Recent Developments in On-Site Well Monitoring Systems

F. S. YOUNG, JR. and K. D. TANNER
Baroid Division N L Industries, Inc.

INTRODUCTION

The complexity of problems associated with deep drilling has resulted in increased emphasis on the collection and interpretation of well drilling information. These data are essential for geological evaluation, cost control and safety.

In deep drilling, rotating costs become a more significant fraction of total well cost. These rotating costs are influenced by drilling practices employed in the operation of the rig equipment, selection of bits, drilling fluid systems, and drilling fluid properties, and the hydraulic design of the circulating system. A proper selection of drilling practices which assures minimization of well costs is the goal of a soundly engineered and executed drilling plan. The basis for this selection is accurate drilling information.

A recent trend toward deeper drilling may be observed in Fig. 1. After a period of 12 years, the world's depth record of 25,340 ft was surpassed in 1970 by Placid Oil Company in St. Bernard Parish, Louisiana. The Louisiana State 1-5407 well was drilled to a total depth of 25,600 ft. This record was short-lived, however, as the Ralph Lowe Estate well in Pecos County, Texas drilled to 28,500 ft in 549 drilling days in early 1972. The target depth of several wells now in progress should soon assure a new world record. At these depths, uncommonly high wellbore temperatures and pressures will be encountered. To work efficiently in this temperature-pressure environment will require a reexamination of nearly all conventional drilling equipment and procedures. Of interest is the fact that record producing depth increases with increasing drilling depth. A new world record producing depth of 22,790 ft was established by Gulf Oil Company in the Gomez Field of West Texas in 1968. With over 50,000 ft of sediments as potential reservoirs in the deeper basins of the U.S., the trend toward deep drilling should continue.[1]

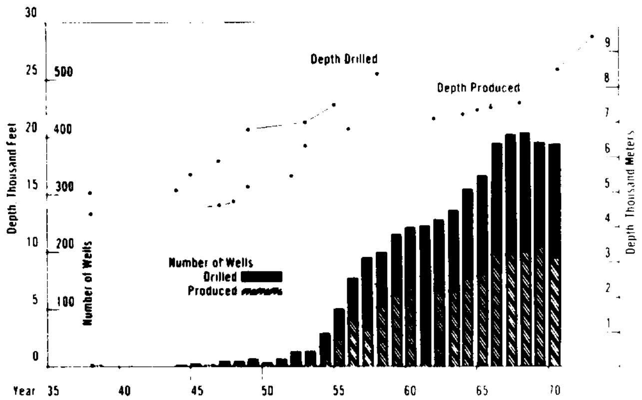


FIGURE 1
DEEP DRILLING STATISTICS

As drilling depth increases, so does the cost of drilling. Figure 2 shows the average cost per foot of hole drilled, and annual footage, plotted with time for the period 1964-1969. This is the latest data available from the Joint Association Survey of drilling and completion costs. As can be seen in Fig. 2, drilling cost is increasing at approximately 7.5 percent per year, while total footage, though erratic, averages in excess of 150 million feet/year. Figure 3 shows the product of cost/foot × footage plotted against time for the base period. From Fig. 3 it can be seen that the U.S. drilling industry is increasing annual expenditures for drilling and completing wells over the period shown, with the 1969 total expenditure in excess of 2.8 billion dollars.

These figures indicate a continuing effort to discover and develop domestic hydrocarbon reserves. However, as the deeper basins are more thoroughly explored, application of all available technology will be required to drill them economically. Much of this technology can be directed also to average depth wells with justification.

The purpose of this paper is to discuss Baroid's recent developments in on-site well-monitoring systems. These systems are designed to provide

