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Full Drift Through a Gas Lift Injection Packer Assembly

Abstract

A gas lift injection packer assembly, a gas lift injection system that includes the assembly, and methods utilizing the assembly and system are disclosed. The gas lift injection packer assembly includes a top sub, a packer coupled to the top sub, a bottom sub coupled to the packer, a sleeve disposed within the top sub, the packer, and the bottom sub. The inner diameters of the components of the gas lift injection packer assembly form a continuous passage from end-to-end of the gas lift injection packer assembly such that a downhole tool can be moved through the gas lift injection packer assembly while the gas lift injection packer assembly is sealed in a wellbore. A gas inlet port of the top sub can be formed such that an inner wall of the gas inlet port is the housing for a check valve.

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Background/Summary

CROSS-REFERENCE TO RELATED APPLICATIONS [0001] This application is a non-provisional patent application claiming the benefit of, and priority to, U.S. Provisional Patent Application No. 63/552,626, filed Feb. 12, 2024, which is incorporated by reference herein in its entirety.

FIELD OF THE DISCLOSURE

[0002] The present disclosure generally relates to gas lift injection, and more particularly to a gas lift injection packer assembly used for gas lift injection.

BACKGROUND

[0003] Wellbores are drilled into a subterranean formation to produce hydrocarbon fluids from a producing portion of the subterranean formation. Most wellbores will initially produce hydrocarbon fluids due to the pressure in the producing portion of the subterranean formation. When hydrocarbon fluid production ceases or slows, artificial lift systems may be used to pressurize the wellbore to aid or force hydrocarbon fluids from the producing portion of the subterranean formation, through the production string, and to a wellhead located above the surface.

[0004] Gas lift injections systems, a type of artificial lift system, are used in this context. In a gas lift injection system, a gas is injected into producing portions of the wellbore through segregated portions of the production string. The injected gas mixes with the hydrocarbon fluids, thereby creating a mixture of fluids with a lower density than the density of the hydrocarbon fluids alone. This density reduction effectively reduces a bottomhole pressure (BHP) at a lower end of the tubing, causing the flow of hydrocarbon fluids to increase and/or resume upwards through the production string and to the wellhead.

[0005] Traditional gas lift injection systems often employ a packer assembly to be installed about the production string, which enables an operator to effectively control operation and production of the wellbore. The packer assembly is used to isolate an upper portion of the wellbore from a lower portion of the wellbore disposed below the packer system to protect the upper portion from the corrosive hydrocarbon fluids and force the produced fluids into the production tubing.

[0006] To deliver the injected gas into the lower portion of the wellbore, traditional gas lift injection systems employ a bypass fluid path through the packer assembly, which commonly requires reduced diameter tubing through the packer system as compared to the diameter of the production tubing attached thereto. Due to the technical limitations on how deep the packer assembly can be set into the wellbore, there are limitations on the equipment that can be deployed downhole, which limits production. The hydrocarbon production industry continues to demand improvement in packer assembly technology that increases the capabilities of downhole production.

SUMMARY

[0007] A gas lift injection packer assembly can include a top sub; a packer coupled to the top sub; a bottom sub coupled to the packer; and a sleeve disposed within the top sub, the packer, and the bottom sub, wherein the sleeve forms a micro annulus in the packer assembly with the top sub and the packer, wherein the sleeve has full drift through the gas lift injection packer assembly. In some aspects, the sleeve can have an inner diameter that is the same as, substantially the same as, or not greater than 5% different than an inner diameter of a production tubing coupled to the top sub, to the bottom sub, or to the top sub and to the bottom sub.

[0008] Another gas lift injection packer assembly can include a top sub having a gas inlet port formed therein; a check valve disposed in the gas inlet port, wherein an inner wall of the gas inlet port is a housing for the check valve; a packer coupled to the top sub; a bottom sub coupled to the packer; a sleeve disposed within the top sub, the packer, and the bottom sub, wherein the sleeve forms a micro annulus with the top sub and the packer, wherein the gas inlet port and the check valve are in fluid communication with the micro annulus.

[0009] A gas lift injection system can include a first production tubing; a gas lift injection packer assembly including a top sub, a packer coupled to the top sub, a bottom sub coupled to the packer, and a sleeve disposed within the top sub, the packer, and the bottom sub; a second production tubing; wherein the top sub is coupled to the first production tubing, wherein the bottom sub is coupled to the second production tubing, and wherein the sleeve includes an inner diameter that is the same as, substantially the same as, or not greater than 5% different than an inner diameter of the first production tubing, an inner diameter of the second production tubing, or the inner diameter of the first production tubing and the inner diameter of the second production tubing.

[0010] Another gas lift injection system can include a first production tubing; a gas lift injection packer assembly including a top sub having a gas inlet port formed therein; a check valve disposed in the gas inlet port, wherein an inner wall of the gas inlet port is a housing for the check valve; a packer coupled to the top sub; a bottom sub coupled to the packer; a sleeve disposed within the top sub, the packer, and the bottom sub, wherein the sleeve forms a micro annulus with the top sub and the packer, wherein the gas inlet port and the check valve are in fluid communication with the micro annulus; a second production tubing; wherein the top sub is coupled to the first production tubing, wherein the bottom sub is coupled to the second production tubing.

[0011] A method of gas lift injection can include one or more of providing a production string including production tubing and a gas lift injection packer assembly coupled to the production tubing, wherein the gas lift injection packer assembly includes a top sub, a packer coupled to the top sub, a bottom sub coupled to the packer, and a sleeve disposed within the top sub, the packer, and the bottom sub, wherein the sleeve forms a micro annulus with the top sub and the packer; flowing the pressurized gas from the annulus of the wellbore through the micro annulus; flowing the pressurized gas from the micro annulus through a gas outlet port formed in the bottom sub into a lower portion of the annulus of the wellbore; and flowing the pressurized gas through one or more gas injection valves disposed in a lower portion of the production tubing. The method can utilize an embodiment of the gas lift injection packer assembly herein.

Description

BRIEF DESCRIPTION OF THE DRAWINGS

[0012] For a more complete understanding of this disclosure, reference is now made to the following description, taken in conjunction with the accompanying drawings, in which:

[0013] FIG. **1** illustrates a schematic diagram of a gas lift injection system according to an embodiment of the disclosure.

[0014] FIG. **2** illustrates an orthogonal side view of a gas lift injection packer assembly according to an embodiment of the disclosure.

[0015] FIG. **3** illustrates a cross-sectional side view of the gas lift injection packer assembly according to an embodiment of the disclosure.

