MULTIPLE INTERVAL PERFORATING AND FRACTURING METHODS

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ABSTRACT

A method for perforating and fracturing a wellbore in a single trip may include installing one or more reservoir access subs on a liner at pre-determined intervals. The method may also include running the liner into the wellbore, securing the liner to the wellbore, and running a bottomhole assembly into the wellbore. The method may further include activating at least one of the reservoir access subs so as to allow fluid communication between the liner and the wellbore, and fracturing at least one interval proximate the activated reservoir access sub. The steps of running the bottomhole assembly into the wellbore, activating the reservoir access subs, and fracturing the interval may be performed in a single trip into the wellbore.
MULTIPLE INTERVAL PERFORATING AND FRACTURING METHODS

BACKGROUND

[0001] The present invention relates perforating and fracturing methods and more particularly to single trip methods for multiple interval perforating and fracturing using straddle packer isolation.

[0002] Because it is generally economically advantageous to shoot all of the well intervals in a single operation, perforating guns have become extremely long and heavy. Deployment of these tool strings is complex due to the need to perform this operation as a live well intervention. Often, the entire tool string must be pulled into a lubricator at the surface before the casing valve can be closed and the spent guns removed from the wellbore. Long tool strings with sufficient lubricator section require special cranes and generally are limited to 50-60 feet of lubricator length (40-50 feet of tool string length). Explosives are most commonly deployed via wireline, which allows for depth control and selectivity. However, the increasing trend toward longer and higher angle wells creates challenges for conventional perforating with electric wireline, particularly where the well inclination and the total weight of the guns increase. A tractor system may be used to aid getting the guns to depth, but can be very time consuming due to the need to make separate trips into the wellbore between fracture and stimulation treatments. Tubing conveyed perforating might be the only effective means of accessing some deep well applications. When coil tubing is used, the length of the lubricator may limit the number of guns deployed. Therefore, in multizone stimulation, it may be necessary to run multiple trips. In some applications, perforating with jointed pipe is a suitable option, offering more push and pull forces at the bottomhole assembly. However, when using jointed pipe, recovery of the guns after detonation may be a slow process with connections to break. Additionally, wellbore pressure and well control may require special equipment and handling provisions. Other approaches include leaving the perforating bottomhole assembly in the wellbore, by dropping the guns on detonation. However, without a suitable rat hole, the production flow paths become restricted.

[0003] Cobra Frac® includes processes and fracturing techniques using coiled tubing to stimulate multiple intervals using straddle packers. Conventionally, Cobra Frac® (which may include Cobra Frac® H) techniques have required that all zones be conventionally perforated prior to running in hole to isolate and pump the fracture treatment. The crushing and compaction of rock caused by conventional (i.e., explosive jet) perforating due to the super heating of gases may substantially impair the flow capacity of the hole by reducing near wellbore permeability. Many countries have restrictions regarding the import and use of explosives. Additionally, conventional perforating may plug the tip of the tunnel with formation debris and metal fragments. The effects of damage caused by conventional perforating may increase as the formation hardness increases, such as, for example in deeper well applications. Excessive perforation damage can mask true formation potential and lead to incorrect diagnosis and decision making. Conventional perforating can also result in significant fracture tortuosity, increasing formation break-down pressure—occasionally beyond the capacity of surface equipment or design rating of the well.

SUMMARY

[0004] The present invention relates perforating and fracturing methods and more particularly to single trip methods for multiple interval perforating and fracturing using straddle packer isolation.

[0005] In some embodiments of the present invention a method for perforating and fracturing a wellbore in a single trip comprises (a) installing one or more reservoir access sub on a liner at pre-determined intervals, (b) running the liner into the wellbore, (c) securing the liner to the wellbore, (d) running a bottomhole assembly into the wellbore, (e) activating at least one of the reservoir access sub so as to allow fluid communication between the liner and the wellbore, and (f) fracturing at least one interval proximate the activated reservoir access sub. Steps (d), (e), and (f) may be performed in a single trip into the wellbore.

[0006] In other embodiments of the present invention a method for perforating and fracturing a wellbore in a single trip comprises (a) running a liner into the wellbore, (b) securing the liner to the wellbore, (c) running a bottomhole assembly into the wellbore, (d) establishing fluid communication between the liner and the wellbore, and (e) fracturing at least one interval proximate the fluid communication. Steps (e), (d), and (e) may be performed in a single trip into the wellbore, and steps (d) and (e) may be repeated in the single trip into the wellbore.

