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LOW-COST DOWNHOLE GAS LIFT SYSTEM FOR NON-GAS LIFT TUBING

Abstract

A method for gas lifting fluid in a well includes creating an opening at a first depth in a production tubing nested within a casing or liner in the well. A gas lift valve is deployed proximate the opening. A pump is deployed in the production tubing at a second depth shallower than the first depth. Gas is pumped into an annular space between the production tubing and the casing or liner so as to enter the production tubing through the gas lift valve. The pump is operated to lift fluid within the production tubing. The pump is stopped and is then removed from the production tubing when gas lifting of fluid in the well is detected.

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Background/Summary

CROSS REFERENCE TO RELATED APPLICATIONS

[0001] The present application claims priority to United Kingdom patent application No. 2401716.2 that was filed on Feb. 8, 2024, which is herein incorporated by reference in its entirety.

BACKGROUND

[0002] This disclosure relates to the field of artificial lift for enhancing fluid production from subsurface wells. More particularly, the present disclosure relates to methods for retrofitting wells with gas lift-type artificial lift devices.

[0003] Subsurface wells used to extract fluids such as oil and gas have as a primary source of energy to move fluids to surface the natural fluid pressure in subsurface formations from which the fluids are extracted. FIG. **1** shows an example of a well W in fluid communication with a subsurface formation F from which fluids are to be extracted. The well W may be drilled to a depth to or below the formation F of interest. A protective pipe **100** such as casing or liner may be cemented in place at least through the formation of interest F. A production tubing **102** may be nested within the liner or casing **100**. An annular space between the liner or casing **100** and the production tubing **102** may be sealed with an annular sealing element **104** such as a packer. The liner or casing **100** may be perforated as shown at **106** to establish fluid communication between the formation F and the interior of the well W (i.e., the liner or casing **100**). The production tubing **102** is typically used to increase velocity of fluids moving from the formation F to the surface, whereby liquid, e.g., water, may be entrained in the flow of fluid so as to reduce hydrostatic pressure in the well W proximate the formation F, thereby enabling fluids to move to surface at suitable rates of flow. The casing **100** and production tubing **102** may terminate at the surface in a valve assembly called a wellhead **108**, wherein various valves **110** may selectively open and close fluid flow from the production tubing **102**, and selectively open and close the annular space between the casing **100** and tubing **102** as may be needed.

[0004] In some instances, the natural fluid pressure is insufficient to move fluids to surface. In other instances, in subsurface formations that initially had sufficient pressure to move fluids to surface, the formation fluid pressure declines as fluids are extracted. When formation fluid pressure reduces to the point where it cannot overcome the hydrostatic pressure of a liquid column (e.g., oil and/or water), fluid production stalls. In gas producing wells, the liquid loading takes place when the gas rate becomes insufficient to lift water or condensate (natural gas liquids) to the surface. An increasing presence of liquid in the well can create new flow patterns such as churn, slug and recirculation zones that generate an excess pressure at the formation interface that can hinder or stop gas production. Such conditions require some form of artificial lift to unload the pressure on the formation to keep the well producing.

[0005] One of the most efficient and popular tools to address the above problems is gas lifting. Referring to FIG. **2**, typically, a gas is injected through the annulus space between the casing or liner **100** and the production tubing **102** nested within the casing or liner **102**. Gas injected into the annulus passes into the production tubing **102** through several valves **112** installed at different depths along the tubing **102**. The number of valves **112** varies depending on well conditions and capacity of the surface equipment for gas injection. Obviously, the system in FIG. **2** is more complicated in installation and servicing than the system shown in FIG. **1**. A well that has not been provisioned for gas lifting will require the original production tubing, e.g., as shown at **102** in FIG. **1**, to be removed and the new tubing with gas injection points to be installed. This is time consuming, risky, and expensive process, in particular because of safety considerations requiring that the well W is never fully open to atmosphere when there are perforations through the casing or liner **100** as shown in FIGS. **1** and **2**. The foregoing requirement necessitates use of special pressure control equipment, such as a snubbing unit, which makes removal of the production tubing **102** and installation of production tubing with features to receive the valves **112** quite difficult and time consuming.

[0006] What is needed is a method for installing and operating gas lift devices in a well without the need to remove the production tubing.

SUMMARY

[0007] One aspect of the present disclosure is a method for gas lifting fluids in a well. A method for gas lifting according to this aspect includes creating an opening at a first depth in a production tubing nested within a casing or liner in the well. A gas lift valve is deployed proximate the opening. A pump is deployed in the production tubing at a second depth shallower than the first depth. Gas is pumped into an annular space between the production tubing and the casing or liner so as to enter the production tubing through the gas lift valve. The pump is operated to lift fluid within the production tubing. The pump is stopped and is then removed from the production tubing when gas lifting of fluid in the well is detected.

