

Recommended Practices for Operation, Maintenance, Surveillance, and Troubleshooting of Gas-lift Installations

API RECOMMENDED PRACTICE 11V5
THIRD EDITION, JUNE 2008

REAFFIRMED, MARCH 2015



AMERICAN PETROLEUM INSTITUTE

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Upstream Segment

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Foreword

This document is under the jurisdiction of the API Committee on Standardization of Production Equipment (Committee 11).

This document presents recommended practices for the operation, maintenance, surveillance, and troubleshooting of gas-lift systems. Other API specifications, API recommended practices, and Gas Processors Suppliers Association (GPSA) documents are referenced and should be used for assistance in design and operation.

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Introduction

These recommended practices 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.

This document may be used in a gas-lift training course or as reference material. It can be obtained in booklet form as an API publication, or on CD ROM or cassette in Adobe PDF format.

These recommended practices discuss continuous gas-lift with injection in 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 may be pertinent to the other forms of gas-lift, but they should be considered and used with caution. Other recommended practices will address dual gas-lift (API 11V9) and intermittent gas-lift (API 11V10).

This document includes:

- Gas-lift Operating System Components and Potential Problems.

Sections 1 through 11 describe the several components of an operating gas-lift system and discuss a number of problems that may be encountered and must be addressed to operate a gas-lift system effectively and efficiently. These sections are new to this edition of the document. A comprehensive checklist of system components is provided and associated problems are discussed. The list can be used when troubleshooting or de-bottlenecking a gas-lift system.

These sections are recommended for use as:

- 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 and/or modelling a gas-lift system;
 - a review before trying to troubleshoot difficult gas-lift system problems.
- Recommended Practices for Gas-lift Operation, Maintenance, Surveillance, and Troubleshooting.

Sections 12 through 17 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;
- re-starting or kick off 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.

Recommended Practices for Operation, Maintenance, Surveillance, and Troubleshooting of Gas-lift Installations

1 Gas-lift Operating System Components and Potential Problems

1.0 Purpose

Each gas-lift system consists of many components that must be understood, operated, and maintained. These components must function together for the system to be efficient and economic in artificially lifting wells.

This document discusses the system components and presents a summary of recommended practices for recognizing and dealing with many of the problems that may cause upsets and/or inefficient operations in continuous gas-lift. The checklist below 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 being addressed in API 11V10.

1.1 Gas-lift System Components

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

- 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 to reduce inefficiencies and unstable operations.

1.2 Gas-lift System Operating Problems

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

a) Wells are being under-lifted (lifting too shallow, too little gas), see 2.1:

- provide monitoring and control equipment and procedures;
- compare actual vs. design/optimum gas-lift performance;
- assure gas-lift valves and other equipment are working properly;
- allocate the available supply of gas to the most profitable wells in an optimal way when the supply is limited.

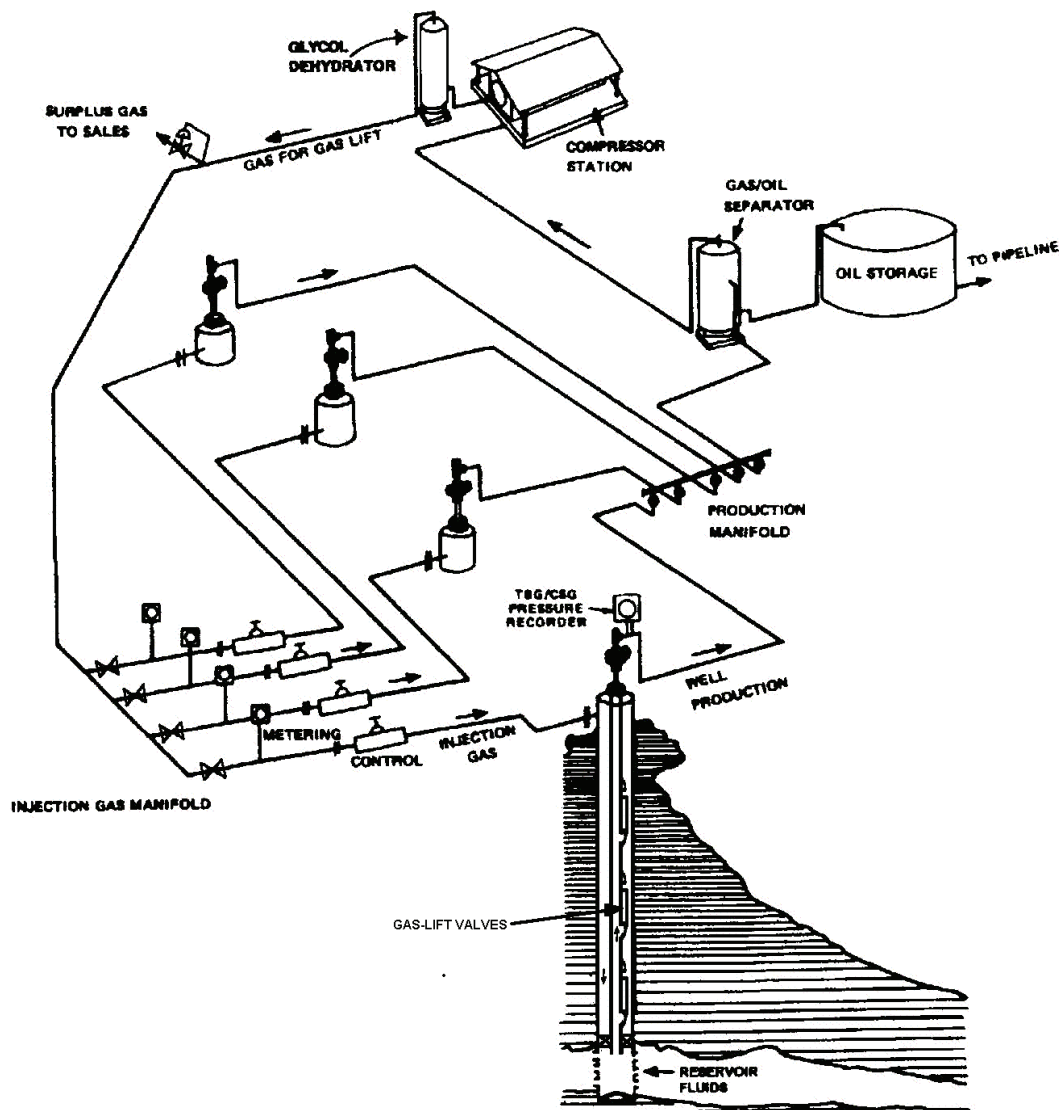


Figure 1—Gas-lift System Components

b) Wells are being over-lifted (too much gas), see 2.1:

- 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 2.2:

- 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 and/or production heading), see 2.3 and Section 4:

- 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 2.5:

- consider all components of the gas-lift system;
- monitor and calibrate all system components;
- establish and practice quality assurance on equipment selection and installation.

1.3 Surface Facility Problems

Typical problems with the surface gas-lift compression, dehydration, and distribution system, and recommended practices to deal with them are as follows.

a) Compression problems, see 3.1:

- maintain the compression facility to provide a consistent supply of lift gas at a stable pressure;
- monitor the compressor output and adjust the 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 maintenance to maximize system availability.

b) Dehydration problems, see 3.2:

- dehydrate gas-lift gas to less than 7 lb (3.175 kg) of water per million cubic ft (28,317 cubic m) of gas to avoid hydrate formation. The recommended water content for cold climate operations is 3 lb (1.36 kg) of water per million cubic ft (28,317 cubic m);
- design the system to avoid the need for large pressure drops. API 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.

c) Distribution system problems, see 3.3:

- use a “finger” style gas-lift distribution system (see Figure 8);
- make the volume of the system as large as economically 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.

1.4 Metering and Control Problems

Typical problems with the gas-lift injection metering and control equipment, and recommended practices to deal with them are as follows.

a) Gas injection metering problems, see 4.1:

- use properly installed, ranged, well maintained, and accurately calibrated meters;
- measure injection pressure at the wellhead, downstream of any obstacles;
- pay special attention to gas measurement accuracy during well tests and pressure surveys.

b) Gas injection control problems, see 4.2:

- operate close to the design conditions of the gas-lift installation;
- redesign and re-install the gas-lift valves if the well's conditions have changed enough to disturb effective operation;
- use a properly ranged gas flow controller to provide consistent, stable flow.

