Recommended Practice for Operations, Maintenance, and Trouble-Shooting of Gas Lift Installations

API RECOMMENDED PRACTICE 11V5
SECOND EDITION, JUNE 1999

American
Petroleum
Institute

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Upstream Segment

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1 Kickoff and Unloading

1.1 GENERAL CONSIDERATIONS

In both closed (packer, reverse, flow checks, and standing valve) and semi-closed (packer, reverse flow checks, or standing valve) installations, the kill fluid trapped in the tubing-casing annulus must be passed through the gas lift valves in order to unload the well. In most gas lift installations, the upper valves serve as unloading valves so that the well can be lifted to the desired depth of injection using the injection gas lift volume and pressure available in the field. Unloading is, therefore, a critical time in the life of a gas lift well, since improper unloading may result in damage to the unloading valves thereby preventing operation from the desired point of injection. This, in turn, may cause the well to lift at a less than optimum production rate. Listed below are some general considerations to reduce the likelihood of damaging the valves:

1.1.1 Use clean workover fluids. Circulate the wellbore clean, and leave filtered workover fluid in the tubing-casing annulus. Unfiltered workover fluids are often a source of solids that can either cut or plug the gas lift valves.

1.1.2 If the wellbore is loaded with mud, it should be circulated clean prior to completing the gas lift valves. If mud was left in the annulus of a well completed with sidepocket mandrels and dummies, it is advisable to set a circulating plug below the bottom mandrel (to keep the mud off of the formation) and circulate the annulus clean prior to running gas lift valves. Circulating mud through an empty gas lift mandrel pocket may damage the mandrel. The use of a circulating gas lift valve or orifice valve (fully open) will prevent damage to the mandrel.

1.1.3 Reverse circulation should not be used during completion of a well with gas lift valves in place, since flow across the valves may occur.

1.1.4 The gas injection line should be blown clean of scale, trash, welding slag, and other debris prior to hookup. This is especially important on new lines. This precaution prevents the introduction of debris into the annulus where it could cut or plug the gas lift valves. If there is pressure on the casing, it is a good practice to bleed a small amount of liquid or gas back through the casing valve to flow out any debris that may have accumulated in this "dead area" during the course of workover or drilling operations. Bleed these fluids into a disposal system, not into the gas injection system.

1.1.5 Separator capacity, stock tank liquid level, and all valves between the wellhead and the tank battery should be checked to ensure that they are operative and fully open. It is also important to check the pop-off safety release valve for the gas gathering system if this is the first gas lift installation in the system.

1.2 INITIAL UNLOADING PROCEDURE FOR INTERMITTENT GAS LIFT WELLS

Intermittent gas lift wells can be designed for either time cycle control or choke control (assuming that annulus volumes and spread characteristics allow the use of choke control). These same control options can be used to unload the well. The former is the most common, since not all intermittent installations can be unloaded or operated by choke control of the injection gas. The type of gas lift valve and the ratio of casing annulus capacity to tubing capacity must be properly matched for choke-controlled unloading. Despite the type of operation, the unloading principal is the same. Ensure that no excessive pressure differential occurs across the valves during the initial U-tubing or unloading operation by following the procedure listed below. The injection gas pressure should be increased gradually to maintain a low fluid velocity through the open gas lift valves. If full injection gas pressure is exerted on top of the fluid column in the well, a pressure differential approximately equal to this line pressure will occur across each valve in the installation. Damage to the valve seats can result from the high fluid velocity through the valves. After the top valve is uncovered, this condition cannot recur, because the top valve will always open before a high-pressure differential can exist across the valves below the fluid level.

The fluid flow rate and subsequent gas flow immediately after the top valve is uncovered can overload the surface facilities in some instances, particularly if the port size of the top valve is large. It may be advisable to restrict the injection gas flow rate during the first head. Some installations are designed with upper gas lift valves having a smaller port than the lower valves to reduce the fluid flow rate and subsequent gas flow as the upper valves are uncovered. If choking is required to prevent overloading of surface facilities, the choke should be installed as far away from the well as possible.

These important points about protecting the gas lift valves and the surface facilities are reasons why this step should be done manually and should be personally observed by the operator. A procedure is given below:

1.2.1 Install a two-pen pressure recorder to record the injection as pressure and production pressure at the surface. Be sure that the injection gas pressure is being measured downstream of the intermitter or choke, and the production pressure is being measured upstream of any flowline choke or choke body.

1.2.2 If the wellhead pressure is greater than the flowline pressure, slowly bleed the wellhead pressure down to flowline pressure (separator pressure).

1.2.3 Remove or fully open the flowline choke.

1.2.4 Set the time cycle controller or input choke to inject gas at a rate which will cause a 50 psi increase in casing pressure over an 8 to 10-minute time period. Continue at this rate until the casing pressure is about 400 psi.

1.2.5 Once 400 psi is reached on the casing, the controller or input choke may be adjusted such that a 100-psi pressure increase is achieved in an 8 to 10-minute time period. Continue this rate until the top valve is uncovered and starts passing gas. An injection gas pressure drop (or reduced pressure increase), and gas return on the production tubing provide this indication.

1.2.6 For wells with a time cycle controller, do not exceed two or three cycles per hour for the first 12 to 24 hours. The injection time should be adjusted to stop when the liquid slug clears the wellhead (the gas bubble first reaches the wellhead). Initially, this may be more than enough gas volume, but will be about right as the well unloads to deeper valves.

1.2.7 For wells on choke control, adjust the injection rate to be only $^2/_3$ of the designed gas injection rate. This may not work the well down to the bottom valve, but it will unload with minimal chances of damaging the valves. After 12 to 18 hours of the reduced injection rate, adjust the injection gas volume to the full amount expected to be used for lifting the well at the target production rate.

1.2.8 The above guidelines are for unloading only. The well should be adjusted to fine tune its performance as discussed in the adjustment section of this publication.

1.3 INITIAL UNLOADING PROCEDURE FOR CONTINUOUS FLOW GAS LIFT WELLS

As previously stated, care in unloading a gas lift well is extremely important since more gas lift valves are damaged at this time than at any other time during the life of the well. Preventing excessive pressure differentials across gas lift valves reduces the chance for equipment failure due to sand and liquid cutting. The following procedure avoids excessive pressure differential across the valves and is recommended for initial unloading:

1.3.1 Install a two-pen pressure recorder to record the well injection gas pressure, and production pressure at the surface. Be sure that the injection gas pressure is being measured downstream of the injection gas choke, and the production pressure is being measured upstream of any flowline choke or choke body.

1.3.2 If the wellhead pressure is greater than the flowline pressure, slowly bleed the wellhead pressure down to flowline pressure (separator pressure).

1.3.3 Remove or open the flow line choke depending on the well's expected reaction to gas lift. An adjustable choke or positive choke should be left on the wellhead connection to the flow line only if the well is expected to flow naturally after it is "kicked off" with gas lift, or if overloading of surface facilities is a possibility as previously discussed. Remove the choke if the well does not flow.

1.3.4 Slowly control the lift gas injection rate into the well so that it takes about 8 to 10 minutes for a 50 psi increase in gas pressure. Continue this rate of injection until the well gas pressure is about 400 psi.

1.3.5 Increase the injection gas rate into the well so that it takes about 8 to 10 minutes for a 100 psi increase in the gas pressure. Continue this rate until gas is injected into the tubing through the top valve. An injection gas pressure drop (or reduced rate of pressure increase) and the return of aerated fluid from the production tubing or casing provide this indication.

1.3.6 After uncovering the first valve, adjust the injection gas rate to the design injection rate for the well. In some instances, it may require more thin the design gas injection rate to initially unload a well.

1.3.7 The above guidelines are for initial unloading only. The well should be adjusted to fine tune its performance as discussed in the following section of this publication, Adjustment Procedures.

2 Adjustment Procedures

2.1 GENERAL

The preceding guidelines for kicking off a well are intended to unload the well with minimum chance of damaging the gas lift valves. They are starting points, and further adjustments will more than likely be required to improve the well's lift efficiency. The following procedures will assist the operator in making specific adjustments to optimize both the producing rate and gas usage.

2.2 ADJUSTMENT OF INTERMITTENT WELLS EQUIPPED WITH A TIME CYCLE CONTROLLER

After an installation is unloaded, the time cycle-operated controller should be adjusted for minimum injection gas requirement for the desired production. Then the injection gas cycle frequency and duration of gas injection should be checked periodically for most wells to assure continued efficient operation. If the producing rate from a well changes, surface control of the injection gas must also be changed to maintain a minimum injected gas liquid ratio (IGLR). If this ratio is excessive as a result of valve spread, a change in cycle frequency should be considered prior to redesigning an installation. Decreasing the injection gas cycle frequency increases the time fluid can accumulate above the operating valve in most intermittent installations. The increase slug length at the instant the valve opens results in increased tubing pressure at valve depth, thus lowering the opening pressure of the operating valve. The injection gas volume per cycle is reduced because of decreased valve spread and more liquid is recovered per cycle. These two things work together to yield a lower IGLR.

2.2.1 Procedure

2.2.1.1 The following procedure is recommended for determining the proper cycle frequency and duration of gas injection immediately after the installation is unloaded and any time during the life of the well.

Step 1. Adjust the controller for a duration of gas injection that will assure more injection gas volume than is normally required per cycle (approximately 500 ft^3/bbl per 1000 ft of lift). Adjusting the controller to stay open until the slug reaches the surface will result in more gas being injected into the casing than is actually needed.

Step 2. Reduce the number of injection gas cycles per day until the well will no longer produce the desired rate of liquid production.

Step 3. Reset the controller for the number of injection gas cycles per day immediately before the previous setting in Step 2. This establishes the proper injection gas cycle frequency.

Step 4. Reduce the duration of gas injection per cycle until the production rate decreases, then increase the duration of gas injection by 5 to 10 seconds for fluctuations in injection gas line pressure.

2.2.1.2 A time-cycle controller on the injection gas line can be adjusted as outlined, provided the line pressure remains relatively constant. If the line pressure varies significantly, the controller should be adjusted to inject an ample gas volume with minimum line pressure. When the line pressure is above the minimum pressure, excessive injection gas is used on each cycle.

2.3 ADJUSTMENT OF INTERMITTENT GAS LIFT WELLS ON CHOKE CONTROL

2.3.1 General

Choke control is another option for operating intermittent lift wells. However, not all intermittent installations can be unloaded or operated with choke control of the injection gas. The type of gas lift valve and the ratio of casing annulus capacity to tubing capacity must be suited for this type of operation. The choke size selected should be considerably smaller than the port size of the gas lift valve to permit the injection pressure in the casing to decrease to the valve closing pressure after a valve has opened.

2.3.2 Initial Selection

The initial surface choke size selection for controlling the injection gas is calculated to pass the lift gas needed for the design production rate.

2.3.3 Final Selection

2.3.3.1 The final selection of the surface choke or opening through a metering valve is determined by trial and error until the desired operation is attained. Since an injection gas pressure operated gas lift valve suited for choke control is opened by both injection gas pressure and production pressure, increasing the injection gas pressure will decrease the production pressure required to open the valve. After an operating valve closes and the slug surfaces, the injection gas and production pressure begin to increase. The rate at which the gas pressure increases is dependent upon the choke size in the injection gas line, whereas the increase in production pressure at valve depth is a function of well deliverability and tubing size.

2.3.3.2 If the injection line choke size is too large, the valve will open at a higher gas pressure than that required for adequate gas storage in the casing. The production pressure will not reach a value that will result in the lower gas pressure needed for minimum injection gas requirement. By decreasing the choke size, the well has a longer time in which to deliver fluid into the tubing which, in turn, increases the production pressure at valve depth and reduces the gas pressure required to open the valve.

2.3.3.3 Choke control of the injection gas is all that is needed for most production pressure-operated valve installations. The gas pressure is allowed to vary with the choke size rather than attempting to maintain a fixed gas pressure for production control.

2.3.4 Procedure

As indicated above, not all intermittent installations can be operated by choke control. The use of a time cycle controller may be necessary if choke control is unsuccessful. A step-by-step procedure for choke control is as follows:

Step 1. Start with the gas input choke size slightly larger than required to pass the design injection gas volume.

Step 2. Reduce the injection choke size in small increments until the production rate declines.

Step 3. Place the well on production using the choke setting that gives the optimum fluid volume with the least number of cycles, which should also be the least injection gas volume.

