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(54) Title: METHOD OF VISCOSIFYING WATER-BASED EPOXY RESIN CONSOLIDATION FLUID

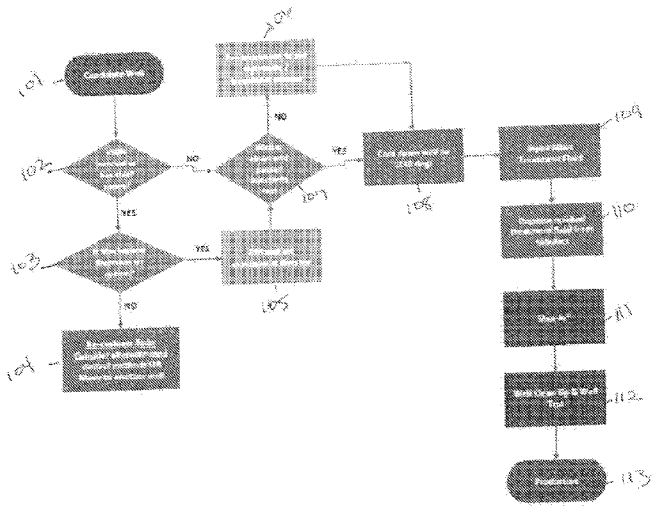

Figure 1 (Prior Art)

(57) Abstract: Embodiments herein relate to apparatus, compositions, and methods for using a resin consolidation system in a subterranean formation traversed by a wellbore including forming a consolidation treatment fluid using an aqueous solvent, a viscosifying agent, a resin, a curing agent, and a surfactant and introducing the treatment fluid into the formation. In some embodiments, the viscosifying agent includes xanthan, guar, biopolymers, synthetic polymers, viscoelastic surfactants, polyacrylamide, hydroxyethyl cellulose (HEC), carboxymethyl cellulose (CMC), viscoelastic surfactant, or a combination thereof. In some embodiments, the curing agent includes a water-soluble polyamine-based epoxy curing agent. In some embodiments, the resin includes a polymerizable epoxy compound having at least one epoxy group per molecule. In some embodiments, the surfactant includes nonionic and amphoteric surfactant, anionic and cationic surfactant, polymeric surfactant, or a combination thereof. The treatment fluid may further include an oxidative

WO 2025/106965 A1

[Continued on next page]

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breaker solution.

METHOD OF VISCOSIFYING WATER-BASED EPOXY RESIN CONSOLIDATION FLUID

CROSS REFERENCE TO RELATED APPLICATION

[0001] This application claims priority to United States Provisional Application Serial Number 63/599,850 filed November 16, 2023 with the same title. The application is incorporated herein by reference in its entirety.

BACKGROUND

[0002] A consolidation fluid is used when the downhole formation is partially losing its mechanical integrity during production. A consolidation fluid is injected to enhance the stability of the formation, prevent excessive sand production and reduce the risk of an eventual partial collapse of the formation/wellbore which would affect production of hydrocarbons. The injection of fluid is highly dependent on actual permeability of the formation and in particular, it is sensitive to contrasts in permeability/porosity which will lead to a poor distribution of the fluid in the treated formation. Figure 1 (Prior Art) shows a workflow for forming and using a consolidation fluid. Candidate wells are first evaluated 101 based on treatment interval and existence of thief zones (zones with significant permeability contrasts) 102. Often, throughout the workflow, the shut-in time for consolidation is minimum 24 hours for formation temperatures greater than 180 °F and minimum 3 days for formation temperatures less than 180 °F. There may be longer shut-in time if clays are present (minimum of 6 days).

[0003] When the well interval is greater than 50 feet and thief zones are present, a mechanical diversion 103 is needed. Mechanical diversion such as an isolation packer is used to isolate or break down or both isolate and break down the interval such that treatments are then viable and then risks are reevaluated 104. When mechanical diversion is not an option, alternative sand control methods such as mechanical methods (screens) should be considered 105 or another candidate should be selected.

[0004] The well may be clean and pass an injectivity test 107. A pre-treatment fluid such as (but not limited to) acidizing and solvent treatment fluids may be required to aid injectivity and facilitate treatment success 106. Then, the well may be cooled down with 2 to 4 percent KCl to at least 140 °F to allow for longer treatment fluid stability 108.

[0005] A main treatment 109 is then followed with a water based sand consolidation system. Post treatment injection residual treatment fluid from the tubulars is displaced using 2 to 4 percent KCl 110. The well is then shut-in as per well conditions (temperature or clay content or both) 111. After shut-in, clean up and well tests are performed prior to putting the well on production 113.

SUMMARY

[0006] This summary is provided to comply with 37 C.F.R. § 1.73, requiring a summary of the invention briefly indicating the nature and substance of the invention. It is submitted with the understanding that it will not be used to limit the scope or meaning of the claims.

[0007] Embodiments herein relate to apparatus, compositions, and methods for using a resin consolidation system in a subterranean formation traversed by a wellbore including forming a consolidation treatment fluid using an aqueous solvent, a viscosifying agent, a resin, a curing agent, and a surfactant and introducing the treatment fluid into the formation. In some embodiments, the viscosifying agent includes xanthan, guar, biopolymers, synthetic polymers, viscoelastic surfactants, polyacrylamide, hydroxyethyl cellulose (HEC), carboxymethyl cellulose (CMC), viscoelastic surfactant, or a combination thereof.