[0008] In some embodiments, detecting gas comprises measuring a property of fluid in the production tubing proximate the pump.

[0009] In some embodiments, the property comprises density, acoustic attenuation and/or acoustic velocity.

[0010] In some embodiments, the deploying a gas lift valve comprises moving a gas lift valve straddle proximate the opening, the gas lift straddle comprising a mandrel and at least two axially spaced apart annular seals disposed on the mandrel.

[0011] In some embodiments, the pump comprises an electric submersible pump.

[0012] In some embodiments, the deploying the pump comprises attaching the pump to an end of an electrical cable and extending the pump and electrical cable into the well from within the production tubing.

[0013] In some embodiments, an annular seal is disposed between the production tubing and the liner or casing at a depth in the well above perforations in the casing or liner. The perforations make hydraulic connection between a fluid producing formation and an interior of the casing or liner, and the opening at the first depth is disposed above the annular seal.

[0014] Some embodiments further comprise determining whether flow in the production tubing continues after switching off the pump before removing the pump from the well.

[0015] In some embodiments, the determining whether flow continues comprises making measurements with at least one sensor associated with the pump.

[0016] In some embodiments, the at least one sensor sensors comprises a flow meter.

[0017] In some embodiments, the flow meter comprises one or more of a spinner flow meter, a hot wire anemometer or a Coriolis effect flow meter.

[0018] In some embodiments, the detecting gas comprises making measurements of rotational speed and/or electric current draw of the pump.

[0019] Other aspects and possible advantages will be apparent from the description and claims that follow.

Description

BRIEF DESCRIPTION OF THE DRAWINGS

[0020] FIG. **1** shows an example well that is completed for fluid production using natural fluid pressure in a subsurface formation.

[0021] FIG. **2** shows an example well having gas lift valves to enhance fluid production when natural pressure is insufficient to lift fluids to the surface.

[0022] FIGS. **3**A and **3**B show using a winch having electrical cable to deploy various devices in a well.

[0023] FIG. **4** shows a schematic diagram of a well having a retrofit gas lift valve installed and a pump operated to hydraulically unload the well.

[0024] FIG. **5** shows the well of FIG. **4** after removal of the pump in order to produce fluid using only gas lift to supplement natural formation pressure.

[0025] FIG. **6** shows an example embodiment of a gas lift valve that may be installed in a production tubing not originally configured for gas lift that may be used in accordance with the present disclosure.

DETAILED DESCRIPTION

[0026] FIGS. **3**A and **3**B show deploying various intervention instruments and/or tools in a well. Certain devices may be used in connection with such deployment irrespective of the type of instruments or tools, and such devices will be shown in each of FIGS. **3**A, **3**B as having like reference numerals. FIG. **3**A shows an example embodiment of a certain type of tool assembly ("assembly") **10**A in accordance with the present disclosure. The assembly **10**A in one part of a method according to the present disclosure may comprise an explosive shaped charge perforating gun, a chemical cutter, a drill, a mill or any other device that can make one or more openings ("perforation" or "perforations") in a production tubing, explained further below.

[0027] The assembly **10**A may be deployed in the subsurface well W drilled through fluid bearing underground earthen formations (F in FIGS. **4** AND **5**). The well W may comprise a protective pipe or casing **32** extending from a valve assembly ("wellhead") **34** coupled to a surface end of the casing **32**, it being understood that the term "liner" (a protective pipe not extending to the surface) is within the scope of the present disclosure with reference to the casing **32**. A string of smaller diameter conduit ("production tubing") **30** may be nested within the casing **32** and provide a smaller cross section conduit than the casing **32** to increase the velocity at which fluids move to the surface to facilitate fluid production, e.g., by entraining higher density fluids such as water within the flow of lower density fluids such as oil and/or gas.

[0028] The wellhead **34** may be disposed at the surface end of the production tubing **30** and may comprise one or more valves, e.g., at **38** to enable fluids moving up the production tubing **30** to leave the well W in a controlled manner. When well intervention devices such as the assembly **10**A are moved into a well, safety considerations usually require that a pressure control device such as a blowout preventer (BOP) stack **40** is coupled above the wellhead **34** to provide positive closure of the well W in the event uncontrolled flow of fluid takes place. A conduit called a lubricator **42** may couple to the top of the BOP stack **40** to provide a sealed enclosure for the assembly **10**A in order to introduce the assembly **10**A into the well W so as to prevent the well W from being exposed at any time. A pack off or grease injection head **44** may be coupled to the top of the lubricator **42** and used to seal against an electrical cable **12** used to deploy the assembly **10**A in the well W, while enabling movement of the electrical cable **12** and thereby the assembly **10**A along the well W as may be needed. The assembly **10**A may be coupled to the electrical cable **12** by a cable head **14** of types well known in the art.

