular primary cementing operations follow the silicate and activating agent procedure(s). Cementing sequence and blends will vary by region, temperature gradients, and numerous other cementing best practices considerations.

[0183] Best cementing practices may include, but are not limited to, scavenger cement blends of increasing density to ultimate cement density over incremental scavenger volumes and displacement rates. Casing movement including reciprocation and/or rotation are recommended as part of cementing “best practices”.

[0184] Referring to FIG. 4, a cement evaluation log (segmented bond tool (SBT) cement bond log 200) for a typical steam assisted gravity drainage (SAGD) type well, common in Alberta, Canada of primary cementing not pre-treated with silicate or activating agent indicates minimal portions of the casing having high cement integrity 230. The interpreted “cement map” depicts mid cement integrity 220, and lower cement integrity 210. A gamma ray reading 250 (left column) indicates primarily sands over the interval shown, the Grand Rapids ‘A’ and Grand Rapids ‘B’ sands. Overall, the cement bond log 200 shown in FIG. 4 indicates a relatively poor quality primary cementing.

[0185] The cement bond log 200 interprets casing collars 240 (connections) as high cement integrity 230 due to attenuation data adjacent to the thicker steel sections (spaced approximately 13.3 m apart in this example).

[0186] Not shown on this example (nor subsequent cement bond logs 200) but evident on most wells in the area of interest is a general trend of high quality cement adjacent to shale formations where higher permeability formation matrix is not present.

[0187] Referring to FIG. 5, an Alberta SAGD well cement evaluation log (segmented bond tool (SBT) cement bond log 200) on a well adjacent to the well shown in FIG. 4 of primary cementing which was pre-treated with silicate (without an activating agent) also indicates minimal portions of the casing having high cement integrity 230. Some improvement may be interpreted compared to FIG. 4 with the application of silicate, but the dominance of lower cement integrity 210 indicates that cement contamination over sand intervals continues.

[0188] The intervals shown may not provide adequate casing support for wellbore integrity in a thermal environment, and good hydraulic isolation over the life of the well cannot be determined with this cement evaluation log alone.

[0189] Referring to FIG. 6, an Alberta SAGD well cement evaluation log (segmented bond tool (SBT) cement bond log 200) on a well adjacent to the example shown in FIG. 4 and FIG. 5 of primary cementing which was pre-treated with an activating agent and silicate after the casing is in place. The cement bond log 200 indicates high cement integrity 230 throughout much of the interval, with only very small portions showing mid cement integrity 220 and lower cement integrity 210. Very good cement quality has been achieved over the entire sand interval.

[0190] Referring to FIG. 7, an Alberta SAGD well cement evaluation log (segmented bond tool (SBT) cement bond log 200) on a well adjacent to the example shown in FIGS. 4-6 of primary cementing which was pre-treated with an activating agent and silicate during drilling operations (prior to casing operations). Mid cement integrity 220 has been achieved over the entire sand interval in this example, also showing significant improvements over those examples shown in FIGS. 4 and 5.

[0191] Referring to FIG. 8, a typical Alberta SAGD well configuration is represented for the wells of the type discussed in FIGS. 4-7. The wellbore 50 has been drilled through several formations 40-401, and the casing 110 is cemented within the wellbore 50. The designs and configurations vary by application and area, and are not specific to the embodiments described.

[0192] Referring to FIG. 8, the Grand Rapids, Clearwater, and Wabaskaw formations shown are part of the stratigraphic sequence of Alberta which are water and gas bearing aquifers of particular interest in establishing quality cement for good hydraulic isolation. In this example of a SAGD well, the McMurray sandstone is known to contain bitumen where steam is injected for thermal stimulation as part of the SAGD process. High quality cement for hydraulic isolation of the steam within the McMurray sands is also of particular interest.

[0193] Referring to FIG. 9, an illustration of various well types and purposes associated with SAGD operations used
the examples discussed above. The various well types shown also penetrate the various sands where cement contamination may be encountered. These include observation wells, monitoring wells, water source wells, disposal wells, and other wells. The methods and compositions disclosed herein may be used in cementing of any such wells.

[0194] Referring to FIG. 10, an example of a particular blend of cement 100 and its compressive strength characteristics versus time at various cement blend densities is shown. For example, if the cement 100 is designed to 1700 kg/m³, it is diluted, for example by ingress of formation fluids such as oil, water, gas etc. or egress of the cement into the formation 40 such that the density is decreased locally to 1400 kg/m³, then at 7 days, the compressive strength would be about 1.5 MPa instead of the design compressive strength of about 8.2 MPa. The methods and compositions disclosed herein reduce contamination of the cement and leak off of the cement so that cement integrity is maintained.

[0195] In the preceding description, for purposes of explanation, numerous details are set forth in order to provide a thorough understanding of the embodiments. However, it will be apparent to one skilled in the art that these specific details are not required. In other instances, well-known structures are shown in block diagram form in order not to obscure the understanding.

[0196] In an embodiment disclosed, the present disclosure provides methods and compositions for treating a formation, proximity a wellbore, prior to primary cementing, by reacting an activating agent and a silicate to provide a barrier between the wellbore and the formation to reduce the contamination of cement by ingress of formation fluids or leakage of cement from the wellbore during cement transitional phases. The activating agent may be provided while the wellbore is being drilled or may be provided subsequent to drilling or may be at least partially naturally occurring in the formation prior to drilling. The silicate may be provided during or subsequent to drilling.

