CONCENTRIC COILED TUBING ANNULAR FRACTURING STRING

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ABSTRACT

An improved concentric coiled tubing annular fracturing string is disclosed having at least two fluid flow paths. An umbilical tube located inside of a coiled tubing string may provide one of the pathways, which may be used to isolate downhole elements, such as a packer, from harmful fluids. The annulus between the umbilical tube and the outer coiled tubing may provide the second flow pathway. The umbilical tube may contain an electric line, which may provide an electrical connection to a bottom hole assembly (“BHA”). The improved system may also provide for the measurement of down hole fracturing fluid pressure or be used to deliver a cross-linking agent to a specified portion of a well. The BHA may include an emergency packer deflation device to rapidly deflate a packer in the event the packer loses its ability to anchor against the casing.
CONCENTRIC COILED TUBING ANNULAR FRACTURING STRING

CROSS REFERENCE TO RELATED APPLICATION

[0001] This application is a Non-provisional application claiming benefit of U.S. Provisional Application Ser. No. 60/753,295, entitled, “Concentric Coiled Tubing Annular Fracturing String,” by John Edward Ravensbergen, Mitch Lambert, and Chad Northeast, filed Dec. 21, 2005, hereby incorporated by reference in its entirety herein.

BACKGROUND OF THE INVENTION

[0002] Field of the Invention

[0003] The present invention relates generally to an improved coiled tubing annular fracturing string and bottom hole assembly (“BHA”). The improved string includes an umbilical tube located inside a coiled tubing string connected to a BHA. The umbilical tube may be used, for example, to inflate or deflate a packer or used to activate a hydraulic set anchor. The invention is particularly useful in fracturing oil and gas wells with coiled tubing.

[0004] Description of the Related Art

[0005] U.S. Pat. Nos. 6,520,255 and 6,394,184 disclose a method of fracturing an oil/gas well, named the Annular Coil Tubing Fracturing Process, or the ACT-Frac Process for short. The ACT-Frac Process, and the corresponding bottom hole assembly (“BHA”) allows for the perforation and fracture of multiple zones downhole during a single trip of the BHA. The BHA disclosed in these patents is comprised of a number of components including an anchor, a packer, and multiple perforating guns. As the name of the process implies, the BHA is connected to the surface by a coiled tubing string.

[0006] In the ACT-Frac Process, the BHA is lowered into the casing of the oil/gas well with the coiled tubing. An electric wireline is located inside a coiled tubing string. The BHA includes an electrical casing collar locator (“CCL”), which is connected to the wireline and may be used to accurately position the BHA in the wellbore. A number of commercially available CCLs known to one of ordinary skill in the art may be used. The CCL is used to locate the first fracturing zone (i.e., lowermost) to be perforated and the perforating guns of the BHA are positioned within the first fracturing zone. After being properly positioned within the first fracturing zone, one of the perforating guns is discharged and the zone is perforated.

[0007] After perforating the fracturing zone, the BHA is lowered beneath the fracturing zone and the anchor is mechanically set against the casing. Fluid is then pumped down the coiled tubing string to inflate the packer until it is secure against the casing. Both the packer and the anchor, which is located below the packer, are set beneath the perforations. Once the packer and the anchor are set, fracturing fluid is pumped down the annulus between the coiled tubing string and the casing and into the perforations. The packer isolates the wellbore beneath the packer from the fracturing pressure.

[0008] After fracturing the zone, the packer is then deflated, the anchor is released, and the BHA is moved through the fracturing fluid/slurry that remains in the central bore. Washing fluid can also be pumped down the coiled tubing string and out one or more circulating ports located above the packer to wash any remaining fracturing fluid or fracturing slurry away from the packer and the BHA. The BHA is then positioned such that the perforating guns are located in the next fracturing zone (above the previously fractured zone) to be perforated and the process is repeated.

[0009] A simpler alternative configuration of a BHA used in the ACT-Frac Process may include an inflatable packer without an anchor. Instead, the inflatable packer is used to both isolate the zone and anchor the BHA against the casing. The packer is inflated against the casing and may be required to hold a pressure differential from above to below the packer of up to 7000 psi. One vital characteristic of the inflatable packer used in this BHA is its ability to anchor itself using the friction force between the inflated packer and the casing, which will typically be sufficient if the pressure within an inflated packer is greater than the pressure above the packer. However, if the pressure drop across the packer is large and the pressure above the packer becomes the same as the pressure inside the inflated packer, the packer will lose its ability to anchor against the casing. In this instance, the force generated by the pressure drop across the packer is now only resisted by the coiled tubing string.

[0010] The failure of the inflatable packer to remain anchored presents a serious problem if the pressure drop across the packer is large as would be appreciated by one of ordinary skill in the art having the benefit of this disclosure. A typical 1 1/4 inch coiled tubing string at a depth of 13,000 feet can typically handle a maximum overpull of 25,000 lbs. If a force of 25,000 lbs. or more is exerted on the coiled tubing string the coiled tubing string may either break or activate an emergency release sub. In either event, the BHA will be dropped into the wellbore, which may require an expensive fishing job to remove the BHA from the wellbore. Fishing for live perforating guns may increase the cost of fishing the BHA due to regulatory pressures. If the packer loses its ability to anchor, a relatively small pressure drop from above to below the packer can create a force of 25,000 lbs. For example, in a 4 1/2 inch casing, a pressure drop of approximately 2,000 psi across the packer will generate a 25,000 lbs. force on the coiled tubing string in the instance that the packer loses its ability to anchor. As the diameter of the casing increases, a smaller pressure drop is required to produce the same amount of force on the coiled tubing string. For example, in a 7 inch casing a pressure drop of approximately 800 psi across the packer may create a 25,000 lbs. force in the event the packer loses its ability to anchor.

[0011] There are two instances when the pressure above the packer becomes the same as the pressure inside of the packer. One such instance is when the pressure inside the packer is reduced. The pressure in the packer can decrease if fluid is removed from inside the packer during the deflation process or if the packer fails, allowing fluid to exit the packer into the wellbore below the packer.

[0012] If the packer is deflated when the pressure drop across the packer is small, the deflation process is done in a controlled and safe manner as the pressure induced load on the BHA is less than the force required to shear the emergency release tool or break the CT string. However, under some circumstances the pressure drop across the packer is
not known before the deflation process begins. In addition, it may be advantageous to hold up to 500 psi pressure differential across the packer during the deflation of the packer to fluidize the proppant that has settled on the packer when the packer is deflated.

[0013] The packer has the highest probability of failing when the pressure differential across the packer is high, and as a result the pressure inside the packer is high. When the pressure differential across the packer is large the forces imparted on the BHA are large. Therefore, there is a high probability that if the packer fails the forces will be large and the emergency release tool may activate or the CT string may break.

