

Operation, Maintenance, Surveillance, and Troubleshooting of Gas-lift Installations

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Contents

	Page
1	Scope 1
2	Terms, Definitions, and Abbreviations 1
2.1	Terms and Definitions 1
2.2	Abbreviations 2
3	Gas-lift Operating System Components and Potential Problems 2
3.1	Purpose 2
3.2	Gas-lift System Components 3
3.3	Gas-lift System Operating Problems 3
3.4	Surface Facility Problems 4
3.5	Metering and Control Problems 5
3.6	Gas-lift Valve Problems 6
3.7	Well Equipment Problems 6
3.8	Gathering System Problems 7
3.9	Well Testing Problems 8
3.10	Production Handling Problems 8
3.11	Information Handling Problems 9
3.12	Surveillance and Control Problems 10
4	Gas-lift Operating Problems 10
4.1	Purpose 10
4.2	Under-lifted and Over-lifted Wells 11
4.3	Ineffective Gas Distribution 18
4.4	Unstable Gas-lift Operation 18
4.5	Types and Causes of Unstable Operation 20
4.6	Other Problems 23
5	Surface Gas-lift Compression, Dehydration, and Distribution 24
5.1	Purpose 24
5.2	Compression Facility 25
5.3	Gas Dehydration Facility 27
5.4	Gas-lift Distribution System 29
6	Gas Injection Metering and Control 31
6.1	Purpose 31
6.2	Gas Metering 31
6.3	Injection Control 33
7	Gas-lift Valves 36
7.1	Purpose 36
7.2	Unloading Valves 36
7.3	Operating Valve(s) 38
8	Well Equipment Tubulars, Completion, and Wellhead 39
8.1	Purpose 39
8.2	Casing/Tubing Annulus 39
8.3	Tubing 41
8.4	Completion 42
8.5	Wellhead 44
8.6	Wellhead Monitoring and Control 45
9	Gathering System-flowline and Manifold 47

Contents

	Page
9.1 Purpose	47
9.2 Flowline	48
9.3 Manifold	50
10 Well Production Rate Testing	51
10.1 Purpose	51
10.2 Well Testing	51
10.3 Well Test Equipment	57
10.4 Well Test Measurements	59
11 Production Handling System	61
11.1 Purpose	61
11.2 Oil Handling System	62
11.3 Water Handling System	62
11.4 Gas Handling System	62
12 Guidelines for Collecting and Using Operating Information	63
12.1 Purpose	63
12.2 Well Test Information	63
12.3 Downtime Information	66
12.4 Pressure and Temperature Surveys	67
12.5 Injection Pressure and Rate Measurements	73
12.6 Wellhead Production Pressure, Temperature, and Rate	74
13 Manual and Automated Well Operation and Control	76
13.1 Purpose	76
13.2 Manual Operations	76
13.3 Automated Operations	77
14 Procedures for Initial Unloading and Kickoff	79
14.1 Purpose	79
14.2 General Unloading Recommendations	79
14.3 Unloading Continuous Gas-lift Wells	80
14.4 Restarting (Kick-off) Continuous Gas-lift Wells	82
14.5 Unloading Intermittent Gas-lift Wells	82
14.6 Restarting (Kick-off) Intermittent Gas-lift Wells	84
15 Procedures for Adjusting (Fine-tuning) Gas-lift Injection Rates	84
15.1 Purpose	84
15.2 Continuous Gas-lift Wells with Steady Pressure	84
15.3 Continuous Gas-lift Wells with Variable Injection Pressures	85
15.4 Intermittent Wells with Time Cycle Control	85
15.5 Intermittent Wells with Choke Control	86
15.6 Intermittent Wells with Automatic Control	87
15.7 Flowline Chokes	87
Bibliography	88
 Figures	
1 Gas-lift System Components	5
2 Problem of Injecting Gas through an Upper Gas-lift Valve	13
3 Problem of Under-injection—Injecting Too Little Gas	14

Contents

	Page
4	Over-injection of Gas 15
5	Determining the Optimum Gas Injection Rate. 16
6	High Injection Pressure Causing an Upper Valve to Open 17
7	Under-injection—Causing Operating Valve to Flood 22
8	Hydrate Conditions..... 27
9	Water Content vs Temperature and Pressure 28
10	Finger Distribution System 29
11	Looped Distribution System 30
12	Adjustable Choke for Continuous Gas-lift Control. 84

Tables

1	Well Test Data Expressed in Oil Field Units 65
2	Well Test Data Expressed in Metric Units 65

Introduction

These recommended practices and requirements are offered to assist gas-lift system operators, analysts, technicians, engineers, and others in understanding how to effectively plan, operate, maintain, troubleshoot, and provide surveillance of gas-lift systems and gas-lift wells.

These recommended practices discuss continuous gas-lift with injection down the casing/tubing annulus and production up the tubing. Annular flow gas-lift (injection down the tubing and production up the annulus), dual gas-lift (two tubing strings in the same casing), and intermittent gas-lift are mentioned; however, most of the discussion focuses on conventional continuous gas-lift. Many of the recommended practices in this document can be pertinent to the other forms of gas-lift, but they should be considered and used with caution. Other API recommended practices address dual gas-lift (API 19G9) and intermittent gas-lift (API 19G10).

This document includes the following.

- Gas-lift operating system components and potential problems.

Sections 3 through 13 describe the several components of an operating gas-lift system and discuss a number of problems that can be encountered and addressed to operate a gas-lift system effectively and efficiently. These sections may be used for:

- part of a training course dealing with gas-lift system operation;
 - a review before beginning a major gas-lift system study;
 - a review before designing or modeling a gas-lift system, or both;
 - a review before trying to troubleshoot difficult gas-lift system problems.
- Recommended practices for gas-lift operation, maintenance, surveillance, and troubleshooting.

Sections 14 and 15 are revisions/upgrades of information that has been in existence since the first edition of this document. These sections contain recommended practices for common gas-lift operations:

- initial unloading of the completion or workover fluid from the annulus of the gas-lift well;
- restarting or kickoff after a period of downtime;
- adjusting or fine-tuning the gas injection rate for optimum operation.

These sections discuss commonly used gas-lift troubleshooting tools. They conclude with sections that review the potential locations of gas-lift problems, a table of possible causes and cures of some common gas-lift system problems, and a troubleshooting checklist.

These sections are recommended for use as:

- part of a training course dealing with gas-lift system operation;
- part of a training course dealing with gas-lift system maintenance;
- a review before trying to troubleshoot a difficult gas-lift operating problem.

Operation, Maintenance, Surveillance, and Troubleshooting of Gas-lift Installations

1 Scope

This recommended practice (RP) provides guidance, background, and requirements for the application and use of gas-lift wells and their related systems. Discussion is included for operation, maintenance, surveillance, and troubleshooting of gas-lift wells and installations.

This RP is intended for use by managers, production technologists, reservoir engineers, facilities engineers, production engineers, well testing engineers, well analysts, operators, and researchers who want to gain a general understanding of gas-lift wells and gas-lift operations. It can be used to prepare and present courses on gas-lift wells and operations.

This RP focuses primarily on continuous gas-lift. However, use of intermittent gas-lift, dual gas-lift, and gas-lift for gas wells is mentioned.

