Acoustic Fluid Level Measurements in Oil and Gas Wells Handbook

A.L. Podio and James N. McCoy

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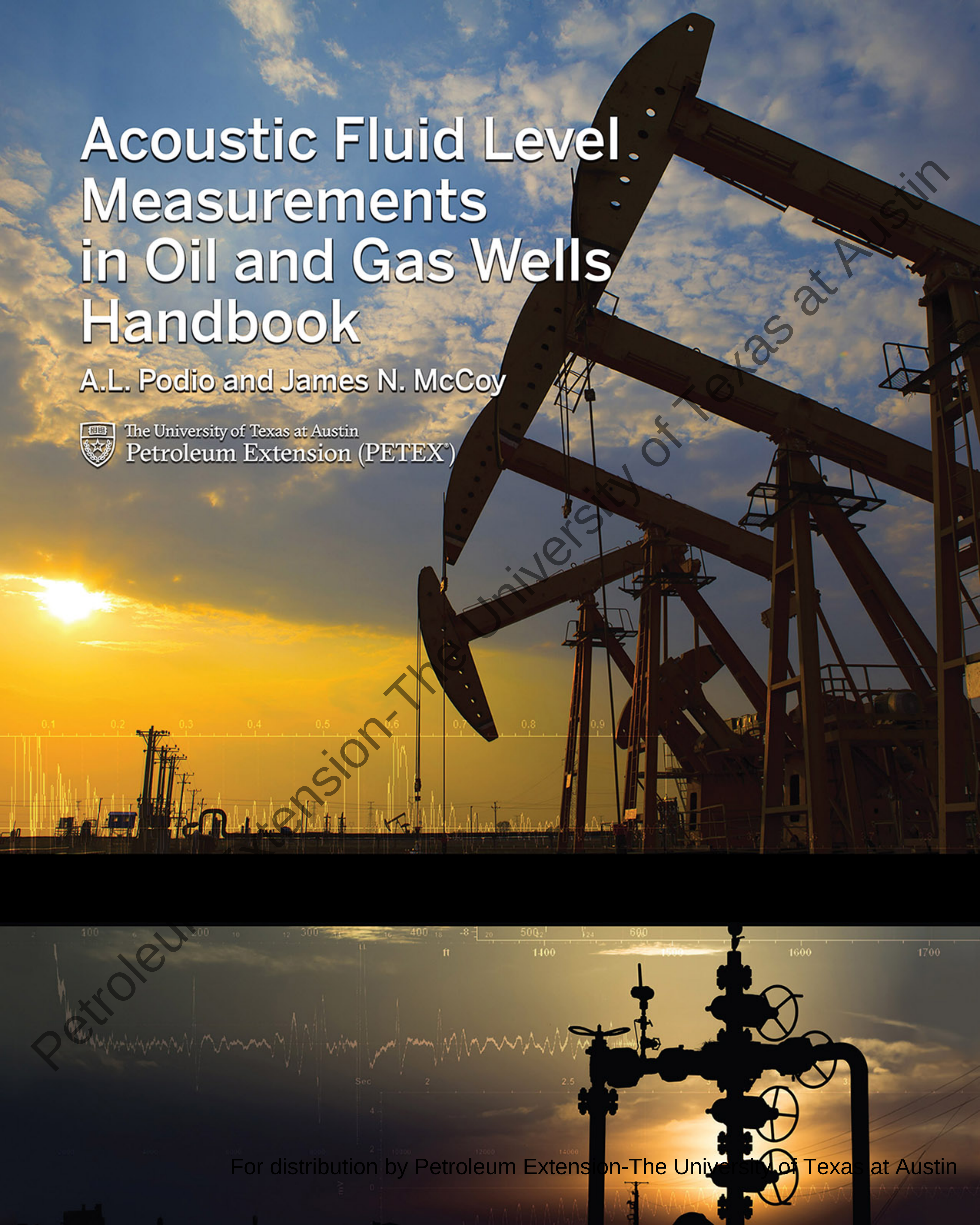
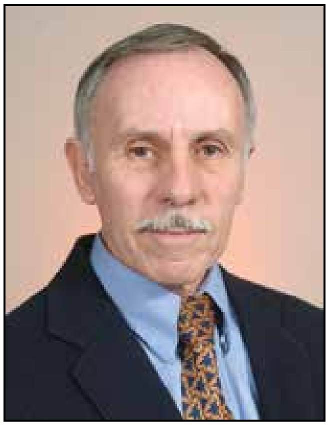


