DEEP WELL BLOWOUT CONTROL

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ABSTRACT

When a well kicks, most well control methods recommend that the well be shut in to observe surface pressures. Many times this is not feasible. An operator must use judgment to determine when he cannot shut in. Underground blowouts can be created by merely closing in a well. To properly control a kick, surface control equipment should be capable of handling large volumes of gas for a relatively long period of time. Bottom-hole circulating pressures can be calculated while circulating out a kick on the chokes. These calculations often relieve the operator from having to shut a well in for pressures when loss of circulation is expected.

Well control methods must be simple to be used in field work. Complicated methods requiring computers for solutions will never be entirely satisfactory for the field. A simple well control method readily usable in the field will be discussed. Calculations allow the operator to estimate the producing potential of a gas well while killing it. Use of proper gas handling equipment and good well control practices allow the operator to safely use underbalanced drilling to cut well costs.

INTRODUCTION

With deep drilling in the early 1960's came potential blowouts and high drilling costs. To combat costs, underbalanced drilling of high-pressure formations was employed. Millions of dollars have been saved by this method. It, however, creates even more chance for a blowout. Any underbalanced high-pressure, high-volume formation is a potential kick zone.

Deep drilling, therefore, has required much better supervision and well control than before. Many well control procedures have been advanced by the industry. Some are highly theoretical and much too complicated for field use.

A simple, practical method is needed. How a kick is handled by a rig crew in the first few minutes can often mean the difference between saving or losing a million dollar well. Such a method and the equipment to make it work are proposed in this paper.

CONVENTIONAL WELL-KILLING PROCEDURES

Most well control procedures begin by recommending that a well be shut in immediately after experiencing a kick. The drill pipe and casing pressures are used to calculate the mud weight required to kill the well. In theory, this approach sounds fine. In actual practice, some wells cannot be closed in to observe the pressure without breaking down weak zones.

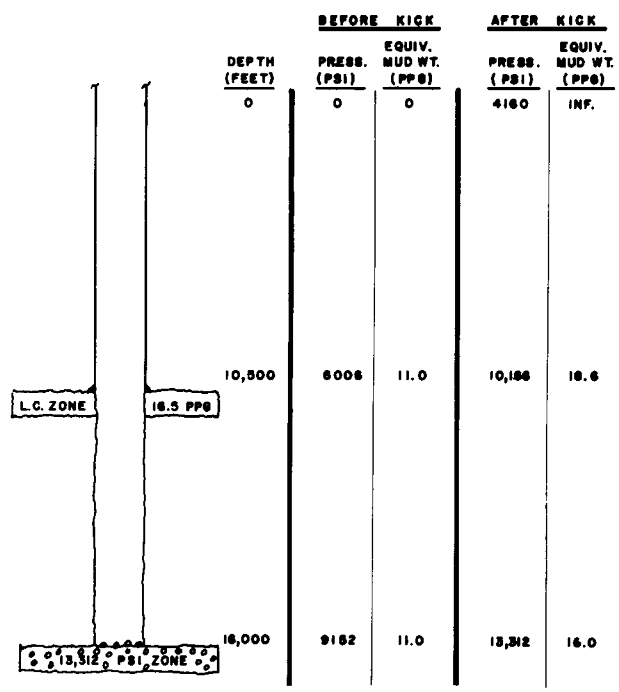

FIGURE 1—LOST CIRCULATION CREATED BY SHUTTING IN "KICKING" WELL

An example is shown in Figure No. 1. Casing is set at 10,500 ft. The well is drilling at 16,000 ft. The mud weight in the hole is 11 lb/gal. The formation immediately below the casing seat at 10,500 ft is known to break down with 16.5 lb/gal. It is known that gas requiring 11 to 16 lb/gal mud weight can be experienced anywhere below 10,500 ft. A gas zone at 16,000 ft with a pressure of 13,312 psi (16 lb/gal equivalent mud gradient) is encountered. It is assumed that the mud gain is observed immediately and that the well is shut in with no gain. In actual practice, the well would gain from 20 to 80 bbl of mud before it could be shut in. Any mud gain will create higher equivalent gradients than if the kick is contained immediately.

