METHOD OF SEALING WELLS BY SQUEEZING SEALANT

Applicant: CSI Technologies LLC, Houston, TX (US)

Inventors: Fred SABINS, Montgomery, TX (US); Clifton MEADE, Houston, TX (US); David BROWN, Cypress, TX (US); Jeffrey WATTERS, Spring, TX (US); Jorge Esteban LEAL, Houston, TX (US)

Filed: Jun. 17, 2016

Related U.S. Application Data
Provisional application No. 62/203,140, filed on Aug. 10, 2015.

Publication Classification

Int. Cl.
E21B 33/14 (2006.01)
E21B 33/12 (2006.01)

U.S. Cl.
CPC ............... E21B 33/14 (2013.01); E21B 33/12 (2013.01)

ABSTRACT

A method for sealing a well includes: placing an obstruction in a bore of an inner tubular string disposed in a wellbore; forming an opening through a wall of the inner tubular string above the obstruction; mixing a resin and a hardener to form a sealant; and squeezing the sealant into the bore, through the opening, and into an annulus formed between the inner tubular string and an outer tubular string, thereby repairing a cement sheath present in the annulus.
METHOD OF SEALING WELLS BY SQUEEZING SEALANT

BACKGROUND OF THE DISCLOSURE

[0001] Field of the Disclosure

[0002] The present disclosure generally relates to a method of sealing wells by squeezing a sealant into an annulus thereof.

[0003] Description of the Related Art

[0004] The hard impermeable sheath deposited in the annular space in a well by primary cementing is subjected to a number of stresses during the lifetime of the well. The pressure inside the casing can increase or decrease as the fluid filling it changes or as additional pressure is applied to the well, such as when the drilling fluid is replaced by a completion fluid or by a fluid used in a stimulation operation. A change of temperature also creates stress in the cement sheath, at least during the transition period before the temperatures of the steel and the cement come into equilibrium. As a result of pressure and temperature changes, the integrity of the cement sheath can be compromised. Thus, it can become necessary to repair the primary cement sheath, such as during a plug and abandonment operation. One way to repair the primary cement sheath is by squeeze cementing, i.e., squeezing Portland cement therein.

[0005] The use of conventional Portland cement for squeeze cementing has limitations, for instance, if the primary cement sheath is leaking fluid, such as gas, through micro-channels, squeeze cementing is not feasible, even using micro-line ground Portland cement.

SUMMARY OF THE DISCLOSURE

[0006] The present disclosure generally relates to a method of sealing wells by squeezing sealant into the annulus between the inner and outer tubular strings. In one embodiment, a method for sealing a well includes: placing an obstruction in a bore of an inner tubular string disposed in a wellbore; forming an opening through a wall of the inner tubular string above the obstruction; mixing a resin and a hardener to form a sealant; and squeezing the sealant into the bore, through the opening, and into an annulus formed between the inner tubular string and an outer tubular string, thereby repairing a cement sheath present in the annulus.

[0007] In another embodiment, a method for sealing a well includes: placing an obstruction in a bore of an inner tubular string disposed in a wellbore; forming an opening through a wall of the inner tubular string above the obstruction; mixing a resin and a hardener to form a sealant; and squeezing the sealant into the bore, through the opening, and into an annulus formed between the inner tubular string and the wellbore, thereby repairing a cement sheath present in the annulus.

BRIEF DESCRIPTION OF THE DRAWINGS

[0008] So that the manner in which the above recited features of the present disclosure can be understood in detail, a more particular description of the disclosure, briefly summarized above, may be had by reference to embodiments, some of which are illustrated in the appended drawings. It is to be noted, however, that the appended drawings illustrate only typical embodiments of this disclosure and are therefore not to be considered limiting of its scope, for the disclosure may admit to other equally effective embodiments.

[0009] FIG. 1 illustrates delivery of an equipment package to a platform for performing the squeeze operation, according to one embodiment of the present disclosure.

[0010] FIG. 2A illustrates perforation of a production casing string. FIG. 2B illustrates deployment of a sealing string.