Contents

About the Authors



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James McCoy was born in Wewoka, Oklahoma. He graduated from the University of Oklahoma with a B.S. in Petroleum Engineering and from Penn State University with an M.S. in Petroleum and Natural Gas Engineering. He worked for a consulting firm and a major oil company and purchased and operated properties. In 1962, he acquired Echometer Company and expanded the acoustic liquid level instrument capabilities into a full Well Analyzer System that operates worldwide. He holds several U.S. and foreign patents. He was instrumental in establishing the McCoy School of Engineering at Midwestern State University and is a member of the Society of Petroleum Engineers and other petroleum engineering organizations.

1

Visualizing Well Performance

In this chapter:

- Principles of well production
- Relation between flow rate and pressure drawdown
- Characteristic performance of flowing wells and pumping wells
- Calculation of pressure distribution in the wellbore from fluid level surveys and casing pressure measurements
- Determining present operating conditions in relation to well potential

This introductory chapter addresses the widespread need for oil and gas field operators to continually verify that wells are being produced close to their optimum capacity and in the most cost-effective manner. The analysis is to be made based on data obtained at the surface without entering the wellbore and must yield an accurate representation of conditions that exist within the wellbore, at the bottom of the well, at the sand face, and within the reservoir. As such, it is not an easy task, since fairly complicated processes are involved in the flow of gas, oil, and water mixtures in wellbores. Operators are often confused by the apparently contradictory evidence that may be obtained.

The objective of this chapter is to present in simplified terms some of the basic concepts of well performance analysis and to recommend a procedure to be followed in obtaining, organizing, and analyzing data acquired with *acoustic fluid level instruments* to visualize the performance of oil and gas wells.

DETERMINING OPTIMUM AND CURRENT WELL PERFORMANCE

The principal question that must be answered is: "Is the well producing all the fluid that it is capable of producing without problems and within the guidelines for optimum reservoir management?" If the answer is negative, then additional questions must be answered to pinpoint the reason(s) why the well is operating below its potential.

An accepted rule of thumb is that the *producing bottomhole pressure* (PBHP) should be less than 10% of the *static bottomhole pressure* (SBHP) to ensure that the maximum production is being obtained from the well. This requires measurement or calculation of both the producing and the static bottomhole pressures. The PBHP must be obtained while the well is being produced under normal conditions, and the SBHP must be obtained when the well has been shut-in long enough that the surface and bottomhole pressures in the wellbore have stabilized and inflow from the reservoir has practically ceased.

Well performance is defined as the relationship between the fluid flow rate and the pressure drawdown between the wellbore and the formation pressure. This relation may take several forms, all of which are approximations of the actual behavior. The most common forms are:

- The *productivity index* (PI), defined as flow rate/drawdown, expressed in barrels per day (bbl/day) per psi[1,2]
- The *inflow performance relationship* (IPR), defined as a functional relationship between flow rate, flowing BHP, and static BHP, the most common of which is Vogel's relation[3]

In order to answer the principal question stated earlier, it is thus necessary to be able to determine the current well performance and to compare it to what is considered optimum for the particular well.

2

Examples of Fluid Level Surveys in Producing and Static Wells

In this chapter:

- Acoustic data analysis and quality control
- Recommendations for optimizing acoustic signal records
- Examples of different well types, acoustic fluid level records, and analyses
- Summary reports and comparisons of multiple records
- Testing for safety valve position and casing integrity, and determining gas composition using acoustic records

This chapter presents a series of examples of acoustic records that illustrate some of the most likely cases encountered in practice. The objective is to provide guidance to the reader for interpretation of the acoustic records acquired in wells with similar characteristics. The assumption is that the reader has access to acoustic analysis software that is similar to that used to process these records[1], provides graphical representation of the acoustic signal, and includes tools to determine the travel time to specific echoes.

