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Application of Well Control Technology to Drilling Problems In the Delaware Basin

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Abstract

Wells drilled to test deep Devonian or Ellenburger formations in the Delaware basin will encounter 5 to 7,000 ft of abnormally pressured Wolfcamp and Pennsylvanian formations. These formations contain many gas bearing sections which require mud weights from 12 to 16.7 lb/gal to balance. Frequently, these gas bearing formations are noncommercial, but of sufficient volume to be troublesome if not controlled. Since drilling with mud weights which overbalance formation pressures is inherently expensive, a great incentive exists to utilize techniques for controlling these formations with as light mud weights as possible.

Successful use of light mud weights to drill Wolfcamp and Pennsylvanian formations requires a knowledge of the detection, interpretation and control of gas in the annulus. This paper discusses these aspects of well control procedures and proposes many cost-saving features that may be incorporated into drilling programs which utilize reliable well control procedures.

Introduction

A knowledge of well control procedures is essential to conducting a safe drilling operation. Protection of life and property is dependent on the ability to control a threatened blowout. However, if the ability to control a threatened blowout reaches a certain stage of accomplishment, then it is possible to effect major changes in a drilling program — all designed to reduce drilling costs.

The need for reliable well control procedures has been receiving increased attention in the past few years.[1-3] Recent advancements in drilling technology[1-6] have pinpointed mud weight as the major variable in an attempt to reduce drilling costs. The major conclusion drawn is to keep mud weight as light as possible to achieve minimum drilling costs. To effect this recommendation requires an accomplished well control program.

Many adverse things can occur while killing a well. The most costly item is loss of circulation and/or stuck drill pipe. A secondary concern is suspension of drilling operations while controlling the well. Minimum drilling costs cannot be achieved if the cost of adverse items outweigh benefits derived from drilling with light mud weights. The purpose of this paper is to reiterate those factors which are necessary to achieve reliable well control and to propose certain drilling procedures that can be achieved with a sophisticated state of well control.

Prior to the publication of O'Brien and Goins[1] in 1960, virtually all articles on well control technology were restricted to discussions about blowout preventers and how to avoid blowout conditions through crew training. O'Brien and Goins were the first to go beyond the statement "put the well on a choke and raise the mud weight".

The next significant contribution to well control technology was made by Records in 1962.[2] Using the concept of maintaining a constant bottom-hole pressure, Records presented a calculation procedure for determining the rate at which to expand the gas as it was circulated up the annulus. Records' contribution was doubly significant in that he also designed a specialized piece of equipment[7] for precision control of surface pressure which regulates pressure directly rather than indirectly through volume control.

A more recent publication by Schurman and Bell[3] proposes an approximate method for a more rapid determination of the back-pressure schedule to be used to control gas expansion in the annulus. After describing their procedure, they made the statement, "The results (well control) depend strongly on the experience and understanding of the (choke) operator." This statement is equally applicable to any subject; but in the field of well control, inexperience and misunderstanding often result in a catastrophe.

Methods for Detecting Kicks

When an extraneous fluid such as gas enters a wellbore while drilling, several phenomena occur which can be used to detect this entry. First, the gas is a volume addition to the drilling fluid system and will be seen as an increase in the mud pit level. Second, fluid output from the annulus will be greater than the volume being pumped into the well, so a flow rate differential exists. Finally, the presence of low density fluids on the annulus

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[1]References given at end of paper.

side of the well will be accompanied by a loss of pump pressure and the well will flow on the annulus side when the pump is stopped.

A large percentage of threatened blowouts occur as a result of swabbing the well when tripping the pipe. The force required to break the mud's gel strength, together with the viscous drag caused by the mud clinging to the drill pipe, combine to effect a temporary reduction in the bottom-hole pressure. If permeable formations are exposed in the borehole they can feed fluids into the wellbore during this temporary reduction in bottom-hole pressure. This type of kick is one of the most difficult to detect and consequently one of the most serious. Usually, a substantial amount of drill pipe will have been pulled before it will be noted that the hole is not taking fluid or that the well is actually flowing at the surface. Unless provisions are made to strip the pipe back to bottom, excessive surface pressures and mud weights will be required to control the well.