[0011] FIGS. 3A-3C illustrate operation of a mixing unit of the equipment package to form sealant.

[0012] FIG. 4 illustrates squeezing of the sealant into an annulus formed between the production casing string and a surface casing string.

[0013] FIGS. 5A and 5B illustrate a first alternative sealing operation, according to another embodiment of the present disclosure.

[0014] FIGS. 6A and 6B illustrate a second alternative sealing operation, according to another embodiment of the present disclosure.

[0015] FIGS. 7A and 7B illustrate a third alternative sealing operation, according to another embodiment of the present disclosure.

DETAILED DESCRIPTION

[0016] FIG. 1 illustrates an illustrative equipment package 1 used for performing the squeeze operation, and located on a platform 2, according to one embodiment of the present disclosure. The platform 2 may be part of a well 3 further including a subsea wellbore 4, a drive pipe 5, a surface casing string 6, a production casing string 7, and a production tubing string 8. The drive pipe 5 is commonly set from above a surface 9 (aka waterline) of the sea 9, through the sea, and into the seafloor 9' (aka mudline). The drive pipe 5 allows the wellhead (not shown) to be located on the platform 2 above the waterline 9.

[0017] Once the drive pipe 5 has been set, and (if desired cemented 10a), the subsea wellbore 4 is drilled into the seafloor 9' within the envelope of the drive pipe 5. The surface casing string 6 is then run-in the drive pipe 5 and into the wellbore 4 and cemented into place by forming a cement sheath 10b. When the wellbore 4 reaches a hydrocarbon-bearing formation 11, i.e., crude oil and/or natural gas, the production casing 7 is run into the wellbore 4 and cemented into place with cement sheath 10c. Thereafter, the production casing string 7 is perforated 12 to permit the fluid hydrocarbons (not shown) to flow into the interior thereof. The hydrocarbons are transported from the formation 11 through the production tubing string 8. An annulus 13 defined between the production casing string 7 and the production tubing string 8 is commonly isolated from the producing formation 11 with a production packer 14.

[0018] During production of hydrocarbons from the well 3, it may become necessary to workover the well, install an artificial lift system, and/or stimulate or treat the formation 11. To facilitate any of these operations, it is typically desirable to temporarily plug the well 3. Also, once the formation 11 has been produced to depletion, regulations often require permanently plugging the well 3 prior to abandoning the well 3. If either or both of the cement sheaths 10b,c have become compromised, they will need to be repaired during either the temporary or permanent plugging and abandonment operation, using the squeeze operation.
In order to prepare for the squeeze operation, the equipment package 1 is delivered to the platform 2 via a transport vessel (not shown). The equipment package includes a coiled tubing unit 15, a mixing unit 16, and a squeeze pump 17. The coiled tubing unit 15 includes a drum having coiled tubing 22 (FIG. 2B) wrapped therearound, a gooseneck, an injector head for driving the coiled tubing, controls, and a hydraulic power unit. A wireline winch 18 onboard the platform 2 may also be used to facilitate the squeeze operation. The wireline winch typically includes a drum having wireline 19 (FIG. 2A) wrapped therearound and a motor for winding and unwinding the wireline, thereby raising and lowering a distal end of the wireline relative to the platform 2.

FIG. 2A illustrates perforation of the production casing string 7. FIG. 2A shows the condition of the well during an abandonment or closing in operation, wherein a lower cement plug 21 has been set and the production tubing string 8 has been cut. To establish this condition, the well 3 abandonment operation commences by connecting a bottomhole assembly (BHA) (not shown) to the wireline 19 extending through a lubricator (not shown). In the embodiment, the BHA includes a cablehead, a collar locator, and a tubing perforator, such as a perforating gun.