Prior to drilling the gas zone at 16,000 ft, the following conditions exist.

1. Hydrostatic pressure of 11 lb/gal mud at 16,000 ft is 9,152 psi.
2. Hydrostatic pressure of 11 lb/gal mud at 10,500 ft is 6,006 psi.

When the zone at 16,000 ft has been drilled and the well shut in with no gain, the following conditions exist.

1. Drill-pipe pressure is 4,160 psi (13,312 psi minus 9,152 psi = 4,160 psi).
2. Casing pressure is 4,160 psi (no mud gain).
3. Pressure at 10,500 ft is 10,166 psi (6,006 psi plus 4,160 psi = 10,166 psi).
4. Equivalent mud gradient at 10,500 ft is 18.6 lb/gal.

Remember that the zone immediately below 10,500 ft will hold only 16.5 lb/gal mud. The equivalent mud gradient at that depth is 18.6 lb/gal. This means that the formation will break down and take mud before 4,160 psi surface pressure can be observed. Actually the surface pressure would rise to about 3,170 psi, where the zone would begin to thief mud.

In the example just given, the well cannot be shut in to calculate the mud weight required to kill it. The example is not absurd. It is typical of conditions encountered in the Delaware and Anadarko Basins.

HYDRAULICS APPROACH TO WELL KILLING

Common hydraulic fluid-flow equations have been used as a tool in well control. The method has been utilized previously to optimize drilling horsepower to the bit with pump equipment available.[1] The primary fluid-flow equation used for well control is shown in Equation 1.

$$P = KQ^n \tag{1}$$

DRILL-PIPE PRESSURE PRIMARILY USED

Regardless of the method used to control a kicking well, the drill-pipe pressure is the primary pressure used. Mud pumped down the drill pipe is free of gas and, being noncompressible, will give valid bottom-hole pressures. A hydraulics approach to well control is applied to allow an operator to kill a well without actually shutting the well down to measure pressures. This method works essentially with drill-pipe pressure. The casing pressure is practically ignored as long as it does not exceed the working pressure of the well control equipment.

CIRCULATION PRESSURE CREATED BY FRICTION

The pressure required to circulate mud through the drilling assembly is created by friction of fluid moving through various restrictions (standpipe, kelly, drill pipe, drill collars, bit jets, and casing annulus).

This friction (pressure drop) will remain constant as long as the following five variables do not change: (1) rate of flow, (2) mud density, (3) mud viscosity, (4) length of drill-string assembly and (5) size of jets in bit.

HYDRAULICS CALCULATIONS

Fluid-hydraulic calculations show that flow rate vs pressure will plot as a straight line on log-log graph paper.[1]

Equation 1 can be used to calculate pressure drop in a circulating system. The value K is a constant derived from the five variables given earlier. As long as the variables do not change, K remains the same. If the variables change, K changes. A value of n = 1.82 (slope of a straight line on log-log graph paper) will give very close results to those actually measured on a drilling-rig circulating system. If one drill-pipe pressure and flow rate is known, additional pressures can be calculated for other rates. Equation 2, a variation of Equation 1, can be used as shown.

$$P_1 = KQ_1^{1.82}$$

or

$$K = P_1/Q_1^{1.82} \quad (2)$$

$$P_2 = KQ_2^{1.82}$$

or

$$P_2 = P_1 Q_2^{1.82}/Q_1^{1.82} \quad (3)$$

$$P_2 = P_1(Q_2/Q_1)^{1.82} \quad (4)$$

A value for K can be obtained from Equation 2. This value is substituted in Equation 3 to give Equation 4. Equation 4 can be used on any drilling rig to calculate normal pump pressure for a given flow rate. Remember that the other four variables must remain constant. Only the rate has been changed. Drill-pipe pressure at varying rates should be measured and recorded while drilling. In case of a blowout, normal circulating pressures are known. In the absence of actual measured date, Equation 4 will yield very good results.