[0008] In some embodiments, the viscosifying agent has a concentration of 10 lb/1000 gal (ppt) to 100 lb/1000 gal (ppt) in the treatment fluid. The viscosifying agent may exist in powder form and have a concentration of 5 lb/1000 gal (ppt) to 50 lb/1000 gal (ppt) in the treatment fluid. In some embodiments, the viscosifying agent is a slurry with an active concentration of 30 weight percent to 60 weight percent and has a concentration of 0.1 volume percent to 1.5 volume percent in the treatment fluid. When the viscosifying agent includes viscoelastic surfactant, the viscosifying agent may have a concentration of 0.1 volume percent to 10 volume percent in the treatment fluid.

[0009] In some embodiments, the curing agent includes a water-soluble polyamine-based epoxy curing agent.

[0010] In some embodiments, the resin includes a polymerizable epoxy compound having at least one epoxy group per molecule.

[0011] In some embodiments, the surfactant includes nonionic and amphoteric surfactant, anionic and cationic surfactant, polymeric surfactant, or a combination thereof.

[0012] The treatment fluid may further include a 2 to 10 weight percent oxidative breaker solution and the breaker solution may be present at a concentration of 0.1 volume percent to 5 volume percent in the treatment fluid.

[0013] Embodiments herein relate to apparatus, compositions, and methods for consolidating proppant or rock or both in a subterranean formation traversed by a wellbore including forming a resin consolidation system including a consolidation treatment fluid, wherein the fluid includes an aqueous solvent, a viscosifying agent, a resin, a curing agent, and a surfactant, introducing the treatment fluid into the formation, and allowing proppant or rock or both to consolidate.

BRIEF DESCRIPTION OF THE DRAWINGS

[0014] Figure 1 (Prior Art) is a workflow regime for forming and using a consolidation fluid;

[0015] Figure 2 is a plot of viscosity as a function of time for a fluid across two time horizons, in accordance with embodiments of the present disclosure;

[0016] Figure 3 is a workflow regime for forming and using a consolidation fluid, in accordance with embodiments of the present disclosure;

[0017] Figure 4 is a workflow for a method for preparation of consolidated proppant packs, in accordance with embodiments of the present disclosure;

[0018] Figure 5 is a series of proppant pack behavior over time, in accordance with embodiments of the present disclosure; and

[0019] Figure 6 is a series of treated proppant pack behavior over time, in accordance with embodiments of the present disclosure.

DETAILED DESCRIPTION

[0020] This disclosure is not limited to the particular systems, devices and methods described, as these may vary. The terminology used in the description is for the purpose of describing the particular versions or embodiments only, and is not intended to limit the scope.

[0021] Unless defined otherwise, all technical and scientific terms used herein have the same meanings as commonly understood by one of ordinary skill in the art. Nothing in this disclosure is to be construed as an admission that the embodiments described in this

disclosure are not entitled to antedate such disclosure by virtue of prior invention. As used in this document, the term "comprising" means "including, but not limited to."

[0022] Embodiments herein relate to a water-based epoxy resin proppant consolidation fluid. The water-based epoxy resin consolidation systems are delivered as an emulsion of the resin in fresh or sea water or synthetic or produced brine and often include three components.

1. A resin source – including but not limited to solid or liquid bisphenol A based epoxy resin predispersed in water, wherein the resin is oil soluble.
2. A curing agent – including but not limited to water-soluble polyamine based epoxy curing agents.
3. A surfactant – including but not limited to nonionic amphoteric surfactants and anionic and cationic surfactants having cloud points between 60 ºC and 90 ºC.

[0023] The resin source may include a polymerizable epoxy compound having at least one epoxy group per molecule. Examples include one or more curable resins, present from about 20 to 70 weight percent, including but not limited to, bis-phenol A, bis-phenol F, brominated and fluorinated phenols, resorcinol, tetrakis phenylolethane, cycloaliphatic epoxides, aliphatic epoxides, glycidyl ethers, glycidyl amines, acrylonitrile glycidyl esters, poly glycidyl ethers, poly glycidyl amines, multi-functional glycidyl ethers, multi-functional glycidyl amines, phenolic or cresol novalac resins, acrylic resins, polyurethane resins, phenol-formaldehyde resin, polyisocyanate resins, and epoxy functional resins.

[0024] One or more curing agents may be present from about 2 to 40 weight percent, depending on the molecular weight of the curing agent. Examples include, but are not limited to, Lewis acids, Lewis bases, tertiary amines, mono ethanol amine, benzyl dimethylamine, 1,4-diaza-bicyclo,[2,2,2]octane, 1,8-diazabicyclo[5,4,0]undec-7ene, ethylene amines, cycloaliphatic amines, amidoamines, polyamidoamines, aliphatic amines, modified aliphatic amines, diethylenetriamine, triethylenetetramine, aromatic amines, diaminodiphenylsulfone, polyamides, boron tri-fluoride derivatives, modified amine complexes of boron tri-fluoride, quaternary ammonium derivatives, dicyandiamide, acid anhydrides, dimethylaminophenol, 2,4,6-tri(dimethylaminomethyl)phenol, imidazoles, imidazolines, , hydrazides, amine-terminated butadiene acrylonitriles, choline chloride, polycarbamides, , dicarboxylic acid cyclic anhydrides quaternary phosphonium salts,

triaryl sulfonium salts, and combinations thereof. The curing agent may be a water-soluble polyamine-based epoxy curing agent.

