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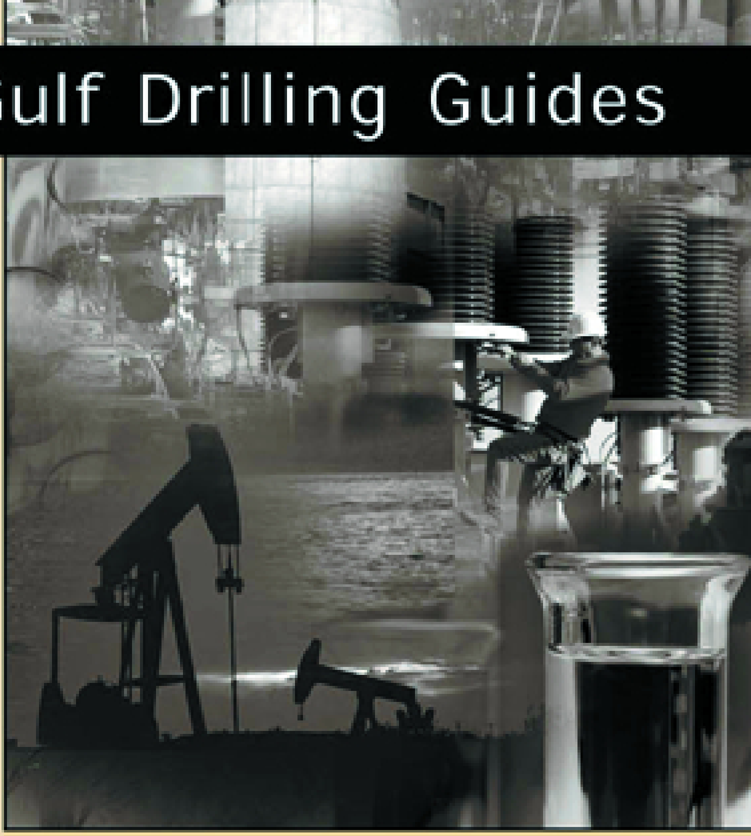

Gas Well Deliquification

Solutions to Gas Well Liquid Loading Problems

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PREFACE

Most gas well streams contain water or condensate. As the well pressure and production rate decline, liquids begin to accumulate in the tubing or flow path. *Gas Well Deliquification* contains methods of predicting and analyzing this situation. Also presented are many proven methods that are used in the oil and gas industry to eliminate or reduce the effects of liquid loading so that gas well production can proceed with minimal interference. This collection of information should be helpful to many gas well producers.

James Lea
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CHAPTER 1

INTRODUCTION

1.1 INTRODUCTION

Liquid loading of a gas well is the inability of the produced gas to remove the produced liquids from the wellbore. Under this condition, produced liquids will accumulate in the wellbore leading to reduced production and shortening of the time until when the well will no longer produce.

This book deals with the recognition and operation of gas wells experiencing liquid loading. It presents materials on methods and tools to enable you to diagnose liquid loading problems and indicates how to operate your well more efficiently by reducing the detrimental effects of liquid loading on gas production.

This book will serve as a primer to introduce most of the possible and most frequently used methods that can help produce gas wells when liquids begin to become a problem. Liquid loading can be a problem in both high rate and low rate wells, depending on the tubular sizes, the surface pressure, and the amount of liquids being produced with the gas. In this book you will learn:

- How to recognize liquid loading when it occurs
- How to model gas well liquid loading
- How to design your well to minimize liquid loading effects
- What tools are available to assist you in the design and analysis of gas wells for liquid loading problems
- The best methods of minimizing the effects of liquids in lower velocity gas wells and the advantages and disadvantages of these methods
- How and why to apply various artificial lift methods for liquid removal

- What should be considered when selecting a lift method for liquid removal

1.2 MULTIPHASE FLOW IN A GAS WELL

To understand the effects of liquids in a gas well, we must understand how the liquid and gas phases interact under flowing conditions.

Multiphase flow in a vertical conduit is usually represented by four basic flow regimes as shown in Figure 1-1. A flow regime is determined by the velocity of the gas and liquid phases and the relative amounts of gas and liquid at any given point in the flowstream.

One or more of these regimes will be present at any given time in a well's history.

- **Bubble Flow**—The tubing is almost completely filled with liquid. Free gas is present as small bubbles, rising in the liquid. Liquid contacts the wall surface, and the bubbles serve only to reduce the density.