BRIEF DESCRIPTION OF THE DRAWINGS

[0007] FIGS. 1A, 1B, and 1C illustrate one embodiment of the present invention. FIG. 1A is a flowchart illustrating the steps of methods of perforating and fracturing a wellbore in a single trip, FIG. 1B is a cross-sectional side view of a reservoir access sub in a wellbore, and FIG. 1C is a side view of a bottomhole assembly for use with the reservoir access sub, in accordance with embodiments of the present invention.

[0008] Generally, FIGS. 2A-2E illustrate one embodiment of a reservoir access sub in accordance with the present invention. FIG. 2A is a side view, FIG. 2B is a cross-sectional view taken along line A-A of FIG. 2A, FIGS. 2C, 2D, and 2E are cross-sectional side views in a wellbore during operation.

[0009] Generally, FIGS. 3A-3E illustrate another embodiment of a reservoir access sub in accordance with the present invention. FIG. 3A is a side view, FIG. 3B is a cross-sectional view taken along line B-B of FIG. 3A. FIGS. 3C, 3D, and 3E are cross-sectional side views in a wellbore during operation.

[0010] Generally, FIGS. 4A-4D illustrate yet another embodiment of a reservoir access sub in accordance with the present invention. FIG. 4A is a side view, FIGS. 4B, 4C, and 4D are cross-sectional side views, in a wellbore during operation.

[0011] FIG. 5 is a partially cutaway side view of an embodiment of a tool in accordance with the present invention.

[0012] Generally, FIGS. 6A-6C illustrate another embodiment of the tool of FIG. 5. FIG. 6A is a side view, and FIGS. 6B and 6C are partially cutaway side views, during operation.

[0013] Generally, FIGS. 7A-7E illustrate another embodiment of a tool in accordance with the present invention. FIGS. 7A and 7B are side views of a punch tool in accordance with
one embodiment of the present invention, and FIGS. 7C, 7D, and 7E are cross-sectional side views, in a wellbore during operation.

[0014] Generally, FIGS. 8A-8D illustrate an embodiment of a sub having activated changes in accordance with the present invention. FIG. 8A is a side view, FIGS. 8B, 8C, and 8D are cross-sectional side views, in a wellbore during operation.

DETAILED DESCRIPTION

[0015] Referring now to FIGS. 1A, 1B, and 1C, and more particularly to FIG. 1A, a method for perforating and fracturing a wellbore in a single trip may comprise a step 10 of installing one or more reservoir access subs 102 (illustrated in FIG. 1B) on liner 104 (illustrated in FIG. 1B) at pre-determined intervals, a step 20 of running liner 104 (illustrated in FIG. 1B) into wellbore 106 (illustrated in FIG. 1B), a step 30 of securing liner 104 to wellbore 106, a step 40 of running bottomhole assembly 108 (illustrated in FIGS. 1B and 1C) into wellbore 106, a step 50 of activating at least one reservoir access sub 102 so as to allow fluid communication between liner 104 and wellbore 106, and a step 60 of isolating and fracturing at least one interval (e.g., first interval 110) proximate activated reservoir access sub 102. Step 50 of activating and step 60 of isolating and fracturing may be repeated on second interval 112, and additional intervals, as needed or desired. In some embodiments, deepest zones or intervals may be treated before more shallow zones or intervals. However, zones or intervals may be treated in any order, depending on the particular conditions present. Steps 40, 50, and 60 (and additional repetitions of steps 50 and 60) may be performed in a single trip into the wellbore. Some embodiments may additionally include a step of installing a depth correlation device or an interval locator (not shown) on liner 104 prior to running liner 104 into wellbore 106.

[0016] Step 10 of installing one or more reservoir access subs 102 on liner 104 may include threading with a thread type appropriate for the casing, or welding. Reservoir access subs 102 may be placed at predetermined intervals, which may be selected based on the position and spacing of the desired fractures required for a given completion. The number of fracture Targets is often optimized by numerical simulation. However, in some cases the number and position of each fracture target may be established through evaluation of well logs to optimize fracture placement based on reservoir quality. The spacing may vary tremendously depending, in part, on whether the annulus of the casing/wellbore is cemented or segmented with annular packer isolation or dynamic fluid diversion. If annular packers are used, the typical spacing between reservoir access subs may be as much as 500 ft. If the casing is cemented the spacing between subs could be as little as 90 ft or as much as 250 ft. In some embodiments, spacing between subs could be less than 50 ft. or greater than 250 ft. Project economics plays a substantial role in determining the number and spacing of these subs. Exemplary embodiments of reservoir access subs 102 are described in detail below, with respect to FIGS. 2A-5.