[0025] The curing of the resin by the curing agent can occur via either mechanism described or a combination of both. The first method of curing is through polyaddition/copolymerization of the resin with a multifunctional curing agent via nucleophilic attack and ring opening of the epoxy resin. The curing agent is directly involved in the bond forming reaction required for cross-linking and is incorporated into the cured polymer network. A second curing mechanism is activation of the epoxy ring which initiates either anionic or cationic homopolymerization of the epoxy resin depending on the chosen curing agent. In this mechanism, the curing agent is not incorporated into the cured polymer network, and only acts as a catalyst where the resin forms the bonds required for cross-linking in the cured polymer. The degree of crosslinking in a polymer is significantly lower when the epoxy resin is cured at room temperature compared to cured at elevated temperatures. Since there is greater potential for interaction between the curing agent and resin, elevated temperatures are required when the resin is cured to achieve maximum mechanical properties.

[0026] Many properties of resin adhesives are influenced by the glass transition temperature (Tg). Tg refers to the temperature at which chain segments in the polymer network can move freely and is dependent on the chemical composition and degree of crosslinking or molecular interaction within the polymer network. When the temperature exceeds the Tg, the resin polymer can deform under impact or assume new alignments due to stress, which greatly diminishes the resin polymer strength and stiffness. For elevated temperature performance, it is necessary that the Tg of the resin adhesive be higher than the highest temperature encountered (i.e. greater than the bottom hole temperature of the well). Cross linking density as well as the properties of the curing agent affects the T_g of the cured resin polymer, thus it is crucial to select appropriate curing agents that give glass transition temperatures that are higher than the bottom hole temperature to ensure that the desired resin polymer properties are achieved.

[0027] The surfactant may be nonionic or amphoteric surfactants or anionic and cationic surfactants or polymeric surfactants having a cloud point between 60 °C and 90 °C.

[0028] Examples include one or more surfactant agents present from 0.1 to 1 weight percent including but not limited to ethoxylated alcohols, alkylphenol ethoxylates, fatty acid ethoxylates, polysorbates (tween series), and polyethylene glycol (PEG) Derivatives.

[0029] The cloud point of the surfactant influences the stability of the oil-in-water (O/W) emulsion. Hence, surfactants with appropriate cloud points are selected for optimizing the water-based emulsion fluid stability, performance, and usability across various temperature conditions.

[0030] The water-based resin consolidation fluid is an all-encompassing fluid consisting of the three components: a resin, a curing agent, and a surfactant. The fluid is prepared at surface by batch mixing the three components in water to form an emulsion. Once mixed the viscosity of the fluid is below 5cP at ambient temperature (~77 °F) and 170 s-1 for at least 24 hours. This low viscosity enables pumpability and penetration into the formation. However, in some applications, treating longer horizontal wells (>50 ft) and high permeability contrast zones (thief zones) requires more effective placement control.

[0031] Figure 2 is a plot of viscosity as a function of time, it compares steady shear viscosity of the water-based consolidation fluid at 77 °F observed immediately after preparation and 24 hours later.

[0032] In some embodiments, viscosifying a fluid with a polymer such as xanthan, guar, hydroxyethyl cellulose (HEC), carboxymethyl cellulose (CMC), or synthetic polymers such as polyacrylamide or a non-polymeric viscosifier such as viscoelastic surfactant (VES) enables better control during placement of the consolidation fluid in longer horizontal sections or thief zones or both thereby eliminating the need for mechanical isolation and increasing treatment efficiency.

[0033] Viscosity control is managed through fluid dynamics, specifically Darcy's law. Higher viscosity fluids flow more slowly through porous media, so increasing the viscosity can effectively slow down its flow through high permeability zones. During pumping sequences, a strategy can be employed by first pumping the higher viscosity fluid followed by the lower viscosity fluid. This approach ensures that lower permeability zones receive proper coverage.

[0034] Further, in some embodiments, the increased fluid viscosity will generate adequate differential pressure during pumping that enables monitoring and control of the fluid when placing it in longer horizontal wells.

[0035] The same principle applies here. Using Darcy's law:

Flow rate = (Permeability x Delta Pressure) / (Viscosity x Length).

[0036] For a given differential pressure, increasing fluid viscosity results in a decreased flow rate. By using higher viscosity fluid, the flow rate through higher permeability zones is reduced, creating a diversion effect and improving coverage treatment.

[0037] The fluid with a viscosifying agent could also be used to plug high permeability thief zones thereby allowing diversion of the fluid to low permeability zones. The viscosified fluid could also be used as a tail-in fluid to a low viscosity fluid with no viscosifying agent. The viscosity contrast between the two fluids can be exploited to monitor changes in pumping pressure and to identify when the low viscosity fluid has been completely displaced from the well. In some embodiments, this will ensure proper placement of the fluids into the formation without residual fluid left in the well. These concepts remain based on Darcy's law.

[0038] An embodiment of the operational workflow follows. First, pump the higher viscosity fluid to achieve the minimum target penetration into the formation (3 feet radial penetration). Next, pump the lower viscosity fluid. Observe a pressure drop during pumping, indicating a change in viscosity at the same pumping rate, followed by a pressure increase, but lower than the initial higher viscous fluid. This indicates that the lower viscosity fluid has now reached the lower permeability zones. The higher permeability zones will have more resistance to accepting additional fluids.