1.5 Gas-lift Valve Problems

Typical problems with the unloading and operating gas-lift valves, and recommended practices to deal with them are as follows.

a) Unloading valve problems, see 5.1:

- check the well performance of each well to detect heading or valve operating problems;
- use small-ported unloading valves to facilitate deeper valve transfer and prevent over injection at upper valves;
- or, use downstream chokes in 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 5.2:

- use an orifice rather than a gas-lift valve in high productivity index (PI) wells [more than 0.5 B/D/psi (.012 m³/D/kPa)] to prevent throttling and permit a wider range of gas injection rates;
- use a gas-lift valve in low PI wells to prevent over injection and low casing gas pressure, which causes hydrates at chokes or excessive gas withdrawal from the distribution pipeline;
- use a choke downstream of the orifice to protect the orifice and avoid over injection;
- redesign and re-install the operating valve/orifice if well conditions change enough to disturb effective operation.

1.6 Well Equipment Problems

Typical problems with gas-lift well equipment such as tubulars, completion equipment, and wellheads, and recommended practices to deal with them are as follows.

a) Casing annulus problems, see 6.1:

- use a casing scraper during workovers to clean debris from the casing wall;
- circulate fluid to insure that the annulus is clean;
- hydrostatically test to gas-lift injection pressure to assure casing integrity;
- avoid attempting to lift two well completions in one casing annulus. (That is, if possible, avoid dual gas-lift. If dual gas-lift is required, refer to API 11V9.)

b) Tubing problems, see 6.2:

- circulate fluid to clean the tubing of corrosion products, scale depositions, paraffin, and asphaltine. If tubing has excessive deposits, pull and replace it with a clean string;
- remove any unnecessary obstacles, such as unnecessary safety valves;
- 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 to be set in the profile. The plug can be set when the tubing and valves must be removed; this eliminates kill fluid damage to the reservoir formation.

c) Completion problems, see 6.3:

- 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 build-up test indicates that skin may 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 6.4:

- minimize flow restrictions such as bends, choke bodies, etc.;
- provide safe and easy access for wireline work.

e) Wellhead monitoring and control problems, see 6.5:

- 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.

1.7 Gathering System Problems

Typical problems with gathering system equipment, including the flowlines and manifold, and recommended practices to deal with them are as follows.

a) Flowline problems, see 7.1:

- keep the flowline clean and avoid unnecessary 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 7.2:

- minimize any unnecessary restrictions or pressure losses;
- keep all manifold valves fully open or fully closed;
- check the manifold for leaking valves using sonic or infrared detectors.

1.8 Well Testing Problems

Typical problems with well production rate testing equipment, and recommended practices to deal with them are as follows.

a) Well test scheduling problems, see 8.1:

- test each well often enough to detect changes in performance;
- test each well long enough to obtain accurate results;
- co-ordinate 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 8.2:

- 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 8.3:

- make well testing a high priority so it receives the attention it deserves.

1.9 Production Handling Problems

Typical problems with production handling equipment, and recommended practices to deal with them are as follows.

a) Oil handling problems, see 9.1:

- measure total oil produced from each set of wells for comparison with estimates and for allocation and troubleshooting purposes.

b) Water handling problems, see 9.2:

- measure or estimate total water production from each set of wells for comparisons and for allocation and troubleshooting purposes.

c) Gas handling problems, see 9.3:

- measure gas production from each set of wells for comparisons and for allocation and troubleshooting purposes.

1.10 Information Handling Problems

Typical problems with information handling, and recommended practices to deal with them are as follows.

a) Well test information problems, see 10.1:

- detect and evaluate “good,” vs. “questionable,” vs. “bad” well tests;
- re-test wells if the data is questionable;
- fix the problem that creates a bad test and then re-test the well;
- use the good well tests to evaluate actual performance and allocate gas-lift production.

b) Downtime information problems, see 10.2:

- 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 10.3:

- obtain pressure surveys annually, or when conditions change;
- follow the procedures in Section 10 to obtain accurate results;
- obtain a pressure build-up if the inflow performance has changed.

d) Gas injection pressure and rate measurement information problems, see 10.4:

- 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 10.5:

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

1.11 Surveillance and Control Problems

Typical problems with the gas-lift surveillance and control system, and recommended practices to deal with them are as follows.

a) Manual operating problems, see 11.1:

- provide competent, dedicated people;
- provide on-going training in all aspects of gas-lift operation;
- provide quality measurement and control equipment;
- perform periodic system reviews to identify bottlenecks and opportunities;
- become familiar with the following checklist for use if problems develop in gas-lift wells.

- 1) is the master valve open?
- 2) is the wing valve open?
- 3) is the operating gas-lift valve open?
- 4) is the downhole safety valve open?
- 5) is the well's flow rate slugging?
- 6) is there a choke in the flowline?
- 7) is the gas-lift injection rate correct?
- 8) is the gas-lift injection pressure reasonable?
- 9) is the gas-lift injection pressure heading or surging?
- 10) is the flowing wellhead pressure reasonable?
- 11) is the flowing wellhead temperature reasonable?
- 12) is the separator pressure reasonable?
- 13) is hydrate forming at chokes or low spots in the piping?
- 14) is well test data (oil/water/gas) reasonable and reliable?

b) Production automation, see 11.2:

- use production automation to improve operational effectiveness.

2 Gas-lift Operating Problems

2.0 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 relatively constant, known pressure and rate. All other components in the system; the gas-lift valves, tubulars, wellheads, flowlines, and separation and treating facilities, must 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 may be “under-lifted,” resulting in lost or deferred production;
- wells may be “over-lifted,” resulting in excess consumption of gas and/or lost production;
- lift gas may be ineffectively distributed, resulting in sub-optimum system performance, even if all other parts of the system are designed adequately;
- wells may be unstable; this can lead to a large number of problems.

2.1 Under-lifted and Over-lifted Wells

A gas-lift well is “under-lifted” when the depth of gas injection is shallower than necessary for optimum lift and/or the rate of gas injection is too low. Both of these conditions 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 and/or the gas injection pressure is too high. These conditions lead to ineffective lift gas utilization. Less than optimum gas-lift exists when a relatively large increase in injection gas 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.

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/s (1.83 m/s) in the gas-lifted mixture in the tubing string above the injection point.

2.1.1 Recommended Practices

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

- Monitor the performance of each gas-lift well using flowing 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, flowing bottomhole pressure(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.
- 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 gradient surveys and production tests that include injection gas measurement. Gas saved in one group of wells may be profitably used in other wells.
- Over-inject in some wells (if necessary on a temporarily basis) to obtain stability by achieving a mixture velocity of approximately 6 ft/s (1.83 m/s) above the point of injection. If this condition persists however, the well should be re-designed to overcome the instability problem. Most gas-lift computer models will calculate the mixture velocity.
- Evaluate the effects on surface facilities caused by over-injection in wells, if this practice is used to maintain stability.
- Assure that the gas-lift valves are properly constructed, assembled, and set before they are installed. Use gas-lift valves manufactured to API 11V1 specifications (or ISO 17078-2 when it is published). Use API 11V7 for repair and reassembly (or ISO 17078-2 when it is published).
- Check and probe test individual valves to assure conformance with design specifications for critical applications, or where there are on-going problems. See API 11V2, *Gas-lift Valve Testing and Modeling*. This document will be replaced by ISO 17078-2 when it is published.
- 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 and/or optimum gas-lift allocation. (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. Compressor downtime should not be greater than 5 %.