[0017] Step 20 of running liner 104 may be accomplished conventionally, as known by those having ordinary skill in the art. Since the perforations may not be activated until after liner 104 has been run, liner 104 may be circuited into the openhole. Liner 104 may be run on drillpipe or coil tubing or otherwise and may be cemented conventionally, or may be secured by activating annular packers. Alternatively, there may be no annular isolation, in some embodiments. Additionally, step 20 of running liner 104 may include a step of activating a liner hanger after liner 104 is in position downhole.

[0018] Step 30 of securing liner 104 to wellbore 106 may include placing cement in annulus 114 formed between liner 104 and wellbore 106 and allowing the cement to set. In other embodiments, step 30 of securing liner 104 to wellbore 106 may include setting one or more packers (not shown) in annulus 114. The packers may be annular isolation packers, such as swell packers, or other isolation devices known to those having ordinary skill in the art.

[0019] Once liner 104, including reservoir access subs 102 has been deployed, bottomhole assembly 108 may be run. Step 40 of running bottomhole assembly 108 may include running on tubing or coiled tubing or a combination string of jointed pipe and coiled tubing. Bottomhole assembly 108 may be deployed to fracture and stimulate individual fractures in any sequence. Bottomhole assembly 108 may include straddle packer 116 connected to tubing 118 via threaded connections, clamp-on connections, slip on connections, or any other suitable connection. Straddle packer 116 may include packer elements, including conventional solid packer-ring elastomers, cup-type elastomers, inflatable elastomers, or combinations thereof, or any other straddle assembly. Bottomhole assembly 108 may include a Cobra Frac® bottomhole assembly, as illustrated in FIG. 1C. As illustrated, in addition to straddle packer 116, bottomhole assembly 108 may include hydraulic hold down 118, centralizer 120, blast joint(s) for spacing 122, frac port 124, equalizing valve 126 (e.g., as described in U.S. Pat. No. 6,474,419 to Maier et al., which is hereby incorporated by reference), and/or packer 128.

[0020] Step 50 of activating at least one reservoir access sub 102 may include applying hydraulic pressure, applying acid, or any of a number of other methods for establishing fluid communication between liner 104 and wellbore 106, as described below with respect to the various embodiments.

[0021] Step 60 of fracturing at least one interval 110 may include a straddle pack technique such as a Cobra Frac® technique. For example, a zone may be sealed, multiple-intervals may be perforated, milling may be done via coil tubing, and fracturing may be done via pinpoint fracture service. The milling step, necessary in conventional perforating, may be omitted when using reservoir access subs 102. Conventionally, milling removes the “burs” created by the explosives. These “burs” may have a detrimental effect on packer elements, but are not be created when using reservoir access subs 102. Therefore, a separate trip into the well for milling may not be required when using reservoir access subs 102. Additionally, other methods of fracturing may be appropriate, depending on the particular circumstances and conditions. Optionaly, a step of isolating interval 110 may precede step 60 of fracturing interval 110.

[0022] Referring now to the embodiment illustrated in FIGS. 2A-2E, and more particularly to FIG. 2A, reservoir access sub 102 may have one or more ports 202 having erodible or soluble material (e.g., acid soluble material 204) therein. The number and size of ports 202 may be determined by the treatment design for each particular wellbore 106. Acid soluble material 204 may partially fill, completely fill, or overfill ports 202. FIG. 2B illustrates acid soluble material 204 overfilling ports 202. The soluble material used may be selected based on rate of solubility in acid (e.g., HCl, HF, or
acetic acid solutions), temperature, or time. Soluble materials useful for this embodiment may include, but are not limited to aluminum, magnesium, marble, tin, zinc, any competent material that dissolves easily in HCL, HF, or acetic acid solutions, any competent material that dissolves over time in aqueous fluid, any competent material that dissolves over time due to temperature, or any other biodegradable material. Solvents useful for this embodiment may include any material or condition suitable for dissolving or otherwise removing the soluble materials listed above (e.g., acids, aqueous fluid, time, temperature, etc.).

