USE OF THE d_C-EXPONENT TO MINIMIZE DRILLING COSTS IN THE DELAWARE BASIN

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The ability to accurately predict formation pressures while drilling is fundamental to the safe and economic operation of any well. This is no less true in the Delaware Basin, despite years of experience in the area.

During drilling, d_C-exponent data is currently the most practical pressure analysis technique in the Delaware Basin. The accuracy approaches that of the acoustic velocity log. Recent innovations have greatly improved the interpretation at the wellsite.

Proper application of d_C-exponent data can be used to minimize drilling costs by aiding in:

1. Selection of casing seats
2. Prediction of hole instability caused by heaving shales in an underbalanced environment
3. Maintenance of well control

d_C-EXPONENT MECHANICS

Anyone can calculate d_C-exponents. Jorden and Shirley[1] presented an excellent nomograph in their original proposal of the concept. A slide rule[2] is now available to quickly calculate d_C-exponent values to within an accuracy of $\pm$ 0.01.

Pressure analysis using d_C-exponents, however, is an art. It requires careful consideration of well conditions tempered with a knowledge of the area. Moreover, the accuracy of the estimates increases with experience. This is no different than the requirements for proper interpretation of acoustic logs.

Figure 1 represents the work of an experienced mud logger. The data was developed while drilling a deep Fusselman test in the center of the Basin. The log-derived pressures were interpreted by an experienced log analyst after completion of the well. The estimated pressures are within 0.5 ppg of each other. The mud logger followed the steps outlined in Table 1 and used the overlay represented by Fig. 2.

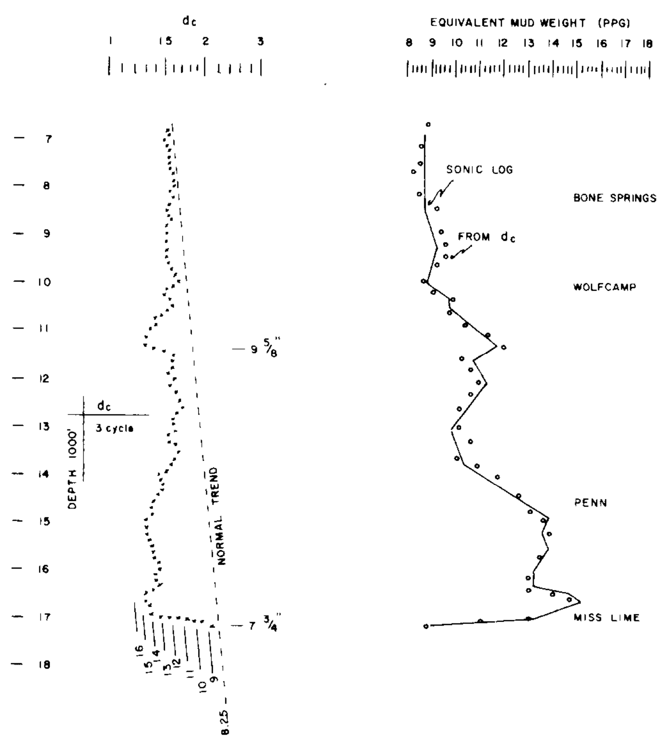

FIG. 1—LOG ESTIMATES VS d_C EXPONENTS' PREDICTIONS (WARD CO. TEX)