The volume of gas which enters the wellbore has a pronounced effect on the pressure required to kill the well (Fig. 1). For this example, all conditions for the kick are equal except that in one case the well flows 20 bbl prior to being shut in and in the second case it has gained 75 bbl prior to being shut in. Fig. 1 shows the required annular pressure to maintain a constant bottom-hole pressure as a function of the volume of mud pumped. The difference in initial shut-in conditions is 500 psi and the difference in maximum surface pressure is 830 psi. If loss of circulation is a potential problem, the difference of 500 psi at shut-in would be equivalent to 1.0 lb/gal of mud weight at a depth of 10,000 ft, and could mean the difference between successfully circulating the well and losing returns. At shallower depths, the equivalent mud weight increases exponentially. Since loss of circulation can result in substantial expense, it is essential that a well be continuously observed for flow and be shut in with a minimum gain. The following mechanical aids are useful in observing flow from the well.

Pit Level Indicators

A convenient method of observing a change in the volume of the surface mud system is to use a series of floats that will transmit changes in the mud level to an indicator or recorder on the rig floor. Most commercially available pit level indicators have the added feature of an alarm system than can be set to blow a horn when the volume of the surface mud system changes by more than a specified volume.

Flow Rate Indicators

There are two types of flow rate indicators available commercially. One monitors the mud flow line and indicates relative changes in the output from the well. This instrument will detect changes in flow rate of approximately 10 gal/min. This instrument is also equipped with an alarm system that signals a gain or loss of flow rate within the instrument's sensitivity.

The other flow instrument is a differential flow meter. This tool monitors both the input and output of the well and indicates the difference. It also has an alarm system and its sensitivity is reported to be 5 gal/min.

Other Indicators

Reduction in hydrostatic pressure on the annulus side of the well which results from gas off bottom can also be detected from the standpipe pressure. Surface indications are identical to those seen when a washout in the pipe occurs; i.e., a loss in standpipe pressure and/or a gain in pump speed. A positive way to distinguish between the two possibilities is to shut off the pump and check for flow from the annulus.

A seldom used but extremely valuable instrument for detecting flow on trips is a pump stroke counter. The static weight of the mud column may be sufficient to control exposed gas-bearing formations, but a reduction in the bottom-hole pressure will occur when the pipe is pulled from the hole. A small annular clearance between the drill collars and open hole, high viscosity and high gel strength mud are factors which increase the bottom-hole pressure reduction resulting from pulling the pipe.

The only known method for detecting whether or not exposed formations are feeding fluids into the wellbore during a trip is to measure the volume of mud required to replace the volume displaced by the drill pipe. Because of the excessive pressures and mud weights required to kill a well with the drill string off bottom, it is important that flow be detected as soon as possible. Accurate volume measurements are needed to detect flow within the first 5 to 15 stands of pipe, and a pump stroke counter fills this need adequately.

Control of Kicks

Much has been written in recent years about the step-by-step procedure to be followed while killing a threatened blowout. Basic concepts of killing wells will be reviewed here and illustrations presented to show the effects of certain variables on the surface pressure required to kill the well.

Basic Concepts

All of the publicized well killing procedures will succeed in killing a threatened blowout if loss of circulation and burst casing do not occur. However, successful control of a threatened blowout should be more restricted than this. If loss of circulation, burst casing, stuck drill pipe or prolonged circulation occurs, any economic benefits derived from drilling with light weight mud will be lost. Therefore, it is imperative that certain basic concepts be understood and accepted before attempting to control a threatened blowout. First, gas must be permitted to expand as it rises in the annulus; second, bottom-hole pressure will remain constant if, and only if, the rate of gas expansion is controlled by a definite schedule of the back-pressure held on the annulus of the well.

Let Gas Expand

If gas is circulated from the bottom of a hole while holding the pit level constant, the annulus will be circulated at constant volume. A circulation at constant volume will result in the gas being circulated at constant pressure, thereby adding the gas pressure to the hydrostatic pressure of the mud below the gas. Theoretically, a surface pressure equal to the original bottom-hole pressure will be obtained. The effective bottom-hole pressure will then be twice its original value. (One author[8] has described this effect by the term "pressure inversion".) Practically, before the surface pressure reaches this value, loss of circulation or even burst casing will have occurred. The gas must be permitted to expand to avoid excessive surface pressures. This requires that the pit level be permitted to gain while circulating gas out of the hole.