GUIDELINES FOR ACOUSTIC RECORD ANALYSIS

The acoustic record analyst should have a clear understanding of the wellbore configuration with all its geometric details. This will allow the analyst to visualize all features that may generate echoes of the acoustic pulse transmitted from the surface. In wells that have a complicated wellbore (multiple casing or tubing sizes, liner, multiple perforations, and so on), it is advantageous to overlay the wellbore diagram onto the acoustic record using a distance scale based on the average acoustic velocity in the wellbore.

The conversion of round trip travel time (RTTT) to a distance implies that an accurate reference distance can be used as the basis of the conversion. Generally, this reference distance is the average length of pipe joints (in feet per joint) or the distance to a known wellbore cross-sectional area anomaly that creates a detectable echo in the acoustic record. It is important that these reference lengths be as accurate as possible, or else the distances computed from acoustic signal travel times can have very significant errors.

The distances to specific points in the wellbore may have been measured either relative to the wellhead or relative to the rotary table of the completion or workover rig. The difference in distance between these values corresponds to what is defined as the *KB correction* (kelly bushing correction) and can be a significant quantity, especially when dealing with wells on offshore platforms. It is important to verify which reference point is used when depth information is provided for input into the acoustic analysis software.

GUIDELINES FOR QUALITY CONTROL OF ACOUSTIC DATA

To determine the position of the liquid level, it is important to obtain a clear indication of the corresponding echo and an accurate measurement of the round trip travel time (RTTT) of the acoustic pulse. This also assumes that the moment of generation of the transmitted pulse is identified correctly and is used as time zero for the record.

3

Fundamentals of Acoustic Fluid Level Surveys

In this chapter:

- Information required for understanding acoustic fluid level records and analyzing surveys
- Propagation of sound and sound pressure waves in pipes and annuli
- Effect of composition, pressure, and temperature on acoustic velocity in gases and other fluids
- Reflection, attenuation, resonance, and interference
- Correlations for acoustic velocity calculations

The bottomhole pressure (BHP) corresponding to various rates of production allows for the determination of a well's productivity potential (as discussed in chapter 1). Thus, it is one of the most important measurements in oil and gas well production studies. For pumping wells, especially rod-pumping wells, direct measurement using downhole pressure sensors is impractical and costly because the rods must be pulled prior to installation of the sensor, which disrupts production and alters the pressure response. Permanently installed pressure sensors with surface readouts are not economically justifiable for routine monitoring of pressure in rod-pumped wells, since most of these wells produce at low oil rates.

For these reasons, acoustic fluid level measurements were introduced long ago with two objectives:

- Determining the distribution of fluids present in the wellbore[1] (particularly the amount of liquid above the pump intake, defined as *pump submergence*)
- Estimating the dynamic and static pressures at the depth of the producing zone without the need to introduce any tools into the well[2]

Over the years, this technology has been refined so that regulatory agencies in many states and countries accept the results of acoustic surveys for calculating well potentials and BHPs[3,4].

SOUND PULSE GENERATION AND WAVE PROPAGATION

A wave is a disturbance or change from a preexisting condition that moves in space from one point to another, carrying the deviation information at a certain finite speed depending on the medium's properties.

Acoustic or sonic waves are generally caused by pressure changes in a gas or liquid and propagate through the fluid at a speed defined as *acoustic velocity,* also known as *sonic velocity*. Propagation of a sonic wave requires the presence of a material medium: solid, liquid, or gas. Sound cannot propagate in a vacuum and is greatly attenuated when the pressure in the gas is lower than atmospheric pressure. The shape or character of the wave is arbitrary; it does not have to be oscillatory or sinusoidal. It can be triangular, rectangular, bell-shaped, or spike-shaped, depending on how it is generated.