To deploy the BHA into the well bore, one or more valves of the tree are opened and the BHA is deployed into the production tubing string in the wellbore 4 using the wireline 19. The BHA is deployed to a depth adjacent to and above the production packer 14. Once the BHA has been deployed to the desired depth, electrical power or an electrical signal is supplied to the BHA via the wireline 19 to fire the perforating gun into the production tubing string 8, thereby forming tubing perforations 20 through the wall thereof. The BHA is retrieved to the lubricator and the lubricator is then removed from the production tree.

Cement slurry (not shown) is then pumped through the production tree head, down the production tubing string 8, and into the annulus 13 via the created tubing perforations 20. Wellbore fluid displaced by the cement slurry will flow up the annulus 13, through the wellhead and to the platform 2. Once a desired quantity of cement slurry has been pumped into the annulus 13, an annulus valve of the wellhead is closed while continuing to pump the cement slurry, thereby forcing or “squeezing” cement slurry into the adjacent formation 11. Once pumped into place, the cement slurry is allowed to cure for a predetermined amount of time, such as one hour, six hours, twelve hours, or one day, thereby forming the cement plug 21 in the annulus, the surrounding formation, and within the lower portion of the production tubing string 8.

Once the cement plug 21 has cured, a second BHA (not shown) is connected to the wireline 19 in the lubricator and deployed through the production tree. The second BHA commonly includes a cablehead, a collar locator, an anchor, a hydraulic power unit (HPU), an electric motor, and a tubing cutter. The second BHA is deployed into the production tubing string 8 to a depth adjacent to and above the production packer 14. Once the second BHA has been deployed to the cutting depth, the HPU is operated by supplying electrical power via the wireline 19 to extend blades of the tubing cutter and operate the motor to rotate the extended blades, thereby severing an upper portion of the production tubing string 8 from a lower portion thereof. The second BHA is then retrieved to the lubricator and the lubricator is removed from the production tree. The production tree is removed from the wellhead and the severed upper portion of the production tubing string 8 is removed from the wellbore 4, leaving the wellbore in the state shown in FIG. 2A.

Once the severed portion of the production tubing string 8 has been removed, a third BHA (not shown) is connected to the wireline 19 in the lubricator and deployed through the wellhead. The third BHA commonly includes a cablehead, a collar locator, a setting tool, and a bridge plug 23. The third BHA is deployed to a setting depth along a portion of the production casing string 7 adjacent, and above, the lower terminus of the surface casing string 6. Once the third BHA has been deployed to the setting depth, electrical power is supplied to the third BHA via the wireline 19 to operate the setting tool, thereby expanding the bridge plug 23 against an inner surface of the production casing string 7. Once the bridge plug 23 has been set as shown in FIG. 2A, the bridge plug 23 is released from the setting tool. The third BHA (minus the bridge plug 23) is then retrieved to the lubricator and the lubricator is removed from the wellhead.

A fourth BHA 24 is then connected to the wireline 19 in the lubricator and deployed through the wellhead. The fourth BHA 24 commonly includes a cablehead, a collar locator, and a casing perforator, such as a perforating gun. The fourth BHA 24 is deployed to a firing depth adjacent to and above the bridge plug 23. Once the fourth BHA 24 has been deployed to the firing depth, electrical power or an electrical signal is supplied to the fourth BHA via the wireline 19 to fire the perforating gun into the production casing string 7, thereby forming casing perforations 25 through a wall thereof as shown in FIG. 2A. The fourth BHA 24 is then retrieved to the lubricator and the lubricator is removed from the wellhead.

FIG. 2B illustrates deployment of a scaling string. A fifth BHA 26 is connected to the coiled tubing 22 in a snubbing unit (not shown) and deployed through the wellhead. The fifth BHA 26 includes a squeeze packer and a setting tool. The injector head of the coiled tubing unit 15 is operated to lower the fifth BHA 26 to a squeezing depth adjacent to and above the casing perforations 25. Once the fifth BHA 26 has been deployed to the squeezing depth, the squeeze pump 17 is operated (not shown), such as a ball, through the coiled tubing 22 to a seat of the setting tool. Fluid pressure may then be exerted on the seated ball to operate the setting tool, thereby expanding the squeeze packer against an inner surface of the production casing string 7 to thereby seal the annulus between the coiled tubing 22 and the production casing string 7. In the embodiment, additional fluid pressure is then applied to drive the ball through the seat of the setting tool, thereby reopening the bore of the coiled tubing 22.