[0039] Adding a viscosifying agent to the water-based consolidation fluid has benefits for some embodiments of the invention. The base fluid of a resin-based consolidation system may be fresh or sea water or synthetic or produced brine. The viscosifying agent may be selected based on its compatibility and efficiency with water of various salinity. The initial base fluid for water-based consolidation is typically fresh water. However, industry practice suggests that brines are more advantageous for minimizing formation damage, such as clay swelling or fines migration. This approach highlights the flexibility of using various base fluids for water-based consolidation, depending on specific formation needs.

[0040] In some embodiments, the viscosity of the fluid should be 20 cP or greater when measured at surface (ambient) temperature and 170 s-1. The viscosifying agent may be added to the fluid at the same time as the other components such as resin, surfactant, and curing agent. Depending upon the water composition and the viscosifying agent, viscosity may be generated fast (within minutes) or viscosity generation may require an extended mixing time (hours). In some embodiments, the viscosifier selection drives this time. That is, both the water composition and viscosifying agent can affect the viscosity generation time. Some embodiments may benefit from a variety of viscosifying agents used to viscosify water-based fluids.

[0041] Examples of viscosifying agents include polysaccharides such as guar gum and its derivatives, xanthan gum, and cellulose derivatives. Synthetic polymers such as polyacrylamides and derivatives could also be employed. Polymer-free viscosifying agents such as viscoelastic surfactants may also be used. Compatibility between the viscosifying agents and other components of the consolidation fluid drives viscosifying agent selection in some embodiments. If the viscosity generation is fast, the viscosifying agent can be mixed "on the fly." If the viscosity generation is slow, batch mixing may be required. If a polymeric viscosifying agent is employed, the consolidating fluid may further require an oxidizer to react with the polymer and ensure that the consolidating fluid does not cause formation damage after placement. Examples of oxidizers are persulfates, bromates, etc.

[0042] Figure 3 provides a workflow with viscosity control. Candidate wells 301 are first evaluated based on treatment interval and existence of thief zones (zones with significant permeability contrasts) 302. The shut-in time for consolidation is minimum 24 hours for formation temperatures greater than 180 °F and minimum 3 days for formation temperatures less than 180 °F. There is a longer shut-in time if clays are present (minimum of 6 days). In some embodiments, this is confirmed by an injectivity test 305.

[0043] When well interval is greater than 50-ft or thief zones are present or both, a viscosifying agent is added to the main treatment fluid 305. Viscosifying the treatment fluid enables one to dictate the fluid flow path within the reservoir, thereby enabling treatment of longer intervals and high permeability contrast zones (thief zones). This eliminates the need for mechanical isolation and increases treatment efficiency.

[0044] A pre-treatment fluid such as acidizing and solvent treatment fluids may be required to aid injectivity and ensure treatment success or both 304. Following which, the well is cooled down with 2 to 4 percent KCl to at least 140 °F to allow for longer treatment fluid stability 306. Exposure to temperatures above 140 °F for greater than 15 minutes destabilizes the oil in water based resin emulsion and cooling down the well to less than or equal to 140 °F is critical to some embodiments.

[0045] The main treatment is then followed with a viscosified water-based sand consolidation treatment 307. Sand consolidation is a sand control technique that binds loose sand grains, which can migrate to the surface due to the loss of natural cementing materials. These loose sand grains have low unconfined compressive strength. Resin-based sand consolidation creates a "glue" effect between the loose sand grains, forming artificial cementing materials. This process improves the rock strength, allowing for increased drawdown pressure without causing sand migration to the surface. Post treatment injection, residual treatment fluid from the tubulars is displaced using brine or slickwater 308.

[0046] Displacement is necessary to remove residual sand consolidation fluid from inside the tubular. In the worst-case scenario, if the tubular is filled with sand consolidation fluid, it will set and plug over time with temperature, blocking production in the production tubing or damaging the coiled tubing pipe. The primary target of this fluid is within the formation, specifically to bind the loose sand grains. The viscosity contrast between the two fluids can be exploited to monitor changes in pumping pressure and identify when the viscosified

[0047] water-based sand consolidation fluid has been completely displaced from the well 309.

Similarly, Darcy's Law principles apply here, for a given differential pressure, increasing fluid viscosity results in a decreased flow rate. By using a higher viscosity fluid, the flow rate through higher permeability zones is reduced, creating a diversion effect and improving coverage treatment for the operational workflow. The pressure trend indicates the completion of displacement stages. In addition to Darcy's law, the Hagen-Poiseuille equation also informs this analysis.

$$\Delta P = (8 \times \text{viscosity} \times \text{length} \times \text{rate}) / (\pi \times \text{radius}^2).$$

[0048] According to this equation, the pressure drop is directly proportional to the fluid viscosity. Therefore, higher viscosity fluids will result in higher pressure. A pressure drop during pumping, compared to the initial stage, indicates that the higher viscosity fluid has been displaced. The well is then shut-in as per well conditions (temperature or clay content or both) 310. After shut-in, clean up and well tests are performed 311 prior to putting the well on production 312.