FLOW RATE VS DRILL-PIPE PRESSURE

Assume that a well is drilling with a pump pressure of 2,500 psi. The mud pump is running at 50 strokes/min and is pumping 250 gal/min. If the pump is slowed down, the pump pressure will decrease. It would be found, if checked, that the rate vs pressure would be as shown in Table 1.

TABLE 1—PUMP PRESSURE VS PUMP RATE

Strokes Per Minute	Gallons Per Minute	Pressure (psi)
50	250	2500
40	200	1665
30	150	985

The pressures and flow rates correspond to a value of n=1.82. Measured and calculated values sometimes vary slightly, but they will be within the accuracy such that mud gauges can be read and pump strokes can be counted. Actual measured pressures will plot a straight line on a log-log graph as long as the fluid is in turbulent flow.

A check of a one-point pressure calculation on a recent drilling rig yielded the results shown in Table 2. The measured pressure exceeded the calculated pressure by approximately 60 psi (Figure No. 2). Many checks made in the field yield similar results.

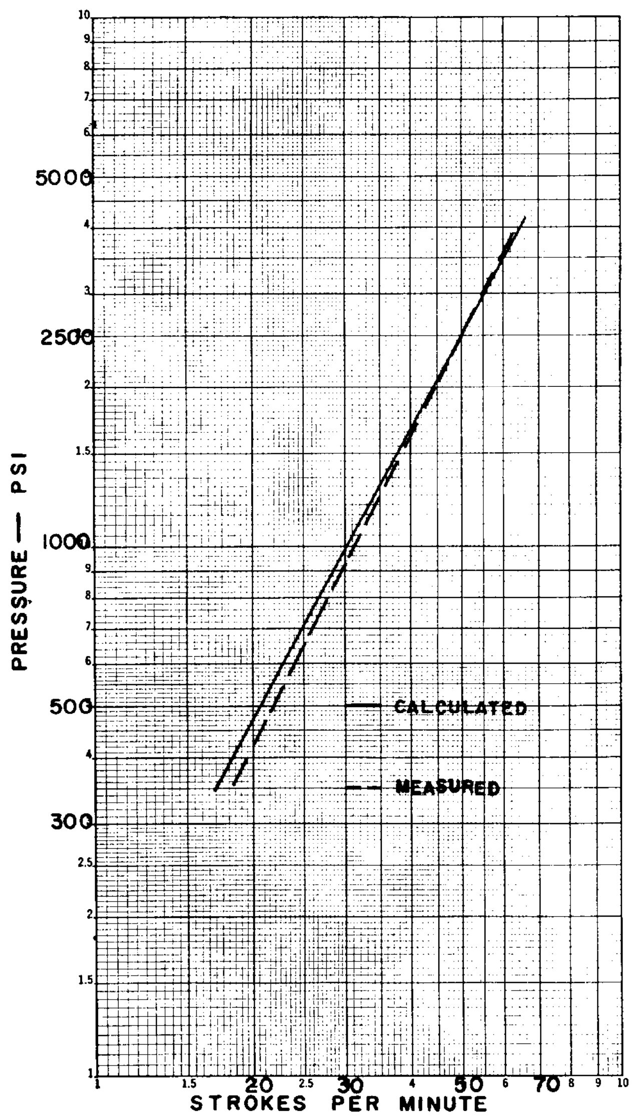

FIGURE 2—FLOW RATE VERSUS PUMP PRESSURE

To validly use the pump-stroke method, a mud pump must be in good shape. If pump strokes are counted, the volume is immaterial as long as a 50% increase in pump strokes yields a 50% increase in mud volume. If the pump pressure and mud volume do not check within reasonable limits, the operator should check for replacement of mud-pump parts or air locking of the pump.