For many types of waves, their motion is described mathematically by the *wave equation*, which can be written as:

$$c^2\nabla^2 u - \frac{\partial^2 u}{\partial^2 t} = 0 \qquad \text{Eq. 3.1}$$

where *u* is the physical property (for example, pressure in a gas or strain in a solid) of the disturbance, the operator is defined as the partial second derivatives with respect to rectangular *xyz* coordinates, *t* is time (in seconds),

4

Acoustic Fluid Level Equipment and Procedures

In this chapter:

- Requirements for state-of-the-art equipment used to acquire and analyze acoustic records
- Background history of equipment and patents
- State-of-the-art equipment used in the field
- Recommended practices for using acoustic fluid level equipment

This chapter presents the specialized equipment and procedures necessary for acquiring acoustic records. The objective of this chapter is to outline the history, practical application, and complexities of generating a viable acoustic pulse, as well as building microphones that detect the pressure pulse and signal processing equipment that records and displays acoustic signals. Also presented are best practices and recommended operating procedures for installing the sound source, preparing the well, and acquiring and recording an optimum, high-quality acoustic signal with minimal interference.

ACOUSTIC PULSE GENERATION AND SIGNAL ACQUISITION

The characteristics of the acoustic pulse used in echometric surveys of oil and gas wells are described in chapter 3. Acoustic pulses need sufficient amplitude and appropriate frequency content in order to generate clear and distinct echoes from the fluid level and all other cross-sectional area discontinuities in the wellbore over distances from a few hundred to several thousand feet. Designing a pulse generation and recording system that satisfies these requirements has to take into account the following two opposing characteristics of sound propagation and reflection that were discussed in chapter 3:

- Acoustic pulse attenuation increases as the square of the frequency content of the pulse. Low-frequency waves propagate with less attenuation than high-frequency waves. Thus, the pulse should have a slow rise time and long wavelength to obtain distinct echoes from deep wells. The pulse should have a spectrum shifted toward low frequencies (1 to 10 Hz).
- Clearly defined echoes from discontinuities of cross-sectional area require a pulse of minimum duration in time with a short wavelength and fast rise time. Thus, the pulse should have a spectrum with high-frequency content (20 to 80 Hz).

Thus, the designer is faced with the problem of creating a pulse generation system that satisfies both objectives, which is very difficult in practice. As a consequence, some systems emphasize low frequencies to provide high-amplitude echoes from deep reflectors, while other systems stress high frequencies to achieve better definition of echoes from shallow- and medium-depth wellbore discontinuities.

This problem is also addressed through signal processing techniques (filtering and variable gain) applied to the received signal, either in real time or by post-processing, to enhance the quality of the displayed record and thus facilitate the analysis.

The pressure of the gas in the well has a major impact on received signal quality since it affects the attenuation of the pulse, causing less attenuation in high-pressure

5

Methods for Determining Distance to the Liquid Level

In this chapter:

- Best methods to obtain accurate results of fluid level depth for various well configurations
- Converting time record to distance
- Identifying collar echoes and echoes from wellbore discontinuities
- Determining acoustic velocity from gas properties
- Correlations and equations of state
- Calculating velocity from acoustic records in similar wells or past surveys

This chapter presents some recommendations for obtaining the most accurate estimates of the distance to the liquid level from acoustic surveys. A number of different methods to obtain the distance using acoustic velocity are explained, from using collar echoes, tubing joints, or collar count to past acoustic surveys in the same region.

CONVERTING ACOUSTIC PULSE TRAVEL TIME TO DISTANCE

Echo signals are registered as the time required for the sound to travel from the pulse generator (gas gun) to the wellbore cross-sectional area change (anomaly) and back to the microphone housed in the gas gun. This time is known as the round trip travel time (RTTT) and, generally speaking, is measured with an accuracy of ±1 millisecond.

The conversion of travel time to the actual distance from the microphone to the anomaly can be made using equation 5.1, if the average acoustic velocity for the gas present in the wellbore between the gun and the anomaly can be determined:

$$D = \frac{\bar{v}\Delta t}{2} \qquad \text{Eq. 5.1}$$

where:

D = distance between the sound source and the reflector (feet)

$\bar{v}$ = average acoustic velocity of gas between the source and the reflector (ft/s)

Δt = round trip travel time (seconds)

As discussed in chapter 3, the acoustic velocity is a function of pressure, temperature, and composition of the gas. Consequently, it differs from well to well and also at various points in a given well because of the increase of pressure and temperature as a function of depth and the possible stratification of the gas column due to the difference in density of the various hydrocarbon components, especially when gas is not being produced from the casing annulus.