[0014] The other such instance of when the pressure above the packer becomes the same as the pressure inside of the packer is when the pressure above the packer, which is the fracturing pressure, increases to the pressure within the packer. The fracturing pressure can rise quickly and unexpectedly during a screen out, also referred to as a sand off. As discussed above, the pressure drop across the packer can be as much as 7000 psi during the fracturing process, but the pressures can exceed 7000 psi if a screen out occurs. The screen out pressure is often above the pressure rating of the packer, which may cause the packer to fail. If the packer were to lose its ability to anchor while experiencing such a high pressure drop, the forces generated by the pressure drop may be too massive for the coiled tubing string to withstand, thus breaking the coiled tubing string or releasing an emergency release sub in the BHA. In the event this occurs, live perforation may be dropped into the wellbore requiring a later retrieval or discharge of the perforation guns.

[0015] As is discussed above, the coiled tubing string has two prime hydraulic functions. Namely, to deliver fluids to set and unset the packer as well as to deliver fluids to one or more wash ports in an attempt to remove any residual fracturing fluid or slurry. The ACT-Frac Process may have certain advantages or potential issues. Many of these disadvantages or potential issues are due to the two hydraulic functions, but only one flow path, i.e. the coiled tubing string.

[0016] One potential issue deals with the hydraulic valves used to switch between delivering fluid to inflate the packer and delivering wash fluid to the ports to remove excess fracturing fluid/slurry. Hydraulic valves have moving parts with small clearances between the moving parts relative to the size of a particle or mill scale typically found in a coiled tubing string. The use of such valves requires the careful filtering of the fluids at both the surface and at the BHA to minimize the risk of damaging or fouling the valve mechanisms.

[0017] The use of hydraulic valves to switch between hydraulic functions of the coiled tubing string also adds complexity to the BHA. The complexity of the BHA may increase the cost to purchase and to maintain the BHA. Additionally, the presence of the valves requires a highly trained staff to maintain and operate the BHA. Over time the valves may not function properly due to repeated use and also being repeatedly subjected to harsh and damaging chemicals.

[0018] Acid and/or inhibited acid may be pumped through the coiled tubing string to stimulate the formation before each fracturing stimulation. Inhibitors in the acid are harmful to the mechanisms in the hydraulic valves and may increase the likelihood of valve failure. Acid is harmful to metal used in the BHA and/or coiled tubing string. The use of inhibitors often creates a coating on the metal in an effort to protect it from the acid, but this coating may seep into the valves potentially causing the valves to malfunction. Additionally, chemically corrosive fluids, such as fluids containing nitrogen, used for stimulation, treatment, or washing of the BHA may be pumped downhole through the coiled tubing string. These fluids can chemically attack the rubber used to manufacture the packer, compromising the packer’s ability to repeatedly hold high pressure at downhole temperatures. The chemicals pumped down the coiled tubing string may also be corrosive to the electric wireline located inside the coiled tubing string used to communicate electrically to the BHA.

[0019] The fact that the coiled tubing string has two hydraulic functions, but only one fluid path presents another potential problem. When fracturing a perforated zone fracturing fluid is pumped down the annulus between the casing and the coiled tubing string while fluid is pumped down the coiled tubing string to inflate and set the packer against the casing holding the BHA in place. However the one fluid flow path may be a problem if circulating fluid needs to be pumped down the coiled tubing string to the fracturing zone. The original process was not designed to handle pumping circulating fluid in a timely manner. Instead, the circulating ports must first be activated by switching the valves in the BHA from the packer to the circulating ports. Additionally, the fluid source for the pump needs to be switched between the fluid used to inflate the packer and the circulating fluid. Alternatively, a second pump attached to the circulating fluid may be used, but this requires hydraulically connecting the second pump to the coiled tubing string. In any case, if a problem with the fracturing fluid arises the original design does not provide an apparent rapid solution.

[0020] Another potential problem of the coiled tubing string and BHA design may arise in the event that the packer fails. The prior design of the BHA used in the ACT-Frac Process does not provide a flapper valves or valve protection against fluid flow up the coiled tubing string. Thus if the packer were to fail, hydrocarbons present in the well may flow up through the coiled tubing string to the surface.

[0021] As is discussed above, prior designs disclose using a mechanically set anchor below the packer. One potential problem with a mechanically set anchor is that the setting mechanism may become damaged or fouled when dirty fluids are present in the well annulus. In addition, while setting an inflatable packer, large additional setting forces can be imparted to the anchor. Theses forces may become large enough that it is no longer possible to release the anchor with the CT string. Additionally, the substantial change in shape of the inflatable packer from its deflated state to its inflated set state may impart loads into the packer mandrel and subsequently into the anchor while the packer is set. The location of the anchor below the packer may lead to the buckling of the packer mandrel for packer designs in 4½ inch casings or smaller due to the loads imparted from the setting of the packer.

[0022] Another problem with current fracturing methods is the failure to know the downhole pressure of fracturing
fluid at all times during the fracturing process. It is useful to monitor the downhole pressure of the fracturing fluid in real time in order to better manage the fracturing process. When fracturing a well the fluid pressure of the fracturing fluid causes a crack or a fracture in the formation to propagate. Proppant in the fracturing fluid holds the fracture open after the fracturing fluid exits the crack. However, too much proppant at the leading edge of the fracture may create a sand-out. A sand-out occurs when the proppant, which is often sand, reaches the leading edge of the fracture thereby not allowing enough fluid flow to continue to propagate the fracture in the formation. The downhole fluid pressure of the fracturing fluid is rather difficult to determine because the composition of the fracturing fluid changes throughout the process as the amount of proppant is increased over the duration of the process, thus changing the density of the fracturing fluid. The changing density as well as frictional pressure drop as the fracturing fluid travels down the annulus makes it difficult to determine the bottom hole pressure of the fracturing fluid.

Another problem with accurately determining the pressure at the perforation tunnel is the fracturing fluid can be designed to cross-link as it moves downhole thus, thickening the fluid. Ideally, the fracturing fluid becomes fully cross-linked just as it reaches the perforated formation in the well. However, the viscosity of the fluid increases as it becomes more cross-linked. The changing viscosity makes it difficult to calculate the frictional pressure drop of the fracturing fluid, thereby making it difficult to calculate the bottom hole pressure of the fracturing fluid.

Another problem relates to the use of inflatable packers comprised of synthetic rubber. Synthetic rubber is used because it is more chemically resistant than natural rubber to hydrocarbon fluids. The packer is one of the most expensive components of the BHA, as a new packer typically is required for each trip of the BHA into the well casing. The use of an inflatable packer may present a problem in the removal of a BHA from the well casing. Generally a packer will deflate to a size that is larger in diameter than its original size (e.g., ½ inch larger in diameter) once it has been inflated and set against the casing. This presents a serious problem as the packer may not allow or make it more difficult for the proppant to flow past the packer after deflation and thereby causing the BHA to become stuck downhole.