2 Terms, Definitions, and Abbreviations

2.1 Terms and Definitions

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

2.1.1

bottomhole pressure

BHP

The pressure measured at the midpoint of the perforated interval.

2.1.2

flowing bottomhole pressure

FBHP

The pressure measured at the bottom of the well, at the midpoint of the perforations, when the well is on production.

2.1.3

inflow performance relationship

IPR

The ratio of production rate (expressed in bbl/day or m³/day) divided by the pressure drawdown (static bottomhole pressure minus flowing bottomhole pressure).

2.1.4

injection pressure operated gas-lift valve

IPO gas-lift valve

A gas-lift valve where the primary opening pressure is provided by the injection pressure.

NOTE The injection pressure is provided by the casing pressure.

2.1.5

production pressure operated gas-lift valve

PPO gas-lift valve

A gas-lift valve where the primary opening pressure is provided by the production pressure.

NOTE The production pressure is provided by the tubing pressure.

2.1.6

static bottomhole pressure

SBHP

The pressure measured at the bottom of the well, at the midpoint of the perforations, when the well is not on production.

2.2 Abbreviations

AWT	automatic well test
BHP	bottomhole pressure
FBHP	flowing bottomhole pressure
FGLR	formation gas-to-liquid ratio
GOR	gas/oil ratio
IGLR	injection gas-to-liquid ratio
IPO	injection pressure operated (gas-lift valve)
IPR	inflow performance relationship
PI	productivity index
PPO	production pressure operated (gas-lift valve)
PVT	pressure-volume-temperature
SBHP	static bottomhole pressure
TGLR	total gas-to-liquid ratio

3 Gas-lift Operating System Components and Potential Problems

3.1 Purpose

Each gas-lift system consists of many components to be understood, operated, and maintained. It is necessary for these components to function together for the system to be efficient.

This document discusses the system components and presents a summary of recommended practices for recognizing and dealing with many of the problems that can cause upsets or inefficient operations in continuous gas-lift, or both. The checklist in 3.3 may be used as a quick reference guide for spotting and addressing common problems that affect continuous gas-lift. This document does not address intermittent gas-lift; it is addressed in API 19G10.

3.2 Gas-lift System Components

The primary components of the gas-lift production system are the following:

- surface gas-lift compression, dehydration, and distribution system;
- gas injection metering and control equipment;
- gas-lift valves;
- well equipment-tubulars, completion, and wellhead;
- gathering system-flowline and manifold;
- well production rate testing facility;
- production handling system.

Each of these components is shown on Figure 1 and is discussed in the sections that follow, along with specific recommended practices that should be followed to reduce inefficiencies and unstable operations.

3.3 Gas-lift System Operating Problems

These are gas-lift system-wide operating problems and recommended practices that should be followed to address them. They are cross-referenced to the section where they are discussed.

- a) Wells that are being under-lifted (lifting too shallow, too little gas) (see 4.1).
 - Provide monitoring and control equipment and procedures.
 - Compare actual vs design/optimum gas-lift performance.
 - Ensure gas-lift valves and other equipment are working properly; allocate the available supply of gas to the most productive wells in an optimal way when the supply is limited.
- b) Wells that are being over-lifted (too much gas) (see 4.1).
 - Provide monitoring and control equipment and procedures.
 - Compare actual vs design/optimum gas-lift performance.
 - Reduce compression or sell excess gas; do not try to inject all of it if overall gas supply is excessive.
- c) Gas-lift distribution is ineffective (lack of good distribution control) (see 4.2).
 - Evaluate overall system constraints, including gas-lift compression, distribution, wells, and handling systems.
 - Distribute or allocate available gas to each well by considering both the gas distribution system and the wells.

d) Gas-lift wells are unstable (injection or production heading, or both) (see 4.3 and Section 6).

- Provide monitoring equipment to detect unstable operation.
- Determine the cause(s) of the instability.
- Eliminate or reduce injection heading; it is very inefficient.

e) Wells have other problems (equipment, instrumentation, etc.) (see 4.5).

- Consider all components of the gas-lift system.
- Monitor and calibrate all system components.
- Establish and practice quality assurance on equipment selection and installation.

3.4 Surface Facility Problems

Typical problems with the surface gas-lift compression, dehydration, and distribution system and recommended practices that should be performed are as follows.

a) Compression problems (see 5.2).

- Maintain the compression facility to provide a consistent supply of lift gas at a stable pressure.
- Monitor the compressor output and adjust the individual well injection rates to optimally balance the demand for gas into the wells with the supply of gas from the compressor plant or other source(s).
- Perform routine compressor preventive or predictive maintenance to maximize system availability, or both.

b) Dehydration problems (see 5.3):

- Dehydrate gas-lift gas to less than 7 lb (3.175 kg) of water per million ft³ (28,317 m³) of gas to avoid hydrate formation. The recommended water content for cold climate operations is 3 lb (1.36 kg) of water per million ft³ (28,317 m³).
- Design the system to avoid the need for large pressure drops. API 14E, Section 2.2 recommends that, for the sizing of pipes receiving gas-lifted production, a surge factor of 40 % to 50 % be added to the estimated steady-state flow rate, compared to 20 % for naturally flowing wells; purge liquid from gas-lift distribution lines periodically.
- Install insulation to reduce ambient temperature effects on freezing problems, except in those cases where ambient temperatures are high and can help prevent freezing problems.

c) Distribution system problems (see 5.4).

- Use a finger style gas-lift distribution system (see Figure 8).
- Make the volume of the system as large as reasonably feasible.
- Avoid combining continuous and intermittent lift in the same gas-lift distribution system unless automatic control is used.
- Measure the total gas into each group of wells to assist with allocation and troubleshooting.