[0023] Referring now to FIG. 2C, reservoir access sub 102 may be installed on liner 104 at predetermined intervals and liner 104 may be run into wellbore 106 and annulus 114 may be isolated or liner 104 may be secured (e.g., via cementing annulus 114 or the use of swell packers). In some embodiments, reservoir access sub 102 may be deployed in wellbore 106 via casing instead of on liner 104. Once reservoir access sub 102 is in place, bottomhole assembly 108, which may include straddle packer 116 may be run into wellbore 106 on tubing 118 (e.g., coil tubing or jointed pipe) to a predetermined treatment depth. The predetermined treatment depth may be an end of a lateral. For applications where the predetermined treatment depth is too great for coil tubing, but the flexibility of coil is desired, a coil tubing/hydraulic workover hybrid unit may be used to get to the treatment depth, and improve efficiency and safety of the operation.

[0024] Once bottomhole assembly 108 reaches the predetermined treatment depth, any of a number of methods may be employed for removing the soluble material from ports 202. For example, a solvent (e.g., acid 206) may be circulated (e.g., reverse circulated) into place and may remain for a predetermined amount of time to erode or dissolve or otherwise remove acid soluble material 204 from within ports 202, and activate reservoir access sub 102.

[0025] Interval 110 may then be isolated and fractured using a Cobra Frac® technique. Referring now to FIG. 2D, once ports 202 are open, straddle packer 116 may be placed across interval 110. Referring now to FIG. 2E, once straddle packer 116 is positioned or set to isolate interval 110, treatment fluid may be pumped down tubing 118. This process may be repeated for additional reservoir access sub 102.

[0026] Referring now to the embodiment of FIGS. 3A-3E, with reference to FIG. 3A, reservoir access sub 102 may have one or more jets 302 having erodible or soluble material (e.g., acid soluble material 204) therein. The number and size of jets 302 may be determined by the treatment design for each particular wellbore 106. Acid soluble material 204 may partially fill, completely fill, or overfill jets 302. FIG. 3B illustrates acid soluble material 204 completely filling jets 302. The soluble material and the solvent may be similar to those described above with respect to FIGS. 2A-2E.

[0027] Referring now to FIG. 3C, reservoir access sub 102 may be installed on liner 104 at predetermined intervals and liner 104 may be run into wellbore 106 and secured in a manner similar to that disclosed above with respect to FIGS. 2A-2E. Likewise, bottomhole assembly 108 may have similar construction and be placed in a manner similar to that of the embodiment of FIGS. 2A-2E, and may incorporate hysdrajetting as set forth in detail in U.S. Pat. No. 5,765,642. Once bottomhole assembly 108 reaches the predetermined treatment depth, the soluble material may be removed from jets 302 in a manner similar to the method for removing the soluble material from ports 202 described above with respect to FIGS. 2A-2E.

[0028] Interval 110 may then be isolated and fractured using a Cobra Frac® technique. Referring now to FIG. 3D, once jets 302 are open, straddle packer 116 may be placed across interval 110. Referring now to FIG. 3E, once straddle packer 116 is positioned or set to isolate interval 110, treatment fluid may be pumped down tubing 118. This process may be repeated for additional reservoir access sub 102.

[0029] Referring now to the embodiment of FIGS. 4A-4D, with reference to FIG. 4A, reservoir access sub 102 may have one or more ports 202 having one or more burst disks 402 therein. Burst disks 402 may partially cover, completely cover, or overlap ports 202. Burst disks 402 may be a thin disc of a material configured to rupture at a predetermined pressure. A predetermined number of burst disks may be installed on a sub, where they are designed to burst when exposed to a predetermined pressure. The number and size of ports 202 and/or corresponding burst disks 402 may be determined by the treatment design for each particular wellbore 106. Burst disks 402 may be designed to burst instantaneously when activated. Selection of type of burst disk 402 may vary with fluids present in wellbore 106, and fluids to be pumped into wellbore 106, temperature, pressure setting, and size. Burst disks 402 may be installed in a number of ways, including, but are not limited to screw-in disk ports, cam lever, bolted, pre-torqued, union, ferrules, companion flanges, and/or “stamped” ports. Burst disks 402 may burst by positive or negative pressure, using forward, reverse, or bi-directional burst disks 402. Materials for construction of burst disks 402 may include, but are not limited to composites, graphite, aluminum or soft metal inserts, and/or ceramic inserts. Additional examples of suitable alternative construction for burst disks 402 are described in U.S. Pat. No. 6,047,773 to Zeltmann et al., which is hereby incorporated by reference.