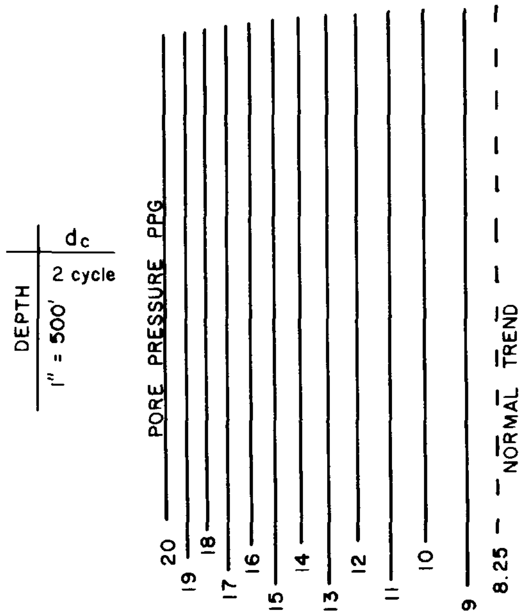

FIG. 2—OVERLAY FOR DETERMINATION OF PORE PRESSURE FROM d_c

TABLE 1—9 STEPS TO ACCURATE d_c INTERPRETATION

1. Within the accuracy of the wellsite equipment, record the average penetration rate, rotary speed, weight on bit and mud weight at 10-ft intervals.
2. Reduce the bit size by 1 in. for insert or diamond bits.
3. Calculate the 10-ft d_c-exponent using the slide rule or suitable nomograph.
4. Average these d_c-exponent values every 50 ft.
5. Plot the 50-ft averages on 2-cycle semi-log coordinates and a vertical depth scale of 500' = 1".
6. Using the transparent overlay similar to Fig. 2, place the normal trend line (8.25 ppg) through the majority of points in the normally pressured section. Do not rotate the overlay.
7. If sufficient points are not available in the normally pressured section, place the trend line to reflect a known or assumed pressure.
8. Shift the trend line only if there is a significant change in drilling variables. Assume the pressure at the change to be equal to that immediately before.
9. Read the estimated formation pressure in ppg.

SELECTION OF CASING SEATS

Williams[3], in an excellent paper on drilling practices in the Basin, provided the following comments on casing setting criteria:

> "The selection of optimum casing setting points usually has more to do with drilling a well safely and economically than any other one thing. Some of the factors which must be considered when selecting Delaware Basin casing setting points are:
>
> 1. to isolate and protect fresh-water-bearing strata from contamination;
> 2. to case-off massive evaporate sections so as to:
>   a. eliminate key seat problems,
>   b. facilitate the use of fresh water for mitigation of loss of circulation and faster penetration rate;
> 3. to case-off zones with low frac gradients and/or lost circulation zones prior to drilling abnormally pressured zones;
> 4. to case-off abnormally pressured intervals requiring high-density drilling fluid prior to drilling normally pressured intervals with low to normal frac gradients;
> 5. to case-off troublesome sloughing shale intervals."

The casing program in the Delaware Basin is relatively standard, because of the experience in the area. Figure 3 reflects the typical situation. Intermediate casing is set in the Upper Wolfcamp to case off the weak Permian formations above. A protective liner is consistently set in the Mississippi Limestone. This isolates the abnormally pressured Wolfcamp and Pennsylvania sections from the weaker Devonian and Ellenburger formations below.

Approximate casing depths are developed from analyses of offset wells. Exact casing seats must be determined from a pressure analysis as the well is drilled. The critical factor is the formation fracture gradient. Note the relationship indicated in the pressure profile in Fig. 4.

Formation pressure appears to have the greatest effect on fracture gradients in the Basin. Reid[4] has provided a useful chart to calculate the fracture gradient, but his estimates seem to be high in the lower pressure ranges. Figure 5 was developed from empirical data in the area. Reid's curve is shown on the chart for comparison.

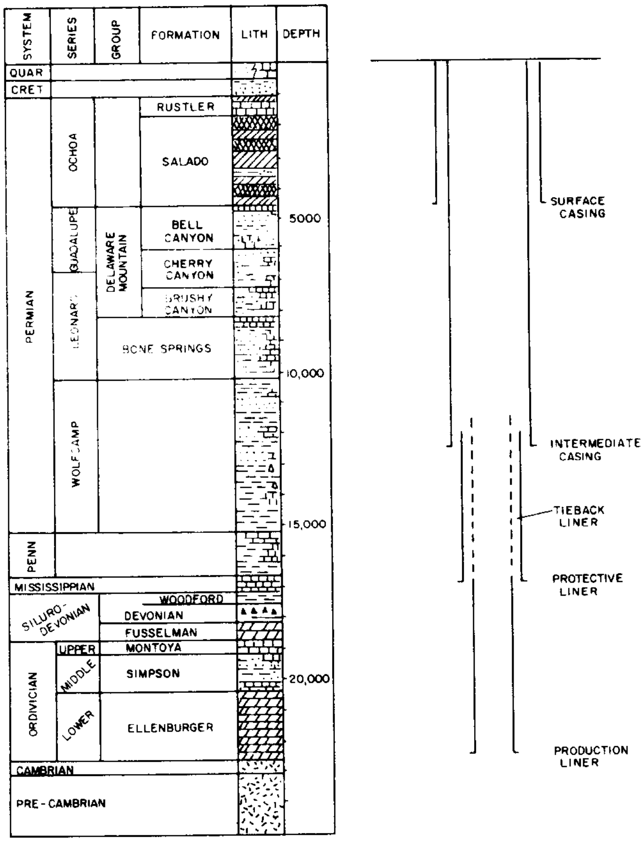

FIG. 3—TYPICAL GEOLOGICAL SECTION AND CASING PROGRAM, DELAWARE BASIN (AFTER WILLIAMS[3]).