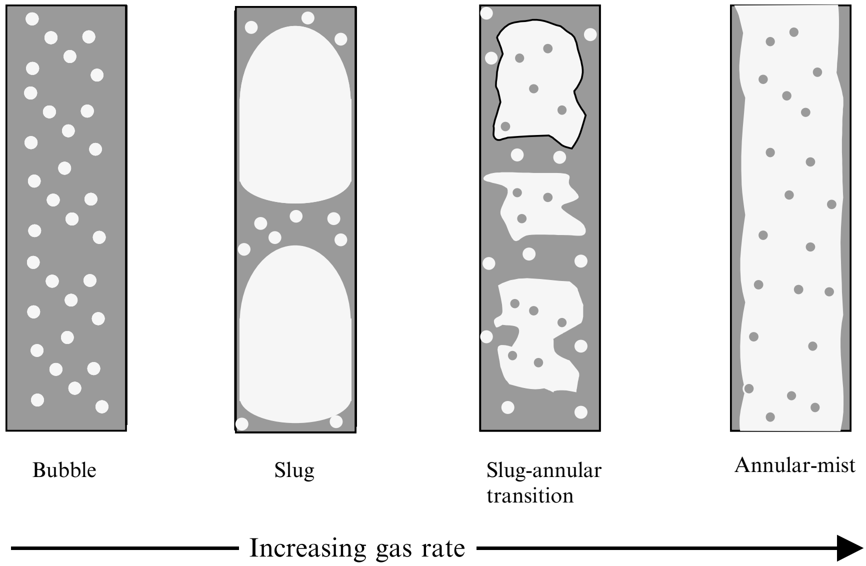

Figure 1-1. Flow regimes in vertical multiphase flow.

- **Slug Flow**—Gas bubbles expand as they rise and coalesce into larger bubbles and then slugs. Liquid phase is still the continuous phase. The liquid film around the slugs may fall downward. Both gas and liquid significantly affect the pressure gradient.
- **Slug-Annular Transition**—The flow changes from continuous liquid to continuous gas phase. Some liquid may be entrained as droplets in the gas. Although gas dominates the pressure gradient, liquid effects are still significant.
- **Annular-Mist Flow**—Gas phase is continuous, and most of liquid is entrained in the gas as a mist. Although the pipe wall is coated with a thin film of liquid, the pressure gradient is determined predominately from the gas flow.

A gas well may go through any or all of these flow regimes during its lifetime. Figure 1-2 shows the progression of a typical gas well from initial production to end of life. In this illustration, it is assumed that the tubing end does not extend to the mid-perforations so that there is a section of casing from the tubing end to mid-perforations.

The well may initially have a high gas rate so that the flow regime is in mist flow in the tubing; however, it may be in bubble, transition, or slug flow below the tubing end to the mid-perforations. As time increases and

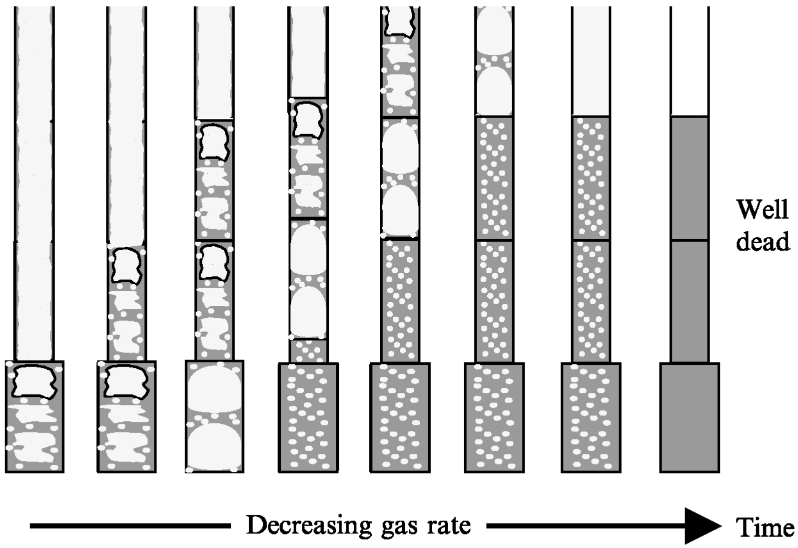

Figure 1-2. Life history of a gas well.

production declines, the flow regimes from the perforations to surface will change as the gas velocity decreases. Liquid production may also increase as the gas production declines. Flow at surface will remain in mist flow until the conditions change sufficiently at the surface so that the flow exhibits transition flow. At this point, the well production will become somewhat erratic, progressing to slug flow as the gas rate continues to decline. This transition will often be accompanied by a marked increase in the decline rate. The flow regime further downhole may be in bubble or slug flow, even though the surface production is in stable mist flow.

Eventually, the unstable slug flow at surface will transition to a stable, fairly steady production rate again as the gas rate declines further. This event occurs when the gas rate is too low to carry liquids to surface and simply bubbles up through a stagnant liquid column.

If corrective action is not taken, the well will continue to decline and will eventually log off. It is also possible that the well may continue to flow for a long period in a loaded condition and that gas produces up through liquids with no liquids rising to the surface.