[0030] Referring now to FIG. 4B, reservoir access sub 102 may be installed on liner 104 at predetermined intervals and liner 104 may be run into wellbore 106 and secured in a manner similar to that disclosed above with respect to FIGS. 2A-2E. Likewise, bottomhole assembly 108 may have similar construction and be placed in a manner similar to that of the embodiment of FIGS. 2A-2E.

[0031] Referring now to FIG. 4C, once bottomhole assembly 108 reaches the predetermined treatment depth, straddle packer 116 may be placed across interval 110 and a predetermined pressure may be applied via tubing 118 to burst at least one burst disk 402 and activate reservoir access sub 102 to expose fracports, jets, soluble jets, or the like. Treatment fluid may then be pumped down tubing 118. Referring now to FIG. 4D, after treating interval 110, straddle packer 116 may be placed across second interval 112, and the process may be repeated.

[0032] Referring now to the embodiment of FIG. 5, reservoir access sub 102 may have at least one shifting sleeve 502 thereon. In some instances, shifting sleeve 502 may open in response to hydraulic activation, such that application of a predetermined pressure through tubing 118 will cause pins to shear and activate shifting sleeve 502. In addition to shifting sleeve 502, reservoir access sub 102 may also have a predetermined number of fracports, jets, soluble jets, or the like, to allow hydraulicjetting and/or a high rate fracture treatment. Soluble materials for use in fracports, jets, soluble jets, or the like may be similar to those described above with respect to
FIGS. 2A-2E. Activating shifting sleeve 502 may include opening shifting sleeve 502 to allow reservoir access via fracports, jets, and/or soluble jets. In some instances, hydrajetting may occur prior to fracturing treatment. One example of shifting sleeve 502 is the DeltaStim Sleeve, which may be used in conjunction with a DeltaStim Initiator in each interval using a Cobra Frac® straddle bottomhole assembly to isolate, pressure up, and activate each initiator. Other examples of shifting sleeves may be found in U.S. Pat. No. 7,575,062.

[0033] Reservoir access sub 102 may be installed on liner 104 (not shown in FIG. 5) at predetermined intervals and liner 104 may be run into wellbore 106 (not shown in FIG. 5) and secured in a manner similar to that disclosed above with respect to FIGS. 2A-2E. Likewise, bottomhole assembly 108 (not shown in FIG. 5) may have similar construction and be placed in a manner similar to that of the embodiment of FIGS. 2A-2E, and may incorporate hydrajetting as set forth in detail in U.S. Pat. No. 5,765,642. Once bottomhole assembly 108 reaches the predetermined treatment depth, straddle packer 116 (not shown in FIG. 5) may be placed across interval 110 (not shown in FIG. 5) and a predetermined pressure may be applied via tubing 118 (not shown in FIG. 5) to move shifting sleeve 502 and activate shifting sleeve 502 to expose fracports, jets, soluble jets, or the like. In other words, fluid connectivity may be established between wellbore 106 (or annulus 114) and liner 104 by actuating shifting sleeve 502 with hydraulic pressure to expose ports 504. Ports 504 on reservoir access sub 102 may contain fracports, soluble jets, or the like. Treatment fluid may then be pumped down tubing 118.

[0034] In some instances, hydrajetting may be desired prior to fracturing. In those instances, jets 302 may be placed in ports 504, prior to running into wellbore 106. Once in place in wellbore 106, jets 302 may be removed with acid or removed by friction caused by abrasive fluid being pumped therethrough (or otherwise), to allow for a conventional fracturing treatment to be performed after the hydrajetting operation. Thus, in some embodiments, the steps may include isolating reservoir access sub 102, pressure activating shifting sleeve 502 to shift open reservoir access sub 102 to expose ports 504 with jets 302, pumping through jets 302 to hydrajet the formation, reverse circulating or circulating acid (or otherwise dissolve or erode) jets 302, and pumping fracture treatment through open ports 504.

[0035] After treating interval 110, straddle packer 116 may be placed across second interval 112 (not shown in FIG. 5), and the process may be repeated. In the embodiment of FIG. 5, straddle packer 116 may be configured to isolate one individual shifting sleeve 502, or it may be configured to isolate a plurality of shifting sleeves 502. Additionally, when the shifting sleeve, tool may allow for shifting sleeve 502 to be closed to isolate the treated interval, if desired.

