Design, Operation, and Troubleshooting of Dual Gas-lift Wells

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1 Scope

This document provides recommended practices (RPs) for the selection, design, operation, surveillance, optimization, automation, and troubleshooting of dual gas-lift wells.

The purpose of this document is to present RPs, guidelines, and tools to help obtain optimum production from dual gas-lift wells. This document also contains practices that should be avoided to minimize problems and inefficiencies that can be associated with ineffective dual gas-lift operations. Compared to single completions, dual completions typically have more operating problems, are more difficult to work over, and can produce less efficiently.

It is not the purpose of this document to recommend the practice of dual gas-lift. In some cases, dual gas-lift is problematic and often ineffective. Often it is difficult or even impossible to effectively produce both completions in a dual well using gas-lift over the long term. Where there are other feasible alternatives to produce dual wells, they should be considered. However, many dually completed oil wells should be artificially lifted initially or after reservoir pressures have declined and/or water cuts have increased. In many cases, the only practical method of artificial lift for these wells is gas-lift. Therefore, every effort should be made to design and operate dual gas-lift systems as effectively as possible.

Annexes to this RP include:

a) an overview of dual gas-lift systems,

b) dual gas-lift mandrel spacing designs,

c) dual gas-lift unloading valve design for production pressure operated (PPO) valves, and

d) dual gas-lift practices not recommended.

2 Terms, Definitions, Acronyms, and Abbreviations

2.1 Terms and Definitions

For the purposes of this document, the following terms and definitions apply.

2.1.1
automation
A system for monitoring, control, diagnosis, and optimization of gas-lift operations that includes measuring important gas-lift parameters, controlling gas-lift injection rate, detecting and diagnosing problems, and optimizing gas-lift operations.

2.1.2
bottomhole pressure
BHP
Normally measured at the midpoint of the perforated interval.

2.1.3
commingling (commingle)
A process where fluids from different productive formations are combined and produced through a single conduit.

2.1.4
cross-flow
The flow of reservoir fluids from one productive formation into another.

2.1.5
dual gas-lift wells
Wells that include two production tubing strings designed to produce from two separate reservoirs, using gas-lift.

2.1.6
field life cycle
Operating conditions from the moment the field is opened to production until it is closed and abandoned.

2.1.7
flow regime
The prevailing gas, oil, and water geometrical distribution when flowing through a pipe.

2.1.8
flow regime classes
Common flow regimes for gas-liquid mixtures such as bubble flow, dispersed bubble flow, plug flow, slug flow, froth flow, mist flow, churn flow, and annular flow.

2.1.9
flowing bottomhole pressure
FBHP
Measured at the midpoint of the perforations when the well is off production.

2.1.10
gas to oil ratio
GOR
The ratio of produced gas to produced oil.

2.1.11
hydrates
Ice-like crystalline compounds formed by water and natural gas molecules at high pressures and low temperatures.

2.1.12
inflow performance
The ability of fluid to flow from the reservoir into the wellbore as a function of pressure differential from the reservoir to the wellbore.

2.1.13
inflow performance relationship
IPR
A curved relationship in barrels per day per psi drawdown.

2.1.14
inflow survey
An evaluation of the lift gas flow used to evaluate well performance.

2.1.15
injection pressure operated
IPO
A type of gas-lift valve used when the injection (casing) pressure is the primary opening pressure.

2.1.16
intelligent wells
Well completions where data recording and well control can be perform remotely.

2.1.17
intermittent
A form of gas-lift where slugs of gas are injected intermittently beneath slugs of liquid.

2.1.18
kicking off
Bringing an off a well back to production after a period of idle time. There may or may not be fluid in the annulus to be unloaded, depending on whether or not there a leak in the tubing.

2.1.19
multilateral completions
Well completions that have more than one wellbore branch radiating from the main borehole.

2.1.20
multipointing
The situation where gas-lift injection gas enters the production stream from more than one position in the tubing string.

2.1.21
optimization
Adjustments to lift gas and well flows to achieve the maximum return without causing formation or system damage.

2.1.22
production heading
A situation where the tubing pressure is fluctuating by more than a defined amount in a defined period of time.

2.1.23
production pressure operated
PPO
A type of gas-lift valve used when the production (tubing) pressure is the primary opening pressure.

2.1.24
productivity index
PI
A straight-line method to define inflow performance expressed in units of production per units of pressure drop from the formation to the wellbore. Measured in barrels per day per psi drawdown.

2.1.25
PTRO
Test rack opening pressure, measured in the test rack when the tubing pressure is atmospheric pressure.

2.1.26
static bottomhole pressure
SBHP
Measured at the midpoint of the perforations when the well is off production.

2.1.27
supervisory control and data acquisition
SCADA
Real-time data captured by a supervisory control and data acquisition system.

2.1.28
surveillance
Monitoring gas-lift operations to determine performance and to detect and address problems.

2.1.29
Thornhill-Craver equation
A commonly accepted equation used to predict the rate of gas passage through a given orifice size.

2.1.30
unloading
The process of displacing initial annular and/or tubing fluids in the well when gas-lift injection gas is started.

2.1.31
vertical pressure profile
A plot of pressure vs depth in a flowing or gas-lift well.

2.2 Acronyms and Abbreviations

BHP	bottomhole pressure
FBHP	flowing bottomhole pressure
GOR	gas to oil ratio
IPO	injection pressure operated
IPR	inflow performance relationship
PI	productivity index
PPO	production pressure operated
SBHP	static bottomhole pressure
SCADA	supervisory control and data acquisition
TVD	true vertical depth

3 Benefits of Dual Wells

3.1 General

Dual wells exist for a number of reasons; the primary ones are summarized in this section.

3.2 More Efficient Drilling

It is often appears more attractive to drill one wellbore to serve two (or more) vertically oriented production zones, rather than to drill two or more separate wells to reach these same zones. In some fields, there are multiple reservoirs “stacked” on top of each other. In some fields, there may be as many as 5, 10, or even more separate reservoirs located vertically above one another. The development plans for such fields are often complex and require study.

The objective is normally to produce the reserves as quickly as feasible, while protecting the environment and being good world citizens. Multiple completions that result in significant loss or deferment of reserves and prolonged production are not recommended. It is tempting to drill one well to intersect several reservoirs, and to produce more than one of the reservoirs at the same time with the same well, to accelerate overall production. But this should be done correctly, or the benefits may not be achieved. One might ask, “Can multiple zones not be produced in the same completion without the need for trying to operate dual completions?” In selecting the best possible development approach for multiple zone reservoirs, there are a number of choices that need to be carefully analyzed.

3.3 Dual Gas-lift Alternatives

3.3.1 General

In some cases, there may be reasonable alternatives to dual gas-lift. These should be considered, recognizing the expertise necessary to effectively operate dual gas-lift wells.

3.3.2 Alternating Production from the Two Zones

In the past, wells had production rates dictated by the regulatory authorities. In those times, it was sometimes possible to produce a well's monthly allowable limit in a few days. It was also sometimes possible to produce one side, with the other side closed in, and then switch sides. This situation is rarely available today. However, it is still sometimes true that the overall production from a dual well can be increased by producing one side and then the other side. This is not the objective of this document, and if the criteria provided are followed it is possible to increase production by producing both zones simultaneously.

3.3.3 Gas-lifting One Side, Gas Assisting the Other

In some cases, one zone should be gas-lifted full time while the other zone will flow once it has been started. In this case, it may be possible to use gas to kick off the "flowing" zone if it loads up; but once it is producing, it can continue to flow on its own. It may be necessary to temporarily close in the side that is normally on gas-lift to do this, as it may also be necessary to set the pressures on the gas-lift valves differently for the two sides of the well.

3.3.4 Gas-lifting One Side, Naturally Flowing the Other

Where it is possible to flow one side while gas-lifting the other side of a dual, this is technically not dual gas-lift. If this is done correctly, the flowing well should not interfere with the single-string gas-lift operation on the other side. The issue here is likely to be possible restrictions in tubular size, due to the need to have two tubing strings in one casing.

3.3.5 Gas-lifting One Side, Pumping the Other Side

Any attempt to pump one side of a dual while gas-lifting the other side would be very rare. One of the main reasons is, it would almost be essential to pump the pumping side below a packer. This would force any gas produced from that zone to flow through the pump; however, most pumps do not perform well in the presence of gas. This alternative should only be considered in the rarest of situations.

4 Dual Gas-lift Practices

4.1 General

The purpose of this section is to summarize the dual gas-lift practices that are recommended, and those that are not recommended (also see Annex D), or to suggest the practices to be followed and those to be avoided. This section contains a summary of the practices that are specified in detail in the following sections of this document.

4.2 Practices That Are Recommended

4.2.1 General

The following dual gas-lift practices are grouped into categories for easy reference. Each recommended practice is supported by additional information in this document.

4.2.2 Selecting Acceptable Wells

The following should be performed when selecting wells for dual gas-lift:

— carefully evaluate all of the factors and only select wells for dual completion where the factors favor dual operation,

— evaluate all potential operational issues and only select wells for dual completion where there is a likelihood of long pre-gas-lift operation and/or where there is a strong likelihood of successful dual gas-lift operation.

4.3 Defining Unacceptable Wells

Avoid attempting dual gas-lift if the casing is too small or the zones are too far apart. See A.3 for additional information on candidate well selection criteria.

4.4 Considering Alternatives to Dual Gas-lift

The following are issues to consider regarding alternatives to dual gas-lift:

— consider commingling the two zones if this is feasible and allowed,

— consider developing the two zones as single completions if production will be important and it would be practically feasible to do so,

— consider alternatives if dual gas-lift expertise is not available.

4.5 Dual Gas-lift Well Design Issues

4.5.1 Mandrel Spacing

It is recommended to install mandrels to within a few tubing joints above the dual production packer. Use a conservative mandrel spacing design; place mandrels close enough together to unload and work down, regardless of the type of gas-lift valves being used. Additionally, it is recommended to space mandrels close enough together to lift at the optimum depth on both zones regardless of the well's reservoir pressure and productivity. Use the same number of mandrels for both zones. Space the mandrels in the upper zone one tubing joint above the mandrels in the lower zone.

4.5.2 When One Zone Is Much Deeper

If the tubing is large enough, use an insert string in the long side of the dual to inject gas into the long side beneath the dual zone production packer. If the tubing is not large enough for an insert string, only design mandrels down to the depth of the upper production packer. Complicated designs should be avoided because of increased mechanical risk.

4.5.3 PPO vs Injection Pressure Operated (IPO) Debate

If the expected depth of lift is known, use IPO gas-lift valves for unloading. If the expected depth of lift is not known and it may be necessary to lift from unloading valves, use PPO gas-lift valves for unloading. The use of "special" gas-lift valves (e.g. balanced IPO valves) should only be considered in special cases where use of IPO or PPO valves is not practical.

4.5.4 Unloading Valves

See Annex C for a recommended unloading design for PPO gas-lift valves.

4.5.5 Operating Valve or Orifice Valves

If the depth of lift is not known and cannot be predicted, design so that the well can operate through an unloading valve if necessary. When the depth of lift is known or can be predicted, and if flexibility is desired in the injection rate, design to operate through an orifice. If the depth of lift is known or can be predicted, if the desired injection rate is also known, and if stability is most important, design to operate through a nozzle venturi orifice.

4.5.6 Where Mandrels Are Too Far Apart

If the upper mandrels are spaced too far apart to support use of PPO, balanced IPO, or differential gas-lift valves, consider using IPO valves in the upper mandrels, until a depth is reached where the well may operate. Then use PPO valves, or use a standard orifice or a nozzle venturi orifice if the deepest mandrel has been reached. See 4.7.2, 5.6, 5.7, 5.10, and 6.5 for more information on designing for dual gas-lift when the mandrels are spaced too far apart.

4.5.7 Various Options

Recognize that there are several alternatives or options available for selecting the types of gas-lift valves to use in dual gas-lift. No one approach is recommended in this RP. It is recommended to discuss these options with experienced operators and try the approaches that have worked the best for them. See A.6 for more information on other options available for selecting gas-lift valves.

4.6 Dual Gas-lift Operations

4.6.1 Installing Equipment

Whenever possible, install the two strings of a dual gas-lift well together. If it is necessary to run the strings separately, the long string should be run first. Have an expert from the packer supply company on site for the installation and testing of the packers on the long string and setting the short string into the dual packer. If using surface-controlled gas-lift valves, have an expert from the surface control company on site for the installation. If installing chemical injection lines, follow the same procedures as outlined for installing electrical cables or hydraulic lines. Pressure test each packer to the recommended pressure.

4.6.2 Wireline Operations/Procedures

Cross-flow between the two sides of a dual gas-lift well can occur from the higher pressure zone to the lower pressure zone when dummies or valves are pulled from the higher pressure tubing string. Set tubing plugs as needed to prevent cross-flow. See 5.10, 6.3, 6.4, 7.2, 7.3, 7.4, 8.3, and A.15 for more information on wireline operations.

Conduct casing, tubing, and packer pressure integrity tests before performing wireline operations on dual gas-lift wells. If problems occur, use the troubleshooting chart in (Table 1) to help diagnose and address the problem(s).

4.6.3 Unloading

Normally, unless there is some strong reason not to do so, unload the casing annulus using the long string, since it normally has the deeper gas-lift mandrels. Follow the detailed unloading procedures outlined in 5.2.

4.6.4 Kicking Off

If both sides of a dual need to be kicked off (restarted after a period of idle time), start with the best zone, get it stable, and then kick off the other zone. If there is a concern about the first zone “robbing” gas while ramping up to kick off the second zone, minimize this by installing chokes in the unloading valves, if IPO gas-lift valves are used. When one side of the dual is kicked off (restarted), follow the same procedure as used to kick off the second zone when both sides are restarted. See 6.6.2 and D.1 for more information on kicking off.

4.6.5 Operating

Try to keep both zones continually on production to avoid the need to restart one or both zones. Try to continuously inject gas at the desired depth in both zones. Try to inject gas in a stable manner, especially during well tests and pressure surveys. If possible, use an automatic control system that can deliver gas at the desired rate and pressure, even in the face of gas-lift system upsets. See Section 6 for more information on operating dual gas-lift wells.

4.6.6 Optimizing

Determine the optimum injection rate for each side of the dual gas-lift well. Do this using the procedures discussed in 6.8 or by using a multirate well test. Determine the allowable range of the injection rate around the optimum rate, from minimum to maximum. Develop a control strategy to allocate gas to each dual well with the objective of keeping the injection rate within the acceptable range for the two sides.

4.7 Poor Candidates for Dual Gas-lift

4.7.1 General

The following characteristics or well conditions may make it difficult to effectively operate dual gas-lift. Many of these are "negative" corollaries of the conditions that define an acceptable candidate for dual gas-lift.

4.7.2 Two Zones Too Far Apart

If the vertical distance between the two zones is more than 305 m (1000 ft), dual gas-lift may be difficult. Gas-lift gas for the deeper zone would need to be injected above the shallow zone's production packer. This could make gas-lift of the lower zone ineffective. If the zones are far apart, it is likely that their reservoir pressures will be very different. They may make their gas-lift operating requirements different.

4.7.3 Low Formation Gas to Oil Ratio

If one or both of the zones has a low formation gas to oil ratio (GOR), it may be difficult to gas-lift the zone because all of the gas needed for production must be injected. This is particularly true if the GOR of the deeper zone is low. The production from the lower zone must flow, under the zone's inflow pressure, from the perforations of the lower zone to the depth of gas-lift injection, which will be above the depth of the shallow zone's production packer.

4.7.4 Intermittent Operation of One or Both Sides

When the reservoir pressure of a zone becomes low, or the inflow performance of the zone deteriorates, it may not be possible to maintain effective continuous gas-lift. When this happens, it may be more effective to lift the well by intermittent gas-lift. With intermittent gas-lift, gas is injected into the tubing in cycles or slugs. This intermittent action is accompanied by significant variations in injection pressure. It may not be feasible to intermit one side of a dual gas-lift well while attempting to continuously gas-lift the other side.

4.7.5 Small Casing Size

The minimum casing size where dual gas-lift should be considered is 17.78 cm (7 in.). This casing size is needed to permit use of the gas-lift mandrels that can accommodate 2.54 cm (1 in.) gas-lift valves, and this is the minimum sized gas-lift valve that can be considered for effective dual gas-lift.

4.8 Considering Artificial Lift Alternatives to Dual Gas-lift

4.8.1 Completing as Single Wells

If the wells can be completed as single producers with one wellbore for each reservoir to be produced, problems associated with dual gas-lift are avoided. This requires a detailed analysis that compares all of the issues associated with drilling, development, operational effectiveness, workover, etc.

4.8.2 Workovers and Abandonments

With dual wells, due to the extra string of tubing, packer, set of gas-lift equipment, etc., it is more challenging to complete the well than a single well. Due to the added complexity of the completion, workovers are more risky and difficult to perform. Additionally, it is more difficult to abandon a dual well because of the extra equipment in the well and the two zones that must be sealed.

4.8.3 Lack of Operating Expertise

Successful operation of dual gas-lift requires knowledge, experience, and expertise. This is not a job to be undertaken by untrained or inexperienced staff. If people with the right knowledge and experience do not exist in the company, and if they cannot be found in appropriate and available service or consulting companies, it would be wise not to undertake dual gas-lift operations.

4.8.4 Commingling Production

If it is allowed and technically feasible to commingle the production from multiple reservoirs in the same wellbore, and if there is an acceptable way to measure or estimate the production from each zone, this may be preferable to attempting dual gas-lift operations.

4.8.5 Potential for Remedial Work

If there is a likely need to perform remedial work (e.g. through tubing perforating, squeeze cementing, sand control, etc.) for the upper zone, below the end of tubing for the upper zone, this can be very difficult, since the tubing for the deeper zone extends through this area. In this case, use of dual gas-lift may be very difficult, and it may risk the integrity of the long side and even of the entire well.

4.8.6 Using Casing Pressure for Surveillance

The casing (injection) pressure is one of the most used variables for gas-lift surveillance. For single gas-lift, this value is often indicative of which gas-lift valve (or valves) is open, where gas is being injected into the tubing, if the well is stable or unstable, what type of instability it has, what the possible cause(s) of the instability are, etc. With a dual well, since the same casing pressure affects both sides of the dual, this surveillance and diagnostic activity is more difficult.

5 Dual Gas-lift Well Designs

5.1 General

The purpose of this section is to put many misconceptions to rest and offer RPs that, if followed, can help lead to successful dual gas-lift system designs.

5.2 Mandrel Spacing

5.2.1 General

Having the correct mandrel spacing is perhaps the most important aspect of dual gas-lift design. It is essential for the well to be able to unload to the desired operating depth. It is also important since there may be occasions when one or both zones are operated from an upper gas-lift mandrel depth. The most important requirement for the mandrel spacing is to allow the well to be unloaded and to work down to the desired operating depth. For a dual gas-lift well, there is only one annulus that needs to be unloaded. The primary RP in mandrel design is to use enough mandrels to allow both zones in the dual well to be unloaded and operated at their respective depths. The options for consideration include the following.

5.2.2 Spacing Based on Requirements of the Lower Zone

Since the annulus of the dual gas-lift well is unloaded (the completion fluid is removed), one common option is to base the mandrel spacing (unloading) design on the requirements of the deepest zone, since this should result in unloading the completion fluid to the bottom operating mandrel depth of the long string. With this approach, the mandrels are spaced based on the requirements of the deeper (long) string. The mandrels for the shorter string are typically placed one tubing joint above the mandrels in the long string to avoid them at the same depths.

5.2.3 Basing the Design Spacing on the Most Prolific Zone

Basing the mandrel spacing on the requirements of the most prolific zone uses the logic that it will result in placing mandrels closer together and high in the well. These locations become important when attempting to lift from the optimum depth for a prolific (high productivity) well. Since the productivity of either zone may not be as good as anticipated, it is wise to install mandrels down to the depth of the upper zone’s production packer. This is referred to as “bracketing.” Mandrels are installed below the depth of the bottom design mandrel. Typically, these lower mandrels are spaced 91.4 m to 152.4 m (300 ft to 500 ft) apart. Again in this case, the mandrels for the short string are placed one tubing joint above the mandrels in the long string.

5.2.4 Design Spacing Based on Conditions/Needs

An alternative is to design the mandrel spacing for each side based on its own requirements. The problem with this method is that the specific requirements of each zone may not be known at the time the mandrel spacing is performed. Normally, the attempt at a specific mandrel spacing design for each zone is not recommended. Special care should be used to make sure that no two mandrels are at the same depth.

5.2.5 Design with Flexibility to Use Different Types of Valves

5.2.5.1 General

The optimum type of gas-lift valve to be used in the well may not (probably will not) be known when the mandrel spacing is designed. Therefore, the most conservative design that will accommodate the type of gas-lift valve that requires the closest spacing should be used.

5.2.5.2 Effect of Different Types of Gas-lift Valves

5.2.5.2.1 General

The different types of gas-lift valves that may be used for dual gas-lift are listed in this section. Each has different requirements and may require a different mandrel spacing to accommodate its needs.

5.2.5.2.2 PPO Gas-lift Valves

The opening and closing of PPO gas-lift valves is primarily controlled by the tubing (production) pressure. In theory, these valves can be designed to all operate with the same surface casing (injection) pressure. Therefore, if the same tubing pressure design line is used as would be used for an IPO gas-lift valve design, the mandrel spacing can be a little further apart than with IPO valves. However, in practice, a higher (further to the right) tubing pressure design line is used, so mandrels designed for PPO usage are normally closer together than mandrels designed for IPO usage. Since PPO valves may be used on one or both sides of a dual, the mandrel spacing should be close enough to accommodate this requirement.

5.2.5.2.3 IPO Gas-lift Valves

The opening and closing of IPO gas-lift valves is primarily controlled by the casing (annulus or injection) pressure. For upper unloading valves to close, the casing pressure must be reduced for each lower valve. This requires that the mandrels be spaced closer together than would be required if this annular pressure drop were not required. However, the tubing pressure design line is normally lower (further to the left) than the tubing pressure for PPO valves. Therefore, the mandrel spacing is normally wider than that required for PPO gas-lift designs. Since IPO valves may be used on one or both sides of a dual, the mandrel spacing should be close enough to accommodate their potential use, even if a different type of valve is used.

5.2.5.2.4 Balanced IPO Gas-lift Valves

Balanced IPO valves have the primary opening force from the casing (injection) pressure, but with a very high tubing effect, normally in the range of 25 %. These valves are more sensitive to changes in tubing (production) pressure than “normal” IPO valves; therefore, they are sometimes considered as an alternative to PPO valves in cases where the mandrel spacing is too wide for “normal” PPO design.

Differential pressure gas-lift valves are typically designed with two ports. They open on a lower differential between injection and production pressure and close on a higher differential pressure. Typically, they are designed by using a production pressure design line parallel to the injection pressure design line. The typical maximum differential pressure is about 2447 kPa (355 psi). The normal differential pressure is about 1724 kPa (250 psi). They require a maximum of 152.4 m (500 ft) mandrel spacing. This type of valve is normally used in unique circumstances. One such special circumstance would be the requirement to test the casing with the valves already in place. The higher casing pressure used for testing forces these valves closed and can support a pressure test of the casing.

5.2.5.2.5 Surface Operated Gas-lift Valves

Surface operated gas-lift valves are controlled from the surface by transmitting an electrical or hydraulic signal to the valve to open or close. With these valves, no extra casing (injection) pressure drop is required. However, even if a well is going to use this type of valve, there is a possibility that another type of valve may be needed to keep the well on production if the surface controlled valve fails. Therefore, the conservative approach for mandrel spacing design should be followed.

5.2.5.2.6 Valve or Orifice at Operating Depth

It is common to use an orifice or a specially designed valve in the bottom operating gas-lift mandrel. But this should have no impact on the mandrel spacing design. However, if the likely depth of operation is not known, it is preferred to plan for operation on an unloading valve rather than placing an orifice midway in the well. Later analysis may indicate the need for an orifice to replace an unloading valve at any depth in the well.

5.3 Gas-lift Mandrel Spacing Production Pressure Design Line Options

5.3.1 General

Gas-lift mandrel spacing is performed using a design casing (annulus or injection) pressure gradient, a design tubing (production) pressure gradient, and a number of other assumptions. Options for the production pressure design line are as follows.

a) *Tubing Pressure Gradient Curve*—This curve is calculated for a given production rate. This method is not recommended for designing mandrel spacing since the production rate is not known at this time, and the well will produce at different rates as it unloads. This method is not recommended for spacing gas-lift mandrels or designing valve settings.

b) *Equilibrium Curve*—The well must produce along an equilibrium curve, but the equilibrium curve cannot be defined when the mandrel spacing design is performed since the well's inflow performance and production rate(s) are not known yet. This method is not recommended for designing mandrel spacing, but it is recommended for designing valve settings.

c) *Straight-line Approximation*—This method approximates a range of equilibrium curves. It is the best method for use during design of mandrel spacing. It is not recommended for design of valve settings, since better information is then available and the equilibrium curve should be used.

5.3.2 Gradient Curves

A frequent method is to use a vertical multiphase pressure gradient curve for the production pressure design line. This method is not recommended. The reason is that the well will not be producing on this curve during the unloading process. It will be producing a various rates as it is unloaded. Initially, when unloading near the top of the well, "production" may only consist of completion fluid being displaced from the annulus. As the unloading process continues, the well will begin to produce some fluid from the formation and some from the annulus. Finally, when the well is fully unloaded, it will produce "formation" fluid from the reservoir.

5.3.3 Equilibrium Curve

The equilibrium curve describes the actual production rate when the well is gas-lifting from any particular depth. The accurate development of an equilibrium curve requires knowledge of the well's inflow performance. This information may not be (is usually not) available at the time the mandrel spacing design is being performed. An alternative to using a single equilibrium curve could be to use a suite of curves, with each representing a different inflow performance. While elegant, this is a lot of work. The method described in Annex B is much easier and accomplishes essentially the same desired result.

5.3.4 Variable Rate or 20 % Design Line Method

This method uses a straight line for the production pressure design line. It is constructed as follows.

1) *Top Point*—The top of the design line is set at a point equal to Equation (1).

$$P_t + 0.2 \times (P_c - P_t) \quad (1)$$

where

P_t is the design tubing-head pressure; and

P_c is the design casing-head pressure.

2) *Bottom Point*—The bottom of the design line is set at a point equal to P_c (at depth)—1379 kPa (200 psi).

The advantages of this method are as follows.

— *Simplicity*—Both the casing (injection) pressure design line and the tubing (production) design lines are straight lines.

— *Flexibility*—The formula for placing the top and bottom points can be adjusted to the right or left as desired. For instance, if it is desired to place the mandrels closer together high in the wellbore, move the top of the production pressure design line to the right. For instance, a position equal to Equation (2) could be used.

$$P_t + 0.4 \times (P_c - P_t) \quad (2)$$

If it is desired to space the mandrels closer together deep in the well, move the bottom of the line to the right. For instance, a position equal to P_c (at depth)—689 kPa (100 psi) could be used. The guidelines presented above have been found to work well in many instances.

5.3.5 Specific (Set) Differential Pressure from Casing Pressure

Another method for choosing the production pressure design line could be to use a constant differential or offset from the injection (casing) pressure design line. This may be appropriate if use of a differential valve is contemplated. However, this method will result in essentially constant mandrel spacing, which is generally not what is required. Normally, the mandrels should be spaced closer together deeper in the hole, since the casing pressure and the production pressure lines converge with each other deeper in the well.

5.3.6 Bracketing to Add Additional Mandrels Deep in the Well

It is recommended to space mandrels to just above the dual production packer. When the design mandrel spacing becomes less than a given distance, the normal RP is to space the bottom mandrels evenly at a fixed vertical distance apart of 91.4 m to 152.4 m (300 ft to 500 ft). This will assure that, if the well's reservoir pressure or productivity decreases with time, it will be possible to inject gas from as deep in the well as possible.

5.4 Gas-lift Mandrel Spacing Design Procedure

5.4.1 General

A number of factors should be considered in performing a gas-lift mandrel spacing design. These are listed below. A recommended design procedure is shown in detail in Annex B.

5.4.2 Pressures

The following pressures should be defined for the unloading design process.

— *Kickoff Casing (Injection) Pressure*—This is the maximum gas pressure that can be supplied to the wellhead. This value is used for the initial unloading. During initial unloading, gas pressure is used to displace completion fluid from the annulus, and the gas injection rate into the annulus is negligible.

— *Kickoff Pressure Safety Factor*—Normally, this is between 0 kPa and 345 kPa (0 psi and 50 psi) to reduce the kickoff pressure for safe unloading design. This is to assure that there will be ample pressure to start the unloading process.