FRICTION-LOSS EQUATIONS

The following equations can be used to calculate pressure drops through a circulating system.[2]

Friction loss through drill pipe or drill collars,

$$P = \frac{6.1 \times 10^{-5}\, dLQ^{1.82}}{D_i^{4.86}} \quad (5)$$

Pressure drop across a single rock-bit nozzle,

$$P = \frac{dQ^2}{6688\ D^4} \quad (6)$$

where:

- P = friction loss (pressure drop), psi
- d = mud density, lb/gal
- L = length of pipe, ft
- Q = circulating rate, gal/min
- D_i = inside diameter of pipe, in.
- D = nozzle diameter, in.

The friction loss through the drill pipe and drill collars must be considered separately. Friction losses in the annulus have been disregarded, since they normally are no more than 10% of the total friction in the system. Equations given in Reference 2 will allow the calculation of these values if the reader desires.

TABLE 2—COMPARISON OF MEASURED AND CALCULATED PRESSURES

SPM	Calculated Pressure	Actual Measured Pressure
50	2500 psi	2500 psi (normal drilling pressure)
40	1665 psi	1610 psi
30	985 psi	925 psi

EXAMPLE OF WELL-KILLING PROBLEM

Taking the drilling conditions just given with the pump running at 50 strokes/min with 2,500 psi drill-pipe pressure, assume the well kicks. The pump available on the rig will only develop 2,700 psi without undue maintenance. The drill-pipe pressure begins to drop, and a mud volume gain is experienced in the pits. The operator begins to choke the well while running the pump wide open at 50 strokes/min until the drill-pipe pressure is at the maximum of 2,700 psi. It is evident that the well will continue to unload under these conditions. Even though the drill-pipe pressure is dropping, the friction pressure in the system is the same as it was before the kick. The drop in drill-pipe pressure is the out-of-balance condition between the drill-pipe fluid and the annulus fluid. If the pump continues at 50 strokes/min and the well is choked until the pump pressure comes back to 2,500 psi, the gas zone will then be feeling the pressure it felt when it kicked. This was not enough to hold the zone. A pressure of 2,700 psi only adds 200 psi above the mud weight. This also is not enough to stop the gain.

With quick calculations, the operator realizes that by slowing the pump to 40 strokes/min (200 gal/min) the normal pump pressure should be 1,665 psi. He slows the pump to 40 strokes/min and keeps it running at precisely this speed. The well is then choked until it stops gaining mud. On this particular example, it takes a drill-pipe pressure of 2,665 psi to stop the gain (1,000 psi above normal pump pressure). This means the bottom of the hole is experiencing a pressure equivalent to the mud weight in the hole plus 1,000 psi. The casing pressure will be higher than 1,000 psi depending on the volume of mud gained while controlling the kick. The casing pressure is relatively unimportant as long as the control equipment will contain it. The drill-pipe pressure is the primary working pressure.

TABLE 3—PRESSURE EXERTED ON BOTTOM IN VARIOUS WAYS

Mud Wt. (lb/gal)	Pump Strokes (spm)	Pump Pressure (psi)	Pressure exerted on bottom
(normal pump pressure - no additional pump pressure applied)			
10.0	50	2500	10.0 lb/gal gradient
10.0	40	1665	10.0 lb/gal gradient
10.0	30	985	10.0 lb/gal gradient
(1000 psi additional pump pressure applied)			
10.0	50	3500	10.0 lb/gal + 1000 psi
10.0	40	2665	10.0 lb/gal + 1000 psi
10.0	30	1985	10.0 lb/gal + 1000 psi

As shown in Table 3, the bottom-hole pressure can be exerted in many ways depending on the pumping equipment available. An additional 1,000 psi can be held on bottom by running the pump at 50 strokes/min and holding 3,500 psi drill-pipe pressure. It can be obtained by running 40 strokes/min and holding 2,665 psi or running 30 strokes/min and holding 1,985 psi drill-pipe pressure. In any of the three cases the kick zone is feeling the same containing pressure.