Note: When using choke control in an intermittent lift well, an adjustable choke controlling the input gas volume is generally preferable, since it is not necessary to interrupt the flow of gas in order to make input changes as with a positive choke.

2.4 ADJUSTMENT OF CONTINUOUS FLOW GAS LIFT WELLS WHERE SUPPLY GAS PRESSURE IS CONSTANT

2.4.1 Where the supply gas pressure is relatively constant, a positive or adjustable choke is generally used to control the supply gas to the well. An adjustable choke or metering valve is recommended since adjustments in choke size do not require interrupting the gas flow. In many cases, choking the injection gas supply to control the injection gas volume may cause freezing problems.

2.4.2 This can be rectified by using a dehydrator in the gas system, installing a gas heater upstream of the choke, injecting methanol upstream of the choke, or by building a heat exchanger around the choke. The latter method will permit the hot produced fluids to flow around the gas line and warm the incoming gas.

2.4.3 A procedure for adjusting the input gas volume is listed below:

Step 1. Start with the input choke sized slightly larger than required to inject the design gas volume.

Step 2. Reduce the injection choke size in small increments until the production rate declines.

Step 3. Readjust the choke to the size that yields optimum fluid volume.

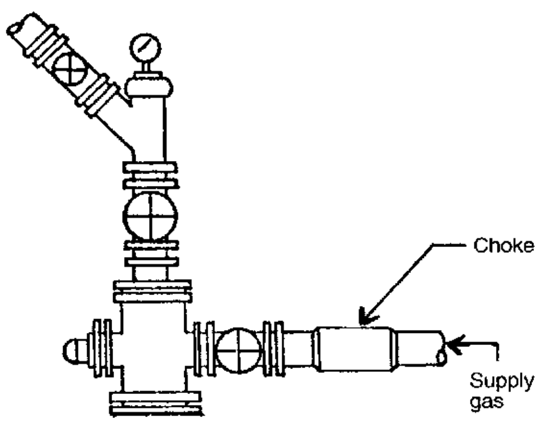


Figure 1—Choke Control, Tubing Flow Well

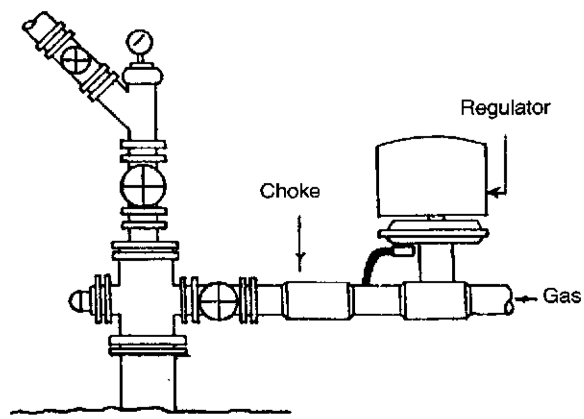


Figure 2—Choke Regulator Control, Tubing Flow Well

2.5 ADJUSTMENT OF CONTINUOUS FLOW GAS LIFT WELLS WHERE SYSTEM PRESSURE FLUCTUATES

2.5.1 The adjustment procedure is the same as the previous example: adjust the choke to get the optimum fluid with the least amount of injection gas. The difference is that a pressure-reducing regulator is installed upstream of the choke to regulate the supply gas at a constant pressure so that the injection gas volume can be more accurately controlled. The limitation of this method is that the regulator must be supplied with a pressure higher than the injection gas pressure required by the valves to operate. In other words, the system will only operate where the gas lift system pressure is higher than the design operating injection gas pressure of the gas lift valves.

2.5.2 Flow regulators maintain a relatively constant injection gas rate despite minor fluctuations in upstream or downstream injection gas pressure. As with pressure reducing regulators, the injection gas pressure must be greater than the operating injection gas pressure required by the downhole gas lift valve design to be effective.

2.6 USE OF FLOWLINE CHOKES

2.6.1 Do not control the production rate by using flowline chokes. Use of flowline chokes can cause excessive gas usage, since the high wellhead pressure resulting from choking the flowstream can cause valves up the hole to reopen by production pressure effect. This valve interference is generally indicated by one or more of the following:

a. Increased gas usage.
b. Reduced fluid production rate.
c. Fluctuating injection gas, and/or production pressures.

2.6.2 In most cases, the production rate can be regulated by making adjustments in the input gas volume.

3 Trouble-Shooting Diagnostic Tools and Location of Problem Areas

3.1 GENERAL

3.1.1 Diagnostic Tools

3.1.1.1 There are many diagnostic tools available to assist in evaluating gas lift performance. These tools can be used individually or collectively to give a picture of what is happening downhole. Some of the techniques have limitations which should be fully understood, so that the data does not misrepresent the actual situation. The techniques to be discussed are the following:

a. Two-pen recorder charts and calibrated pressure gauges.
b. Acoustical surveys.
c. Tagging fluid level and/or bottom with wireline.
d. Flowing pressure surveys and/or temperature surveys.
e. Flowmeter survey.

3.1.1.2 A discussion of each item is given in the following pages.

3.1.2 Prioritizing of Candidates

The flowing pressure survey is the most accurate method of determining gas lift performance; however, there is an element of mechanical risk. In order to maximize the return on money spent on gas lift diagnostic work, it is desirable to prioritize candidates for this type of work. Prioritizing can be accomplished by some of the less expensive techniques mentioned above to identify potential candidates for flowing surveys.

3.2 TWO-PEN PRESSURE RECORDER CHARTS

3.2.1 General

The two most significant pressures acting on any gas lift valve are the production pressure and the injection gas pressure. From these known pressures at the surface (recorded on a two-pen chart), the downhole pressures existing in the tubing and casing can be calculated and compared to the operating characteristics of the type gas lift valves in service. From this information, it is possible to estimate the point of operation. The accuracy of the recorded pressures is very important. Check the accuracy of the two-pen recorder using a calibrated pressure gauge or dead-weight tester. Two-pen recorder charts can also be used to optimize surface controls, locate surface problems, as well as identify downhole problems.

3.2.2 Where to Install a Two-Pen Pressure Recorder

3.2.2.1 Connect injection gas pressure recording line:

a. At the well; not at compressor or gas distribution header.

b. Downstream of input choke or time cycle controller so that the true surface injection gas pressure is recorded.

3.2.2.2 Connect production pressure recording line:

a. At the well; not at the battery, separator, or production header.

b. Upstream of choke body or other restrictions. (Even with no choke bean, less than full opening is found in many choke bodies.)

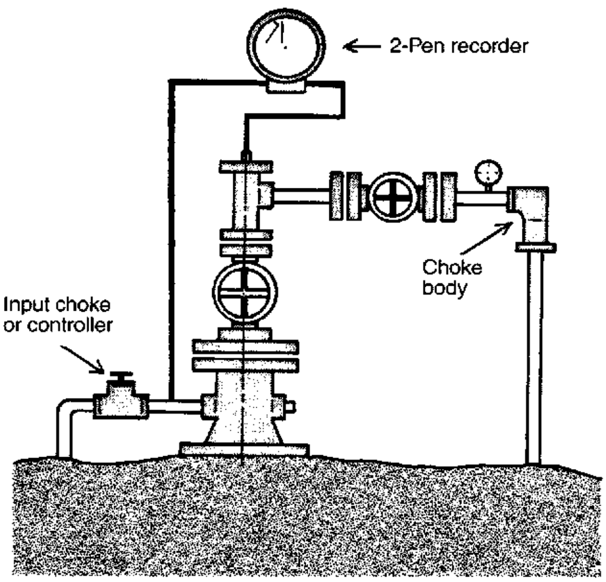


Figure 3—Two-Pen Recorder Installation

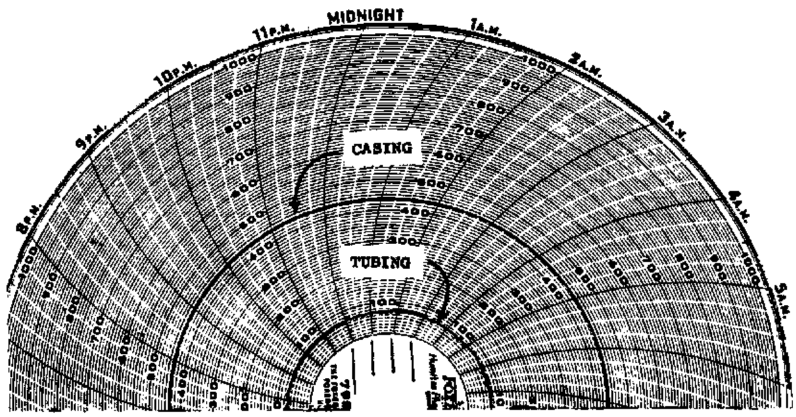
3.2.3 Chart Interpretation

3.2.3.1 The following examples are typical two-pen pressure recorder charts for both continuous flow and intermittent gas lift wells, with comments on interpretation.

3.2.3.2 Some problems, such as blowing around, create a rather unique pattern on a two-pen recorder chart which can be useful in identifying and remedying such problems, however, the reader should concentrate on the underlying causes of fluctuations in the production pressure and injection gas pressure pens rather than just attempting to compare chart patterns from other wells. Few two-pen charts are ever exactly alike.

3.2.4 Examples of Pressure Recorder Charts from Continuous Flow Wells

The following illustrations, Figures 4A through 4N, are examples of pressure recorder charts from continuous flow wells.



OPERATION: Continuous flow, casing choke control, tubing flow.

TYPE OF WELL: High productivity, high bottom-hole pressure.

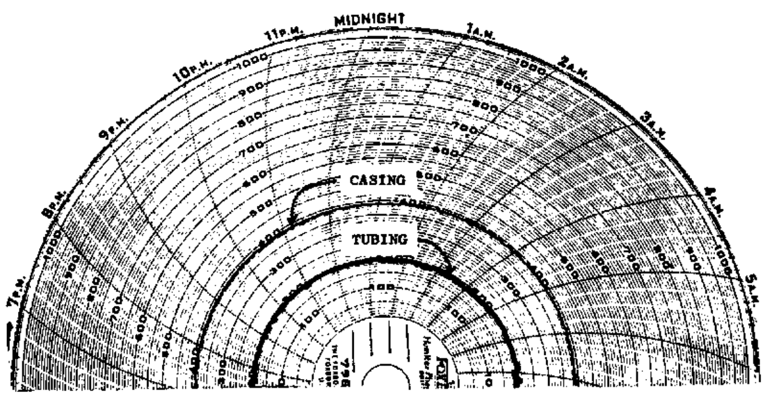
TROUBLE: None.

RECOMMENDATION: Leave well alone.

TYPE OF GAS LIFT VALVES: Injection pressure operated.

REMARKS: Good continuous flow operation. Well has a high working fluid level. The low flowing well-head pressure should be noted. Well producing 2000 bbl of fluid per day—95% water—from water drive reservoir, through $2^7/_8$ in. tubing.

Figure 4A—Example of a Pressure Recorder Chart from Continuous Flow Wells



OPERATION: Continuous flow, casing pressure control with regulator, tubing flow.

TYPE OF WELL: High productivity, high bottom-hole pressure.

TROUBLE: Inadequate production.

RECOMMENDATION: Reduce back pressure.

TYPE OF GAS LIFT VALVES: Injection pressure operated.

REMARKS: Excessive back may be due to one or more of the following:

a. Choke in flow line.

b. Restriction in flow line (paraffin, sand, etc.).

c. Flow line too small or too long.

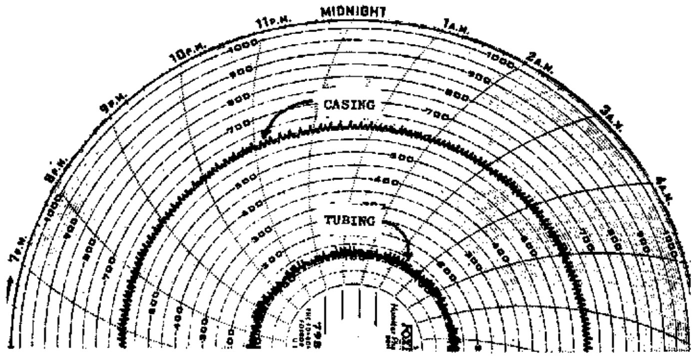
d. Separator pressure too high.

e. Too many sharp bends in flow line.

f. Highly emulsified fluid.

g. Excessive input gas.