In light of the foregoing, it may be desirable to provide an emergency packer deflation device that may rapidly remove the fluid from an inflated packer in the event the packer loses its ability to anchor against the casing. By removing the fluid from the packer, the packer rapidly deflates and the coiled tubing string will not be subjected to a large force due to a pressure drop across the packer. It may further be desirable to provide an emergency packer deflation device that is adapted to equalize the pressure across the packer.

It may be desirable to provide a coiled tubing string that does not have one fluid flow path for two hydraulic functions. It may also be desirable to provide a coiled tubing string that does not use valves to switch between hydraulic functions. Further, it may be desirable to provide a coiled tubing string that has separate fluid paths to eliminate potential problems caused by corrosive chemicals pumped down to the BHA. It may be desirable for a coiled tubing string to be able to pump down fluid to circulate downhole fracturing fluid while also pumping fluid in a separate fluid path that keeps a packer inflated and/or an anchor set against a well casing. It may also be desirable to provide a coiled tubing string that allows for the monitoring of hydrostatic pressure or downhole temperature at the perforation tunnel. Additionally, it may be desirable for a coiled tubing string to provide for the injection of a cross-linking catalyst at the fracturing zone. It may also be desirable for a coiled tubing string that provides negative pressure to a packer to ensure that the packer deflates substantially its original dimensions. It may further be desirable for the BHA to include a hydraulically set anchor located above the packer for 4½ inch diameter and smaller casing sizes. Finally, it may be desirable for the BHA to include flapper valves to prevent the flow of well fluid up the coiled tubing string even if the packer was to fail.

The present invention is directed to overcoming, or at least reducing the effects of, one or more of the issues set forth above.

SUMMARY OF THE INVENTION

The present application discloses an improved annular coiled tubing fracturing system that provides separate fluid paths to the BHA for at least two different hydraulic functions. In one embodiment, this is achieved by installing an umbilical tube inside the coiled tubing string. Preferably, the umbilical tube is a coiled tubing string with a smaller diameter inserted inside a large coiled tubing string (“the CT string”). Preferably, the umbilical tube and the CT string create a concentric coiled tubing string. The umbilical tube may be used to deliver fluid to inflate a packer and/or to activate a hydraulic set anchor. The umbilical tube may also provide the fluid path for the release of fluids to deflate the packer and/or deactivate the hydraulic set anchor. The umbilical tube can also be used in a conduit for the electric wireline to protect it from corrosive fluids pumped down the CT string. The CT string may be used to deliver different fluids to fluidize settled proppant, and/or wash proppant out of the wellbore between fracturing procedures. Alternatively, the umbilical tube may be used to deliver fluids to fluidize settled proppant and/or wash proppant while the CT string may be used to deliver fluid to inflate a packer and/or to activate a hydraulic set anchor.

In one embodiment, the CT string may be attached to a BHA with at least one fluid port located near the top of the packer. In one embodiment, the at least one fluid port may include a one way valve, such as a flapper valve for example, to prevent fluid in the well from flowing up the CT string.

The umbilical tube may be connected to a packer element of the BHA and may provide a fluid path to inflate or deflate the packer. The umbilical tube may additionally be connected to a hydraulically actuated anchor and provide a fluid path to activate or deactivate the anchor.

In one embodiment an electric line or a wireline may be run downhole inside the umbilical tube. The electric line may be electrically connected to various elements in the BHA. The electric line may be encased by a number of steel cables, which both protect the electric line as well as provide the requisite strength to the line. The umbilical tube may be
used to protect the wireline from acid, as wirelines are often made from galvanized extra plow steel, which is susceptible to corrosive attack from acids.

[0032] The use of an umbilical inside the CT string provides two fluid flow paths allowing for the use of different fluids. Specifically, the two fluid paths allow the use of a washing fluid and a different less corrosive fluid to control the packer and/or anchor. In one embodiment, the umbilical may be corrosion free tubing, such as stainless steel tubing, and may deliver clean fluids to the packer, anchor or both. The two fluid flow paths allows for the circulation of fracturing fluid while a different fluid is pumped down the umbilical tube to inflate the packer, if needed.

[0033] In one embodiment, a fluid with a specific gravity lower than water may be used in the umbilical. A low specific gravity umbilical fluid is useful to create a hydrostatic pressure in the BHA that is less than the hydrostatic pressure in the wellbore when the BHA is in the wellbore at typical fracturing depths. A relatively low pressure in the BHA, with respect to the wellbore pressure, may be useful in forcing the packer to completely deflate and return to its original shape. A relatively low pressure in the BHA, with respect to the wellbore pressure, may also be useful to force the buttons of a hydrostatic set anchor to completely retract.

A completely deflated packer and completely retracted buttons may decrease the chance that the BHA becomes stuck in the wellbore. An example of a suitable low specific gravity fluid is Petro-Canada’s HT 40N drilling mud, which is a clear fluid with a specific gravity of 0.83. Additionally, Petro-Canada’s HT 40N drilling mud also has a high dilution number and therefore is not chemically aggressive toward synthetic rubber. The use of fluid with a low freezing temperature in the umbilical may allow operation in the winter when temperatures drop below the freezing point of water based fluids. The use of other fluids, such as methanol/water acid, that do not harm the rubber in a natural rubber packer may allow the repeated use of the same packer in subsequent downhole trips removing a considerable expense of such operations.

[0034] Explosive decompression occurs in rubber when exposed to high pressure gas. The use of an umbilical may prevent exposure of the rubber in the packer to high pressure gas. Wash fluid is often water or a water based fluid mixed with nitrogen gas, as it is an ideal, low cost fluid for performing clean up operations. However, fluids containing nitrogen may damage the rubber used to construct inflatable packers. The umbilical tube may be used to eliminate exposure to nitrogen gas on the inside of the packer.

[0035] As discussed above, a serious problem occurs if the packer becomes stuck downhole. In one embodiment, a special fluid may be pumped down the umbilical tube and/or the CT string in an effort to help dislodge the packer. The fluid may contain a chemical, such as xylene, that attacks or weakens the rubber elements in the packer. After weakening the rubber elements, the packer may then be able to be removed from the wellbore.

[0036] In one embodiment, the CT string may be used to deliver a cross-linking catalyst to the fracturing fluid to cross-link the fracturing fluids at the perforations, just before the fracturing fluid slurry enters the formation. The cross-linking agent may be pumped down the CT string and enter the casing at the fracturing zone, which is the portion of the wellbore directly above the packer, via circulation ports allowing for better control of the timing of the cross-linking, optimizing the suspension of the propellant in the fracturing fluid.