— *Operating Casing (Injection) Pressure*—This is the injection pressure that can be supplied to the wellhead at the design unloading rate. This injection pressure is used when gas injection begins into the top gas-lift valve.

— *Casing Pressure Reduction for Each Deeper Gas-lift Mandrel*—This is the amount by which the casing pressure is reduced for each deeper gas-lift mandrel. This pressure drop is required to assure that the upper valves will close when operating on the lower valves. A value of between 0 kPa and 345 kPa (0 psi and 50 psi) is normally used. A common value is 207 kPa (30 psi). This value is appropriate when 3.81 cm (1.5 in.) gas-lift IPO gas-lift valves are used.

NOTE This casing pressure drop is required when spacing for IPO gas-lift valves. It is usually not required when spacing for PPO gas-lift valves.

— *Operating Tubing (Production) Pressure*—This is the production pressure that is needed to flow liquid produced from the well to the production facility.

— *Production Pressure Safety Factor*—This is the amount, normally between 0 kPa and 345 kPa (0 psi and 50 psi), to increase the production pressure for safe unloading design. This is used to assure that there will be ample pressure to produce the fluid from the well during the unloading process.

5.4.3 Fluid Gradients

The following fluid gradients and associated parameters should be defined for the unloading design process.

— *Completion Fluid Gradient*—This is the pressure gradient (in kilopascals per meter or pounds per square inch per foot) of the completion fluid in the annulus.

— *Gas Gradient*—This is the pressure gradient (in kilopascals per meter or pounds per square inch per foot) of the gas-lift injection gas. It is a function of the injection gas gravity, the injection pressure, the wellhead temperature, and the temperature at depth in the well.

5.4.4 Other Factors

The following other factors are required for the unloading design process.

— *Mandrel Depth Safety Factor*—This is the amount by which each calculated mandrel depth is reduced to assure that the unloading process can continue. Each mandrel must be located between two tubing joints. A typical safety factor is between 0 m to 15.2 m (0 ft to 50 ft).

— *Minimum Mandrel Spacing*—This is the minimum mandrel spacing distance. It is expressed in vertical as opposed to measured depth units. A typical value is between 91.4 m to 152.4 m (300 ft to 500 ft).

— *Depth of Upper Zone Production Packer*—This is the depth of the upper zone's production packer. It should be known in both true vertical and measured depth terms.

5.5 Installation Issues

5.5.1 Installing the Two Tubing Strings Separately

There may be cases where it is necessary to install each of the two dual tubing strings separately. In this case, the long string should be installed first. If the two strings are installed separately, the second (short) string and its mandrels must be installed past the first (long) string and its mandrels. The long string production packer and the short string or dual packer must both be run on the long string. When the short string is run, it will be stabbed into the short string or dual packer.

5.5.2 Installing and Pulling Both Zones at the Same Time

This is the normal RP for a dual completion. This method is preferred so that the spacing between the gas-lift mandrels on the two strings can be assured. The completion should be designed so that it will be possible to pull the tubing/mandrels from one zone past the other zone's tubing/mandrels.

5.6 When One Zone Is Much Deeper than the Other

5.6.1 General

Dual gas-lift should not be attempted if the upper and lower zones are too far apart. Normally, the maximum vertical distance should not be more than about 305 m (1000 ft). However, in some cases a well may have zones that are further apart. If this case is considered, some alternatives are discussed.

5.6.2 Alternatives Where Two Zones Are Vertically Far Apart

5.6.2.1 General

Use an injection string beneath the upper packer with side-string mandrels. With this design option, a separate injection tube is installed below the upper packer. This packer should accommodate three tubing strings and is connected to the gas-lift mandrels in the long string. These mandrels are installed in the long string beneath the upper packer, which permits gas to be injected deeper in the deep zone's tubing but isolates the injection gas from the short zone's production interval (see Figure 1). Additional options include the following.

— If the tubing is large enough, the first and simplest option is to design both gas-lift strings down to the depth of the upper zone's dual production packer. The disadvantage of this approach is that it will not be possible to inject gas deep into the lower zone of the dual well.

— An insert string may be used in the long side of the dual to inject gas into the long side beneath the dual zone production packer.

— If the casing is large enough to accommodate a three-hole packer and an injection line beneath the dual packer, use the approach illustrated in Figure 1.

— If the long string tubing is not large enough for an insert string, and the casing is not large enough to accommodate a three-hole packer and an injection line beneath the dual packer, design mandrels only down to the depth of the upper dual zone packer.

5.6.2.2 Design Both Sides Down to the Dual Packer

The simplest option is to design both gas-lift strings down to the depth of the upper zone's production packer. This packer is also known as the dual packer. The disadvantage of this approach is that it will not be possible to inject gas deep into the lower zone of the dual well.

5.6.2.3 Injection String

A second option is to use an injection string beneath the upper packer with side-string mandrels. With this design option, a separate injection tube is installed below the upper packer. This packer should accommodate three tubing strings and is connected to the gas-lift mandrels in the long string. These mandrels are installed in the long string beneath the upper packer. This permits gas to be injected deeper in the deep zone's tubing but isolates the injection gas from the short zone's production interval (see Figure 1).

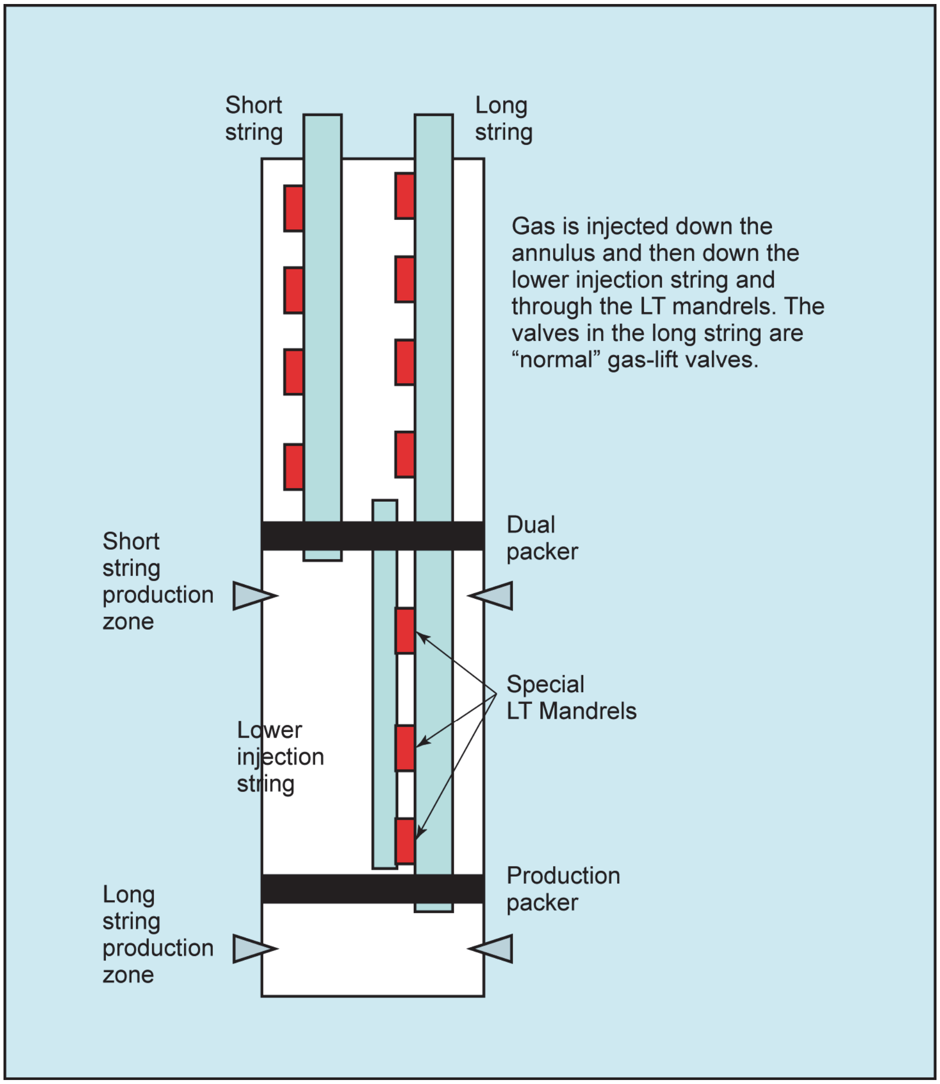

Figure 1—Mandrel with Injection String Beneath the Upper Packer

5.6.2.4 Concentric Snorkel (Dip Tube)

A third option is to use a concentric snorkel (dip tube) to inject deeper in the long string. Inject around end of dip tube, or use mandrels on the dip tube. This design includes the injection tube for the long string, below the upper dual packer, which is concentric inside the long string tubing rather than being installed on the outside of the long string tubing and connected to the long string's mandrels. Gas can be injected down the well's annulus, then into the dip tube, down the dip tube, and then into the deep zone's tubing string, either by injecting around the end of the dip tube (not recommended) or through gas-lift valves installed in the dip tube. This works where the long string's tubing size can accommodates a concentric injection string.

5.6.2.5 Comingling Two Zones

Commingle two zones and inject down the short string beneath the dual packer. If the pore pressure gradients of the short string zone and the long string zone are the same, then the zones can be commingled without risk of significant cross-flow when the wells are closed in. Additionally, if the flowing bottomhole pressure (FBHP) at the upper zone is expected to be less than the lift gas pressure at depth, the long string can be used as the production string and the short string used to deliver gas to the upper zone perforations.

To accomplish this, perform the following steps:

a) open a sliding sleeve adjacent to the upper perforations or perforate the long string tubing at the upper zone perforation depth;

b) install unloading valves in the mandrels of the long string, including the lowermost mandrel;

c) install dummy valves in all of the mandrels of the short string with the exception of the lowest mandrel;

d) install a gas-lift orifice in the lowest mandrel (short string), sized to deliver the rate of lift gas required.

To operate the well:

a) leave the short string wellhead valves closed,

b) open the long string wellhead valves,

c) inject lift gas into the casing.

The unloading valves in the long string will unload/kick off the well down to the depth of the lowest mandrel. The gas-lift orifice in the short string lowest mandrel will then pass gas from the casing into the tubing and out the end of the tubing and down to the depth of the perforations or open sliding sleeve adjacent to the perforations of the upper zone. The lift gas rate is controlled normally.

5.7 PPO and IPO Gas-lift Valves Compared

5.7.1 General

It is thought by some people that the only type of gas-lift valve for a dual gas-lift well is a PPO type. The applied logic is that since there are two different zones, it is practical to let the production pressure of each zone control which valves are open, rather than the common injection pressure that may not be fully effective for either zone. Additionally, some people feel that IPO valves should be selected since the purpose is to unload the well and IPO valves are better controlled for this.

Accurate gas-lift valve performance models are available for IPO and PPO gas-lift valves. API 19G2 provides methods for accurately testing and developing performance models for gas-lift valves. Many of the commonly used IPO and PPO valves have been modeled using API 19G2. These models can be used in designing the opening and closing pressures and in determining the gas flow rates through the valves at a range of operating pressures.

5.7.2 PPO Type Valves

5.7.2.1 General

There are arguments, logic, and issues associated with using PPO gas-lift valves in dual wells. Use of PPO valves does not isolate the well from upsets in injection pressure; however, they are less sensitive to changes in injection pressure than IPO valves.

5.7.2.2 Using PPO Type Valves

The primary open/closing force for PPO valves is provided by the production (tubing) pressure. Therefore, they are less sensitive than IPO valves to changes or upsets in injection pressure. This may be a plus for PPO valves if there is a likelihood of significant changes in the gas-lift system pressure. However, there are proven techniques to maintain a relatively constant system pressure and thus avoid upsets.

5.7.2.3 PPO Valves Crossover Port Flow Restrictions

Some PPO valves have had restrictions to gas flow through their crossover ports; others have been redesigned to improve this situation. If there is any question about the performance of a specific PPO valve, it should be tested and modeled as defined in API 19G2 to accurately determine its performance.

5.7.2.4 PPO Valve “Self-adjustment”

PPO valves do not self-adjust. Once they are set, they open and close at specific values of injection and production pressure. Therefore, if the production pressure changes due to a change in the well’s productivity, an upper unloading valve may reopen at the higher production pressure and allow the well to operate up the hole.

5.7.2.5 Spring-loaded PPO Valve Temperature Insensitivity

If a spring is used, in lieu of nitrogen gas charge, to provide the closing force, the valve will not be sensitive to the temperature in the well. This is not an advantage for PPO valves relative to IPO valves, since both types of valves can use a spring in lieu of nitrogen gas.

5.7.2.6 Using IPO Type Valves on Both Sides of Dual Gas-lift Wells

The primary purpose of unloading valves is to remove the liquid from the annulus so the gas-lift gas can be injected to the desired depth. If unloading were the only purpose of these valves, IPO valves would be the choice as they are well known and very commonly used for unloading single-string gas-lift wells. If both sides of a dual can be unloaded to bottom, and operated from bottom, IPO valves are the best choice.

Other types of valves are sometimes (perhaps even often) recommended for use in dual wells if it may become necessary for one or both sides of the dual to not lift from the deepest operating point, but higher. When a gas-lift well must operate “up the hole,” it may be more logical to use a different type valve that can open based on the demands of the tubing pressure, regardless of the value of the casing pressure. When one or both sides of the dual may need to lift from “up the hole,” either the design of the gas-lift valves should be changed or a different type of gas-lift valve should be considered. If it can be determined, for example, that one side of a dual must lift from the third mandrel, IPO valves can still be used if an injection orifice is installed in the third mandrel.

If both sides of a dual well can be successfully unloaded down to the desired operating depth, and if they can be operated at that depth, IPO valves should be the first choice. This includes the case where the necessary operating depth changes in one zone, if the gas-lift string can be redesigned to place an operating valve or orifice at the required operating depth. If it is unlikely that both sides of a dual can be operated at the desired depth, and if the actual depth of operation in one or both zones is not known, then IPO valves may not be the best choice.

5.7.2.7 Injection Pressure Drop to Close Upper Valves

With IPO valves, there is a need to take an injection pressure drop from valve to valve to close upper valves. The primary opening and closing force on IPO valves is provided by the injection pressure; an injection pressure drop should be taken between each successive depth to assure that the upper valves are closed when injecting through a lower valve. This required reduction in injection pressure for each lower valve means that the gas-lift mandrels must be spaced slightly closer together than for types of valves that do not require a casing pressure drop between valves.

5.7.2.8 Upper Mandrel Spacing Too Far Apart for PPO Valves

If upper mandrels are too far apart, IPO valves may be needed. Even though the IPO design requires an injection pressure drop between valves, it is possible to work with a wider mandrel spacing than if other types of valves are used. The reason is that the tubing pressure design line for IPO valves may be further to the left (lower tubing pressure) than the tubing pressure design line needed for other types of valves. If it is reasonably certain that neither side of the dual well will need to “work” (inject) in the upper part of the well, the use of IPO valves should present no problem.

5.7.2.9 Switching from IPO Valves to PPO Valves

The operator can use IPO valves in top mandrels (that are further apart) and then can switch to PPO valves deeper in the well. IPO valves can be used for unloading in the upper part of the well, where it is unlikely that the well will need to operate. Lower in the well, where the well may need to operate (inject gas), PPO valves can be used.

5.7.2.10 Nitrogen-charged IPO Valves

IPO valves that are charged with nitrogen (N_2) gas are temperature sensitive. While IPO valves can use springs to provide the closing force, most use N_2 gas in the bellows to provide the closing force. The pressure of the nitrogen is temperature sensitive, so it is necessary to accurately measure or estimate the temperature at the depth of the valves’ installation.

5.7.2.11 Using a Choke in IPO Unloading Valves

A choke installed in the valve nose, downstream of the port, can be used in IPO unloading valves. The majority of the pressure drop across the valve occurs at the choke. This keeps the pressure drop across the port lower and holds the valve open until its closing pressure is reached. This prevents throttling, whereby the gas inject rate through the valve decreases as the valve begins to close at a lower tubing pressure.

5.7.3 Balanced IPO (Continuous or Constant Flow) Valve Support, Logic, and Issues

5.7.3.1 General

Another option is to use a balanced IPO, also known as a continuous flow or a constant flow valve. The primary opening force is supplied by the casing (injection) pressure, but unlike normal IPO valves, they have a much greater tubing effect. Normally the R-value, the ratio of the area of the port to the area of the bellows, is approximately 0.25, as compared to 0.10 or less for most common IPO valves. Also, these valves normally have a choke installed upstream of the port of the valve. The choke causes the casing (injection) pressure to drop as gas enters the valve. This makes the closing sensitive to the tubing (production) pressure.

5.7.3.2 Temperature Sensitivity

Balanced IPO valves are sensitive to temperature. Normally, these valves use a nitrogen gas charged bellows as the closing force. The pressure in the bellows is sensitive to temperature, so the temperature at the depth of each valve must be known or estimated for accurate design. It is possible to use a spring as the primary closing force to remove the temperature sensitivity; however, these valves are much less commonly used.

5.7.3.3 Valve Closing Pressure

Balanced IPO valves can be designed on constant P_c but close with a decline in P_t. Since these valves have a significant tubing effect on valve opening and closing, they can be designed based on a constant casing (injection) pressure. A reduction in casing pressure is not required to close the upper valves. They can be designed to close on a reduction in tubing (production) pressure as the well unloads.

5.7.3.4 Unloading Valves

Unloading valves can be locked closed by a decline in P_c after reaching the operating point. As with any IPO valves, these valves can be locked closed by reducing the casing (injection) pressure after the operating depth is reached. This reduction in casing pressure can be achieved if the well is operating from an orifice or a "flag" valve that is designed to operate at a lower casing pressure.

This valve is intended for unloading/kickoff only, not for operating, and the well should operate beneath it on an orifice or IPO valve. Normally, the operating point should be on an orifice or a gas-lift valve designed to operate at a lower casing pressure. However, a balanced IPO valve could also be used if it can be operated at a lower casing pressure than that used for the unloading valves.

5.7.3.5 Design Information

The designer should know P_c, P_t, and T to design; if any of these are unknown, it may not work. To design these valves, it is important to know the casing pressure, tubing pressure, and temperature at the depth of each valve. However, this is also required for other nitrogen charged gas-lift valves.

5.7.4 Selection Criteria for Unloading Valves

The following considerations are recommended for selecting an unloading valve. If the expected depth of lift is known, IPO gas-lift valves should be used for unloading; if the depth of lift is not known, it may be necessary to lift from unloading valves. PPO gas-lift valves should be used for unloading; special gas-lift valves (e.g. balanced IPO valves) should only be used where IPO or PPO valves are not practical.

5.8 Unloading Gas-lift Valves

5.8.1 General

Annex C contains an unloading valve design for PPO gas-lift valves. Gas-lift mandrel example spacing design is included in Annex B.

5.8.2 Unloading Valve Design for Each Type of Valve

A typical design for PPO gas-lift valves is included in Annex C. There are many design programs available where information is available for other valve designs. Options for unloading valves include: PPO gas-lift valves, IPO gas-lift valves, and balanced IPO gas-lift valves.

5.9 Operating Unloading Gas-lift Valves

5.9.1 Unloading Valve(s)

Often the actual depth of gas-lift injection is not known and cannot be predicted with accuracy. This is true for new completions or where the reservoir pressure, inflow productivity, or fluid properties are subject to change. In this case, it may be necessary to operate from an unloading valve either for the long term, or at least until the actual depth of lift can be determined. If the unloading valve is selected and designed to minimize throttling, this can provide acceptable operation. If the well conditions change, the depth of lift can automatically change to another valve.

It may be necessary to operate from more than one unloading valve. In some instances, where the casing (injection) pressure is relatively low, it may not be possible to inject the desired rate at the deepest mandrel depth. In such cases, multipointing or the simultaneous injection into more than one valve may be warranted and may be beneficial. Injection of some gas through an upper valve may lighten the tubing pressure gradient enough to allow more gas to be injected into the next deeper valve, if an appropriate type of valve is used.

Even if gas injection through an upper unloading valve is anticipated, it may be wise to install an orifice, a nozzle venturi orifice, or a "flag" valve in the deepest mandrel in both sides of the dual. In this way, if the well does work down to the deepest mandrel, this can be seen. If injection through an upper unloading valve is anticipated, the use of PPO or balanced IPO valves is recommended. The reason is that the depth of lift can then be determined by the well's producing conditions. If IPO valves were used, the operating valve would depend on a change in the casing pressure, not the producing conditions of the well.

5.9.2 Alternatives for Operating Gas-lift Valve or Orifice

An unloading gas-lift valve, an orifice, a nozzle venturi orifice, or a "flag" valve may be used for gas-lift injection at the design operating depth. These alternatives are used for the operating points in dual gas-lift designs. If the desired operating depth is known, the recommendation is to use a standard orifice, a nozzle venturi orifice, or a "flag" valve. If the depth of operation is not known, or cannot be predicted with certainly, operation may be from an unloading valve.

5.9.3 Orifice Valves

If the depth of lift is known to be from the deepest gas-lift mandrel, or from some other known depth, many operators install an orifice at this depth. The advantage of the orifice is that it is always fully open. It can accommodate a wide range of gas injection rates without throttling, when flow is not in the critical range. Critical flow occurs when the pressure downstream of the orifice, the tubing pressure, is less than approximately 60 % of the upstream (casing) pressure.

Thus, the injection rate can be adjusted to optimize the performance of the well. This can be done over a wide range of injection rates where the injection pressure is not increased high enough to reopen an upper valve. One of the most common problems with the use of an orifice valve is defining the size of the orifice port. If it is too large, the well will become unstable. The orifice port size should be carefully chosen to allow the correct gas injection rate, and support the desired flexibility, without being large enough to allow well instability. An orifice valve does have a built-in check valve to prevent back flow from the tubing to the casing annulus in cases where the tubing pressure is higher than the casing pressure.

5.9.4 Nozzle Venturi Orifice Valves

If the desired injection rates into one or both sides of the dual gas-lift well are known, a nozzle venture-orifice may be used. A nozzle venturi is an orifice with a venturi configuration on the valve port. The venturi design causes the critical flow to occur when the pressure downstream of the port is less than approximately 92 % of the upstream pressure. This means that as long as the critical flow range can be maintained, the gas injection rate can be held at a constant value. This can be very advantageous in a dual gas-lift well. The desired injection rate into each side of the dual can be designed and maintained, with the upstream (casing) pressure maintained and while the downstream (tubing) pressure is kept below 92 % of the upstream (casing) pressure. Unlike the simple orifice, the nozzle venturi does not provide flexibility in gas injection rate, so it does not support hands-on changing of the injection rate to optimize the well. The desired injection rate should be determined in advance, and the nozzle venturi should be sized for this rate.

5.9.5 Flag Valve (PPO, IPO, Balanced IPO Designs)

Rather than using an orifice or a nozzle venturi, some operators prefer to use a "flag" valve in the bottom gas-lift mandrel. A "flag" valve is a normal PPO, IPO, or balanced IPO valve that is designed to operate at a lower injection pressure than the unloading valves. It is normally held fully open by the injection and production pressures at depth, but if the pressures fall too low for some reason, this valve, unlike an orifice or nozzle venturi, can close.

5.10 Designing for Dual Gas-lift if Mandrels Spaced Too Far Apart

5.10.1 General

In some cases, the upper gas-lift mandrels may be spaced too far apart to support use of PPO or other types of gas-lift valves. In this case, it may be necessary to use IPO valves or other approaches to unload the well.

5.10.2 IPO Valves in Upper Mandrels

IPO valves may be necessary in upper mandrels. IPO valves can work with a wider mandrel spacing than can PPO or balanced IPO valves. If there is little possibility that the well will need to operate from these upper mandrels, the use of IPO valves is a logical choice.

5.10.3 Use of Pack-off Valves

If for some reason use of IPO valves does not appear feasible, use of a pack-off valve can be considered. This might be necessary if the upper mandrel spacing was too wide, even for IPO valves. A pack-off valve requires that a hole be punched in the tubing and the pack-off valve is set across the hole. A disadvantage of this is that it is not possible to perform wireline work beneath the pack-off device, unless it is removed.

5.10.4 Use of Concentric String

A third option, if the production tubing is large enough, could be to install an insert concentric tubing inside the primary production tubing. This concentric tubing could be outfitted with the necessary gas-lift mandrels/valves to permit unloading.

5.11 Dual Gas-lift System Design Options

5.11.1 General

Several options are discussed for selecting types of gas-lift valves for dual gas-lift. It is not the purpose of this RP to give specific recommendations on these options. However, they are listed in this section for consideration by those who operate dual gas-lift wells.

5.11.2 PPO Valves on Both Sides

Some operators choose to use PPO valves on both sides (in both tubing strings) of a dual gas-lift well. They normally install an orifice or venturi orifice valve in the bottom (or lowest) operating valve. Their reasoning for this is typically twofold:

1) use of PPO valves can allow the well to work down with less loss in casing pressure; and

2) if one zone (side of the dual) needs more or less gas than the other side, this can be better accommodated by PPO valves than by IPO valves, where the valve opening/closing is more controlled by the injection (casing) pressure.

5.11.3 IPO Valves High in the Hole, PPO Valves Lower in the Hole

Some operators suggest it may be preferable to use IPO valves higher in the well and PPO valves lower. The logic of this is that it may be easier to unload a well using IPO valves, but PPO valves should be used in the lower portion of the well, where most wells are operated. This logic is supported by the fact that a dual well needs to be unloaded once to remove the liquid from the casing/tubing annulus; this is accomplished with an IPO design. When the well is unloaded, the operation can be fine-tuned by using PPO valves near the operating depth.

5.11.4 IPO Valves on One Side, PPO Valves on the Other Side

An alternative to the approach in 5.11.3 is to use IPO valves on one side of the dual and PPO valves on the other side. The logic of this approach is similar; the side with the IPO valves can be used to unload the well, with the other side closed in during the unloading process. Then, the well can be placed on gas-lift with both sides open. The advantage of this is that unloading to bottom can be achieved with relative assurance. The potential disadvantages of this approach are:

a) the casing pressure will be somewhat reduced by unloading with IPO valves, and

b) the side with the IPO valves may tend to “rob” gas from the other side.

If this approach is used, relatively small-ported gas-lift valves, and a small orifice, should be used to prevent either side from taking too much gas. Also, use of chokes in the gas-lift valves should be considered.

5.11.5 IPO Valves on Both Sides

A further alternative is to use IPO valves on both sides. This alternative can work if both zones are well understood, the depth of lift for both zones can be accurately predicted, and the amount of gas required by both zones can be accurately predicted so the port sizes or choke sizes can be accurately designed for both sides of the dual. Unfortunately, it is usually not possible to accurately know these factors. When one or both wells change, the injection rate may require change and it may be difficult to accommodate with IPO valves on both sides.

5.11.6 Single-point Injection

Where there is sufficient gas injection pressure available to inject from bottom without the need to install unloading valves, single-point injection can be used by injecting through an orifice just above the depth of the dual packer. This can work very well where the sizes of the orifices are chosen to prevent over-injection.

6 Dual Gas-lift Well Operations

6.1 General

In most production organizations, regardless of who designed the artificial lift systems, it is left to the production operations staff to operate the well and to try to do so successfully over the long term. Operating any gas-lift well can be a challenge, and operating a dual gas-lift well can be more challenging. This section defines the issues to be addressed to successfully operate dual gas-lift wells over the long term.

6.2 Installing Dual Gas-lift Equipment

6.2.1 Running Two Strings Together Simultaneously

When installing dual gas-lift equipment in a well, it is usually recommended to run both tubing strings at the same time (simultaneously). To do this, the following conditions should be met.

a) There must be a dual set of slips.

b) There must be a dual string elevator.

c) There must be sufficient clearance in the casing annulus so both strings and their gas-lift mandrels can be run into the well simultaneously.

d) The two sets of mandrels must be able to pass one anther if one side must be pulled while the other is left in place, or if the mandrels on the short string must pass those on the long string when the short string is stung into the dual packer.

e) One string, normally the long string, should be stacked in the derrick first. Then, the second (short) string picked up from the rig floor.

f) The dual packer must be run on the long string.

g) The short string must be stung into the dual packer once it is at the desired depth.

6.2.2 Running Two Strings Separately

If the two strings are run separately, the installation can be more complicated. The following should be considered when running two strings separately:

a) the long string should be run first,

b) there must be sufficient clearance in the casing annulus so the short string and its mandrels can pass down the annulus and past the long string and its mandrels that are already in place,

c) the dual packer must be run on the long string,

d) the short string must be stung into the dual packer once it is at the desired depth.