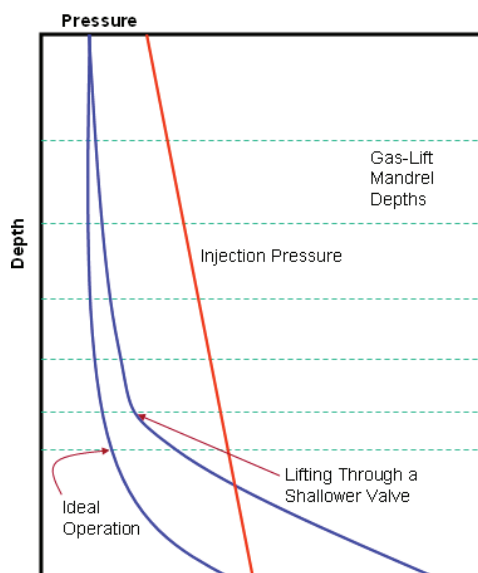
2.1.2 Well Under-lifted—Injection Too Shallow

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

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

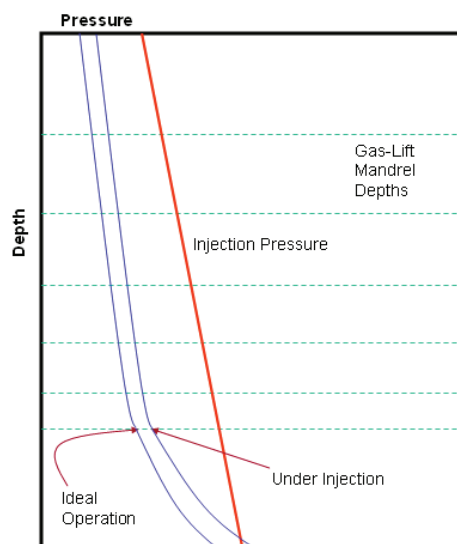
If the injection is occurring through an upper unloading valve or valves, or through a hole or leak, the well's FBHP can not be drawn down to the desired value, and the production rate will be less than intended or desired (see Figure 2). This condition can be caused by a number of problems including:

- 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; it 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 injecting through an upper gas-lift valve, even with the same amount of gas, the operating bottomhole pressure is increased and the production rate is reduced.

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



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

2.1.3 Well Under-lifted—Injection Rate Too Low

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 flowing bottomhole pressure, even if injection is at the desired operating valve or orifice. This may 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;
- gas composition/density is significantly higher or lower than design specific gravity;
- 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.

2.1.4 Well Over-lifted—Injection Rate Too High

A too high gas-lift injection rate should be avoided for practical reasons, as follows.

- *May allow injection gas to enter an upper valve.*

Excess gas may raise casing pressure above the set point for upper unloading valves, causing one to open with loss of efficiency and production rate.

- *May lose production.*

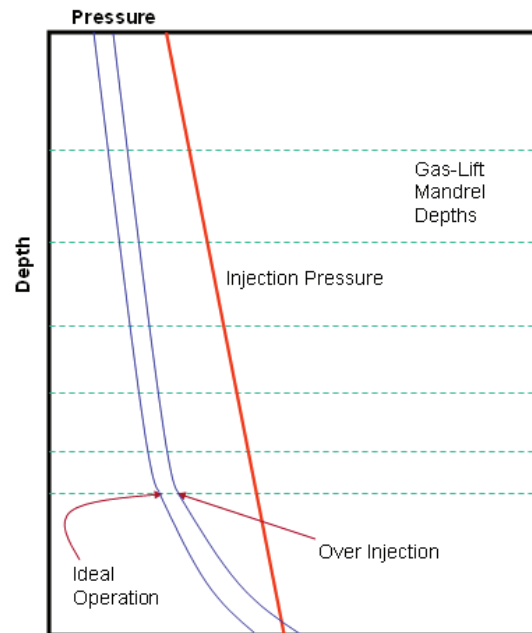
Excess gas can also increase friction in the surface flowline and tubing. This can cause a higher FBHP resulting in less drawdown and a lower production rate. The gas rate can become so great that the effect of friction loss exceeds the reduction in fluid density and the pressure gradient actually begins 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 is labelled “Ideal Operation” may be considered to be on the minimum practical pressure gradient. The injection gas rate for a continuous gas-lift well should normally be substantially less than the rate required to reach the minimum gradient.

- *May increase costs.*

The cost for compressing, dehydrating, distributing, injecting, recovering, and treating gas rises 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 cost of injection becomes equal to and then exceeds the incremental value of the increased production. This is called the economic limit or “point of diminishing returns” (see Figure 5). Even before this point, the incremental profit may fall below an acceptable limit. From an economic point of view, a well should not be operated beyond the point of acceptable incremental profit (see API 11V8, Section 7).

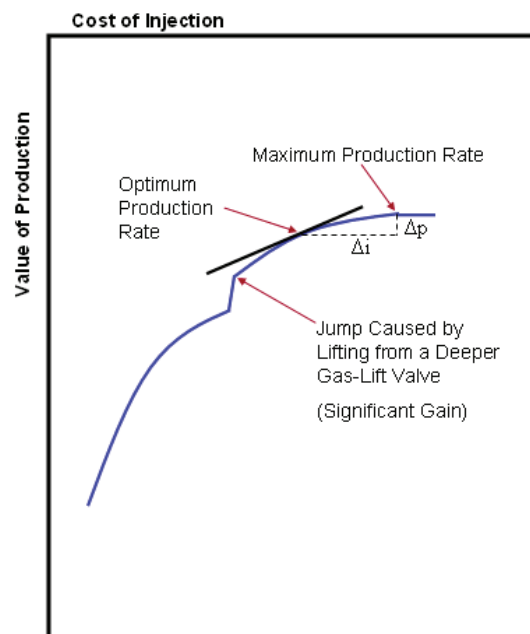
2.1.5 How to Determine Optimum Gas-lift Injection Rate

The optimum gas-lift injection rate is related to the economic limit. This is usually substantially less than the minimum gradient which can be modelled with a validated computer program, as discussed in API 11V8, Section 4 and Section 8. Determining the economic limit requires reliable cost and revenue data.



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

Figure 4—Problem of Over Injection—Injecting Too Much Gas



NOTE The optimum production rate occurs where the incremental cost of injection is equal to the incremental value of production.

Beyond this point, very little value (Δp) is gained for a significant increase in cost (Δi).

Figure 5—Determining the Optimum Gas Injection Rate

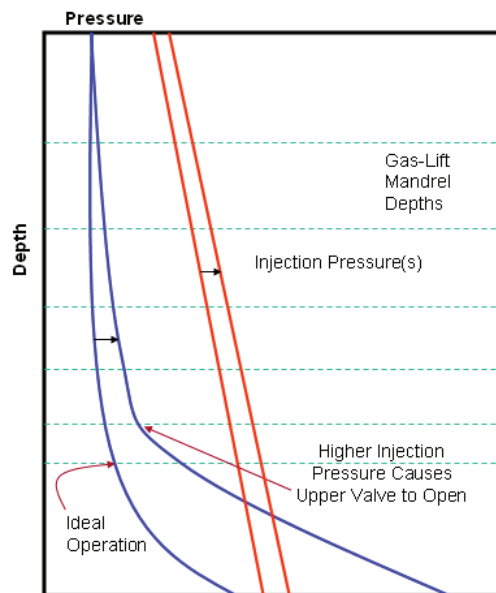
2.1.6 Well Over-lifted—Injection Pressure Too High

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, must rise 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 2.3.

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



NOTE If the injection pressure is too high for any reason, it can cause an upper valve to open, leading to inefficient and very likely unstable lift operation.

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

2.2 Ineffective Gas Distribution

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.

2.2.1 Recommended Practices

The following practices are recommended 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 may be under injected if

they are far from the source of the gas or hydrate is occurring in the pipeline at a low spot. Or some wells may 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, and/or unstable.
- 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 normally be distributed to the wells with the objective to maximize oil production; but optimization can also be expressed in terms of gas compression costs 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 costs.

If there is an under supply, the lower priority wells (high water cut, low productivity, etc.) should be given relatively less gas than the high priority wells (low water cut, high productivity, difficult to re-start). If there is a temporary compressor outage, shut in some of the lowest priority wells so that the better wells can continue to be produced effectively. In manually operated gas-lift systems, valves with small ports, or chokes, can be installed to limit the gas injection rate to assure 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, Section 7.

2.3 Unstable Gas-lift Operation

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

2.3.1 Recommended Practices

The following practices are recommended for unstable gas-lift operation:

- use pressure transducers to gather and display injection or casing pressure, and producing or tubing pressure;
- 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 2.2;
- see 2.4 to evaluate the type(s) or cause(s) of instability.

2.3.2 Unstable or Heading Gas-lift Operations Can Cause a Number of Problems

The following are possible problems arising from unstable or heading gas-lift operations.