[0049] Experimental Results

[0050] Initially, we prepared consolidated proppant packs. To perform testing on loose proppant, the proppant was first confined in a protective sleeve (heat shrink-Teflon tubing) with screens on both ends (step 1). This enabled handling the loose proppant like a core plug. Cylindrical proppant packs having dimensions of 1-in. diameter by 2-in. length were prepared. 20/40 Carbolite proppant was used. Once prepared, the sand packs were saturated in 2% KCl (step 2). Next, initial permeability was measured (step 3) using 2% KCl, after which 3 pore volumes of the viscosified water-based sand consolidation fluid were injected into the packs (step 4) using a syringe pump at 1 to 2 mL/min. The treated sand packs were then cured in an oven at temperatures for sufficient time (step 5). Once cured, the consolidated sand packs were cut open from the protective sleeve, and their final permeability and unconfined compressive strength (UCS) were measured (step 6). Figure 4 shows a schematic of the consolidation process.

[0051] Example 1: Consolidation of 20/40 Carbolite proppant with water based epoxy resin fluid viscosified using 1 volume percent xanthan and cured at 180 degF for 4 days. Figure 5 shows the results of the testing.

[0052] Example 2: Consolidation of 20/40 Carbolite proppant with water based epoxy resin fluid viscosified using 0.5 volume percent xanthan and containing 12 lb/1000 gal (ppt) oxidizer breaker and cured at 180 degF for 7 days. Figure 6 shows the results of the testing.

[0053] The present disclosure is not to be limited in terms of the particular embodiments described in this application, which are intended as illustrations of various aspects. Many modifications and variations can be made without departing from its spirit and scope, as will be apparent to those skilled in the art. Functionally equivalent methods and apparatuses within the scope of the disclosure, in addition to those enumerated herein, will

be apparent to those skilled in the art from the foregoing descriptions. Such modifications and variations are intended to fall within the scope of the appended claims. The present disclosure is to be limited only by the terms of the appended claims, along with the full scope of equivalents to which such claims are entitled. It is to be understood that this disclosure is not limited to particular methods, reagents, compounds, compositions or systems, which can, of course, vary. It is also to be understood that the terminology used herein is for the purpose of describing particular embodiments only, and is not intended to be limiting.

[0054] Various of the above-disclosed and other features and functions, or alternatives thereof, may be combined into many other different systems or applications. Various presently unforeseen or unanticipated alternatives, modifications, variations or improvements therein may be subsequently made by those skilled in the art, each of which is also intended to be encompassed by the disclosed embodiments.

We claim:

1. A method for using a resin consolidation system in a subterranean formation traversed by a wellbore, comprising:

forming a consolidation treatment fluid comprising an aqueous solvent, a viscosifying agent, a resin, a curing agent, and a surfactant; and

introducing the treatment fluid into the formation.

2. The method of claim 1, wherein the viscosifying agent comprises xanthan, guar, biopolymers, synthetic polymers, viscoelastic surfactants, or a combination thereof.

3. The method of claim 1, wherein the viscosifying agent comprises polyacrylamide.

4. The method of claim 1, wherein the viscosifying agent comprises hydroxyethyl cellulose (HEC) or carboxymethyl cellulose (CMC) or a combination thereof.

5. The method of claim 1, wherein the viscosifying agent has a concentration of 10 lb/1000 gal (ppt) to 100 lb/1000 gal (ppt) in the treatment fluid.

6. The method of claim 1, wherein the viscosifying agent is in powder form.

7. The method of claim 6, wherein the viscosifying agent has a concentration of 5 lb/1000 gal (ppt) to 50 lb/1000 gal (ppt) in the treatment fluid.

8. The method of claim 1, wherein the viscosifying agent is a slurry with an active concentration of 30 weight percent to 60 weight percent.

9. The method of claim 8, wherein the viscosifying agent has a concentration of 0.1 volume percent to 1.5 volume percent in the treatment fluid.

10. The method of claim 1, wherein the viscosifying agent comprises a viscoelastic surfactant.

11. The method of claim 10, wherein the viscosifying agent has a concentration of 0.1 volume percent to 10 volume percent in the treatment fluid.

12. The method of claim 1, wherein the curing agent comprises a water-soluble polyamine-based epoxy curing agent.

13. The method of claim 1, wherein the resin comprises a polymerizable epoxy compound having at least one epoxy group per molecule.

14. The method of claim 1, wherein the surfactant comprises nonionic and amphoteric surfactant, anionic and cationic surfactant, polymeric surfactant, or a combination thereof.

15. The method of claim 1, wherein the treatment fluid further comprises a 2 to 10 weight percent oxidative breaker solution.

16. The method of claim 16, wherein the breaker solution is at a concentration of 0.1 volume percent to 5 volume percent in the treatment fluid.

17. A method for consolidating proppant or rock or both in a subterranean formation traversed by a wellbore, comprising:

forming a resin consolidation system comprising a consolidation treatment fluid, wherein the fluid comprises an aqueous solvent, a viscosifying agent, a resin, a curing agent, and a surfactant;

introducing the treatment fluid into the formation; and

allowing proppant or rock or both to consolidate.

18. The method of claim 17, wherein the viscosifying agent comprises xanthan, guar, biopolymers, synthetic polymers, viscoelastic surfactants, polyacrylamide, hydroxyethyl cellulose (HEC), carboxymethyl cellulose (CMC), viscoelastic surfactant, or a combination thereof.