[0037] Another improvement of the umbilical embodiment is that the electric line in the umbilical can be used during the ACT-Frac Process to measure the fracturing fluid pressure real time. During the ACT-Frac Process it is difficult to know the pressure down hole from measuring the fracturing fluid injection pressure due to the dynamics of the pumping process and the changing properties of the fracturing fluids. Additionally, the frictional pressure drop of the slurry is difficult to calculate. In real time, the downhole pressure may be measured down hole via a pressure transducer and be communicated back to surface via the electric line.

[0038] In another embodiment, the fracturing pressure may also be determined by measuring the injection pressure into the CT string at surface or the injection pressure into the umbilical string at surface. Typically the fluid properties in the CT string or the umbilical string are not changing in time and their properties are well understood. In addition, the injection rate may be low or even static such that the frictional pressure drop may not complicate the interpretation of the pressure down hole. Thus, it is relatively easy to calculate the hydrostatic pressure in both the CT string and the umbilical. The downhole pressure can be substantially determined by slowly pumping fluid down the CT string to where the pumped fluid very slowly exits the CT string from the circulation ports. Because the fluid is pumped slowly, any frictional forces may be disregarded and the downhole fracturing fluid pressure may be approximated by adding the hydrostatic pressure of the CT string to the pumping pressure.

[0039] Another embodiment of the present disclosure may include a second umbilical tube in the CT string. The second umbilical may be run the length of the CT string or alternatively be a partial length and be used to pump a third fluid down the CT string. The fluid pumped down the second umbilical may be nitrogen used to chase or de-pressure at least a portion of the CT string or the other umbilical string. The number of umbilical tubes and fluids used in them may be varied according to BHA applications as would be apparent to one of ordinary skill in the art having the benefit of this disclosure.

[0040] Another embodiment of the present disclosure may include an emergency packer deflation device that quickly draws the fluid out of the inflatable packer once the packer loses its ability to anchor against the casing. The emergency packer deflation device may be connected to the BHA directly above the inflatable packer. As discussed above, once the packer loses its ability to anchor the pressure drop across the packer transfers a load onto the CT string. This load may shear a set of shear pins in the emergency packer deflation device. The pressure drop may also rapidly push the packer downhole. The rapid movement of the packer away from the emergency packer deflation device may stroke a piston, which may rapidly draw the fluid out of the packer through a large area flow path between the packer and the emergency packer deflation device. Once the packer is deflated, the pressure drop across the packer is greatly
reduced, thus reducing the load on the CT string. Further, the emergency packer deflation device may be adapted such that once the piston stops moving the pressure within the emergency packer deflation device may be equalized with the wellbore pressure. This rapid deflation of the packer may prevent dropping the BHA into the wellbore due to the breakage of the CT string or the releasing of an emergency release sub.

[0041] One embodiment is a method of fracturing a perforated zone of a wellbore with a coiled tubing string having at least two flow paths the method includes pumping a first fluid down a first flow path of the coiled tubing string to inflate a packing element to isolate a zone of a wellbore and pumping fracturing fluid down the annulus between the coiled tubing string and the wellbore. The method includes pumping a fluid down the second flow path of the coiled tubing string, the fluid being a wash fluid and circulating the wash fluid to the perforating zone through one or more fluid ports in the coiled tubing string.

[0042] The method may further include applying a negative pressure within the first flow path of the coiled tubing string to deflate the packing element. The application of a negative pressure may provide that the packing element adequately deflates decreasing the chance that the packing element may become stuck within the wellbore. A fluid with a low specific gravity fluid may be pumped down the first flow path to inflate the packing element.

[0043] The method may include communicating with a downhole element connected to the coiled tubing string to determine the temperature, pressure, or location of the fracturing zone. An electrical wireline located within the first flow path may be used to communicate with the downhole element. In one embodiment the method may include pumping fluid down the first flow path of the coiled tubing to set an anchor. Alternatively, the inflated packing element may anchor within the wellbore. The method may include pumping a cross-linking agent down the second flow path of the coiled tubing string circulating the cross-linking agent through the one or more fluid ports in the coiled tubing string. The method may include pumping a fluid down the second flow path and circulating the fluid out of the one or more fluid ports to determine the fluid pressure of the zone of the wellbore, wherein the fluid is slowly pumped down the second flow path. The method may include pumping a fluid down a second flow path of the coiled tubing string, the second fluid being acid and circulating the acid to the perforating zone through one or more fluid ports in the coiled tubing string.

[0044] Another embodiment is a method of fracturing the formation of a perforated zone of a wellbore with a coiled tubing string having a first flow path and a second flow path, the method includes pumping a first fluid down the first flow path to inflate a packing element to isolate a zone of a wellbore and pumping fracturing fluid down the annulus between the coiled tubing string and the wellbore after the zone of the wellbore has been isolated, wherein the fracturing fluid is pumped down the annulus until the formation is fractured. The method further includes pumping a fluid down the second flow path of the coiled tubing string while the fracturing fluid is pumped down the annulus and circulating the fluid that includes a cross-linking agent to the perforating zone through one or more ports in the coiled tubing string while the fracturing fluid is pumped down the annulus. The method may include pumping wash fluid down the second flow path after the fracturing fluid is no longer pumped down the annulus and circulating the wash fluid to the perforating zone through the one or more ports in the coiled tubing string.

[0045] The method may include pumping acid down the second flow path and circulating the acid to the perforating zone prior to pumping fracturing fluid down the annulus. The method may also include applying a negative pressure within the first flow path of the coiled tubing string to deflate the packing element after circulating wash fluid to the perforating zone.

[0046] Another embodiment is a method of fracturing a perforated zone of a wellbore with a coiled tubing string comprising setting a packing element to isolate the perforated zone of the wellbore, pumping fracturing fluid down the annulus between the coiled tubing string and the wellbore, pumping a wash fluid down the coiled tubing string, and circulating the wash fluid to the perforating zone through one or more fluid ports in the coiled tubing string.

[0047] Another embodiment is a method of fracturing a perforated zone of a wellbore with a coiled tubing string having at least two flow paths. The method includes pumping a first fluid down a first flow path to inflate a packing element to isolate a zone of a wellbore and pumping fracturing fluid down the annulus between the coiled tubing string and the wellbore after the zone of the wellbore has been isolated, the fracturing fluid being pumped until the formation is fractured. The method further includes pumping a wash fluid down a second flow path of the coiled tubing string while the fracturing fluid is pumped down the annulus and circulating the wash fluid to the perforating zone through one or more ports in the coiled tubing string while the fracturing fluid is pumped down the annulus.

BRIEF DESCRIPTION OF THE DRAWINGS

[0048] FIG. 1 shows the BHA used in the ACT-Frac Process.

[0049] FIG. 2 shows the BHA used in the preferred embodiment of the present disclosure.

[0050] FIG. 3 shows a cutaway view of the present disclosure of a CT string that includes an umbilical tube positioned inside the CT string.

[0051] FIG. 4 is a pressure schematic of a BHA having an umbilical connected to both a hydraulic anchor and a packer.