Figure 4B—Example of a Pressure Recorder Chart from Continuous Flow Wells



OPERATION: Intermittent continuous flow, time cycle control, tubing flow.

TYPE OF WELL: High productivity, high bottom-hole pressure.

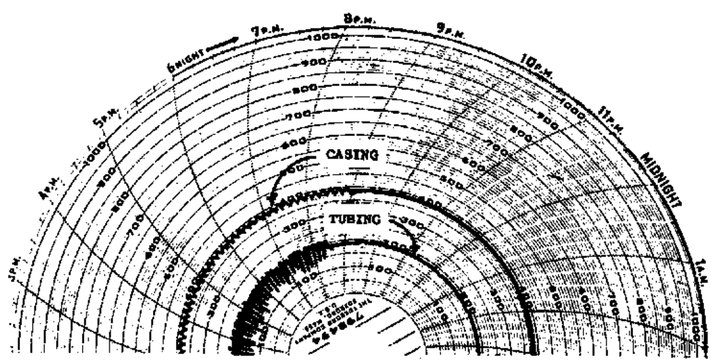
TROUBLE: None.

RECOMMENDATION: Leave well alone.

TYPE OF GAS LIFT VALVES: Injection pressure operated, intermittent (choked).

REMARKS: Well is injecting 30 seconds. Every 5 minutes. Well was first placed on tubing control. The fluid was heavily emulsified and the well was not making its production. After placing it on time cycle control, the emulsification stopped and the well made its production.

Figure 4C—Example of a Pressure Recorder Chart from Continuous Flow Wells



OPERATION: Intermittent injection vs. continuous flow, tubing flow.

TYPE OF WELL: Borderline production rate.

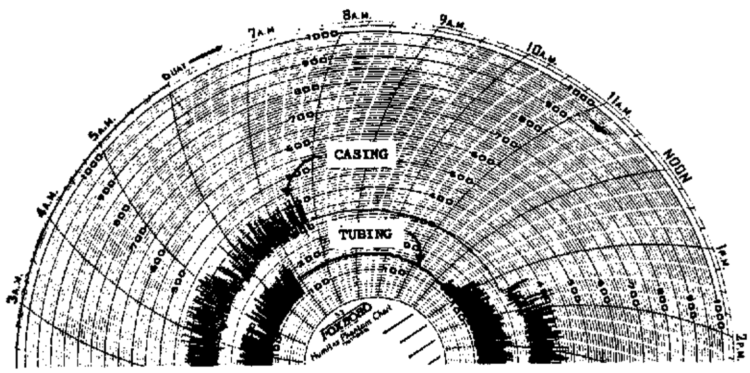
TROUBLE: Inadequate production.

RECOMMENDATION: An intermittent and continuous gas injection comparison.

TYPE OF GAS LIFT VALVES: Injection pressure operated.

REMARKS: Compare intermittent to continuous injection of gas to determine most efficient production rate.

Figure 4D—Example of a Pressure Recorder Chart from Continuous Flow Wells



OPERATION: Tubing control without choke in gas line, tubing flow.

TYPE OF WELL: High productivity, high bottom-hole pressure.

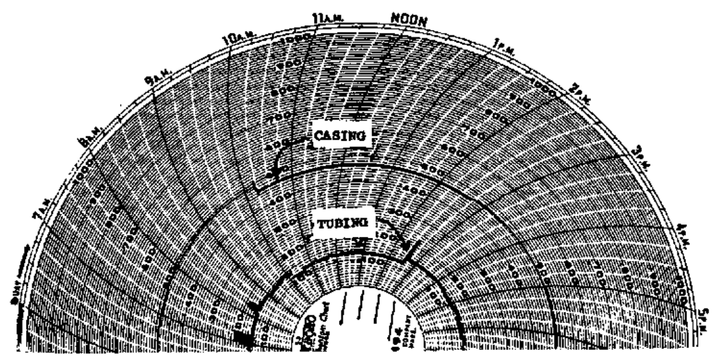
TROUBLE: Supply gas was closed to well. Well was off production $5^1/_2$ hours.

RECOMMENDATION: An intermittent and continuous gas injection comparison.

TYPE OF GAS LIFT VALVES: Injection pressure operated.

REMARKS: Work was being done on the gas system. Well should never be operated without a choke, or some type of control, on injection gas.

Figure 4E—Example of a Pressure Recorder Chart from Continuous Flow Wells



OPERATION: Continuous flow, casing choke control, tubing flow.

TYPE OF WELL: High productivity, high bottom-hole pressure.

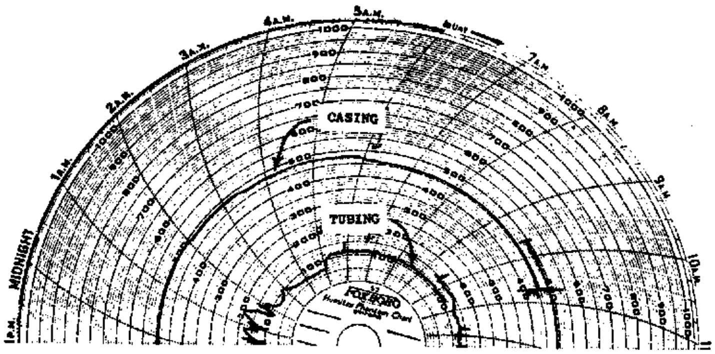
TROUBLE: None.

RECOMMENDATION: Leave well alone.

TYPE OF GAS LIFT VALVES: Injection-pressure operated.

REMARKS: The well had been shut in overnight, and the gas had been turned on shortly before the chart was changed. The casing pressure was at 460 psig at the beginning at 10:15 a.m. There was a gradual pressure rise to 468 psig due to fluid temperature increase affecting valve. At 2:45 p.m. the casing pressure increased to 480 psig and a "kick" can be noted on the tubing pressure. This was due to an upper valve becoming the operating valve. At 10:00 a.m. the next morning the casing pressure had increased to 490 psig due to temperature effect.

Figure 4F—Example of a Pressure Recorder Chart from Continuous Flow Wells



OPERATION: Continuous flow, casing choke control, tubing flow.

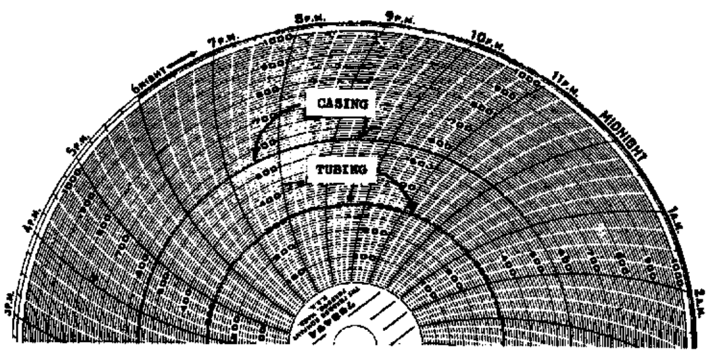
TYPE OF WELL: High productivity, high bottom-hole pressure.

TROUBLE: Choke on gas line froze.

RECOMMENDATION: A gas heater might be installed ahead of the choke; or a jacket might be welded around the choke to permit the hot flow-line fluids to pass over it; or the well might be placed on intermittent injection.

TYPE OF GAS LIFT VALVES: Injection-pressure operated.

Figure 4G—Example of a Pressure Recorder Chart from Continuous Flow Wells



OPERATION: Continuous flow, casing choke control, tubing flow.

TYPE OF WELL: High productivity, high bottom-hole pressure.

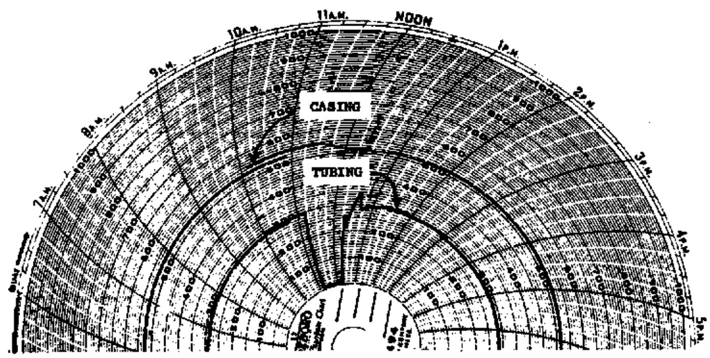
TROUBLE: None, well is flowing.

RECOMMENDATION: Leave well alone.

TYPE OF GAS LIFT VALVES: Injection pressure operated.

REMARKS: Well is flowing; no gas is being injected.

Figure 4H—Example of a Pressure Recorder Chart from Continuous Flow Wells



OPERATION: Continuous flow, casing choke control, tubing flow.

TYPE OF WELL: High productivity, high bottom-hole pressure.

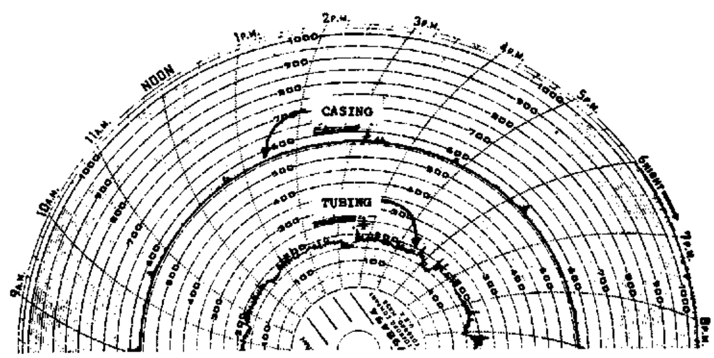
TROUBLE: Well was closed in to repair flow line.

RECOMMENDATION: None.

TYPE OF GAS LIFT VALVES: Injection pressure operated.

REMARKS: When the master valve was opened the tubing pressure was 250 psig at the peak of U-tube. As the gas cleared through the gas lift valve, the tubing pressure increased to a maximum of 345 psig, then fell off and finally stabilized at 285 psig.

Figure 4I—Example of a Pressure Recorder Chart from Continuous Flow Wells



OPERATION: Continuous flow, tubing control, tubing flow.

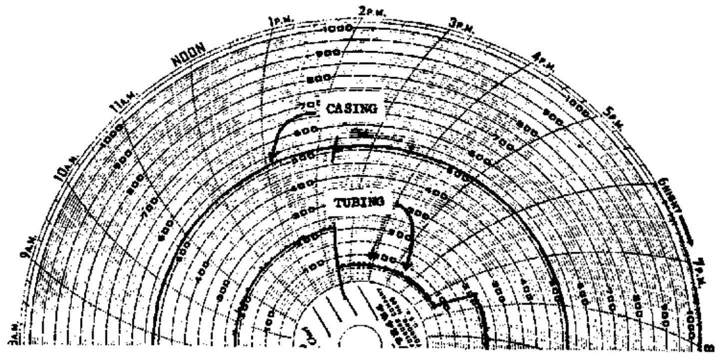
TYPE OF WELL: High productivity, high bottom-hole pressure.

TROUBLE: Well is flowing, but loads up with water periodically.

RECOMMENDATION: Operating satisfactorily.

REMARKS: The tubing control element is set to inject gas into the well when the pressure decreases to 160 psig. It can be noted by the rise in casing pressure opposite the drop in tubing pressure.

Figure 4J—Example of a Pressure Recorder Chart from Continuous Flow Wells



OPERATION: Continuous flow, casing choke control, tubing flow.

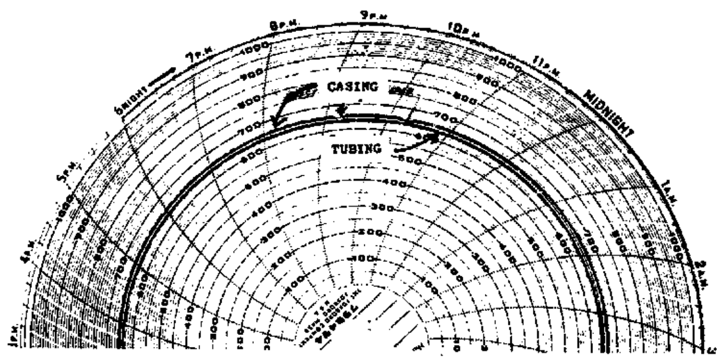
TYPE OF WELL: High productivity, high bottom-hole pressure.