Rate of Gas Expansion

The opposite extreme of the "pressure inversion" effect is an uncontrolled rate of gas expansion. The hole can unload a large volume of mud and reduce the hydrostatic pressure, resulting in an uncontrolled blowout at the worst and the hole's falling in at the least. Obviously there is a compromise between the extremes.

The desired rate of gas expansion, as demonstrated by Records,[2] maintains a constant bottom-hole pressure throughout the circulation. (It can be shown that this procedure results in the borehole's being exposed to minimum fracturing gradients.) This is achieved by manipulating the surface pressure to compensate for the loss of hydrostatic mud pressure as the gas expands. The need to manipulate the surface pressure while the gas is expanding (and producing a larger volume of fluid from the hole than is being pumped into the hole) is the basic reason for advocating that well control procedures be based on control of pressure directly rather than indirectly through volume control. During the time interval immediately before and after gas reaches the surface, both the rate of flow from the well and the density of the produced fluids is changing rapidly. Both these variables have a strong influence on the pressure drop across an orifice, and are fluctuating widely at the time when pressure control is most critical.

The situation described above is the cause for the often heard remark "I almost had the well killed when something went wrong".

Variables Affecting Surface Pressure

Many variables affect the precise surface pressure needed while circulating to control a well. However, this discussion will be limited to those which produce the largest effects or are most applicable to Delaware basin drilling. Items to be considered are (1) size of gain (Fig. 1), (2) gas expansion following a trip, (3) size of kick, (4) drill pipe/annulus volume ratio, and (5) use of excessive mud weight to kill a kick.

The basic problem in predicting the surface pressures required to maintain a constant bottom-hole pressure is to predict the gradients of various density fluids in the annulus. The method for identifying and predicting these gradients has been presented by Records and Everett.[2]

The purpose of the following illustrations is to depict the wide range of surface pressures that result from the major variables encountered in well killing operations. It is not intended to be a set of instructions on how to kill each type of kick, but rather as a warning to those who are inclined to write "simplified" instructions for use on the rig. Killing a well is a serious business and carries with it major economic implications: a large potential loss if unsuccessful and a large potential drilling-cost reduction if successful.

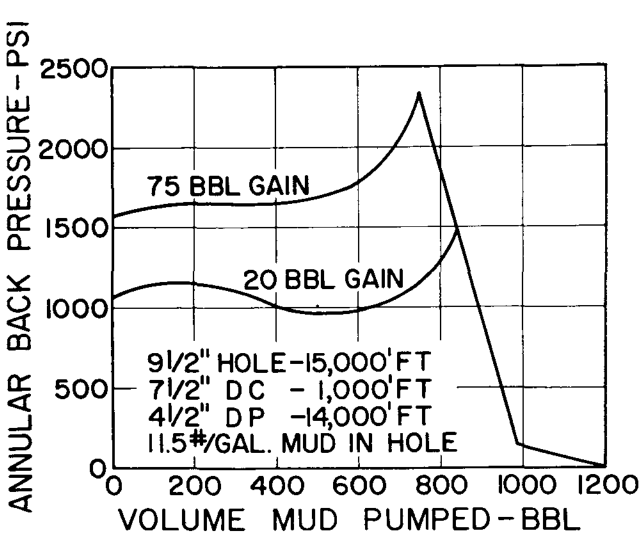

Fig. 1—Effects of size of gain on annular pressure required to control a kick.

All surface pressures presented in the following figures were calculated by the procedure published by Records and Everett. These reference well conditions will all be the same:

Depth: 15,000 ft, 9½-in. hole
Casing: 10¾-in. set at 12,000 ft
Drilling assembly: 1,000 ft of 7½-in. collars; 10,000 ft of 4½-in., 16.6 lb/ft drill pipe; 4,000 ft of 4½-in., 20.0 lb/ft drill pipe
Mud weight in hole: 11.5 lb/gal.

Gas Expansion Following Trip

As a direct result of drilling with light weight muds through low permeability formations, the well frequently will flow while tripping the pipe. Once back on bottom, it will be necessary to kill the well on bottoms-up. Fig. 2 shows the back-pressure required to kill a bottoms-up which results from a 25-bbl flow while out of the hole. No increase in mud weight was used. During approximately 70 per cent of the circulation time, the pressure does not change by more than ± 100 psi. However, during the last 30 per cent of the circulation, it rises to 1,080 psi and falls to zero.