- *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 may 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 2.4 under the topic of injection heading.

— *Loss of production.*

When a gas-lift well is heading, the pressure in the flow tube (normally 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 may 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.

— *Damage to the well bore.*

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.

— *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.

— *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 costs, gas flaring, and lead to nuisance shutdowns.

— *Upsets to other wells on the system.*

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

— *Difficulties in gas and liquid measurement and control.*

The majority of 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 may 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 which make accurate tubing pressure and well test measurements difficult to obtain.

— *Difficulties in analyzing gas-lift performance.*

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

2.4 Types and Causes of Unstable Operation

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."

2.4.1 Recommended Practices

The following practices are recommended 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 may 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.

2.4.2 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 may vary slightly, or the well may produce in slugs with periods of no production in between heads. The heads may be moderate, or they may be severe with the tubing-head pressure varying by several hundred psi (kPa) and the instantaneous flow rate varying by several hundreds or thousands of barrels per 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 holdup. Production heading may also be caused by inflow from more than one zone; or by restrictions in the surface facilities; or it may 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 downstream 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:

- determine if tubing heading is occurring by itself, or in conjunction with casing heading. Use pressure transducers to evaluate the fluctuations;
- 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 may be cured or reduced;
- do not choke the tubing at the surface to cure tubing heading, other than to protect surface facilities from severe slugging. Choking will increase the pressure in the tubing, increase the amount of gas required to produce the well, and may reduce the production rate from the well;
- Inject more gas to alleviate tubing heading if adequate gas is available and this results in more economic 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/s (1.83 m/s).

2.4.3 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 may 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, and/or operating gas-lift valve or orifice) 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.

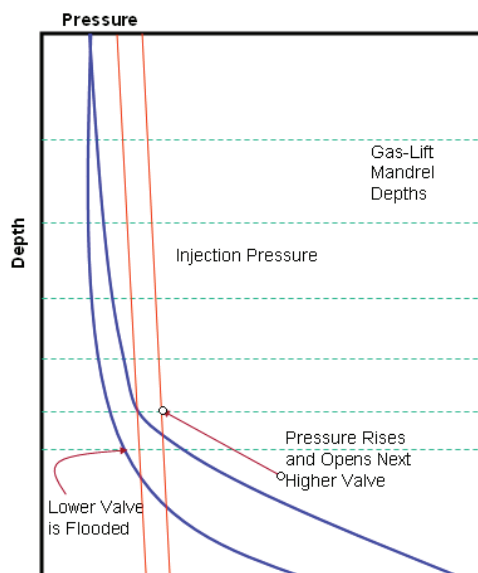
Stable operation is attained when the actual flow rate into the casing equals the flow rate out of the casing annulus. A slight imbalance will gradually change the volume of gas in the casing annulus; but a large imbalance leads to casing heading as the flow rate through the operating valve or orifice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

This problem may 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 may reopen.

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

Casing heading can usually be prevented or cured by the following steps.

- Use flowing and static surveys and production tests to find the depth of gas injection, obtain the inflow performance or *PI*, and create a valid compute model.



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—Problem of Under Injection—Causing Operating Valve to Flood

- Use the model to evaluate the improvement from injecting more gas or injecting deeper. Do not be surprised if this analysis indicates that more injection gas will be required to stabilize the well's operation.
- Redesign the gas-lift valve pressure settings, port sizes, and/or mandrel locations to permit gas injection from the optimum depth, with no interference from upper unloading valves. Use an “orifice” valve at the operating point for high *PI* wells and a gas-lift valve for low *PI* wells. Do not oversize the orifice, as this can cause heading in both the tubing and the casing.
- Eliminate outside effects such as upsets from other wells, fluctuations, bottlenecks, or other problems in the distribution system that may be causing or aggravating the heading problem.
- Install chokes downstream of the ports in unloading gas-lift valves to prevent over injection. This can prevent over injection and a resulting reduction in casing pressure, which can then cause the valve to close. It can also prevent throttling (reduction in gas passage as the valve begins to close). Furthermore, it can help protect the valve's seat, stem, and ball from erosion during the unloading process. Moreover, it can allow the field to maintain only one port size in their gas-lift valve inventory since various required rates can be achieved by choosing the appropriate choke size.
- Consider installing a smaller tubing string to increase the relative velocity in low-rate wells. Be aware that sizes smaller than 2 3/8-in. (6.06 cm) can cause wireline problems.
- Use an automatic control valve to control the injection rate. The controller is sensitive to changes in both supply pressure and rate, and thus prevents heading from occurring or becoming aggravated when outside interruptions occur.

2.5 Other Problems

There are additional problems.

2.5.1 Recommended Practices

The following practices are recommended for problems with the gas-lift system:

- treat the entire gas-lift system as a “system” consisting of many parts that all must work together, rather than as individual parts which can be considered individually;
- establish and maintain an automatic monitoring system to routinely check and/or calibrate all components of the system;
- establish quality assurance procedures for the assembly, repair, setting, testing, and installation of gas-lift valves and assure that these procedures are followed.

2.5.2 Typical Problems

Problems encountered in gas-lift systems are as follows.

- *Equipment malfunction.*

Implement preventive maintenance on a regular basis to minimize unscheduled down time. Compressor and piping components are mechanical and are subject to malfunction due to wear, corrosion, erosion, or plugging.

- *Instrument malfunction.* Maintain and calibrate the pressure, flow, and temperature measurement devices. Sometimes the failure is obvious but often the device appears to be working, but the information is faulty. Periodic calibration is required.
- *Equipment selection, assembly, or application.*

Quality assurance is best provided by the following steps.

- Provide written standards to the gas-lift valve shops for valve assembly and cleaning, repair, and re-assembly, pressure charging the bellows, testing, etc. Assure that available API specifications and recommended practices are followed. See API 11V7, *Repair, Testing, and Setting Gas-lift Valves*. This document will be replaced by ISO 17078-2 when it is published.
- Inspect the valves to insure that proper chokes are installed, if chokes are being used.
- Test the valves in the gas-lift shop or on location before they are installed in the well to insure they are properly set to meet design specifications. This testing can also assure that the valves will open as designed, will close as designed, can provide the desired rate of gas passage, and do not leak. See API 11V2, *Gas-lift Valve Testing and Modeling*. This document will be replaced by ISO 17078-2 when it is published.
- Monitor the installation procedure to insure the valves are run and set in the correct order and at the correct depths. (For example, sometimes mandrels are to be skipped. Be sure that the wireline operator is aware of this.)
- *Hydrates.*

Hydrates are prevented by using dehydration to reduce water vapor content in the gas; this prevents water condensation at cold temperatures. Pressure drops occur throughout a gas-lift system, and temperature drops always accompany pressure drops. If the right temperature and pressure conditions are present to condense water, hydrates can form resulting in blockage of gas flow. This is addressed in 3.2.

— *Gas-lift models.*

Operation of a comprehensive gas-lift system depends on being able to model many aspects of the overall process, from the reservoir-to-well inflow, the vertical flow in the well, and flow through the surface lines and facilities. Choice and proper use of the best models is necessary to fully understanding the gas-lift operation. This subject is dealt with in API 11V8, *Recommended Practice for Gas-lift System Design and Performance Prediction*.

3 Surface Gas-lift Compression, Dehydration, and Distribution

3.0 Purpose

Gas-lift compression and dehydration facilities, and pipeline distribution networks, are often already installed; changes can be justified only if production can be increased or downtime associated with gas-lift failures can be eliminated.

However, the compression, dehydration, and distribution systems should be evaluated for effectiveness, and improvements should be justified if they will result in sufficient reductions in operating expense or increases in production.

3.1 Compression Facility

The compression facility should consistently deliver gas to the gas-lift distribution system at an adequate rate to allow a constant system pressure. This rate and pressure should be monitored to verify this condition and detect any problems. A master gas-lift distribution meter (or meters) should be used, in conjunction with a gas flow computer, to continuously monitor both the system gas input rate and pressure.