TROUBLE: Well is being tested in test separator.

RECOMMENDATION: Remove high normal back pressure, or test against same high back pressure for accurate flow test.

REMARKS: It would be impossible to have an accurate production test on the well under the above conditions.

Figure 4K—Example of a Pressure Recorder Chart from Continuous Flow Wells



OPERATION: Continuous flow, casing choke control, tubing flow.

TYPE OF WELL: High productivity, high bottom-hole pressure.

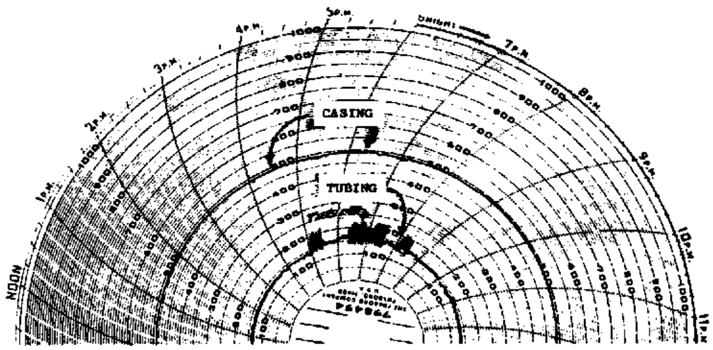
TROUBLE: Well is closed in.

RECOMMENDATION: Check to see why it is closed in.

TYPE OF GAS LIFT VALVES: Injection pressure operated.

REMARKS: On checking, it was noted that the well had produced its monthly allowable, and had been closed in. This can hurt some oil wells. It is better to cut the daily production and produce the well constantly.

Figure 4L—Example of a Pressure Recorder Chart from Continuous Flow Wells



OPERATION: Continuous flow, casing choke control, tubing flow.

TYPE OF WELL: High productivity, high bottom-hole pressure.

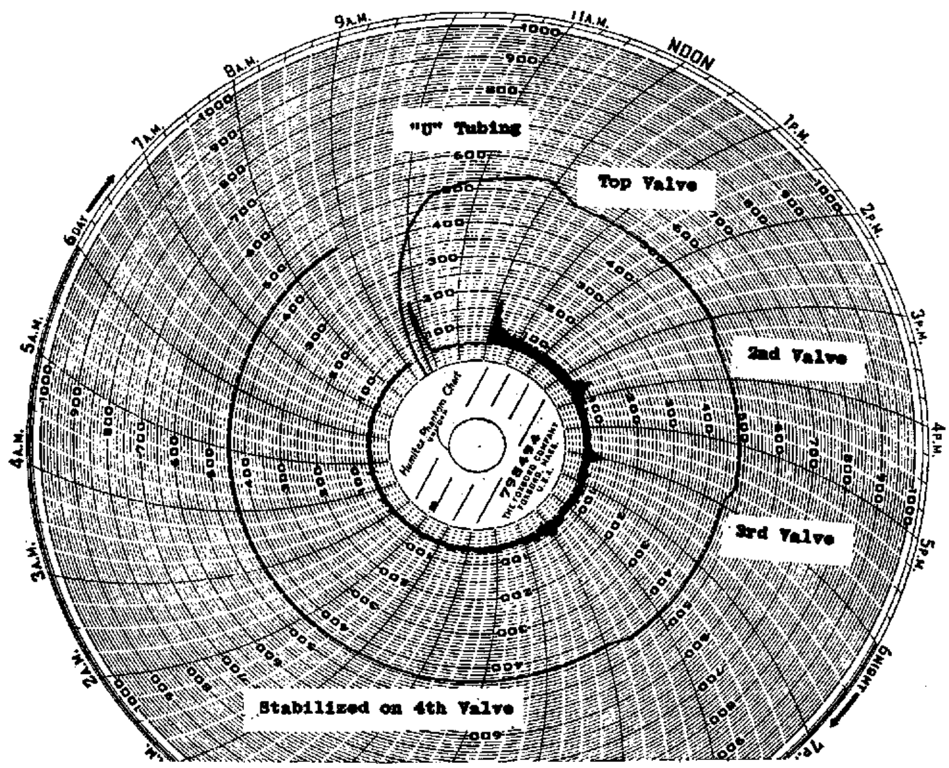
TROUBLE: Not serious, well is "heading."

RECOMMENDATION: Check to see if system gas pressure fluctuates.

TYPE OF GAS LIFT VALVES: Injection pressure operated.

REMARKS: Reasonably good operation. Well has a tendency to "head," which could be caused by erratic valve operation or a fluctuating system pressure.

Figure 4M—Example of a Pressure Recorder Chart from Continuous Flow Wells



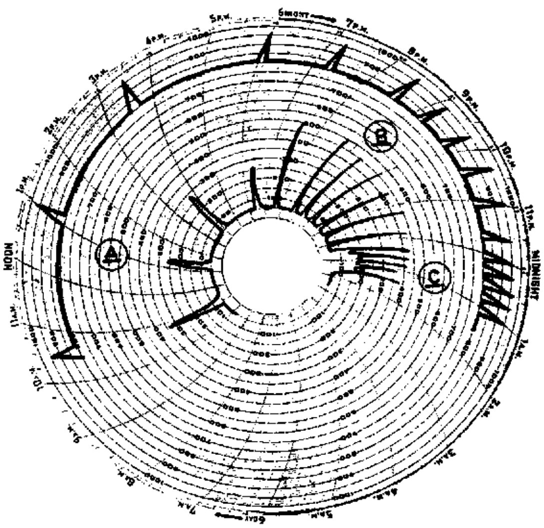
A choke was used on the gas line to control the gas volume into the casing-tubing annulus. When the gas was first turned on, an immediate surge of fluid returned from the tubing as the well was completely full of salt water. When the liquid volume displaced in the annulus stabilized to the gas volume rate of the injection gas, the tubing pressure remained at 50 psig until the top valve was uncovered and gas entered the tubing. A surge in tubing pressure is noted as each valve is uncovered. The well finally stabilized on the 4th valve.

Figure 4N—Unloading Continuous Flow Well

3.2.5 Two-Pen Recorder Charts Showing Examples of Intermittent Gas Lift Malfunctions

This section contains 11 two-pen recorder charts (Figures 5A through 5K) that illustrate most of the common problems that may occur in an intermittent gas lift operation. These may be used by the operator in spotting problems before they become too severe. The charts were hand drawn so that examples of malfunctions could be exaggerated for clarity.

In each of the charts, the outer trace represents a recording of the casing pressure and the inner tracer presents a recording of the tubing pressure.

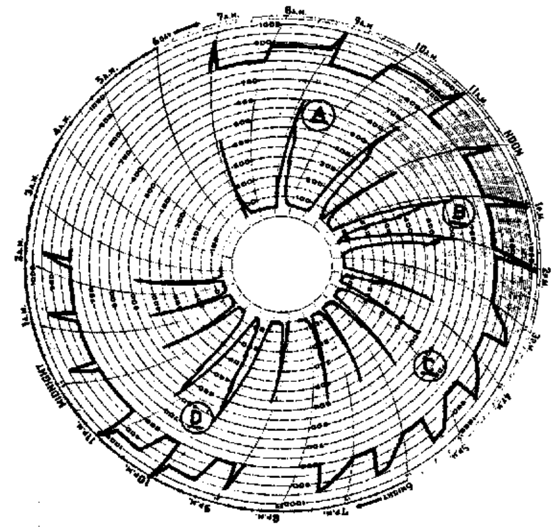


A: Cycle frequency too long. Tubing kicks are low and thick.

B: Increased cycle frequency yields tall, thin, tubing kicks, and more production.

C: Cycle frequency too fast. Tubing pressure does not have time to reduce to normal.

Figure 5A—Example of Intermittent Gas Lift Malfunction



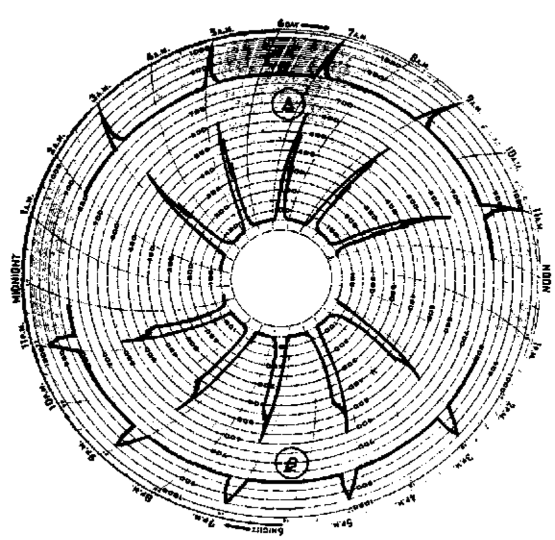
A: Erratic gas system pressure. The pressure has declined after timer was adjusted so that now two injections are required per cycle.

B: Timer is then opened for longer injection. When gas system pressure increases, too much gas is used.

C: To help stabilize gas system pressure, use choke and timer.

D: Injection frequency too fast; gas lift valve is not loaded so does not open until second injection. Too much gas is evident in tubing kick. Reduce injection frequency for better operation.

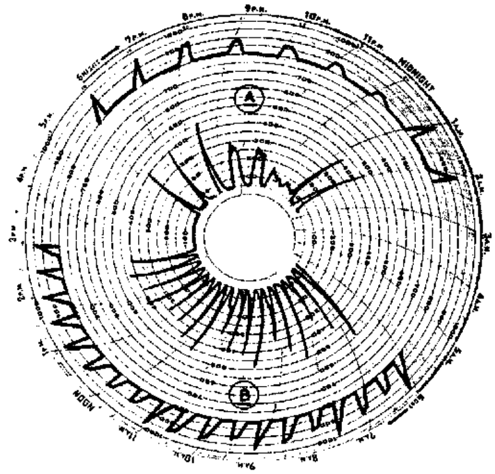
Figure 5B—Example of Intermittent Gas Lift Malfunction



A: Injection rate too high. May cause more than one gas lift valve to open. This condition is evidenced on the casing pressure by a change in the pressure decline rate after a gas lift valve closes. The multiple points on the tubing pressure also evidence this condition.

B: Too much gas. Tubing kicks are too high and too thick. Casing pressure decline is rather slow.

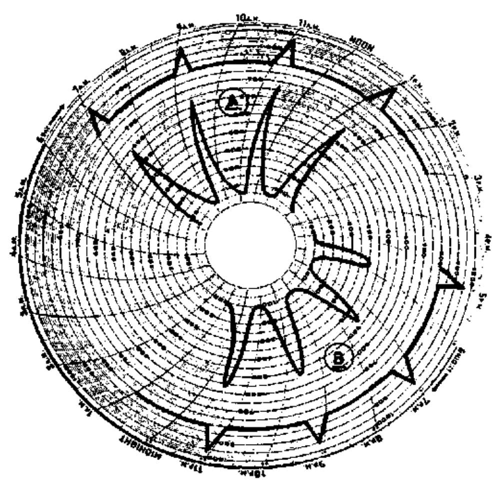
Figure 5C—Example of Intermittent Gas Lift Malfunction



A: Well loading up. Evidence of excessive fluid load when gas lift valve opens early. As this continues, problem is shown by shorter and wider tubing kicks until the lower valve becomes submerged and operation continues on an upper valve. A decline in produced fluid is experienced.

B: Well unloading. This illustrates how the fluid load decreases from a maximum when a gas lift valve operates the first time to a minimum when the valves operate the last time just before transferring to the next lower valve.

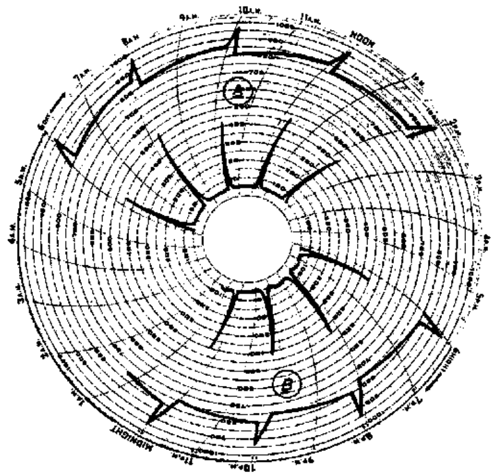
Figure 5D—Example of Intermittent Gas Lift Malfunction



A: Choked well (flowline choke). Restriction of choke causes slug velocity to be slow and pressure reduction period to be long. Also, tubing pressure is too high.