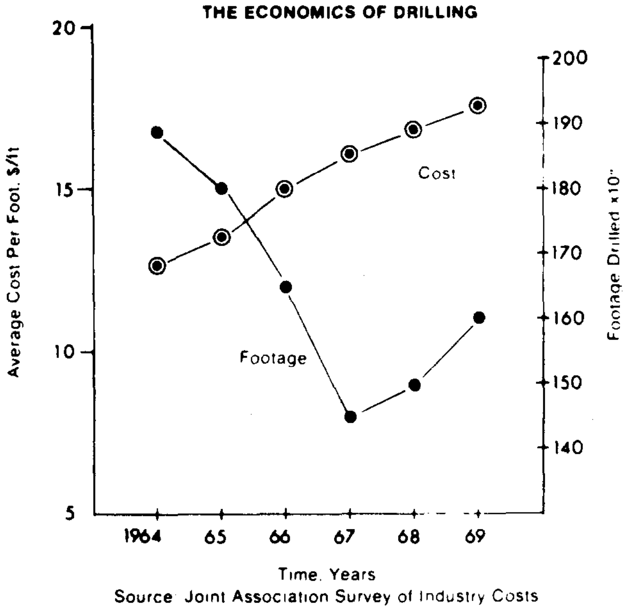


FIGURE 2
DRILLING COST AND FOOTAGE DRILLING VS. TIME

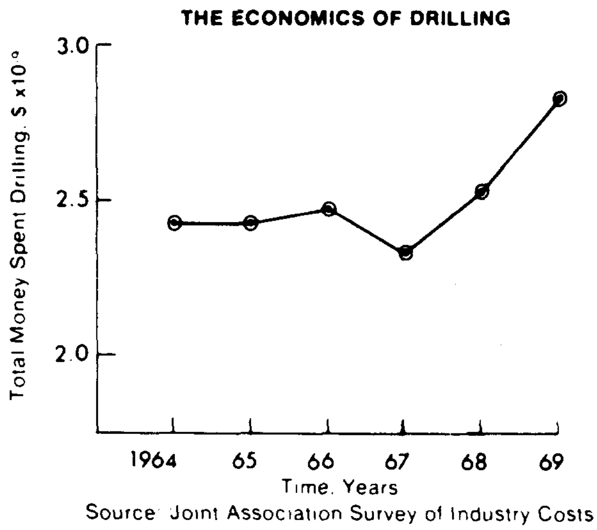


FIGURE 3
TOTAL DRILLING EXPENDITURES VS. TIME

rapid, accurate drilling information to assist in the drilling of the deeper, more difficult wells. Well information gathered and analyzed is discussed. Methods of interpreting this information for pore pressure prediction and minimum cost drilling are presented. Finally, an economic analysis of these well monitoring units which relates their cost to value is given, so that the merits of such systems may be evaluated.

WELL MONITORING SYSTEMS

Equipment and Logs

The early development of well monitoring equipment may be traced to the origin of the mud logging concept in 1939. From laboratory work of the Barnsdall Oil Company, the first commercial logging service was offered by Baroid in August of 1939. Early logs prepared during the drilling of the well recorded lithology, mud and cuttings gas content, water intrusion and drilling rate. These data, after appropriate corrections for annular travel time, were plotted with depth to create the mud log. This log was utilized as a qualitative tool on exploratory wells for identifying formation tops and potential coring points.[2]

Later refinements of the early mud logging equipment provided for the quantitative analysis of drilling mud for volatile hydrocarbons by use of gas chromatography and the Steam Still.[3] From an analysis of the components of the logged gas, it became possible to develop meaningful ratios between methane and the other components to indicate potential productivity.[4]

By 1966, basic concepts for determining the presence of abnormally pressured formations from continuous well logs were established. New measurements were introduced into the conventional mud logging service to enable prediction of abnormal pore pressure. Equipment was developed to monitor mud pit level, mud flow, pump and choke pressure, bit weight and rotary speed, and shale density. These data were utilized to prepare logs which would, in addition to providing mud logging information, indicate the presence of abnormal pore pressure.[5] Thus, a new service which assisted the operator in maximizing drilling rate by minimizing mud weight was developed, and more accurate determinations of casing depth requirements could be made.

During 1967, Humble Oil and Refining Company began field testing an instrumented van capable of optimizing the drilling operation by adjusting bit weight and rotary speed. The objective of these tests was to evaluate the use of an onsite digital computer to optimize drilling continuously by minimizing cost per foot.[6] Results of these tests provided the following conclusions:

1. A digital computer could be successfully employed to optimize continuously bit weight and rotary speed in a field environment.
2. Drilling costs could be reduced by improv-

ing drill rate and lengthening useful bit life.

3. Improved drilling instrumentation was needed.
4. Experienced and highly trained personnel were required to operate the unit and to evaluate results.

Although it was recognized that the computer could be utilized to perform many other routine drilling functions, a decision was made by Humble to sell the original equipment to a service company for further implementation. Because of Baroid's experience in well logging, their current involvement in closely related engineering applications and future development plans, the Humble unit was sold to Baroid in late 1969. Under a special development contract to Humble, the original unit was modified by equipping it with additional instruments and reprogramming the on-board computer. The unit was then returned to the field, under the supervision of Baroid's Technical Operations Department. These and later improvements have resulted in the newly developed Computerized Drilling Control (CDC) Service.

Total capabilities of these new units are summarized in Table 1. In addition to obtaining geological information, CDC units monitor drilling variables, analyze the data for prediction of pore pressure and solution of drilling fluid-related problems, optimize drilling, and gather useful information for planning development wells. Another important feature is the early warning sensing of potential problems that may result in unscheduled lost time. A complete list of drilling parameters which are directly monitored or computed is shown in Table 2.