3.1.1 Recommended Practices

The following practices are recommended for a compression facility:

- design or configure the gas compression facility to deliver gas at a stable rate and constant pressure. Implement a compressor monitoring system to measure the flowrate and pressure of gas entering the distribution system. If one compressor goes down, some wells must be immediately reduced or shut down to prevent system upsets;
- set the pressure regulator on the compressor output to the gas sales system at the pressure required for the gas-lift distribution system or a minimum of 20 psi (137.9 kPa) above the sales line pressure. This will prevent fluctuations or upsets in the sales system from upsetting the distribution system while allowing the excess reservoir gas to flow to the sales line;
- send excess gas to the sales line, or re-inject it into an oil or gas reservoir, rather than increase the distribution system pressure and over-lift some or all of the gas-lift wells;
- design the compression facility to deliver sales gas before it enters the gas-lift stage(s) if the sales line pressure is considerably lower than the gas-lift pressure;
- design or configure the compression system to have 10 % to 20 % excess capacity to prevent short-term compressor outages from adversely affecting the gas-lift distribution system;
- implement a compressor monitoring system to measure the flowrate and pressure of gas entering the distribution system. The rate and pressure entering the system is important information; especially if the compressor facility is running fully loaded. If one compressor goes down, the rate into the system will be reduced and the injection rate into some wells must be immediately reduced or shut down to prevent system upsets;

- provide a make-up or recycle gas supply to maintain a stable compressor suction pressure. If the separator gas from the field is fluctuating, possibly due to heading wells, this make-up supply will permit the compressor to continue stable operation;
- implement a control system to prevent the compressor facility from delivering excess gas into the distribution system. Maintain a constant pressure in the gas-lift delivery system. Send any excess gas to the sales line or to some alternative use, or re-cycle it rather than allowing it to be delivered into the distribution system to result in increasing the distribution system pressure and over-lifting some of the wells. This requires a pressure set point for the desired pressure on the distribution system. Measure the volume of any gas sent to the sales line;
- perform routine compressor maintenance and implement a preventive maintenance program to minimize any unscheduled compressor outages;
- coordinate any planned compressor maintenance with well operations so a balance can be maintained between the gas rate being delivered to the distribution system and the sum of the injection rates into the wells being served by the system.

3.1.2 Compression Facility

The gas-lift compression facility should be maintained using accepted troubleshooting and preventive maintenance techniques with an objective of at least 95 % on-line time. Frequent upsets will cause corresponding upsets in the gas-lift system that may result in lost production and require significant operator effort. Several days may be required for a gas-lift system to return to stable operation following a compressor upset.

When a compressor goes down or must be shut down for maintenance, the gas distribution must be adjusted as quickly as possible to keep from adversely affecting the wells in the system. The gas going to the poorer wells should be cut back so as not to adversely affect the better wells. In the extreme, it may be necessary to shut in the poorer wells during the outage.

Compressor outage in a large gas-lift system requires a contingency plan that can be implemented quickly. If a system is operated manually, the best plan is to shut down the least profitable wells as quickly as possible. If a system is operated with computer controlled distribution and injection, optimal well-by-well adjustment may be possible.

Gas compressors are often used both for sales and gas-lift distribution. The pressure should be regulated to meet the maximum requirement; either gas-lift or sales line pressure. The pressure regulator should be kept in good working condition, and should be set at least 20 psi (137.9 kPa) above the required sales line pressure so that upsets in the sales system will not affect the pressure of the distribution system.

A gas-lift system pressure chosen years ago, when conditions in the field were different, may benefit from a system pressure increase for more effective gas-lift. Wells that may benefit include ones:

- that have high productivities;
- are producing with high water cuts;
- are producing from high in the hole because the system pressure is too low to permit working down to the bottom gas-lift valve.

In other cases, the pressure should be decreased if the current system pressure is too high for the current well and reservoir conditions. This would normally only be true if the wells have low productivities and/or have depleting reservoir pressures.

Changing system pressure may be as easy as changing the set point on the sales pressure regulator. However, system pressure increase may require a change of the compressor cylinders or stages, and/or the distribution system

piping, meters, control valves, and gas-lift valves. To decrease the system pressure, the regulator must be reset and the gas-lift valves may have to be reset.

Raising gas-lift system pressure requires a review of the pressure ratings of the piping, flanges, and valves in the system. For example, many systems are rated at ANSI/ASME 400, 600, or 900 corresponding to pressures of 960 psi (6,618 kPa), 1440 psi (9,928 kPa), or 2160 psi (4,893 kPa), respectively. These are common pressure ratings for piping, flanges, and valves.

The compression horsepower required increases with the pressure ratio (compression ratio). The capital cost and operating expense is a function of the amount of gas being compressed. If less injection gas is required at a higher distribution system pressure, then overall compression costs are reduced.

Another way to improve gas-lift efficiency is to minimize the compressor suction pressure. When suction pressure is reduced, this may permit the operating wellhead pressure to be reduced, which improves the efficiency of the gas-lift wells. A lower limit to suction pressure can be calculated (an example is given in API 11V8, Section 6).

3.2 Gas Dehydration Facility

Most gas-lift systems use dehydrated gas; however, in some fields wet un-dehydrated gas is used. This may lead to corrosion or formation of hydrates and plugging of piping if temperatures fall below the hydrate formation temperature for the system pressure. Hydrates are solid crystals that form when gas molecules are trapped within a cage of water molecules. If water is present, hydrates can form at 80 °F (26.67 °C) in high-pressure systems.

A large temperature drop accompanies a large pressure drop, due to the Joule-Thomson effect; this can cause hydrates in the gas. Hydrate formation at the chokes or in the distribution lines causes increased pressure drops, which makes the freezing problem worse. The blockage can rapidly diminish the flow of gas and cause the well to be shut down. Figure 8 (courtesy GPSA, *Engineering Data Book*) shows potential hydrate conditions.

Liquid in the gas-lift distribution system can also cause problems with measurement or control. Liquid tends to collect in any low spot in the distribution system; when a sufficient quantity has collected, it moves as a slug. Liquid slugging significantly affects and/or damages gas meters, controllers, and gas-lift valves and/or orifices. Inaccurate measurement, ineffective gas control, permanent damage to equipment, and/or severe production heading in the tubing can result from slugging.

3.2.1 Recommended Practices

The following practices are recommended for a gas dehydration facility:

- dehydrate all gas that enters a gas-lift distribution system. The objective is to lower the dew point below the lowest expected temperature to prevent hydrate formation. In many fields, this can be achieved by dehydrating to 7 lb (3.18 kg) of water per million standard cubic ft (28,317 m³) of gas. Even drier gas may be needed in very cold weather, or when CO₂ is present, where the guide is 3 lb (1.36 kg) per million standard cubic ft (28,317 m³). Figure 9 (courtesy GPSA, *Engineering Data Book*) shows water content versus dew point temperature with gas pressure as the parametric lines;
- design gas-lift systems to avoid excessive pressure drops in the surface piping distribution system. Minimize the pressure drop across the surface control choke or control valve by using a gas-lift valve (rather than an orifice) as the operating valve on low *PI* wells so that casing pressure will be higher;
- design gas-lift systems with liquid traps at low spots where liquid can accumulate, especially upstream of gas flowrate meters or control devices. Install blow down valves in the traps so any accumulated liquid can be

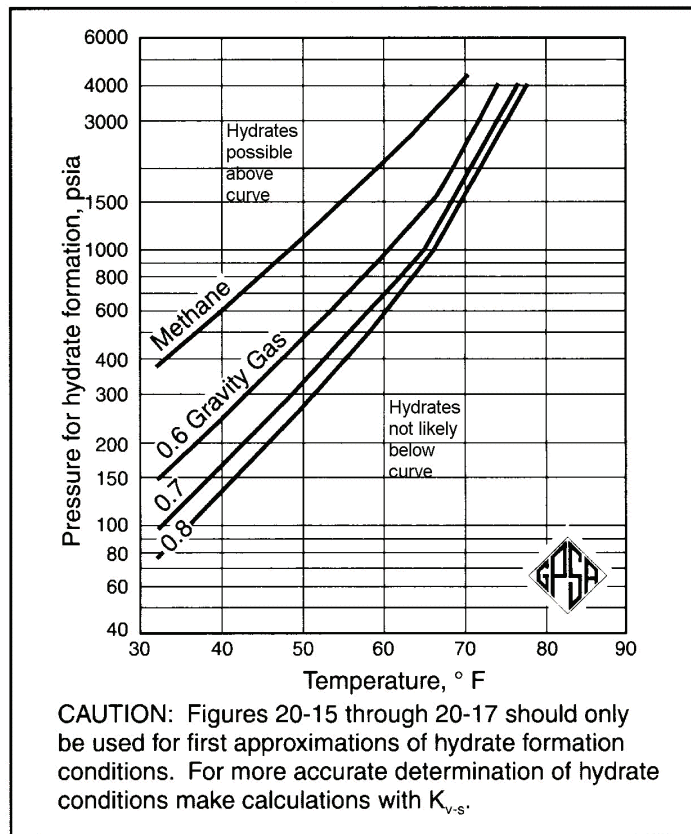


Figure 8—Hydrate Conditions

periodically removed from the system. Large piping distribution systems, particularly offshore, should have pig launchers and receivers to remove liquid and debris by periodic pigging;