B: Flow line restriction. About the same effect as choke. Tubing pressure changes are gradual because restriction is distant from wellhead.

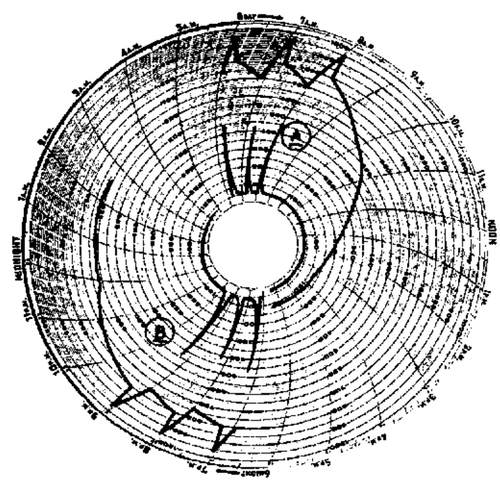
Figure 5E—Example of Intermittent Gas Lift Malfunction



A: Leak in surface intermitter. Good operation is maintained.

B: Small leak in tubing string. Between each cycle, the casing pressure declines slowly after the gas lift valve closes. Tubing kicks are very good.

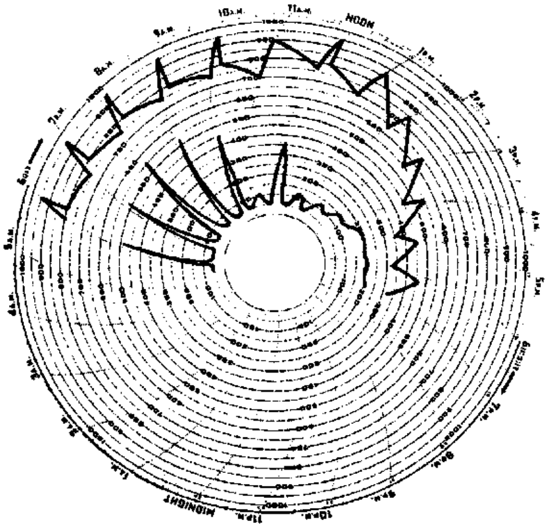
Figure 5F—Example of Intermittent Gas Lift Malfunction



A: Leak high in tubing. Leak is small since tubing kicks are normal. First sign of leak is evidenced when casing pressure continues to decrease after gas lift valve closes. When gas to casing is shut off, casing declines to a value near the tubing pressure.

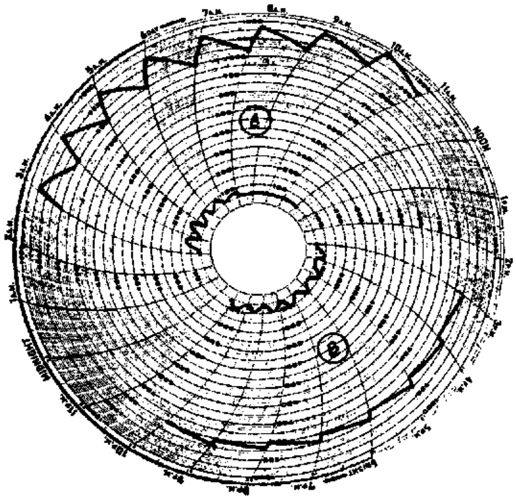
B: Leak low in tubing. Operating pressure about the same as above. Difference shows when gas to casing is shut off. Then casing pressure declines to a value well above the tubing pressure (fluid seal over the valve).

Figure 5G—Example of Intermittent Gas Lift Malfunction



Large leak in tubing string. At first, it shows as a small leak, then leak is such that the casing pressure sometimes fails to open the gas lift valve. When the leak exceeds the cycle gas requirement, the casing pressure declines well below the normal range and a saw tooth pattern is traced. The tubing pressure reaches a steady, elevated pressure.

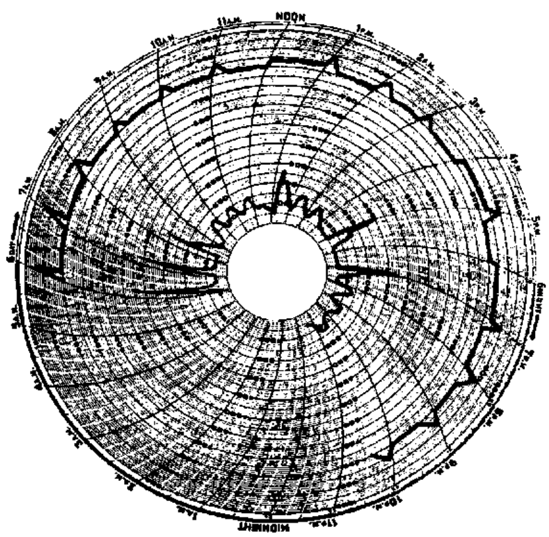
Figure 5H—Example of Intermittent Gas Lift Malfunction



A: Plugged valve. Very slow decline of casing pressure is an indicator of this problem. The tubing pressure kicks are rounded and misty because of excessive fall back. As condition gets worse, the casing pressure stays above valve closing pressure, and tubing pressures stabilize. Then, only gas is obtained from fluid.

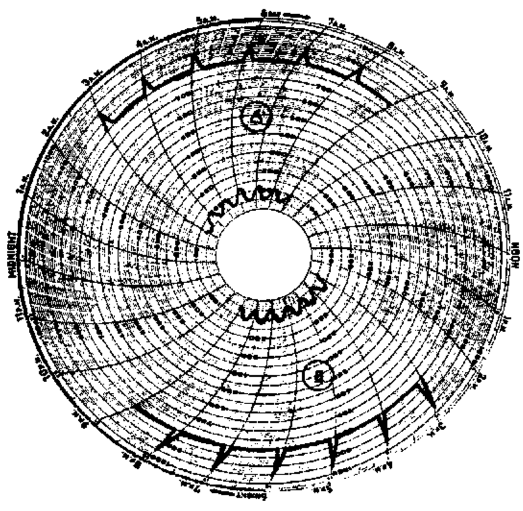
B: Plugged tubing, very similar to situation A, but tubing pressure reflects injection cycles. Very little fluid is produced.

Figure 5J—Example of Intermittent Gas Lift Malfunction



Gas line pressure becomes too low. Casing pressure fails to get high enough. Tubing kicks change from good slugs, to small slugs, to a misty spray.

Figure 5I—Example of Intermittent Gas Lift Malfunction



A: Not enough gas. Fall back is excessive so fluid recovery is small. Tubing pressure has rounded, sluggish kicks. Casing pressure operating spread is too small.

B: Not enough fluid. Casing pressure operating spread is normal, but tubing pressure is rounded and sluggish.

Figure 5K—Example of Intermittent Gas Lift Malfunction

3.3 ACOUSTICAL SURVEYS

3.3.1 General

The well "sounder" is an acoustical instrument that works on the echo principal. The sound pulse is initiated by either explosion or implosion with the echoes or sound reflections being recorded on a strip of paper. The firing head and microphone are generally connected to a valve in communication with the tubing-casing annulus. The sound waves travel down the annulus. Each tubing collar, gas lift mandrel, and the static fluid level in the annulus reflect the sound to varying degrees. These sound echoes are received by the microphone, amplified, and recorded on a moving strip of paper. The liquid level in the well reflects most of the sound and is recorded as a very large deflection compared to other reflections caused by collars or mandrels, etc. Figure 6 shows a typical recording.

3.3.2 Applications

Well sounding devices can be used to determine a variety of diagnostic information. Some of the things they can help to determine are the following:

a. Casing or tubing fluid level.

b. Estimate operating valve.

c. Estimate static bottom-hole pressure.

d. Locate the approximate depth of leaks in tubing string (fill casing, unload to leak, sound C.F.L.).

e. Locate mandrel depths.

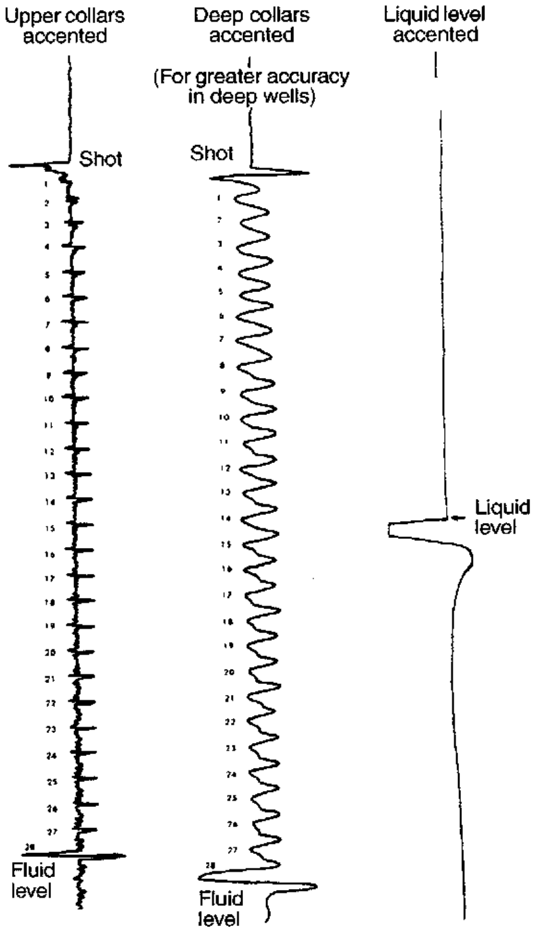


Figure 6—Typical Acoustic Recordings

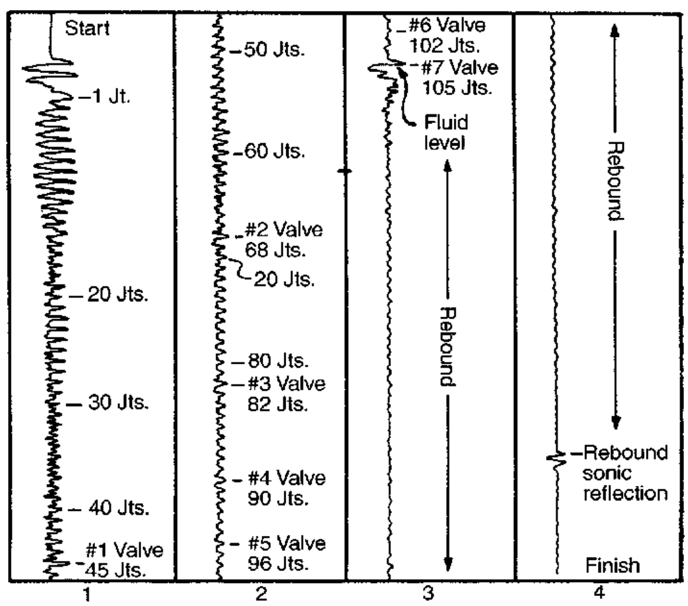


Figure 7—Typical Acoustic Survey of Gas Lift Well Two-Pen Recorder Charts

3.3.3 Limitations

3.3.3.1 The fluid level in the casing does not always indicate the operating valve depth. The casing fluid level only indicates the deepest point to which a well has been unloaded—not necessarily the current point of operation.

3.3.3.2 The information provided by well sounding devices can be a great help in gas lift trouble-shooting, especially when combined with, and used to verify, the other methods discussed in this manual.

3.4 TAGGING FLUID LEVEL AND/OR BOTTOM

3.4.1 General

In many cases, a wireline unit may be working in the field when gas lift problems are encountered on another well in the field. It is common practice in many areas to tag the tubing fluid level in order to determine the point of operation, or tag bottom to find possible obstructions, sand bridges, or fill above the perforations. Such work can be helpful and can locate the source of many problems. For example, if the tubing fluid level is below the bottom valve, or an obstruction is located in the tubing string, the cause of the problem may be identified. Unfortunately, this method is not accurate enough to determine the specific operating valve, and can sometimes be misleading.