6.2.3 Multiple Packers on Long String

There will always be at least two packers on the long string: the long-string packer that is set above the deeper zone, and the dual packer that is set above the shallower zone. In some cases, there may be a need for more packers if, for example, an intermediate zone is to be isolated and saved for potential future completion using a sliding sleeve. Proper setting and testing of each packer is essential. It is recommended to plan the installation with an expert from the packer supplier and have this person on location to assist with setting and testing the packers during the installation procedure.

6.2.4 Surface-controlled (Electric, Hydraulic, Cableless) Gas-lift Valves

Some operators consider the use of surface-controlled gas-lift valves. These may be operated by electric power with electric cables, hydraulic power with hydraulic lines, or by using cableless electric power transmission. It is recommended that an operator become familiar with using these types of systems on single completions before attempting to use them on dual gas-lift wells. Some considerations when using this technology on a dual gas-lift well are as follows.

a) Whenever use of this technology is considered, plan the installation with an expert from the surface control service provider. Have this person on location to assist in running and testing the equipment.

b) When using electric cables or hydraulic lines, the lines should be strapped to each tubing string, with at least five straps per tubing joint, to avoid any cable or line slack or movement.

c) The tubing stings should be run at the same time to avoid damaging the cables or lines when passing a gas-lift mandrel on the other string.

d) Electric or hydraulic continuity should be tested as every few joints of tubing strings are run. If a problem is found, the tubing strings should be pulled and the problem corrected.

e) When using cableless electric power transmission, the two tubing strings should be electrically isolated and from the casing.

6.2.5 Chemical Injection Lines

In some cases, lines are run so chemicals can be injected deep in the well for corrosion control, prevention of scale formation, control of paraffin, etc. It may be sufficient to run one chemical line for the dual well; in other cases, a separate line is needed for each string. When planning the installation, the same considerations are important as defined for installing electrical lines or hydraulic cables. In addition, chemical lines may be connected to mandrels that are designed to inject chemical into the tubing.

6.2.6 Testing the Packer

The packer test is an important part of the procedure in dual gas-lift completions. A dual completion with a leaking packer will have communication between the two producing zones through the gas-lift valves. The packer test procedure depends on whether the completion has been set up with dummy valves or live gas-lift valves. Test the casing to 10,342 kPa (1500 psi) or another recommended pressure to check for leaks in the casing, tubing strings, and dual packer. If the pressure cannot be held stable for 30 minutes without bleed-off, the casing leak should be repaired. The following describes test procedures depending on the valve type.

a) *Dummy Valves*—The casing can be pressured up to the desired pressure and held for 30 minutes.

b) *Live Gas-lift Valves*—A plugging device should be set at the bottom of the production strings, below all live gas-lift valves, and then they are pressured up to a predetermined limit. This will energize and seal the checks in the live gas-lift valves. Holding this pressure on both tubing strings will allow pressure to be placed on the casing for a packer test with no interference from the live gas-lift valves. The plugging device is typically a standing valve set with slick line or a ceramic flapper that can be broken with either pressure or slick line after the test.

Some wells that are completed with gas-lift equipment will flow naturally for a long period of time. During the natural flowing period, leaks can develop in the tubing strings, casing string, or the packer. If any type of leak is suspected, the procedure above can be reapplied before gas-lifting the well to ensure good system integrity.

6.3 Dual Gas-lift Well Wireline Operations

6.3.1 General

Successful wireline operations are essential for successful dual gas-lift. Recommendations for successful operations while changing gas-lift valves are presented below.

6.3.2 Possibility of Cross-flow When Changing Gas-lift Equipment

When changing out gas-lift valves in a dual completion, it should be recognized that the string being worked on may have a higher bottomhole pressure (BHP) than that of the opposite string. When a gas-lift valve is pulled from the higher pressured string, the tubing pressure will equalize with the casing pressure through the empty gas-lift mandrel. Cross-flow of well fluids may occur from the string being worked on, through the empty gas-lift mandrel, into the annulus, through the opposite string's gas-lift valve(s), and into that opposite string's wellbore. Although check valves are incorporated in the gas-lift valves to prevent wellbore fluids from flowing into the annulus, this is a moot point when the gas-lift valve is pulled out. Cross-flow, which can be at very high flow rates, can easily cut out the seats in the gas-lift valve(s) in the opposite string. This can cause problems and add to troubleshooting confusion with the dual completion after a gas-lift valve replacement.

Cross-flow can even prevent the proper setting of gas-lift valves within the mandrel pocket. As the bottom seal assembly is driven past the upper polish bore area in the mandrel pocket, cross-flow will be from the bottom of the mandrel, out through the mandrel ports, and into the annulus. As the valve is jarred further into the pocket, it has to overcome the upward force of the cross-flow through the mandrel. The wireline operator may think that the valve is set, allowing the latch to lock into the latch profile. The wireline operator then jars up to shear off and inadvertently pulls the valve out of the pocket or leaves the valve partially within the pocket. The following should be considered when changing gas-lift valves in a dual well.

6.3.3 Changing Gas-lift Valves in a Dual Completion

6.3.3.1 Opposite String Has Lower Pressure than Working String

Set a wireline plug or a standing valve with an equalizing assembly in the opposite string to prevent cross-flow. Set a valve catcher (wireline landing nipple lock, plug, standing valve, etc.) in the working string to catch dropped tools, or set a wireline plug with an equalizing assembly in the working string to prevent cross-flow from the working string and also act as a valve catcher.

6.3.3.2 Opposite String Has a Higher Pressure than the Working String

There is no need to set a plug in the opposite string, as the check valve in the gas-lift valves will prevent cross-flow. As a precaution, the tubing in the opposite string should be pressure tested to ensure that the check valves are sealing properly and no other leaks exist in the tubing string. Set a valve catcher in the working string to prevent problems if a valve or valves are dropped.

6.3.3.3 Run Impression Block

After running all the gas-lift valves in the working string, an impression block should be run down to the valve catcher to see if a gas-lift valve may have fallen out of a pocket. If the impression returned is that of the valve catcher fishing neck, it may be assumed that all the valves are set in their mandrel pockets.

6.4 Additional Recommended Wireline Procedures

6.4.1 General

This section contains additional recommendations for successful wireline operations in dual gas-lift wells.

6.4.2 Running Gas-lift Valves in Dual Gas-lift Wells

When performing valve revisions in dual completions, both strings of the dual should be shut in for the entire duration of the wireline work. It is never safe to flow one string of the dual while changing valves in the other.

6.4.3 Installing Valves When Dummy Valves Are in the Other String

With dummy valves in the other side of the dual, the wireline procedure is the same as running valves in a single completion. Extra precaution should be taken to ensure there is no communication in either of the tubing strings before any valves are pulled. After the valves have been installed, a tubing integrity test with water or gas should be made to ensure the valves are properly sealed in the mandrels. If gas is used, it is recommended to use an acoustic sounding device to record the casing fluid level during the test.

The following procedure should be performed during wireline operations:

a) perform a tubing integrity test of both sides of the dual before any valves are pulled,

b) install a standing valve below all mandrels on the tubing string being worked on,

c) fill the tubing with water and perform a positive pressure test against the standing valve,

d) install a junk basket on top of the standing valve,

e) equalize the casing and tubing pressures,

f) pull all valves starting at the deepest mandrel location,

NOTE An orienting style kick-over tool should be used if the mandrels are equipped with an orienting sleeve.

g) install live gas-lift valves in order starting at the shallowest location,

h) pressure up the tubing with water and perform a positive test for 30 minutes,

i) pull the junk basket,

j) equalize pressure across the standing valve and pull the standing valve,

k) unload the well according to API 11V5.

6.4.4 Alternate Procedure (with Dummy Valves in the Other String)

This alternate procedure should be used on wells where the casing fluid pressure at the deepest gas-lift mandrel is equal to or less than the static tubing pressure at the same location. There is no plugging device that could hold a column of water in the tubing for equalization. The following method is used on live valve change-outs, where the casing fluid has already been unloaded from a previous string of live valves:

a) perform a tubing integrity test of both sides of the dual before any valves are pulled,

b) install a tubing stop or collar stop below all mandrels on the tubing string being worked on,

c) install a junk basket on top of the tubing or collar stop,

d) equalize the casing and tubing pressures,

e) pull all valves starting at the deepest mandrel location,

NOTE An orienting style kick-over tool should be used if the mandrels are equipped with an orienting sleeve.

f) install live gas-lift valves in order starting at the shallowest location,

g) pressure up the tubing with water and perform a positive test for 30 minutes,

h) pull the junk basket,

i) equalize the pressure across the standing valve and pull the standing valve,

j) unload the well according to API 11V5.

6.4.5 Installing Valves in Duals with Live Valves in the Other String

When live valves are used on the other side of the dual, extra precautions are required to prevent the well from flowing into the other string during the valve replacement. If the static bottomhole pressures (SBHPs) of both reservoirs are known, then it is possible to pull the valves in the lowest pressured string using the above RP provided that the tubing integrity proves good in both sides of the dual. Ensure the use of the static gradient from the depth difference of the two zones compared to BHPs.

When pulling valves from the string with the higher BHP, there should be a downhole device installed to prevent any cross-flow between the zones. Where there is doubt about the current SBHPs, then treat the string you are working on as if it were the higher pressured zone when applying the following procedures. The practices recommended here utilize standing valves as the means to prevent cross-flow between the two zones when pulling gas-lift valves. Proving tubing integrity after each gas-lift valve installation greatly increases the success of dual installations.

6.4.6 Installing Valves on the Higher Pressured Zone

The following steps should be performed when installing valves on the higher-pressurized zone:

a) shut in both sides of the dual,

b) rig up on the lower pressured zone first,

c) install a standing valve in the lower pressured zone below the deepest live valve,

d) fill the tubing with water and perform a positive pressure test against the standing valve,

e) hold this pressure on the tubing string for the duration of the wireline work on the other side of the dual,

f) rig up on the higher pressured zone,

g) install a standing valve below all mandrels on the tubing string being worked on,

h) fill the tubing with water and perform a positive pressure test against the standing valve,

i) install a junk basket on top of the standing valve,

j) equalize casing and tubing pressures,

k) pull all valves starting at the deepest mandrel location,

NOTE An orienting style kick-over tool should be used if the mandrels are equipped with an orienting sleeve.

l) install the live gas-lift valves in order starting at the shallowest location and working down,

m) pressure up the tubing with water and perform a positive test for 30 minutes,

n) pull the junk basket,

o) equalize the pressure across the standing valve and pull the standing valve,

p) rig up on the other side of the dual (lower pressured string),

q) equalize the pressure across the standing valve and pull the standing valve,

r) unload the well according to API 11V5.

6.4.7 Other Methods

An alternative procedure is available for operators that can depress the tubing fluid column below the deepest gas-lift mandrel with gas pressure. If enough gas pressure is available to depress the tubing fluid level below every gas-lift valve that is to be pulled, then the standing valve can be eliminated for both strings. The gas pressure should be maintained during the entire wireline procedure to keep the formation from feeding into the casing. This procedure is more common when changing out just the shallower valve locations or in wells where the SBHP has depleted resulting in a fluid level deep in the well. The alternative procedure follows.

a) Perform a tubing integrity test of both sides of the dual before any valves are pulled.

b) Shut in both sides of the dual string.

c) Pressure up on the tubing with gas pressure to depress the tubing fluid level below the deepest mandrel to be pulled.

d) Run in the hole with slick line and tag the tubing fluid level to make sure it is below the deepest gas-lift valve that is to be pulled.

e) Install a tubing stop or collar stop below the deepest valve to be pulled.

f) Install a junk basket on top of the tubing or collar stop.

g) Pressure up the casing with gas to equalize with the tubing pressure.

h) Pull all valves starting at the deepest mandrel location. Use an orienting style kick-over tool if the mandrels are equipped with an orienting sleeve.

i) Install the live gas-lift valves in order, starting at the shallowest location.

j) Bleed the casing down 3447 kPa (500 psi) and hold for the tubing integrity test.

k) Pull the junk basket.

l) Pull the tubing or collar stop.

m) Unload the well according to the API unloading procedure (see API 11V5).

6.4.8 Valve Installation Problems

Many problems can be encountered when installing gas-lift valves. Table 1 covers the problems specifically related to gas-lift equipment or kick-over tools and the recommended solutions. Many problems will be prevented by using the proper wireline procedures and by inspecting the running, pulling, and kick-over tools before each use.

Table 1—Gas-lift Valve Installation Problems

Problem	Solution
Cannot locate the pocket or the kick-over tool will not sit down in the pocket.	Ensure the proper kick-over tool is being used for the mandrel type—orienting vs non-orienting types. Test the kick-over tool on the surface to ensure proper operation. Run a 3.175 cm ($1^1/_4$ in.) impression block on the kick-over tool and sit down in pocket to identify if a valve is in place.
Cannot get the valve in the pocket.	Test the kick-over tool on the surface to ensure proper function of the kick-over trigger. Check all joints on the tool. Worn joints appear loose and are not be of the stiffness needed to align the valve in the pocket.
Valve goes in the pocket but will not stay.	Check the latch no-go for an indication that the valve has bottomed in the pocket. If the no-go shoulder has a ring indicating it bottomed out in the pocket, the mandrel latch lug is either worn or corroded. Use either an oversize latch lug or a bottom latch valve. If the latch no-go did not bottom out (no indicating marks on the no-go shoulder), consider more jarring on the next run. A roller stem should be considered in highly deviated wells to minimize drag and provide stronger jarring hits.
Valves or latches bend during installation.	Check the kick-over tool for proper operation and firmness of joints. Valves are more prone to bend on the first jar hits since it requires a few hits for the kick-over tool to properly align the valve with the pocket. Jarring softly for the first several hits will reduce the bending tendency. Consider using less stem.
Valve locks in pocket but leaks due to cut packing.	Jar more softly when running the valve, especially during the first several hits.
Valve locks in pocket but leaks. Packing is not cut.	There may be damage to the gas-lift mandrels polished bore. Change the packing on the valve to a better sealing type. Also a valve with an extended packing area can be used. If possible, eliminate this valve from the design. Seal this mandrel off with a dummy with an extended packing section. Install a gas-lift valve on a pack off across the mandrel as a last resort.

6.5 Unloading Dual Gas-lift Wells

6.5.1 General

This section contains options and RPs for unloading dual gas-lift wells. Unloading is necessary whenever there is completion or other fluid in the annulus that must be removed so the well can be placed on gas-lift. This should occur when a well is first placed on gas-lift, when it has been worked over, or any time the gas-lift valves are pulled from either tubing string. Since only one zone is needed for initial unloading of the annulus, the unloading process is essentially the same as it is for a single gas-lift well.

6.5.2 Options for Unloading Dual Gas-lift Wells

6.5.2.1 General

A dual gas-lift well has one annulus, so it is only necessary to unload the well once per unloading occasion. The goal of unloading is to remove the annular fluid down to the deepest point where gas-lift injection can occur. Normally, this will be the bottom gas-lift mandrel in the long string.

6.5.2.2 Unload Using Deeper Zone

Normally, the gas-lift mandrels are spaced deeper, if only by one tubing joint, in the long string or deeper zone. Thus, it is logical to use this side of the dual for initial unloading.

6.5.2.3 Unload Using Poorer Zone

It may make sense to use the poorer zone (zone with the lower BHP) for unloading. This is the case if the unloading gas-lift mandrels are spaced too far apart and it is necessary to depress the fluid level in the tubing to permit unloading.

6.5.2.4 Preparing Surface Pressure and Flow Rate Measurement Systems

For a dual gas-lift well, just as with a single gas-lift well, it is essential to monitor the unloading process to assure that unloading occurs correctly and completely. For this, accurate methods are required to measure the injection pressure, production pressure, and injection rate during the unloading process and the ongoing production process after unloading. These measurements should be taken with a fully tested and calibrated two- or three-pen chart, or a set of pressure and flow transducers connected to a computer-based surveillance system before starting unloading.

6.5.2.5 Preparing Surface Equipment

The surface equipment should be prepared and ready for the unloading process to begin. The production tubing and flowline valves should all be fully open. The flowline should be pigged or cleaned to be sure it is clear. The injection system should be prepared to deliver full (initial kickoff) pressure to the wellhead. If necessary, the injection line should be pigged or cleaned as well.

6.5.2.6 Slowly Increasing Injection Pressure

To start the unloading process, very slowly apply injection pressure to the annulus. The injection pressure should be increased from 0 kPa (0 psi) up to 2758 kPa (400 psi), in increments of no more than 345 kPa (50 psi) each 10 minutes. When the pressure has reached this level, it can be increased up to the design injection pressure at a rate of 689 kPa (100 psi) each 10 minutes. However, the rate of gas injection should be maintained until the top unloading gas-lift valve has been uncovered and gas is being injected through it. The reason for this very slow buildup in pressure is to very slowly push the annular completion or other liquid through the unloading gas-lift valves. These valves are designed to inject gas. If liquid is injected through them at too high a velocity, the valves may erode.

6.5.2.7 Ramp Injection Rate Up to Design Unloading Gas Rate

Once gas is being injected through the top unloading gas-lift valve, the rate of gas injection can be gradually ramped up to the design injection rate for that side of the dual well. This gradual rate of increase in the gas injection rate should not be faster than 28.3 m^3/day (100 MCF/day) each 10 minutes. The reason for this slow buildup in rate is to avoid making any rapid reductions in the tubing pressure that could result in large pressure surges on the production formation. It is necessary to ramp the injection rate up to the full design rate for the one side so the well can unload down to each deeper unloading gas-lift mandrel/valve.

NOTE The gas injection rate is only increased to the design injection rate for the side of the dual well that is being used for unloading, not to the total injection rate that will be required when both sides of the dual are on gas-lift.

6.5.2.8 Monitor the Unloading Process

Carefully monitor the gas-lift injection pressure, production pressure, and gas-lift injection rate throughout the unloading process. This will provide valuable information on the success of the unloading process. If there are any problems, such as the unloading process becoming stymied at a given valve depth, this can be detected by close monitoring of the pressures and the injection rate.

6.5.2.9 When Unloading Is Not Successful

If the unloading process is not successful in reaching the desired depth, which is normally the deepest injection point in the side of the dual that is being used for unloading, it may be possible to complete the unloading process by using the other side of the dual. In this case, the following procedure is recommended.

a) Close in the side of the dual that was being used for unloading.

b) Slowly ramp the injection gas into the other side and the initial slow pressure buildup is not necessary since some of the completion or other liquid has been removed from the annulus.

c) Continue this unloading process until the well is unloaded to the desired depth.

d) Monitor the unloading process.

Since unloading was not completed successfully with the first side of the dual, the reason for this should be determined. If it was because of a failed or incorrectly set gas-lift valve, replacement is required.

6.6 Kicking Off Dual Gas-lift Wells

6.6.1 General

The term “kickoff” is used to describe the process when gas-lift must be restarted in a well. This process is not the same as unloading. Unloading is the process to remove the completion or other fluid from the well’s annulus. Once this fluid is removed from the annulus, the check valves in the gas-lift valves or orifices should prevent well liquid from reentering the annulus. Therefore, when a well must be restarted (kicked off), it is not necessary to remove liquid from the annulus unless one of the check valves is leaking. For single-string gas-lift, the kickoff process is simple. Normally, the gas is turned back on to the well at the desired injection rate and the well is left to kick off and restart on its own. The following situation needs to be considered for dual wells.

Often when a well has been off production for a period of time, a fluid level rises in the tubing. If the well is off production long enough, it may rise to the depth where the pressure at the bottom of the fluid column is equal to the static reservoir pressure. This liquid column in the tubing may exert a pressure in the tubing that is higher than the gas pressure in the annulus, especially at some of the deeper gas-lift valves. When this occurs, gas cannot be immediately injected at the desired operating depth. The well must once again worked down to the desired depth.

6.6.2 Kicking Off When Both Zones Are Restarted

When both zones have been off production and require restarting, there are two options: start both zones at the same time, or first start one zone, then the other. Normally, the recommended approach is to start the better of the two zones first. The better zone should reestablish lift from the desired deepest depth before restarting the other zone. When the first of the two zones is kicked off, the process is essentially the same as for a single-string gas-lift well. The challenge arises when the other zone is restarted.

When the second zone is started, the gas-lift injection rate should be increased to the amount needed by the two zones. At this point, there is nothing to prevent some of the added gas from being injected into the first zone. It may be injected into some of the upper unloading valves in the first zone and cause that zone to begin multipointing and become unstable. This will not only be bad for the first zone; it may inhibit effective kick off of the second zone. To minimize this problem, the RP is to use chokes in the unloading valves. The chokes will help limit the amount of gas that can be injected into the first zone’s unloading valves. This is only pertinent where IPO valves are used for unloading.

6.6.3 Kick Off Both Zones at the Same Time

If it is desired to start both zones at the same time, the total gas-lift injection rate should equal the total required for both zones. This approach is not recommended. If for some reason most of the gas is taken by one side of the dual well, it may never be possible to successfully work both zones down to their desired operating depths. If the SBHPs of both zones are lower than the gas-lift injection pressure, it will be necessary to open both zones at the same time. Otherwise, the side that is still shut in may take injection gas into the formation.

6.7 Operating Dual Gas-lift Wells

6.7.1 General

Once a dual gas-lift well has been successfully unloaded and/or kicked off, the easy part is over. Now the well must be operated successfully over the long term. There are many aspects to successful operation of a dual gas-lift well.

6.7.2 Keeping Both Zones on Production

6.7.2.1 General

Because starting and/or restarting a dual gas-lift well can be difficult and time consuming, the first goal should be to keep both zones on production as much of the time as possible. Even if there are upsets in the gas-lift system, such as a compressor shutdown, the dual gas-lift wells should be kept on production if possible. The next objective, or set of objectives, is to keep both zones lifting deep, stable, and at their individual optimum injection rates.

6.7.2.2 Depth of Lift

Deep lift is, of course, relative to the conditions of the well. Each zone should be lifted as deep as possible, considering its reservoir pressure, reservoir productivity, fluid gradient, physical integrity, etc. The primary surveillance strategy should be designed to determine if the well is lifting from its desired lift depth. If it is not, then steps should be taken to correct the lift depth.

6.7.2.3 Stability

Stable lift, with a stable injection rate and pressure and a stable production pressure, is always more efficient than any alternative. The second surveillance strategy should be to detect any instability. If the well is unstable, the cause(s) of the instability should be determined and corrected.

6.7.2.4 Optimum Injection Rate

Once a well is lifting deep and stable, an effort can be undertaken to inject the optimum rate of lift gas. This can be especially difficult on a dual gas-lift well since the injection gas can go into either string, unless the operating gas-lift valves or orifices are properly designed. Determine the correct amount of gas to inject into the well to gas-lift both zones. This depends on the gas-lift designs, the design of the operating gas-lift valves or orifices for both zones.

6.7.2.5 Controlling the Correct Gas Injection Rate

Once the correct gas-lift injection rate is known, this rate should be maintained. The best way to do this is with a method for gas injection control where the rate of gas injection can be maintained if either the upstream or downstream pressure changes. This requires a flow rate controller or an automatic gas control valve. If a fixed choke or control valve is used, the gas rate through the device will change when either the upstream or downstream pressure changes. This changing rate will have an impact on the operation of the well.

If the gas injection rate is controlled by a flow rate controller or automatic control valve, the rate can be held constant, even in the face of upsets in the gas-lift distribution system. If a fixed choke or valve is used for control, the rate will change if there is a system upset.

6.7.3 Inject at the Correct Pressure

For correct gas-lift operation, the gas should be injected at the design pressure. It can only be achieved by the design and operation of the gas-lift system. To maintain the gas-lift system pressure at the correct value, the total gas flow rate out of the system and into the gas-lift wells should be kept in balance (equal to) the total gas rate into the system from the various sources of gas. There are automatic gas-lift system control strategies that can be used to assure this pressure stability.

6.7.4 Operation When One or Both Zones Are Under Test

When a well is being tested, it is especially important to keep the gas-lift operation of the well stable. Therefore, especially during well testing and pressure surveys the gas-lift injection rate and pressure should be held as constant and steady as possible.

6.7.5 Operation During Pressure Surveys

Just as with operation during a well test, it is especially important to maintain stable operation when pressure surveys are being run.

6.7.6 Manual Operation

If gas-lift injection control is manual with a fixed choke or valve, the recommended approach is to set the injection rate close to the “optimum” injection rate when the system pressure is stable. It will not be possible to maintain this rate during upsets, but during “normal” operation the injection rate will be close to correct.

6.7.7 Semiautomatic Operation

Semiautomatic operation occurs when a manually set flow rate controller is used to control the gas injection rate. The controller will maintain the gas injection rate at the desired value, even when there are upsets. To change the injection rate, the injection set point of the controller must be manually changed.

6.7.8 Automatic Operation

When automatic operation is used, the gas-lift injection rate can be changed automatically if required when the system changes. If possible the injection should be held constant at all times, even in the face of system upsets. But if changes are needed, they are made quickly.

6.8 Dual Gas-lift Well Optimizing

6.8.1 General

Often when a dual gas-lift well lifting is successfully from both zones, attempts to fine tune or optimize the operation are not performed. However, there can be significant benefits from optimization.

Optimization of a dual gas-lift well essentially requires separate optimization of both sides of the dual, which can be difficult to achieve. The primary steps are:

a) achieve deep, stable lift in both sides of the dual;

b) determine the optimum injection rate for each side of the dual;

c) devise some practical means to inject the optimum rate (or a rate close to optimum) into each zone.

6.8.2 Determination of Optimum Injection Rate

The normal process to determine the optimum injection rate for each zone is described. Another way to do this empirically is a multirate well test of each zone. A multirate test is conducted as follows.

a) Close in one side of the dual gas-lift well.

b) Conduct a well test on the other side of the dual.

c) Conduct the test for long enough to measure the injection rate and associated production rate.

d) Then change the injection rate and conduct another test or another segment of the multirate test.

e) Continue this process until three or more data points of production rate vs injection rate have been determined.

Plot these on a plot of production rate vs injection rate. This becomes a gas-lift response curve that can be used to determine or estimate the optimum injection rate as shown in Figure 2. It is normally possible to determine the optimum injection rate for each zone, where a stable flowing and static pressure survey can be run, or if an accurate multirate well test can be conducted. However, it is generally not possible to inject gas into each zone at the optimum rate. The reasons for this are as follows.

— It is very difficult to accurately control the injection rate into both sides of a dual, since one side may naturally take more or less gas than desired.

— The amount of gas available for injection into the wells served by the gas-lift system will rarely be equal to the sum of the optimum rates for each well. So, the available amount of gas should be apportioned to the wells, with the goal of injecting each well as close to its optimum as possible.

When considering the allocation of gas to a well, it is important to know the range of injection rates—the plus and minus range about the optimum injection rate. The rate should not be too high or low as this can be inefficient and cause heading. As part of the optimization process, it is important to determine the acceptable range of injection.

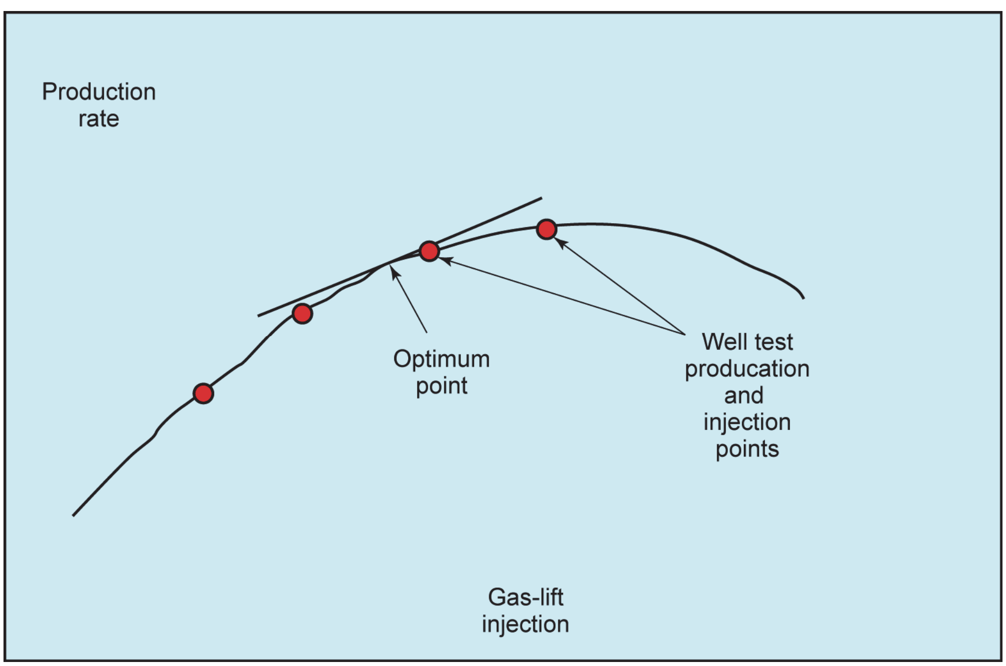

Figure 2—Gas-lift Response Curve

6.8.3 Allocation of Lift Gas (Staying Near Optimum)

6.8.3.1 General

When the optimum injection rates are known for both sides of the dual, two important considerations remain:

a) injecting a rate into the well that is not too little, not too much, and close to the sum of the optimum injection rates for the two zones;

b) devising a means to assure that the correct amount is injected into each side of the dual.