19. The method of claim 17, wherein the curing agent comprises a water-soluble polyamine-based epoxy curing agent.

20. The method of claim 17, wherein the resin comprises a polymerizable epoxy compound having at least one epoxy group per molecule.

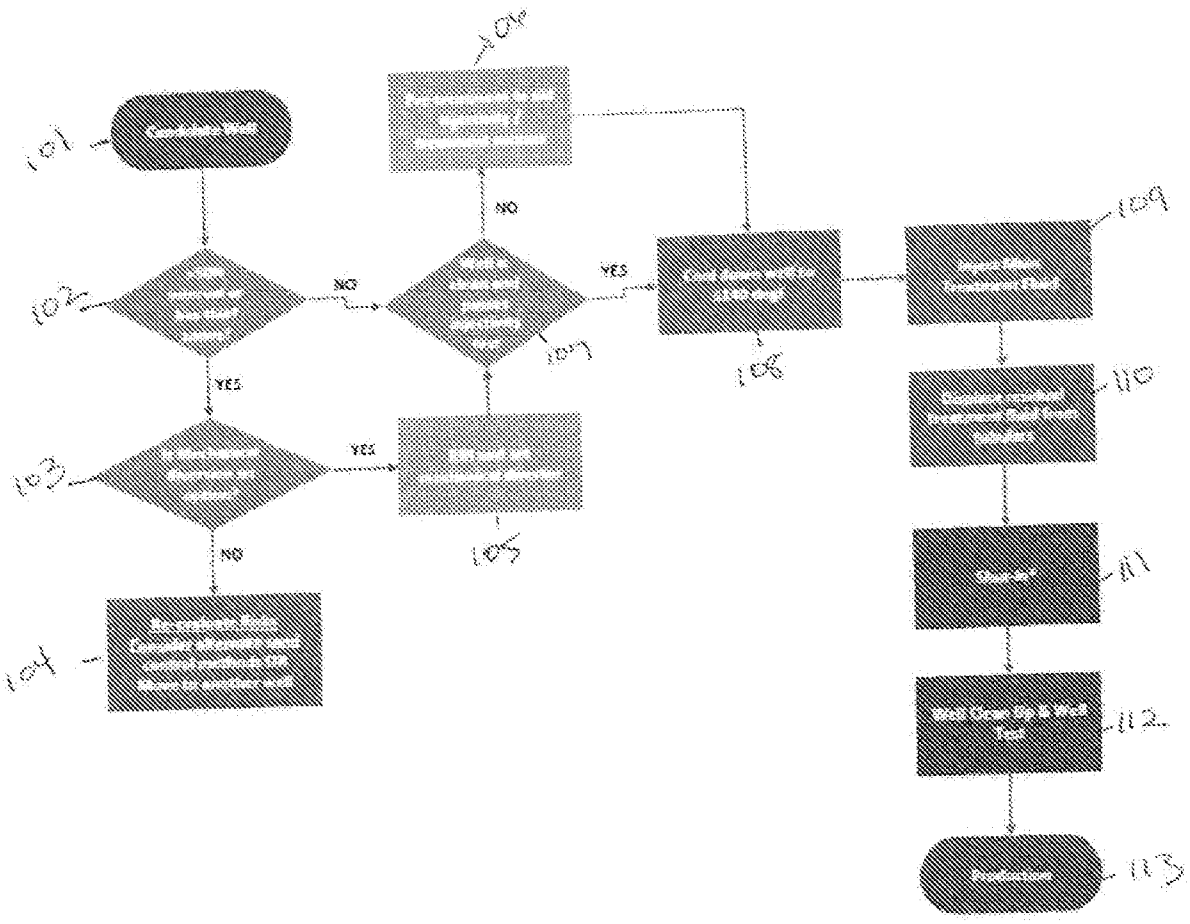

Figure 1 (Prior Art)