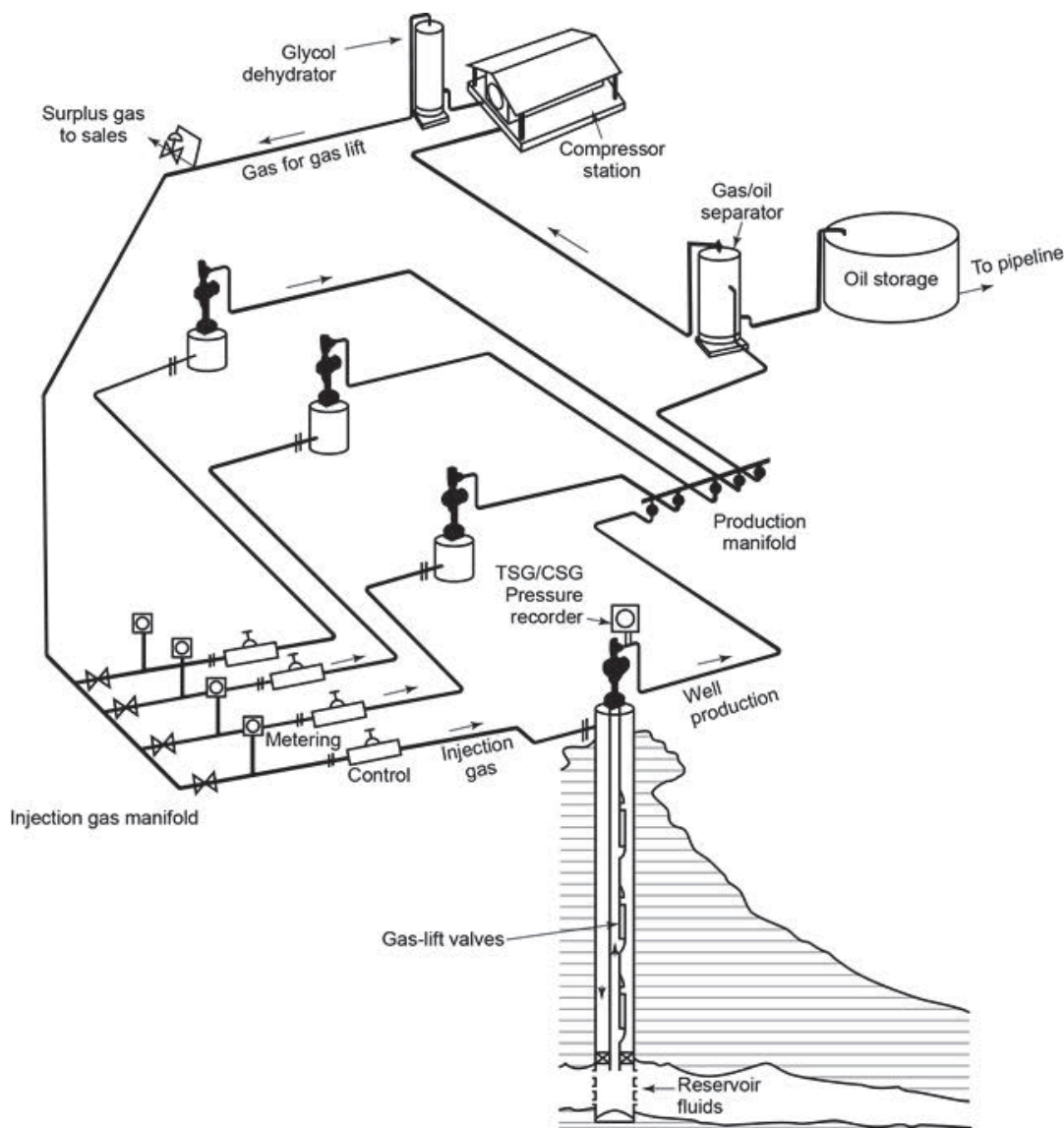


Figure 1—Gas-lift System Components

3.5 Metering and Control Problems

Typical problems with the gas-lift injection metering and control equipment and recommended practices that should be performed are as follows.

- a) Gas injection metering problems (see 6.1).
 - Use properly installed, ranged, well maintained, and accurately calibrated meters.
 - Measure injection pressure at the wellhead, downstream of any obstructions.
 - Pay special attention to gas measurement accuracy during well tests and pressure surveys.

b) Gas injection control problems (see 6.2).

- Operate close to the design conditions of the gas-lift installation.
- Redesign and re-install the gas-lift valves if the well conditions have changed enough to disturb effective operation.
- Use a properly ranged gas flow controller to provide consistent, stable flow.

3.6 Gas-lift Valve Problems

Typical problems with the unloading and operating gas-lift valves and recommended practices that should be performed are as follows.

a) Unloading valve problems (see 7.2).

- Check the gas-lift performance of each well to detect heading or valve operating problems.
- Size the unloading valves to provide for enough gas passage to facilitate transfer to the deeper valves during kickoff and unloading or, use downstream chokes in IPO unloading valves to minimize throttling, avoid over-injection, and minimize damage to the valve port and seat during the unloading process.
- Follow the unloading procedures in Section 12 to work down to the desired operating valve and avoid valve damage during unloading operations.

b) Operating valve problems (see 7.3).

- Use an orifice rather than a gas-lift valve in high productivity index (PI) wells [more than 0.5 B/D/psi (0.012 m³/D/kPa)] to prevent throttling and permit a wider range of gas injection rates.
- Use an IPO gas-lift valve in low PI wells to prevent over-injection and low casing gas pressure, which causes hydrate formation at chokes or excessive gas withdrawal from the distribution pipeline; use of a PPO valve in this case is not recommended.
- Use a choke downstream of the orifice to protect the orifice and avoid over-injection.
- Resize and re-install the operating valve/orifice if well conditions change enough to disturb effective operation.

3.7 Well Equipment Problems

Typical problems with gas-lift well equipment such as tubulars, completion equipment, and wellheads and recommended practices include the following.

a) Tubing/Casing annulus problems (see 8.2).

- Use a casing scraper during workovers to clean debris from the casing wall.
- Circulate fluid to ensure that the annulus is clean.
- Hydrostatically test to gas-lift injection pressure to verify casing integrity.
- Avoid attempting to lift two well completions in one casing annulus. If possible, avoid dual gas-lift. If dual gas-lift is required, refer to API 19G9.

b) Tubing problems (see 8.3).

- Circulate fluid to clean the tubing of corrosion products, scale depositions, and paraffin. If tubing has excessive deposits, pull and replace it with a clean string.
- Remove any unnecessary obstructions, such as scale or paraffin or an unnecessary safety valve if one is not needed if the well can't sustain flow to the surface.
- Use a mechanical set permanent or retrievable packer that holds in both directions.
- Use an on-off tool with a profile nipple that permits an X-plug with equalizing prong or another type of landing nipple with a different profile (such as R, RPT, DB, etc.) to be set in the profile. The plug can be set when the tubing and valves are removed to eliminate kill fluid damage to the reservoir formation.

c) Completion problems (see 8.4).

- Run flowing bottomhole pressure (FBHP) and static bottomhole pressure (SBHP) surveys at least annually to assess and track well performance and reservoir productivity.
- Stimulate a well if its productivity becomes impaired and a pressure buildup test indicates that skin can be the problem.
- Minimize pressure surges and heading in a well that has sand producing reservoir rock or a sand control screen or gravel pack.

d) Wellhead problems (see 8.5).

- Minimize flow restrictions such as bends, choke bodies, etc.
- Provide safe and easy access for wireline work.

e) Wellhead monitoring and control problems (see 8.6).

- Measure the wellhead production pressure on a consistent basis.
- Consider continuous measurement of the well's production rate using multiphase metering or production flow rate estimating technology.

3.8 Gathering System Problems

Typical problems with gathering system equipment, including the flowlines and manifold, and recommended practices that should be performed are as follows.

a) Flowline problems (see 9.2).

- Keep the flowline clean and avoid restrictions.
- Use appropriate treatments if needed to remove scale deposits, paraffin, etc.
- Avoid using one flowline for more than one well; this is to minimize excessive backpressure and avoid complications in monitoring the production of each well.

b) Manifold problems (see 9.3).

- Minimize any restrictions or pressure losses.
- Keep all manifold valves fully open or fully closed.
- Check the manifold for leaking valves using sonic or infrared detectors.

3.9 Well Testing Problems

Typical problems with well production rate testing equipment and recommended practices that should be performed are as follows.

a) Well test scheduling problems (see 10.2).