[0036] In any of the above-described embodiments, activating reservoir access sub 102 may allow fluid communication between liner 104 or casing and wellbore 106. Additionally, the step 50 of activating reservoir access sub 102 may be repeated as many times as desired for the particular application.

[0037] Referring now to FIGS. 6A-6C, shifting sleeve 601 may be combined with frac ports 124 situated between straddle packer 116 and below hydrajet tool 604. Bottomhole assembly 108 including straddle packer 116 may have a similar construction and be placed in a similar manner to the embodiment disclosed in FIG. 5. Likewise, the activation of shifting sleeve 601 may be similar to shifting sleeve 502. As shifting sleeve 601 opens, jets 302 may be exposed, as illustrated in FIG. 6B. Flow may be diverted through jets 302 to allow hydrajetting operations to occur. A predetermined number of jets 302 may be installed to allow for hydrajetting. Thus, jets 302 may be isolated by shifting sleeve 601, allowing the fluid to flow past reservoir access sub 102, into hydrajet tool 604, and out through frac ports 124. Ball 606 may then be dropped or pumped down to land on hydrajet tool 604, and move shifting sleeve 601 to divert flow through jets 302, as illustrated in FIG. 6C. Once hydrajetting is complete, the ball may be circulated out, shifting sleeve 601 may return to an original position, isolating jets 302. In some embodiments, ball 606 may be placed in the tool while being run into wellbore 106 while forward circulating to shift shifting sleeve 601 to allow fluid to flow through jets 302. Bottomhole assembly 108 may then be moved to straddle hydrajetted interval, to isolate the interval and set the tool to isolate the zone and fracturing may begin pumping through frac ports 124 (shown in FIG. 6A). While hydrajet tool 604 is illustrated above straddle packer 116, other configurations may be used, depending on the particular circumstances present. For example, hydrajet tool 604 may be below or between straddle packer 116. Likewise, activation may be accomplished by any of a number of methods, only one of which is dropping a ball.

[0038] Generally referring now to FIG. 7 and FIGS. 8A-8D, some embodiments do not have reservoir access sub 102. Rather, these embodiments include a hydraulically (or otherwise) actuated device for establishing fluid communication between liner 104 and wellbore 106. Thus, step 10 of installing one or more reservoir access sub 102 on liner 104, and step 50 of activating at least one reservoir access sub 102, may be replaced by another method of establishing fluid communication between liner 104 and wellbore 106.

[0039] Referring now to the embodiment of FIGS. 7A-7E, this may involve installing punch tool 702 on bottomhole assembly 108 prior to running bottomhole assembly 108 into wellbore 106. Liner 104 or casing may optionally be present in wellbore 106 prior to introduction of bottomhole assembly 108, including punch tool 702. Punch tool 702 may be configured to cut holes, or slots through casing, depending on particular design of wellbore 106. Punch tool 702 may be designed to cut through steel casing, and different tools may be used, depending on casing size, type, and thickness.

[0040] A single run may allow for fracture stimulation of all intervals. Bottomhole assembly 108 may have a similar construction and be placed in a manner similar to that of the embodiment of FIGS. 2A-2E, which may centralize and anchor bottomhole assembly 108 and punch tool 702. Punch tool 702 may be run in a deactivated position, as illustrated in FIG. 7A. Referring now to FIG. 7C, bottomhole assembly 108 may have similar construction and be placed in a manner similar to that of the embodiment of FIGS. 2A-2E. Referring now to FIG. 7D, once bottomhole assembly 108 reaches the predetermined treatment depth, straddle packer 116 may be placed across interval 110 isolating at least one punch tool 702, and punch tool 702 may be activated by pumping a ball through tubing 118, causing penetrators 704 in punch tool 702 to move outward, as illustrated in FIG. 7B, and puncture, or create openings in liner 104 or otherwise establish fluid communication between liner 104 and wellbore 106. If more than one set of openings is desired at the predetermined treatment depth, punch tool 702 may be rotated (e.g., via ratchet tool) the desired amount. Further, any number of
punch tools 702 may be placed in any phrasing or spacing, etc. The ball may then be reversed out and treatment fluid may be pumped down tubing 118. Referring now to FIG. 7E, after treating interval 110, straddle packer 116 may be placed across second interval 112, and the process may be repeated.