[0197] As used herein, reference to formation 40-40H1 means one or more of formation 40, 40A, 40B, 40C, 40D, 40E, 40F, 40G, and 40H1 or combinations thereof.

[0198] In embodiments disclosed, the formation is treated with the activating agent first and then the silicate. In embodiments disclosed, the formation is treated with the silicate first and then the activating agent.

[0199] The above-described embodiments are intended to be examples only. Alterations, modifications and variations can be effected to the particular embodiments by those of skill in the art without departing from the scope, which is defined solely by the claims appended hereto.

What is claimed is:

1. A method of primary cementing of a casing in a wellbore drilled in a formation comprising:
   treating the formation, proximate the wellbore, with an activating agent; and
   treating the formation, proximate the wellbore, with a silicate,
   prior to the primary cementing of the casing in the wellbore.

2. The method of claim 1, wherein a reaction between the activating agent and the silicate forms a gel or precipitate substantially within the formation.

3. The method of claim 2, wherein the gel or precipitate forms a region of reduced permeability within the formation, proximate the wellbore.

4. The method of claim 1, wherein the pressure in the wellbore is increased by a squeeze pressure, to squeeze at least a portion of the activating agent or the silicate or both into the formation.

5. The method of claim 4, wherein the squeeze pressure is less than a formation fracture pressure.

6. The method of claim 5, wherein the squeeze pressure is held for a squeeze time.

7. The method of claim 6, wherein the squeeze time is between 1 min. and 30 min.

8. The method of claim 7, wherein the squeeze time is between 5 min. and 20 min.

9. The method of claim 1, wherein the activating agent is provided in a drilling fluid during drilling of the wellbore.

10. The method of claim 1, performed after the wellbore has been drilled to a selected total depth (TD), the wellbore cleaned, and the casing run into the wellbore.

11. The method of claim 10, wherein an annulus is formed in the wellbore between the casing and the formation, wherein the pressure of the annulus is increased by a squeeze pressure, to squeeze at least a portion of the silicate or the activating agent or both into the formation.

12. The method of claim 11, wherein the squeeze pressure is less than a formation fracture pressure.

13. The method of claim 12, wherein the squeeze pressure is held for a squeeze time.

14. The method of claim 13, wherein the squeeze time is between 1 min. and 30 min.

15. The method of claim 14, wherein the squeeze time is between 5 min. and 20 min.

16. The method of claim 1, the activating agent comprising one or more light metal cations.

17. The method of claim 16, wherein the light metal cations are selected from the group consisting of Ca⁺⁺, Mg⁺⁺, Na⁺, and K⁺.

18. The method of claim 17, the activating agent comprising Ca⁺⁺ ions.

19. The method of claim 18, wherein an activating agent concentration of the Ca⁺⁺ ions is between 500 mg/L and 50,000 mg/L.

20. The method of claim 19, wherein the activating agent concentration is between 2,000 mg/L and 50,000 mg/L.

21. The method of claim 20, wherein the activating agent concentration is between 20,000 mg/L and 40,000 mg/L.

22. The method of claim 19, wherein the volume of activating agent solution is between 2 m³ and 40 m³.

23. The method of claim 1, wherein the activating agent contacts the formation for a contact time.

24. The method of claim 23, wherein the contact time is between 1 min. and 30 min.

25. The method of claim 24, wherein the contact time is between 5 min. and 20 min.

26. The method of claim 1, wherein a silicate concentration is between 4 percent and 50 percent.

27. The method of claim 26, wherein the silicate concentration is between 8 percent and 30 percent.

28. The method of claim 27, wherein the volume of silicate solution is between 2 m³ and 40 m³.

29. The method of claim 27, wherein the silicate contacts the formation for a contact time.

30. The method of claim 29, wherein the contact time is between 1 min. and 30 min.

31. The method of claim 30, wherein the contact time is between 5 min. and 20 min.
32. The method of claim 1, further comprising treating the formation with a further activating agent or a further silicate or both.

33. The method of claim 1, further comprising monitoring returns in order to estimate the placement of the activating agent or the silicate or both in the formation.

34. A method of primary cementing of a casing in a wellbore, comprising:
   - drilling the wellbore in a subterranean formation;
   - providing a casing in the wellbore;
   - providing a first fluid spacer into an annulus between the casing and the formation;
   - providing an activating agent into the formation;
   - providing a second fluid spacer into the annulus;
   - providing a silicate into the formation;
   - providing a third fluid spacer into the annulus; and
   - conducting the primary cementing of the casing in the wellbore.

35. A method of primary cementing of a casing in a wellbore, comprising:
   - providing a drill bit on a drill-string for drilling a wellbore in a subterranean formation;
   - drilling the wellbore in the formation, pausing above a zone of interest;
   - drilling the wellbore through the zone of interest with a drilling fluid laden with activating agent and pausing drilling shortly thereafter;
   - providing a first fluid spacer into an annulus between the drill-string and the formation;
   - providing a silicate into the formation;
   - providing a second fluid spacer into the annulus;
   - continuing drilling the wellbore;
   - installing the casing; and
   - conducting the primary cementing of the casing.

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