[0052] FIG. 5 is a pressure schematic of a BHA having an umbilical connected directly to a packer.

[0053] FIG. 6 shows an embodiment of the present disclosure of a BHA that includes an emergency packer deflation device.

[0054] FIG. 7 shows the packer moving away from the emergency packer deflation device of FIG. 6.

[0055] FIG. 8 shows the removal of fluid from the packer by the emergency packer device of FIG. 6.

[0056] FIG. 9 is cross-section view E-E of the embodiment of the BHA of FIG. 6.
Fig. 10 shows the fluid in the packer and emergency packer deflation device at the same pressure and in fluid communication with the wellbore fluids.

While the invention is susceptible to various modifications and alternative forms, specific embodiments have been shown by way of example in the drawings and will be described in detail herein. However, it should be understood that the invention is not intended to be limited to the particular forms disclosed. Rather, the intention is to cover all modifications, equivalents and alternatives falling within the spirit and scope of the invention as defined by the appended claims.

Illustrative embodiments of the invention are described below as they might be employed in the use of designs for concentric coiled tubing annular fracturing. In the interest of clarity, not all features of an actual implementation are described in this specification. It will of course be appreciated that in the development of any such actual embodiment, numerous implementation-specific decisions must be made to achieve the developers' specific goals, such as compliance with system-related and business-related constraints, which will vary from one implementation to another. Moreover, it will be appreciated that such a development effort might be complex and time-consuming, but may nevertheless be a routine undertaking for those of ordinary skill in the art having the benefit of this disclosure.

Further aspects and advantages of the various embodiments of the invention will become apparent from the following description and drawings.

As shown in Fig. 1, a BHA 5 is connected to the surface via coiled tubing 10. The BHA 5 has circulation ports 55 and includes a coiled tubing connector 50, a fishing sub 60, an inflatable packer 70, a mechanically set anchor 80, a CCL 90, and perforating guns 100. As discussed above, the original ACT-Frac Process required fluid to be pumped down the coiled tubing string 10 to both wash the packer using the circulation ports 55 and to inflate the packer 70. The BHA may be connected to an electric line that runs from the surface down the coiled tubing 10. The electric line is used to activate one of the perforating guns 100. The electric line is thus exposed to each potentially corrosive fluid that flows through the coiled tubing 10. The improved system and process of the present disclosure provides the benefit of a separate flow path from the coiled tubing.

Fig. 2 shows a preferred embodiment of a BHA 5 used in the ACT-Frac process. The CT string 10, the umbilical tube 20 and electric line 30 are connected to the BHA 5 through a grappling with centralizer 13. At the top of the BHA 5 is an electric line and umbilical anchor release 14 and a double flapper check valve 16.

The BHA 5 may contain a shear sub 17. If the packer or BHA becomes stuck in the hole, the upper portion of the BHA can be separated from the lower portion of the BHA at the shear sub 17. The BHA may further include an upper universal connect/disconnect ("UCD") 18 connected to a lower UCD 19. A deployment bar 21, which may include a hydraulic filter, may be connected to the lower UCD 19. The BHA may include a double flapper check valve 22 and memory gauges 23 above an anchor 80. In a preferred embodiment, the anchor 80 is hydraulically set. In casing sizes of 4 1/2 inches and smaller in diameter, the anchor may be located above the packer 70. Wash ports 55 connected to the CT string 10 may be located between the anchor 80 and the packer 70 and may be used to wash away proppant from the packer 70 and the anchor 80, or the entire BHA 5. A bypass screen 26, 97 may be used to filter the fluid passing through the bypass. The bypass may allow fluid to travel from below the packer to above the packer at all times, which may prevent pressure from building up below the packer 70. The BHA 5 may also contain an element 24 to rapidly deflate the packer 70 in an emergency.

The packer may include a packer mandrel 71 that has a spring loaded sliding end 72. Below the packer mandrel 71 may be a double flapper check valve 96 that prevents the flow of fluid down the bypass. Below the double flapper check valve 96 may be a lower bypass screen 97, a memory gauge 98 for the lower zone of the BHA 5, and a connection 99 to lower elements such as a CCL and/or perforation guns.

As shown in Fig. 3, the improved concentric coiled tubing annular fracturing string includes an umbilical tube 20 contained inside of the CT string 10. This configuration provides separate fluid paths 15, 25 for at least two different functions. The umbilical tube 20 can be used to deliver fluid via fluid path 25 to inflate a packer 70 and/or to activate a hydraulic set anchor 80. The umbilical tube 20 may also provide the fluid path 25 for the release of fluids to deflate the packer 70 and/or deactivate the hydraulic set anchor 80. The fluid delivered by the umbilical tube 20 may be filtered or be a clean non-corrosive fluid that will not chemically attack the packer 70 or the anchor 80. Thus, the packer can be constructed of natural rubber and may be used in repeated trips of the BHA downhole. In one embodiment, the umbilical tube 20 may be comprised of a different material than the CT string 10, such as stainless steel.

An electric wireline 30 may be run downhole inside the umbilical tube 20 as shown in FIGS. 2 and 3. The electric wireline 30 may be electrically connected to various elements in the BHA 5. For example, the electric wireline 30 may be connected to the perforating guns 100 allowing an electric signal to be sent from the surface to discharge a selected perforating gun 100. The electric wireline 30 may be encased by a number of steel cables 40, such as a 7/32 inch diameter steel cable commercially offered by Camesa, Inc. of Rosenberg, Tex., which both protects and strengthens the electric line 30. The umbilical tube 20 may be used to protect the wireline 30 from acid as electric wirelines are often galvanized extra plow steel, which is susceptible to corrosive attack from acids. The electric wireline 30 in the umbilical tube 20 may also be used to measure the fracturing fluid pressure as well as the downhole temperature as the electric wireline 30 may be connected to a pressure transducer and/or a temperature device. The electric wireline 30 in the umbilical tube 20 may also be used to operate an electrical CCL.

While the umbilical tube 20 may contain an electric line 30 and may be used to deliver fluid to a packer 70 and/or anchor 80, the CT string 10 may be used to fluidize settled proppant, and/or wash proppant out of the wellbore between fracturing procedures. The CT string 10 may also be used to deliver acid to the fracturing zone before each fracturing.
procedure. The CT string 10, attached to the BHA 5, may include at least one fluid port 55 located near the top of the packer 70. The at least one fluid port 55 may include a one way valve, such as a flapper valve 16 (shown in FIG. 2) for example, to prevent fluid in the well from flowing up the CT string 10.

[0068] FIG. 4 shows a pressure schematic of an umbilical 20 in fluid communication via fluid path 25 to both an anchor 80 and a packer 70. The end of the umbilical 20 may be connected to a check valve 65 preventing downward flow that is in parallel with a pressure relief valve 85. The pressure relief valve 85 may be set at a predetermined pressure, such as 500 psi, thus requiring that the pressure builds in the umbilical before the pressure relief valve opens and the hydraulic anchor 80 is activated. Check valves 65 and pressure relief valve 85 may function together. The purpose of the valves 65, 85 is to isolate the packer and anchor from relatively high hydrostatic pressure within the BHA.