The recommended procedure for proper selection of casing seats is as follows:

1. Estimate the formation pressure on a continual basis using the d_c-exponents.
2. Estimate the fracture gradients using Fig. 5 or a similar chart.
3. For intermediate casing:
   a. Drill into Wolfcamp. Do not let the mud weight exceed the strength of the upper formations.
   b. Pick the logging point as the depth where the fracture gradient is greater than the maximum expected formation pressure.
   c. Confirm the formation pressure by analysis of the acoustic log.
   d. If the information is supported, run pipe.
   e. Run a pressure or lead-off test on the formation to confirm the estimated fracture gradient.
4. For the protective liner:
   a. Correlate the d_c value with geological information.
   b. Drill 50-100 ft into the Mississippi Limestone (just below the base of the pressured sections).
   c. Run pipe.

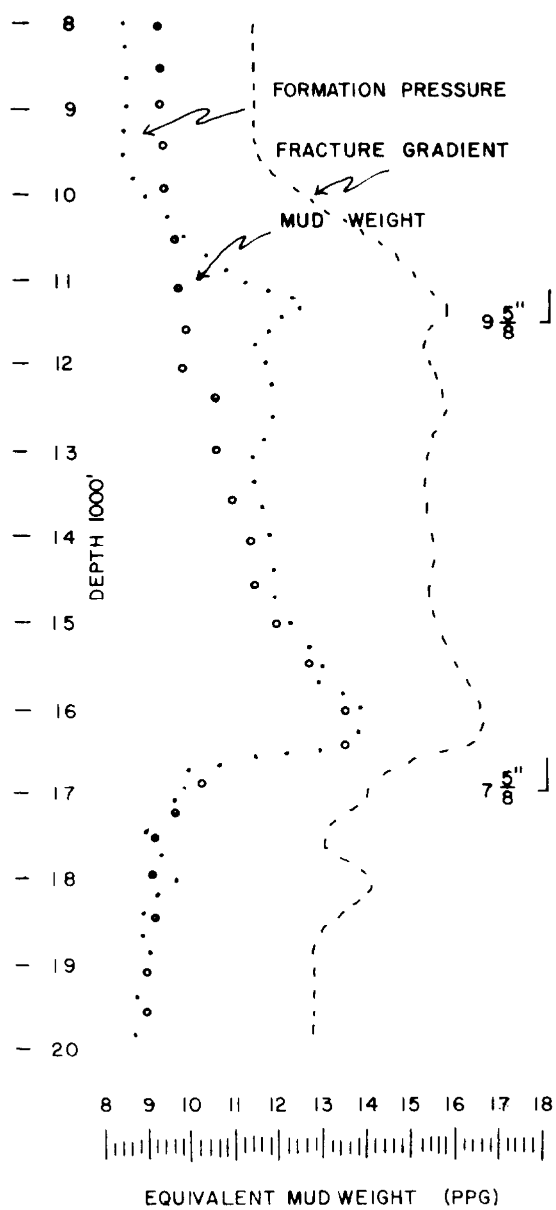

FIG. 4—PRESSURE PROFILE OF A 21,000 FT ELLENBURGER TEST (REEVES CO. TEX.)