Some operators handle bottoms-up in the Delaware basin by "choking" the returns only a few hundred pounds, if any at all. Because of the frequent low permeability of the exposed formations, little additional feed-in might occur. However, for a period of time the hydrostatic bottom-hole pressure will be reduced (because surface pressure is not applied) by 800 psi or more. If casing is set at 12,000 ft, this is equivalent to making a reduction in mud weight equal to 1 lb/gal. Exposing the open hole to this amount of mud weight reduction will frequently

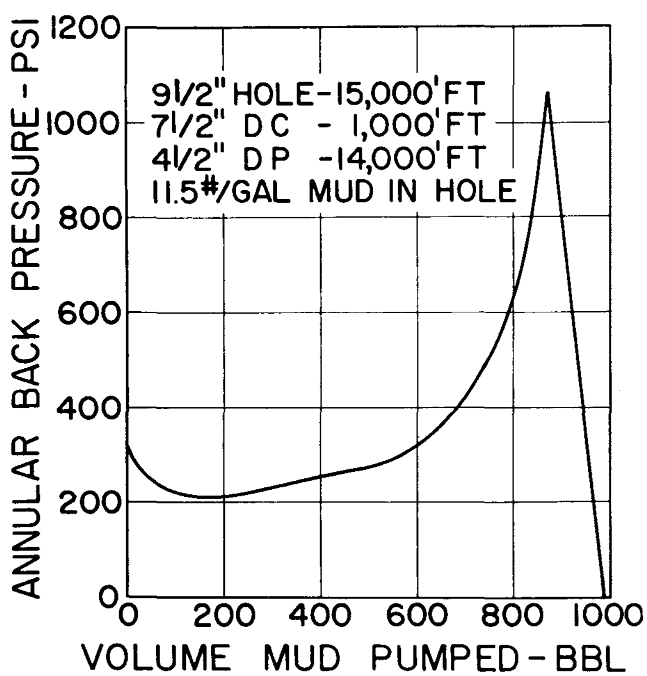

Fig. 2—Annular pressure required to control bottoms-up (no increase in mud weight).

cause severe shale sloughing and may result in a stuck drill string.

Size of Kick

Fig. 3 illustrates the effect the size of a kick has on annular back-pressure. This comparison is for two kicks —one requiring an increase of 0.5 lb/gal in mud weight and the other requiring an increase of 1.5 lb/gal. The small kick exhibits a maximum pressure when the gas reaches the surface and is approximately 30 per cent greater than the initial shut-in pressure. The large kick has its maximum pressure at shut-in conditions.

Annulus/Drill Pipe Size

The ratio of the volume of the annulus to the capacity of the drill pipe has a pronounced effect on the shape of the required annular back-pressure curve. Fig. 4 shows this comparison for an identical kick in two sizes of casing string. For the small clearance case, all corresponding pressures are higher and change more rapidly than they do in the large clearance case. These differences grow very rapidly as the annulus/drill pipe ratio decreases, so careful thought needs to be given to any attempt to kill a well by reverse circulation.

Effect of Excess Mud Weight

Fig. 5 illustrates graphically why one should kill a kick with the precise mud weight required to contain the formation. As a result of using excess mud weight, the open hole is subjected to excessive fracturing gradients and can turn a relatively easy killing operation into the nightmare of an underground blowout.

Applications of Well Control Technology To Drilling Programs

Common problems encountered in drilling deep Ellenburger wells in the Delaware basin are (1) loss of circulation, (2) multiple casing strings, (3) low penetration rates, (4) high, time-dependent mud costs, and (5) interruption of drilling progress to control the well. In some instances, an operator will follow the philosophy that it is cheaper to stay out of trouble than to get out of trouble and will drill a high cost but trouble-free well. All the previously mentioned items are made more severe as mud weight is increased and, correspondingly, all items are reduced in severity as mud weight is decreased.