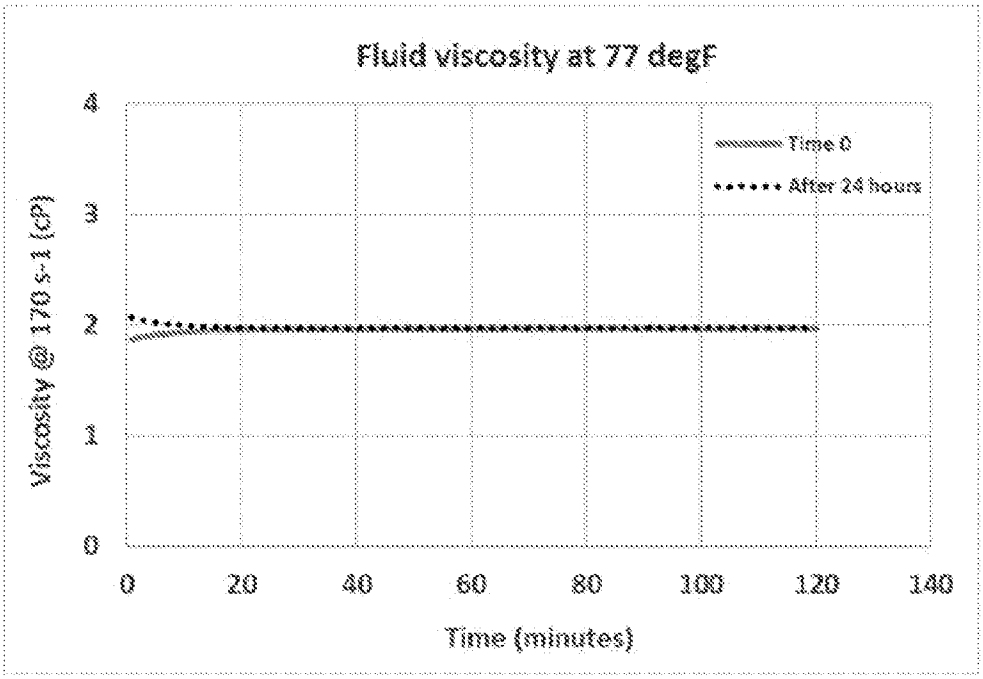

Figure 2

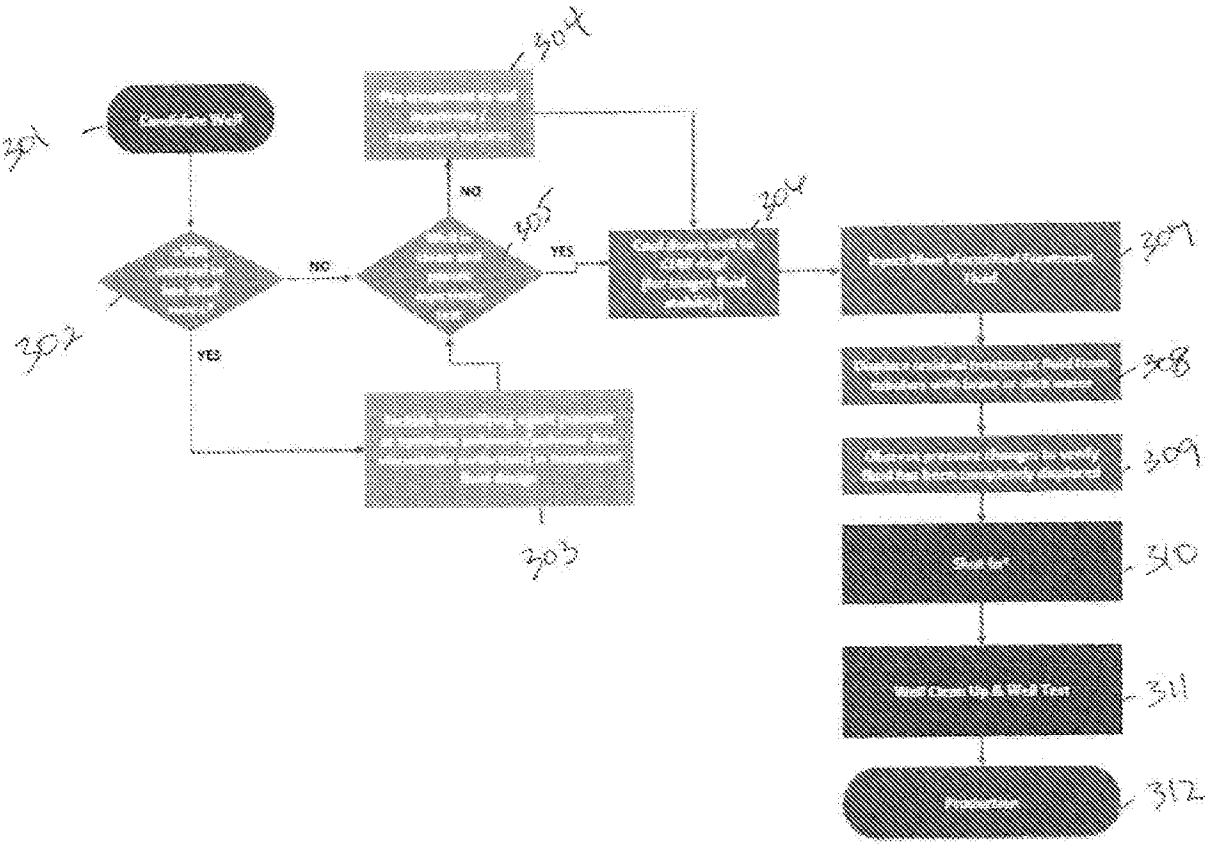

Figure 3

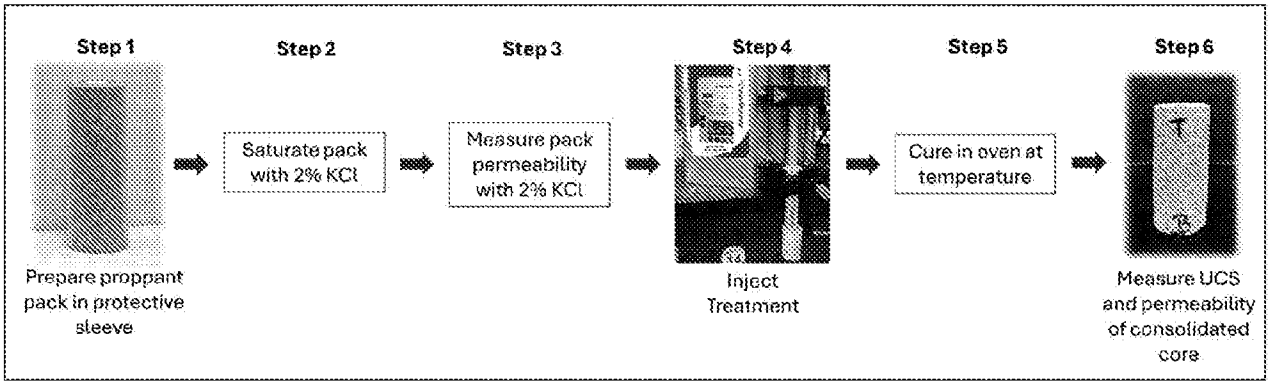

Figure 4

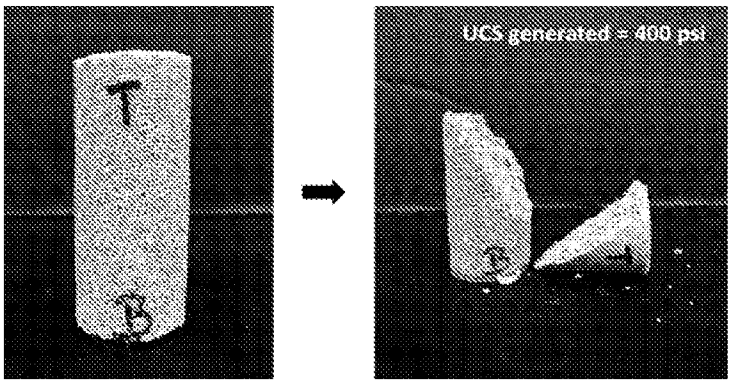

Figure 5

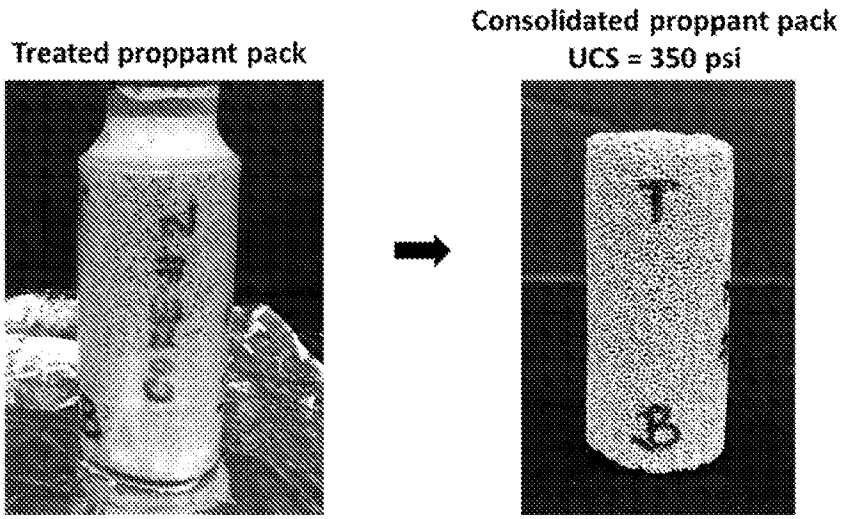

Figure 6

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US2024/056371

A. CLASSIFICATION OF SUBJECT MATTER

C09K 8/68(2006.01)i; **C09K 8/80**(2006.01)i

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

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)

C09K 8/68(2006.01); C09K 8/035(2006.01); C09K 8/528(2006.01); C09K 8/70(2006.01); C09K 8/72(2006.01); C09K 8/74(2006.01); E21B 43/02(2006.01); E21B 43/16(2006.01)

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

Korean utility models and applications for utility models
Japanese utility models and applications for utility models

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)

eKOMPASS(KIPO internal) & Keywords: resin consolidation system, subterranean formation, wellbore, consolidation treatment fluid, aqueous solvent, viscosifying agent, resin, curing agent, surfactant, xanthan, guar, biopolymers, polyacrylamide, polyamine-based epoxy curing agent, polymerizable epoxy compound

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 2013-0118748 A1 (SCHLUMBERGER TECHNOLOGY CORPORATION) 16 May 2013 (2013-05-16) paragraphs [0007], [0010], [0018], [0024], [0042]; and claims 27, 29, 31	1-11,14,17,18
Y		12,13,15,16,19,20
Y	WO 2007-143749 A1 (M-I LLC et al.) 13 December 2007 (2007-12-13) claims 1-3	12,13,19,20
Y	US 2020-0277528 A1 (HALLIBURTON ENERGY SERVICES, INC.) 03 September 2020 (2020-09-03) claim 1	15,16
A	WO 99-50529 A1 (SOFITECH N.V. et al.) 07 October 1999 (1999-10-07) whole document	1-20

☑ Further documents are listed in the continuation of Box C. ☑ See patent family annex.

* Special categories of cited documents:
"A" document defining the general state of the art which is not considered to be of particular relevance
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"L" document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)
"O" document referring to an oral disclosure, use, exhibition or other means
"P" document published prior to the international filing date but later than the priority date claimed
"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention
"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone
"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art
"&" document member of the same patent family

Date of the actual completion of the international search	Date of mailing of the international search report
28 February 2025	**28 February 2025**

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

International application No.
PCT/US2024/056371

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
A	US 2011-0152135 A1 (CHEN, YIYAN et al.) 23 June 2011 (2011-06-23) whole document	1-20

INTERNATIONAL SEARCH REPORT
Information on patent family members

International application No.
PCT/US2024/056371

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