- Test each well often enough to detect changes in performance.
- Test each well long enough to obtain accurate results.
- Coordinate well testing with other activities such as pressure surveys.
- Use automatic or semi-automatic well testing to improve testing accuracy and reduce testing labor.

b) Test separation problems (see 10.3).

- Purge time is required to thoroughly flush the previous well's production from the system.
- Maintain the test separator backpressure consistent with the production system pressure.
- Check and calibrate the well test meters.

c) Test measurement problems (see 10.4) make well testing a high priority so it receives the attention it deserves.

3.10 Production Handling Problems

Typical problems with production handling equipment and recommended practices that should be performed are as follows.

- a) Oil handling problems (see 11.2): measure total oil produced from each set of wells for comparison with estimates and for allocation and troubleshooting purposes.
- b) Water handling problems (see 11.3): measure or estimate total water production from each set of wells for comparisons and for allocation and troubleshooting purposes.
- c) Gas handling problems (see 11.4): measure gas production from each set of wells for comparisons and for allocation and troubleshooting purposes.

3.11 Information Handling Problems

Typical problems with information handling and recommended practices that should be performed are as follows.

a) Well test information problems (see 12.2).

- Detect and evaluate good-vs-questionable-vs-bad well tests.
- Retest wells if the data is questionable.
- Fix the problem that creates a bad test and then retest the well.
- Use the good well tests to evaluate actual performance and allocate gas-lift production.

b) Downtime information problems (see 12.3).

- Detect and account for all downtime.
- Use this data to allocate production to the wells, calculate production deferment due to downtime, and prioritize remedial work.
- Keep unplanned downtime to a minimum.
- Use well downtime plus facility downtime to develop an operating factor for groups of lifted and naturally flowing wells. The operating factor (fraction of online time) multiplied by daily oil production gives the average calendar-day contribution from each well group.

c) Pressure and temperature survey information problems (see 12.4).

- Obtain pressure surveys annually, or when conditions change.
- Follow the procedures in 12.4 to obtain accurate results.
- Obtain a pressure buildup if the inflow performance has changed.

d) Gas injection pressure and rate measurement information problems (see 12.5).

- Monitor and continuously record the injection pressure and rate;
- Gather this information during well tests, pressure surveys, and unloading;
- Use this and related information to perform gas-lift surveillance and build accurate gas-lift models.

e) Wellhead (production) pressure and temperature information problems (see 12.6).

- Monitor and continuously record the production pressure;
- Gather this information during well tests, pressure surveys, and unloading.

3.12 Surveillance and Control Problems

Typical problems with the gas-lift surveillance and control system and recommended practices that should be performed are as follows.

a) Manual operating problems (see 13.2.2).

- 1) ensure operations tasks are performed by qualified persons;
- 2) provide ongoing training in all aspects of gas-lift operation;
- 3) provide quality measurement and control equipment;
- 4) perform periodic system reviews to identify bottlenecks and opportunities;
- 5) become familiar with the following checklist of questions to address if problems develop in gas-lift wells:
 - is the master valve open?
 - is the wing valve open?
 - is the operating gas-lift valve open?
 - is the downhole safety valve open?
 - is the well's flow rate slugging?
 - is there a choke in the flowline?
 - is the gas-lift injection rate correct?
 - is the gas-lift injection pressure reasonable?
 - is the gas-lift injection pressure heading or surging?
 - is the flowing wellhead pressure reasonable?
 - is the flowing wellhead temperature reasonable?
 - is the separator pressure reasonable?
 - is hydrate forming at chokes or low spots in the piping?
 - is well test data (oil/water/gas) reasonable and reliable?

b) Production automation, see 13.3; use production automation to improve operational effectiveness.

4 Gas-lift Operating Problems

4.1 Purpose

A gas-lift system is intended to operate with a stable supply of lift gas and the gas should be delivered to the wells at a constant, known pressure and rate. All components in the system, including the gas-lift valves, tubulars, wellheads, flowlines, and separation and treating facilities, shall be sized properly for stable operation.



If one or more of the system components are not working as intended, one or more problems can arise:

- wells can be under-lifted, resulting in lost or deferred production;
- wells can be over-lifted, resulting in excess consumption of gas or lost production, or both;
- lift gas can be ineffectively distributed, resulting in sub-optimum system performance, even if other parts of the system are designed adequately;
- wells can be unstable and can lead to numerous problems.

4.2 Under-lifted and Over-lifted Wells

4.2.1 General

A gas-lift well is under-lifted when the depth of gas injection is shallower than necessary for optimum lift or the rate of gas injection is too low, or both. Both of these conditions can lead to ineffective lift gas utilization and lower than desired production.

A gas-lift well is over-lifted when the rate of gas injection is too high or the gas injection pressure is too high, or both. These conditions can lead to ineffective lift gas utilization. Less than optimum gas-lift exists when a large increase in injection gas rate results in a small gain or even a loss in production. The objective is to use the total available injection gas in an optimum way to maximize the total oil production rate. Over-lifting can also cause high casing pressures and reopening of upper unloading valves resulting in much less efficient use of lift gas and wear on unloading valves.

When the compressor capacity exceeds optimum injection gas required for the group of wells, the criteria of flow stability can be applied. Stability requires a velocity of about 6 ft/sec (1.83 m/sec) in the gas-lifted mixture in the tubing string above the injection point.

4.2.2 Practices for Under-lifted and Over-lifted wells

The following practices are recommended and should be followed for under-lifted and over-lifted wells.

- Monitor the performance of each gas-lift well using flowing pressure and temperature surveys, and static pressure surveys, in conjunction with accurate well test and injection information, to determine (or estimate) the current producing gradients, depth(s) of gas-lift injection, FBHP(s), and inflow performance. Use this data to create a calibrated computer model for use in surveillance and troubleshooting. Apply the same procedures to natural flow wells that will eventually be artificially lifted.
- As an alternative to a flowing pressure and temperature surveys, a CO₂ tracer survey method may be used to determine the depth(s) of gas-lift injection. Here, a small amount of CO₂ is injected along with the injected gas-lift gas. The return production is monitored and the time for the return of the CO₂ is determined. The time of the CO₂ return is correlated to the depth(s) of injection from the casing annulus into the tubing. This method can be used on both single and dual string gas-lift wells.
- Use a calibrated computer model, with current operating conditions, to detect a well that is being under-lifted, and to predict the optimum gas-lift injection rate, pressure, depth, and expected increase in production from solving the problem.