[0041] Referring now to the embodiment of FIG. 8A-8D, establishing fluid communication between liner 104 and wellbore 106 may involve installing one or more subs 802 on liner 104 at predetermined intervals prior to running liner 104 into wellbore 106, in a manner similar to that described above with respect to reservoir access subs 102. Referring now to FIG. 8A, subs 802 may include a predetermined number of activated charges 804 designed to activate when exposed to a predetermined pressure. In some embodiments, activated charges 804 may include at least one hydraulically actuated perforating gun or other explosive components.

[0042] Referring now to FIG. 8I, bottomhole assembly 108 may have similar construction and be placed in a manner similar to that of the embodiment of FIGS. 2A-2E. Referring now to FIG. 8C, straddle packer 116 may be placed across interval 110 isolating at least one sub 802 and pressure may be applied via tubing 118 to activated charges 804 to activate guns to puncture liner 104 or otherwise establish fluid communication between liner 104 and wellbore 106. Treatment fluid may then be pumped down tubing 118. Referring now to FIG. 8I, after treating interval 110, straddle packer 116 may be placed across second interval 112, and the process may be repeated.

[0043] Additional embodiments may combine features from the above-described embodiments. For example, but not by way of limitation, one liner may contain any combination of punch tools 702, activated charges 804, reservoir access subs 102 having ports 202, reservoir access subs 102 having jets 302, and/or reservoir access subs 102 having burst disks 402. In each of the embodiments described herein, the methods may additionally include a step of installing an interval locator (not shown) on liner 104 prior to running liner 104 into wellbore 106. The interval locator may be a ‘Mechanical Casing Collar Locator’ (where short joints can be run below each interval to be treated), ‘Hydraulic Casing Collar Locator’, ‘Coil Tubing Acoustic Tool’ (which is described in U.S. Pat. No. 6,880,634), ‘Tag’ bridge plug, or a Hydraulically Activated Interval Locator which is a tool that would activate a key that once on depth would ‘tags’ 102. Referring now to the interval that would place the straddle over the zone of interest and offer a clear ‘positive’ indication on surface that the tool is on depth to perform treatment.

[0044] As used herein, the term “treatment fluid” describes any fluid useful for treatment in a wellbore. Treatment may include fracturing fluids, such as gelled fluids, foamed gels, water, potassium chloride water, acids, etc., or any other treatment useful in wellbore operations. As used herein, the term “shifting sleeve” generally refers to sleeves that move relative to a reference point, including axially, radially, rotationally, or the like. As used herein, the term “tubing” refers to any conduit suitable for the purposes indicated herein, including, but not limited to coiled tubing, jointed pipe, and combinations thereof. As used herein, the term “liner” includes conventional liners, as well as casing, tubulars, and other conduit.

[0045] The methods of this disclosure may allow alternative perforating methods to be applied in conjunction with the Cobra Frac® processes to stimulate multiple intervals economically and efficiently. The methods of this disclosure may also allow for the use of a straddle packer system to perform multiple fracture treatments in a single trip via coil tubing, jointed pipe, or a hybrid unit. The methods of this disclosure may further enable pinpoint placement and isolation of the stimulation treatment. Additionally, the methods of this disclosure may eliminate the need to dedicate one or more trips in hole to perforate. The methods of this disclosure may further eliminate the need for explosives, and associated issues. The methods of this disclosure may remove the significant completion challenges associated with conventional perforating. The methods of this disclosure may offer alternative perforation techniques that will mitigate the effects of conventional perforating while creating an effective communication path to the pay zone. Some methods of this disclosure utilize hydrajetting in situations where it is more advantageous. The methods of this disclosure may be applicable in vertical, deviated, and horizontal wells and may be applied safely in uncemented and cemented applications. The methods of this disclosure may reduce cycle time without sacrificing production efficiency. The methods of this disclosure may reduce costs of multizone stimulations, and improve safety on location. The methods of this disclosure may eliminate the need for a mill run subsequent to a perforating run.

[0046] Therefore, the present invention is well adapted to attain the ends and advantages mentioned as well as those that are inherent therein. The particular embodiments disclosed above are illustrative only, as the present invention may be modified and practiced in different but equivalent manners apparent to those skilled in the art having the benefit of the teachings herein. Furthermore, no limitations are intended to the details of construction or design herein shown, other than as described in the claims below. It is therefore evident that the particular illustrative embodiments disclosed above may be altered or modified and all such variations are considered within the scope and spirit of the present invention. Also, the terms in the claims have their plain, ordinary meaning unless otherwise explicitly and clearly defined by the patentee.