For fluid level surveys in real wells, the following four methods are used to determine the average acoustic velocity:

- Determination using identification and counting of echoes from tubing or casing collars
- Determination using the distance to a known anomaly in the wellbore
- Calculation from gas gravity or composition
- Estimation based on experience or previous measurements

All of these four methods involve varying degrees of uncertainty, but generally, it is considered that the first two (the collar count and anomaly methods) yield the best estimates of the distance to the liquid level.

6

Calculating Wellbore Pressure Distribution from Acoustic Fluid Level Surveys

In this chapter:

- Pressure distribution in pumping wells
- Classification of wells by wellbore and producing conditions
- Gaseous liquid column gradient
- Liquid level depression test
- Gas-free liquid pump submergence
- Correlations and mechanistic models
- PBHP and SBHP calculations

Acoustic determination of the depth to the liquid in the wellbore was introduced in the 1930s by C. P. Walker[1], who also outlined graphical methods for obtaining the pressure distribution in the well. At that time, the main objective was determining the depth of the gas/liquid interface in relation to the depth of the pump intake in order to estimate the pump submergence. Downhole pump submergence is defined as the amount (height) of liquid that exists above the pump intake. Since the early days of rod pumping applications in the oilfield, the submergence of the pump has been the parameter most commonly used for monitoring and troubleshooting well operation. Often abbreviated FAP for "fluid above pump," it was (and still is today) periodically monitored and recorded. Based on its value, the operation of the pumping system can be adjusted to maintain an adequate submergence, which has been defined as about 100 feet of fluid, to provide sufficient pump intake pressure to force the fluid into the pump at the operating pumping rate.

The importance of knowing the pressure distribution in the wellbore for detailed analysis of well performance was recognized early in the 1930s[2]. However, for many years it remained a research tool because of the difficulties involved in obtaining accurate values of fluid properties as a function of pressure and temperature and the lengthy iterative computations.

The advent of portable digital data acquisition and processing provided the tools needed to routinely convert fluid level measurements into estimates of downhole pressure distribution in the wellbore at the well site[3]. Today, surface pressure and pump submergence are easily converted to pressure at both the depth of the pump intake and the depth of the producing formation and then reported with an analysis of acoustic fluid level records.

WELL PERFORMANCE AND POTENTIAL ANALYSIS

As discussed in chapter 1, the producing efficiency of a well can be determined at a given time using an inflow performance relation (IPR) that expresses the effect on pressure drawdown of the rate of production from the formation. These relations require knowing the producing bottomhole pressure (PBHP) and the static bottomhole pressure (SBHP) corresponding to a steady production flow rate. The simplest relation, applicable to wells producing primarily liquids, is given by the productivity index (PI), defined as "barrels per day of gross liquid

7

Applied Well Testing for Pressure Transient Data Acquisition

In this chapter:

- Automatic acoustic determination of formation pressure
- Factors that influence pressure transient testing
- Programmed fluid level surveys
- Data acquisition and processing background
- Recommended procedures for optimum quality of recorded data
- Examples of well surveys from the field

Proper reservoir management and production optimization require up-to-date information about formation pressure, permeability, and wellbore skin factor. Pressure transient tests using wireline-conveyed or permanently installed surface readout pressure gauges are commonly run into flowing wells. However, the presence of artificial lift equipment complicates and often precludes the use of wireline-conveyed devices. Thus, conventional pressure transient tests are seldom performed in these wells. The result is poor reservoir and production management.

Since the 1980s[3,6], the oil and gas industry has relied on programmable equipment to calculate bottomhole pressure (BHP) from surface pressure and acoustically measured liquid level data in pumping wells. Over the years, advances in electronics, computer software, and transducer technology have vastly improved the data quality and usability of this equipment. In fact, because the equipment provides real-time data with the quality that is necessary for pressure transient analysis, this method is considered to be a reliable[11] and cost-effective way to determine BHP.