6.8.3.2 Injecting the Desired Rate

The desired injection rate is the sum of the optimum injection rate into the two sides of the dual. If there are both single and dual gas-lift wells being served by a single gas-lift injection system, and it becomes necessary to adjust the injection rate into some of the wells to keep the system in balance, it is preferred to adjust the single wells and hold the dual wells constant.

If there is a flow control capability that is automatically set, the injection rate can be controlled to the desired rate. If the injection rate is controlled manually, the recommended approach is to set the injection rate as close as possible to the sum of the optimum rates for the two sides of the dual.

6.8.3.3 Controlling the Gas-lift Rate for Each String

The control of the desired rate of injection into the well is expected; however, it can be difficult to assure that the desired rate is injected into each side of the dual. The recommended approach is to design the operating gas-lift valve, orifice, or nozzle venturi orifice to inject the desired rate at the expected condition of injection and production pressures. This can be difficult to achieve with a gas-lift valve that throttles or with a square edge orifice, since the rate can change significantly depending on the upstream and downstream pressures. This control can potentially be achieved with a nozzle venturi orifice since it operates in the critical flow regime when the downstream pressure is less than 92 % of the upstream pressure. If the upstream pressure is known and the downstream pressure can be kept at less than 92% of this amount, the rate can effectively be controlled.

7 Dual Gas-lift Well Surveillance

7.1 General

Surveillance is the process of continually, or frequently, checking on the operation of a well to be assured that it is operating correctly. If it is not operating properly, determine the cause(s) of the problem(s) so they can be addressed. Any problem left undetected and/or uncorrected can lead to production deferment, wasting of injection gas, and possibly serious damage to the well and or to other wells in the system. The most common dual gas-lift surveillance practices are as follows.

7.2 Wireline Operations

Side-pocket mandrels and conventional mandrels are built with full-bore tubing ID. This provides the operator the convenience of utilizing conventional slick line and electric line tools as needed. When running wireline tools in wells through side-pocket mandrels, the operator should be aware of the possibility of sitting down on the latch of the gas-lift valve.

Deviated wells should be completed with orienting style side-pocket mandrels that have orienting sleeves to align the gas-lift valves within the pockets when running or pulling valves. These orienting sleeves are equipped with tool deflectors that are designed to deflect larger wireline tools away from the latch and allow equipment to by-pass the mandrel without risking damage to the latch. If it is necessary to bypass mandrels with tools that have a smaller diameter than the tool deflector, it should be done with great caution.

7.3 Pressure/Temperature Surveys

7.3.1 General

Two of the most useful tools for diagnosing and troubleshooting dual gas-lift completions are pressure and associated temperature surveys. The SBHP survey can identify a potential cross-flow problem during gas-lift valve change outs. A flowing pressure/temperature survey can indicate the depths of gas injection on the side of the well in which it is performed and can also identify leaking gas-lift valves within the gas-lift string. FBHP information can help determine the productivity of the well by measuring the amount of pressure drawdown at the perforations.

Some production operators are reluctant to run pressure surveys, especially under flowing conditions. The fear of losing wireline tools in the well and the possibility of losing the well altogether are major concerns. But the information gathered from static and flowing surveys can be valuable when troubleshooting an existing gas-lift design or in proposing a new string of gas-lift valves. Detailed RPs for running pressure surveys are included in API 11V5.

7.3.2 SBHP Survey

A SBHP survey is straightforward. The gas-lift injection is stopped and the casing and tubing pressures are allowed to bleed down. The well is shut in for a predetermined amount of time. The measuring device is run to the perforations, if possible, and kept on bottom for a predetermined amount of time. Then stops are made coming out of the hole to determine the fluid gradient in the wellbore. At least four stops, at least 121.6 m (300 ft) apart vertically, are recommended when pulling out. This is to measure the static pressure gradient and to determine if there is an oil/water contact in the well.

Some production operators are uncomfortable with running a pressure measurement device below the end of the tubing, especially for the upper zone of a dual gas-lift well. If the pressure measurement device cannot be run to the midpoint of the perforations, the static reservoir pressure can be determined by extrapolating the static pressure profile from the bottom measurement depth down to the midpoint of the perforations. The static pressure gradient can be extrapolated up-hole to determine the height of the static fluid column when the well is off production. This is valuable information to have when the well must be kicked off (restarted).

7.3.3 FBHP Survey

The performance of FBHP surveys requires care; due to limitations on the length of the wellhead lubricator, the wireline tool string may not be long enough to incorporate the stem weight to offset the upward flow of the well. If this is the case, an alternative approach is to temporarily shut in the well, run the pressure measuring device to bottom, and then open the well back to production Once the well has stabilized and is performing normally, stops are made coming out of the well, preferably below and above each gas-lift mandrel. Stops are made below the mandrels, in case a gas-lift valve suddenly opens, allowing a surge of gas into the wellbore and possibly blowing the tool string up the hole. A lightening of the pressure gradient from below to above a mandrel and cooling “spikes” in the temperature trend are indicators that gas is entering at a particular gas-lift mandrel.

If the well must be stopped to run the flowing pressure survey, the static pressure survey should also be run while the well is stopped. Also, it can be difficult to restart a dual well and return it to its “normal” operation. Therefore, stopping a dual well should be avoided unless it is absolutely necessary. When these flowing surveys are taken, it is important to stop the measurement tool at each depth long enough for the temperature device to stabilize to the temperature at each depth. Also, if the well is heading or surging, it is important to stop it for at least as long as the period of the pressure fluctuation.

7.3.4 Memory Production Logging Tools

Conventional pressure surveys require that the wireline operator note the time of each wireline stop, so the time can be correlated to the wireline depth, thus providing a graphical representation of depth vs pressure. The problem with this information is that it is a snapshot representing an instantaneous pressure at an exact moment in time, at a certain stop depth.

The pressure information between stop depths is also important during a flowing pressure survey. On a conventional flowing pressure survey, a slugging well may appear to show that every gas-lift valve is opening, as the survey records a gas slug from below as it passes the pressure measurement device as it is recording pressure at a stop just below a gas-lift mandrel. Since no survey tool can provide a snapshot of pressure information along the entire wellbore at any given instant in time, the next best thing is to have wellbore pressures for the entire length of the wellbore. Previously this involved electric line surveys; now the memory production logging tool is available.

This memory tool incorporates a casing collar locator, density, pressure, temperature, and spinner rate tools. Data are stored in the tool's memory and downloaded at the surface after the survey is run. These data are correlated back to measured depth and is presented in an electric line log format. Temperature anomalies can be verified with the spinner or density tools to prove or disprove gas injection at mandrel depths. Slugging can be easily identified and differentiated from mechanical problems (i.e. bad gas-lift valve) or as a result of cross-flowing between multiple production layers within the wellbore. The quick response of the tool does not require stops within the wellbore.

7.3.5 Practices for Running Pressure/Temperature Surveys

The following are recommended for running pressure/temperature surveys.

a) Pressure/temperature surveys should be run frequently.

b) A flowing pressure/temperature survey should be run at least once a year to evaluate the well's gas-lift performance. A well test should be conducted in association with the survey.

c) A static pressure and an associated FBHP survey should be conducted when the well, or one side of the well, must be closed in for some reason. Use this to evaluate the well's inflow performance and to calibrate the vertical two-phase pressure model.

d) A well test should be conducted in association with the survey run in accordance with API 11V5.

Consider running a memory production logging tool to obtain continuous pressure information across the well's entire depth.

7.4 Evaluating with Pressure/Temperature Surveys

7.4.1 General

There are two fundamental reasons for running pressure surveys. To evaluate the well's productivity, and to diagnose/troubleshoot its gas-lift performance, flowing surveys with gradient stops are also performed to match the well's flowing gradient to a flowing correlation for computer modeling and optimization.

7.4.2 Determining the Well's Productivity

The productivity of the well can be described with either a straight-line productivity index (PI) or by using an inflow performance relationship (IPR) curve. The IPR relationship is the more accurate way of describing the reservoir's feed-in ability, but the PI can be sufficient in wells producing above the bubble-point pressure or wells that produce mostly water. Data for developing these are obtained by running BHP surveys. When running the flowing pressure survey, special care needs to be taken to ensure the well is flowing at its normal stabilized rate. If any wireline work is required to prepare for running the BHP instruments, it is a good practice to complete this work the day before the survey is run, thus allowing the well plenty of stabilization time. When recording the static pressure, the shut-in time should be long enough to record true static conditions of the reservoir. It is important to measure the producing rates of the well while the flowing BHP is being run.

The PI of the well can be calculated by measuring the flowing and SBHPs with the well on test. A pressure buildup is not required when a PI is used to describe the reservoir in-flow. This makes using the PI approach easier since accurate pressure buildup surveys are difficult to obtain. When stabilized conditions exist while measuring the flowing and static pressures, it does not matter which is measured first.

If a more accurate reservoir model is needed, a pressure buildup survey can be conducted so that permeability and skin values can be obtained for developing an IPR model. This IPR will be useful in total well optimization as a more accurate flow rate can be modeled for reservoirs producing below the bubble point. And with a known skin value, the well can be analyzed for stimulation.

Obtaining an accurate pressure buildup in gas-lift wells is difficult since during the initial shut-in some additional gas will be entering the tubing through the operating gas-lift valve and will result in inaccurate early data. Additional complications to the buildup data will occur if unloading gas-lift valves (typically PPO) reopen during the buildup survey. Since the PPO valves are primarily tubing pressure sensitive, reopening of the unloading valves is expected as the tubing pressure is building up. A shut-in device is recommended to obtain a pressure buildup with PPO valves. It, it should be set below all mandrels to prevent valve interference.

7.4.3 Diagnose/Troubleshoot Performance

To diagnose and troubleshoot gas-lift performance, flowing surveys can be run measuring the well's flowing pressure and temperature gradient. This can be done with either the pressure/temperature logging tools that take frequent readings while running in the well at a constant speed or by taking gradient stops at predetermined depths. The survey should be run while measuring the production rate and gas injection rate. It is a good practice to monitor the well's injection pressure and tubing pressure during the procedure for analysis of heading. A production automation system graph or two-pen chart recording these parameters during the survey procedure will add confidence to the final diagnosis.

There is some risk in running a wireline tool string in the well while it is producing. To minimize the risk, a tubing or collar stop is placed at the bottom of the tools string. This will prevent the tool string from falling out the end of the tubing in the event of a lost tool string. A stop should always be run when the survey is in the short string.

An anti-blowup tool should also be included in the tool string to prevent the tools from being blown up the hole in the event of high velocity in the flow stream. The highest velocity in the tubing will be near the surface where the pressures are the lowest. Extra attention should be paid to the weight indicator at the shallow locations. If the tools do not freely travel down the well, the survey should be stopped and more weight added to the tool string. Choking back the well to allow the tool string to fall freely is not recommended. Although choking the well will decrease the velocity of the flow stream, it also increases the flowing tubing pressure. This places the well flow outside of normal conditions and could lead to inaccurate conclusions.

Flowing surveys may be run using continuous logging tools. This method is ideal for determining points of gas injection and locating leaks in the gas-lift valves or even tubing leaks. A collar locator can be added to the tool string to provide accuracy in the location of any leaks that may be identified. The best results are obtained when the well is lifting in a stable manner. Since the readings are being recorded at a rapid interval while running in the well, any heading that occurs during the survey can lead to inaccurate results. An added benefit of this method is that cross-flow between dual completions can sometimes be detected. If cross-flow is suspected, the survey can be designed specifically to diagnose and locate the depth of the cross-flow.

Flowing surveys may be run using gradient stops. Taking gradient stops at predetermined locations are required when a slow responding pressure or temperature element is used. The main drawback in using this procedure is that leaks occurring in between gradient stops can go undetected. Using gradient stops is usually the preferred method whenever a well is heading severely and the heading cannot be smoothed out with surface adjustments. When this type of heading is occurring, the time cycle of the heads should be known to design the survey procedure. Each gradient stop is made for the duration of one heading cycle. The pressure and temperature information is then analyzed using minimum, average, and maximum readings at each gradient stop. Analyzing the data from a heading gas-lift well is difficult, and an accurate diagnosis is not always possible.

7.5 Fluid Levels

7.5.1 General

Use and analysis of the fluid level in the annulus is very common in pumping wells. Since a packer is normally not used in these wells, the fluid level can be used to indicate both the static reservoir pressure when the well is not pumping and the flowing or operating BHP when the well is pumping. A production packer, or more than one packer, is used in the vast majority of gas-lift wells. Therefore, the fluid level is not as useful; however, it can provide valuable information.

7.5.2 Maximum Depth at Which Well Has Been Unloaded

One important piece of information is the maximum depth to which the well has been unloaded. If there are no leaks between either production tubing string and the annulus, and if the upper dual packer is not leaking, the static fluid level provides an indication of the deepest point at which the well has been unloaded, and therefore, the bottom of the gas column when the well is on gas-lift. Hopefully, the static fluid level will be at the depth of the bottom gas-lift mandrel in the long string, or the tubing string with the deepest mandrels. If it is not, there may be a leak or the well may not have been fully unloaded.

7.5.3 Checking for Leaks

If the static fluid level is not at the depth of the deepest mandrel or at the depth of the deepest “operating” mandrel, and if gas-lift valves are not installed at the bottom, then there may be a leak. The static fluid level will not define where the leak is, as fluid entering into the annulus from a leak will collect in the deepest part of the annulus. In this case, the fluid level may provide an indication of the amount of fluid that has entered the annulus, but not necessarily where the fluid originates. This may be determined by evaluating the sonic pressure trace made by the fluid level detection instrument. Analysis of the sonic pressure trace may indicate the leak location.

7.6 Well Tests

7.6.1 General

There are several options or approaches when conducting well tests on dual gas-lift wells. Specific objectives for each approach are described.

7.6.2 Testing Either Well, with the Other Producing

The typical approach is to test each well (side of the dual gas-lift well) with the other side on production. Dual gas-lift wells should only be stopped when absolutely necessary. This minimizes disruptions to each zone; it also provides information on how each side of the well normally produces. If a flowing pressure survey is being run to evaluate the performance of a dual gas-lift well, this test should be run in conjunction with the pressure survey. The objective of this test and survey is to understand and diagnose the current operation.

7.6.3 Testing Each Well, with Other Well Shut In

When information is needed on the productivity of each side of a dual gas-lift well, it may be necessary and prudent to close in the other zone while testing one zone. When the other zone is closed in, the zone being tested can be treated and analyzed as a single-string well. When a well is being tested to determine its productivity, the well test is conducted in conjunction with a static and flowing pressure survey. It is very desirable, to have the well producing in a stable manner. To stabilize the well it may be necessary to temporarily choke the well, or temporarily increase the gas-lift injection rate. This process is discussed in API 11V5.

When a stabilized well productivity test is being run, every effort should be made to conduct an accurate well test, with accurate measurements of oil, water, and gas production, and gas-lift injection. With only one side of the dual on production, it is certain that all of the injection gas is going into the well on test. If there are accurate measurements of the injection gas and the total produced gas, the formation gas production rate can be calculated by subtracting the injection gas from the total produced gas. Also, if an accurate flowing pressure survey is run in conjunction with the well test, the vertical multiphase pressure model can be calibrated for the conditions of the well. This calibration process is described in API 11V5.

When there is good information on each zone's productivity and when the pressure model has been calibrated for both zones, this information can be used to predict the well's performance under various gas-lift design and operating conditions. Changes to the well design and operation can be evaluated.

7.6.4 Parallel Testing Both Wells

A third potential type of well test is to test both sides of a dual well at the same time, in the same well test separator. The only reason for this type of test is to measure the total production rate from the combined zones. This may be necessary if there is reason to expect that the actual total production rate is different than the sum of the tests of the two zones when they are tested separately. If this is the case, this combined test may be necessary to more accurately allocate production to the two sides of the well.

7.7 CO_2 Tracer

7.7.1 General

A CO_2 tracer survey can be an incisive way to evaluate gas-lift performance in both single and dual gas-lift wells. A small slug of CO_2 is injected into the injection gas stream. The time between when the CO_2 is injected and it returns to the surface in the production tubing is measured. By knowing the gas injection rate, pressure, and temperature, and the size of the annulus, the depth of the gas injection into the tubing can be determined. Also, multipoint gas injection can be detected. Uses of this technique are discussed in this section.

7.7.2 Determining the Highest Injection Point

By measuring the time for the CO_2 slug to return to the surface, in both zones of the dual, the depth of the shallowest injection in both zones can be determined. If the well is operating as designed, these depths of injection should be close to the same depth. If injection in one zone is significantly higher than in the other zone, this may indicate a leak or gas-lift valve problem in the zone with the shallow injection.

7.7.3 Determining if Either Side Is Multipointing

If either side of the dual is multipointing, i.e. if gas is being injected into the well through more than one gas-lift valve or through a valve and a leak, this should be readily apparent with the CO_2 survey. Confirm this with a second CO_2 run or with a flowing pressure/temperature survey. If it is suspected that gas is being injected through more than one gas-lift valve or if the well is multipointing, pull the valves and redesign them to permit working below them to the desired depth of lift. If it is suspected that there is a leak in the tubing, confirm the location of the leak. Either correct the leak with a pack-off valve or pull and replace the leaking tubing.

7.7.4 Determining the Depth of Lower Injection Point(s)

It may be difficult to determine the depth of lower injection point(s) because the gas velocity in the annulus below the top injection point is not known. This is complicated in a dual gas-lift well, where some of the gas is entering one side of the dual and some is entering the other side.

7.8 Continuous Monitoring and Control

7.8.1 General

Much can go wrong with a dual gas-lift well; any time the well is not performing as desired, with deep, stable, optimum gas-lift on both sides of the dual, production is being deferred and injection gas may be wasted. Upsets that can have a negative impact on that well and on other wells in the gas-lift system may be occurring.

For dual gas-lift to be successful, the operating gas-lift injection rate and pressure should be consistent with the gas-lift valves and system design. It should be controlled for stability, even in the face of various types of gas-lift system upsets. The axiom of control is that for any variable to be correctly controlled, it should first be accurately measured. This method supports continuous monitoring (and measurement) of each well to detect any operating problems so they can be addressed rapidly. There are various methods for continuous monitoring and control; some require more work initially, and others are harder to maintain.

7.8.2 Methods of Continuous Monitoring

The primary methods of continuous gas-lift monitoring that are covered in this RP are manual methods (not recommended), chart recorders and manual chokes or valves, electronic measurements and flow controllers, and production automation systems. Production automation is covered in more depth in Section 8.

7.8.3 What to Monitor

The primary recommendation on "what to monitor" is to monitor just enough for effective surveillance and control. Any monitored item requires that a detection or measurement device be installed, calibrated, maintained, and checked.

Based on experience, the minimum items that need to be continuously monitored for effective surveillance and control include:

— gas injection pressure,

— gas injection rate,

— production pressure on both sides of the dual,

— the item that needs to be controlled is the gas-lift injection rate.

With these items, most dual gas-lift problems can be detected. Further measurements such as well tests, pressure/temperature surveys, CO_2 surveys, fluid levels, etc., may be required to fully diagnose the cause of a problem once it is detected; however, these items are sufficient for routine surveillance. Some production operators also measure:

— gas injection temperature, when this is necessary to compensate the gas injection rate measurement;

— production temperature and use of this as a way to detect changes in liquid production rate;

— production rate of liquid where this can be measured with a multiphase meter or estimated with a technique such as the differential pressure method;

— downhole pressure, temperature, and/or gas injection rate via a surface-controlled gas-lift valve installation.

Some production operators use special devices that are designed to provide gas injection measurement and control in one system. The system includes a method to measure the gas injection pressure, the temperature, and the rate by measuring the differential pressure across a control valve (basically a variable orifice). It contains flow control logic so the injection rate can be maintained to the desired injection rate set point. In addition to these items on each well, there are certain items that need to be monitored/measured on the gas-lift system. The most important are as follows.

— *Gas-lift System Pressure*—An important goal is to maintain the system pressure as constant and stable as possible.

— *Gas-lift Rate Available for Injection*—To keep the gas-lift system stable, the system should be kept in balance. To do this, the total injection rate into all of the gas-lift wells served by the system should be maintained equal to the total source of gas into the system.

7.8.4 Manual Methods

The manual method of surveillance is typically based on periodic well tests. If the well test shows the anticipated results, the well is assumed to be operating properly. If the well test is abnormal, troubleshooting is required to determine the cause(s) of the problem. This method is not recommended, as it does not provide the timeliest surveillance of dual gas-lift well performance.

7.8.5 Chart Recorders and Manual Control Valves

Chart recorders and manual control valves or orifices have been the normal method for gas-lift monitoring and control for many years. If there is sufficient staff to routinely install, maintain, and analyze/evaluate the information on the charts, and to keep the manual control valves/orifices properly set, this can provide acceptable performance. However, it is often difficult to keep them functioning properly and it is usually not feasible to keep the gas-lift system stable and in balance, since there is limited time to respond to upsets. If sufficient staff cannot be assigned, this method is not recommended.

7.8.6 Electronic Measurements and Flow Controllers

The use of electronic measurements and flow controllers is a step up from charts and manual control valves. This method provides gas-lift injection rate and pressure and production pressure to be measured and recorded electronically and potentially transmitted into a computer system for analysis. Gas-lift injection rate set points can be loaded into a flow controller, and the desired injection rates are maintained during system upsets. If a compressor goes down, more controls may be needed to maintain the system pressure. For example, it may be necessary to temporarily close in some wells to avoid “starving” all of the wells.

7.8.7 Production Automation Systems

The preferred approach for continuous dual gas-lift monitoring and control is a production automation system. Here the measurements are made continuously, and the control set points can be updated remotely by an operator or automatically by the automation system if/when appropriate. Production automation systems offer many advantages for effective dual gas-lift surveillance and control. These are discussed in more detail in Section 8.

7.8.8 Optimum Monitoring Frequency

When dual gas-lift wells are monitored/measured with electronic measurements and/or with a production automation system, the optimum frequency for these measurements is once per minute. This frequency has been determined based on extensive testing of both more and less frequent measurement periods. If the measurements are taken less frequently, some important gas-lift phenomena such as heading or multipointing may be obscured. If they are taken more frequently, data are generated that does not add value.

NOTE For intermittent gas-lift, it may be necessary to monitor the variables more frequently to optimize the size and period of individual gas-lift injection cycles. However, since intermittent gas-lift is rarely considered with dual gas-lift wells, this is not a major consideration.

7.8.9 Using Monitoring Information

In many production operations, much more information is collected than can be effectively used. This is true for charted or electronic data. An effective approach to this is the use of exception reporting. This can work well with a production automation system if it is programmed to provide this service. The system reviews all of the information and uses it to check for alarm conditions, inefficiencies, etc. It then reports problems or inefficiencies for further review. Another important use of monitored information is for checking and calibration of gas-lift models against theoretical values for these predicted by the gas-lift models.

8 Dual Gas-lift Diagnosis and Troubleshooting

8.1 General

This section provides specific examples and case histories of successful (and unsuccessful) diagnosis and troubleshooting of dual gas-lift operations. The primary information from this section includes details of methods and systems that have worked for others, and if something does not work, it is necessary to understand why.

8.2 Diagnostic Techniques

8.2.1 General

The process of surveillance gathers pertinent information to find problems with the wells, so these problems can be corrected. There are several diagnostic techniques and troubleshooting to determine their causes. The actual cause(s) of problems require identification before they can be solved.

8.2.2 Library of Typical Problems

8.2.2.1 General

A technique to help determine the cause(s) of problems is to compare appropriate measures of a dual gas-lift well's current performance with a library of comparable measures taken from wells with typical problems that have been diagnosed and analyzed by experts. These cases are usually normalized so that wells of different depths, tubing sizes, etc., can be compared with the library of cases. Data from current dual gas-lift wells are then collected, normalized, and compared with the library of cases.

For a dual gas-lift well, the appropriate measures also include:

a) a plot of injection pressure and the two tubing pressures vs time;

   NOTE These can be on either a circular or a linear chart.

b) a plot of the flowing pressure surveys for both zones, plotted on the same axis.

8.2.2.2 Library Management Software

Software is available to manage the library and perform the matches. Operators should consider providing typical problem cases that have been analyzed.

This technique works as follows:

a) when a new appropriate measure is taken, it is automatically normalized and compared with the cases stored in the library;

b) the software creates an exception report of the best match(es);

c) the gas-lift analyst can focus on the specific problems to analyze the cause(s) of the problems.

8.2.3 Comparison with Two-pen Chart Recorders

For dual gas-lift wells, this comparison needs to be made with "three-pen or four-pen" charts (or linear plots of automatically gathered data) since the information of interest includes the injection pressure, the production pressure from both zones, and the injection rate. Just as with similar plots for single gas-lift wells, there are many typical shapes of these plots that can indicate typical problems including:

a) heading, in one zone, the other zone, or both zones;

b) injecting shallow in one zone and deep in the other;

c) one side taking all (or most) of the gas;

d) gas freezing;

e) and many others.

8.2.4 Comparison of Flowing Pressure Surveys

For comparison purposes, flowing pressure surveys need to be taken on both sides of the dual well. The two surveys are normalized by plotting them on the same pressure/depth axis. This plot can be compared with cases stored in the library. Just as with the two- or three-pen charts, this can provide valuable clues. Comparison with the library of information adds more insight. With these plots, one can usually determine the depth(s) of lift on both sides of the dual and detect leaks or cross-flow between zones. If the well is stable when the surveys are conducted, these plots can also determine the operating (flowing) BHP and can be used to calibrate the mathematical model of the vertical pressure profile.

8.2.5 Measurements of Well Performance

8.2.5.1 General

The desired performance of a dual gas-lift well is to have both zones lifting from deep in the zone, with stable injection and production pressures and optimum injection rates. In addition, it is desired to have the wells' inflow performances both known and stable. Therefore, the desired measurements of well performance that can be determined from the above charts and surveys are as follows.

8.2.5.2 Gas-lift System Performance

The depth of injection, and the stability or instability of the well, can be determined by examination and analysis of the "two- or three-pen" chart data and the flowing pressure survey. The data from the chart should be analyzed by using a vertical multiphase pressure profile program and gas-lift valve performance data. The information from the pressure survey can provide a direct indication of the depth of injection, by noting the depth where the pressure profile changes slope (see Figure 3).

8.2.5.3 Well Inflow Performance

The well's inflow performance can be determined from the FBHP, the SBHP, and an associated well test. This can be used to generate an IPR curve or IPR for the well. This calculation should be performed each time flowing and static pressure surveys are run. The IPR curve from this analysis should be compared with the curve from the previous surveys, to determine if the well's performance has changed (see Figure 4).

8.2.5.4 Gas-lift Response Curve

When an IPR curve has been developed, a well's gas-lift response curve can be generated. This is a plot of production rate vs injection rate. It can be used to determine the optimum injection rate (see Figure 5).

8.2.5.5 Optimum Injection Rate

Once a well's gas-lift response curve has been generated, the optimum gas-lift injection rate can be determined. It is the injection rate at which the benefit derived from the addition of one more unit of injection gas is less than the additional injection. There are computer programs to calculate this value.

8.2.6 Calibration of a Gas-lift Model

If a flowing pressure survey is measured when the well has stable production, it can be used to calibrate the mathematical vertical pressure model for the well. The calibration process is performed by adjusting various immeasurable parameters until the calculated pressure profile closely matches the measured profile. The items most often adjusted to find this match are:

a) formation gas production rate,

b) effective tubing diameter,

c) gas-lift injection rate,

d) water production rate,

e) water density.