[0016] FIG. **4**A illustrates a detailed cross-sectional side view of a top portion of the gas lift injection packer assembly according to an embodiment of the disclosure.

[0017] FIG. **4**B illustrates a detailed cross-sectional side view of a top portion of the gas lift injection packer assembly according to another embodiment of the disclosure.

[0018] FIG. **4**C illustrates an isolated cross-sectional view of a port formed in the top sub, without the check valve placed in the gas injection port.

[0019] FIG. **4**D illustrates an isolated cross-sectional view of a port formed in the top sub, with the check valve placed in the gas injection port.

[0020] FIG. **5** illustrates a detailed cross-sectional side view of a bottom portion of the gas lift injection packer assembly according to an embodiment of the disclosure.

[0021] FIG. **6** illustrates a flowchart of a method of gas lift injection according to an embodiment of the disclosure.

DETAILED DESCRIPTION

[0022] Referring to FIG. **1**, a schematic diagram of a gas lift injection system **100** is shown according to an embodiment of the disclosure. The gas lift injection system **100** may generally be configured for producing hydrocarbon fluids from a wellbore **130** that extends into a subterranean formation. More specifically, the gas lift injection system **100** may comprise a form of artificial lift system that may be used to selectively inject pressurized gas into the wellbore **130** to increase the production of the hydrocarbon fluids from the subterranean formation.

[0023] The gas lift injection system **100** may generally comprise a wellhead **102**, a production string **104** extending from the wellhead **102** into the wellbore **130**, a separator **106** connected to the wellhead **102**, a gas lift injection compressor **108**, a gas lift injection control valve **110**, and a control system **112**. The wellhead **102** may generally be disposed on top of the wellbore **130**, or in some aspects, on top of a casing cemented within the wellbore **130**. The wellhead **102** may be coupled to the production string **104** and configured to receive produced hydrocarbon fluids therefrom. In some embodiments, the wellhead **102** may include components known in the art with the aid of this disclosure, such as a production tree, stuffing box, one or more seals, a blowout preventer (BOP), or any combination thereof.

[0024] In some aspects, the wellhead **102** may be fluidly connected to the separator **106**. The wellhead may be configured to deliver fluids produced from the wellbore **130** to the separator **106**. The separator **106** may separate the produced hydrocarbon fluids from the injected gas that has aided in carrying the hydrocarbon fluids to the wellhead **102**. After separation, the separator **106** may subsequently distribute the separated hydrocarbon fluids to a storage vessel and/or pipeline for production.

[0025] The production string **104** may generally be connected to the wellhead **102** and extend from the wellhead **102** into the wellbore **130**. The production string **104** may comprise upper production tubing **114**, a gas lift injection packer assembly **200** comprising one or more packer elements or seals **118**, and a lower production tubing **120**. The upper production tubing **114** may be coupled to the wellhead **102**, the gas lift injection packer assembly **200** may be coupled to the upper production tubing **114**, and the lower production tubing **120** may be coupled to the gas lift injection packer assembly **200**. Collectively, the production string **104** may extend into the wellbore **130** and comprise a fluid pathway for the produced hydrocarbon fluids to reach the wellhead **102**. An annulus **140** may be present between an outer surface of the production string **104** and an inner surface of the wellbore **130** or an inner surface of a casing that can be cemented to the inner surface of the wellbore **130**, through which the pressurized gas from the gas lift injection system **100** is delivered.

[0026] The packer element or seal **118** may be disposed in the annulus **140** and between a sleeve of the gas lift injection packer assembly **200** and the inner surface of the wellbore **130** or the inner surface of the casing that is cemented in the wellbore **130**. The packer element or seal **118** may form a fluid tight seal that fluidly isolates an upper portion of the annulus **140** located above the packer element or seal **118** from a lower portion of the annulus **140** located below the packer element or seal **118**. The seal contains hydrocarbon fluids within the lower portion of the annulus **140** and forces hydrocarbon fluids into the lower production tubing **120** of the production string **104**. In some embodiments, the packer element or seal **118** may be elastomeric and may be selectively expandable to from the seal in the annulus **140**.

[0027] The gas lift injection system **100** may generally comprise a gas lift injection compressor **108**. The gas lift injection compressor **108** may be configured to receive an injection gas (e.g., a low pressure natural gas (or other gas) from a so-called “sales line” or from a neighboring well, nitrogen or other inert gas, carbon dioxide, air, or combinations thereof) and pressurize the injection gas for use in the gas lift injection system **100**. The gas lift injection compressor **108** may be coupled to a gas lift injection control valve **110** that selectively regulates the pressure and/or flow of the pressurized gas from the gas lift injection compressor **108** into the wellbore **130**, and more specifically into the upper portion of the annulus **140** formed between the production string **104** and the wellbore **130**. In some embodiments, the pressurized gas may be injected into the wellbore **130** through a portion of the wellhead **102**.

[0028] The gas lift injection system **100** may also comprise a control system **112** that is configured to control the mechanical equipment of the gas lift injection system **100**. In some embodiments, the control system **112** may comprise one or more control interfaces. In some embodiments, the control system may be networked with sensors disposed in the gas lift injection system **100** and/or the wellbore **130** to facilitate real-time feedback and control of the gas lift injection system **100** and/or its individual components (e.g., via Wi-Fi, Bluetooth, NFC, ethernet cables, other wired connections, or combinations thereof).

[0029] During operation of the gas lift injection system **100**, the control system **112** may operate to control the flow of pressurized gas from the gas lift injection compressor **108**, through the gas lift injection control valve **110**, and into the wellbore **130**. The pressurized gas is delivered into the upper portion of the annulus **140** formed between the production string **104** and the casing of the wellbore **130**. The pressurized gas may enter the gas lift injection packer assembly **200** from the annulus **140** above the packer element or seal **118**, pass through the gas lift injection packer assembly **200**, and exit the gas lift injection packer assembly **200** into the lower portion of the annulus **140** below the packer element or seal **118**, where the pressurized gas may enter one or more gas injection valves **122** disposed in the lower production tubing **120** of the production string **104**.

[0030] When injected into the lower production tubing **120** via the gas injection valves **122**, the pressurized gas may mix with the hydrocarbon fluids in the lower production tubing **120** and/or the wellbore **130**, thereby creating a mixture of fluids having a lower density than the density of the hydrocarbon fluids alone. This density reduction caused by the mixture of the pressurized gas with the hydrocarbon fluids effectively reduces a bottomhole pressure (BHP) at a lower end of the production string **104** and/or the wellbore **130**, causing the flow of hydrocarbon fluids to increase and/or resume (in the case of a non-productive well) upwards through the production string **104** and to the wellhead **102**, where the mixture can be passed through the separator **106** to separate the hydrocarbon fluids from the injected gas.