As described above, a low specific gravity fluid may be used to create a relatively low hydrostatic pressure within the BHA when the BHA is at typical fracturing depths. A relatively low pressure in the BHA can also be created by pumping fluid into the wellbore depending on the reservoir’s hydraulics. However, it is possible to have a relatively low pressure within the BHA at typical fracturing depths, but to have a relatively high pressure within the BHA at shallower depths. The valves 65, 85 ensure that the pressure in the BHA does not exceed the pressure in the wellbore so that the packer may remain deflated and the buttons in the anchor may remain retracted.

[0069] Below the anchor 80, the hydraulic circuit may include a pilot operated valve 110 in parallel with both a check valve 115 and another pressure relief valve 95. The check valve 115 prevents downward flow, but may allow the packer fluid to drain into the umbilical tube during deflation. An additional check valve 105 may be used to prevent wellbore fluids from entering the BHA while the pilot valve 110 is open. The pilot operated valve 110 may be normally open to the fracturing zone 120 allowing fluid to flow out of the BHA into the fracturing zone 120. The pilot operated valve 110 is set to close when the pressure in the anchor 80 reaches a predetermined pressure, such as 4500 psi, above the fracturing zone 120 pressure. The pilot operated valve 110 is set to re-open when the pressure in the anchor is 2500 psi above the fracturing zone pressure. This configuration of the pilot operated valve 110 ensures that the anchor 80 is set before the packer 70 inflates and that the packer 70 deflates before the anchor 80 is deactivated. The pressure relief valve 95 may be configured such that it is closed until the pressure in the anchor reaches a predetermined pressure, such as 5000 psi above the fracturing zone pressure, which is greater than the closing pressure for the pilot operated valve 110.

[0070] Once the pressure inside the hydraulic circuit reaches the predetermined pressure causing the pressure relief valve 95 to open, the flow through the hydraulic circuit will begin to inflate the packer 70 expanding the packer 70 against the well casing. The hydraulic circuit may include a pressure relief valve 75 that prevents overflow of the packer. The pressure relief valve 75 may allow fluid to pass out of the BHA into the fracturing zone 120 when the pressure in the packer 70 exceeds a predetermined pressure, such as 1000 psi, above the fracturing zone 120 pressure. The pressure relief valve 75 ensures that the pressure in the packer 70 is greater than the pressure in the fracturing zone 120, but limits the buildup of excess pressure within the packer 70. Therefore the pressure relief valve 75 enables the packer 70 to remain 1000 psi above the fracturing zone 120 pressure. In this manner, the fracturing zone 120 pressure does not need to be well understood before the fracturing process is started. The packer 70 pressure may dynamically respond increasing as the fracturing zone 120 pressure increases.

[0071] The specific pressure set points of each valve in the embodiment of FIG. 4 are more illustrative purposes and may be varied depending on the environmental conditions and type of application as would be apparent to one of ordinary skill in the art having the benefit of this disclosure. Additionally, the embodiment provides a relief valve 75 that may prevent the over-inflation of the packer 70. The embodiment of FIG. 4 also provides that the anchor 80 may remain set even if the pressure in the packer 70 decreases due to a leak or a failed packer. Further, the use of the umbilical tube 20 to inflate the packer 70 may protect the internal portion of the packer 70 from washing fluids pumped down the CT string 10, which may be harmful to the rubber elements in the packer 70. The configuration of FIG. 4 may ensure that the pressure in the anchor 80 is greater than the pressure in the packer 70.

[0072] FIG. 5 shows an embodiment having a direct connection between the umbilical tube 20 and the packer 70 with a pressure relief valve 145 in parallel with a check valve 135. The pressure relief valve 145 is set to open at a predetermined pressure. Such a configuration may be used with a BHA that does not have an anchor. The pressure relief valve 145 may be set at a predetermined pressure, such as 500 psi, thus requiring that the pressure builds within the umbilical before the pressure relief valve 145 opens and the packer 70 may be inflated. The valves 135, 145 may function together to isolate the packer 70 from relatively high hydrostatic pressure within the BHA. As described above, a low specific gravity fluid may be used to create a relatively low hydrostatic pressure within the BHA when the BHA is at typical fracturing depths. A relatively low pressure within the BHA can also be created by pumping fluid down the wellbore depending on the reservoir’s hydraulics. However, it is possible to have a relatively low pressure in the BHA at typical fracturing depths, but to have a relatively high pressure in the BHA at shallower depths. The valves 135, 145 may prevent the pressure within the BHA from exceeding the pressure within the wellbore, thus ensuring that the packer 70 remains deflated. In an alternative embodiment of the present disclosure, an umbilical tube may be connected directly to a packer without any valves.

[0073] The umbilical connected to either of the hydraulic circuits shown in FIGS. 4 and 5 may contain a fluid with a specific gravity lower than water to place a negative pressure on the packer 70 and anchor 80. The use of such a fluid may help the packer to deflate to its original deflated size. A number of low specific gravity fluids may be suitable, such as Petro-Canada’s HCT 40N drilling mud, a 50/50 methanol water mixture, as would be appreciated by one of ordinary skill in the art having the benefit of this disclosure. Addi-
ationally, the use of a low viscosity fluid in the umbilical may allow for usage in the winter at low temperatures.

The presence of two fluid paths 15, 25 allows the CT string 10 to be used to deliver a cross linking agent to the fracturing fluid to cross-link the fluids at the perforations, just before the fracturing fluid slurry enters the formation. The cross-linking agent may be pumped down the CT string 10 and enter the casing at the fracturing zone via circulation ports 55 may allow for better control of the timing of the cross-linking chemistry.

The presence of two fluid paths 15, 25 in the concentric coiled tubing string may also allow for the performance of two different hydraulic functions without the manipulation of any valves, This allows the BHA to be simpler and easier to assemble than the previous design. Additionally, the two fluid paths may eliminate the need of a highly trained staff to operate the BHA downhole.

The presence of two fluid paths 15, 25 may allow the CT string 10 to be used to determine the fracturing pressure by measuring the injection pressure into the CT string 10 at surface. Alternatively, the umbilical string may be used to determine the fracturing pressure in the same way. Typically the fluid properties in the CT string 10 are not changing over time and their properties are well understood. In addition, the injection rate may be low or even static such that the frictional pressure drop may not complicate the interpretation of the pressure down hole. Thus, it may be relatively easy to calculate the hydrostatic pressure in both the CT string 10 and the umbilical tube 20. The downhole pressure can be substantially determined by slowly pumping fluid down the CT string 10 such that fluid very slowly exits the CT string 10 from the circulation ports 55. Because the fluid is pumped slowly any frictional pressure losses may be disregarded and the downhole fracturing fluid pressure may be estimated by adding together the pumping pressure and the hydrostatic pressure of the fluid within the CT string 10.