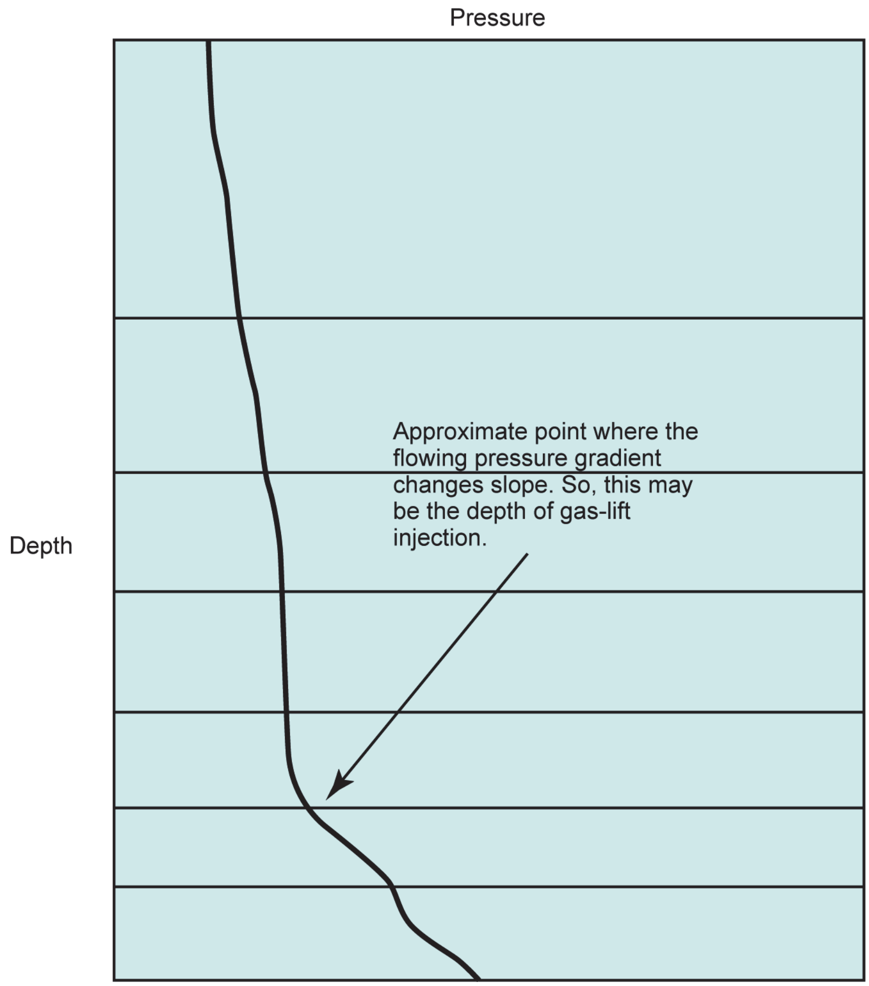

Figure 3—Flowing Pressure Survey

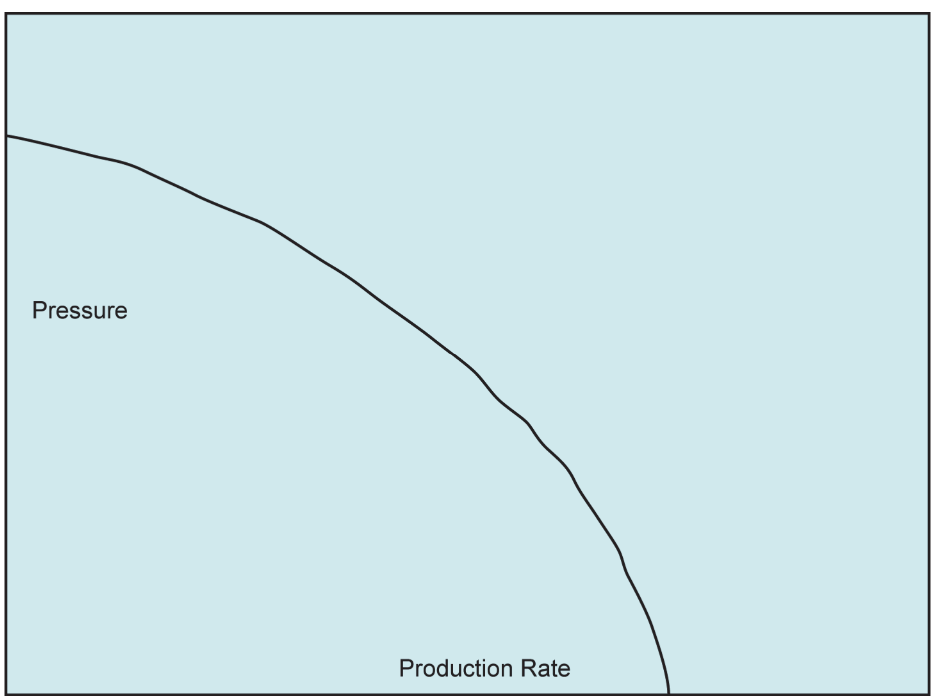

Figure 4—Inflow Performance Relationship

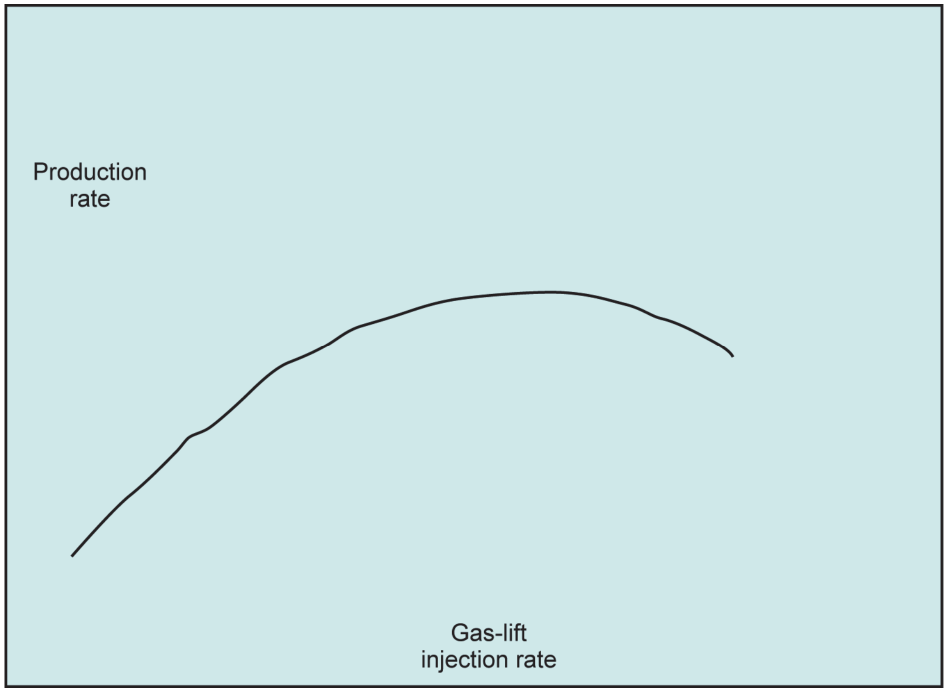

Figure 5—Gas-lift Response Curve

There are existing computer programs to perform this calibration. Once the mathematical vertical pressure model is calibrated for the well's conditions, it can be used to design and analyze gas-lift performance.

8.2.7 Comparing Current Measurements with a Calibrated Model

When the vertical model has been calibrated, and the gas-lift performance curve has been generated, a benchmark for comparing future measurements is provided. When new well tests are conducted, the calibrated model can be used to calculate the FBHP. With the current well test rates, and the most recent SBHP, a new IPR curve can be calculated and compared with the most recent IPR curve for analysis with the deviations noted.

Another comparison is to plot the current well test rate and gas-lift injection rate on the gas-lift performance curve (see Figure 6). If the point falls on or close to the curve, it can be assumed that the well is still performing as expected. If the point falls far from the curve, and is confirmed by a second well test, it can be assumed that the performance of the well has changed and it is time to conduct another flowing/static pressure survey with an associated well test.

This comparison can also indicate how close the current gas-lift injection rate is to the "optimum" injection rate determined previously. If it is not as close as desired, corrective action can be taken.

Figure 7 is another example of this curve. It shows three different well tests that indicate the well lifting from three different depths. This could possibly occur if the well is tested while it is unloading and producing from different depths during the unloading process.

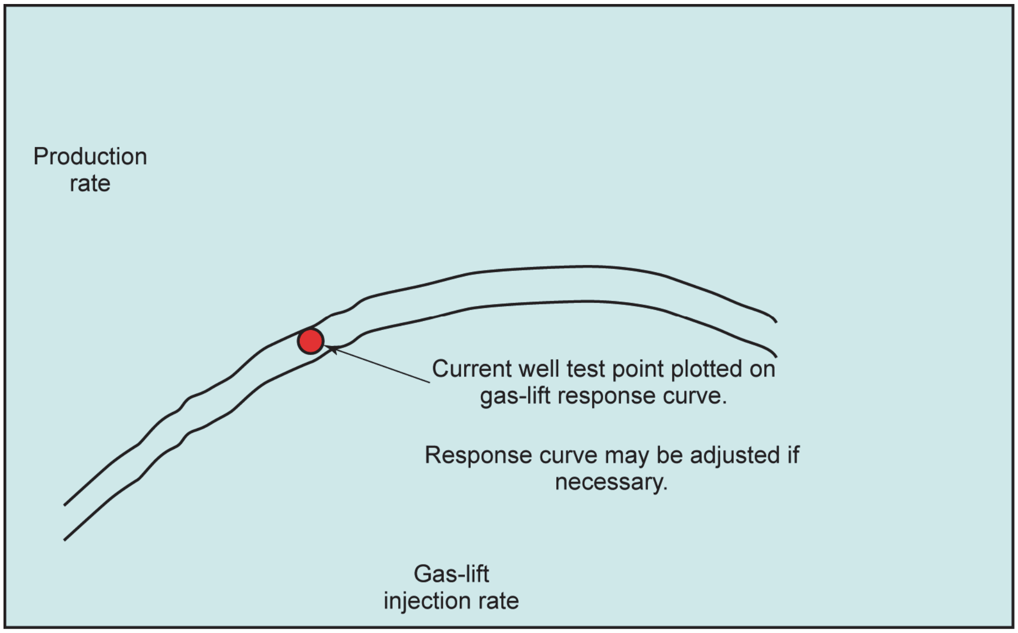

Figure 6—Gas-lift Response Curve Comparison

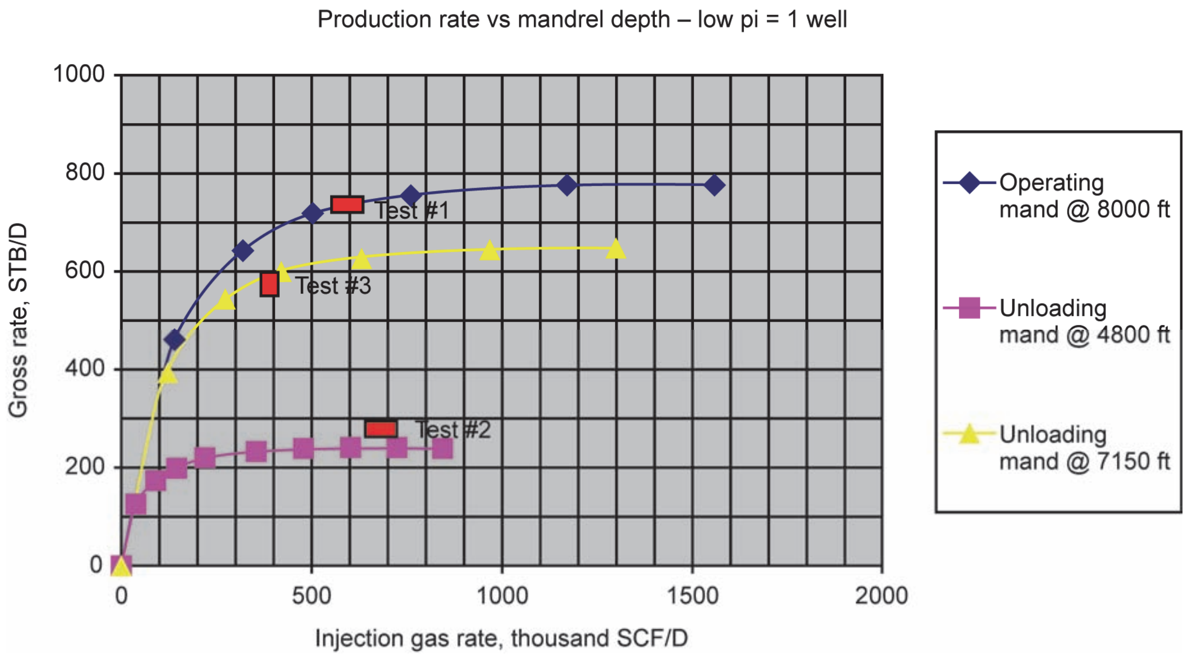

Figure 7—Production Rate vs Mandrel Depth

8.2.8 Exception Reporting of Deviations

If the surveillance and data acquisition is being performed by a production automation system, it may have the ability to provide exception reports to the gas-lift analysts. The idea of exception reporting is to report only those wells and conditions that require immediate attention. This allows the analyst to focus on the problems. When an exception is reported, it may also be possible to present pertinent information, such as the following.

a) Wells that do not appear to be lifting from the deepest possible point. Include a vertical pressure plot to indicate the likely actual depth of injection.

b) Wells that appear to be unstable. Include a plot of injection and production pressure vs time to indicate the degree of instability.

c) Wells where the apparent inflow performance has changed significantly from the last measurement. Include the most recent IPR plot and the potential change in inflow productivity.

d) Wells where the gas-lift performance appears to have changed. Include the most recent gas-lift performance plot, with the current point of production rate vs injection rate plotted on the same axis.

8.3 Locating Communication Problems

8.3.1 General

Proving good tubing integrity is one of the first steps in troubleshooting dual gas-lift wells since tubing-casing communication problems may be more common in dual wells than in single completions. In that event, troubleshooting tools such as pressure surveys, temperature surveys, and spinner surveys can lead to false interpretations of the data if communication is undetected. In any gas-lift well, communication problems can go undetected for long periods of time since casing pressure may not show the problem if the leak is deep, and other symptoms of communication can take some time to show up. An acoustic sounding device is a necessary tool for determining tubing integrity.

8.3.2 Proving Communication

The following procedure can be used to check for possible tubing communication (leak).

a) Shut in both sides of the dual at the wing valves and allow both tubing pressures to equalize with the casing pressure.

b) Connect an acoustic sounding device to the casing.

c) Connect a chart recorder to both tubing strings. A third pen recording the casing pressure is also helpful.

d) Bleed the casing pressure down as fast as possible, preferably through a 1.27 cm ($^1/_2$ in.) ball valve.

e) Monitor the tubing pressures during the bleed-down process for any signs of falling pressure.

f) Monitor the casing fluid level with the acoustic sounding device during the bleed down process.

Communication is recognized by a falling tubing pressure in either string or by a rising casing fluid level. In wells with deep communication below the static tubing fluid level, the tubing pressure can drop somewhat and then return to its original shut-in pressure or higher. This is caused by the reservoir feeding in and usually occurs after the casing bleed-down stops. A drop in tubing pressure identifies a communication problem in that string.

Wells with communication problems may not display a tubing pressure drop when the casing pressure is bled down. This sometimes occurs in wells that have communication below the tubing's static fluid level. As the casing pressure is bled down, the casing fluid level will rise due to tubing fluid entering the casing annulus at the communication point. High productivity wells will feed fluid into the tubing and through the communication point very quickly resulting in no change in tubing fluid level and no pressure change at the surface. Communication in these wells can be detected by monitoring the casing fluid level as the casing is bled down.

8.3.3 Locating Tubing-casing Communication

There are several methods for locating a tubing-casing point of communication or leak.

a) *Tubing Caliper Survey*—This is the only method for locating tubing-casing communication (leak) that will reliably locate more than one hole in the tubing. Although the caliper survey is the best method for locating holes in the tubing, it cannot locate communication occurring in gas-lift mandrels.

b) *Other Methods*—Locating the point of tubing-casing communication includes the hole finder, ponytail, spinner, and pressure/temperature surveys. These methods involve circulating either liquid or gas through the point of communication and are usually only good for finding one hole. If the tubing has multiple holes, generally the top hole is the only hole that will be located. The advantage in using these methods is the capability of detecting communication at gas-lift mandrels.

c) *Hole Finder*—This tool can be used for multiple pressure tests in different locations of the tubing without shearing off the tool string. This tool is run to the deepest point to be tested and is anchored with either a collar stop or tubing stop. Sitting down on the tool seals the tool against the tubing wall and the tubing is pressured up for testing. After the tubing is tested, equalization across the tool is achieved with a straight pull. Light jarring will then release the tool and permit it to be moved up hole to the next test depth.

d) *Spinner*—The spinner can identify more than one hole provided there is steady flow occurring at each point of communication. A collar locator is usually run with it to more accurately locate the depth.

e) *Ponytail*—Generally any strong rope can be frayed and used as a ponytail. One end is frayed, and the other end is tied to a light wireline tool string. The tool string is run slowly down hole while circulating gas or pumping water down the tubing and up the casing. The hole(s) is located when the rope is sucked into the hole and will temporarily hang up the tool string. This method is not as reliable as the hole finder since there are many things that can cause a light tool string to sit down and give a false indication of a hole. If the circulating rate is not high enough to flow the rope into the hole, no detection will occur.

f) *Pressure/Temperature Surveys*—Although these are generally run to optimize the gas-lift design, they can also be used to locate a tubing leak if the leak is taking injection during the procedure. A fast responding temperature element is necessary and a collar locator is recommended to pinpoint the holes location.

8.4 Dual Gas-lift Typical Problems

8.4.1 High Backpressure

High wellhead backpressure causes inefficient operation in any gas-lift well; this inefficiency can be greatly magnified in duals, especially when they are equipped with PPO gas-lift valves. Higher tubing backpressure prevents the upper unloading valves from closing or can cause closed valves to reopen. This causes heading and also results in shallow injection points that limit the drawdown of the reservoir. Heading problems are compounded since two production strings share the same casing. Some causes of high backpressure include surface restrictions, long flowlines, small diameter flowlines, emulsions, flowline plugging with paraffin or sand, and over-injection.

8.4.2 Low Injection Pressure

This is one of the most common causes of inefficiencies in dual gas-lift wells. When one string works with less than the designed injection pressure, that string may take the majority of the injection gas and thus rob it from the other side of the dual. With PPO, the designed injection pressure must be maintained on the casing for the gas-lift valves to properly transfer down to the well's optimum lifting depth. In some cases this problem is a result of under-injection and can be corrected by increasing the gas injection rate. If increasing the injection rate does not raise the injection pressure to the designed conditions, the well should be checked to see if the gas-lift valve port sizes were properly selected. Tubing-casing communication can also cause this problem. In duals that have been equipped with IPO valves, the low casing pressure can be a result of a cooler flowing temperature profile than the designed conditions.

8.4.3 High Injection Pressure

When a higher injection pressure than the original design conditions occurs, both sides of the dual should be tested individually to check each well's injection rate and make sure that no over-injection is occurring. In dual wells equipped with PPO valves, higher injection pressure is not always a problem since the higher pressure might allow the well to transfer to deeper injection points. This will not result in over-injection since the PPO valve is only slightly affected by the injection pressure.

8.4.4 One String with Little or No Injection Gas

One of the main reasons for one string to not take injection gas is a failed PPO valve, since this type of valve fails in the closed position, but other factors can cause the operating valve to not be open. These include low injection pressure, a lighter gas gradient in the casing than the design parameters assumed, a heavier unloading fluid gradient than the one assumed, not enough fluid head in the tubing, plugged valves, and the tubing plugging with sand, scale, or paraffin.

8.4.5 One String with Too Much Injection Gas

One string taking more injection gas than its designed rate can be caused by tubing-casing communication, leaking valves, or a gas-lift design that needs to be revised. A tubing integrity test should be run to rule out a communication problem. When the tubing integrity is proven to be good, a flowing survey is usually required to identify the problem. If the well is experiencing problems with heading, attempts to stabilize the flow should be made before running the flowing survey. Shutting in the other side of the dual and/or changing the gas injection rate may help stabilize the production rate.

8.4.6 One Shut-in String with Pressure Depletion

The SBHP of the shut-in side should be measured to make sure it is higher than the gas-lift operating pressures. If the SBHP of the shut-in side is lower than the injection pressure of the producing side, shutting in the well at a surface wing valve will result in losing injection gas into the formation. A plug will need to be set in the depleted side below the bottom gas-lift mandrel to prevent losing injection gas into the formation.

8.4.7 Tubing-casing Communication

Communication is usually recognized due to heading problems and a loss in fluid rate. Duals with a communication problem below the operating valve will sometimes show no initial symptoms. This will not last long since the formation will fill up the casing after each shut-in, and this casing fluid will be unloaded through the gas-lift valves when the well is brought back on production. Only after gas-lift valves begin to flow-cut from constantly unloading casing fluid, will these symptoms begin.

8.4.8 Wells That Produce Emulsions

Emulsions that result in higher fluid viscosities will cause a heavier flowing tubing gradient and higher flowing tubing pressures. This will frequently cause heading and reduce the gas-lift efficiency of both sides of the dual. A downhole chemical injection system can be installed to inject an emulsion breaker to control the emulsion downhole. If it is not feasible to install this system, the emulsions can sometimes be controlled by injecting an emulsion breaker with the injection gas. Chemical usage will be higher with this method as both sides of the dual will be taking the emulsion breaker with no means of control over the chemical rate of either side. Injected chemicals should be tested for compatibility with the packing and O-rings of the gas-lift valves.

8.4.9 Sand Production

If a dual well begins to make sand and it is not feasible to install sand control, it may be necessary to reduce the well's flow rate. The production rate of the sand-producing side can be reduced by lifting the well at a shallower point of injection or by lowering the gas injection rate of this side. It is important to note that reducing the gas injection rate of the sand-producer will likely require a valve revision to decrease the port sizes (or chokes) of the gas-lift valves. If the surface injection rate is reduced without making a gas-lift valve revision, the injection rate of both the sand-maker and the sand-free side will likely be reduced. And with the lower injection rate, heading or pressure surges may occur.

Installing a surface choke to control the sand production should only be considered as a last resort when other options have failed. A surface choke will affect the operation of the gas-lift valves and can create heading problems in both sides of the dual. If heading is induced with the surface choke, sand problems can be magnified even with lower production rates.

8.4.10 Other Typical Gas-lift Problems

There are a number of other typical gas-lift problems that the dual gas-lift diagnostic system should be able to detect. Most of these can be problems either with single or with dual gas-lift wells.

a) *Blowing Gas Around*—This occurs when there is a leak of some nature high in one or both wells. Gas is injected through the leak and recycles up the tubing without performing any gas-lift function. This can be detected if the gas-lift injection rate is still normal, or nearly normal, but the injection pressure is very low and the well is no longer producing fluid.

b) *Gas Freezing*—This occurs when water vapor in the gas freezes at a point of pressure (and temperature) drop. This most often occurs at a control choke or valve, if the gas has not been properly dried. This can be detected if the gas-lift injection rate has fallen very low or to zero (0), the upstream injection line pressure is high, and the downstream wellhead injection pressure is low.

c) *Well Heading*—This occurs when there are pressure (or rate) fluctuations in the casing annulus and/or the production tubing. Such heading or fluctuations can be especially detrimental in dual wells because instability in one zone can easily cause instability in the other zone. An extreme case of heading may occur when one or both zones of a dual gas-lift well are incapable of maintaining continuous gas-lift and begin to “self-intermit.” Heading can be detected by noting periodic fluctuations in injection and/or production pressure.

d) *Well Dying or Dead*—In some cases, a well may be incapable of maintaining gas-lift on a consistent basis and may be either dying (starting to cease production) or already dead (off production). This condition is detected by very low production pressure.

9 Dual Gas-lift Well Automation

9.1 General

Operators drill dual gas-lift wells to reduce overall drilling and the operators are most anxious to effectively produce both sides of a dual well. Often, these people lack confidence that automation systems will improve efficiency. This section recommends production automation practices, which can help dual gas-lift wells become more efficient.

9.2 Automation Logic

9.2.1 General

There are several effective gas-lift automation systems in use. Some of the key components of these systems include continuous processes to:

a) monitor (measure) key well parameters;

b) monitor (measure) key gas-lift system parameters;

c) provide surveillance (analysis) of this information to find problems;

d) report problems to gas-lift analysts on an exception basis;

e) control gas-lift injection into the wells to keep the gas-lift system in balance and the wells operating as close as possible to their individual optimum;

f) integrate gas-lift operations with other field operations such as well testing, production facility operations, etc.;

g) provide information and training on how to make best use of the automation system to gas-lift operators, technicians, analysts, and engineers.

9.2.2 Practices for Automation Logic

The following should be examined when considering automation logic.

a) Assume that a gas-lift automation system will be justified on every important dual gas-lift operation.

b) Take the approach that a justification must be prepared to “not” use automation.

c) Use a proven gas-lift automation system. There are several acceptable systems available.

d) Provide training to the gas-lift system operators for effective use of the automation system.

9.3 Key Measurement Parameters

9.3.1 General

There are a few key measurements that are essential on each gas-lift well and the gas-lift system. There are additional optional measurements that are warranted in some cases. These measurements should be recorded once per minute.

9.3.2 Required Well Measurements

For dual gas-lift automation, the following measurements are needed for analysis and control; therefore, they should be measured on each gas-lift well.

a) *Injection Pressure*—The surface injection pressure can be used to calculate the pressure in the well, at the depth of each gas-lift mandrel for each side of the dual. This should be measured at the wellhead, downstream of any obstruction or pressure drop device such as a control valve, orifice meter, etc.

b) *Injection Rate*—The gas-lift injection rate is controlled at the surface to provide the combined rate needed by the two sides. The rate can be measured with various devices including an orifice meter, turbine meter, etc. This can be measured at the wellhead; or at the gas-lift injection manifold.

c) *Production Pressure on Each Side of the Dual*—This is used to calculate the production pressure in the well, at the depth of each gas-lift mandrel for each side of the dual. This should be measured at the wellhead, upstream of any obstruction or pressure drop device such as a choke body, control valve, differential pressure device, etc.

d) For each gas-lift system, measure the total flow rate of gas that is available for gas-lift and the system pressure.

9.3.3 Optional Well Measurements

The following measurements are optional on each gas-lift well.

a) *Injection Temperature*—In some cases, the injection temperature is needed to compensate the injection flow rate measurement. In other cases, the temperature can be estimated with sufficient accuracy so that measurement is not required. If the gas injection is being measured and controlled at a gas-lift manifold, one temperature can be used for all of the wells.

b) *Production Rate*—It can be advantageous to measure or estimate the production rate of both sides of the dual. One method is the "differential pressure" method wherein, the differential pressure is measured across a small pressure drop device such as a body. This, with the production pressure and the gas-lift injection rate, is used to estimate the production rate of liquid (oil + water) and gas.

c) *Production Temperature*—Some production operators like to measure the production temperature as an indication of a change in flow rate. If the production temperature rises, this may indicate a higher flow rate. If it falls, this may indicate a lower production rate. If the production fluid temperature is measured, it should be in a location that is not affected by air temperature, sunlight, etc.

d) *Flowline Pressure*—This value, in conjunction with the pressure at the production manifold, can provide an indication if there is any blockage in the flowline. It should be measured downstream of any wellhead pressure drop device.

e) *Production Manifold Pressure*—This value, in conjunction with the flowline pressure at the wellhead, can provide an indication if there is any blockage in the flowline.

9.3.4 Required System Measurements

The following measurements should be performed on each gas-lift system.

a) *Total Available Gas-lift Flow Rate*—This is the amount that is available for gas-lift injection into all of the gas-lift wells that are served by the system. Often this cannot be determined with one measurement but is determined from the sum (or subtraction) of several measurements. For example, combining the gas from several compressors and subtracting gas used for purposes such as fuel, sales, burning a flare pilot, etc.

b) *Gas-lift System Pressure*—If the system is large, it is still necessary to choose one system pressure that is most representative of the system. Since this value is important for control, it may be appropriate to measure two or more pressures as back-up to the primary pressure measurement.