- if the presence of liquid cannot be avoided, periodically purge the distribution system to remove accumulated liquid. Purge orifice meter pressure and differential pressure taps periodically;
- use seal pots (liquid traps) on orifice meter pressure and differential pressure taps and purge periodically. Install the meter recorders or transmitters at higher elevation above the orifice tube and insure the connecting instrument piping has no traps;
- use methanol to avoid temporary freezing problems. Also insulate control valves or chokes where large pressure drops may occur. Methanol is a hydrate point depressant that lowers the dew point. The best approach is to avoid the problem and cost by using effective dehydration;
- use a heater (line, gas, or catalytic) as an alternative to avoid hydrate formation if effective dehydration is not an option.

3.3 Gas-lift Distribution System

The best type of distribution system is one with a large volume. This ensures that relatively small changes in inlet or outlet rates will not cause corresponding rapid changes in pressure throughout the system.

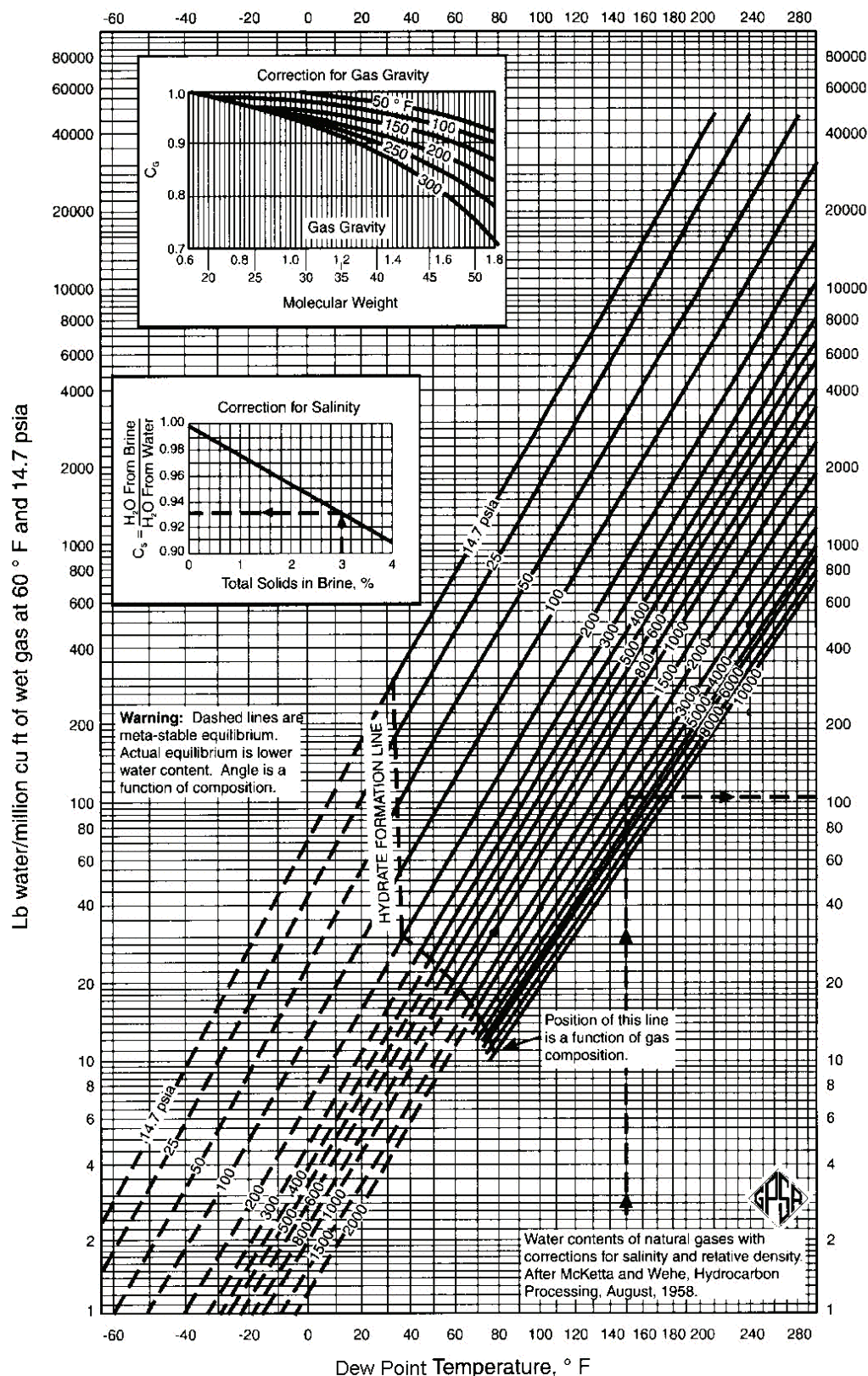


Figure 9—Water Content vs. Temperature and Pressure

3.3.1 Recommended Practices

The following practices are recommended for an unstable gas-lift distribution system:

- use a “finger” distribution system, Figure 10, with each well served by an individual injection line from a manifold;

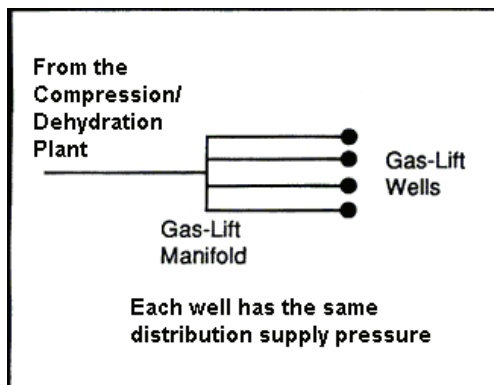


Figure 10—Finger Distribution System

- measure and control the injection rate to each well at the manifold. Measure the injection gas pressure at the wellhead just before the gas enters the casing annulus;
- if a manifold is used, the injection rate to each well can be measured and controlled at the manifold, to save cost. However, unless the individual injection lines are short, avoid the temptation to measure the injection pressure at the manifold. This should be measured at the wellhead just before the gas enters the casing annulus;
- where a “finger” system can not be used, consider a “looped” system, Figure 11, to expand the volume of the distribution system to minimize upsets caused by minor fluctuations in inlet or outlet rates;

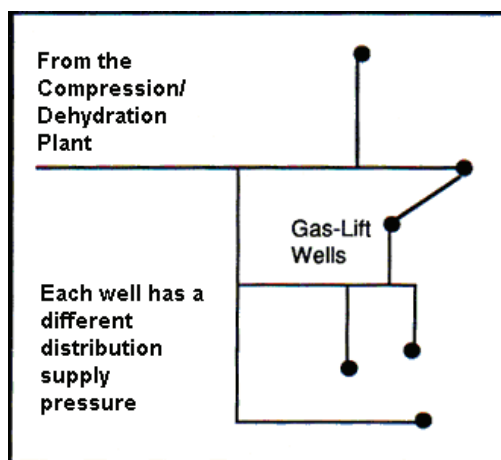


Figure 11—Looped Distribution System

- use larger diameter distribution piping if combining continuous and intermittent gas-lift wells on the same system. If possible, schedule the intermittent cycles to minimize upsets, which could occur due to concurrent, uncoordinated injection cycles;
- Avoid combining both continuous and intermittent gas-lift wells on the same system. If this is necessary, set the intermittent controllers to open at different times, or automatically schedule the intermittent cycles from a central control location to minimize the upsets which could occur due to concurrent, uncoordinated injection cycles.