[0031] As will be discussed herein in more detail, the gas lift injection system **100** may allow gas injection to occur at a bottom of the production string **104** and/or the wellbore **130**. Additionally, the gas lift injection system **100** may enable selectively deployment of downhole tools, such as plunger **124**, past or through the gas lift injection packer assembly **200**, thereby enabling increased drawdown of pressure within the wellbore **130**, which increases production and is not readily achievable with traditional gas lift injection systems that have a reduced diameter through the packer assembly portion of a traditional production tubing.

[0032] The following discussion shall refer to components of the gas lift injection packer assembly **200** that are illustrated in one or more of FIGS. **2**, **3**, **4**A, **4**B, **4**C, **4**D, and **5**. FIG. **2** illustrates an orthogonal side view of a gas lift injection packer assembly **200**, FIG. **3** illustrates a cross-sectional side view the gas lift injection packer assembly **200**, FIG. **4**A illustrates a detailed cross-sectional side view of a top portion of the gas lift injection packer assembly **200**, FIG. **4**B illustrates another detailed cross-sectional side view of a top portion of the gas lift injection packer assembly **200**, FIG. **4**C illustrates an isolated cross-sectional view of a port formed in the top sub, without a check valve placed in the gas injection port, FIG. **4**D illustrates an isolated cross-sectional view of a port formed in the top sub, with the check valve placed in the gas injection port, and FIG. **5** illustrates a detailed cross-sectional side view of a bottom portion of the gas lift injection packer assembly **200** are shown according with embodiments of the disclosure.

[0033] The gas lift injection packer assembly **200** may be suitable for use in the gas lift injection system **100**. The gas lift injection packer assembly **200** may comprise a top sub **202**, a packer **204**, a bottom sub **206**, and a sleeve **208**. In some aspects, the gas lift injection packer assembly **200** includes one or more check valves embedded in the top sub **202**. In aspects, the inner diameters of the sleeve **208**, the top sub **202**, the bottom sub **206**, and the production tubing form a continuous passage that enables movement of a downhole tool through the gas lift injection packer assembly **200**.

[0034] The top sub **202** may comprise a main annular body **210** and may be connectable to the upper production tubing **114** (in FIG. **1**) via an upper threaded connection **212** of the top sub **202**. In some embodiments, the upper threaded connection **212** may comprise a 2.875″ EUE (8RD) female thread configured to receive a complementary male thread of the upper production tubing **114**. The body **210** may comprise a central bore **214** configured to receive the sleeve **208**. In some embodiments, one or more annular seals **216** may be disposed within one or more recesses **218** formed in the central bore **214** that are configured to form an annular fluid tight seal between the top sub **202** and the sleeve **208** and/or retain or secure the sleeve **208** within the central bore **214** of the top sub **202**.

[0035] The body **210** of the top sub **202** may also comprise one or more gas inlet port **222** formed in a protruding shoulder **211** of the body **210**. The gas inlet port **222** in FIG. **3** is illustrated as housing a check valve **220**, the arrangement which is described in more detail herein

[0036] FIG. **4**A illustrates one gas inlet port **222** having one check valve **220** housed therein, and FIG. **4**B illustrates two gas inlet ports **222** and **231**, where gas inlet port **222** has check valve **220** and gas inlet port **231** has check valve **221** housed therein.

[0037] The gas inlet port **222** is fluidly connected to an injected gas runner **224**, and the injected gas runner **224** is fluidly connected to a micro annulus **226**, for example, via a manifold **230**. The injected gas runner **224** functions as a channel for flow of gas therethrough, that connects the gas inlet port **222** with the manifold **230**. While one gas inlet port **222** is illustrated in FIG. **4**A, this disclosure contemplates that multiple gas inlet ports **222** can be formed in a circumferential manner in the body **210** of the top sub **202**, such as is illustrated in FIG. **4**B where the protruding shoulder **211** extends around the entire circumference of the top sub **202**. An inner wall **223** of the gas inlet port **222** has an inner diameter sufficient to hold a valve seat **400** of a check valve **220**. The gas inlet port **222** and the check valve **220** can be in fluid communication with the micro annulus **226**. The valve seat **400** can be connected to the inner wall **223** in friction fit relationship, such as via threads on an outer surface of the valve seat **400** that mate with threads on the inner wall **223**. The check valve **220** can include a seal ring **401**, a check seal **402**, a check seal retainer **403**, a dart **404**, and a spring **405**. The seal ring **401** is positioned between the valve seat **400** and the inner wall **223** of the gas injection port **222**. The seal ring **401** creates a seal between the inner wall **223** of the gas injection port **222** and the outer surface of the valve seat **400** of the check valve **220**. The check seal **402** is positioned within the gas injection port **222** to contact the bottom of the valve seat **400**, the inner wall **223**, the check seal retainer **403**, and the dart **404**. The check seal retainer **403** is positioned within the gas injection port to contact the inner wall **223** of the gas injection port **222**, the bottom of the check seal **402**, and a shoulder of the dart **404**. The check seal retainer **403** is configured to retain the check seal **402** in position. The dart **404** is configured to move longitudinally in the gas injection port **222**. A head of the dart **404** is configured to fit into the interior **406** of the valve seat **400**, and when paced into contact with the valve seat **400**, obstructs a flow of fluid from the runner **224** into the valve seat **400** by a seal that is created by the dart **404** against the valve seat **400**, the check seal **402**, the check seal retainer **403**, or a combination thereof. The spring **405** contacts the dart **404** and the abutment surface **227**. The spring **405** can compress in response to a pressure that pushes the dart **404** from the valve seat **400** toward the runner **224**, and the spring can extend to seat the head of the dart **404** against the valve seat **400** when a pressure less than the spring force is present outside the top sub **202**. Movement of the dart **404** and spring

405 open and close the check valve **220** for flow of gas, or to stop flow of gas, into the runner **224** and prevent fluid from traveling from the runner **224** and out of the top sub **202**.