1.3 WHAT IS LIQUID LOADING?

When gas flows to surface, the gas carries the liquids to the surface if the gas velocity is high enough. A high gas velocity results in a mist flow pattern in which the liquids are finely dispersed in the gas. This results in a low percentage by volume of liquids being present in the tubing (i.e., low liquid "holdup") or production conduit, resulting in a low pressure drop caused by the gravity component of the flowing fluids.

According to the Interstate Oil and Gas Compact Commission, in 2000, 411,793 stripper oil wells in the United States produced an average of 2.16 bpd and 223,707 stripper gas wells produced an average of 15.4 Mscf/D. For the lower-producing gas wells operating on the edge of profitability, optimization and reduction of liquid loading can mean the difference between production and shutting the well in. Liquid loading in gas wells is not limited, however, to the low rate producers; gas wells with large tubulars and/or high surface pressure can suffer from liquid loading even at high rates.

A well flowing at a high gas velocity can have a high pressure drop caused by friction; however, for higher gas rates, the pressure drop caused by accumulated liquids in the conduit is relatively low. This subject is discussed in greater detail later in the book.

As the velocity of the gas in the production conduit drops with time, the velocity of the liquids carried by the gas declines even faster. As a result, flow patterns of liquids on the walls of the conduit, liquid slugs forming in the conduit, and eventually liquids accumulating in the bottom of the well occur; all of which increase the percentage of liquids in the conduit while the well is flowing. The presence of more liquids accumulating in the production conduit while the well is flowing can either slow production or stop gas production altogether.

Few gas wells produce completely dry gas. Under some conditions, gas wells will produce liquids directly into the wellbore. Both hydrocarbons (condensate) and water may condense from the gas stream as the temperature and pressure change during travel to the surface. In some cases, fluids may come into the wellbore as a result of coning water from an underlying zone or from other sources.

Most of the methods used to remove liquids from gas wells do not depend on the source of the liquids. However, if a remediation method is considered that addresses condensation only, then it must be determined that this is indeed the source of the liquid loading. If not, the remediation will be unsuccessful.

1.4 PROBLEMS CAUSED BY LIQUID LOADING

Liquid loading can lead to erratic, slugging flow and to decreased production from the well. The well may eventually die if the liquids are not removed continuously, or the well may produce at a lower rate than possible.

If the gas rate is high enough to continually produce most or all of the liquids, the wellbore formation pressure and production rate will reach a stable equilibrium operating point. The well will produce at a rate that can be predicted by the reservoir inflow performance relationship (IPR) curve (see Chapter 4).

If the gas rate is too low, the tubing pressure gradient becomes larger because of the liquid accumulation resulting in increased pressure on the formation. As the backpressure on the formation increases, the produced rate from the reservoir decreases and may drop below the so-called "gas critical rate" required to continuously remove the liquid. More liquids will accumulate in the wellbore, and the increased bottomhole pressure will reduce production or may kill the well.

Late in the life of a well, liquid may stand over the perforations with the gas bubbling through the liquid to the surface. The gas is producing at a low but steady rate, and no liquids may be coming to the surface. If this was observed without any knowledge of past well history, one might assume that the well is only a low gas producer, not liquid loaded.

All gas wells that produce liquids—whether in high or low permeability formations—will eventually experience liquid loading with reservoir depletion. Even wells with very high gas-liquid ratios (GLR) and small liquid rates can load up if the gas velocity is low. This condition is typical of very tight formation (low permeability) gas wells that produce at low gas rates and have low gas velocities in the tubing. Some wells may be completed and produce a considerable gas rate through large tubulars, but may be liquid loaded from the first day of production. Lea and Tighe[1] and Libson and Henry[2] provide an introduction to loading and some discussion of field problems and solutions.

1.5 DELIQUEFYING TECHNIQUES

The following list[3] (modified) introduces some of the possible methods to deliquefy gas wells that are discussed here. These methods may be used singly or in combination. This list is based roughly on the static reservoir pressure.

Each of these methods is discussed in some detail. This list is not presented as being 100% complete. Special methods, such as using a pumping system to inject water below a packer to allow gas to flow up the casing-tubing annulus, are covered in the chapters on de-watering using beam and ESP pumping systems. Depth considerations and certain economic considerations also are not detailed.

The method that is most economic for the longest period of operation is the optimum method. The criteria for selecting the optimum method are: methods in similar fields that are used successfully, vendor equipment availability, reliability of equipment, manpower required to operate the equipment, and lifting capacity.

- Reservoir Pressure >1500 psi
  - Evaluate best natural flow of the well
  - Use Nodal Analysis to evaluate the tubing size for friction and future loading effects
  - Consider possible coiled tubing use