3.3.2 Distribution System

Pressure pulsations can reduce production if the piping size of the distribution system is small. The system volume capacity may be increased by connecting the annulus of a temporarily abandoned well to the system. Verify the integrity of the casing and wellhead, and mount a pressure transducer on the casing head. There should be no restrictions (chokes, orifices, control valves, etc.) between the distribution system and the storage annulus. This added distribution system volume will help smooth out pressure fluctuations in the system, and it will serve as a convenient gas storage location if the wells must be shut in for a hurricane or other reason. Having some high-pressure gas trapped in the distribution system can help return the wells to production, since after a system is shutdown, there may be insufficient gas production to bring the system back onto operation.

The recommended “finger” configuration with a large distribution pipeline minimizes interference between wells since they are isolated from each other through the manifold. With this system, the pressure, temperature, and rate of gas entering the manifold from the distribution system should be measured. This can be useful in troubleshooting problems in the overall distribution system and in determining the amount of gas available to the group of wells being served by the manifold. The injection pressure and production pressure should be measured at the wellhead.

Fields using a “series” or “looped” system can suffer interference between wells, which may be partially mitigated by increasing the volume of the system with larger pipe diameter. This can be aided by using the annuli of non-producing wells or by using parallel looped lines. These systems should have the gas flow rate, casing pressure, and tubing pressure data measured at the well site.

In any continuous gas-lift distribution system, and especially in “series” or “looped” systems, it is important to avoid pressure fluctuations and rate surges, as these can upset the wells and may become aggravated as instability in one well can lead to instability in adjacent wells. In these systems, it is important to address heading problems (see 2.5) and to avoid use of intermitters or intermittent gas-lift. If intermittent gas-lift must be used to produce some of the lower rate wells, the intermittent cycles should be scheduled and controlled centrally, according to a schedule, to minimize severe interference and fluctuations. Or, if possible, the intermittent wells should be isolated from the continuous gas-lift wells, on a separate portion of the distribution system.

Just as with “finger” distribution systems, it is important that the pressure and rate be measured and recorded at key points or branches in the system. This can be beneficial in troubleshooting problems in the system and with the wells served by a particular branch of the system. However, accurate gas measurements may be difficult in systems with fluctuating pressures.

4 Gas Injection Metering and Control

4.0 Purpose

Gas-lift requires points where the gas being injected into each well is measured and controlled. These provide the operator with control over system operation and data for finding under-performing wells. Gas-lift measurement and control must be performed as correctly, accurately, and consistently as possible.

4.1 Gas Metering

Gas injection measurement is important in gas-lift optimization and troubleshooting. Continuous injection pressure and rate measurement of a single phase fluid is more accurate than the separator gas measurement during a well test, which often is slugging and with gas that is saturated with liquid. Other variables that can be measured at the wellhead are injection (casing-head) pressure, injection gas temperature, producing (tubing-head) pressure, producing temperature, and in some cases production rate.

4.1.1 Recommended Practices

The following practices are recommended for gas metering:

- measure the gas injection pressure and rate for each well;
- use a properly installed, properly ranged, well-maintained, accurately calibrated flow rate measurement device;
- use flow computers to obtain improved accuracy for well analysis. Use multi-range differential pressure transmitters that extend the maximum and minimum rate capability of the orifice meter;
- use a computer automation system to gather information;
- pay special attention to obtaining accurate gas injection pressure and rate information during each well test.

4.1.2 Metering Location

The meter location depends on the type of distribution system. A “finger” system normally has the meter at the manifold. If a “series” or “looped” system is used, the meter is at each well. The rates should be measured upstream of each well’s control valve so the “static” pressure measurement is the upstream distribution system pressure; and temperature can also be recorded to improve measurement accuracy. The data serves both rate measurement and analysis of the distribution system pressure fluctuations.

4.1.3 Metering Devices

The orifice meter is the most commonly used device in the oil field for measuring gas injection. This meter tube and orifice plate device is satisfactory when coupled with a flow computer or calibrated chart recorder:

An orifice meter, flow computer, or chart recorder should meet the following criteria.

- applicable API, GPA, or ASME standards should be followed;
- the orifice meter should be properly located with respect to chokes, control valves, pipe, and bends;
- the orifice meter instrument tubing to the pressure transducers or chart recorder should avoid low spots that can collect condensed moisture. Seal pots can be used to trap condensation;
- chart recorders should be equipped with a three-way or five-way manifold for easy and safe blow down and purging. The tubes should be routinely purged;
- the orifice meter tube and orifice plate should be correctly sized to measure the expected gas flow rate. The differential pressure, or variation from maximum to minimum, should fall in the midrange of the computer or recorder chart, not near the bottom or the top of the scale. Use multi-range transmitters for flow computers;
- the orifice plate should not be painted, dirty, scaled, scarred, nicked, worn, bent, or damaged. When they are not in use, orifice plates should be stored to prevent damage or corrosion;
- if chart recorders are used, they should be calibrated on a routine basis, and the recorder’s pens should be routinely checked to maintain proper inking. The recorder should be equipped with a 24-hour clock drive for well testing and charts changed before and after well testing. 8-day clocks are adequate for routine surveillance but the measurements are difficult to read;
- use the injection gas rate from the flow computer or chart in conjunction with a well test (discussed further in 10.1) for gas-lift surveillance. Also, formation gas/oil ratio is determined by subtracting the gas injected during the

well test from the total gas recovered (produced plus injected) during the test. Thus, both readings must be accurate to determine the reservoir gas production rate;

- operators can use recorders with linear charts or L-10 (square root) charts. L-10 charts have the advantage that a 100-in. (256-cm) water column (maximum range) differential pressure can be directly obtained from the chart reading. However the static pressure must be calculated with equations to convert from square root to linear. Some charts have both scales for convenience.

4.1.4 Metering Alternatives

Microprocessor based gas measurement devices can also serve for gas flow rate control. The flow computer can give more accurate gas measurements than chart recorders, especially for heading wells. They require less time for maintenance, calibration, and reading, and they can communicate with a remote computer for display, use, and storage of the pressure, rate, and volume information at a central location.

Other metering alternatives are available, but orifice meters and flow computers are proven methods. Other methods include flow nozzles, Venturi meters, vortex shedding meters, and turbine meters.

4.2 Injection Control

The term “gas injection control” implies controlling the gas rate into the well's casing annulus for stability reasons and controlling the injection rate into the production stream for gas-lift optimization. There is a significant difference that is important to understand.

4.2.1 Recommended Practices

The following practices are recommended for injection control:

- operate the well close to the original design conditions of injection pressure and rate until reservoir pressure and water cut changes require gas-lift revisions;
- consider pulling and redesigning the unloading gas-lift valves, or the operating gas-lift valve, when reservoir and water conditions change, rather than attempting to compensate with a limited control capability, since operating a gas-lift well far from its design settings may lead to unstable, inefficient operation. If tubing must be pulled to change valves, potential reservoir formation rock damage and reduced production should be evaluated;
- use a gas flowrate controller so that the desired injection rate can be consistently maintained with minimum impact of either upstream or downstream pressure fluctuations or upsets;
- use of a controller that can incorporate pressure overrides or limits to restrict the range of casing-head pressures that the controller will permit;
- a gas-lift control device (variable orifice, choke, control valve, etc.) is not a measurement device; the pressure drop across such as device gives only an estimate of the rate. There are some exceptions to this. Some companies produce calibrated control devices that can also provide flow rate measurements. Normally these are considered when there is inadequate space to install separate flow measurement and control devices;
- finally, a gas-lift controller is not a shut-off valve. Do not depend on it to be gas tight.

4.2.2 Gas-lift Control

A continuous gas-lift well is designed based on a defined production and gas injection rate and water cut. The well's actual conditions will vary with time from the design assumptions, which will require injection rate variation but still

remain within the design limitations. However, when gas injection rates no longer match port sizes or pressure settings, instability or non-optimum operation ensues.

A flowing pressure survey and validated well model should be used to evaluate whether a redesign of gas-lift valves and/or the operating gas-lift orifice will better meet the new actual and/or desired operating conditions. The economics of the changes and the potential for formation damage can be simulated with the computer model. New control equipment can be implemented if necessary.