After the well is contained and a gas cut mud is being circulated on the choke, the mud weight is then raised in an attempt to contain the zone without casing pressure. As the mud weight is increased, the operator must realize that the gas zone on the bottom is feeling the hydrostatic pressure of the column of gas-free mud in the drill pipe plus or minus any variation from normal pump pressure. It must be remembered that normal pump pressure will not be the same as it was before the mud weight is raised. As the mud weight is raised, the second variable is being changed. Usually mud viscosity (the third variable) is also changed. An increase in each of these variables increases circulating friction through the system. In essence, the normal circulating pressure is increased. If the same changes had been made to the mud before the well kicked, the normal pump pressures would have increased to reflect the changes. These pressure increases are there. It is more difficult now to recognize them since the well is being controlled on a choke. A change in density affects circulating pressure much more than a change in viscosity does. Normally, viscosity is not changed enough to make an appreciable difference. Pressure increase due to density is linear (see Equation 5). The pressure exerted on the offending zone is usually not the pressure it takes to kill the zone. It is only the pressure required to keep the well from unloading more mud while producing a given volume of gas. The well system has established an equilibrium where the well will give up gas against the back pressure. As the mud weight is increased, the casing pressure will decrease and the drill-pipe pressure will attempt to increase. The choke will be opened slowly to prevent the drill-pipe pressure from exceeding its normal value. The well will probably not be dead. As the mud weight is raised, the choke pressure can be decreased until the choke is no longer needed. The drill-pipe pressure will be normal with no choke pressure required. Often wells can be contained and an equilibrium established with the pump pressure below normal. This depends upon the capability of the well to produce. An example given later illustrates this point.

SURFACE CONTROL EQUIPMENT NEEDED

To adequately use the hydraulic well control method, special surface equipment should be used.

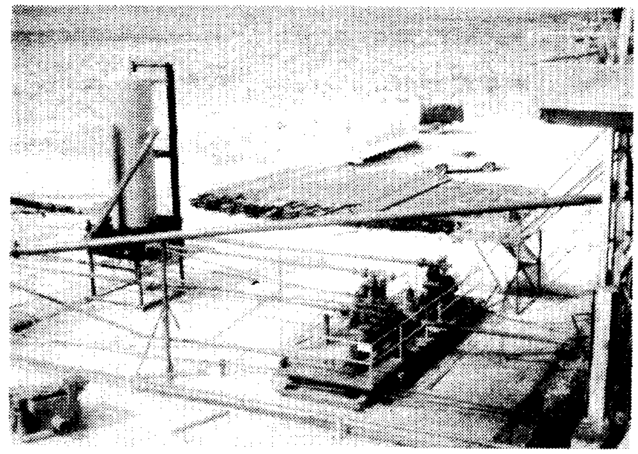

FIGURE 3—TYPICAL MUD-GAS SEPARATOR HOOKUP

A well must be equipped to handle commercial volumes of gas with the drilling fluid.[3] A mud separator unit as pictured in Figure No. 3 should be used to separate free gas from the mud. A 10,000 psi wp hydraulically operated choke currently available on the market also simplifies the well control operation. To evaluate and control a kicking well adequately, these two items are almost a necessity. Without a means of separating the gas from the drilling mud, a well must be killed immediately to prevent losing the mud system. On many wells, lost circulation is such a problem that the well cannot be killed immediately. A hydraulically operated choke and mud separator will allow an operator the circulating facilities to handle gas until a loss zone is sealed and the well can be killed. A schematic of the mud separator unit is shown in Figure No. 4.

BLOWOUT CONTROL METHOD USED TO SAVE MILLION-DOLLAR WELL

On a deep Delaware Basin well the hydraulic well control method, in conjunction with hydraulically operated chokes and mud separators, was used to save a million-dollar well.[3] The conditions of the well are shown in Figure No. 5. During drilling, this particular well had so much gas that dual hydraulically operated chokes were installed. Two completely independent mud-gas separator units were installed. The units were paralleled with hydraulic chokes discharging into each of the units. Separate gas lines were installed to the reserve pits. Separate mud lines to the shale shaker were installed. The systems were completely independent