What is claimed is:
1. A method for perforating and fracturing a wellbore in a single trip comprising:
   (a) installing one or more reservoir access subs on a liner at pre-determined intervals;
   (b) running the liner into the wellbore;
   (c) securing the liner to the wellbore;
   (d) running a bottomhole assembly into the wellbore;
   (e) activating at least one of the reservoir access subs so as to allow fluid communication between the liner and the wellbore;
   (f) fracturing at least one interval proximate the activated reservoir access sub;
   wherein steps (d), (e), and (f) are performed in a single trip into the wellbore.
2. The method of claim 1, wherein at least one of the reservoir access subs comprises one or more ports at least partially filled with a soluble material, and wherein activating the reservoir access subs comprises reverse circulating a solvent to dissolve the soluble material in the ports.
3. The method of claim 1, wherein at least one of the reservoir access subs comprises one or more jets at least partially filled with a soluble material, and wherein activating the reservoir access subs comprises reverse circulating a solvent to dissolve the soluble material in the jets.
4. The method of claim 1, wherein at least one of the reservoir access subs comprises one or more ports with burst disks, and wherein activating the reservoir access subs com-
prises isolating at least one of the reservoir access subs with a straddle packer and applying pressure to burst the disks.

5. The method of claim 1, wherein at least one of the reservoir access subs comprises at least one shifting sleeve, and wherein activating the reservoir access subs comprises applying pressure to open the shifting sleeve to expose fracports, jets, and/or soluble jets.

6. The method of claim 1, comprising repeating step (e) for additional reservoir access subs.

7. The method of claim 1, comprising installing an interval locator on the liner prior to running the liner into the wellbore.

8. The method of claim 1, wherein securing the liner to the wellbore comprises placing cement in an annulus formed between the liner and the wellbore, and allowing the cement to set.

9. The method of claim 1, wherein securing the liner to the wellbore comprises setting one or more packers in an annulus formed between the liner and the wellbore.

10. The method of claim 1, wherein fracturing comprises using a straddle technique.

11. The method of claim 1, comprising repeating steps (e)-(f) for one or more additional intervals.

12. The method of claim 1, wherein the bottomhole assembly comprises at least one straddle packer.

13. The method of claim 1, wherein the bottomhole assembly comprises a Cobra Frac® bottomhole assembly.

14. The method of claim 1, comprising isolating the interval, wherein isolating is performed prior to fracturing.

15. A method for perforating and fracturing a wellbore in a single trip comprising:
   (a) running a liner into the wellbore;
   (b) securing the liner to the wellbore;
   (c) running a bottomhole assembly into the wellbore;
   (d) establishing fluid communication between the liner and the wellbore; and
   (e) fracturing at least one interval proximate the fluid communication;

wherein steps (c), (d), and (e) are performed in a single trip into the wellbore; and

wherein steps (d) and (e) are repeated in the single trip into the wellbore.

16. The method of claim 15, comprising installing at least one punch tool on the bottomhole assembly prior to running the bottomhole assembly into the wellbore, wherein establishing fluid communication between the liner and the wellbore comprises activating the punch tool.

17. The method of claim 15, comprising installing one or more subs on the liner at pre-determined intervals prior to running the liner into the wellbore, wherein the subs comprise comprising hydraulically activated charges, and wherein establishing fluid communication between the liner and the wellbore comprises isolating at least one of the subs with a straddle packer, and applying hydraulic pressure to activate the charges.

18. The method of claim 17, wherein the hydraulically activated charges comprise at least one gun.

19. The method of claim 15, comprising installing an interval locator on the liner prior to running the liner into the wellbore.

20. The method of claim 15, wherein securing the liner to the wellbore comprises placing cement in an annulus formed between the liner and the wellbore, and allowing the cement to set.

21. The method of claim 15, wherein securing the liner to the wellbore comprises setting one or more packers in an annulus formed between the liner and the wellbore.

22. The method of claim 15, wherein fracturing comprises using a Cobra Frac® technique.

23. The method of claim 15, comprising repeating steps (d)-(e) for one or more additional intervals.

24. The method of claim 15, wherein the bottomhole assembly comprises at least one straddle packer.

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