[0029] The electrical cable **12** may transmit electrical power to operate the assembly **10**A and may communicate signals from various measuring instruments (not shown separately) which may be associated with the assembly **10**A as it is operated in the well W. In the event the assembly **10**A comprises one or more of the perforating devices explained above, the electrical cable **12** may provide electrical power to actuate the foregoing when the assembly **10**A is disposed at a predetermined depth in the production tubing **30**.

[0030] The electrical cable **12** may be extended from and retracted onto a winch **48** of types well known in the art in order to move the assembly **10**A within the well W.

[0031] In some embodiments, the assembly **10**A may also comprise a gas lift valve, of a type that will be further explained below with reference to FIG. **6** and in such cases, both making an opening in the production tubing **30** and setting a gas lift valve may be performed in the well in the same intervention operation. In some embodiments, the assembly **10**A may comprise only the perforating device. In such cases, the assembly **10**A may be changed after the perforation or opening is created in the production tubing **30**. In such cases, the assembly may be removed from the well W, the assembly **10**A may be changed to include the gas lift valve (e.g., FIG. **6**) and the gas lift valve may then be run into the production tubing **30** and set at or proximate the depth of the perforation. Either of the foregoing implementations is within the scope of the present disclosure.

[0032] After the gas lift valve e.g., (FIG. **6**) is set as explained above, and referring to FIG. **3**B, the assembly **10** may be changed to comprise a pump, as will be explained further below. The changed assembly **10** may be connected to the cable head **12** and deployed in the well in a manner similar to that explained with reference to FIG. **3**A. A surface end of the electrical cable **12** may in such instance be electrically connected to a surface system **50** of types well known in the art used in connection with electric submersible pumps (ESPs). The surface system **50** may comprise (not shown separately) pump speed control devices such as a variable frequency drive and/or devices to detect measurements made by various sensors in a sensor package **18**. In FIG. **3**B, as well as FIG. **3**A, the electrical cable **12** may pass through one or more sheaves **46** between the winch **48** and the well W in order to direct the electrical cable **12** properly to move the assembly **10** freely along the interior of the well W.

[0033] The assembly **10**, as previously explained with reference to FIG. **3**A, may be coupled to the electrical cable **12** by a cable head **14** of types well known in the art.

[0034] When the assembly **10** comprises the pump **22**, the following description may apply. The assembly **10** may comprise an electric motor **16** such as a permanent magnet motor rotationally coupled, through a protector assembly **20** and the previously described sensor package **18**, to a pump **22** such as a centrifugal pump. An inlet **22**A to the pump **22** may be disposed proximate a lower end of the assembly **10**, at least disposed below a resettable annular seal (“packer”) **26** disposed along the assembly **10**. A discharge **22**B of the pump **22** may be disposed on an opposed axial side of the resettable packer **26**. Thus, flow from the pump **22** is constrained to move upwardly in the production tubing **30**. A bypass valve **24** may be provided in the assembly **10** for circumstances wherein flow from parts of the well W below the resettable packer **26** exceeds the flow rate of the pump **22**. Such flow may move through the bypass valve **24** upwardly through the production tubing **30**.

[0035] The resettable packer **26** may comprise an inflatable seal, or may comprise a J-slot mechanism (not shown) to set the packer **26** in a desired axial position in the production tubing **30**. The J-slot mechanism may be operated by lifting and lowering the electrical cable **12**. A seal element (not shown) in the resettable packer **26** may be energized using the weight of the assembly **10** alone, that is, to activate the seal element (not shown) the electrical cable **12** is unspooled from the winch **48** after the J-slot mechanism sets, such that weight of the assembly **10** will be applied to the resettable packer **26** to activate the seal element (not shown). When it is desired to release the resettable packer **26** to move the assembly **10**, the electrical cable **12** may be spooled onto the winch **48** to lift the assembly **10** and relieve weight from the resettable packer **26**. The resettable packer **26** may be configured to resist forces bi-directionally, preventing differential pressure (blow-out) caused or other unwanted movement of the assembly **10** along the production tubing **30**. The resettable packer **26** may be configured to resist blowout, e.g., by providing additional gripping elements (“slips”) to engage the interior of the production tubing **30** when the resettable packer **26** is released (unset) if naturally produced fluid causes sufficient upthrust on the assembly **10**. The resettable packer **26** in some embodiments may comprise any mechanism to radially expand gripping elements (not shown separately) arranged to axially lock the assembly **10** into position within the production tubing **30**, and to actuate the seal element, that is not operated by fluid pressure (i.e., an inflatable packer).