From a management perspective, the industry's primary objective is to achieve maximum production efficiency with minimum engineering and technical labor. The majority of onshore oilwells in the U.S. are produced through artificial lift pumping systems. Therefore, it is necessary to monitor and analyze the performance of these systems. The principal tools that are used in the field to determine indicators that influence production rates—such as reservoir pressure, formation permeability, productivity index, pump efficiency, and skin factor—include:

- Flowing BHP surveys
- Pressure buildup tests
- Pressure drawdown tests
- Inflow performance analyses

These techniques are widely used in flowing wells and some gas lift wells, where the pressure information is easily obtained from wireline-conveyed BHP recorders.

In rod-pumped wells, the presence of sucker rods essentially precludes the practical, routine, and direct measurement of BHP, thus eliminating the single most important parameter for well analysis. Permanent installation of surface-indicating BHP gauges is not yet cost-effective for wells with low production rates. As discussed in chapter 6, one solution to this problem is to calculate the BHP from the casinghead pressure measurement and then determine the annular fluid head from echometric surveys that yield the depth of the gas/liquid interface and the gradient of the annular fluids[1,2].

8

Applications of Fluid Level Measurements to Pumping Wells

In this chapter:

- Total monitoring of pumping system operation and wellbore fluid and pressure distribution
- Rod-pumped wells
- Well pressure survey
- Correlation of fluid level with dynamometer measurements
- ESP and PCP wells
- Recommended procedures and special considerations for quality control and analysis

Throughout the world, the most commonly used method to artificially produce oilwells is by sucker rod lift and has been since the early times of the industry. Efficient application of all types of well pumping systems requires knowledge of the position of the liquid in relation to the intake of the pump. This quantity is defined as the pump submergence, and its determination was the primary reason for the early development[1] of acoustic fluid level instruments, as discussed in detail in chapter 4. The refinement of this technology and the advent of portable computers have expanded the application of fluid level measurements for optimization of the total pumping system through detailed analysis of the pressure and fluid distribution in the well.

Most operators want wells to produce at or near their capacity. When a well is producing at a maximum rate (defined as its potential), the producing bottomhole pressure (PBHP) will be very low compared to the static bottomhole pressure (SBHP), which is equivalent to the static reservoir pressure. If the PBHP is larger than 15% of the static reservoir pressure, then the current production may be significantly lower than what the formation is able to provide, indicating the reservoir is not being produced efficiently.

Inefficient reservoir production by pumping may be caused by one of two reasons:

- The pumping system is operating efficiently at its maximum capacity, but is under-designed and cannot displace liquid into the bottom of the tubing at the rate that the formation could deliver it to the wellbore.
- The pumping system's theoretical displacement capacity equals or exceeds the formation productivity, but the pump is operating inefficiently at a lower effective displacement rate, which in turn limits the liquid inflow from the reservoir.

Experience has shown that the majority of pumping wells experience the second situation listed above, where the low pump volumetric efficiency is the controlling factor.

The "First Law of Pumping" may be stated as: In a well that is artificially lifted by pumping, the reservoir cannot produce more liquid into the wellbore than the pump can displace from the wellbore into the tubing.

Fluid production (oil, water, and gas) from the formation is controlled by the pump displacement, which means that at stabilized conditions, the formation produces fluid at the rate that fluid is removed from the wellbore by the pumping system. Depending on formation productivity, the PBHP will stabilize at a specific level and remain constant as long as the pump liquid displacement rate remains constant. In the annulus of the wellbore, the vertical distribution of produced fluids is controlled by gravity, with gas overlaying a column of fluid generally consisting of a mixture of gas and liquid. For a given

9

Fluid Level Measurement Applications for Gas Wells

In this chapter:

- Monitoring gas well performance with fluid level measurements in tubing and casing
- Determination and analysis of liquid loading
- Gas well troubleshooting
- Tubing and casing integrity testing

The principal objective when performing acoustic measurements in a flowing gas well is to determine the quantity of liquid inside the tubing (or the annulus, when the tubing is used for removing liquid from the wellbore by means of a pump) and whether the produced liquid (1) is uniformly distributed over the length of the well as a mist or annular flow pattern or (2) has fallen back, accumulating near the bottom of the well.