9.3.5 Optional System Measurements

The following measurements are optional on each gas-lift system.

a) *Intermediate Gas-lift Flow Rate Measurements*—In some large gas-lift distribution systems, there may be several gas-lift manifolds with "master" meters associated with each manifold. These can be included and used to enhance the accuracy of gas-lift injection measurements. For example, they can be used to help detect a measurement error in one gas-lift injection meter.

b) *Flow Rate Measurements at Each Compressor*—While it is not necessary for the gas-lift system, it may be desired to measure the gas flow rate into each gas-lift compressor, the discharge rate, and the recirculation rate, if any. This information can be used in compressor monitoring and control.

c) *System Temperature*—In some cases, it may be desired to measure the gas-lift system temperature and use this to compensate gas-lift system flow rate measurements, or flow rate measurements to each well, if these measurements are taken at a gas-lift manifold.

9.4 Dual Gas-lift Controls

9.4.1 Required Well Controls

For dual gas-lift automation, it is necessary to control the rate of gas-lift injection into each well. This control can be performed at a gas-lift manifold or at the gas-lift wellhead. The injection rate must be sufficient to lift both sides of the dual. The following shall be considered.

a) The gas-lift injection rate into each dual well should be as close as possible to the sum of the optimum injection rates for both zones.

b) Because of the difficulty of starting a dual gas-lift well, the injection rate should be held constant as much as possible.

c) If the gas-lift injection rate into a dual well must be adjusted, it should be changed as little as possible to maintain injection into both sides of the dual.

9.4.2 Optional Well Controls

The following controls are optional on each gas-lift well.

a) *Injection Pressure*—When the injection rate into a dual gas-lift well is controlled to a fixed value, the injection pressure can change. It changes if, for example, the pressure in the gas-lift distribution system changes or if the conditions in the well change. Because the injection pressure is important to the operation of the gas-lift valves, production operators work to maintain the injection pressure within a desired range by using pressure override control.

   This technique controls the injection rate within limits. They restrict the range of injection rate control to maintain the injection pressure within prescribed maximum and minimum values. If an injection rate control action would cause the injection pressure to exceed a prescribed high limit or fall below a prescribed low limit, they override the injection rate control and limit its adjustment to the desired range.

b) *Production Pressure*—Some production operators control the production pressure. By making relatively small adjustments to the production pressure (the backpressure on the production string), they minimize instability on the production side. This technique is not widely used.

9.4.3 Required System Controls

There are no required controls on the gas-lift system other than to control the rate of gas injection into each of the wells served by the system.

9.4.4 Optional System Controls

The following controls are optional on each gas-lift system.

a) *Compressor System*—Some production operators place controls on their gas-lift compressors to enhance their operation.

b) *Gas-lift Distribution*—Some production operators control the distribution of gas-lift gas to various portions of the gas-lift system. For example, this may be used if a compressor plant is compressing gas for use on multiple platforms.

9.5 Responding to Gas-lift System Problems

9.5.1 General

With a production automation system, it is possible to respond directly to some gas-lift system problems.

9.5.2 Gas-lift System Upsets

If an upset occurs in the gas-lift system, due to a compressor shutdown or restart, to a production station trip or restart, or to an upset in another well on the system, the production automation system can rapidly react to keep the system in balance, keep the system pressure relatively stable, and maintain control within the defined parameters

To maintain system balance in the face of a system upset, the injection rates into some (or all) of the wells should be adjusted. If possible, any necessary adjustment should be made to single gas-lift. If an adjustment must be made to a dual gas-lift well, keep it to the minimum possible change to maintain injection into both zones.

9.5.3 Restarting After an Upset

If it has been necessary to decrease the gas-lift injection rate into a dual well to the degree that one or both sides of the dual may have stopped producing, the well should be restarted after the cause of the upset has been corrected using the defined restart or kickoff technique.

9.5.4 Controlling the Well During Testing

When one or both sides of a dual gas-lift well are being tested, the gas-lift injection rate should be maintained constant, regardless of upsets in the gas-lift distribution system. This is necessary to obtain useful well test information.

9.5.5 Responding to Gas-lift Problems

The production automation system will be able to detect many obvious gas-lift problems. If, based on the problem detected, it is clear that the well is not producing effectively, injection to the well should be stopped, and the production operator should be alerted immediately.

10 Dual gas-lift Special Issues

10.1 General

This section addresses some special issues that arise from time to time. The coexistence of a flowing and a gas-lift well in the same wellbore happens frequently. The others happen infrequently.

10.2 Gas-lift and a Flowing Well in One Wellbore

10.2.1 General

When gas-lift coexists with a flowing well in the same wellbore, one side of a dual well may require gas-lift, while the other side of the well continues to flow. The following issues merit consideration.

10.2.2 Mandrel Spacing

Check the spacing of the gas-lift mandrels. If it is sufficient for use of IPO gas-lift valves, then use of IPO gas-lift valves is recommended since this will be operated as a single gas-lift well as long as the other side of the dual continues to flow.

10.2.3 Considerations

Unloading, kickoff, operations, troubleshooting and surveillance should be performed just as it would for a single gas-lift well. See API 11V5 for additional guidance.

10.2.4 Special Concerns

There are a few special concerns that may be important in this situation.

a) If one side of the dual well is flowing at a high rate, it may be hot. This may increase the temperature, and this should be considered when designing and setting the gas-lift valves.

b) When it becomes necessary to lift the side of the dual that was flowing, it may be necessary to redesign the gas-lift valves or change the type of valve.

10.3 Gas-lift and a Pumping Well in One Wellbore

10.3.1 General

In this situation, the following issues should be considered.

10.3.2 Treating the Well as a Single Gas-lift Well

In this case the gas-lift side of the well should be treated as a single gas-lift well. If it is the shallow zone (short string) of the dual, the gas can be injected down the annulus and the well can be unloaded, kicked off, and operated as a single well. If it is the deep zone (long string) of the dual, gas cannot be injected down the annulus, as this would inhibit pumping of the other zone. Therefore, gas would be injected down a coiled tubing inside of the main production tubing, or a third injection line would be required in the annulus.

10.3.3 Pumping Below the Packer

Normally a packer is not used in a pumping well, so the gas can flow up the annulus and not through the pump. However, in this case, it might be necessary to pump the well below a packer and force all of the gas to go through the pump. If the pumping side of the dual is the shallow zone (short string), the tubing could be landed above the dual zone packer and it could be pumped normally. However, if the pumping zone is the long string, that zone would need to be isolated. It would be essential to use a tubing anchor on the tubing string of the side being pumped, to keep the tubing from moving and rubbing against the tubing of the side on gas-lift. Document the experience for the benefit of others in the industry.

10.4 Intermitting One or Both Zones

10.4.1 General

There are many cases where it is more efficient to intermit a gas-lift well than to attempt continuous gas-lift. However, this is rarely tried in a dual well. The following issues should be considered.

10.4.2 Evaluate Both Sides

If only one side of the dual should be intermitted, it may be very difficult to effectively lift the other side with continuous gas-lift. Therefore, it may be appropriate to either attempt to intermit both sides, convert the well to a single, or try pumping one side.

Some other issues to consider are:

a) it may be ineffective to intermit the lower zone (long string) if the intermitted gas-lift valve must be installed above the dual packer and if this packer is located a long distance above the lower zone;

b) a standing valve should be installed in the zone(s) being intermitted to prevent pressure being exerted back on the production formation;

c) normally, a carefully designed intermittent operation is preferable to a “self-intermitting” well. Therefore, if one or both sides of a dual gas-lift well are self-intermitting (heading uncontrollably due to low production rate or low BHP), intermittent gas-lift may be more effective than continuous gas-lift.

10.4.3 Intermitting One Side

If it is essential that one side be intermitted while the other is operated continuously, the following suggestions may be pertinent.

a) Use a choke control on the surface, so the injection rate into the annulus is reasonably steady.

b) In lieu of a choke, use a flow rate controller; a control valve so the injection into the annulus is constant.

c) On the continuous gas-lift side of the dual, use a nozzle venturi orifice so the injection rate into it can be held relatively constant.

d) On the intermittent side of the dual, use a pilot valve if a 3.81 cm (1.5 in.) valve can be used, or a large ported IPO valve if a 2.54 cm (1 in.) valve should be used. A large ported 2.54 cm (1 in.) IPO valve, with an R-value of 0.24, will open on an increase in tubing pressure.

10.4.4 Intermitting Both Sides

If both sides of a dual gas-lift well must be intermitted, the recommendations for intermitting one side should be followed. In addition, the two operating gas-lift valves should be set to open at very different pressures to avoid having both sides of the dual trying to lift at the same time.

NOTE The opening pressures are a function of the injection pressure and the head (level) of liquid above the valves in the tubing.

10.5 Important Consideration for Completing With or Without Mandrels

10.5.1 General

In a few cases, one zone of a dual well may have gas-lift mandrels and the other zone may not. This could occur if the zone without the mandrels was originally designed as a gas well or an injection well and is now to be converted to gas-lift. If this situation should arise, the following issues should be considered.

10.5.2 Equipping the Well for Gas-lift

The options for equipping the well for gas-lift should be evaluated. There are three options to equip the well for gas-lift:

a) use pack-off gas-lift valves;

b) use coiled tubing with gas-lift mandrels and valves on the coiled tubing; or

c) use coiled tubing with single point injection.

This must be considered in the design if the well is offshore or in a location where a subsurface safety valve is required.

10.5.3 Pack-off Valves

The first option is to install pack-off gas-lift valves in the tubing string. The following should be considered when installing pack-off valves:

a) pack-off gas-lift valves can be installed in the tubing string that does not have gas-lift mandrels;

b) it is possible to install multiple pack-off valves in one tubing string, and they can be used in 6.03 cm ($2^3/8$ in.) or 7.30 cm ($2^7/8$ in.) tubing;

c) the pack-off valves can be 1.59 cm ($^5/8$ in.) or 2.54 cm (1 in.) valves, and the pack-off gas-lift valves can be designed like normal IPO gas-lift valves.

10.5.4 Coiled Tubing

The second option is to run coiled tubing inside the production tubing, with coiled tubing gas-lift mandrels and valves installed on it. This will limit the rates that can be produced. With this option, a method to create a seal between the bottom of the coiled tubing and the production tubing should be implemented.

10.5.5 Single Point Injection

A third option is to run coiled tubing inside the production tubing and either inject gas around the end of the coil and produce up the annulus between the coil and the production tubing or inject gas down the annulus and produce up the coil. To consider this option, the surface injection pressure should be high enough to support injection at depth, without the possibility of unloading the well.

10.5.6 Single Point Injection on Both Sides of Dual

A fourth option could be to convert both sides of the dual to single point injection and operate both zones with the same surface injection pressure. Again, the issue of unloading and kickoff should be considered.

10.6 Transitioning from Flowing to Dual Gas-lift Operation

10.6.1 General

Pertinent questions are as follows.

— When should a flowing well be placed on gas-lift?

— How should this be done?

— Are there extra issues if the well is a dual well?

10.6.2 When to Convert from Flowing to Gas-lift

There are several answers to the question of when is the best time to convert a flowing well to gas-lift.

A flowing well should be placed on artificial lift, and specifically on gas-lift, when the production rate of the well can be increased by gas-lift.

a) The production rate may be declining, and it may be possible to arrest the decline, or perhaps even increase the production rate, with gas-lift.

b) The well may begin heading, and it may be possible to stabilize the well with gas-lift.

c) The well may occasionally load up and need to be unloaded or kicked off with gas-lift.

d) The well may not return to natural flow when it needs to be stopped. Gas-lift may be required to reestablish natural flow.

If the well will not flow any longer, it should be artificially lifted. If a well dies and will not flow naturally, it may be placed on gas-lift to continue production.

There are other considerations.

a) If the well under consideration is the first side of the dual to require gas-lift, it may be possible to treat it like a single gas-lift well.

b) If the other side of the dual well is already on gas-lift, this side should be treated as a dual gas-lift well with all of the considerations that this entails.

c) The fundamental point is to not hesitate to place a dual well on gas-lift if needed to sustain production.

Annex A
(informative)

Overview of Dual Well Gas-lift Systems

A.1 General

This annex provides logic and philosophy for considering and applying dual gas-lift. Properly applying dual gas-lift can be challenging and difficult. It should only be used when a better alternative does not exist. This annex will help the reader evaluate the use of dual gas-lift. Typically, during their flowing lives, dual wells cause few additional operating problems relative to single completions. When one zone dies (no longer flows on its own) but the other zone is still flowing, the poorer zone can often be placed on artificial lift with relatively minor difficulties. The more difficult condition arises when both zones need to be gas-lifted at the same time. This is known as dual gas-lift.

Frequently, the term “dual gas-lift” is used incorrectly. Often, it is applied to situations where one or both sides of a dual completion are being gas-lifted. The term dual gas-lift should only technically be used when attempting to gas-lift both sides of a dual completion at the same time using a common gas source (i.e. common annulus). If one side is flowing or shut in, and only one side is on gas-lift, it is not a dual gas-lift well.

It may be desirable for both sides of a dual completion to be gas-lifted, but one side cannot be lifted for one reason or another. If it is desirable for both sides to be gas-lifted, the well should be considered as a dual gas-lift candidate, even if only one side of the dual is currently on production. In fact, working to address and improve this situation is one of the primary objectives of this document.

A.2 Goals of Dual Gas-lift

A.2.1 General

The goals of dual continuous gas-lift are similar to those of single-string gas-lift. These goals can be found in A.2.2 through A.2.6.

A.2.2 Inject in Both Strings Simultaneously

The objective of continuous dual gas-lift is to inject gas into both strings (both sides of the dual gas-lift well) at the same time, continuously. Often, the biggest problem with dual gas-lift is that one side “robs” all of the gas, changing the operating conditions sufficiently to prevent injection into the other side. One of the primary concerns is to design the installation to avoid this problem and to allow both sides of the dual to work (gas-lift) simultaneously.

A.2.3 Inject as Deep as Possible in Both Sides

The primary objective in dual gas-lift is to inject gas in both sides as deep as possible. Often, even if gas is injected into both sides, it is injected through a shallow gas-lift valve in one or both sides. This greatly limits the effectiveness of the gas-lift system.

A.2.4 Inject in a Stable Manner

Just as with continuous single-string gas-lift, another important objective is to inject into both zones of the dual in a continuous and stable manner. Severe production heading or fluctuations that may be caused by unsteady or fluctuating injection at the downhole operating point can lead to significant inefficiency in gas-lift operation. If one zone is unstable, it will cause instability in the injection pressure and in the other zone.

A.2.5 Injection at Optimum Rates

Just as with continuous single-string gas-lift, if gas-lift injection can be established in both sides of a dual completion, and if this injection can be maintained in a stable fashion, the next important objective is to optimize the rate of gas injection to obtain optimum operating performance from the well.

A.2.6 Documentation of Gains

It is especially important that all dual gas-lift successes, gains, and benefits be well documented and communicated to management and others. In some cases, it may be appropriate to communicate these results in industry meetings such as the annual International Gas-lift Workshops. Presentations at such workshops can provide valuable exposure to those participating and are equally valuable to the industry.

A.3 Dual Gas-lift Acceptable Candidate Wells

A.3.1 General

The primary driving force for considering dual gas-lift is to minimize drilling. Often, it is expected that the overall benefits of recovering hydrocarbon reserves from multiple reservoirs will be enhanced by using dual wells. However, the potential candidates for dual gas-lift should be carefully screened.

Attempting to simultaneously gas-lift two completions (two tubing strings) in the same wellbore is always more difficult than operating a single gas-lift completion. However, when a well has two completions in the same wellbore; several factors should be considered before deciding to attempt dual gas-lift. This section reviews the characteristics of acceptable candidates.

A.3.2 Drilling and Completion Issues

The upfront challenges associated with drilling and completion is often cited as a reason to consider dual wells. It is assumed to be easier to drill one well and complete in two separate reservoirs in the well than to drill and complete two separate wells. This may be a valid assumption in many cases and can be a valid reason to consider dual wells if the operational issues listed below are favorable.

A.3.3 Accelerating Production and Rapid Depletion from Multiple Reservoirs

An obvious potential advantage of a dual well is the possibility of accelerating production from multiple reservoirs. Clearly, if both sides of a dual can be produced simultaneously, production from both zones can be accelerated relative to producing the two zones sequentially. Often, this argument is strengthened when one or both sides of the dual are expected to naturally flow for a substantial period. If both sides of a dual are flowing wells, there may be little interference between the two. A similar issue exists when one or more of the reservoirs penetrated by a well are in a competitive situation, where another operator can produce from the same reservoir across a lease line. If oil and gas is not produced from this reservoir now, it may be captured by the competitor and the reserves may be lost.

A.3.4 Limited Surface Space

On an offshore platform, there may not be sufficient surface space or well slots to support enough wells to drill single completions into each reservoir. It may be essential in this case to attempt to produce multiple reservoirs with single wellbores.

A.3.5 Operational Issues

If there is good reason to expect that one or both sides of the dual well will have a long flowing life, it may be a valid candidate for dual operation. As mentioned previously, if one or both zones are flowing, a dual well should offer few problems more than a single completion.

A.3.6 Future Zone Conversions

If it is anticipated that one zone will, after its flowing life, be converted to another use, such as becoming an injection well, then it may be a valid candidate for dual operation. An injection well should be able to coexist with a flowing well or a gas-lift well in the same wellbore without significant additional problems.

A.3.7 Favorable Well Completion Designs and Reservoirs

The following well completion designs and reservoir configurations may favor the use of dual gas-lift.

— Casing size should be at least 17.78 cm (7 in.) for dual gas-lift to be considered. Even larger casing size is strongly preferred so that larger tubing sizes, e.g. 730 cm ($2^{7}/_{8}$ in.), can be used. The larger casing size will support larger gas-lift mandrels that can support larger gas-lift valves, e.g. 3.81 cm (1.5 in.) vs the smaller and less effective 2.54 cm (1 in.) valves.

— If the vertical distance is not too great, i.e. it is less than about 305 m (1000 ft), this makes it easier for dual gas-lift than if the reservoirs are further apart.

— If the pressures in the two reservoirs are not too different, i.e. if the pressure difference is less than about 3447 kPa or 34.47 bar (500 psi), this can make it easier for dual gas-lift than if the reservoir pressures are further apart.

— Well inflow productivities from the two reservoirs are not too different, i.e. if the productivity difference is less than 0.0231 m^3/day/kPa (1 bpd/psi), this can make it easier for dual gas-lift than if the flow rates are further apart.

A.3.8 When Multiple Reservoirs Should Not Be Commingled

If a wellbore penetrates multiple reservoirs, it is not always possible or at least not feasible to consider commingling them. In such cases, dual operation may be considered.

— *Different Pressure Gradients*—Risk of cross-flow. In some cases, it may be impractical to consider commingling production from two reservoirs if there is a likelihood of cross-flow. If cross-flow exists, the production from one zone could flow into the other zone rather than to the surface. This would inhibit the production from both zones. Where commingling is not feasible, the only alternative is to produce the two zones sequentially.

— *Regulatory Considerations*—Occasionally, there are regulatory (legal) reasons why the production from two zones cannot be commingled. This could occur if the ownership of the two reservoirs was different or if one was produced with more than one operator having wells in the same reservoir. In such cases where commingling is not allowed, produce the two zones concurrently as a dual well.

A.4 Dual Well Gas-lift Requirements

A.4.1 General

For dual wells to be acceptable candidates for dual lift, the following conditions should be met.

a) A sufficient amount (volume) of high-pressure gas must be available for gas-lift injection.

b) The gas injection pressure should be high enough to permit injecting the gas deep in the wellbores of the gas-lift wells. This is also true whether the gas-lift is for single or dual completions.

Although not required, dual wells should have a relatively high GOR. A frequent characteristic of gas-lift wells is that their native GOR is high enough that it may be difficult to pump them.

A.4.2 Summary of RPs for Selecting Acceptable Candidates

The following are recommended when evaluating candidate wells for dual gas-lift operation.

— All pertinent factors should be evaluated; only those wells where the factors all favor dual operation should be selected for dual completions.

— All potential operating issues should be evaluated; only those wells with the likelihood of long pre-gas-lift operation and successful gas-lift operation should be selected for dual completion.

A.5 Dual Gas-lift Choices to Be Made for Multiple Zone Wells

A.5.1 Separate Reservoir Production

The first alternative to be considered is one where the zones are not commingled. Drill to the deepest zone and produce the lowest zone to its productive limit. Plug back to the next lowest zone, produce it, and continue until all zones are depleted. The basic disadvantage of this approach is the resulting long life. Also, well spacing and location may not be ideal for all the reservoirs. A problem with this approach is that offset development by other operators may drain the reserves from the unproduced reservoirs held by others.

A.5.2 Separate Wells for Each Reservoir

Another approach is to drill separate individual wells to each reservoir. Each reservoir is treated separately, and well spacing and location are selected for each individual reservoir. This may be the best approach in some cases for shallow normally-pressured reservoirs. Initial drilling and development are more using this approach, since there are more wells, but operational problems are only the ones associated with single completions. However, development of reservoirs with low reserves may not be justified if only single production wells are used.

A.5.3 Commingling Production from Multiple Reservoirs

A.5.3.1 General

In some cases, commingling of production downhole from different reservoirs is the best approach. This should be done with care, as there are several potential problems. In some cases, it is not allowed to commingle multiple zones in the same wellbore.

A.5.3.2 Government Regulations, Mineral Rights, and Field Rules

Complications with commingling in the early 1900s caused government regulations where poor choices were made in the completion design and reserves were lost. In some cases, cross-flow downhole resulted, and production measurement from the individual reservoirs was poor. Such problems need to be prevented; however, with proper design and good operating practices, commingling may be an acceptable approach and a much simpler approach than using dual or multicompletions. In some cases, different parties own the mineral rights in different zones. Accurate measurement from each zone is essential for commingling to be considered.

A.5.3.3 Differences in Fluid Properties and Reservoir Pressures

Occasionally, the pressures or the fluid properties of different zones are very different. This could make it difficult to commingle the zones in the same wellbore without creating operating problems. In the extreme, production from one zone might totally preclude production from another zone if the two were commingled.

A.5.3.4 Differences in Well Depths

In some cases, the depths of different zones vary. That is, one zone may be much deeper, e.g. >305 m (1000 ft), than the other zone in the same well. This can make it very difficult to effectively lift the deeper zone, or the producing pressure from the lower zone may preclude production from the shallower zone. (This is also true for dual gas-lift, but it can be more difficult if the zones are commingled.)

A.5.3.5 Use of Multiple Completions

Experience with triple and an even greater number of completions in a single wellbore has resulted in numerous operating problems and is not recommended. However, dual completions are another approach that should be considered and compared. The key for such studies is to have reliable operating information for the various plans. Initial drilling, completion, and workovers can be reasonably predicted, but the operating requirements and production data models should be obtained from comparable fields (which is difficult to obtain).

A.5.3.6 Possible Mitigating Factors

A.5.3.6.1 General

Some alternative approaches may support the possibility of commingling multiple zones in a single wellbore. Where feasible, these should be considered as an alternative to dual gas-lift completions.

A.5.3.6.2 Large Tubing and Zonal Isolation

The concept here is to use one large tubing string and separate each reservoir with packers. The upper zones can be produced into the tubing via sliding sleeves. If necessary, a specific zone can be closed off to prevent commingling incompatible fluids or to isolate zones of very different productivities or pressures.

A.5.3.6.3 Downhole Measurement Systems

If commingling has been prohibited because of the need to know the amount of production from two or more separate zones, the advent of modern downhole measurement systems may overcome this limitation. There are downhole meters that offer the potential to provide continuous measurement of the volumes of oil and water (and possibly even gas) from separate downhole zones.

A.5.3.6.4 Downhole Control Systems

There are modern downhole control systems that may make it feasible to control one zone for more effectively commingling with another zone. For example, if the pressure of one zone were much higher than that of another zone, it is possible to “control” the inflow from the higher pressure reservoir in a way to not “overwhelm” the lower pressure zone.

A.5.3.6.5 Reservoirs with Low Reserves

Reservoirs with low reserves may not be justified as a single zone producer. Commingling or completing such zones as dual producers in conjunction with other reservoirs with higher reserves may make development feasible.

A.5.3.6.6 Multilateral Completions

Many wells are completed with horizontal legs or laterals, and often a well will have multiple laterals. In some cases, the different laterals may contact very different parts of a reservoir, and it may be more appropriate to produce them separately, rather than to commingle them. In this case, a “dual” well may actually contain two separate completions to produce two separate parts of the same reservoir.

A.6 Dual Gas-lift Valve Type Selections

The rule of thumb in the industry has been that while IPO gas-lift valves are more effective for single-string gas-lift wells, PPO valves are used for dual gas-lift wells. The justification for this practice is: the injection pressure primarily controls the opening and closing of IPO valves. Since the injection pressure for the separate individual strings cannot be effectively controlled in a dual well, PPO valves should be used so that the well's production pressure controls the opening and closing of the gas-lift valves. This technique may cause a number of problems.

a) *Small Valves*—Many dual wells are constrained to use small tubing with small gas-lift mandrels and small 2.54 cm (1 in.) gas-lift valves. Most PPO gas-lift valves use a crossover technique to allow the production pressure to be exerted on the gas-lift valve bellows. The 2.54 cm (1 in.) OD of the valve limits the flow areas of the internal components. Valves that are used outside of the narrow operating envelope dictated by their construction will perform poorly. However, recent developments partially offset this concern. Some 2.54 cm (1 in.) PPO gas-lift valves have been redesigned to improve their flow areas.

b) *Crossover Ports*—Are susceptible to plugging by any form of sand, dirt, deposits, corrosion products, etc. that may be found in the produced fluid or injected gas. This has been partially overcome in some newer PPO valves that have larger crossover port areas.

c) *Casing Pressure Effect*—While many IPO valves are largely controlled by injection pressure, with a modest "tubing pressure effect," many PPO valves have a considerable "casing pressure effect" in addition to the primary "tubing effect," especially as the port size in increased. This makes it difficult to predict how these valves work under actual operating conditions. The casing effect may be best understood by using measured valve flow performance data.

d) *Less Well-known Tubing Pressure*—Design of IPO valve opening and closing pressures is based largely on the (relatively well-known) casing (gas) pressure gradient in the well and the operating temperatures. Design of PPO valves depends largely on the tubing pressure gradient in the well, which is influenced by dynamic factors such as GOR, water cut, PI, etc. Tubing pressures typically vary during unloading and with time.

A.7 Dual Gas-lift Associated Problems

A.7.1 General

There are a host of problems associated with dual gas-lift. Many are discussed in this section, at least in part in the hopes that some may be overcome by proper design and operation of dual gas-lift wells.

A.7.2 Completion Issues

A.7.2.1 General

Completion designs often affect the operating envelope of the dual gas-lift system. The following are several related topics.

A.7.2.2 Casing Size

If the casing size is smaller than desired, due to the same drivers that resulted in the use of dual completions in the first place, the dual tubing strings may need to be smaller than desired. To match the casing size, the tubing strings may be too small to effectively gas-lift the wells at the desired production rates.

As an example, dual completions inside 17.78 cm (7 in.) casing typically result in parallel strings of 6.03 cm ($2^3/_8$ in.) tubing. Due to the relatively small 5.067 cm (1.995 in.) tubing ID, the production from each zone may be restricted. Rates of 158 m^3/day (1000 bpd) or more from a reservoir will result in high tubing friction losses. Rates of 79.5 M^3/day (500 bpd) or less will result in only small friction losses in 6.03 cm ($2^3/_8$ in.) tubing and should not cause undue gas-lift problems, but this may be less than the desired production rate.

The casing size for dual gas-lift wells may make it necessary to use smaller, i.e. 6.03 cm ($2^3/_8$ in.), gas-lift mandrels that can only accept 2.54 cm (1 in.) gas-lift valves. This can be a limitation in that 3.81 cm (1.50 in.) gas-lift valves are generally regarded to be superior to 2.54 cm (1 in.) valves in ruggedness and performance.

This is especially true if it is necessary to use PPO gas-lift valves. The internal construction of PPO valves places a number of limitations on the range of operation in a 2.54 cm (1 in.) diameter valve.

Normally, the casing-tubing annulus is large enough that there is very little pressure drop as the gas is injected down the annulus. Normally, the pressure at depth can be calculated from the surface pressure and temperature, and the weight of the gas in the annulus, which is a function of its composition and temperature. However, if the casing-tubing annulus cross sectional area is small (as it may be in a dual well), there may be a significant pressure drop as the gas flows down the annulus and as if flows past the gas-lift mandrels. This will, of course, affect the pressure that is available at the operating gas-lift valves. For most typical dual gas-lift situations, e.g. two tubing strings of 6.03 cm ($2^3/8$ in.) tubing in 17.78 cm (7 in.) casing, or two strings of 7.30 cm ($2^7/8$ in.) or 8.89 cm ($3^1/2$ in.) tubing in 24.45 cm ($9^5/8$ in.) casing, this is not a serious problem.