- Maintain the desired gas-lift injection control with a gas measurement system and an automated control valve to maintain the desired injection rate and pressure.
- Find over-lifted and under-lifted wells using flowing and temperature gradient surveys, or the CO₂ method described above, and production tests that include injection gas measurement. Gas saved in one group of wells may be used to advantage in other wells.
- Increase the injection rates to non-optimal rates in some wells (if necessary, on a temporarily basis) to obtain stability by achieving a mixture velocity of approximately 6 ft/sec (1.83 m/sec) above the point of injection. If this condition persists, however, the well should be redesigned to overcome the instability problem by increasing the injection rate. Most gas-lift computer models can calculate the mixture velocity.
- Evaluate the effects on surface facilities caused by temporary over-injection in wells, if this practice is used to maintain stability.
- Verify that the gas-lift valves are properly constructed, assembled, and set before they are installed. Use gas-lift valves manufactured to API 19G2 specifications. See API 19G2 for repair and reassembly.
- Check and probe test individual valves to verify conformance with design specifications for critical applications, or where there are ongoing problems. See API 19G2 for gas-lift valve testing and modeling procedures.
- Identify wells that are being under-lifted and check for an inadequate supply of gas due to pipeline restrictions or limited compressor capacity. Evaluate the wells and establish a production priority or optimum gas-lift allocation, or both (see API 11V8).
- Determine the frequency of compressor shutdowns. The wells may not be able to work down and maintain stable, deep injection if there are frequent interruptions. It may be necessary to redesign the unloading valves with smaller ports or chokes and adjust the gas injection control. An alternative can be to place the gas-lift injection orifice at a shallower depth. Compressor downtime should not be greater than 5 %.

4.2.3 Shallow Under-lifted Injection

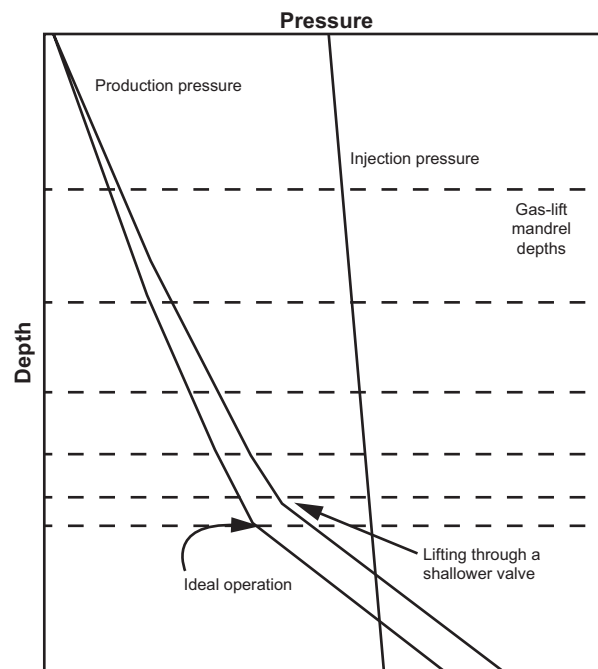
For a well to be lifted properly, the gas shall be injected at the design (optimum) injection depth. The desired point of lift should be within three joints [about 100 ft (30.48 m)] above the production packer, but the actual point of lift is based on the following:

- depth of the well;
- reservoir pressure;
- well's productivity (inflow performance);
- available gas-lift system pressure;
- production back pressure.

If the injection is occurring through an upper unloading gas-lift valve or valves, or through a hole or leak, the well's FBHP cannot be drawn down to the desired value, and the production rate will be less than desired (see Figure 2).

This condition can be caused by a number of problems including:

- lower than desired injection gas pressure;
- improper gas-lift mandrel spacing;
- valves that are not assembled or set properly; valves that are installed in the wrong mandrels; use of the wrong types of valves, or ports that are too large;
- leak in an upper unloading valve, upper mandrel, tubing, or connection;
- well not properly unloaded; the unloading process never reached the intended operating valve;
- other problems that do not allow the well to work down to its design injection depth are restrictions at the surface, inadequate injection control, and frequent shutdowns.



NOTE By injection through an upper gas-lift valve, even with the same amount of gas, the operating bottomhole pressure is increased and the production is reduced.

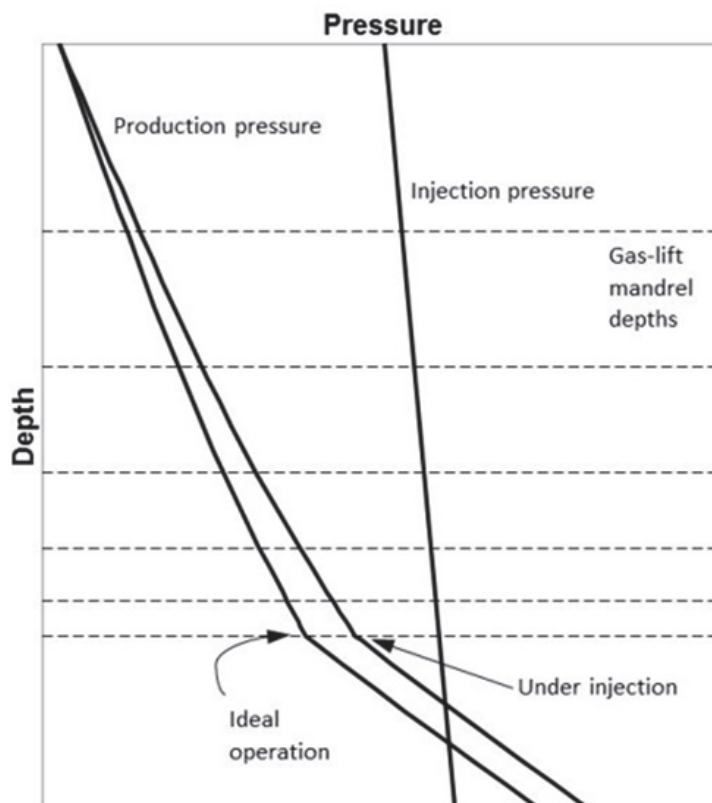
Figure 2—Problem of Injecting Gas through an Upper Gas-lift Valve

4.2.4 Low Under-lifted Injection Rate

Continuous gas-lift design specifies the injection rate needed to achieve a desired flowing pressure gradient from the design point of gas entry to the surface. If the gas injection rate is too low, the gradient will be too heavy and the well will not be drawn down to the desired FBHP, even if injection is at the desired operating valve or orifice. This can result in the well producing less than the potential rate (see Figure 3).

This condition can be caused by:

- rate of gas available to the well is less than design;
- injection gas pressure available to the well is lower than design;
- flow restrictions at the surface;
- control choke or valve at the surface is improperly set and the injection rate is less than design;
- hydrates forming in the choke or gas line serving the well;
- the gas-lift valve port size, or choke size, is too small to accommodate the desired gas injection rate;
- increased water cut requiring additional injection gas to maintain the desired pressure gradient.



NOTE By not injecting enough gas, even through the same valve, the operating bottomhole pressure is increased and the production rate is reduced.

Figure 3—Problem of Under-injection—Injecting Too Little Gas

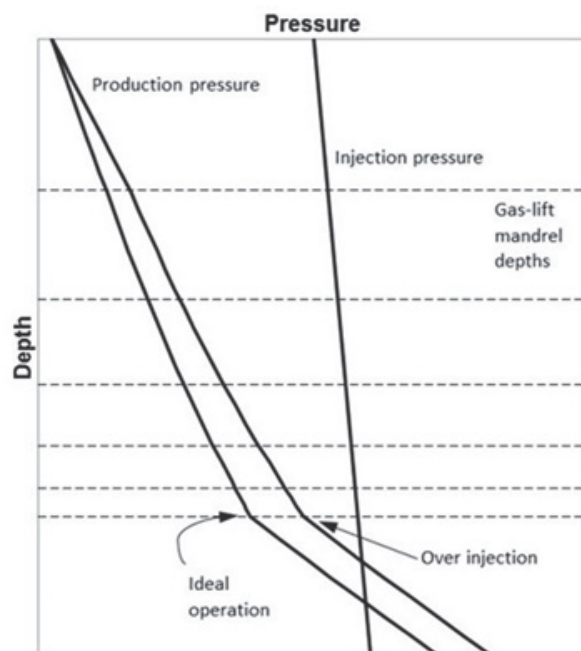
4.2.5 High Over-lifted Injection Rate

An excessive gas-lift injection rate should be avoided because it can allow injection gas to enter an upper IPO gas-lift valve. Excess gas can raise casing pressure above the set point for upper IPO unloading valves, causing one to open with a loss of efficiency and production rate.