FIGS. 3A-3C illustrate operation of the mixing unit 16 to form sealant 28. The mixing unit 16 in the embodiment includes two or more liquid totes 29a, b, and a transfer pump 30a, b for each liquid tote, a dispensing hopper 31, and a blender 32.

Each transfer pump 30a, b is, in the embodiment, a metering pump and the dispensing hopper 31 is a metering hopper. An inlet of each transfer pump 30a, b is connected to a respective liquid tote 29a, b.

A first liquid tote 29a of the liquid totes 29a, b includes a resin 33r. The resin 33r may be an epoxide, such
as bisphenol F. The viscosity of the sealant 28 may be adjusted by premixing the resin 33r with a diluent, such as alkyl glycidyl ether or benzyl alcohol. The viscosity of the sealant 28 may range between fifty and two thousand centipoise. The epoxide may also be premixed with a bonding agent, such as silane. A second liquid tote 29b of the liquid totes 29a,b may include a hardener 33b selected based on the temperature in the wellbore 4. The contents of the liquid totes 29a,b may be reversed. For low temperature applications, the hardener 33b may be an aliphatic amine or polyamine or a cycloaliphatic amine or polyamine, such as tetraethylenepentamine. For high temperature applications, the hardener 33b may be an aromatic amine or polyamine, such as diethyltoluenediamine. The dispensing hopper 31 includes a particulate weighing material 34 having a specific gravity of at least two. The weighting material 34 may be barite, hematite, hausmannite ore, or sand.

0030 Alternatively, wellbore fluid may be non-aqueous and the resin 33r may also be premixed with a surfactant to maintain cohesion thereof. Alternatively, the resin 33r may also be premixed with a defoamer.

0031 To form the sealant 28, the first transfer pump 30a is operated to dispense the resin 33r into the blender 32. A motor of the blender 32 is then activated to churn the resin 33r. The hopper 31 is then operated to dispense the weighting material 34 into the blender 32. The weighting material 34 is added, as required, in a proportionate quantity such that a density of the sealant 28 corresponds to a density of the wellbore fluid. The density of the sealant 28 may be equal to, slightly greater than, or slightly less than the density of the wellbore fluid.

0032 The second transfer pump 30b is operated to dispense the hardener 33b into the blender 32. The hardener 33b is added in a proportionate quantity such that the thickening time of the sealant 28 corresponds to the time required to pump the sealant through the coiled tubing 22, plus the time required to squeeze the sealant into the annulus 36 (FIG. 4) formed between the production casing string 7 and the surface casing string 6, plus a safety factor, such as one hour. Once the blender 32 has formed the components of the sealant 28 into a homogenous mixture, a supply valve 35 connecting the outlet of the blender ultimately to the squeeze pump 17 may be opened.

0033 FIG. 4 illustrates squeezing of the sealant 28 into the annulus 36. The squeeze pump 17 is operated to pump the sealant 28 from the blender 32 and into the coiled tubing 22. The pumping may be monitored using the pressure gauge 37 of the equipment package 1. Once the sealant 28 has been pumped into the coiled tubing 22 downstream of the squeeze pump 17, the inlet of the squeeze pump 17 is then connected to a supply of chaser fluid (not shown), such as seawater, and the squeeze pump 17 is operated to pump the chaser fluid into the coiled tubing 22, thereby driving the sealant 28 through the coiled tubing 22 and into the annulus 36 via the casing perforations 25. The sealant 28 flows into or through voids in the cement sheath 10c, present in the annulus 36, thereby filling the voids and restoring the integrity of the cement sheath 10c. As the stroke volume of the squeeze pump may be known or calculated, a stroke counter of the squeeze pump 17 may be monitored during pumping and the squeeze pump shutoff once a desired volume of the chaser fluid has been pumped based on a certain number of strokes, corresponding to the internal volume of the coiled tubing 22 extending from the squeeze pump 17, thereby ensuring that all of the sealant 28 has been discharged from the coiled tubing 22. A portion of the sealant 28 also typically forms a bore plug in the production casing string 7. The sealant 28 may also plug a portion of the cement sheath 10c adjacent to the surface casing string 6.