A.7.2.3 Vertical Distance Between Zones

Another problem may be the vertical distance between the two zones to be dually lifted in the single wellbore. The uppermost packer should be set above the shallower of the two zones. Gas-lift gas can only be injected as deep as the upper dual packer, unless some uncommon and potentially risky completion equipment and measures are used. If it is a long distance between the two zones, it may be difficult and ineffective to gas-lift the lower zone, since the gas is injected relatively high in its production string, relative to its reservoir depth. Typically, the greater the distance between the zones, the higher the difference between the reservoir pressures, thus increasing the possibilities of cross-flow and workover difficulties. However, if the lower zone has a strong water drive and high productivity, it may be possible to lift it from above the dual packer.

A.7.2.4 Spacing Between Mandrels

Normally, a number of factors are considered in designing the spacing of gas-lift mandrels. These factors include: available casing-head (injection) pressure, expected tubing-head (production) pressure, static reservoir pressure, expected operating BHP, completion and production fluid properties, etc. In a dual well, it may be necessary to restrict the locations of mandrels, since both zone's tubing strings and the associated mandrels must be accommodated. Key is to install the same number of mandrels for both sides of the dual, with one set (typically, the upper zone mandrels) offset a tubing joint or two above the other set. Normally, the mandrels should be spaced for the side of the dual that requires more mandrels for successful unloading. If the tubing strings are run independently, a graphical layout of the mandrel depths should be made to ensure that the two sets of mandrels are not at the same depths.

A.7.2.5 Wellbore Problems

Often there are wellbore problems of one type of another in dual gas-lift wells. These may be related to the more complex completion or the more difficult workover situation or it may just be bad luck. There are sometimes damaged sections of casing, or tubing, which prevent installing and operating the dual gas-lift equipment in the optimum fashion.

A.8 Dual Gas-lift Design Issues

A.8.1 General

There are several fundamental problems associated with dual gas-lift design. The most important are outlined in A.8.2 and A.8.3.

A.8.2 Design Method or Program

While there are excellent published gas-lift design methods, and readily available gas-lift design computer programs, for single-string gas-lift, there are few such accepted design methods and programs for dual gas-lift. Therefore, past experience and rules of thumb are often used.

A.8.3 Unloading Design

As with any gas-lift well, unloading is an essential step. The liquids must be produced out of the casing annulus before the well can be gas-lifted. Normally, when a gas-lift well is unloaded, the liquids are produced from the annulus and the well is kicked off and brought on production.

For dual gas-lift, it may be instructive to think of unloading and kickoff separately. If the spacing and design of the unloading gas-lift mandrels and valves are correct in the zone with the deeper mandrels (this may be either the deeper or the shallower of the two production zones), this side can (and should) be used to unload the liquids from the annulus while the other side remains closed in. If this process works correctly, the "unloading" side will also be "kicked off" and will produce at the end of the unloading process.

For the other side, unloading is no longer required; it has already been unloaded and the second zone needs to be kicked off. This may require fewer mandrels and valves, and a different process. The unloading designs for a dual gas-lift well should accommodate the possibility that either side may need to be used for unloading. Therefore, it is required to install enough mandrels in both strings to support unloading. If one side is not needed for unloading at the current time, dummy valves can (and should) be installed in the mandrels that are not required.

A.9 Dual Gas-lift Operational Issues

A.9.1 General

Once a dual gas-lift well is completed and unloaded, it must be successfully operated for the long term, if the operation is to be successful. There are several operational problems that must be overcome.

A.9.2 Well Production

The goal is to keep both sides of the dual completion on production at reasonable rates. Many operators have said that they can increase the production from a dual well by closing in one side; this is not the desired approach. It is important to know what production is from each zone, so it will be readily apparent if one (or both) zones are producing ineffectively. The desired rates are determined by conducting an accurate well test of each side of the dual well.

To keep both sides on production, a well-designed control strategy is needed. Some dual gas-lift wells are successfully operated with manual methods, but gas-lift automation can be more effective in keeping the desired rates on a continuous basis, especially if there are frequent upsets or changes in the gas-lift distribution system. Frequent impediments to keeping both sides on production are equipment problems.

A.9.3 Lifting from Desired Depths

The second goal is to keep both sides lifting from the desired depth. If one side is lifting from the desired operating point, but the other side is lifting from high in the well, it will be producing very inefficiently. The requirement to achieve this goal is to properly design the gas-lift valves to support the unloading process and then to remain closed when the well has been unloaded and it is time to lift from the desired operating depth. To accomplish this, not only should the valves be properly designed, but also the well should be properly operated, with the correct injection rate and pressure.

If the well is designed with IPO valves, the injection rate and pressure should be kept at the values necessary to prevent increasing the pressure in the annulus so that upper valves may be reopened. If the well is designed with PPO valves, the injection pressure should be kept constant and the injection rate maintained to achieve the correct production pressure to prevent the upper valves from being reopened by excess pressure.

A.9.4 Unequal Injection Rates

A frequent problem in dual gas-lift occurs when most (or all) of the gas is injected into one side and the other side receives very little or no gas. This can occur if a valve or mandrel on one side is leaking. It can also occur if one or more unloading valves, or the operating valve or orifice, is too large. If the problem is due to a leak, it should be detected and corrected. If the problem is due to a large gas-lift valve, orifice port size, or choke size, it must be correctly resized.

A.9.5 Lifting in a Stable Manner

Unstable operation is an even more serious problem in dual gas-lift than in a single gas-lift well, because any instability in one side is certain to affect the other side.

There are several causes of instability:

a) a too large operating gas-lift valve port, orifice port, or choke size;

b) valve interference where one or more upper unloading valves are intermittently opening and closing; or

c) a leak in an upper part of the tubing string on one or both sides of the dual.

The first requirement is to determine the cause of the instability. With a dual well, it is very important that the injection rate be maintained at the value that is compatible with the design rate into the two zones.

A.9.6 Lifting in an Optimal Manner

Once both sides are being lifted in a stable manner from the desired operating depth, it is time to optimize the injection rate into both zones.

A.10 Dual Gas-lift Completion/Operational Concerns

A.10.1 General

While it may be easier to drill a dual well rather than two (or more) single wellbores, it is often much more difficult to complete, operate, and maintain a dual well. There are many reasons for this, including:

a) increased completion complexity,

b) increased operating complexity,

c) increased complexity when performing workovers,

d) increased difficulty in performing artificial lift operations,

e) increased difficulty in conducting production surveys,

f) increased production deferment due to dual well problems.

The true value of dual wells must be carefully evaluated, considering the full life cycle issues of drilling, completion, operation, maintenance, artificial lift, deferment, etc. The benefits of less drilling for dual wells is overshadowed, in the long term, by more challenges for other well operations.

A.10.2 Controls

One of the largest challenges is to effectively control dual gas-lift wells. One operator attempted to solve its dual gas-lift control problems by removing all of the surface measurement and control equipment. The idea was that dual wells cannot be properly controlled anyway, so why waste time and money on trying? They planned to let each well control itself with use of PPO gas-lift valves. Years later they acknowledged that this did not solve the problem. This document offers RPs to address the control issues.

A.10.3 Integrating the Control and Design Process

A problem with dual gas-lift is the necessity of controlling the operation consistent with the way its design. For successful operation, the well should be successfully unloaded and gas should be continuously injected into both zones, from as deep as possible. This means that there should be clear communication between the designers of the gas-lift system and those who operate it. The designers and operators should know the gas injection pressure and rate that can be consistently supplied to the well. If these values cannot be consistently provided, a system redesign is required.

A.10.4 Developing an Effective Control Strategy

The first step in correctly controlling a dual gas-lift well is to develop and implement a correct control strategy. The normal and probably the most effective strategy is to control the rate of gas injection into the annulus of the dual gas-lift well. The rate of injection should be sufficient to properly lift both zones of the dual.

Other control strategy alternatives are to control the injection pressure or the production pressure of both zones. These have some logical merits but are much more difficult to implement and maintain. Therefore, most operators choose the first approach of controlling the gas-lift injection rate. Also, control of the gas-lift injection rate is consistent with the need to control the overall distribution of gas from the gas-lift system. This is necessary to maintain a stable, nearly constant, system pressure.

Ultimately, the choice of the best control method is a matter of expediency. Experience over many years indicates that the lesser choices very often do not support the desired dual gas-lift operation. The later choices, and especially the last choice of automatic control, can lead to very desirable dual gas-lift control and operation. If a production automation system is already used, or is being contemplated for a field, the incremental benefit of providing automatic control may be worth it.

A.10.5 Controlling the Injection Rate

The next issue is to determine specifically what and how to control the gas-lift injection rate into the well. Several methods are considered.

a) *No Surface Control*—As mentioned, some operators use no surface control and rely on the downhole gas-lift valves to control the injection rate into the tubing strings. There is broad consensus that this method is not sufficient to provide adequate gas-lift injection control.

b) *Fixed Choke or Orifice*—This provides some degree of flow restriction and some limited control. However, with this method it is not possible to actually control the rate of gas-lift injection to a specific desired rate. As the upstream or downstream pressure changes, the gas flow rate through the device will change.

c) *Variable Choke or Orifice*—Is functionally the same as a fixed choke or orifice, but the opening or flow restriction can be changed. This is easier to adjust than a fixed device, but it cannot dynamically adjust to changes in upstream or downstream pressure, so the flow rate may not be controlled to a desired rate.

d) *Flow Controller*—This will set the injection rate to the desired rate, and the controller will maintain the desired injection rate by adjusting its opening when upstream or downstream pressure changes.

e) *Automatic Control Valve*—This is functionally the same as a flow controller. Here the desired injection rate can be automatically set into the "brain" of the controller, from a remote computer or similar device. This allows an operator to remotely adjust the injection rate. Also, where necessary, the automation system itself can adjust the injection rate to optimize the well performance or to keep the injection into the well consistent with the overall operation of the gas-lift system.

A.10.6 Integrated Control Approach

The appropriate choice of a control approach should never be made without considering all available information. Almost without exception, dual gas-lift wells exist within a gas-lift system that serves other dual wells. A control strategy that best manages the overall gas-lift system to best serve all of the wells in the system is necessary. If, for example, injection into single wells is controlled, but it is not controlled into dual wells, the efficiency of all wells in the gas-lift system will be affected.

A.11 Dual Gas-lift Surveillance

A.11.1 General

The first step in solving any problem is awareness. The second is to have enough valid information to determine the cause of the problem and how best to create a solution. There are some special problems and challenges in implementing and maintaining an effective dual gas-lift surveillance system over the long term.

A.11.2 Operating Variables

The choice of which operating variables to monitor depends on how the variables are monitored. Some of the choices are as follows.

a) *Monitor Nothing*—The logic for this is related to the logic for not controlling anything either. The philosophy here is to let each well take care of itself. As with the option of providing no control, experience has shown that this is not sufficient for good dual gas-lift performance.

b) *Wellhead Charts*—Traditionally, wellhead charts (two-pen or three-pen charts) have been used to monitor single-string gas-lift wells. Traditionally, these charts are used to monitor injection pressure, production pressure, and often also the differential pressure across an orifice meter used to measure injection gas. With a dual gas-lift well there is still only one injection pressure and only one injection rate, but there are two production pressures. So, it may be necessary to use two wellhead charts. The disadvantages or challenges with this method of monitoring include the following.

   i. *Maintenance of the Charts*—It may be very time consuming to properly maintain the charts so that they continuously provide accurate, readable results.

   ii. *Use of the Charts*—Consistent use of the charts to monitor and diagnose gas-lift performance can be very time consuming. And it requires a high degree of skill in interpreting the chart data.

   iii. *Automatic Monitoring*—Another alternative is to automatically measure key operating parameters with a supervisory control and data acquisition (SCADA) or other computer-based system. Here the system can monitor the injection pressure, the two production pressures, and the injection rate on a continuous basis. If the necessary equipment and techniques are used, it can also monitor the liquid production rates of both zones of the dual gas-lift well.

A.11.3 Monitoring Frequency

Frequency is also a function of the method used for monitoring. If charts are used, well operations should be annotated on the charts. For instance, it should be noted on the chart if a well is stopped or started, if the injection rate is changed, etc. This will assist in analyzing the well’s performance.

Some of the options are follows.

a) *Never*—If nothing is measured, this is the only choice available.

b) *Well Tests*—When wellhead charts are used, some operators only install paper charts and measure the information when the well is on test. With this method, there is no monitoring between tests.

c) *Eight-day Charts*—Many operators use eight-day charts for the advantage of once per week changes. The disadvantage is that it can be very difficult to diagnose unstable wells since short-term changes become masked. If the injection pressure, production pressures, or injection rate are changing frequently, the chart can be "painted" and it can be impossible to detect the specific pattern(s).

d) *24-hour Charts*—One-day charts provide resolution so that short-term changes can be more easily detected and evaluated. Of course, maintenance and must occur daily.

e) *Continuous Monitoring*—If a SCADA or production automation system is used, monitoring can be conducted continuously and automatically. The optimum frequency for "continuous" monitoring has been evaluated by extensive field studies as measuring each data point (pressure, flow rate, etc.) once per minute.

NOTE This frequency may not be frequent enough for diagnosis and optimization of intermittent gas-lift wells.

A.11.4 Using Monitored Information for Surveillance

The application of information is an important issue typical alternatives include the following.

a) *Monthly Well Surveillance*—Use the information as part of the evaluation of well performance when a well test is conducted. In many fields, this means that the wellhead information will be collected and used once per month in conjunction with a monthly well test.

b) *Weekly Basis*—In some fields, a gas-lift analyst, technician, or engineer is assigned to evaluate each eight-day chart when it is collected. Based on experience, it is very difficult to maintain this practice due to competing job responsibilities.

c) *Daily Basis*—This is even more time consuming and challenging than using eight-day charts.

d) *Use on an Exception Basis*—When continuous monitoring systems are used, it is possible to include an "exception reporting" capability. In such cases, the system can automatically detect potential well problems: e.g. well stopping, heading, freezing, etc. A gas-lift analyst, technician, or engineer can be automatically alerted of a potential problem on an exception basis.

A.11.5 Presenting Information for Surveillance

Gas-lift surveillance information needs to be presented to the person(s) who have the responsibility, skill, time, and interest to use it for surveillance of the wells. This person(s) may be gas-lift operators, analysts, technicians, or engineers. They may be employed by the operating company, a gas-lift service company, or a consulting company. For effective dual gas-lift to occur, personnel skilled in the art need to accept the responsibility to monitor, diagnose, and optimize dual gas-lift operations.

Alternatives for presentation of surveillance information include the following.

a) *Charts*—If wellhead charts are used, they are typically the best information for surveillance. If a chart was measured while the well was on test, the test rates should be written on the chart or presented with the chart. Well operations occurring while the chart was in use should be annotated.

b) *Reports*—Some staff members request reports from the dual gas-lift wells being monitored by a computer system, these reports may contain:

— minimum, maximum, and average injection pressures;

— minimum, maximum, and average production pressures;

— minimum, maximum, and average injection rates;

— minimum, maximum, and average production rates, if measured; on production and downtime;

— alarms such as heading, freezing, blowing around, etc.

c) *Plots*—If monitoring is performed by computer, plots can be presented. A typical computer system can plot injection pressure, production pressure, injection rate, etc. vs time. It is possible for the computer system to annotate the plots with known events such as well stopping, well starting, and alarms.

A.11.6 Pressure/Temperature Surveys

Run and record the data from frequent pressure/temperature surveys. Run and analyze a flowing pressure/temperature survey at least once per year to evaluate the well's gas-lift performance. Conduct an accurate well test in association with the survey. Run a static pressure and an associated FBHP survey when the well, or one side of the well must be closed in for some reason. Use this to evaluate the well's inflow performance and to calibrate the vertical two-phase pressure model. Conduct an accurate well test in association with a survey in accordance with API 11V5. For additional data consider running a memory production logging tool to obtain continuous pressure information across the well's entire depth, without the need to stop the pressure/temperature measurement device below and above each gas-lift mandrel.

A.11.7 Using Surveys to Diagnose Problems

Use pressure/temperature surveys to determine the well's PI or IPR. Use surveys to help diagnose problems with current gas-lift operations. Understand the different roles and procedures required for these two different types of surveys. Do use an inflow survey to diagnose gas-lift problems, and do not try to use a diagnostic survey to determine a well's inflow performance. This issue is discussed in detail in API 11V5.

A.11.8 Fluid Level Determinations

A fluid level may be determined, using a sonic fluid level detection device, to check if there is a leak from one or both of the tubing strings into the annulus. It will not identify where the leak is, but it will indicate how much fluid has leaked into the annulus.

A.11.9 Well Tests

Conduct a periodic well test on each side of a dual gas-lift well with the other side on production. This is how the well "normally" produces, and it avoids needing to stop the other side of the dual. When conducting a well analysis pressure/temperature survey, close in the side not being tested and conduct an accurate test on the side being analyzed. If there is concern that the total production from the well may not equal the sum of the tests of each side, test both sides in the same test separator at the same time.

A.11.10 CO_2 Tracer

Consider using a CO_2 tracer survey, in between pressure/temperature surveys, to detect the depth(s) of gas-lift injection in the two sides of a dual gas-lift well.

A.11.11 Continuous Monitoring

To continuously monitor and control each dual gas-lift well, either provide an adequate staff level to perform frequent monitoring and control with manual means or consider use of electronic monitoring/control and/or production automation systems. Measure at least the gas-lift injection rate and pressure and the production pressures of both sides of the dual. Measure each variable once per minute when using a production automation system. Generate exception reports for review of problem issues.

A.12 Dual Gas-lift Diagnosis and Troubleshooting

A.12.1 Diagnostic Techniques

Develop a library of typical dual gas-lift problems; use a proven software program to compare current cases to those stored and determine likely causes of problems and their corrective measures. Routinely evaluate "two-pen" charts or plots of injection and production pressures to detect typical dual gas-lift problems.

Carefully compare and evaluate flowing pressure surveys. Use the pressure surveys to determine the well's inflow productivity and to calibrate the mathematical model used to calculate the vertical pressure profile.

Routinely generate the appropriate measurements of well performance, including the gas-lift performance, the well inflow performance, the gas-lift response curve, and the optimum injection rate. Use an exception reporting technique to highlight problems that the gas-lift analysts need to address.

A.12.2 Locating Communication Problems

Communication problems between the annulus of a dual gas-lift well and one or both tubing strings can occur, and since they can go undetected by normal surveillance means, special tests to check for a leak should be run on a prescribed frequency or whenever a communication problem or leak is expected. See 8.3.

A.13 Dual Gas-lift Automation

A.13.1 Automation Logic

Take the approach that a justification must be prepared to not use automation. Also, assume that use of a gas-lift automation system will be justified on every important dual gas-lift operation. Use only a field proven gas-lift automation system. Provide training to the gas-lift personnel so they can make effective use of the automation system.

A.13.2 What to Measure

For each gas-lift well, measure the:

a) injection pressure at the wellhead, downstream of any pressure drop device;

b) measure the injection rate, either at a gas-lift manifold or at the wellhead;

c) measure the production pressure of each side of the dual at the wellhead, and upstream of any pressure drop device.

For each gas-lift system, measure the total flow rate of gas that is available for gas-lift and measure the gas-lift system pressure at a location that is most representative for the system.

A.13.3 What to Control

Carefully control the gas-lift injection rate into each dual gas-lift well. The objectives of this control include:

a) inject as close as possible to the sum of the optimum injection rates for both sides of the dual;

b) keep the injection rate constant to the degree possible; and

c) if the rate must be adjusted, make small adjustments so injection into both sides can be maintained.

A.13.4 Responding to System Problems

Each dual gas-lift well should be controlled to maintain its desired operation and stability, with consideration of potential upsets in the gas-lift distribution system. If adjustments in the system are necessary, make these to single-string gas-lift wells where possible. With adjustments minimize the degree of changes with the goal of maintaining injection into both zones. If it is necessary to adjust the injection rate into a dual well so that one or both sides stops producing, use appropriate procedures to restart the well.

A.14 Dual Gas-lift Special Issues

A.14.1 Flowing and Gas-lift in Same Well

Unless there is reason that flowing and gas-lift in same well cannot be done, treat the side with gas-lift as though it is a single gas-lift well, with IPO gas-lift valves and normal single gas-lift unloading, kickoff, and operating procedures.

A.14.2 Pumping and Gas-lift in Same Well

Expect the shallow zone (short string) to operate acceptably as either a gas-lift or a pumping well. Expect the deep zone (long string) to have problems. There will be difficulty in injecting gas for a gas-lift well, and in pumping beneath a packer for a pumping well, for future well operators.

A.14.3 Intermitting One or Both Zones

Carefully evaluate both sides of the dual to make certain that intermittent gas-lift of one or both zones is the best approach. If only one side is to be intermitted, use “choke” control for injection into the annulus and a pilot valve or a large-ported gas-lift valve to minimize casing pressure upsets. Use a nozzle venturi orifice on the continuous side. If both sides are to be intermitted, set the operating valves to open at different pressures so both sides of the dual do not cycle at the same time.

NOTE The opening pressures are a function of the injection pressure and the head (level) of liquid above the valves in the tubing.

A.14.4 Lack of Mandrels in a Zone

Consider using pack-off gas-lift valves to equip the side without mandrels for gas-lift. If this option is not viable, consider installing coiled tubing in the production tubing and use coiled tubing gas-lift mandrels and valves, or single-point injection near the bottom of the coiled tubing.

A.14.5 Transitioning from Flowing to Dual Gas-lift

If a flowing well can no longer produce on its own, or if its production rate can be improved with gas-lift, take the steps necessary to place the well on gas-lift. These steps will depend on whether it is the first side of the dual requiring lift or if the other side of the dual is already on gas-lift.

A.15 Staffing Dual Gas-lift Operations

A.15.1 General

The challenges to “get it right” and “keep it right” for dual gas-lift are much greater than for almost any other form of artificial lift. In single wells, some claim that gas-lift can be forgiving, i.e. inject some gas and some liquids (oil) will be produced. This is not the case with dual gas-lift. For this process to be technically successful, and for it to remain successful, a significant level of commitment is required by several members of the production organization, and those that support them. The following should be considered by management when staffing dual gas-lift operations: recognize the management, technical, and staffing challenges that should be met to be successful in dual gas-lift, and be committed to provide the required staffing and financial support. Members of the dual gas-lift team should become familiar with dual gas-lift RPs, operational issues, and do’s and don’ts and be willing to work together.

A.15.2 Management Commitment

A.15.2.1 General

People in management make the decisions to complete dual wells. They should understand the full implications and consequences of their actions and should be committed to providing the resources required for successful implementation and operation of dual gas-lift wells. The issues of dual gas-lift extend from the initial decision to drill a dual well, through the actions to complete the well, operate the well, optimize the well, and finally to abandon it. One time training and familiarization with old technology is not sufficient. Management should encourage the staff to continuously improve their knowledge and experience in dual gas-lift.

A.15.2.2 Continuity of Team Members and Champions

An essential aspect of staffing for dual gas-lift success is continuity. One of the best ways to assure continuity is to have key personnel specifically identified as dual gas-lift champions. Identified champions should have access to management so they can propose appropriate staffing, training, and acquisition of technology, tools, and techniques. The champion is a person who is committed to dual gas-lift technology over a longer period of time, who becomes well versed in the technology and practice, who is well respected in his/her company, and who is well recognized in industry. The champion is in a position to identify and train (or find training for) staff in the company. He/she is also able to evaluate and recommend appropriate existing or new technologies, tools, and techniques for effective dual gas-lift.

A.15.2.3 Long-term Training and Support Requirements

Personnel who are involved with dual gas-lift require appropriate and current training. This includes engineers, well analysts, technicians, operators, well servicing personnel, and others. This training should be in the form of continuing education. They should also receive appropriate refresher courses, on-the-job training, mentoring, etc. There has been an insufficient commitment on the part of trainers to develop and present dual gas-lift training programs. There are two reasons for this. First, there has been a lack of good tools, techniques, and practices upon which to base a good dual gas-lift training program. Second, the industry has not demanded this training. However, based on the fairly widespread use of dual gas-lift and the obvious advantages of "getting it right and keeping it right," effective training programs are required.

It is important for the staff to be trained regarding dual gas-lift and learn the essential aspects of design, installation, operation, and optimization. Most gas-lift schools focus on single, continuous gas-lift with only a mention dual gas-lift in passing. One method to become educated on dual gas-lift is to spend time with someone who is well versed in the technology. As more companies become active in the practice of dual gas-lift, special training courses in dual gas-lift will become more available.

A.15.2.4 Use Drilling/Completion Savings for Increased Operating/Surveillance

A consideration for management is to realize that there will be increased issues for operation and surveillance of dual gas-lift wells. One way to help justify these additional expenditures is to consider this as part of the benefit associated with achieving savings on drilling and completing dual wells.

A.15.3 Engineering Commitment

A.15.3.1 General

Some engineers aspire to become managers. Some aspire to obtain a very broad experience by working in many facets of production operations. For dual gas-lift in particular, to be successful, some engineering staff should be dedicated to becoming sufficiently expert to design, install, and operate it successfully. The following should be considered by engineers when participating in dual gas-lift operations: become educated in dual gas-lift RPs, operational issues, appropriate procedures, and precautions and become familiar with API 19G1, API 19G2, API 19G3, API 19G4, API 11V5, and API 11V8, to build and support an effective dual gas-lift team.

For an engineer to become a specialist in dual gas-lift, he/she should be very knowledgeable in the needs and responsibilities of several other engineering disciplines. And he/she should communicate with the other engineers so they understand the limitations and constraints imposed by dual gas-lift. It may be necessary for the gas-lift champion or engineer to provide training to these staff members.

A.15.3.2 Reservoir Engineers

Reservoir engineers are interested in effective, continuous, and rapid production of the reserves in each reservoir. They may not fully appreciate the limitations on reservoir production that may be imposed by dual gas-lift. If their expectations cannot all be met, the reasons for this should be made clear to them. Then, they may assist in helping to justify corrective actions to improve dual gas-lift performance and, therefore, production from the reservoirs.

A.15.3.3 Drilling Engineers

Drilling engineers are responsible for drilling wells in ways that are consistent with the long-term objectives for the well. It is necessary that they fully appreciate the value of providing adequate hole and casing size for dual gas-lift. While a smaller hole and smaller casing may be sufficient for a single completion, larger casing size is very important for dual lift.

A.15.3.4 Completion Engineers

Completion engineers are responsible for designing and implementing the wellbore completion. This often includes perforating, sand control, tubing and packer selection, etc. In many cases, it also includes determining the depths of the gas-lift mandrels. The gas-lift specialist and the completion engineer(s) should work together on tubing design and mandrel spacing to assure a design that will be consistent with effective dual gas-lift.

A.15.3.5 Facilities Engineers

Facilities engineers are responsible for design of production and well test separation systems, and often they are also responsible for design of production flowlines and gas-lift distribution lines. The gas-lift distribution system should deliver enough gas to the wellhead to lift two zones. Also, there may be special well testing requirements for dual gas-lift wells that should be accommodated by the well test separation system.

A.15.3.6 Operations and Maintenance Engineers

Operations and maintenance engineers are responsible for continuous, effective operation and maintenance of the various systems that support dual gas-lift operations. This includes the gas compression system, the gas dehydration system, gas measurement, gas delivery, gas injection control, etc. Essential requirements include provision of high-pressure dry gas at a stable pressure, accurate measurement and control of the gas injection system, and understanding the operational issues that affect dual gas-lift.

A.15.4 Field-wide System Optimization

In many fields, several gas-lift wells are served by a common gas-lift system. Often, this group of gas-lift wells may include continuous single-string gas-lift wells, dual gas-lift wells, and intermittent gas-lift wells. For the performance of the gas-lift system to be effective and optimum, the sum of the injection into all of the wells should equal the total amount of gas available for gas-lift injection. If the total available amount of gas changes, due to a compressor stopping or starting, a production station stopping or starting, etc., the injection into some or all of the wells must change. Therefore, some of the wells should be operated in a flexible way so their injection rates can be changed, or the gas can be turned off, if this is dictated by system performance.

A.15.5 Workover/Recompletion Issues

One zone in a dual well cannot be worked over or recompleted without affecting the other zone. In some cases, it may be necessary to defer a workover or recompletion in one zone if the performance of the other zone is jeopardized. In some cases, workovers or recompletion operations can be conducted through tubing on one side without seriously affecting the other side. In some cases, it will be necessary to perform a full workover that affects both sides. When this is required, every precaution should be used to protect the zone that is not the primary target of the workover. Before the workover is performed, both zones should be carefully evaluated to see if any improvements in the completion are needed.