FIG. 6 shows an embodiment of a BHA of the present disclosure that includes an emergency packer deflation device that quickly draws the packer fluid 230 out of the inflatable packer 270 once the packer 270 loses its ability to anchor against the casing 240. The emergency packer deflation device may be connected to the BHA directly above the inflatable packer 270. The emergency packer deflation device includes a piston rod 130, piston 180, and spring 190 closed within a housing 170. A shear ring 140 connects the housing 170 to the top portion of the piston rod 130. The emergency packer deflation device may also include a crush ring 150.

The BHA may include a bypass filter 200, which contains bypass fluid 210, between the emergency packer deflation device and the inflatable packer 270. The packer 270 is inflated with the inflatable packer fluid 230. The packer 270 includes a packer mandrel 220 from which it expands. The inflatable packer fluid 230 passes through a mandrel ring 250 that includes flow slots 255 (shown in FIG. 9) to inflate or deflate the packer 270.

As discussed above, once the packer 270 loses its ability to anchor the pressure drop across the packer 270 transfers a load onto the CT string. This load may shear the shear ring 140 allowing the pressure drop across the packer 270 to push the packer 270 downhole away from the piston rod 130 of emergency packer deflation device as shown in FIG. 7. The movement of the packer 270 away from the mandrel 130 of the emergency packer deflation device may cause the housing 170 to travel relative to the piston 180. The stroking of the piston 180 may increase the volume within the housing 170 below the piston 180, which may rapidly draw the inflatable packer fluid 230 out of the packer 270 causing the packer 270 to deflate as shown in FIG. 8. The packer 270 may be adapted with a large flow area to allow for the rapid removal of the inflatable packer fluid 230. The smallest cross sectional area in the flow path between the packer 270 and the emergency packer deflation device is shown in FIG. 9, section EE in FIG. 6. The emergency packer deflation device includes a crush ring 150 which may decelerate the housing 170 and the portion of the BHA connected thereto preventing the housing 170 from damaging the piston 180 once the piston 180 has traveled to the end of its stroke.

Once the packer 270 is deflated (shown as 280 in FIG. 8), the pressure drop across the packer 270 may be greatly reduced, thus reducing the load on the CT string. Further, as shown in FIG. 10, the emergency packer deflation device may be adapted such that the pressure within the housing 170 above and below the piston 180 may be equalized with the wellbore pressure after the housing 170 and the packer 270 have come to a rest.

FIG. 9 shows the cross-section of the mandrel ring 250 of the embodiment of FIG. 6, section EE. This section represents the minimum flow area between the packer 270 and the emergency packer deflation device housing 170. The mandrel ring 250 includes flow slots 255 which allow for the rapid flow of inflatable packer fluid 230 to the housing 170 so as to rapidly deflate the packer 270. If the flow area between the packer 270 and the housing 170 is too small, the result is a large pressure drop between the packer 270 and the housing 170. The pressure in the housing 170 becomes too large relative to the pressure in the packer 270 and as a result there is a pressure induced force on the piston 180. The force on the piston 180 is reacted by a force from the CT string. This force can become too large, releasing the emergency release tool or breaking the CT string, if the flow area is too small. The required flow area is determined by the area at which the housing 170 and the packer 270 move down the wellbore once the packer 270 looses its ability to anchor itself to the casing. As discussed above, the rapid deflation of the packer 270 is important to prevent an excessive load on the CT string due to a pressure drop across the packer 270 in the event the packer 270 has lost its ability to anchor against the casing 240. If the load on the CT string is not decreased, the CT string may break dropping the BHA into the wellbore.

Although various embodiments have been shown and described, the invention is not so limited and will be understood to include all such modifications and variations as would be apparent to one skilled in the art.

What is claimed is:

1. A coiled tubing annular fracturing string, the string comprising:
   a coiled tubing string:
   a bottom hole assembly including an inflatable packing element, the bottom hole assembly connected to the coiled tubing string; and
an umbilical tube located within the coiled tubing string, wherein the umbilical may be used to inflate or deflate the inflatable packing element.

2. The string of claim 1 wherein the bottom hole assembly further includes an anchor.

3. The string of claim 2 wherein the umbilical tube may be used to set or release the anchor within a wellbore.

4. The string of claim 1 wherein the inflatable packing element anchors the bottom hole assembly against a casing of a wellbore when inflated.

5. The string of claim 1 further comprising an emergency deflation device in communication with the packing element, wherein the packing element is deflated if the inflated packing element is no longer anchored against the casing.

6. The string of claim 5 the emergency deflation device includes a piston rod, a piston, and a spring.

7. The string of claim 6 wherein the emergency deflation device is adapted to equalize the pressure across the inflated packing element.

8. The string of claim 1 further comprising an electric wireline located within the umbilical tube.

9. The string of claim 8 wherein the electric wireline allows communication between the surface and an element of the bottom hole assembly.

10. The string of claim 9 wherein the element is a set of perforating guns, a pressure transducer, a temperature gauge, or a casing collar locator.

11. The string of claim 1 further comprising one or more fluid ports located above the packing element.

12. The string of claim 11 wherein the coiled tubing string delivers wash fluids or circulating fluids through the one or more fluid ports to a location within the wellbore.

13. The string of claim 1 wherein the one or more fluid ports include a one way valve.

14. The string of claim 1 wherein a negative pressure is applied to the packing element through the umbilical tube to deflate the packing element.

15. The string of claim 1 further comprising a second umbilical tube located within the coiled tubing string, wherein the second umbilical provides a third fluid flow path.

16. The string of claim 15 wherein the second umbilical does not extend the entire length of the coiled tubing string.

17. The string of claim 1 wherein the umbilical tube delivers a low specific gravity fluid to the packing element.

18. A coiled tubing string for use in the annular coil tubing fracturing, the coiled tubing string comprising:

   a. a bottom hole assembly, the bottom hole assembly including an inflatable packing element;

   b. a first fluid flow path, wherein the first fluid flow path may be used to deliver fluid to a desired downhole location within a wellbore; and

   c. a second fluid flow path, wherein the second fluid flow path may deliver fluid to inflate or deflate the inflatable packing element.

19. The coiled tubing string of claim 18 further comprising an electric wireline located within the second fluid flow path.

20. The coiled tubing string of claim 18 further comprising at least one fluid port in communication with the first fluid flow path.

21. The coiled tubing string of claim 20 further comprising an one way valve preventing two way flow through the at least one fluid port.