3.4.2 Application

A wireline unit can give valuable information concerning the operation, or cause of improper operation of a gas lift well. Some of the problems this method can be used to identify are listed below:

a. Plugged or obstructed tubing.
b. Paraffin, scale, or other deposits.
c. Fill-in over the perforations.
d. Abnormally low fluid level, at or below the gas lift valves, can indicate SBHP decline or formation damage.
e. Abnormally high fluid level, above the intended operating valve, can indicate tubing leaks, or gas lift valve malfunctions.

3.4.3 Limitations

Tagging the fluid level in a well with wireline tools can often give an incorrect estimation of the operating valve. Fluid feed-in will sometimes raise the fluid level before the wireline tools can get down the hole. In addition, fluid fall-back will always occur after the gas lift gas has been shut off. Both of these factors will cause the observed fluid level to be above the operating valve. Care should be taken to ensure that the input gas valve is closed prior to closing the wing valve, or the gas lift system pressure will drive the fluid level back down the hole and below the point of operation, thus giving erroneous fluid level data.

3.5 FLOWING PRESSURE SURVEYS

3.5.1 General

In this type of survey, a pressure recording instrument is run in the well under flowing condition while the well is being tested. A no-flow device is run with the tools and prevents the tools from being blown up the hole. The no-flow device is equipped with "dogs" or slips that are activated by sudden movement up the hole. The pressure recording instrument is stopped above and/or below each gas lift valve for a period of time, and records the pressures at each valve. Making additional stops between valve stations can be helpful in plotting and interpreting the survey data. From this information the exact point of operation can be determined, as well as the actual flowing bottom-hole pressure. This type of survey is the most accurate way to determine a gas lift well's performance. Flowing pressure surveys can accurately determine or provide the following information:

a. The depth of gas injection.
b. The flowing bottom-hole pressure.
c. The P.I. of the well. (This can be calculated when the production test data and static BHP Data are gathered in conjunction with the flowing pressure data.)
d. The location of tubing leaks within the range of stops.
e. A base line reference of well performance to aid in identification of future problems.
f. Provide information for the redesign of valve spacing for maximum production.

3.5.2 Objective of Flowing Survey

Flowing surveys define what is occurring in the system at a given set of conditions such that predictions can be made as to well performance under a different set of conditions (such as a new valve spacing, higher operating pressure, etc.). In order to accomplish this objective, it is essential that the test conditions accurately duplicate normal producing condition. This means that the survey must be initiated under stable flowing conditions. Do not shut-in the well prior to the flowing survey. In some cases, this may mean that a crown valve or swab valve must be added to the tree so that the wireline unit can rig up the lubricator without shutting in the well.

3.5.3 Procedural Points to Remember

3.5.3.1 Enter the well under flowing conditions. Entering the well under flowing conditions eliminates the possibility of inaccurate results. It is essential that the well be producing under stabilized conditions which are representative of normal operating conditions during the survey. Conducting a survey on a gas lift well that is unloading will yield inaccurate data.

3.5.3.2 Test the well during the survey. To get productivity data, a well test must be known for the specific drawdown conditions measured during the survey. The test should be as long as possible. A 24-hour test can be obtained if the test is started the day before the wireline unit runs the survey. The required test data includes accurate measurements of barrels of oil and water per day, total return gas volume, injection gas volume, and both fluid and gas gravities.

3.5.3.3 Record tubing and casing pressure. A calibrated two-pen recorder chart should be used to document tubing and casing pressures during the survey. This information is vital in determining gas lift valve performance.

3.5.3.4 Locating leaks. If a tubing leak is suspected, at least one stop should be made between each valve; more in the area of the suspected leak. This will allow more accurate location of the tubing leak.

3.5.3.5 Run small-diameter pressure recording instrument. Running a small-diameter pressure recording instrument is desirable in order to minimize the restriction to flow. This serves two purposes: (a) it will minimize a reduction in flow rate due to a restriction, and (b) it will minimize the chances of the tools being "blown up the hole." Most pressure recording instruments are available in $1^1/_4$ inch diameter, with some being available in 1-inch and $^3/_4$-inch diameter.

3.5.3.6 Safety precautions. Since the well is being entered under flowing condition, it is important to take adequate steps to reduce the chances of the tools being blown up the hole. In addition to small-diameter pressure recording instruments mentioned above, weighted stems and "no-flow latches" should be used. Upward movement of the tool string activates a set of slips in the no-flow latch to prevent being blown up the hole. Be sure that the diameter of the stem and/or tools above the no-flow latch is not greater than the diameter of the stem and tools below the no-flow latch. If the largest restriction to flow is above the no-flow latch, the force trying to blow the tools up the hole will be above the no-flow latch, and thereby prevent it from activating. If the pressure recording instrument goes in the hole freely for the first 100 feet or so, no further trouble should be encountered because maximum fluid velocities occur near the surface of the well. Fifteen feet of $1^1/_4$-inch stem should be sufficient in most cases. A typical assembly might consist of a rope socket, 5 feet $1^1/_4$-inch stem, no-flow latch(es), 10 feet $1^1/_4$-inch stem, and pressure recording instruments (if 1-inch pressure recording instruments are being used, substitute 1-inch stem).

3.5.3.7 Tandem instruments. Running tandem temperature/pressure recording instruments can save lost time, effort, and money by providing a back-up in the event that one instrument fails or is reporting erroneous pressures. Most electronic instruments record both temperature and pressure. This allows back-up capability for both temperature and pressure with only two instruments in the tool string.

3.5.3.8 Temperature recording. Recording temperatures in conjunction with flowing surveys can give valuable additional information in many cases. This type of information may identify problems such as valves working improperly due to being designed on erroneous temperature data, or locating leaks due to the cooling effect associated with the expansion of gas. Many instruments have built-in temperature recording capability. However, if they do not, it will be necessary to run a temperature recording instrument in tandem with a pressure instrument. In addition to the stop in the lubricator, it is a good practice to make a stop below the mud line for offshore wells, and several hundred feet below the permafrost level for wells in arctic or near-arctic areas so that a true flowing temperature gradient can be determined.

3.5.3.9 Instrument pressure recording range and clock rotation. For mechanical pressure recording instruments, it is recommended that the maximum anticipated pressure in the well be approximately 75% of the maximum pressure range of the instrument. This practice will eliminate inaccuracy due to attempting to record low pressures on a pressure instrument designed to record high pressures.

In general, a fast clock rotation makes it easier to detect and interpret pressure changes. It is desirable to run as fast a clock as possible depending on the depth of the well, the number of stops, and the desired time on "bottom." For temperature elements that operate on vapor pressure, the recorded temperature must be in the upper half of the range of the instrument for good sensitivity.

3.5.4 Plotting Survey Results

3.5.4.1 Graphically plotting the results of a flowing pressure survey will aid in interpretation. Figure 8 is a flowing survey run on a continuous flow well. The well is operating from the 5th valve making 1000 BFPD as indicated by the sharp break in the flowing pressure gradient. The fluid level in the casing was sounded with an acoustical instrument and found to be just above valve 6. A wide spacing prevented operating from the bottom valve. Respacing the valves increased production to 1600 BFPD. Note how surface and subsurface pressure measurements combined with casing fluid level data painted an accurate picture of well performance.

3.5.4.2 Figure 9 shows flowing pressure and temperature surveys conducted on an intermittent gas lift well. Of particular interest is the temperature data that compliments the pressure survey. The operating valves are hard to determine from the pressure survey alone; however, the temperature survey clearly indicates operation from the valves at 4534 feet and 5025 feet. Notice that as the tubing pressure goes from its minimum to maximum value at 5025 feet, the tubing pressure slightly exceeds the casing pressure. This could indicate initial operation from the 5025 feet valve and valve interference from the valve at 4534 feet; or that the well is lifting from 4534 feet with the lower valve opening slightly after the 4534 feet valve opens. In either case, most of the gas appears to be

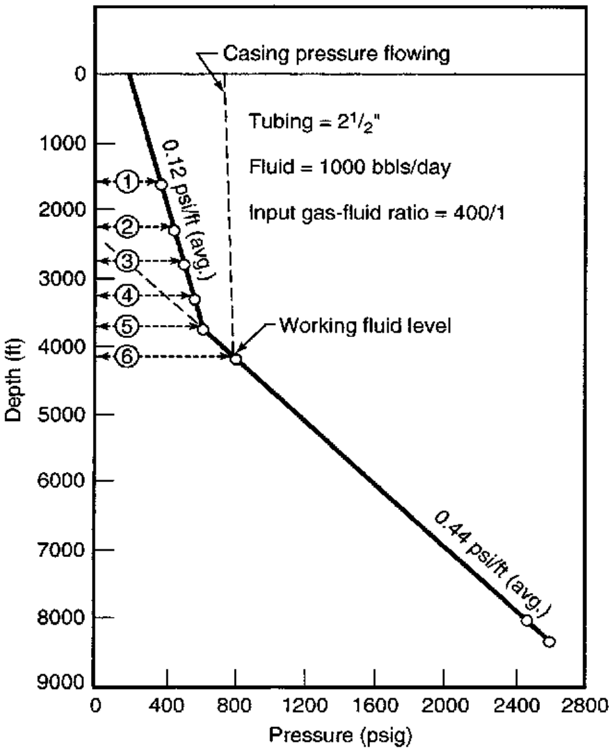


Figure 8—Flowing Pressure Survey

entering at the 4534-feet valve as indicated by temperature survey. It should be noted that temperature fluctuations at the operating valve are not nearly as easy to recognize on high volume wells.

3.5.5 Procedure For Running Flowing Bottom-Hole Pressures/Temperature Survey Where Well is Equipped With Gas Lift Valves

3.5.5.1 Intermitting Gas Lift Wells

Step 1. Be sure well has been flowing to test separator for 24 hours to obtain a stabilized production rate. (Test conditions should duplicate as nearly as possible normal production conditions.)

Step 2. Put well on test before running bottom-hole pressure. Test should be for a minimum of 6 hours. Production test information, two-pen pressure recorder chart, separator orifice meter chart and input gas orifice meter chart should be sent in with pressure traverse. Accurate test information is essential or meaningful results.

Step 3. Pressure/temperature recording instruments should be equipped with one and preferably two "no-blow" latches.

Step 4. Install lubricator and pressure recording instruments (see 3.5.3.9 for discussion of clock speed). Record surface pressure in lubricator during at least one complete cycle. Dead-weight test the lubricator pressure for later comparison with pressure instrument. Run instrument, making stops 15 feet below* each gas lift valve. Be sure to record a maximum and minimum pressure at each gas lift valve by remaining at each valve for at least one complete cycle. (Do not shut well in while rigging up or recording flowing pressures in tubing.)

Note: *Some operators like to make stops both above and below each gas lift valve. If a temperature survey is being conducted to locate the depth of gas injection, the instrument must be stopped in the mandrel or immediately above the mandrel to record the cooling effect of the injection gas.

Step 5. Leave instruments on bottom for at least two complete intermitting cycles.

Step 6. High and low tubing and casing pressure should be checked with a dead weight tester, recently calibrated two-pen recorder, or calibrated pressure gauge.

Step 7. If a static BHP is desired, shut off lift gas and allow the well to die to the separator. Leave instruments on bottom for a minimum of 12 hours.

3.5.5.2 Continuous Flow Gas Lift Wells

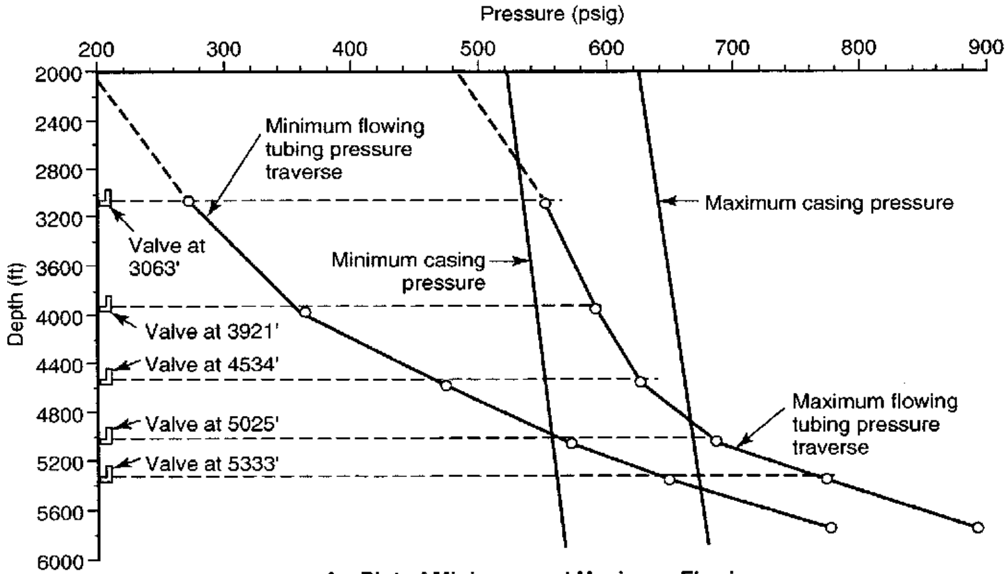
Step 1. Be sure well has been flowing to test separator until stabilized. (Test facilities should duplicate as nearly as possible normal production facilities.)