0034 The squeeze packer is then unset, such as by exerting tension on (pulling on) the coiled tubing 22. The coiled tubing 22 and the fifth BHA 26 is retrieved to the platform 2 and the sealant is allowed to cure for a time, such as between one to five days. If the abandonment operation is permanent, once the sealant 28 has cured, the drive pipe 5, surface casing string 6, and production casing string 7 will typically be cut at or just below the sealfloor 9c, thereby completing the abandonment operation.

0035 FIGS. 5A and 5B illustrate a first alternative sealing operation, according to another embodiment of the present disclosure. In this alternative method of sealing, a sixth BHA 27 is deployed instead of the fourth BHA 24. The sixth BHA 27 is deployed to the firing depth adjacent to and above the bridge plug 23. The sixth BHA 27 is similar to the fourth BHA 24 except for having a deep casing perforator, such as a perforating gun, instead of the casing perforator. The deep casing perforating gun has a charge strength sufficient to form deep perforations 38 through the walls of the production 7 and surface 6 casing strings and the cement sheath 10c without damaging the wall of the drive pipe 5, thereby establishing access to the cement sheath 10b in an annulus 39 formed between the production and surface casing strings. After performing the perforation step, the sixth BHA 27 is retrieved to the lubricator and the lubricator is removed from the wellhead.

0036 The fifth BHA 26 is then connected to the coiled tubing 22 and the injector head of the coiled tubing unit 15 is operated to lower the fifth BHA to the squeezing depth adjacent to and above the deep perforations 38. Once the fifth BHA 26 has been deployed to the squeezing depth, the squeeze packer of the fifth BHA 26 is set. The squeeze pump 17 is operated to pump the sealant 28 from the blender 32 and into the coiled tubing 22 and then to chase the sealant with a secondary fluid such as seawater, thereby driving the sealant 28 through the coiled tubing 22 and into the annulus 36, 39 via the casing perforations 38. The sealant 28 flows into and through voids in the cement sheath 10b present in the respective annulus 36, 39, thereby filling the voids and restoring the integrity thereof. The sealant 28 may also plug a portion of the cement sheath 10c adjacent to the surface casing string 6 and a portion of the cement sheath 10b adjacent to the drive pipe 5.

0037 FIGS. 6A and 6B illustrate a second alternative sealing operation, according to another embodiment of the present disclosure. In this second alternative sealing method, the third BHA is deployed into the production casing string 7 to an alternative setting depth adjacent to a top of the severed production tubing string 8 and adjacent to the wellbore wall instead of along a portion of the production casing string 7 adjacent to the surface casing string 6. Once the third BHA has been deployed to the alternative setting depth, the bridge plug 23 is set and released from the setting tool. The third BHA (minus the bridge plug 23) is then be retrieved to the lubricator and the lubricator is then removed from the wellhead.

0038 The fourth BHA 24 is then connected to the wireline 19 in the lubricator and deployed through the wellhead. The fourth BHA 24 is deployed to an alternative firing depth
adjacent to and above the bridge plug 23. Once the fourth BHA 24 has been deployed to the alternative firing depth, electrical power or an electrical signal is supplied to the fourth BHA via the wireline 19 to fire the perforating gun into the production casing string 7, thereby forming alternative casing perforations 40 through a wall thereof. The fourth BHA 24 is then retrieved to the lubricator and the lubricator is removed from the wellhead.