An excessive gas-lift injection rate can also limit production. Excess gas can also increase friction in the surface flowline. This can cause a higher FBHP resulting in less drawdown and a lower production rate. The gas rate can become so high that the effect of friction loss exceeds the reduction in fluid density and the pressure gradient begins to increase, the FBHP rises, and the liquid rate decreases.

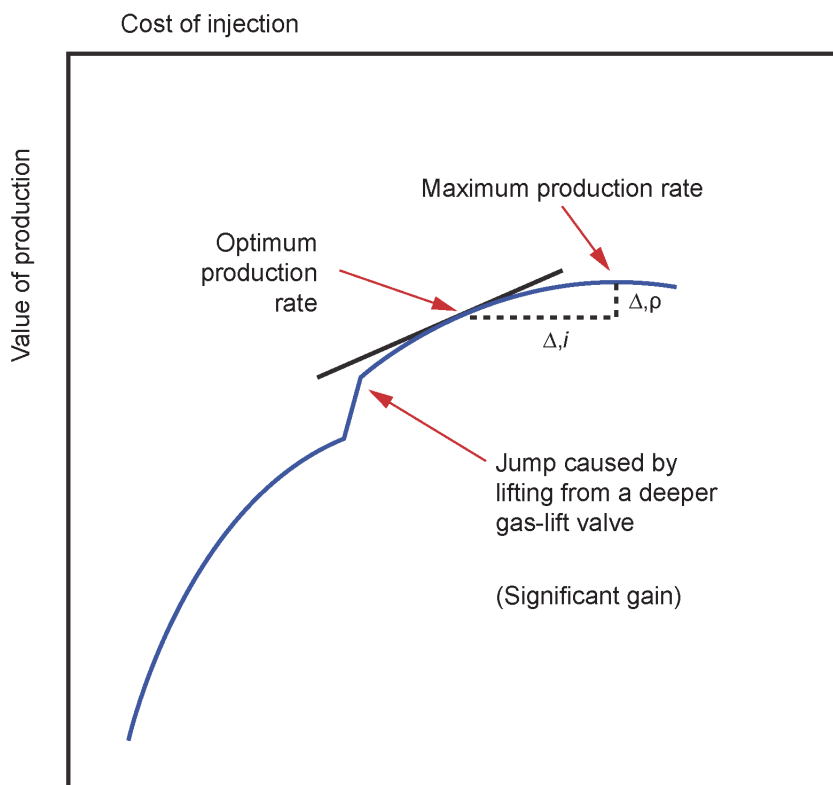
When gas is injected into a continuous gas-lift well, it mixes with the liquid in the production stream (usually the tubing). Gas is less dense than liquid, thus it lightens the pressure gradient (reduces the mixture density), allowing the well to produce with lower production pressure drops. As gas injection is increased, the production pressure continues to drop, up to a point. This point is called the minimum pressure gradient (see Figure 4). The point labeled "Ideal Operation" is considered to be on the minimum practical pressure gradient. The injection gas rate for a continuous gas-lift well should be less than the rate required to reach the minimum gradient, which can increase challenges.

The issues for compressing, dehydrating, distributing, injecting, recovering, and treating gas increase as the rate of gas injection increases; and usually the production rate also increases. At some point, usually well before the minimum gradient is reached, the incremental amount of injection becomes equal to and then exceeds the increment of the increased production. This is called the "point of diminishing returns" (see Figure 5). Even before this point, the incremental benefits can fall below an acceptable limit. From a practical point of view, a well should not be operated beyond the point of acceptable incremental benefit (see API 11V8).



NOTE By injecting too much gas, the gradient is made heavier, which results in higher operating bottomhole pressure and reduced production rate.

Figure 4—Over-injection of Gas



NOTE The optimum production rate occurs where the incremental injection is equal to the incremental value of production. Beyond this point, very little value (Δ, p) is gained for significant increase in injected amount (Δ, i).

Figure 5—Determining the Optimum Gas Injection Rate

4.2.6 Determining Optimum Gas-lift Injection Rate

The optimum gas-lift injection rate is related to the point of diminishing returns. This is usually substantially less than the minimum gradient, which can be modelled with a validated computer program, as discussed in API 11V8. Determining the point of diminishing returns requires reliable operational data.

4.2.7 High Over-lifted Injection Pressure

The surface gas-lift injection control valve is a flow rate control device, either automatic or manual; the rate is controlled by adjusting the opening.

If the gas rate is measured and regulated with a meter, flow controller, and automated control valve, a uniform rate can be achieved. The position (opening) of the valve can continually change to maintain a desired injection rate.

A control problem can occur in gas-lift wells. The gas is primarily controlled on the surface. However, it is also (secondarily) controlled by the downhole operating valve or orifice. If more gas is injected at the surface than can be handled by the downhole valve or orifice, the pressure upstream of the gas-lift valves in the casing annulus increases as the volume of gas in the annulus increases. As this pressure rises, the opening forces on the unloading valves increase. When one of these unloading valves (usually the deepest in the well) opens, gas from the annulus will enter the tubing at this point (see Figure 6). This unloading valve becomes the operating valve or the well has multipoint injection. This is inefficient and can lead to an unstable or heading condition that can cause several other problems. Unstable operation is discussed in detail in 4.4.

Over-lifting a gas-lift well should be avoided. It can be inefficient and cause increased operating issues and can cause severe operating problems.