In the first case, the gas flow rate is above a value defined as the *critical rate*, and the liquid is uniformly distributed. The gas velocity is sufficient to continuously carry liquid as a fine mist or small droplets to the surface, establishing a relatively low and fairly uniform flowing pressure gradient throughout the tubing.

In the second case, when the gas flow rate is below the critical rate, the gas velocity is not sufficient to carry all the produced liquid to the surface, and most of the liquid accumulates and stays in the lower part of the well. A *flowing pressure traverse* in the wellbore will show two different gradients: a light gas gradient above the gas/liquid interface and a heavier gradient in the lower section of the well below the gas/liquid interface. The gradient of the fluid below the gas/liquid interface reflects the liquid concentration, which is controlled by the gas flow rate. The liquid in this section of the wellbore recirculates in place, with zero net liquid flow, as the gas bubbles or slugs of gas percolate through the liquid, and only the gas flows to the surface.

Knowledge of the flowing gradient and fluid distribution in the well is important in determining the additional back-pressure acting on the formation when there is liquid loading in the tubing. When gas velocity drops below the critical rate, production rates are reduced by liquid accumulation in the tubing. Removing this liquid requires applying a deliquifying technique, such as installing plungers or pumps, adding surfactants, or redesigning the flow string to increase gas velocity[1].

The acoustic test in flowing gas wells is designed to determine which flowing gradient conditions exist in a well. The test involves performing a series of fluid level and surface pressure measurements while the flow at the surface is stopped for a length of time sufficient to identify the behavior and distribution of the fluids in the tubing or tubing/casing annulus. The advantages of the acoustic test over wireline flowing pressure surveys include lower costs, because equipment is very portable, and lower risks, because measurement tools are not introduced into a flowing well. An important byproduct of acoustic testing is determining the condition of the downhole hardware and integrity of the tubulars.

DETERMINING LIQUID LOADING OF A GAS WELL

The acoustic fluid level test is used to determine the tubing (or annular) pressure distribution in a flowing gas well by momentarily shutting in the flow for the duration of the test. An analysis of the acoustic fluid levels acquired on gas wells can be used to determine the:

- Amount of liquid loading on the formation

10

Fluid Level Measurement Applications for Gas Lift Wells

In this chapter:

- Unloading status and operating valve identification
- Determining static and producing BHP
- Pressure distribution at steady flowing conditions
- Pressure distribution at shut-in conditions
- Recommended equipment and procedures
- Example acoustic records

Optimizing the design and operation of wells produced by continuous or intermittent gas lift, requires determining the SBHP, the PBHP, the well inflow performance, and quantifying the overall gas lift system efficiency. The normal gas lift well is assumed to be a continuous flow well in which a packer is placed immediately above the formation at the bottom of the tubing. The inside of the tubing is open from the bottom to the top of the well, but in some cases, it may have a standing valve. This prevents backflow from the tubing to the lower part of the wellbore when gas injection is stopped.

The packer is used to stabilize the fluid level in the casing annulus and prevent injection gas from blowing around the lower end of the tubing in wells with a low flowing BHP. The packer is particularly important for gas lift when the injection gas line pressure varies or the injection gas supply is interrupted periodically. When the installation does not include a packer, the liquid that accumulates in the annulus must be displaced after each shutdown. Any changes in the injection gas line pressure causes the working fluid level to oscillate unless a packer is set. This causes additional flow of liquid through the lower valves and possibly more wear of the valve seat and stem.

Figure 10.1 illustrates a typical continuous injection gas lift well showing that gas is being injected from the bottommost valve (known as the *operating valve*) while the upper valves (known as the *unloading valves*) are closed. Details about gas lift systems and operations are discussed briefly at the end of this chapter.