[0038] The check valve **220** has no separate housing as is conventionally used for check valves in gas lift injection systems. Instead, the inner wall **223** of the gas injection port **222** is the housing for the check valve **220**, e.g., the inner wall **223** is the housing for the valve seat **400** and other components of the check valve **220** (e.g., the seal ring **401**, the check seal **402**, the check seal retainer **403**, the dart **404**, and the spring **405**. The components of the check valve **220** can be referred to as "embedded" in the body **210** of the top sub **202** because the check valve **220** has no component that is a housing and instead the inner wall **223** of the gas injection port **222** is the housing for the check valve **220**. In aspects, an inner diameter of the gas injection port **222** can be greater than an inner diameter of the runner **224** such that an abutment surface **227** is formed where the gas injection port **222** meets the runner **224**. The abutment surface **227** can keep the moving components (e.g., ball and spring) of the check valve **220** in the gas injection port **222** and can keep components of the check valve **220** from moving into the runner **224**.

[0039] In some embodiments, a longitudinal axis of the gas injection port **222** and the check valve **220** (see axis L-L in FIG. **4**C and FIG. **4**D) may be disposed at an angle of between about **10** degrees and **15** degrees with respect to a central axis (e.g., a longitudinal axis) of the gas lift injection packer assembly **200**. In a particular embodiment, the gas injection port **222** and check valve **220** may be disposed at an angle of about 12 degrees with respect to a central axis of the gas lift injection packer assembly **200**. The gas inlet port **222** may comprise an injected gas runner **224** in fluid connection with a micro annulus **226** formed in the body **210** between a second bore **228** of the top sub **202** and the sleeve **208**. The second bore **228** may be axially aligned with the central bore **214** and comprise a diameter that is larger than the diameter of the central bore **214**. The second bore **228** and the micro annulus **226** may extend from the injected gas runner **224**, or a manifold **230** that annularly fluidly connects the injected gas runner **224**, through a lower distal end of the top sub **202**.

[0040] FIG. **4**B illustrates that, in some embodiments, the protruding shoulder **211** of the body **210** of the top sub **202** can extend around the entire circumference of the body **210** of the top sub **202** to accommodate formation of multiple gas inlet ports. The protruding shoulder **211** in such embodiments may comprise one or a plurality of gas inlet ports (e.g., two gas inlet ports **222** and **231** being illustrated in FIG. **4**B) formed therein, wherein a check valve is placed in each port (e.g., check valve **220** is placed in port **222** and check valve **221** is placed in port **231**). The check valve **220** and port **222** have the same components and configuration as described for FIG. **4**A. The check valve **221** and port **231** have the same configuration and components as the check valve **220** and port **222**.

[0041] The check valve **220** is embedded as described above for FIG. **4**A. Likewise, the check valve **221** has no separate housing as is conventionally used for check valves gas lift injection systems. Instead, the inner wall **225** of the gas injection port **231** is the housing for the check valve **221**, e.g., the inner wall **225** is the housing for the valve seat **450** and other components of the check valve **221**. The components of the check valve **221** can be referred to as "embedded" in the body **210** of the top sub **202** because the check valve **221** has no component that is a housing and instead the inner wall **223** of the gas injection port **222** is the housing for the check valve **220**.

[0042] FIG. **4**C illustrates an isolated cross-sectional view of a gas inlet port formed in the top sub **202**, without a check valve placed in the gas injection port. The gas inlet port illustrated is applicable for port **222** and port **231**, and will be referred to as ports **222**/**231**. The remainder of the discussion for FIG. **4**C shall use reference numerals that refer to both ports **222**/**231**. The inner wall **223**/**225** of the gas injection ports **222**/**231** has first section **223**A/**225**A, second section **223**B/**225**B, third section **223**C/**225**C, and fourth section **223**D/**225**D. A diameter of the first section **223**A/**225**A is greater than a diameter of the second section **223**B/**225**B such that abutment surface **235** is formed. A diameter of the second section **223**B/**225**B is greater than a diameter of the third section

223C/**225**C such that abutment surface **237** is formed. A diameter of the third section **223**C/**225**C is greater than a diameter of the fourth section **223**D/**225**D such that abutment surface **239** is formed. The abutment surfaces **235**, **237**, **239**, **227**/**299** are configured to contact and hold various components of the check valves **220** and **221** as described in FIG. **4**D.

[0043] FIG. **4**D illustrates an isolated cross-sectional view of the gas injection port of FIG. **4**C, with the check valve **220**/**21** placed in the gas injection port **222**/**231**. Check valve **220** can have the valve seat **400**, the seal ring **401**, the check seal **402**, the check seal retainer **403**, the dart **404**, and the spring **405**. The check valve **221** can have the valve seat **450**, the seal ring **451**, the check seal **452**, the check seal retainer **453**, the dart **454**, and the spring **455**. The abutment surface **235** can contact a bottom side of a top portion of the valve seat **400**/**450**. The abutment surface **237** can contact the seal ring **401**/**451**. The abutment surface **239** can contact the check seal retainer **403**/**453**. The abutment surface **227**/**229** can contact the spring **405**/**455**. The check valve **220**/**221** is in the closed position, in that the head of the dart **404**/**454** can be seen obstructing a flow of fluid in the direction from the runner **224**/**233** into the interior **406**/**456** of the valve seat **400**/**450**. The dart **404**/**454** and spring **405**/**455** move in the direction of the longitudinal axis L-L. In the open position, the head of the dart **404**/**454** moves downwardly (with reference to direction in the view, not necessarily to direction in position in a wellbore) such that the head of the dart **404**/**454** does not obstruct a flow of gas that flows through the interior **404**/**456** of the valve seat **400**/**450** and into the runner **224**/**233** Legs of the dart **404**/**454** can be seen in operable connection with the spring **405**/**455**.

[0044] Returning to FIG. **2**, the packer **204** may generally be connectable to the top sub **202** via a threaded connection **232**. In some embodiments, the threaded connection **232** may comprise a 2.875″ EUE (8RD) thread. In some embodiments, the top sub **202** may comprise the male thread, and the packer **204** may comprise the female thread, such that the top sub **202** is threaded into the packer **204** to form a fluid tight seal between the top sub **202** and the packer **204**. In some embodiments, the packer **204** may be formed from multiple components that are coupled to form a fluid tight seal therebetween. However, in some embodiments, the packer **204** may be formed from a unitary component.

[0045] The packer **204** may comprise a central bore **234**. The central bore **234** may extend through the entire length of the packer **204**. The central bore **234** may form the micro annulus **226** through the packer **204** between the central bore **234** and the sleeve **208**. In some embodiments, the central bore **234** may comprise the same or substantially similar diameter as the second bore **228** through the top sub **202**, such that the micro annulus **226** maintains a constant and continuous diameter through each of the top sub **202** and the packer **204**.