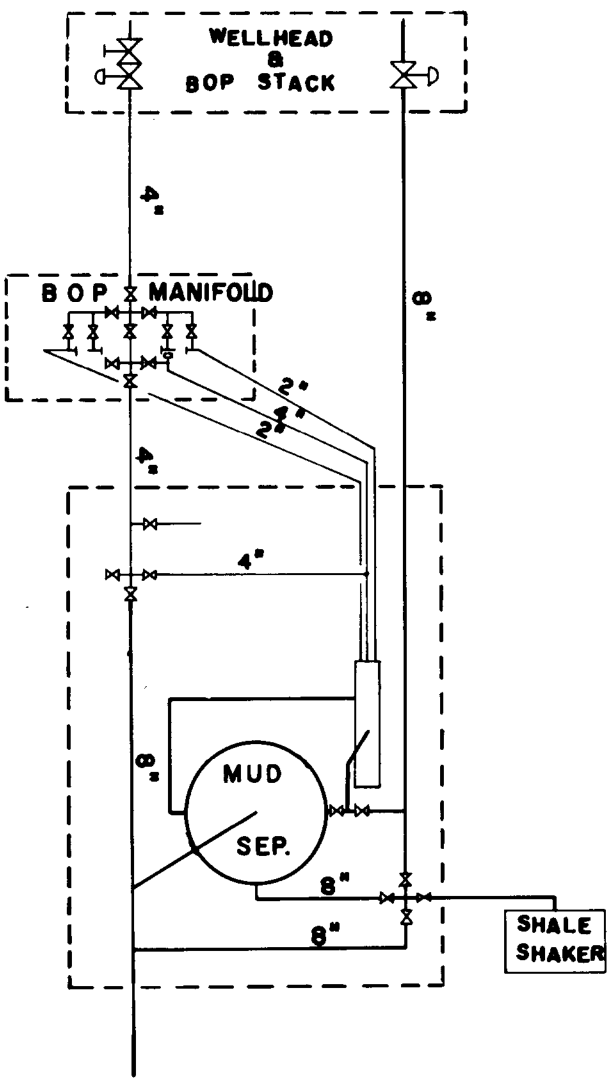

FIGURE 4—SCHEMATIC OF MUD SEPARATOR UNIT

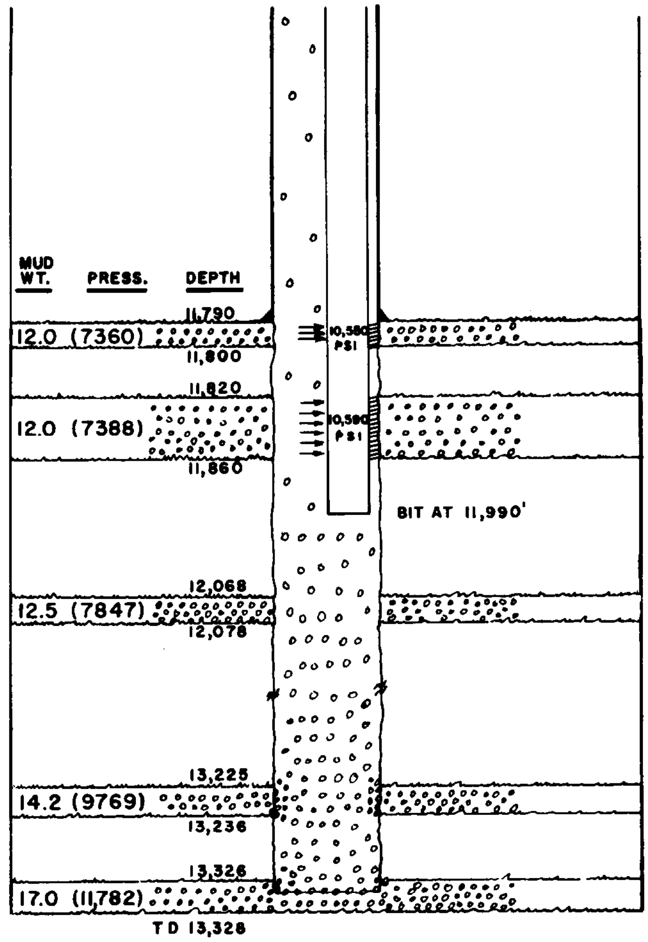

FIGURE 5—CROSS-SECTION OF PROBLEM WEST TEXAS WELL

of each other to prevent ever having to shut the well in for repairs to the surface equipment.