Step 2. Put well on test before running bottom-hole pressure. The test should be at a stabilized rate. Gas and fluid test, two-pen pressure recorder chart and separator orifice meter chart, and input gas orifice meter chart should be sent in with pressure traverse.

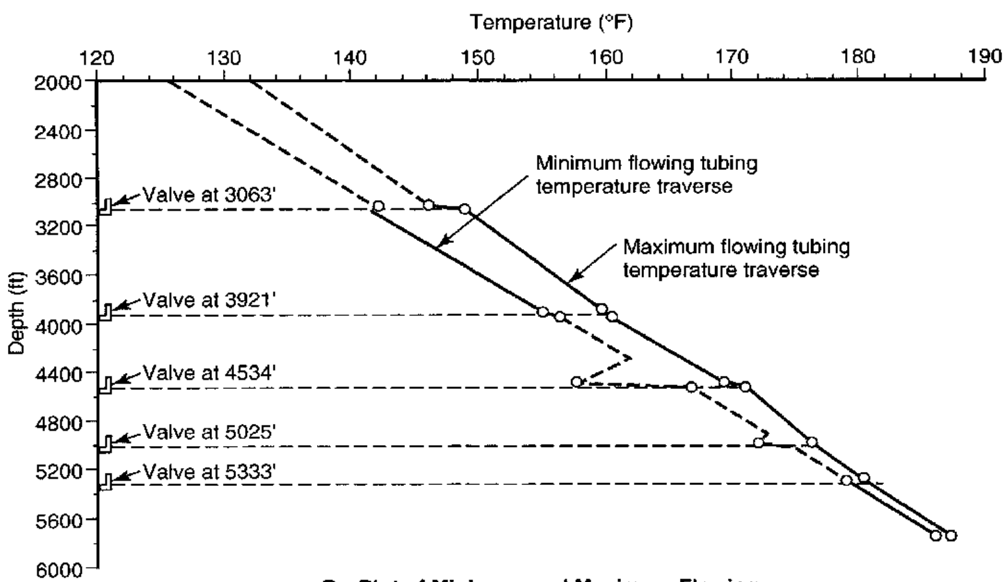
Step 3. Pressure/temperature recording instruments should be equipped with one and preferably two no-blow latches.

Step 4. Install lubricator and pressure recording instruments (see 3.5.3.9 for discussion of clock speed). Record surface pressure in lubricator for 15 minutes. Dead-weight test the lubricator pressure for later comparison with instrument pressure. Run instruments, making stops 15 feet below* each gas lift valve for 15 minutes. Shorter or longer stops may be dictated by well conditions. (Do not shut well in while rigging up or recording flowing pressures in tubing.)

Note: *Some operators like to make stops both above and below each gas lift valve. If a temperature survey is being conducted to locate the depth of gas injection, the instrument must be stopped in the mandrel, or immediately above the mandrel, to record the cooling effect of the injection gas. High flow rates relative to the tubing size may prevent or minimize the chances of detecting a temperature change.



A—Plot of Minimum and Maximum Flowing Tubing Pressures Versus Depth



B—Plot of Minimum and Maximum Flowing Tubing Temperatures Versus Depth

Figure 9—Results of Flowing Pressure and Temperature Surveys Conducted During Intermittent Operation of High Capacity Well to Locate Operating Valve

Step 5. Leave instruments on bottom for at least 30 minutes.

Step 6. Casing pressure should be taken with a dead-weight tester or recently calibrated two-pen pressure recorder or calibrated pressure gauge.

Step 7. If a static BHP is desired, shut off lift gas and close the wing valve. Leave instruments on bottom until the pressure stabilizes.

Note: If a tubing leak is suspected, make one or more stops between valves so the location of the leak can be determined.

3.6 RECOMMENDED PRACTICES FOR WELLS THAT PRODUCE SAND

3.6.1 General

3.6.1.1 Gas lift offers one of the better methods for lifting sand, in that the sand is actually produced from the well to the surface without passing through the gas lift valves. Since surging increases any sand problems, wells on gas lift that produce sand should not be intermittently operated. Continuous flow with very constant rate is best for wells that produce sand. The velocity must be sufficient to keep the sand suspended and bring it to the surface, and sometimes requires higher than normal gas/liquid ratios. If the well is rate-sensitive to the production of sand, it may be produced at a lower rate to prevent excessive sand entry from the formation into the wellbore. This can be accomplished by choking the injection gas to obtain lower stabilized flow rates. Chokes installed in the flowline may worsen the sand problem. Improper size chokes in flowlines can cause surging, and reduce velocities letting the sand fall out in the tubing, with plugging or bridging occurring. If chokes are used in the flowlines, they should be used in conjunction with sand probes. Through trial and error, the well would be produced with the largest choke possible that will not activate the sand probe.

3.6.1.2 Standing valves are usually not used in continuous flow wells, and should be removed to eliminate possible plugging problems.

3.6.2 Location of Gas Lift Problem Areas

Gas lift problems are usually associated with three areas: (a) inlet, (b) outlet, and (c) downhole. Examples of inlet problems may be the input choke sized too large or small, fluctuating line pressure, plugged choke, etc. Outlet problems could be high back pressure due to a flowline choke, a closed or partially closed wing or master valve, or plugged flowline. Downhole problems, of course, could include a cut-out valve, restrictions in the tubing string, or sand-covered perforations. Often, the problem can be found on the surface. If nothing is found on the surface, a check can then be made to determine whether the downhole problems are wellbore problems or gas lift equipment problems. Trouble-shoot your well before you call a rig!

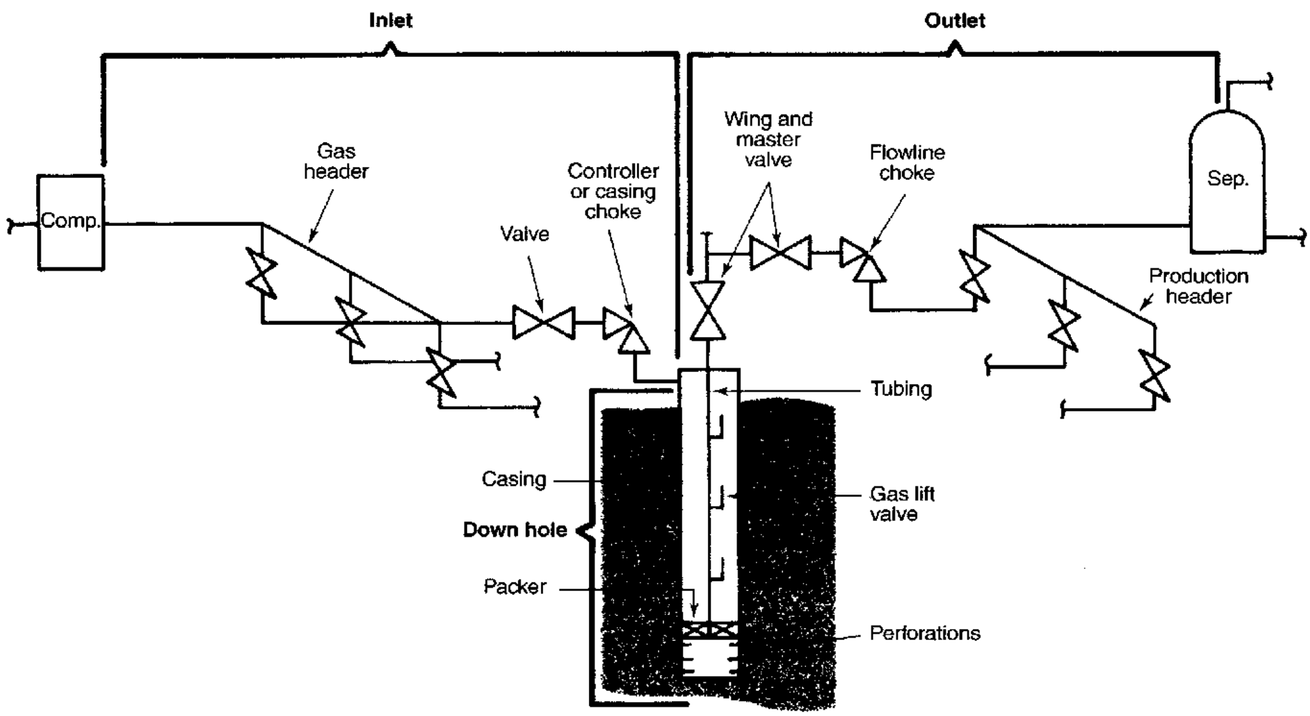


Figure 10—The Gas Lift System

3.6.2.1 Inlet Problems

3.6.2.1.1 Injection gas choke sized too large. Check for casing pressure at or above design operating pressure. This can cause reopening upper pressure valves and/or excessive gas usage.

3.6.2.1.2 Injection gas choke sized too small. Check for reduced fluid production as a result of insufficient gas injection. This condition can sometimes prevent the well from fully unloading, or cause heading.

3.6.2.1.3 Low injection pressure. Verify that the injection gas line is supplying full injection pressure at the wellsite and that the injection pressure is above the design operating injection pressure required by the gas lift valves. This condition can occur due to the input gas choke being sized too small, or being plugged or frozen up. Choke freezing can often be eliminated by continuous injection of methanol in the gas lift gas, heating the gas upstream of the injection choke, dehydrating the gas, or by use of a heat exchanger. A check of gas volume being injected will separate freezing from low injection pressure due to a hole in the tubing or cutout valve (a hole or cut out valve will cause high gas usage). Verify the gauge readings to be sure the problem is real.

3.6.2.1.4 High injection pressure. This condition can occur due to the input gas choke being sized too large; check for excessive gas usage due to reopening upper pressure valves. If high-injection pressure is accompanied by low-injection gas volumes, it is possible that the operating valve may be partially plugged or high tubing pressure may be reducing the differential between the tubing and casing (remove flowline choke or restriction) or an indication of temperature scrambling. Verify the gauge readings to be sure the problem is real. High-injection gas pressure can also be caused by high back pressure at the wellhead preventing the well from unloading to deeper valves.

3.6.2.1.5 Verify gauge. Inaccurate pressure gauges can cause false indications of high or low injection pressures. Always check the wellhead casing and tubing pressures with a calibrated gauge or dead weight tester.

3.6.2.1.6 Low gas volume. Verify that the injection gas line is supplying full injection pressure at the well site, and that the injection pressure is above the design operating injection pressure required by the gas lift design. Also check to ensure that the gas lift line valve is fully open and that the injection choke is not too small, frozen, or plugged. Sometimes a higher than anticipated producing rate and the resulting higher temperature will cause the valve set pressure to increase and thereby restrict the gas input.

3.6.2.1.7 Excessive gas volume. This condition can be caused by the injection choke sized too large or excessive injection pressure. Check to see if the injection pressure is above the design pressure to see if upper pressure valves may be open. A tubing leak, or cut-out valve, can also cause this symptom but they will generally also cause a low injection pressure. High wellhead pressure can also cause multipoint injection from upper valves and result in excessive gas usage.

3.6.2.1.8 Intermitter problems. Intermitter cycle time should be set to get the maximum fluid volume with the minimum number of cycles. Injection duration should then be adjusted to minimize "tail gas." Check to make sure that the intermitter has not stopped whether it be a manual wind or battery operated model. Many problems inherent with the use of mechanical clocks can be eliminated by using the newer electronic type of intermitters. Wells intermitting in excess of 250 BFPD should be evaluated for continuous flow application.