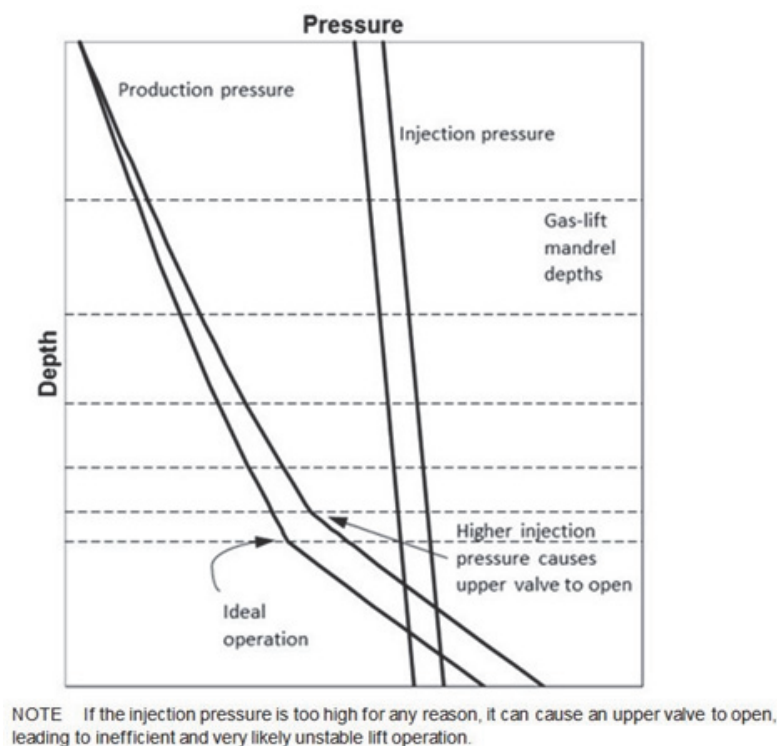


Figure 6—High Injection Pressure Causing an Upper Valve to Open

4.3 Ineffective Gas Distribution

4.3.1 General

Ideally, the rate of gas available in a field should be equal to the sum of the optimum injection rates into the gas-lift wells in the field. In real life this situation never occurs. Either more gas is available than optimally needed, resulting in some degree of over-injection, or less gas is available than optimally desired, resulting in some degree of under-injection.

4.3.2 Gas Distribution Practices

The following practices are recommended and should be followed for effective gas distribution.

- Evaluate performance of the system, in addition to each well. Periodic evaluation can detect patterns of problems associated with ineffective gas distribution. For example, all wells in one part of a field can be under-injected if they are far from the source of the gas or hydrate formation is occurring in the pipeline at a low spot. Or some wells can be unstable if they are downstream of other unstable wells.
- Use a map of the distribution system to indicate which wells are normal and which are under-lifted, over-lifted, or unstable, or a combination thereof.
- Use system-wide solutions to address distribution bottlenecks, gas shortage or oversupply problems, or ineffective gas dehydration indicated by hydrate formation.
- Develop a plan for the optimum distribution of the gas that will be available with every scenario of compressor outage. See API 11V8 for a detailed discussion of this process. With an automatic control system, the allocation can be more easily optimized.

Gas should be distributed to the wells with the objective to maximize oil production; but optimization can also be expressed in terms of gas compression rates vs the value of oil produced.

If there is over supply, the excess gas should be sold rather than being injected ineffectively or injected into wells that have a stability problem. In some cases, gas can be sold at an intermediate pressure that is less than the final gas-lift pressure, thus avoiding some of the compression issues.

If there is an under supply, the lower priority wells (high water cut, low productivity, etc.) should be given less gas than the high priority wells (low water cut, high productivity, difficult to restart). If there is a temporary compressor outage, reduce injection to or shut in some of the lowest priority wells so that the higher productivity wells can continue to be produced effectively. In manually operated gas-lift systems, gas-lift valves with small ports, or chokes, can be installed to limit the gas injection rate to ensure that less gas is given to low priority wells.

The topic of gas-lift optimization-determining the optimum rate of gas injection into each well, and optimally distributing the gas in cases of short supply-is discussed in API 11V8.

4.4 Unstable Gas-lift Operation

4.4.1 General

Unstable operation or heading (not to be confused with the slug flow pattern in multiphase flow) is a serious problem confronting gas-lift wells designed for continuous operation.

4.4.2 Unstable Gas-lift Mitigation Practices

The following surveillance practices are recommended and should be followed for unstable gas-lift operation:

- use pressure transducers to gather and display injection or casing pressure, and production or tubing pressure;
- non-electronic recording devices may be used if electronic devices are not available;
- use a gas meter and flow computer to obtain gas injection rate (and upstream pipeline pressure and differential pressure);

note patterns of instability and use these in gas-lift system analysis, as discussed in 4.3;

see 5.5 to evaluate the type(s) or cause(s) of instability.

4.4.3 Unstable or Heading Gas-lift Operations

4.4.3.1 General

Sections 4.4.3.2 through 4.4.3.10 describe possible problems arising from unstable or heading gas-lift operations.

4.4.3.2 Excessive Use of Lift Gas

Unstable operation or heading is associated with gas being over-injected during parts of the cycle and under-injected during other parts. Gas is being wasted during the over-injection periods and used very ineffectively during the under-injection periods. The overall result is a very poor total ratio of injection gas to total liquid production. Unstable gas-lift heading is never as effective as steady flow in terms of lift gas utilization. Surprisingly, while the use of lift gas can be very inefficient when heading is occurring, one of the cures may be to increase the rate of gas injection, at least on a temporary basis, in conjunction with other steps to improve the overall gas-lift design. This is discussed further in 4.5 under the topic of injection heading.

4.4.3.3 Loss of Production

When a gas-lift well is heading, the pressure in the flow conduit (the tubing) is fluctuating, and as a result, the FBHP is fluctuating. Production rate, based on the pressure drop from the reservoir to the well bore, is a function of the time-weighted average FBHP, which can be significantly higher than the minimum bottomhole pressure. Thus, a heading gas-lift well produces less than a stable well that is operating with a constant, minimum FBHP.

4.4.3.4 Damage to the Wellbore

Unstable operation can lead to fluctuating inflow velocities and excessive stresses on reservoir formation rock and sand control systems. Sand production can, in turn, cause damage to the well bore and gas-lift equipment, and to surface equipment. Excessive sand production can plug a producing well and lead to total well failure.

4.4.3.5 Upsets to Fluid-handling Facilities

Heading can become severe, resulting in large pressure and rate surges that can cause upsets in gathering, fluid separation or testing, and treating equipment. These upsets can, in turn, result in liquid carryovers, gas flaring, meter damage, rupture of a burst disc, or blowing open thief hatches on tanks.

4.4.3.6 Upsets to Gas-handling Facilities

System upsets caused by severe unstable operation can affect gas compression, dehydration, and distribution systems, causing increased compression and handling issues, gas flaring, and lead to nuisance shutdowns.

4.4.3.7 Upsets to Other Wells on the System

Heading can be induced in an otherwise stable well. Heading in one well can cause gas pressure fluctuations that interfere with and have a negative effect on other wells on the same distribution system.

4.4.3.8 Difficulties in Gas and Liquid Measurement and Control

In many cases gas measurements are made with differential pressure devices (e.g. orifice meters) and systems that record the static pressure, differential pressure across the device, and sometimes temperature. These devices work best when the variables are stable. When a well is heading, the static pressure is fluctuating and the differential pressure can be varying rapidly and widely, which greatly diminishes gas measurement accuracy; however, an improvement is gained when a flow computer with rapid sampling is used.

Unstable well operation leads to surging production rates that make accurate tubing pressure and well test measurements difficult to obtain.

4.4.3.9 Difficulties in Analyzing Gas-lift Performance

A good method for evaluating and analyzing gas-lift performance is with a flowing pressure and temperature survey, where the production pressures and temperatures are measured under flowing conditions. When a well is heading, these surveys are more difficult to obtain and analyze. The results can be meaningless unless pressure data is collected throughout the heading cycle at each depth (see 12.4.4).

4.4.3.10 Difficulties in Controlling and Optimizing Gas-lift Performance

All theories and methods for continuous gas-lift system design, operation, troubleshooting, and optimization are based on stable operation. The theories all consider the steady-state operating pressure, rate, and depth; not some range of pressures, rates, and depths. When one or more wells in a system are unstable, the gas-lift models are less accurate, and the gas-lift operators cannot depend on these models for guidance.