22. A coiled tubing string, the coiled tubing string comprising:

   a. a first fluid flow path within the coiled tubing string;

   b. a second fluid flow path within the coiled tubing string;

   c. a bottom hole assembly, the bottom hole assembly including a hydraulically set anchor and an inflatable packing element;

   d. means for requiring a first predetermined pressure within the second fluid flow path before the anchor is set; and

   e. means for requiring a second predetermined pressure within the second fluid flow path before the packing element begins to inflate.

23. The coiled tubing string of claim 22 further comprising means for ensuring that the anchor is set prior to beginning to inflate the packing element and means for ensuring that the packing element deflates prior to unsetting the anchor.

24. The coiled tubing string of claim 22 further comprising means for preventing the over inflation of the packing element.

25. The coiled tubing string of claim 24 further comprising means for ensuring that the pressure within the packing element is greater than the pressure of a fracturing zone within a wellbore.

26. The coiled tubing string of claim 22 further comprising means for ensuring that the pressure within the anchor is greater than the pressure within the packing element.

27. The coiled tubing string of claim 22 wherein the second fluid flow path protects the packing element from harmful fluids present in the first fluid flow path.

28. The coiled tubing string of claim 22 wherein the second fluid flow path contains a low specific gravity fluid.

29. A coiled tubing string, the coiled tubing string comprising:

   a. a first fluid flow path within the coiled tubing string;

   b. a second fluid flow path within the coiled tubing string;

   c. a bottom hole assembly, the bottom hole assembly including an inflatable packing element;

   d. a pressure relief valve, the pressure relief being in communication with the second fluid flow path and the packing element, wherein the pressure relief valve is biased to a closed position preventing the inflation of the packing element; and

   e. a check valve, the check valve parallel with the pressure relief valve being in fluid communication with the second fluid flow path and the packing element.

30. The coiled tubing of claim 29 wherein the pressure relief valve requires a predetermined amount of pressure to be within the second fluid flow path before the pressure relief valve opens.

31. The coiled tubing of claim 30 wherein the second fluid flow path contains a low specific gravity fluid.

32. A emergency deflation device for a coiled tubing string, the device comprising:
a housing connected above an inflatable packing element, the packing element being able to anchor against a casing when inflated with fluid;
a chamber within the housing, the chamber being in fluid communication with the packing element;
a piston and a piston rod positioned within the chamber;
at least one shearable element, the shearable element selectively securing the housing to the piston rod;
wherein if the packing element loses the ability to anchor against the casing the load on the packing element shears the at least one shearable element releasing the housing from the piston rod; and
wherein the housing and packing element moves away from the piston rod causing the piston to stroke within the chamber drawing the fluid out of the packing element.

33. The emergency deflation device of claim 32 further comprising a crush ring, wherein the crush ring prevents damage to the piston.

34. The emergency deflation device of claim 32 wherein the housing is adapted to equalize the pressure above and below the packing element and the piston has been stroked within the chamber.

35. A method of fracturing a perforated zone of a wellbore with a coiled tubing string having at least two flow paths, the method comprising:
pumping a first fluid down a first flow path of a coiled tubing string to inflate a packing element to isolate a zone of a wellbore;
pumping fracturing fluid down the annulus between the coiled tubing string and the wellbore;
pumping a fluid down the second flow path of the coiled tubing string, the fluid being a wash fluid; and
circulating the wash fluid to the perforating zone through one or more fluid ports in the coiled tubing string.

36. The method of claim 35 further comprising applying a negative pressure within the first flow path of the coiled tubing string to deflate the packing element.

37. The method of claim 35 wherein the first fluid is a low specific gravity fluid.

38. The method of claim 35 further comprising communicating with a downhole element connected to the coiled tubing string to determine the temperature, pressure, or location of the fracturing zone.

39. The method of claim 38 wherein an electrical wireline located within the first flow path is used to communicate with the downhole element.

40. The method of claim 35 further comprises pumping the first fluid down the first flow path of the coiled tubing string to set an anchor.

41. The method of claim 35 wherein the inflated packing element anchors the coiled tubing string to casing of the wellbore.

42. The method of claim 35 further comprising pumping a cross-linking agent down the second flow path of the coiled tubing string.

43. The method of claim 42 further comprising circulating the cross-linking agent through the one or more fluid ports in the coiled tubing string.

44. The method of claim 35 further comprising pumping a fluid down the second flow path and circulating the fluid out of the one or more fluid ports to determine the fluid pressure of the zone of the wellbore, wherein the fluid is slowly pumped down the second flow path.

45. The method claim 35 further comprising pumping a fluid down a second flow path of the coiled tubing string, the second fluid being acid.

46. The method claim 45 further comprising circulating the acid to the perforating zone through one or more fluid ports in the coiled tubing string.

47. A method of fracturing the formation of a perforated zone of a wellbore with a coiled tubing string having a first flow path and a second flow path, the method comprising:
pumping a first fluid down the first flow path to inflate a packing element to isolate a zone of a wellbore;
pumping fracturing fluid down the annulus between the coiled tubing string and the wellbore after the zone of the wellbore has been isolated, wherein the fracturing fluid is pumped down the annulus until the formation is fractured;
pumping a fluid down the second flow path of the coiled tubing string while the fracturing fluid is pumped down the annulus, wherein the fluid includes a cross-linking agent; and
circulating the fluid that includes the cross-linking agent to the perforating zone through one or more ports in the coiled tubing string while the fracturing fluid is pumped down the annulus.

48. The method of claim 47 further comprising pumping wash fluid down the second flow path after the fracturing fluid is no longer pumped down the annulus and circulating the wash fluid to the perforating zone through the one or more ports in the coiled tubing string.

49. The method of claim 47 further comprising pumping acid down the second flow path and circulating the acid to the perforating zone prior to pumping fracturing fluid down the annulus.

50. The method of claim 47 further comprising applying a negative pressure within the first flow path of the coiled tubing string to deflate the packing element after circulating wash fluid to the perforating zone.

51. A method of fracturing a perforated zone of a wellbore with a coiled tubing string having at least two flow paths, the method comprising:
pumping a first fluid down a first flow path to inflate a packing element to isolate a zone of a wellbore;
pumping fracturing fluid down the annulus between the coiled tubing string and the wellbore after the zone of the wellbore has been isolated, wherein the fracturing fluid is pumped down the annulus until the formation is fractured;
pumping a fluid down a second flow path of the coiled tubing string while the fracturing fluid is pumped down the annulus, wherein the fluid is a wash fluid; and
circulating the wash fluid to the perforating zone through one or more ports in the coiled tubing string while the fracturing fluid is pumped down the annulus.
52. A method of fracturing a perforated zone of a wellbore with a coiled tubing string, the method comprising:

setting a packing element to isolate the perforated zone of the wellbore;

pumping fracturing fluid down the annulus between the coiled tubing string and the wellbore;

pumping a fluid down the coiled tubing string, the fluid being a wash fluid; and

circulating the wash fluid to the perforating zone through one or more fluid ports in the coiled tubing string.

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