[0046] The packer **204** may also comprise one or more packer elements or seals **236**. The packer elements or seals **236** may form a fluid tight seal between the upper portion of the annulus **140** located above the packer elements or seals **236** and a lower portion of the annulus **140** located below the packer elements or seals **236** to contain hydrocarbon fluids within the lower portion of the annulus **140** and force hydrocarbon fluids into the production string **104**. In some embodiments, the packer elements or seals **236** may be elastomeric and may be selectively expandable to seal the annulus **140**.

[0047] As illustrated in FIG. **5**, the bottom sub **206** may comprise a main annular body **238** and may be connectable to the packer **204** via an upper threaded connection **240**. In some embodiments, the threaded connection **240** may comprise a 2.875″ EUE (8RD) thread. In some embodiments, the packer **204** may comprise the male thread, and the bottom sub **206** may comprise the female thread, such that the packer **204** is threaded into the bottom sub **206** to form a fluid tight seal between the packer **204** and the bottom sub **206**.

[0048] The body **238** of the bottom sub **206** may comprise a central bore **242** configured to receive the sleeve **208**. In some embodiments, one or more annular seals **244** may be disposed within one or more recesses **246** formed in the central bore **242** that are configured to form an annular fluid tight seal between the bottom sub **206** and the sleeve **208** and/or retain or secure the sleeve **208** within the central bore **242** of the bottom sub **206**.

[0049] The body **238** of the bottom sub **206** may also comprise one or more gas outlet port **248**. The gas outlet port **248** may be annularly disposed about the body **238** of the bottom sub **206**. The gas outlet port **248** may be in fluid connection (e.g., via a manifold **252**) with the micro annulus **226** formed between the packer **204** and the sleeve **208** to allow the pressurized gas that enters the gas lift injection packer assembly **200** from the upper portion of the annulus **140** of the wellbore **130** to exit the gas lift injection packer assembly **200** and enter the lower portion of the annulus **140** of the wellbore **130**. In aspects, the manifold **252** has an inner diameter that is greater than an inner diameter of the central bore **242**.

[0050] The bottom sub **206** may also comprise a second bore **253** that extends from the central bore **242** of the bottom sub **206** to a distal end of the bottom sub **206**. The second bore **253** may be axially aligned with the central bore **242** and comprise a diameter that is smaller than the diameter of the central bore **242**. In some embodiments, the second bore **253** may comprise a diameter that is the same or substantially similar as the inner diameter of the upper production tubing **114** and/or an inner diameter of the inner surface **258** of the sleeve **208**. Additionally, the bottom sub **206** may also be connectable to the lower production tubing **120** via a lower threaded connection **254**.

[0051] The sleeve **208** may be disposed within each of the top sub **202**, the packer **204**, and the bottom sub **206**. In aspects, the sleeve **208** is a floating tube, in that, the sleeve is held in place by the top sub **202**, the packer **204**, and the bottom sub **206**; and may contact one or more of the top sub **202**, and the bottom sub **206**; but is not connected to the top sub **202**, the packer **204**, or the bottom sub **206**. The sleeve **208** may float within the top sub **202**, the packer **204**, and the bottom sub **206** via seals **216** and seals **244**. In some embodiments, the sleeve **208** may comprise a unitary component in the shape of a tube. In other embodiments, the sleeve **208** may be formed from a series connectable components, such a series of tube segments connected end to end to one another to form the sleeve **208**. The sleeve **208** may generally comprise an outer surface **256** having an outer diameter and an inner surface **258** having an inner diameter. The sleeve **208** also comprises a length that may be determined by the size of the top sub **202**, the packer **204**, the bottom sub **206**, a curvature of the wellbore **130**, or a combination thereof.

[0052] The sleeve **208** may be sized to facilitate hydrocarbon fluid production through the gas lift injection packer assembly **200**. In some embodiments, the central bore **214** of the top sub **202** and the central bore **242** of the bottom sub **206** may be sized to accommodate the sleeve **208**. In some embodiments, the central bore **214** of the top sub **202** and the central bore **242** of the bottom sub **206** may be about 2.165+/−0.010 inches, and the outer diameter of the outer surface **256** of the sleeve **208** may be about 2.15 inches. In some embodiments, the second bore **228** of the top sub **202** and the central bore **234** of the packer **204** may be sized to form the micro annulus **226** with the outer surface **256** of the sleeve **208**. In some embodiments, the second bore **228** of the top sub **202** and the central bore **234** of the packer **204** may be about 2.50+/−0.010, and the outer surface **256** of the sleeve **208** may be about 2.15 inches.

[0053] Further, the sleeve **208** may be sized to prevent restriction to the flow of produced hydrocarbon fluids through the gas lift injection packer assembly **200**, while also enabling selective movement of downhole tools, such as plunger **124**, past or through the gas lift injection packer assembly **200**, which increases production and is not readily achievable with traditional gas lift injection systems. In some embodiments, the inner diameter of the inner surface **258** of the sleeve **208** may be about 1.952+/−0.015 inches. Accordingly, it will be appreciated that the upper production tubing **114** and the lower production tubing **120** may comprise the same or substantially similar diameter. In some embodiments, the difference between the inner diameter of the inner surface **258** of the sleeve **208** and the inner diameters of the upper production tubing **114** and the lower production tubing **120** may be not greater than 5.0%, 4.5%, 4.0%, 3.5%, 3.0%, 2.5%, 2.0%, 1.5%, 1.25%, 1.0%, 0.75%, 0.50%, 0.40%, 0.30%, 0.20%, 0.10%, or even 0%. In aspects, the inner diameter of the inner surface **258** of the sleeve **208** and the inner diameters of the upper production tubing **114** and the lower production tubing **120** can be the same or substantially the same. The size of the inner diameter of the inner surface **258** of the sleeve **208** relative to the inner diameter(s) of the production tubing attached gas lift injection packer assembly **200**, as disclosed herein, can be referred to as “full drift,” or the gas lift injection packer assembly **200** having a “full drift.” “Full drift” can additionally refer to a smallest diameter of any bore formed along a longitudinal axis of the top sub **202** being the same as, substantially the same as, or greater than the inner diameter of the production tubing **114**, **120**. “Full drift” can additionally refer to a smallest diameter of any bore formed along a longitudinal axis of the bottom sub **206** being the same as, substantially the same as, or greater than the inner diameter of the production tubing **114**, **120**.