4.5 Types and Causes of Unstable Operation

4.5.1 General

Two basic types of unstable operation or heading in continuous gas-lift wells are production (tubing) heading and injection (casing) heading. The two types of heading and their causes and cures should be recognized and understood so they can be differentiated and addressed properly.

The goal in continuous gas-lift is to inject gas at a constant pressure and rate. With intermittent gas-lift, the objective is to produce slugs of liquid from the well by intermittently opening and closing the operating gas-lift valve and intermittently injecting volumes of gas into the production stream. This latter operation is not considered unstable, even though the well is slugging.

4.5.2 Mitigation of Unstable Operation

The following practices are recommended and should be followed for differentiating and addressing types and causes of unstable operation:

- analyze a well's heading or unstable operating characteristics to determine if the well is experiencing production (tubing) heading, injection (casing) heading, or both tubing and casing heading;
- indicate wells with heading problems on a distribution system map to determine if the problem is random or is common to several wells in a particular part of the system. If the problem is common to several wells, it can be

caused by an upstream restriction, instability in the injection system, or a problem with the backpressure regulator that controls the pressure in the injection system;

- work through the heading analysis procedures to determine the most likely cause(s) of heading;
- take the recommended steps to eliminate or minimize the heading problem. Heading is always less efficient than stable operation and severe heading can cause upsets or harm surface facilities.

4.5.3 Production (Tubing) Heading

A stable well produces with approximately constant production (tubing-head) pressure and flow rate. An unstable well experiences production (tubing) heading indicated by a varying tubing-head pressure and a varying flow rate vs time.

The tubing-head pressure and flow rate can vary slightly, or the well can produce in slugs with periods of no production in between heads. The heads may be moderate, or severe with the tubing-head pressure varying by several hundred psi (kPa) and the instantaneous flow rate varying by several hundreds or thousands of bbl/day (m³ day).

Tubing heading can occur without casing heading and can occur in natural flowing wells. The usual cause is the production rate is too low for the tubing size in the well; the low velocity initiates excessive liquid fallback. Production heading can also be caused by inflow from more than one zone, by restrictions in the surface facilities or it can be caused or seriously aggravated by casing heading.

When a well has tubing heading, the pressure will be fluctuating at all depths in the tubing, including at the gas-lift valves. Since the gas flow rate through a valve or orifice is a function of the differential pressure between the casing and tubing pressure, the flow rate will change as the tubing pressure changes (up to critical flow). As the gas flow rate from the casing annulus to the tubing changes, the casing pressure changes, which is defined as casing heading.

Methods to prevent or cure tubing heading include the following.

- Determine if tubing heading is occurring by itself or in conjunction with casing heading. Use pressure transducers to evaluate the fluctuations or as an alternative, use a chart recorder;
- Cure tubing heading by choosing a tubing size that increases mixture velocity. An option may be to insert a coiled tubing string inside of the original production tubing string;
- Cure tubing heading that is induced by casing heading by reducing the valve or orifice port size to create critical flow. The port reduction breaks the link between the casing heading and the induced tubing heading. If casing pressure fluctuation is eliminated, the problem of tubing heading can be cured or reduced;
- Do not choke the tubing at the surface to cure tubing heading, unless choking is needed to protect surface facilities from severe slugging. Choking will increase the pressure in the tubing and increase the amount of gas required to produce the well, and can reduce the production rate from the well;
- Inject more gas to alleviate tubing heading if adequate gas is available and this results in more effective overall production. A strategy based on operating experience is to increase the injection gas rate to raise velocity above the injection point to approximately 6 ft/sec (1.83 m/sec).

4.5.4 Injection (Casing) Heading

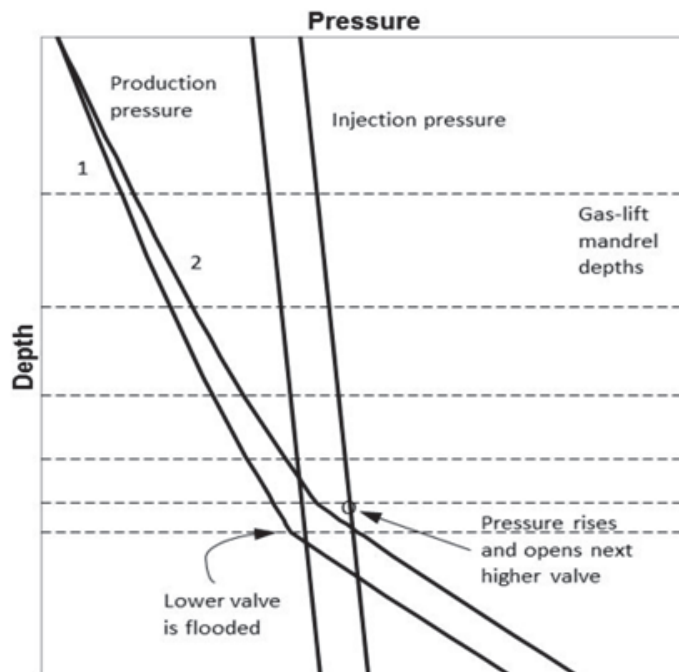
A continuous gas-lift well should have a constant injection (casing) pressure and gas injection rate. Casing heading is defined as a varying injection (casing-head) pressure, which can be associated with a varying gas injection rate. However, even if the injection rate is held constant with a flow rate controller, this may or may not eliminate casing pressure heading. Tubing heading is often caused or aggravated by casing heading.

Casing heading occurs when the gas-lift well's components (surface injection control device, unloading gas-lift valves, or operating gas-lift valve or orifice, or a combination thereof) are not correctly sized or adjusted for steady-state operation. The most common cause is an operating valve or orifice that is sized too large. This allows the gas injection rate into the tubing to fluctuate. This causes the tubing flow rate and pressure to vary and further aggravates casing pressure (and the casing gas inflow and outflow rate) heading.

Stable operation is attained when the actual flow rate into the casing equals the flow rate out of the casing annulus. A slight imbalance will gradually change the volume of gas in the casing annulus, but a large imbalance leads to casing heading as the flow rate through the operating valve or orifice is alternately larger and smaller than the rate of gas injected at the surface.

This problem can be compounded when the operator wants to increase the production from the well. When the surface control valve is opened further, the injection rate and the casing pressure increase. Production may increase and tubing heading may be decreased. However, the casing pressure cannot be increased too much, or one or more unloading valves can reopen. This statement pertains to ISO unloading gas-lift valves.

Casing heading can also be intensified by under-injection which leads to self-intermitting at the operating valve (see Figure 7). This is true for production pressure operated (PPO) gas-lift valves that are more sensitive to changes in tubing pressure. It is also true for surface gas distribution system problems caused by heading in adjacent wells, by upsets in the gas compression, or by backpressure control regulator malfunction.



NOTE: If the injection rate is too low, the production gradient will increase and may flood the operating valve, causing the injection pressure to rise and the next valve to open.

Figure 7—Under-injection—Causing Operating Valve to Flood