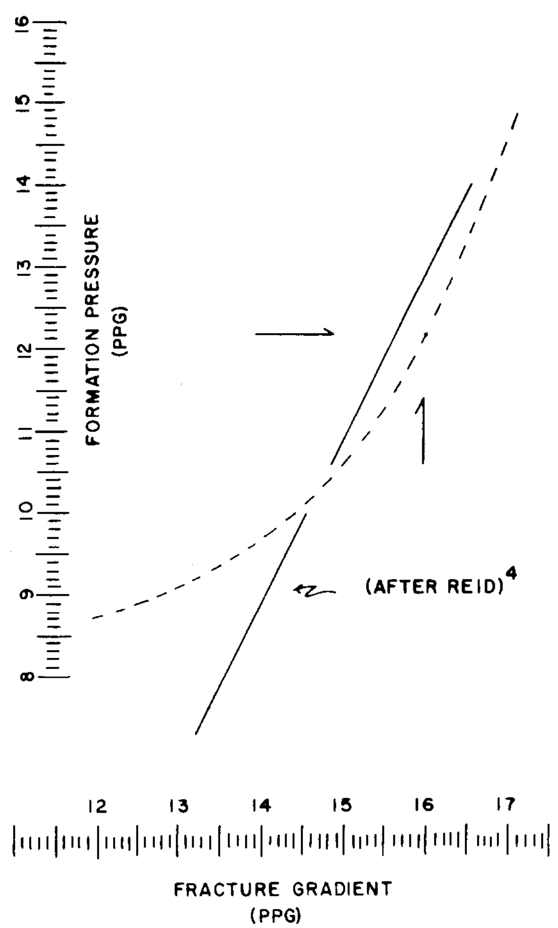

FIG. 5—ESTIMATED FRACTURE GRADIENT, DELAWARE BASIN

PREDICTION OF HOLE INSTABILITY

The pressured section is the most expensive portion of the hole, because of the high daily cost and the time required to drill. One of the more significant practices employed to minimize the cost and drilling time, whether intentional or not, is to drill in an underbalanced environment. (See Fig. 4). This can lead to heaving shale problems if the differential is too great, thereby offsetting the savings.

It is a gross oversimplification to imply that the degree of underbalance is the sole or even major cause of hole instability. Development of special muds has certainly eased the problem.[4] Experience in the area, however, has shown that the formation pressure should not exceed the mud weight by more than 2.0 - 2.5 ppg with any mud system. As before, the formation pressure is required and the d_c-exponent is the most practical method to determine the formation pressure.

MAINTENANCE OF WELL CONTROL

Characteristically, the Wolfcamp and Pennsylvania sections exhibit the low permeability necessary for underbalanced drilling. This occurrence, however, is not totally predictable and can lead to severe well control problems. Because it is not economically feasible to eliminate underbalanced drilling in the Delaware Basin, more attention should be devoted to maintenance of well control.

The primary concern, of course, is to set the intermediate casing at the proper depth. Repeating, the fracture gradient at this depth must be greater than the maximum expected formation pressure. As the formation pressure begins to approach the fracture gradient, less pressure can be applied at the surface after a kick without losing circulation at the shoe.

The lower the mud weight for a given formation pressure, the greater the kick magnitude. Consequently, more pressure is required at the surface to control the well. A simple equation has been derived to estimate the lower limit of the mud weight during underbalanced drilling:

$$MW = \frac{(FP)\,(D) - (FG)\,(Df)}{D - Df - L} \qquad (1)$$

where MW = Minimum mud weight, ppg
D = Drilling depth, ft
FP = Formation pressure gradient derived from the d_c-exponent at depth D, ppg
FG = Fracture gradient at shoe, ppg
Df = Depth of casing shoe, ft
L = Assumed length of gas kick, ft

The length of kick, L, is set up as a design rather than an actual criterion. The limits of L are specified as follows:

$$O < L < Df \quad \left(\frac{FG}{FP} - 1\right) \qquad (2)$$

As L approaches the upper limit, the minimum mud weight in Eq. (1) approaches the formation pressure, FP.

An example illustrates the use of Eqs. (1)

and (2):

Given:

FP = 14 ppg (from d_c exponent)
D = 15000 ft
FG = 15.5 ppg (from pressure test)
Df = 11000 ft
L = 500 ft (assumed design criteria)

Solution:

1. Using Eq. (2), compare the range of L to the assumed kick length.

$$L \text{ (upper limit)} = (11000)\left(\frac{15.5}{14} - 1\right)$$

$$= \underline{1179 \text{ ft}}$$

2. The design length of L = 500 ft is satisfactory. Solve for MW using Eq. (1).

$$MW = \frac{(14)(15000) - (15)(11000)}{15000 - 11000 - 500}$$

$$= \underline{12.9 \text{ ppg}}$$

3. The mud weight must be greater than 12.9 ppg to minimize the probability of breaking down the formation at the shoe in the event of a kick.
4. Since the differential for well control (1.1 ppg) is less than that recommended for hole stability (2.0 - 2.5 ppg), the 12.9 ppg mud weight overrides.

The use of this technique in no way implies that the risk of a blowout is totally eliminated. It is simply a method of using the formation pressure derived from the d_c-exponent to better understand the wellsite conditions.

CONCLUSIONS

1. Knowledge of the formation pressure while drilling is important to the safe and economic operation of wells in the Delaware Basin.
2. The d_c-exponent provides a practical approach to determine formation pressure while drilling.
3. The d_c-exponent can be used to assist in pinpointing casing seats.
4. The d_c-exponent can be used to predict the onset of hole instability when the mud weight is 2.0 - 2.5 ppg under the shale formation pressure.
5. The risk to well control can be estimated by using the d_c-exponent to determine formation pressure.

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