[0054] Referring to FIGS. **1-5** collectively, the gas lift injection packer assembly **200** may be disposed as a component of the production string **104** between the upper production tubing **114** and the lower production tubing **120**. During a gas lift injection operation, the gas lift injection control valve **110** may be operated to control the flow of pressurized gas from the gas lift injection compressor **108**, through the gas lift injection control valve **110**, and into the upper portion of the annulus **140** of the wellbore **130** formed between the production string **104** and the casing of the wellbore **130**. The pressurized gas may enter the gas inlet port **222** and the check valve(s) **220** of the top sub **202** of the gas lift injection packer assembly **200** from the annulus **140**. In some embodiments, the check valve(s) **220** may only allow the pressurized gas to enter the gas lift injection packer assembly **200** when the pressure is high enough or surpasses a predetermined threshold.

[0055] When the pressure of the pressurized gas is sufficient, the pressurized gas may pass through the check valve(s) **220**, through the injected gas runners **224**, and enter the manifold **230**, where the pressurized gas may enter the micro annulus **226**. The pressurized gas may pass through the top sub **202** and the packer **204** via the micro annulus **226** and exit the gas lift injection packer assembly **200** via the gas outlet port **248** formed in the bottom sub **206**. This allows the pressurized gas to bypass the packer elements or seals **236**. The pressurized gas may flow through the gas outlet port **248** in the bottom sub **206** into the lower portion of the annulus **140** below the packer elements or seals **236**, where the pressurized gas may enter one or more gas injection valves **122** disposed in the lower production tubing **120** of the production string **104**.

[0056] When injected into the lower production tubing **120** via the gas injection valves **122**, the pressurized gas may mix with the hydrocarbon fluids in the lower production tubing **120** and/or the wellbore **130**, thereby creating a mixture of fluids having a lower density than the density of the hydrocarbon fluids alone. This density reduction caused by the mixture of the pressurized gas with the hydrocarbon fluids effectively reduces a bottomhole pressure (BHP) at a lower end of the production string **104** and/or the wellbore **130**, causing the flow of hydrocarbon fluids to increase and/or resume (in the case of a non-productive well) upwards through the production string **104** and to the wellhead **102**, where the mixture can be passed through the separator **106** to separate the hydrocarbon fluids from the injected gas.

[0057] Further, during the gas injection operation, and as a result of the matching inner diameters of the sleeve **208**, the upper production tubing **114**, and the lower production tubing **120**, downhole tools such as submersible pumps or plunger **124** may be selectively deployed through the gas lift injection packer assembly **200**, which is not readily achievable with traditional gas lift injection systems that have a reduced diameter through the packer assembly portion of a traditional production tubing string. Thus, the gas lift injection system **100**, when employing the gas lift injection packer assembly **200**, enhances hydrocarbon production, which may reduce waste, reduce the number of wells needing to be drilled into a subterranean formation, and further offset expensive operating costs associated with hydrocarbon production.

[0058] FIG. **6** illustrates a flowchart of a method **600** of gas lift injection according to an embodiment of the disclosure. The description of the method **600** may use reference numerals labeled in any of the foregoing figures.

[0059] The method **600** may begin at block **602** providing a gas lift injection packer assembly **200** in a production string **104** of a gas lift injection system **100**. The gas lift injection packer assembly **200** has any configuration described herein, and these configurations are not reproduced here.

[0060] The method **600** may continue at block **604** by injecting a pressurized gas into the wellbore **130**. In some embodiments, the pressurized gas may be injected into an upper portion of an annulus **140** of the wellbore **130** formed between the production string **104** and the casing of the wellbore **130** and disposed above the packer elements or seals **236**.

[0061] The method **600** may continue at block **606** flowing the pressurized gas through the gas lift injection packer assembly **200** to bypass the packer elements or seals **236**. In some embodiments, flowing the pressurized gas through the gas lift injection packer assembly **200** may comprise flowing the pressurized gas from the upper portion of the annulus **140** of the wellbore **130** through a one or more check valves (e.g., check valve **220**, check valve **221**) embedded in the top sub **202**, through one or more injected gas runners (e.g., runner **224**, runner **233**), optionally into the manifold **230** of the top sub **202**, into and through the micro annulus **226** formed between the sleeve **208** and each of the top sub **202** and the packer **204**, and through a gas outlet port **248** formed in the bottom sub **206** to the lower portion of the annulus **140** of the wellbore **130** below the packer elements or seals **236**.

[0062] The method **600** may continue at block **608** by flowing the pressurized gas through one or more gas injection valves **122** disposed in the lower production tubing **120** of the production string **104**. In some embodiments, flowing the pressurized gas through the gas injection valves **122** may allow the pressurized gas to mix with hydrocarbon fluids in the lower production tubing **120** and/or the wellbore **130**, thereby creating a mixture of fluids having a lower density than the density of the hydrocarbon fluids prior to gas injection. In some embodiments, flowing the pressurized gas through the gas injection valves **122** may reduce the bottomhole pressure (BHP) at a lower end of the production string **104** and/or the wellbore **130** and urge a plunger **124** to push the mixture of fluids having the lower density after gas injection upwards through the production string **104** (e.g., the lower production tubing **120**, the gas lift injection packer assembly **200**, and the upper production tubing **114**) and to the wellhead **102**. After the fluid is produced from the wellbore **130**, the plunger **124** can fall down through the production string **104** (e.g. fall through the upper production tubing **114**, the gas lift injection packer assembly **200**, and then the lower production tubing **120**).