Abnormal pressures found in the Wolfcamp and Pennsylvanian formations will usually require from 12.0 to

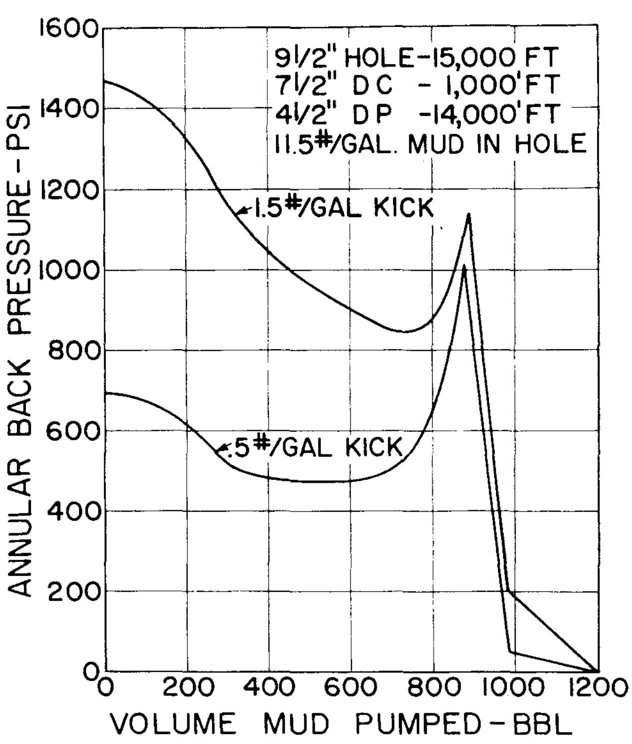

Fig. 3—Effect of size of kick on annular pressure.

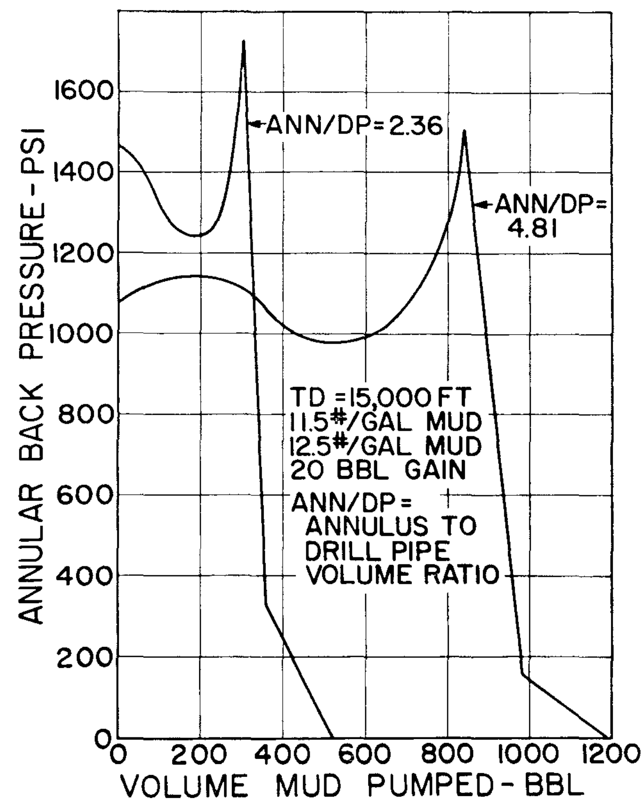

Fig. 4—Effect of ratio of annular volume to drill pipe capacity on annular pressure.

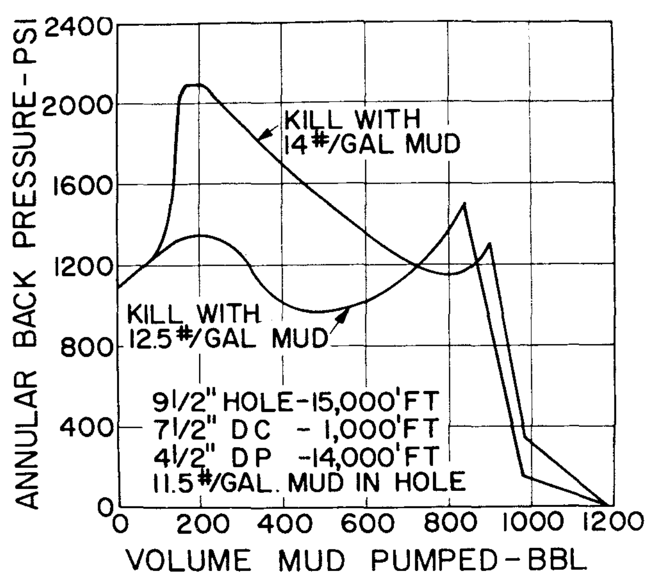

Fig. 5—Effect of excess mud weight on annular back-pressure.