A.15.6 Awareness of Adverse Downhole Issues

Various downhole problems, such as corrosion, scale deposition, paraffin deposition, formation of emulsions, or leaks, can have an adverse effect on any well and especially on a dual well. The gas-lift engineer should be aware of the possibility of these problems, how to detect their presence, and what the most appropriate remedial actions may be. Communication with a chemical engineering specialist can be very beneficial.

A.15.7 Awareness of Inter-zone Communication

With dual gas-lift, two productive zones are open in the same wellbore at the same time. If the pressures or flow rates from the two zones are very different, they may interfere with each other, even if they are each confined within their own production tubing strings. For example, if the pressure of one zone is substantially higher than that of the other zone, the depth of gas-lift injection may need to be very different. This may make it very difficult to simultaneously inject gas into both zones at the desired rates and depths. If the production rate of one zone is much higher than that of the other zone, its producing temperature may be higher. This may have an impact on the performance of the gas-lift valves in the lower temperature zone.

A.15.8 Communications Within the Gas-lift Team

The gas-lift champion or engineer should promote frequent communication between the members of the gas-lift team. Communication within the gas-lift team should work in all directions. When any member of the team has a success, a failure, or a question, he/she should communicate this with the other members of the team, especially including the engineer/champion so he/she can help to spread the word and/or find an appropriate solution if needed. This can be done in several ways including:

a) frequent face-to-face meetings of the gas-lift team members to conduct well reviews, review designs, discuss new technologies, and share recommended and non-recommended practices;

b) video conferencing can be a good way to have frequent gas-lift team meetings when people are located in different physical locations: engineering office, field office, service company office, etc.;

c) some formal reports are important to communicate gas-lift designs, the results of special well tests, and the successes and failures that have occurred;

d) it is important for management to be aware of the work of the various members of the gas-lift team and for the team members to receive encouragement, support, and feedback from management.

A.15.9 Commitment Required by the Dual Gas-lift Team

A.15.9.1 General

Each member of the dual gas-lift team has an important role to play and should be committed to this role and participate in all aspects of the team's work. This includes selecting dual gas-lift candidates, selecting equipment, designing the dual gas-lift installation, planning the operation of the well, and performing surveillance and troubleshooting operations.

The key members of the team are the following.

— *Gas-lift Champion*—In many cases, the champion will serve as the leader or mentor of the team.

— *Gas-lift Engineer(s)*—The engineer is primarily responsible for selection of the dual gas-lift equipment and design of the dual gas-lift system.

— *Well Analyst(s)*—Are in touch with the operation of the dual gas-lift wells on a day-to-day basis. They are responsible for determining how to operate the wells for maximum effectiveness. They are also responsible for monitoring the wells, providing routine surveillance of their operations, detecting problems with the wells, and diagnosing the causes of the problems, so they can be solved.

— *Gas-lift Technician(s)*—Are responsible for setting and providing quality assurance testing of gas-lift equipment (especially gas-lift valves) before it is placed into service and again when it is removed from service. The pre-service setting and testing is necessary to assure that only properly set, high quality equipment is used. The post-service testing is necessary to fully understand the causes of any misapplication or failure of equipment so these problems can be corrected on future installations.

— *Operations Personnel*—Implement control of the wells, unless control of the gas-lift injection is automated. They install and collect wellhead charts, unless monitoring of this data is automated. They place the wells on test, unless this process is automated. They operate the gas-lift compressors and dehydrators and operate the production systems.

— *Well Servicing Personnel*—Well servicing personnel run and pull gas-lift valves, run pressure surveys, cut paraffin, and provide other wireline work on the wells. They also perform or supervise workovers.

— *Service Company Personnel*—Service company personnel provide the gas-lift equipment. They may also be responsible for setting and testing gas-lift valves.

A.15.9.2 Understanding the Advantages

Because of its challenges, and frequent disappointments, some may perceive that dual gas-lift work is frustrating and perhaps may result in poor evaluation of their performance by management. This negative perception can be overcome by understanding dual gas-lift well enough to assure some successes and by communicating these successes to management.

A.15.9.3 Continuing Education

The members of the gas-lift team should learn the important aspects of dual gas-lift. In many cases, the same classes will be pertinent for both engineers and for other members of the team. All members of the team should insist on receiving continuing education to stay abreast of the latest dual gas-lift technology, tools, and techniques. API RPs are one potential training and educational resource.

A.15.10 Effective Dual Gas-lift Training Programs

A.15.10.1 General

Several different forms of training programs are required to provide initial understanding, in-depth knowledge, and practical experience in dual gas-lift. Brief discussions of several types of training programs are as follows.

A.15.10.2 Classroom

Fundamental training is provided in the classroom, and the typical gas-lift course is one week in duration. A version of this course could be offered for dual gas-lift. It could contain many of the same basics as a standard gas-lift course but focus on dual gas-lift equipment selection, dual gas-lift design, dual gas-lift operation, and dual gas-lift surveillance and troubleshooting.

A.15.10.3 On Site

Typically, a classroom course is offered in some central location where it can be attended by people from different companies. A similar course could be provided on location in the engineering office or even in the field office of an operating company. One advantage is that the course can be tailored to local needs.

A.15.10.4 One-on-one Mentoring

One of the best forms of training is one-on-one or one-on-few mentoring where one or more people have a chance to learn “on the job” by working side-by-side with an expert. This can be easier if an outside expert is needed, but it can work very well if an expert (e.g. the company’s gas-lift champion) has the time to provide this mentoring.

A.15.10.5 Computer-based Training

The following are several types of computer-based training/advising.

a) *Online Help*—The best gas-lift design and analysis programs have very good online “help” information that not only explains how to run the program but also how to perform the design or surveillance activities, what parameters are important, etc.

b) *Computer Simulators*—There are computer simulators that provide good understanding in “normal” gas-lift operations, problem cases, and how to solve problems.

c) *Computer Courses*—Provide the student with information and tests. These systems thereby provide rapid feedback on the right and wrong answers; thus, the learning is rapid.

d) *Web-based Training*—Web-based training programs allow the student to interact with the instructor via the internet to facilitate rapid knowledge growth.

e) *Remote Computer-based Advising*—An expert, possibly at a remote location, can access and evaluate information from dual gas-lift wells, via the internet, if the wells have the necessary instrumentation, computer system(s), and communications. The expert can help to troubleshoot problems and can provide valuable feedback to the local staff on how to improve the operations to avoid future problems.

A.15.10.6 Physical Models

The final method of training is with a physical model of a dual gas-lift well. There are a few single gas-lift models in existence, and they are excellent in providing insight into gas-lift operations and problems. If there were sufficient interest, a physical dual gas-lift model could be constructed. It could simulate both good and bad performance and be used to experiment with various strategies to solve typical operating problems.

Annex B
(informative)

Dual Gas-lift Mandrel Spacing Design

B.1 Introduction

This annex provides an example mandrel spacing design for dual gas-lift. It is presented for illustration and training purposes. Generally, a manual method such as this will not be used; a computer program will normally be used to design mandrel spacing. Not all computer programs support the “straight-line” tubing pressure design line method. It is recommended to use a program that does. This example spacing is used to perform a gas-lift valve design for PPO gas-lift valves.

The gas-lift mandrel spacing design is done before and separately from the gas-lift valve design because this is the normal situation. Typically, the mandrels are spaced and installed when the well is completed or recompleted. The valves are designed when the well is placed on gas-lift.

B.2 Well Description

Table B.1 describes the well characteristics for this example.

B.3 Design Assumptions

Table B.2 provides the gas-lift characteristics for this example. The design assumptions are as follows.

— Use IPO spacing design. This will provide a conservative mandrel spacing design. That is, they will be closer together than if a PPO spacing design were used.

— Space mandrels based on the long string.

— Space the short string mandrels one tubing joint [use 15.2 m (50 ft)] above the lower zone mandrels.

— Use the “straight-line” design method. This provides a conservative design that makes it easier to unload the well.

— Design the mandrels down to just above the dual production packer.

B.4 Mandrel Spacing Design for the Long String

B.4.1 Manual Design Method

This design is explained as though it were being performed manually using graph paper. There are several computer programs that can provide the design automatically.

B.4.2 Step 1—Casing Pressure Design Line

Draw the kickoff casing pressure gradient design line. Draw it from the kickoff pressure at surface, minus the kickoff pressure safety factor, using the injection gas gradient.

Table B.1—Example Well Parameters

Well Parameter	Units	
	SI	USC
Well depth	2438 m	8000 ft
Geothermal surface temperature	38 °C	100 °F
Casing size	17.78 cm	7 in.
Tubing size—both zones	6.03 cm	2.375 in.
Depth of lower production zone	2377 m	7800 ft
Depth of long string production packer	2347 m	7700 ft
Static reservoir pressure of lower zone	22,063 kPa	3200 psi
Reservoir temperature of lower zone	82 °C	180 °F
Flowing surface temperature of lower zone	49 °C	120 °F
Depth of upper production zone	2011 m	6500 ft
Depth of short string dual zone packer	1951 m	6400 ft
Static reservoir pressure of upper zone	17,237 kPa	2500 psi
Reservoir temperature of upper zone	66 °C	150 °F
Flowing surface temperature of upper zone	43 °C	110 °F
Casing pressure for kickoff	8274 kPa	1200 psi
Casing pressure for operation	7929 kPa	1150 psi
Minimum stable tubing pressure	1034 kPa	150 psi
Completion fluid specific gravity	1.05	1.05
Completion fluid gradient	10.28 kPa/m	0.455 psi/ft
Injection gas specific gravity	0.65	0.65
Injection gas gradient	0.5311 kPa/m	0.0235 psi/ft

Table B.2—Example Gas-lift Characteristics

Gas-lift Characteristic	Units	
	SI	USC
Gas-lift mandrels	KB	KB
Gas-lift valves	2.54 cm	1 in.
Kickoff pressure safety factor	345 kPa	50 psi
Kickoff depth safety factor	15.24 m	50 ft
Tubing pressure safety factor	345 kPa	50 psi
Injection pressure drop between valves	207 kPa	30 psi
Minimum spacing between mandrels	91.44 m	300 ft

B.4.3 Step 2—Tubing Pressure Reference Line

Draw the straight tubing pressure reference line. Draw it from the tubing pressure at surface, plus the tubing pressure safety factor, plus a value equal to 0.2 times the kickoff injection pressure minus its safety factor, minus the tubing pressure plus its safety factor. Draw it to a value equal to the casing pressure at the depth of the dual zone production packer minus 1379 kPa (200 psi).

In equation form:

$P_{ts} = P_t + P_t$ safety factor

$P_{cs} = P_c - P_c$ safety factor

Draw the line from $P_{ts} + 0.2 \times (P_{cs} - P_{ts})$.

Draw it to P_c at depth of short string production packer—1379 kPa (200 psi).

B.4.4 Step 3—Initial Unloading Gradient Line

Draw the initial unloading gradient line. Draw it from P_{ts} at the surface using the completion fluid pressure gradient.

B.4.5 Step 4—Intersection of Design Lines

Find the intersection of initial unloading gradient line and the casing pressure design line.

B.4.6 Step 5—Depth of Top Gas-lift Mandrel

Find the depth of the top gas-lift mandrel. It is at the intersection found above minus the kickoff depth safety factor.

B.4.7 Step 6—Reduced Casing Pressure Design Line

Draw the reduced casing pressure design line. This is the new casing pressure design line that is parallel to the original casing pressure line. It is offset from the original casing pressure line by the injection pressure drop between valves.

B.4.8 Step 7—Next Unloading Gradient Line

Draw the next unloading gradient line from the intersection of the top mandrel depth and the tubing pressure design line. Draw it parallel to the previous unloading gradient line.

B.4.9 Step 8—Next Mandrel Depth

Find the intersection of the new unloading gradient line and the new, reduced casing pressure line. This is the depth of the second mandrel.

B.4.10 Step 9—Continue the Process

Continue this process to work down until the depth of the upper zone packer, or the minimum spacing between mandrels, is reached.

B.4.11 Step 10—Add Extra Mandrels

Add extra mandrels down to packer, if pertinent. Use the minimum spacing between mandrels. The idea here is to space mandrels as close to the packer as is reasonable. Normally do not space a mandrel closer than 30.5 m (100 ft) above the packer.

Table B.3 provides the calculated long string mandrel depths, and Table B.4 provides the calculated short string mandrel depths.

Table B.3—Calculated Long String Mandrel Depths

Mandrel	Depth	
	m	ft
1st mandrel	661.4	2170
2nd mandrel	1027.2	3370
3rd mandrel	1322.8	4340
4th mandrel	1539.2	5050
5th mandrel	1697.7	5570
6th mandrel	1828.8	6000
7th mandrel	1920.2	6300

Table B.4—Calculated Short String Mandrel Depths

Mandrel	Depth	
	m	ft
1st mandrel	646.1	2120
2nd mandrel	1011.9	3320
3rd mandrel	1307.6	4290
4th mandrel	1524.0	5000
5th mandrel	1682.5	5520
6th mandrel	1813.6	5950
7th mandrel	1905.0	6250

B.5 Graphical Design

Figure B.1 shows the mandrel spacing design on a graphical layout.

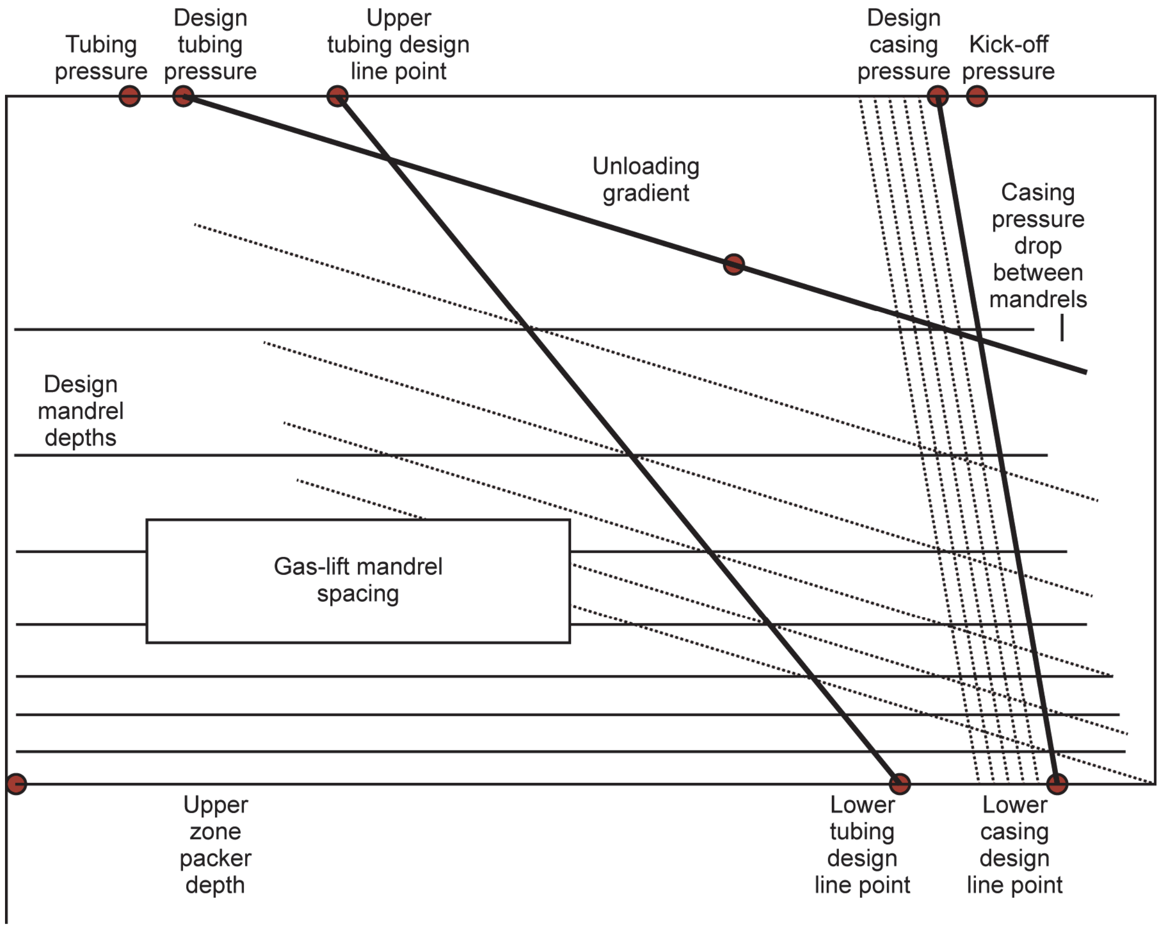

Figure B.1—Gas-lift Mandrel Spacing

Annex C
(informative)

Dual Gas-lift Unloading Valve Design for PPO Valves

C.1 Introduction

C.1.1 General

This annex provides an example gas-lift valve setting design for dual gas-lift. It uses the well parameters and mandrel spacing determined in Annex B. This is presented for illustration and training purposes. Normally, a manual method will not be used; a computer program will normally be used to design valve settings. This annex recommends drawing a flowing pressure gradient. This is supported by most computer programs. However, it is preferred to use an equilibrium curve if one can be generated for the well. The well parameters given in Annex B are used for the PPO gas-lift valve design. The mandrel spacing for the long string will be used in the calculations.

Since PPO valves are mainly controlled by the production pressure in the tubing, it is common to have more than one valve injecting gas while operating under normal conditions. Although multipoint injection is generally considered inefficient, it should be planned for in any PPO design. This design method uses undersized ports in the gas-lift valves to allow for this occurrence. By using undersized ports in the valves, the operator can maintain full operating pressure while injecting in more than one gas-lift valve. The inefficiencies of multipoint injection are usually less important compared to the benefits of the deeper injection point obtained when gas-lifting at the full operating pressure available to the well.

This method applies best to any well that does not operate on the bottom valve. If the well parameters are such that the well will unload and operate on the bottom mandrel, then the port sizes of the valves do not need to be undersized.

C.1.2 Step 1—Depth of Perforations

Draw a horizontal line at the true vertical depth (TVD) of the midpoint of the perforations.

C.1.3 Step 2—Injection Gas Gradient Line

Draw the injection gas gradient line for the kickoff and operating pressures from the surface down to the perforations.

NOTE The kickoff pressure line is only used for location of the top mandrel in the mandrel spacing. It will not be used in the calculations but is drawn for reference.

C.1.4 Step 3—Flowing Pressure Gradient Line

Draw in the flowing pressure gradient for the objective production rate and injection gas liquid ratio.

C.1.5 Step 4—Transfer Pressure for Each Gas-lift Valve

Find the transfer point pressure of each valve (PT). This is done graphically using the slope of the completion fluid gradient. The first valve transfer point will be drawn starting at the intersection of the second valve and the operating pressure gradient. Draw the line up until it intersects the depth of the first mandrel. The pressure at the intersection is the transfer point pressure of the first valve. Continue this for the remaining valves in the well. The bottom valve will not have a transfer point.

C.1.6 Step 5—Safety Factor

To ensure that any valve is capable of transferring deeper before it closes, a safety factor is subtracted from the transfer point pressure to determine the valve's closing pressure. Typically, 344.7 Pa (50 psi) is used for this safety factor.

PVC = PT – 344.7 kPa (50 psi)

C.1.7 Step 6—Gas-lift Valve Port Size

Select the valve's port size. If valve performance tests are available, they can be used for finding the port size needed. When performance tests are not available, the gas passage through a valve can be approximated using 70 % of the Thornhill-Craver equation charts. Once the proper size is found, it is recommended to drop down to the next standard port size. This is necessary since it is common to have more than one PPO valve open while under normal operating conditions. Once the port size of the valve is selected, the R-factor is obtained from the manufacturer of the gas-lift valve.

C.1.8 Step 7—Test Rack Opening Pressure

Calculate test rack opening pressures for each unloading valve.

PTRO = PVC / (1 – R)

C.1.9 Step 8—Opening Pressure at Depth

Calculate the opening pressure (at valve depth) of each unloading valve.

OP = (PVC – $P_{c} \times R$) / (1 – R)

C.1.10 Step 9—Valve or Orifice at Operating Depth

Select either an IPO valve or an orifice for the bottom valve location. If an IPO valve is selected, it should be "flagged" at 689.5 kPa (100 psi) less than the operating pressure. IPO valve calculations are used to calculate the test rack pressure of the valve.

C.1.11 Graphical Method for Design

Figure C.1 provides a graphical method for designing PPO gas-lift valves.

C.1.12 Valve Calculations for PPO Gas-lift Valves

Table C.1 shows the PPO valve gas-lift calculations.

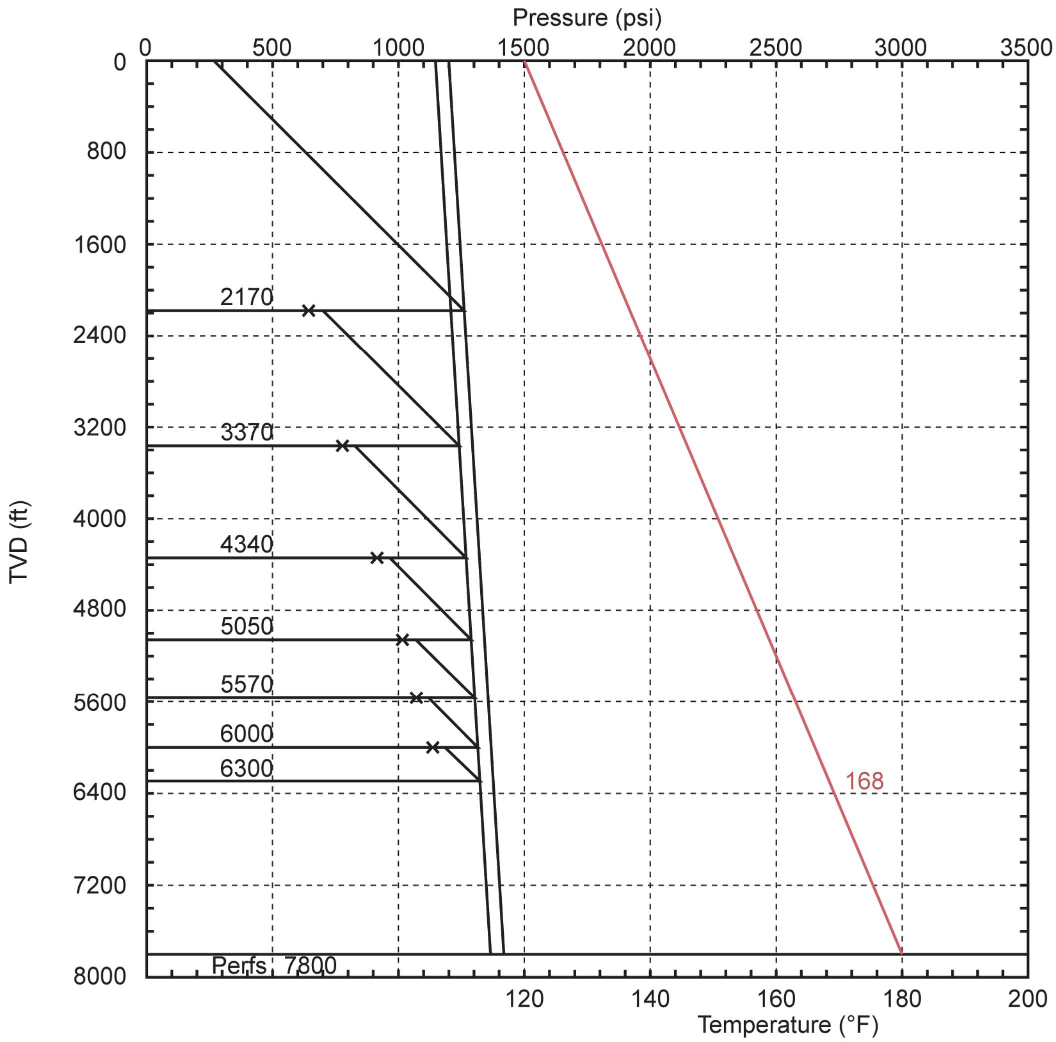

Figure C.1—Graphical Method for Design

Table C.1—PPO Valve Calculations

Valve No.	Depth TVD ft	Depth MD ft	PC at Depth ft	PVC psi	PT psi	$P_C R$ psi	Port Size in.	1-R in.	R in.	OP [a] psi	PTRO [b] psi
1	2170	2170	1261	648	698	50	8/64	0.9600	0.0400	622	675
2	3370	3370	1244	781	831	50	8/64	0.9600	0.0400	761	815
3	4340	4340	1272	918	968	51	8/64	0.9600	0.0400	903	955
4	5050	5050	1291	1019	1069	52	8/64	0.9600	0.0400	1008	1060
5	5570	5570	1306	1072	1122	52	8/64	0.9600	0.0400	1063	1115
6	6000	6000	1318	1140	1190	53	8/64	0.9600	0.0400	1132	1185

Valve No.	Depth TVD ft	Depth MD ft	TV °F	TCF °F	Port Size in.	R in.	DPC ft	PT psi	PTR psi	PSC psi	PVC psi	OP psi	PSO psi	PD at 60 °F psi	PTRO psi
7	6300	6300	168	0.8084	10/64	0.0610	176	1020	62	1050	1225	1239	1063	991	1055

NOTE The variables in this table are shown in USC units; they can also be produced in SI units.

[a] OP is the opening pressure = (PVC – $P_C R$)/1 – R).

[b] PTRO is the test rack opening pressure = (PVC)/(1 – R).

Annex D
(informative)

Dual Gas-lift Practices Not Recommended

D.1 Practices That Are Not Recommended

D.1.1 General

There are several practices that are not recommended when attempting to implement and operate dual gas-lift wells. Each of these issues are addressed in their discrete sections of this document; for further information please review them.

D.1.2 Selecting Candidate Wells

Do not try to dual gas-lift any well that can be produced as a single or that can be commingled.

D.1.3 Staff Selection

Do not try to design and operate dual gas-lift without adequately trained, motivated, and supported staff.

D.1.4 Design

Do not try to minimize the number of gas-lift mandrels—use enough to support various dual gas-lift designs. See 4.5, Section 5, Annex A, Annex B, and Annex C for more information on dual gas-lift design.

D.1.5 Operation

Do not assume that a dual gas-lift well will "operate itself." This assumption is sometimes made with impunity on single-string gas-lift, but care is essential in installing, unloading, kicking off, operating, and optimizing a dual gas-lift well. Do not change the operation of a dual gas-lift well unless it is essential. Once a dual well is lifting deep, stable, and optimum, try to leave it alone and keep it operating deep, stable, and optimum, even in the face of system changes or upsets.

D.1.6 Surveillance

Do not neglect the surveillance process on dual gas-lift wells. With duals, there are many more things that can go wrong that will result in inefficient operation. The purpose of the surveillance process is to frequently (continually, if possible) watch for problems so they are addressed before they become excessive.

D.1.7 Diagnosis and Troubleshooting

Use proven diagnostic and troubleshooting techniques to understand the causes of the problems. Do not use one pressure survey to analyze the well's productivity and its inflow performance unless the well is very stable. Usually, one survey is needed to evaluate gas-lift problems, and a different, stable survey is needed to evaluate well productivity. Do not use an uncalibrated mathematical vertical pressure profile program for gas-lift design and analysis. Do not try to diagnose and troubleshoot every well every day. Use exception reporting to focus only on those wells with significant problems. Do not ignore possible communication problems between the annulus and one or both tubing strings.

D.1.8 Automation

Overlooking the significant benefits that can be realized by automation of the gas-lift system and the dual gas-lift wells is a problem. Do not be deterred by the challenges of gas-lift automation, because often the issues are minor compared with the benefits of automatic monitoring, control, and problem detection/diagnosis.

Bibliography

[1] API Specification 19G1, *Side-pocket Mandrels*

[2] API Specification 19G2, *Flow-control Devices for Side-pocket Mandrels*

[3] API Specification 19G3, *Running Tools, Pulling Tools and Kick-over Tools and Latches for Side-pocket Mandrels*

[4] API Recommended Practice 19G4, *Practices for Side-pocket Mandrels and Related Equipment*

[5] API Recommended Practice 11V5, *Recommended Practices for Operation, Maintenance, Surveillance, and Troubleshooting of Gas-lift Installations*

[6] API Recommended Practice 11V8, *Recommended Practice for Gas Lift System Design and Performance Prediction*

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