ASPECTS

[0063] Aspect 1. A gas lift injection packer assembly comprising: a top sub; a packer coupled to the top sub; a bottom sub coupled to the packer; and a sleeve disposed within the top sub, the packer, and the bottom sub, wherein the sleeve forms a micro annulus in the packer assembly with the top sub and the packer, wherein the sleeve comprises an inner diameter that is the same as, substantially the same as, or not greater than 5% different than an inner diameter of a production tubing coupled to the top sub, to the bottom sub, or to the top sub and to the bottom sub. [0064] Aspect 2. The gas lift injection packer assembly of Aspect 1, wherein a smallest diameter of any bore formed along a longitudinal axis of the top sub is the same as, substantially the same as, or greater than the inner diameter of the production tubing. [0065] Aspect 3. The gas lift injection packer assembly of Aspect 1 or 2, wherein a smallest diameter of any bore formed along a longitudinal axis of the bottom sub is the same as, substantially the same as, or greater than the inner diameter of the production tubing. [0066] Aspect 4. The gas lift injection packer assembly of any one of Aspects 1 to 3, wherein the top sub comprises a central bore configured to receive an end of the sleeve and a second bore that forms the micro annulus with the sleeve; wherein the packer comprises a central bore that forms the micro annulus with an outer surface of the sleeve through the packer; wherein the bottom sub comprises a central bore configured to receive an opposite end of the sleeve, a manifold that fluidly connects the micro annulus to a gas outlet port formed in the bottom sub, and a second bore that fluidly connects an outlet of the bottom sub to an interior of the sleeve. [0067] Aspect 5. The gas lift injection packer assembly of any one of Aspects 1 to 4, wherein the inner diameters of the sleeve, the top sub, the bottom sub, and the production tubing form a continuous passage that enables movement of a downhole tool through the packer assembly. [0068] Aspect 6. The gas lift injection packer assembly of Aspect 5, wherein the downhole tool comprises a submersible pump, a plunger, or a combination thereof. [0069] Aspect 7. The gas lift injection packer assembly of any one of Aspects 1 to 6, wherein the top sub comprises a body having a gas inlet port formed therein, wherein a valve seat of a check valve is disposed in the gas inlet port. [0070] Aspect 8. The gas lift injection packer assembly of Aspect 7, wherein the valve seat of the check valve is threaded into the gas inlet port formed in the body of the top sub. [0071] Aspect 9. The gas lift injection packer assembly of Aspect 7 or 8, wherein the check valve is configured to allow pressurized gas injected into a wellbore to enter the micro annulus. [0072] Aspect 10. The gas lift injection packer assembly of any one of Aspects 7 to 9, wherein an inner wall of the gas inlet port is a housing for the check valve. [0073] Aspect 11. The gas lift injection packer assembly of any one of Aspects 7 to 10, wherein the gas inlet port and the check valve are disposed at an angle of between about 10 degrees and 15 degrees with respect to a central axis of the gas lift injection packer assembly. [0074] Aspect 12. The gas lift injection packer assembly of any one of Aspects 7 to 11, wherein the top sub comprises an injected gas runner fluidly connecting the gas inlet port with the micro annulus. [0075] Aspect 13. A gas lift injection packer assembly comprising: a top sub having a gas inlet port formed therein; a check valve disposed in the gas inlet port, wherein an inner wall of the gas inlet port is a housing for the check valve; a packer coupled to the top sub; a bottom sub coupled to the packer; and a sleeve disposed within the top sub, the packer, and the bottom sub, wherein the sleeve forms a micro annulus with the top sub and the packer, wherein the gas inlet port and the check valve are in fluid communication with the micro annulus. [0076] Aspect 14. The gas lift injection packer assembly of Aspect 13, wherein the sleeve comprises an inner diameter that is the same as, substantially the same as, or not greater than 5% different than an inner diameter of a production tubing coupled to the top sub, to the bottom sub, or to the top sub and to the bottom sub. [0077] Aspect 15. The gas lift injection packer assembly of one of Aspect 13 or claim 14, having any of the features of any one of claims 2 to 12. [0078] Aspect 16. A gas lift injection system comprising: a first production tubing; a gas lift injection packer assembly comprising a top sub, a packer coupled to the top sub, a bottom sub coupled to the packer, and a sleeve disposed within the top sub, the packer, and the bottom sub; and a second production tubing; wherein the top sub is coupled to the first production tubing, wherein the bottom sub is coupled to the second production tubing, and wherein the sleeve comprises an inner diameter that is the same as, substantially the same as, or not greater than 5% different than an inner diameter of the first production tubing, an inner diameter of the second production tubing, or the inner diameter of the first production tubing and the inner diameter of the second production tubing. [0079] Aspect 17. A gas lift injection system comprising: a first production tubing; a gas lift injection packer assembly comprising a top sub having a gas inlet port formed therein; a check valve disposed in the gas inlet port, wherein an inner wall of the gas inlet port is a housing for the check valve; a packer coupled to the top sub; a bottom sub coupled to the packer; and a sleeve disposed within the top sub, the packer, and the bottom sub, wherein the sleeve forms a micro annulus with the top sub and the packer, wherein the gas inlet port and the check valve are in fluid communication with the micro annulus; and a second production tubing; wherein the top sub is coupled to the first production tubing, wherein the bottom sub is coupled to the second production tubing. [0080] Aspect 18. The gas lift injection system of Aspect 16 or 17, further comprising: a gas injection compressor configured to pressurize a gas; a gas lift injection control valve configured to regulate a flow of the pressurized gas from the gas injection compressor into a wellbore; and a wellhead disposed on top of the wellbore; wherein the first production tubing is coupled to the wellhead and extends into the wellbore. [0081] Aspect 19. The gas lift injection system of any one of Aspects 16 to 18, wherein the gas lift injection packer assembly has the features of any one of claims 1 to 15. [0082] Aspect 20. A method of gas lift injection, comprising: providing a production string comprising production tubing and a gas lift injection packer assembly coupled to the production tubing, wherein the gas lift injection packer assembly comprises a top sub, a packer coupled to the top sub, a bottom sub coupled to the packer, and a sleeve disposed within the top sub, the packer, and the bottom sub, wherein the sleeve forms a micro annulus with the top sub and the packer, and wherein the sleeve comprises an inner diameter of not greater than 5% different than an inner diameter of the production tubing; injecting a pressurized gas into an upper portion of an annulus of a wellbore; flowing the pressurized gas from the annulus of the wellbore through the micro annulus; flowing the pressurized gas from the micro annulus through a gas outlet port formed in the bottom sub into a lower portion of the annulus of the wellbore; and flowing the pressurized gas through one or more gas injection valves disposed in a lower portion of the production tubing. [0083] Aspect 21. The method of Aspect 20, further comprising flowing the pressurized gas through one or more check valves embedded in the top sub, through one or more injected gas runners formed in the top sub, through the micro annulus, and out of a one or more gas outlet port formed in the bottom sub. [0084] Aspect 22. The method of Aspect 20 or 21, wherein flowing the pressurized gas through the one or more gas injection valves allows the pressurized gas to mix with hydrocarbon fluids in the lower production tubing to create a fluid mixture having a lower density than a density of the hydrocarbon fluids alone. [0085] Aspect 23. The method of any one of Aspects 20 to 22, wherein flowing the pressurized gas through the one or more gas injection valves reduces a bottomhole pressure (BHP) at the lower production tubing portion to increase the flow of hydrocarbon fluids upwards through the production string and to a wellhead. [0086] Aspect 24. The method of any one of Aspects 20 to 23, having any feature of any one of claims 1 to 19. [0087] Aspect 25. The method of any one of Aspects 20 to 24, wherein the inner diameters of the sleeve, the top sub, the bottom sub, and the production tubing form a continuous passage, the method further comprising: moving a downhole tool through the gas lift injection packer assembly via the continuous passage. [0088] Aspect 26. The method of Aspect 25, wherein the downhole tool comprises a submersible pump, a plunger, or a combination thereof.