16.7 lb/gal mud weight to balance. These formations are additionally characterized by having very low permeabilities and/or noncommercial volumes of gas. The combination of permeability and volume is frequently such that production of a few hundred thousand cubic feet of gas per day will draw down the reservoir to the point where it can be drilled and tripped with substantial hydrostatic underbalance. Reliable well control procedures permit production of gas during routine drilling operations by flowing a small bottom-hole volume of gas and circulating it to the surface. Depending on the particular combination of permeability and mud weight in use at that time, the result could be gas only on bottoms-up, continuous gas-cutting of the mud or a continuously maintained surface pressure to limit the rate of feed-in. During the drilling of a particular well, any one of the three methods might predominate.

West[9] has published data showing the casing setting depth into the Wolfcamp that is required to contain specific mud weights. A reduction of 2 lb/gal in mud weight required to drill through the Mississippian series offers a potential saving of 700 to 2,000 ft of protective casing set into the Wolfcamp. From another point of view, a reduction of 2 lb/gal in mud weight reduces the risk of having to run a liner prior to reaching the Devonian. Most cases of lost circulation that occur below a long string of pipe in the Delaware basin are associated with the handling of kicks or bottoms-up following a trip. It can be shown that in these cases the maximum fracturing gradients will occur at the time the well is initially shut in. So, if the well has been shut in without losing circulation, and subsequently loses circulation, then it was fractured by the choke operator and not by the kick.

One of the major benefits that can be derived from drilling hydrostatically underbalanced is the extension of the depth that can be drilled with brine or weighted water. Major increases in penetration rate can be obtained for that interval.

By following a mud program that calls for increasing the mud weight only when necessary to stabilize the borehole or when killing a high permeability formation, mud costs are minimized and penetration rates are maximized. Lower density fluids improve bottom-hole cleaning and reduce differential chip hold-down.

Fig. 6 is an actual example of a bottoms-up on a well which was drilled underbalanced, allowing a continuous feed-in of gas to the wellbore. The difference between the shape of this curve and the theoretical curve shown in Fig. 2 is due to the heavy gas cut annulus which existed at all times. Trip gas was circulated out while maintaining the bottom-hole pressure constant. Gas expansion can be readily recognized by the mud pit volume increase. Premature surfacing of gas is due to gas migration while the trip