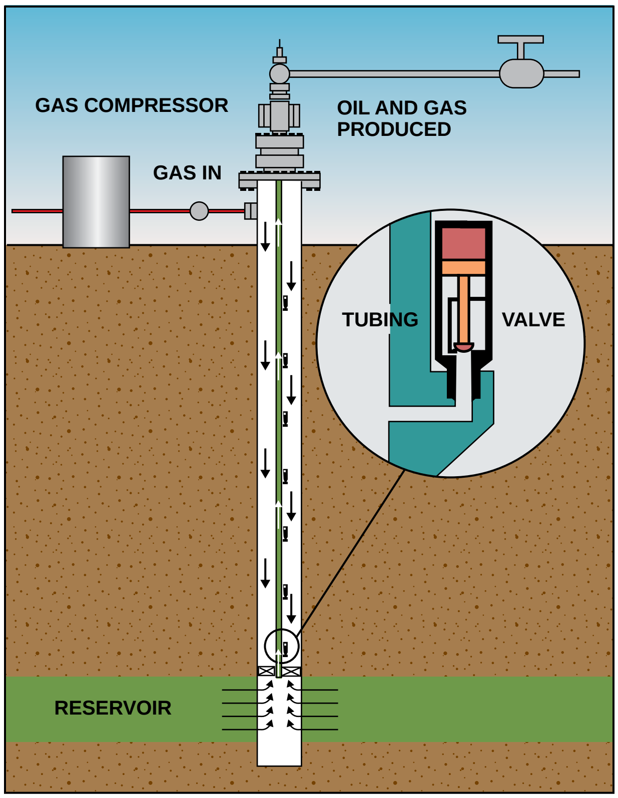

Figure 10.1 Typical continuous injection gas lift well

11

Fluid Level Measurement Applications for Plunger Lift Wells

In this chapter:

- Detailed analysis of plunger cycle performance
- Basics of plunger lift to produce liquid and gas
- Acoustic survey and monitoring
- Plunger fall characteristics
- Problem detection and analysis
- Benefits of plunger tracking

Plunger lift is a low-cost method for lifting liquids (water, condensate, and/or oil) from gas and oil wells. In general, the objective is to remove as much of the liquid accumulating in the well as possible and to increase gas production by minimizing back-pressure on the formation. The plunger lift system reduces the cost of operating a well compared to other artificial lift methods because the formation pressure supplies most of the energy required to lift the liquids.

During plunger lift operations, a motor-controlled valve is opened and closed at specified intervals to cycle a gas-driven plunger from the bottom to the top of the tubing and remove any liquid that accumulated at the bottom of the well. When the surface valve to the flow line is closed, the produced gas and liquid accumulate inside the well's casing and tubing. When the flow is stopped at the surface, the plunger falls down to the bottom of the tubing. After a predetermined amount of time, the surface flow valve opens, and the tubing head pressure drops to the flow-line pressure. The differential force across the plunger—due to the drop in pressure in the tubing above the liquid column and the high well pressure below the plunger—lifts the plunger and a portion of the liquid above the plunger to the surface. Gas and some liquid continue to flow out to the flow line until the motor valve is closed. The open and shut-in operational cycle of the plunger lift system is repeated throughout the day to produce liquids and gas from the well.

In plunger lift wells, acoustic fluid level instruments are used to monitor and analyze the progress of the cyclical plunger operation in real time and determine the:

- Position and depth of the plunger as a function of time
- Fall velocity of the plunger
- Rise velocity of the plunger
- Plunger travel time to the liquid and to the bottom of the tubing
- Tubing and casing pressure as a function of time
- Volumes of gas and liquid flowing into and out of the well

The objective is to visualize in detail the performance of the plunger lift system to determine the appropriate cycle time for optimum operation. Acquisition and analysis of acoustic and pressure data is generally performed automatically, using a portable computer with appropriate software. Thus, the operator can quickly and efficiently determine the adjustments necessary to optimize the plunger lift operation[1,2].

The following sections present a brief overview of plunger lift operation and describe in detail the equipment and procedure used to acquire and interpret the acoustic data for plunger lift analysis.

Index

Throughout this index, an *f* indicates a figure and a *t* indicates a table on that page.

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