The original design constraints or conditions are important; this information should be made readily available to those who must operate the gas-lift system over the long term.

4.2.3 Gas-lift Control Challenges

Manual variable chokes are adjusted until the desired differential pressure reading is obtained on the flow computer or chart recorder. The control setting obtained in this manner is only valid for one set of conditions of upstream and downstream pressure. It is difficult to maintain consistent control, since the injection rate associated with a certain differential pressure pen reading on one day will not be the same as the rate associated with the same reading on another day under different conditions.

The rate of gas passage through a variable choke or orifice depends on the upstream pressure, the downstream pressure, and the size of the restriction. (This is true as long as there is not critical flow through the restriction. Critical flow occurs when the downstream pressure is less than approximately 60 % of the upstream pressure. When this occurs, the flow rate depends only on the upstream pressure and the size of the restriction.) If any of these variables change, which is likely on a continuous basis in a dynamic gas-lift system, due to pressure variations in the delivery system, injection rate adjustment to another well, wells heading, or production pressure variations, this will cause the rate of gas injection into the well to change.

Injection control is complicated since surface choke size and gas rate into the casing are further affected by the restriction through the operating gas-lift valve or orifice and its pressures, both upstream and downstream. This control of the injection at two locations can lead to instability, or heading, or inability to pass the adequate rate of gas.

The surface control presents a dilemma: use a high kick-off casing pressure and small pressure drops to “work down” and inject gas into the production stream as deep as possible, or use a high kick-off pressure and larger pressure drops for control, but with resulting shallower injection depth. The initial unloading or kick-off casing pressure and the ultimate operating casing pressure may differ for IPO gas-lift valves by several 10s or 100s of psi (100s or 1,000s of kPa). This is discussed further in 5.1.

The higher the pressure drop at the surface, the greater the degree of “control” of the injection, and the better the degree of isolation between the well and upsets in the upstream distribution system. Unfortunately, this can cause hydrate formation, even in “warm” climates.

A small surface pressure drop relative to the pressure drop across the downhole operating gas-lift valve or orifice (have the surface restriction or choke larger than the downhole restriction) is the best design. The ideal case is to control the rate of gas passage into the producing stream at the downhole valve or orifice, but this design method is very difficult to accomplish. If the surface pressure drop is large relative to the downhole pressure drop (surface restriction is small relative to the downhole restriction), serious heading can result.

4.2.4 Control Option—Gas Controller

Automated gas flow rate controllers provide better control options than fixed-bean chokes, manual control valves, or variable orifices:

- use a gas flowrate controller that can maintain a constant flow rate in the face of varying upstream and downstream pressures by dynamically adjusting the size of the opening based on feedback from the gas measurement device;
- use a pressure controller for a constant downstream pressure, but only for wells with PPO valves or a single orifice point of injection into the tubing;
- a third alternative is a combination device that would provide flow control with a pressure override or pressure limiting capability to avoid re-opening upper gas-lift valves.

A flow controller provides an improvement over manual control methods; however, this provides no guarantee of desired performance. If the flowrate into the casing is greater than the flowrate capacity of the operating gas-lift valve or orifice at the downhole pressures, instability and heading or multi-point operation, both of which are undesirable, will still occur. Similarly, a gas-lift valve or orifice with greater capacity than the inlet gas rate will lead to another instability and heading. However, if the valve or orifice is resized, the flow controller is a significant improvement over manual flowrate control.

A gas flowrate controller can be a relatively expensive device. However, as mentioned above, microprocessor-based units can combine the gas measurement and gas flowrate control into one unit, so overall costs may be minimized.

Use of a gas flowrate controller has another advantage. The operator can test the well at various injection rates and determine the optimum rate for each well. This can be accomplished by using multi-rate well testing, where the well is produced at various injection rates and the corresponding production rates are measured and analyzed.

4.2.5 Control Strategy

Use of a manual control device requires a surface pressure drop (during operation, not during unloading) of at least 50 psi (345 kPa) but not more than 150 psi (1,034 kPa) in a 1,000 psig (6,895 kPa) system, and from 100 psi to 200 psi (690 kPa to 1,380 kPa) in a 1,440 psi or 2,200 psi (9,928 kPa or 13,790 kPa) system. These pressure drops will usually be achieved if adequate “unloading” casing pressure drops are included in the gas-lift valve design to permit the system to effectively “work down” to the operating gas-lift valve or orifice. The design of gas-lift valves for unloading is discussed in 5.1.

If the pressure drops at the surface are much less than these guidelines, any small change or upset in either the upstream or downstream pressure can cause a significant change in the gas injection rate. If the surface pressure drop is much more than these guidelines, the surface restriction is too small, relative to the downhole restriction in the operating gas-lift valve or orifice, and serious casing heading can result. The downhole valve or orifice should be changed to a smaller size.

Surface control and heading wells have some or all of the following characteristics: low bottomhole pressure, poor inflow performance, low production rate, or gas-lift valve ports (or chokes) that are too large. The pressure available in the system may be more than is needed for the low productivity, heading wells. To restrict the pressure and rate of gas injection into these wells, the surface restriction may have to be very small and the surface pressure drop may have to be very large (sometimes several hundred psi) relative to the pressure drop across the operating gas-lift valve or orifice. This situation is almost guaranteed to cause or aggravate a serious heading problem, and may cause hydrate problems if any water vapor is present in the gas.

The potential use of a pressure controller was mentioned above. Such a device would attempt to maintain a constant downstream or casing-head pressure. To do this, it would need to vary the injection rate as either the upstream

pressure or the downstream pressure varied. Since the gas flow is actually controlled at two locations, the second being the downhole operating valve or orifice, the variable rate would affect the downhole operation and the flow into the production stream, leading to instability in the system. Also, the casing-head pressure of a gas-lift well must change as the well unloads. Therefore, there would need to be a separate unloading scheme, since strict pressure control would not permit unloading, with the possible exception of where PPO gas-lift valves are used. In general, this approach is not recommended.

The possible use of a flowrate controller with a pressure override or pressure limiting capability was discussed above. As indicated, the unloading process is basically a pressure-controlled process, whereas the actual control of a gas-lift well depends on control of the gas injection rate. There may be times in the operation of a well when it must either be unloaded or kicked off, or the operating point may need to be changed. In these instances, it may be necessary to limit, control, or influence both the injection rate and the injection pressure. No precise guidelines can be given in this area, since each situation is different, but the ability to control both flowrate and pressure may be necessary for the most effective means of overall gas-lift control.

5 Gas-lift Valves

5.0 Purpose

Gas-lift valves are used in most gas-lift wells, except for very shallow wells or high pressure systems where gas can be injected deep in the well or around the end of the tubing with no valves. Valves are primarily used to “unload” the well (remove completion or other fluid from the gas injection conduit—usually the casing/tubing annulus) down to the depth where gas is to be injected into the production conduit (usually the tubing). A gas-lift valve or orifice controls the rate of gas injection into the production stream.

The process of gas-lift design consists of spacing the gas-lift mandrels and calculating the set pressures of the gas-lift valves. The objectives are to space the mandrels and select the types of valves, port sizes, set pressures, and choke sizes to achieve the desired well operation.

5.1 Unloading Valves

After allowing the well to “unload,” the unloading valves should stay closed so the gas will be injected below them and through the operating gas-lift valve or orifice.

5.1.1 Recommended Practices

The following practices are recommended for unloading valves:

- check the performance of each gas-lift well frequently with pressure surveys and use the data to create a calibrated computer model. If a pressure survey can not be easily run, such as on some offshore and sub-sea wells, it may be possible to do this with information from downhole pressure and temperature gauges, which are often installed in these types of wells;
- adjust input gas control and eliminate wellhead restrictions if a well is heading, or is found to be operating through one or more upper, unloading valve(s). If adjustments do not resolve the heading, consider pulling and redesigning the unloading valves with smaller ports and/or change the operating valve or orifice to better match the well's current operating condition (see also under-lifted wells in 2.1);
- review Section 12 for additional recommendations pertaining to unloading valves and initial unloading practices.

5.1.2 Unloading Valve Problems

Unloading mandrel depths and valve pressure settings are based on the original well conditions. A problem could occur when changes occur in the well, or in the surface gas-lift distribution system including the availability of lift gas