The fifth BHA 26 is then connected to the coiled tubing 22 and the injector head of the coiled tubing unit 15 is lowered to the fifth BHA 26 to an alternative squeezing depth adjacent to and above the alternative casing perforations 40. Once the fifth BHA 26 has been deployed to the alternative squeezing depth, the squeeze packer of the fifth BHA 26 is set. The squeeze pump 17 is operated to pump the sealant 28 from the blender 32 and into the coiled tubing 22 and then to the sealant with a secondary fluid such as seawater, thereby driving the sealant 28 through the coiled tubing 22 and into the annulus 36 and the alternative casing perforations 40. The sealant 28 flows into and through the voids in the cement sheath and present in the annulus 36 thereby filling the voids and restoring the integrity of the cement sheath. The sealant 28 thereby plugs a portion of the cement sheath adjacent to the wellbore wall.

The fifth BHA 26 is then connected to the coiled tubing and the injector head of the coiled tubing unit 15 is lowered to the fifth BHA 26 to an alternative squeezing depth adjacent to and above the alternative deep perforations 41 through walls of the production 7 and surface 6 casing strings and the cement sheath 10c.

The fifth BHA 26 is then connected to the coiled tubing and the injector head of the coiled tubing unit 15 is lowered to the fifth BHA 26 to an alternative squeezing depth adjacent to and above the alternative deep perforations 41. Once the fifth BHA 26 has been deployed to the second alternative squeezing depth, the squeeze packer of the fifth BHA 26 is set. The squeeze pump 17 is operated to pump the sealant 28 from the blender 32 and into the coiled tubing 22 and then to the sealant with an alternative fluid such as seawater, thereby driving the sealant 28 through the coiled tubing 22 and into the annulus 36 and the casing perforations 38. The sealant 28 flows into and through voids in the cement sheath present in the respective annulus 36, 39, thereby filling the voids and restoring the integrity thereof. The sealant 28 plugs a portion of the cement sheath adjacent to the surface casing string 6 and a portion thereof adjacent to the wellbore wall. The sealant 28 may also plug a portion of the cement sheath adjacent to the wellbore wall.

Alternatively, a pipe string is used instead of the coiled tubing 22 to transport the sealant into the wellbore 4. The pipe string typically includes joints of drill pipe or production tubing connected together, such as by threaded couplings.

Alternatively, a cement plug is used instead of or in addition to the bridge plug 23.

Alternatively, the well may further include one or more intermediate casing strings between the surface 6 and production 7 casing strings and the sealant is squeezed into one or more annuli formed between the production casing string and the intermediate casing strings. Alternatively, the sealant is squeezed into an annulus formed between a liner string and a casing string or between the liner string and the wellbore wall.

Alternatively, the wellbore 4 may be subsea having a wellhead located adjacent to the seafloor and any of the sealing operations may be staged from an offshore drilling unit or an intervention vessel. Alternatively, the wellbore 4 may be subterranean and any of the sealing operations may be staged from a drilling or workover rig located on a terrestrial pad adjacent thereto.

While the foregoing is directed to embodiments of the present disclosure, other and further embodiments of the disclosure may be devised without departing from the basic scope thereof, and the scope of the invention is determined by the claims that follow.

1. A method for sealing a well, comprising:
   a. placing an obstruction in a bore of an inner tubular string disposed in a wellbore;
   b. forming an opening through a wall of the inner tubular string above the obstruction;
   c. mixing a resin and a hardener to form a sealant; and
   d. squeezing the sealant into the bore, through the opening, and into an annulus formed between the inner tubular string and an outer tubular string, thereby repairing a cement sheath present in the annulus.

2. The method of claim 1, wherein:
   a. the annulus is an inner annulus,
   b. the opening is also formed through a wall of the outer tubular string, and
   c. the sealant is also squeezed into an outer annulus, thereby repairing a cement sheath present in the outer annulus.

3. The method of claim 1, wherein the inner and outer tubular strings are both casing strings.

4. The method of claim 1, further comprising squeezing at least a portion of the sealant into a formation into which the inner tubular string extends.

5. The method of claim 1, further comprising squeezing at least a portion of the sealant into a formation into which the outer tubular string extends.