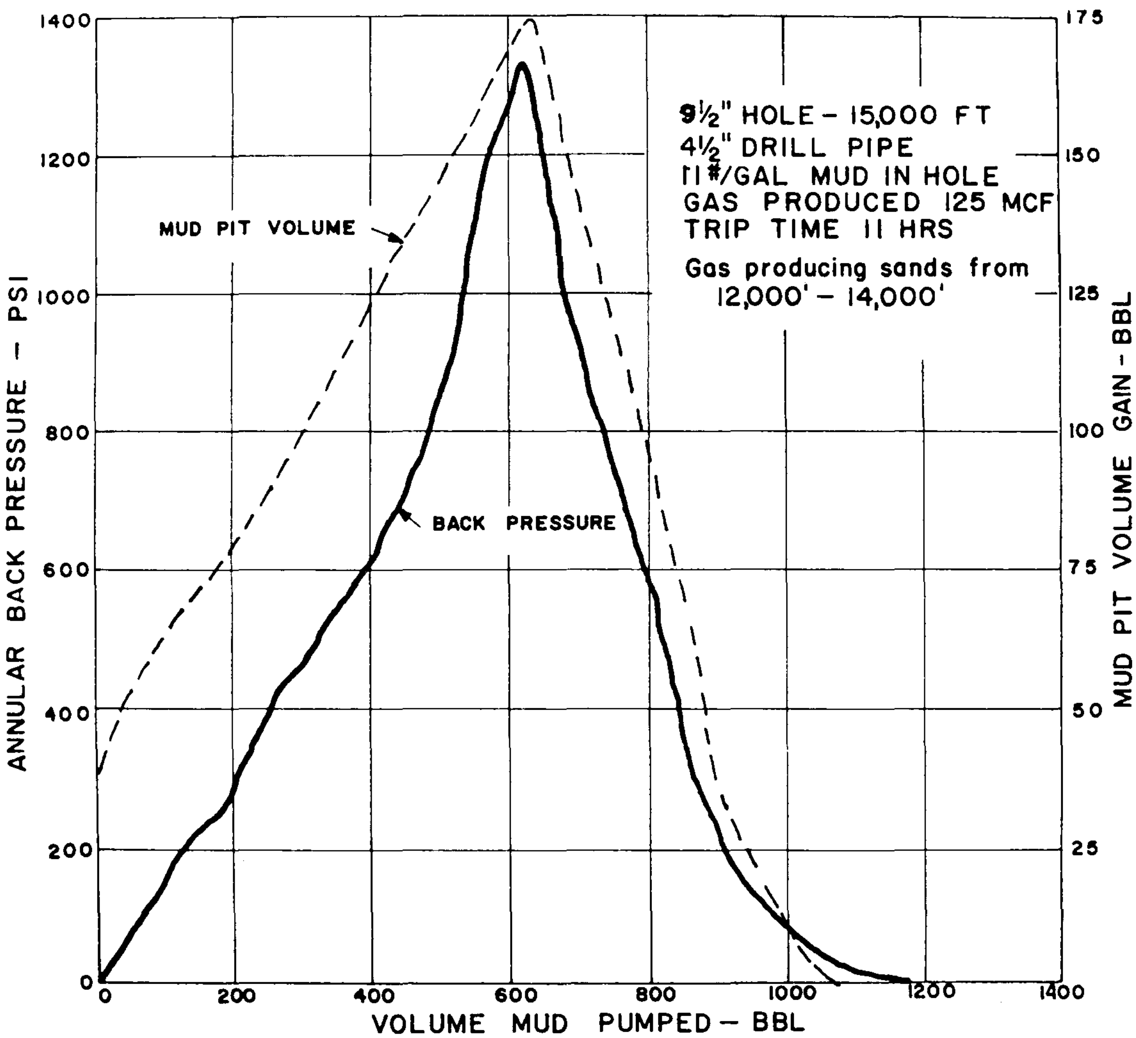

Fig. 6—Example of bottoms-up.

was in progress and drill string displacement. Actual control of this back-pressure schedule is determined by changes in the mud pit level and stand pipe pressure, as well as a predetermined estimate. Pressure adjustments in the order of 30 psi/min are necessary at a circulation rate of 10 bbl/min.

Drilling Under Pressure

A major advantage of utilizing well control procedures based on control of pressure directly rather than indirectly through volume control is that it permits drilling under an applied surface pressure. Generally, the procedure is to install a rotating blowout preventer, circulate the well with a mud weight less than that required to kill the well and control the rate of gas influx by a continuously applied surface pressure. Main economic advantages are a large increase in drilling rate, rapid drawdown of noncommercial reservoirs and an ability to drill through troublesome lost-circulation zones with full returns.

Not every well is susceptible to pressure drilling. First, the well must be capable of producing gas continuously. Next, the combination of permeability, productive interval exposed, mud weight in the hole and applied surface pressure must be such that making connections and trips is not unduly complicated.

The procedure for making trips must be determined on each well and will probably change during the course of drilling. Among the choices, in order of economic preference, are (1) let the well flow while making a trip; (2) use dual mud systems—one for drilling and one for tripping; (3) slug the hole with heavy mud; and (4) strip in and out of the hole. Use of diamond bits is preferred while pressure drilling.

If it were possible to describe mathematically the annular friction loss for two-phase flow, then it would be possible to predict the combination of variables previously mentioned that would permit pressure drilling. The complication arises in that gas, upon expansion, will create three distinct flow patterns: tiny bubbles at the point of entry, then plug flow of mud and gas and, ultimately, the gas will head. It has been determined empirically that a small change in surface pressure will have a substantial effect on flow by heading of the gas; this is the flow pattern that exhibits the largest pressure drop per unit length. Until such time as it is possible to describe these friction losses analytically, it will be necessary to determine empirically for each well whether or not it is susceptible to pressure drilling.

Some guidelines are available on the range of variables observed during pressure drilling operations conducted in the past (Table 1).

TABLE 1—RANGE OF VARIABLES ENCOUNTERED DURING PRESSURE DRILLING OPERATIONS

Variable	Range
Surface pressure	50 to 500 psi
Gas production rate	50 mcf-3 MMcf
Apparent permeability	0.1 to 15 md
Hydrostatic underbalance	1 to 4 lb/gal
Increase in drill rate	2- to 4-fold

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