The well encountered a high-pressure, high-volume gas zone at 11,800 ft (approximately 700 ft above known zones in offset control wells) before the intermediate casing could be set. Lost circulation zones prevented killing the well with weighted mud. Weighted mud was spotted on bottom and 9-5/8-in. casing was stripped into the hole and cemented. Gas zones as shown in Figure No. 5 were encountered and killed until a fractured section from 13,326 to 13,328 ft was drilled. The well kicked with 14.7 lb/gal mud in the hole. Mud weight was increased to 15.8 lb/gal because the hole began taking mud. With lost circulation material the mud was increased to 17.2 lb/gal, which would still not kill the well without lost circulation. Mud weighing 21 lb/gal was spotted on bottom. The bit was pulled to approximately 10,700 ft (1,100 ft up inside 9-5/8-in. casing). Three thousand sacks of cement were pumped through the bit and drilling assembly into the lost-circulation zone at approximately 11,800 ft. The zone was squeezed and excess cement circulated out. The hard cement was drilled with 17.2 lb/gal mud. The lost circulation zone held this mud weight. Below the cement plug the well kicked again. With the well shut in on choke and the bit at 11,900 ft, the drill collar's differential stuck at the two top porosity zones immediately below the 9-5/8-in. casing. The drill pipe could not be moved. The well could not be killed with the bit 1,300 ft above bottom. It could not even be adequately plugged.

Throughout these occurrences the well was making 1 to 2 MMcf/D of gas while circulating on the choke with 17.2 lb/gal mud. It was believed that the zone would be very limited in extent since it was a fractured zone and pressured to such an abnormal level. The decision was made, therefore, to deplete the zone to a pressure that could be handled with a reasonable mud weight.

By using the hydraulic control method, the drill-pipe pressure was reduced by 1,000 psi (from 1,650 to 650 psi) by gradually opening the hydraulically operated choke and letting the well unload mud from the annulus. The hydraulic control method allowed good calculations of the bottom-hole pressure while reducing the pump pressure. With the pump pressure maintained at 650 psi by holding annulus pressure with the choke (pump running wide open at constant flow rate) the mud weight was then reduced slowly from 17.2 lb/gal to 15.8 lb/gal. The pressure gradient was reduced to approximately 13.5 lb/gal on the bottom zone. At a calculated gradient of 14 lb/gal, the gas zone at 13,225 to 13,236 ft began to flow. This gave a good check to confirm the calculations. Both zones were flowing against a 13.5 lb/gal gradient. Gas production was 2 to 3 MMcf/D through the mud separation equipment. For 10 days the gas zones were depleted. Mud was circulated at 7 bbl/min. Gas was produced at a rate of 2 to 3 MMcf/D. The well was never shut in except to change mud pumps (3 to 5 minutes) throughout the operation. After 10 days, the mud weight was increased to 16.5 lb/gal, and the pump pressure increased to normal pressure of 1,650 psi. The well was killed with the bit still stuck 1,300 ft above the bottom. The drill collars were washed over and recovered. The hole was cleaned out to total depth. Drilling was resumed with 16.5 lb/gal mud. The mud was then cut back to 16.3 lb/gal as drilling progressed.

CONCLUSIONS

The hydraulic well control method is a simple, practical approach to controlling blowouts. This method, in conjunction with mud-gas separators and hydraulically operated chokes, gives an operator a highly effective tool with which to minimize deep well drilling hazards. Field personnel who are properly educated in well control and who use this system can efficiently bring a kicking well under control.

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