6. The method of claim 1, wherein the squeezing of the sealant into the bore, through the opening, and into an annulus formed between the inner tubular string and an outer tubular string comprises:
   a. pumping the sealant through a tubular extending into the inner tubular string and having a fluid volume; and
   b. thereafter pumping a quantity of chaser fluid into the tubular having at least the volume of the tubular.

7. The method of claim 1, wherein:
   a. the sealant is squeezed into the bore through coiled tubing, and
   b. the method further comprises:
      i. lowering the coiled tubing and a bottom hole assembly through the bore, and
      ii. forming the obstruction by setting a squeeze packer of the BHA against an inner surface of the inner tubular string.

8. The method of claim 1, wherein:
   a. the wellbore is a subsea wellbore,
   b. the method further comprises, prior to placing the obstruction:
      i. severing an upper portion of a production tubing string disposed in the wellbore from a lower portion thereof, and
      ii. placing a bridge plug in the wellbore,
removing the upper portion of the production tubing string from the wellbore.

9. The method of claim 1, wherein:
the resin is bisphenol F epoxide,
the hardener is selected from a group consisting of tetracylenepentamine for a low temperature well and diethyltoluenediamine for a high temperature well, and
the resin is premixed with a diluent selected from a group consisting of alkyl glycidyl ether and benzyl alcohol, and
the weighting material having a specific gravity of at least 2 is mixed with the resin and the hardener.

10. A method for sealing a well, comprising:
placing an obstruction in a bore of an inner tubular string disposed in a wellbore;
forming an opening through a wall of the inner tubular string above the obstruction;
mixing a resin and a hardener to form a sealant; and
squeezing the sealant into the bore, through the opening, and into an annulus formed between the inner tubular string and the wellbore, thereby repairing a cement sheath present in the annulus.

11. The method of claim 10, wherein:
the annulus is an inner annulus,
the opening is also formed through a wall of an outer tubular string, and
the sealant is also squeezed into an outer annulus, thereby repairing a cement sheath present in the outer annulus.

12. The method of claim 10, wherein the inner tubular string is a casing string.

13. The method of claim 10, wherein:
the sealant is squeezed into the bore through coiled tubing, and
the method further comprises:
lowering the coiled tubing and a bottom hole assembly (BHA) through the bore; and
setting a squeeze packer of the BHA against an inner surface of the inner tubular string.

14. The method of claim 10, wherein:
the wellbore is a subsea wellbore,
the method further comprises, prior to placing the obstruction:
severing an upper portion of a production tubing string disposed in the wellbore from a lower portion thereof; and
removing the upper portion of the production tubing string from the wellbore.

15. The method of claim 1, wherein:
the resin is bisphenol F epoxide,
the hardener is selected from a group consisting of tetracylenepentamine for a low temperature well and
diethyltoluenediamine for a high temperature well, and
the resin is premixed with a diluent selected from a group consisting of alkyl glycidyl ether and benzyl alcohol.

16. The method of claim 10, wherein the density of the sealant corresponds to the density of fluid present in the well.

17. The method of claim 10, wherein a viscosity of the sealant is between 50-2,000 cp.

18. The method of claim 10, wherein:
the resin is premixed with a bonding agent, and
the bonding agent is silane.

19. A method of infiltrating openings in a cement liner on the exterior of a subsurface tubular, comprising:
preparing a sealant comprising:
an epoxide resin,
a hardener selected from a group consisting of tetracylenepentamine for a low temperature well and
diethyltoluenediamine for a high temperature well, wherein:
extending a conduit inwardly of the subsurface tubular to a location therein having at least one opening extending through the wall thereof, the opening located above an obstruction in the tubular and extending through the tubular in a location where a cement is present on the exterior of the tubular; and
pumping the sealant through the conduit and through the at least one opening in the wall of the tubular, and thence into openings in the cement.

20. The method of claim 19, further comprising an obstruction between the conduit and the wall of the tubular in a location above the openings in the wall of the tubular before pumping the sealant.