3.6.2.2 Outlet Problems

3.6.2.2.1 Valve restrictions. Check to ensure that all valves at the tree and header are fully open, or that an undersized valve is not in the line (i.e., 1-inch valve in 2-inch flowline). Other restrictions may result from a smashed or crimped flowline (check around places where the line crosses a road).

3.6.2.2.2 High back pressure. Wellhead back pressure should be kept to a minimum since the pressure is transmitted to the bottom of the hole and reduces the differential into the wellbore thereby reducing production. Check to ensure that no choke is in the flowline. Even with no choke bean in a choke body, it is usually restricted to less than full ID. Remove the choke body if possible. Excessive 90° turns can cause high back pressure and should be removed where feasible. High back pressure can also result from paraffin, salt, or scale buildup in the flowline. Hot oiling the line will generally remove paraffin. However, scale may or may not be able to be removed depending on the type. Where high back pressure is due to long flowlines, it may be possible to reduce the pressure by looping the flowline with an inactive line. The same would apply to cases where the flowline ID is smaller than the tubing ID. Sometimes a partially stuck check valve in the flowline can cause excessive back pressure. Check all possibilities and remove as many restrictions from the system as possible. High wellhead pressure can cause operation from upper valves and prevent unloading, resulting in excessive gas usage and reduced production.

3.6.2.2.3 Separator operating pressure. The separator pressure should be maintained as low as possible for gas lift wells. Often a well may be flowing to a high or intermediate pressure system when it dies and is placed on gas lift. Ensure that the well is switched to the lowest pressure system available.

3.6.2.3 Downhole Problems

3.6.2.3.1 Hole in tubing. Indicators of a hole in the tubing include abnormally low injection pressure and excess gas usage usually accompanied by a reduced production rate. Similar symptoms can be caused by leaking or cut gas lift valves, and tubing hanger or packer leaks (although a packer leak in a high flowing bottom-hole pressure well may be hard to detect). A hole in the tubing can be confirmed by the following procedure: Equalize the production pressure and casing pressure by closing the wing valve with the gas lift gas still on. After the pressures are equalized, shut off the gas input valve and rapidly bleed-off the injection pressure on the well. If the production pressure bleeds down as the injection pressure drops, then a hole is indicated. The production pressure will hold if no hole is present since both the check valves and gas lift valves will be in the closed position as the injection pressure bleeds to zero. Thus, the source of the problems can be identified as a gas lift valve problem rather than a tubing leak.

3.6.2.3.2 Operating pressure valve by surface closing pressure method. An injection pressure-operated valve will pass gas until the injection pressure drops to the closing pressure of the valve. As a result, the operating valve can often be determined by shutting off the input gas and observing the pressure at which the injection pressure holds. This pressure is the surface closing pressure of the operating valve. When compared to the surface closing pressure of each valve, the operating valve can often be determined.

3.6.2.3.3 Well blowing dry gas. For injection pressure-operated valves, check to ensure that the injection pressure is not in excess of the design operating pressure, thereby causing operation from the upper valves. Ensure that no hole exists in the tubing by the above method, and sound the casing fluid level. If the upper valves are not being held open by excess injection pressure, no hole exists, and the casing fluid level shows the well to be fully unloaded, then operation is probably from the bottom valve. However, this can be verified by comparing the surface closing surface pressure with that of the bottom valve. The bottom valve is usually flagged such that its surface operating pressure and closing pressure are noticeably less than the other valves in the string. In the case where the well is equipped with production pressure-operated valves and a pressure valve on the bottom, blowing dry gas is a positive indication of being on the bottom valve after the possibility of a hole in the tubing has been eliminated, because production pressure-operated valves will not remain open if there is no fluid pressure. Operation from the bottom valve generally indicates a lack of feed-in. Often it is advisable to tag bottom with wireline tools to see if the perforations have been covered by sand or debris. If the well is equipped with a standing valve, check to ensure the standing valve is not plugged.

3.6.2.3.4 Well not taking any input gas. Eliminate the possibility of a frozen or plugged input choke, a closed injection gas valve, or closed valves on the outlet side. If production pressure-operated valves were run without an injection pressure-operated valve on bottom, this condition is probably an indication that all the fluid has been lifted from the tubing and not enough production pressure remains to open the valves. Check for feed-in problems.

If injection pressure-operated valves were run, check to see if the well started producing above the design fluid rate, as the higher rate may have caused the temperature to increase sufficiently to lock-out the valves. If temperature is the problem, the well will probably produce periodically, then quit. If this is not the problem, check to make sure that the valve set pressures are not too high for the available injection pressure.

3.6.2.3.5 Well flowing in slugs. This condition can occur due to several causes. With injection pressure-operated valves, one cause is port sizes too large as would be the case if a well initially designed for intermittent lift were placed on continuous flow due to higher than anticipated fluid volumes. In this case, large production pressure effects are involved and the well will lift until the fluid gradient is reduced below a value that will keep the valve open. Injecting through oversized orifices at the operating valve can also cause slugging. Slugging can also occur due to temperature interference. For example, if the well started producing at a higher than anticipated fluid rate, the temperature could increase, causing the valve set pressures to increase and thereby lock them out. When the temperature cools sufficiently, the valves will open again, thus creating a condition where the well would flow by heads. With injection pressure-operated valves having a high production pressure effect or production pressure-operated valves, slugging can occur as a result of limited feed-in. The valves will not open until the proper fluid load has been obtained, thus creating a condition where the well will intermit itself whenever adequate feed-in is achieved. Heading can also be caused by having a tubing size too large for the production rate being lifted. Slugging can also result from any condition that causes a well to work from two or more gas lift valves, such as excessive valve spacing for low injection gas rate, varying injection gas line pressure, insufficient injection gas rate, or valve interference caused by using flow line chokes.

3.6.2.3.6 Installation stymied and will not unload. This condition generally occurs when the fluid column is heavier than the available lift pressure. Applying injection gas pressure to the top of the fluid column (usually with an equalizing line) will often drive some of the fluid column back into the formation, thereby reducing the height of the fluid column being lifted and allowing unloading with the available lift pressure, provided that there is no standing valve in the tubing. The check valves prevent this fluid from being displaced back into the injection gas side. For production pressure-operated valves, rocking the well in this fashion will often open an upper valve and permit the unloading operation to continue. Sometimes a well can be swabbed to allow unloading to a deeper valve; but swabbing should be avoided if at all possible due to the chances of sticking a swab cup, inadvertently pulling a retrievable valve with the swab, or getting blown up the hole.

3.6.2.3.7 Valve hung open. This case can be identified when the injection pressure will bleed below the surface closing pressure of any valve in the hole, but tests to determine if a hole exists show that no hole is present. Try shutting the wing valve on the flowline and allowing the casing pressure to build up as high as possible, then opening the wing valve rapidly. This action will create high differential pressures across the valve seat, hopefully removing any trash that may be holding it open. Repeat the process several times if required. In some cases, valves can be held open by salt deposition, and pumping several barrels of fresh water into the casing will solve the problem. Where fresh water-sensitive formations exist, be sure that this technique will not allow the water to contact the formation. If the above actions do not help, a flow cut or flat valve may be the cause.

3.6.2.3.8 Valve spacing too wide. In some instances, a well will not fully unload due to an excessively wide valve spacing. This generally occurs when a well produces at a higher rate than anticipated by the valve design. Try rocking the well as indicated when the well will not unload, as this will sometimes allow working down to lower valves. If a high pressure gas well is nearby, using the high pressure from this well may allow unloading. Where injection pressure operated valves are in the hole, this will require sufficient lift gas volume to override the gas passage capability of the upper valve(s), thus allowing the injection pressure to build up. Producing the well to an atmospheric tank or pit will sometimes allow unloading. If the problem is severe, respacing, installing a packoff gas lift valve between existing valves, or shooting an orifice into the tubing may be the only solution.

Table 1—Possible Causes and Cures of Some Common Malfunctions of Gas Lift Systems

Malfunction	Cause	Cure
Communication Between Casing and Tubing	A. Valve stuck open	Rock the well, flush the valve
	B. Packer leaking	Reset packer
	C. Tubing/tubing head leak	Pull, repair leak and rerun
	D. Circulating sleeve	Close it
	E. Dummy or valve jarred loose	Replace valve or dummy
Injection Pressure Increases	A. Operating valve changed to higher valve in installation	Adjust injection gas for maximum production
	B. Valve plugged	Pull well if conventional, pull valve if retrievable
	C. Temperature rise in well affecting valves	Exchange for valves that are not affected by temperature, or lower the test rack opening pressure of bellows charged valve
	D. Small fluid head	Reduce cycle frequency
	E. Valve(s) "take-on" pressure	Pull valves & check for tail plug and gasket leaks
Fluid Slug Velocity Less Than 1,000 Feet Per Minute	A. Fluid load very heavy	Increase cycle frequency
	B. Low injection line pressure	Increase pressure or space valves closer
	C. Valve partially plugged	Flush with fresh water or solvent
	D. Tubing partially plugged	Run paraffin knife or clean with solvent
	E. Poor valve response	Increase injection gas rate to achieve rapid build-up of injection pressure on casing
	F. Valve port too small	Exchange for large ported valves
High Back Pressure at Well Head	A. Plugged flow line	Look for partially closed valves, fouled checks, or sand
	B. High separator pressure	Reset back pressure valve or add gas accumulator tanks
	C. Flow line too small	Loop flow line or replace it with larger line
	D. Using too much gas	Adjust injection control equipment
	E. Choke in flowline	Remove choke
Sudden Drop in Production (Valves Open and Close Near Normal)	A. Plugged formation	Clean out well
	B. Plugged tubing	Check tubing below operating valve, wash or pull
	C. Too much or too little gas	Readjust injection gas controls
	D. Standing valve stuck open/closed	Pull and clean
	E. Subsurface safety valve closed	Correct cause of premature closing or reset safety valve

Figure 11—Gas Lift Trouble-Shooting Check List

Well: ______________________________

Field: ______________________________

Date: ______________________________

Inlet

A. Problem

1. [ ] Choke sized too large [ ] Reopening upper valves [ ] Excessive gas usage
2. [ ] Choke sized too small [ ] Cannot unload [ ] Insufficient gas
3. [ ] Choke plugged [ ] Choke frozen up
4. [ ] Bad Pressure Gauges-Causing insufficient or excessive injection gas pressure to be applied
5. [ ] Intermitter stopped [ ] Incorrect cycle or injection time
6. [ ] Intermitter on constant flow well
7. [ ] Intermitter malfunction, other
8. [ ] Gas lift supply gas shut off
9. [ ] Line pressure down, why?
10. [ ] Fluctuating line pressure, why?
11. [ ] Other problems/remarks: ______________________________

B. Corrective Action: ______________________________

II. Outlet

A. Problem

1. [ ] Master valve or wing valve closed
2. High back pressure due to:
   [ ] Flowline choke [ ] Flowline choke body [ ] Excessive 90 turns (more than 4)
   [ ] Long [ ] Flowline [ ] Flowline plugged or partially plugged
   [ ] Emulsions [ ] Hilly terrain [ ] Excessive canal crossings
   [ ] Flowline ID smaller than tubing
3. [ ] Valve shut at header [ ] Restricted ID valve [ ] Plugged or jammed flowline check valve
4. [ ] Valve at header leaking causing back pressure (from another well)
5. [ ] Separator operating pressure too high
6. [ ] Separator orifice plate sized too small
7. Other problems/remarks: ______________________________

B. Corrective Action: ______________________________

III. Downhole

A. Problem

1. [ ] No feed-in; fluid standing at or below bottom valve
2. [ ] Perforations covered
3. [ ] Fluids too light to load valves
4. [ ] Restrictions in tubing string
5. [ ] Spacing too wide to allow unloading
6. [ ] On bottom valve---not valved deep enough
7. [ ] Cutout valve or tubing leak
8. [ ] Flat valve [ ] Valve plugged
9. [ ] Valve pressures set too low [ ] Too high
10. [ ] Salt deposits or trash in valves
11. [ ] Leaking packoff gas lift valve
12. [ ] Excessive back pressure reopening valves up the hole
13. Working as deep as possible but:
    - [ ] Back pressure preventing higher rate
    - [ ] Low casing pressure preventing higher rate
14. [ ] Dual gas lift:
    - [ ] One side robbing gas
    - [ ] Temperature affecting other string
15. [ ] Other problems/remarks: ____________________

B. Corrective Action: ____________________

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