[0036] In some embodiments, production logging sensors **28** may be coupled to the assembly **10** at a selected axial position, such as below the resettable packer **26** as shown in FIG. **3**B. The production logging sensors **28** may comprise at least a sensor responsive to the presence of gas bubbles in fluid being moved through the production tubing **30** when the pump is operated and when gas is injected into a gas lift valve, to be explained further with reference to FIGS. **4** and **5**. Example embodiments of such sensors may comprise, without limitation density sensors, acoustic attenuation sensors and acoustic velocity (travel time) sensors.

[0037] In an example embodiment of a method according to the present disclosure, and referring to FIG. **4**, the assembly (**10**A in FIG. **3**A) may comprise any form of device used to create one or more perforations **64** in the production tubing **30**. In some embodiments, the assembly (**10**A in FIG. **3**A) may be withdrawn from the well, and a device comprising a gas lift valve, e.g., a gas lift straddle **62** may be affixed to the cable head (**14** in FIG. **3**A) and lowered to the depth of the perforation(s) **64**. The cable head (**14** in FIG. **3**A) may then be disconnected from the gas lift straddle **62** and the cable (**12** in FIG. **3**A) and cable head (**14** in FIG. **3**A) may be withdrawn from the well. Then the assembly (**10** in FIG. **3**B), comprising an ESP system as explained with reference to FIG. **3**B may be connected to the cable head (**14** in FIG. **3**B), deployed in the well and set (by setting the resettable packer **26**) at a selected depth in the well W. The pump (**22** in FIG. **3**B) may then be started. Contemporaneously, gas, e.g., nitrogen, may be pumped into the annular space **31** such that the gas lift valve (e.g., on the straddle **62**) opens and gas begins to flow into the production tubing **30**. The selected depth for deploying the pump (**22** in FIG. **3**B) may depend on parameters such as the density of fluid in the well W prior to gas lift, the density of the fluid produced from the formation F, among other parameters.

[0038] Measurements from the production logging sensors (**28** in FIG. **3**B), if included in the assembly (**10** in FIG. **3**B), may be used to determine when gas pumped through the gas lift valve (e.g., in the straddle **62**) reaches the pump intake (**22**A in FIG. **3**B), and when fluid production is stable by reason of gas lift. At such time, the pump (**22** in FIG. **3**B) may be stopped and the assembly (**10** in FIG. **3**B) may be withdrawn from the well W. It will be appreciated that when the pump (**22** in FIG. **3**B) comprises a bypass valve (**24** in FIG. **3**B) as previously explained with reference to FIG. **3**B, fluid flowing upwardly in the production tubing **30** as a result of gas lift may continue flowing even when the pump **22** is switched off. In some embodiments, the production logging sensors (**28** in FIG. **3**B) may comprise one or more flow meters, e.g., a spinner flow meter, Coriolis effect flow meter or hot wire anemometer. Measurements from the flow meter may be used to confirm that fluid flow in the production tubing continues after the pump (**22** in FIG. **3**B) has been switched off. If fluid movement stops after the pump (**22** in FIG. **3**B) is switched off, an injection rate of gas through the gas lift valve may be increased and the pump restarted. Fluid movement may be reconfirmed after stopping the pump (**22** in FIG. **3**B). The foregoing may be repeated at successively higher gas injection rates until stable fluid movement by gas lift is determined. The pump (**22** in FIG. **3**B) may then be switched off and withdrawn from the well. In some embodiments, fluid movement by reason of gas lift may be determined by detecting gas bubbles in the well fluid proximate the surface (e.g., in the wellhead).

[0039] The assembly (**10** in FIG. **3**B) may thus be withdrawn from the well W while fluid flow continues upwardly in the production tubing **30**. Referring to FIG. **5**, after the assembly (**10** in FIG. **3**B) is withdrawn from the well W, producing fluids to surface may continue by way of gas being pumped through the gas lift valve (e.g., the straddle **62**) to relieve hydrostatic pressure in the well W proximate the formation F.

[0040] In some embodiments, detecting gas proximate the pump inlet as an indicator of fluid movement may comprise making measurements of the pump rotational speed and/or electric current load from the pump **22**. Sensors for making such measurements are typically included in the monitoring package (**18** in FIG. **3**B) of ESPs. In such embodiments, the pump **22** may omit the production logging sensors (**28** in FIG. **3**B). Indications of gas bubbles reaching the pump inlet may include increased pump rotation speed and/or reduced current draw. Such measurements continued over time may be used to establish stable fluid production by reason of gas lift, at which time the pump (**22** in FIG. **3**) may be stopped and the assembly (**10** in FIG. **3**B) withdrawn from the well W.