[0089] Although the present disclosure and its advantages have been described in detail, it should be understood that various changes, substitutions, and alterations can be made herein without departing from the spirit and scope of the disclosure. Moreover, the scope of the present application is not intended to be limited to the particular embodiments of the process, machine, manufacture, composition of matter, means, methods and steps described in the specification. As one of ordinary skill in the art will readily appreciate from the disclosure, processes, machines, manufacture, compositions of matter, means, methods, or steps, presently existing or later to be developed that perform substantially the same function or achieve substantially the same result as the corresponding embodiments described herein may be utilized according to the present disclosure. Accordingly, the appended claims are intended to include within their scope such processes, machines, manufacture, compositions of matter, means, methods, or steps.

Claims

1. A gas lift injection packer assembly comprising: a top sub; a packer coupled to the top sub; a bottom sub coupled to the packer; and a sleeve disposed within the top sub, the packer, and the bottom sub, wherein the sleeve forms a micro annulus in the packer assembly with the top sub and the packer, wherein the sleeve comprises an inner diameter that is the same as, substantially the same as, or not greater than 5% different than an inner diameter of a production tubing coupled to the top sub, to the bottom sub, or to the top sub and to the bottom sub.

2. The gas lift injection packer assembly of claim 1, wherein a smallest diameter of any bore formed along a longitudinal axis of the top sub is the same as, substantially the same as, or greater

than the inner diameter of the production tubing.
3. The gas lift injection packer assembly of claim 1, wherein a smallest diameter of any bore formed along a longitudinal axis of the bottom sub is the same as, substantially the same as, or greater than the inner diameter of the production tubing.
4. The gas lift injection packer assembly of claim 1, wherein the top sub comprises a central bore configured to receive an end of the sleeve and a second bore that forms the micro annulus with the sleeve; wherein the packer comprises a central bore that forms the micro annulus with an outer surface of the sleeve through the packer; wherein the bottom sub comprises a central bore configured to receive an opposite end of the sleeve, a manifold that fluidly connects the micro annulus to a gas outlet port formed in the bottom sub, and a second bore that fluidly connects an outlet of the bottom sub to an interior of the sleeve.
5. The gas lift injection packer assembly of claim 1, wherein the inner diameters of the sleeve, the top sub, the bottom sub, and the production tubing form a continuous passage that enables movement of a downhole tool through the packer assembly.
6. The gas lift injection packer assembly of claim 5, wherein the downhole tool comprises a submersible pump, a plunger, or a combination thereof.
7. The gas lift injection packer assembly of claim 1, wherein the top sub comprises a body having a gas inlet port formed therein, wherein a valve seat of a check valve is disposed in the gas inlet port.
8. The gas lift injection packer assembly of claim 7, wherein the valve seat of the check valve is threaded into the gas inlet port formed in the body of the top sub.
9. The gas lift injection packer assembly of claim 7, wherein the check valve is configured to allow pressurized gas injected into a wellbore to enter the micro annulus.
10. The gas lift injection packer assembly of claim 7, wherein an inner wall of the gas inlet port is a housing for the check valve.
11. The gas lift injection packer assembly of claim 7, wherein the gas inlet port and the check valve are disposed at an angle of between about 10 degrees and 15 degrees with respect to a central axis of the gas lift injection packer assembly.
12. The gas lift injection packer assembly of claim 7, wherein the top sub comprises an injected gas runner fluidly connecting the gas inlet port with the micro annulus.
13. A gas lift injection system comprising: a first production tubing; a gas lift injection packer assembly comprising a top sub, a packer coupled to the top sub, a bottom sub coupled to the packer, and a sleeve disposed within the top sub, the packer, and the bottom sub; and a second production tubing; wherein the top sub is coupled to the first production tubing, wherein the bottom sub is coupled to the second production tubing, and wherein the sleeve comprises an inner diameter that is the same as, substantially the same as, or not greater than 5% different than an inner diameter of the first production tubing, an inner diameter of the second production tubing, or the inner diameter of the first production tubing and the inner diameter of the second production tubing.
14. The gas lift injection system of claim 13, wherein the top sub has a gas inlet port formed therein, wherein the gas lift injection packer assembly further comprises: a check valve disposed in the gas inlet port, wherein an inner wall of the gas inlet port is a housing for the check valve; and a sleeve disposed within the top sub, the packer, and the bottom sub, wherein the sleeve forms a micro annulus with the top sub and the packer, wherein the gas inlet port and the check valve are in fluid communication with the micro annulus.
15. The gas lift injection system of claim 13, further comprising: a gas injection compressor configured to pressurize a gas; a gas lift injection control valve configured to regulate a flow of the pressurized gas from the gas injection compressor into a wellbore; and a wellhead disposed on top of the wellbore; wherein the first production tubing is coupled to the wellhead and extends into the wellbore.
16. A method of gas lift injection, comprising: providing a production string comprising production

tubing and a gas lift injection packer assembly coupled to the production tubing, wherein the gas lift injection packer assembly comprises a top sub, a packer coupled to the top sub, a bottom sub coupled to the packer, and a sleeve disposed within the top sub, the packer, and the bottom sub, wherein the sleeve forms a micro annulus with the top sub and the packer, and wherein the sleeve comprises an inner diameter of not greater than 5% different than an inner diameter of the production tubing; injecting a pressurized gas into an upper portion of an annulus of a wellbore; flowing the pressurized gas from the annulus of the wellbore through the micro annulus; flowing the pressurized gas from the micro annulus through a gas outlet port formed in the bottom sub into a lower portion of the annulus of the wellbore; and flowing the pressurized gas through one or more gas injection valves disposed in a lower portion of the production tubing.

17. The method of claim 16, further comprising flowing the pressurized gas through one or more check valves embedded in the top sub, through one or more injected gas runners formed in the top sub, through the micro annulus, and out of a one or more gas outlet port formed in the bottom sub.

18. The method of claim 16, wherein flowing the pressurized gas through the one or more gas injection valves allows the pressurized gas to mix with hydrocarbon fluids in the lower production tubing to create a fluid mixture having a lower density than a density of the hydrocarbon fluids alone.

19. The method of claim 16, wherein flowing the pressurized gas through the one or more gas injection valves reduces a bottomhole pressure (BHP) at the lower production tubing portion to increase the flow of hydrocarbon fluids upwards through the production string and to a wellhead.

20. The method of claim 16, wherein the inner diameters of the sleeve, the top sub, the bottom sub, and the production tubing form a continuous passage, the method further comprising: moving a downhole tool through the gas lift injection packer assembly via the continuous passage.