[0041] An example embodiment of a gas lift valve, which may in some embodiments form part of a gas lift straddle is shown schematically in FIG. **6**. The gas lift straddle **62** may comprise a mandrel **71** having diameter enabling through passage along the interior of the production tubing (**30** in FIG. **4**). The mandrel may comprise longitudinally spaced apart annular seals **70**, which act to seal an annular space between the mandrel **71** and the interior of the production tubing (**30** in FIG. **4**) when actuated. A gas lift valve **72** may be disposed along the mandrel **71** between the annular seals **70**, and have an operating port in fluid communication with the interior of the production tubing (**30** in FIG. **4**). A discharge port on the gas lift valve may be communication with a through passage **74** inside the mandrel **71**, such that gas from the annular space (**31** in FIG. **5**) may be introduced into a fluid flow stream passing through the through passage **74**, thus providing gas lift. A non-limiting example type of gas lift straddle is available commercially from Peak Well Systems, Pty Ltd., Perth, Western Australia. As explained above, the gas lift straddle **62** may form part of the assembly (**10**A in FIG. **3**A) deployed in the well at the same time as the perforating apparatus, or it may be deployed in the well subsequent to perforating the production tubing in a separate intervention operation in the well from the perforating. Methods according to the present disclosure and associated apparatus may enable installing gas lift into a well that was not originally configured for gas lift without the need to remove the production tubing, and correspondingly to kill the well or use snubbing equipment to pull and reinstall tubing in a live well.

[0042] In light of the principles and example embodiments described and illustrated herein, it will be recognized that the example embodiments can be modified in arrangement and detail without departing from such principles. The foregoing discussion has focused on specific embodiments, but other configurations are also contemplated. In particular, even though expressions such as in “an embodiment,” or the like are used herein, these phrases are meant to generally reference embodiment possibilities, and are not intended to limit the disclosure to particular embodiment configurations. As used herein, these terms may reference the same or different embodiments that are combinable into other embodiments. As a rule, any embodiment referenced herein is freely combinable with any one or more of the other embodiments referenced herein, and any number of features of different embodiments are combinable with one another, unless indicated otherwise. Although only a few examples have been described in detail above, those skilled in the art will readily appreciate that many modifications are possible within the scope of the described examples. Accordingly, all such modifications are intended to be included within the scope of this disclosure as defined in the following claims.

Claims

1. A method for gas lifting fluid in a well, comprising: creating an opening at a first depth in a production tubing nested within a casing or liner in the well; deploying a gas lift valve proximate the opening; deploying a pump in the production tubing at a second depth shallower than the first depth; pumping gas into an annular space between the production tubing and the casing or liner so as to enter the production tubing through the gas lift valve; operating the pump to lift fluid within the production tubing; and stopping the pump and removing the pump from the production tubing when gas lifting of fluid in the well is detected.

2. The method of claim 1, wherein detecting gas lifting comprises measuring a property of fluid in the production tubing proximate the pump.

3. The method of claim 2, wherein the property comprises density, acoustic attenuation and/or acoustic velocity.

4. The method of claim 1, wherein the deploying a gas lift valve comprises moving a gas lift valve straddle proximate the opening, the gas lift straddle comprising a mandrel and at least two axially spaced apart annular seals disposed on the mandrel.

5. The method of claim 1, wherein the pump comprises an electric submersible pump.

6. The method of claim 1, wherein the deploying the pump comprises attaching the pump to an end of an electrical cable and extending the pump and electrical cable into the well from within the production tubing.

7. The method of claim 1, wherein an annular seal is disposed between the production tubing and the liner or casing at a depth in the well above perforations in the casing or liner, the perforations making hydraulic connection between a fluid producing formation and an interior of the casing or liner, and wherein the opening at the first depth is above the annular seal.

8. The method of claim 1, further comprising determining whether flow in the production tubing continues after switching off the pump before removing the pump from the well.

9. The method of claim 8, wherein the determining whether flow continues comprises making measurements with at least one sensor associated with the pump.

10. The method of claim 9, wherein the at least one sensors comprises a flow meter.

11. The method of claim 10, wherein the flow meter comprises one or more of a spinner flow meter, a hot wire anemometer or a Coriolis effect flow meter.

12. The method of claim 1, wherein the detecting gas comprises making measurements of rotational speed and/or electric current draw of the pump.