TABLE 1

TOTAL CAPABILITIES OF CDC UNITS

Geological and Engineering Tools

I. Geological Information
   A. Lithology
   B. Hydrocarbon Shows (ppm Analysis)

II. Well Monitoring Equipment

III. Analysis of Data
   A. Pressure Prediction
   B. Drilling Fluid related Problems

IV. Optimization
   A. Hydraulics
   B. Bit Selection
   C. Mud Type and Weight
   D. Weight/Speed

V. Planning for Development Wells

TABLE 2

PARAMETERS MONITORED OR CALCULATED WITH CDC UNITS.

	PARAMETER	SOURCE
1	BIT WEIGHT	P/I TRANSDCR
2	ROTARY SPEED	TACHOMETER
3	ROTARY TORQUE	TRANSDCR/AMP
4	PIPE DISPLACEMENT	FOLLOW LINE
5	DEPTH	FOLLOW LINE
6	PENETRATION RATE	CALCULATED
7	MUD FLOW, SUCTION	FLOW METER
8	MUD FLOW, FLOW LINE	FLOW METER
9	PUMP STROKES	RELAY
10	STANDPIPE PRESSURE	P/I TRANSDCR
11	CHOKE LINE PRESSURE	P/I TRANSDCR
12	MUD PUMP EFFICIENCY	CALCULATED
13	MUD TEMPERATURE, SUCTION	THERMISTOR
14	MUD TEMPERATURE, FLOW LINE	THERMISTOR
15	AMBIENT TEMPERATURE	THERMISTOR
16	FORMATION TEMP GRADIENT	CALCULATED
17	MAX CIRCULATING TEMP	CALCULATED
18	PLASTIC VISCOSITY	VISCOMETER
10	YIELD POINT	VISCOMETER
20	MUD WEIGHT, SUCTION	P/I TRANSDCR
21	MUD WEIGHT, FLOW LINE	P/I TRANSDCR
22	EQUIVALENT CIRC DENSITY	CALCULATED
23	MUD CONDUCTIVITY, SUCTION	RESIST. PROBE
24	MUD CONDUCTIVITY, FLOW LINE	RESIST. PROBE
25	DIFFERENTIAL CONDUCTIVITY	CALCULATED
26	MUD GAS (CATALYTIC/THERMAL)	DETECTOR
27	BIT TOOTH WEAR	CALCULATED
28	BIT BEARING WEAR	CALCULATED
29	TIME ON BIT	REAL TIME CLOCK
30	FEET ON BIT	FOLLOW LINE
31	CURRENT COST PER FOOT	CALCULATED
32	NORMALIZED "D" EXPONENT	CALCULATED
33	DRILLABILITY	CALCULATED
34	FORMATION LITHOLOGY FACTOR	CALCULATED
35	FORMATION DENSITY	MANUAL
36	FORMATION FACTOR	MANUAL
37	BIT JET VELOCITY	CALCULATED
38	BIT HYDRAULIC HORSEPOWER	CALCULATED
39	BIT JET IMPACT	CALCULATED
40	EST FORMATION PRESSURE	CALCULATED
41	FRACTURE GRADIENT AT CASING	CALCULATED
42	SLIP VELOCITY OF CUTTING	CALCULATED
43	MUD PIT TOTAL VOLUME	PIT FLOATS
44	MUD PIT VOLUME CHANGE	PIT FLOATS
45	TORQUE RATE ENERGY FACTOR	CALCULATED
46	STROKES LAG IN SYSTEM	MANUAL-CALC
47	PREDICTED FEET TO BIT FAIL	CALCULATED
48	PREDICTED TIME TO BIT FAIL	CALCULATED
49	MINIMUM COST BIT WEIGHT	CALCULATED
50	MINIMUM COST ROTARY SPEED	CALCULATED
51	PRESSURE DROPS IN SYSTEM	CALCULATED
52	CRITICAL VELOCITIES	CALCULATED
53	ANNULAR VOLUME	CALCULATED
54	FORMATION ABRASIVE FACTOR	CALCULATED
55	BEARING CONSTANT	CALCULATED

A functional diagram of the computer system may be seen in Fig. 4, which describes how low voltage electrical sensors provide the measurement data from the rig. The results of the computer analysis are provided in the following forms:

1. A cathode ray tube (CRT) displays 50 numbers which are updated each four seconds.
2. Three 8-channel strip chart recorders plot data with time (16 channels) and depth (8 channels). These data provide a continuous log of drilling events.
3. An ASR teletype logs critical information, such as drilling breaks, gas in mud, pit level change and weight speed optimization. These reports are typed together with the data and time to provide a permanent record of drilling operations.
4. A remote CRT in the rig supervisor's quarters duplicates the function described in (1) above. In a matter of seconds, the supervisor is informed of current operating conditions, allowing for quick analysis of conditions at all parts of the rig operation, including surface and subsurface.
5. A remote drilling console on the rig floor displays important information for the driller; any four parameters may be recorded with time on a strip chart located within this console.
6. Special alarm lights on the CDC operator's panel and the floor console indicate out-of-limits operation, such as: flow-in minus flow-out not equal to zero, washout indication, or bit wear condition.
7. A high-speed (110 character/min paper tape punch is used to generate drill data tapes. As many parameters as desired may be punched onto these tapes at depth intervals as small as one foot. This source of information, in digitized form, can be used to prepare listings of all data punched. A standard ASR teletype can be used for this purpose. If remote transmission of data is desirable,

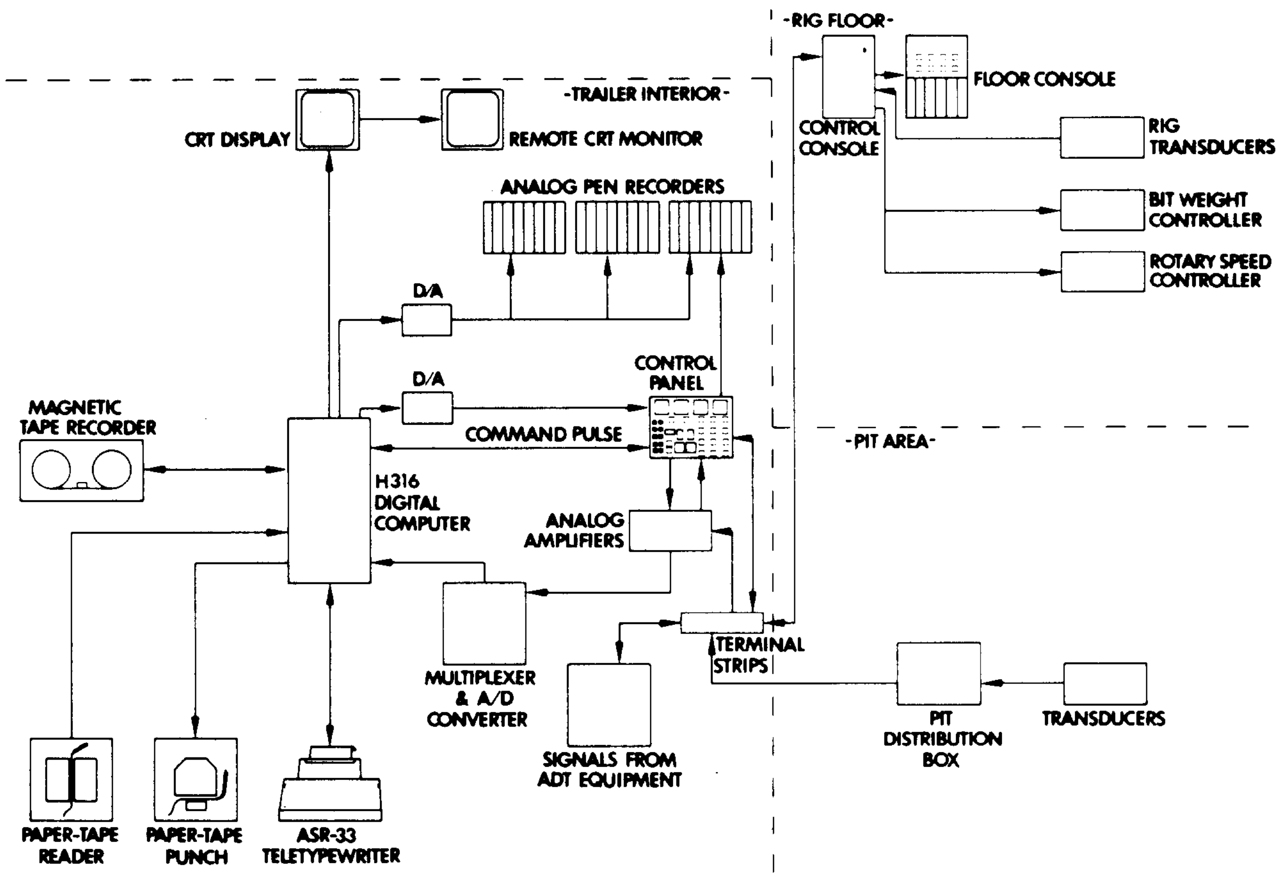


FIGURE 4

FUNCTIONAL DIAGRAM OF CDC UNIT

the tapes may be transmitted over TWX to the operator's office. This form of data provides an excellent basis for research work, as the tapes are compatible with peripheral input devices normally used in research centers.

Software

The focal point of this data acquisition system is a programmable digital computer. Because of its high computational speed and error-free operation, the digital computer may be programmed to monitor and analyze the incoming data

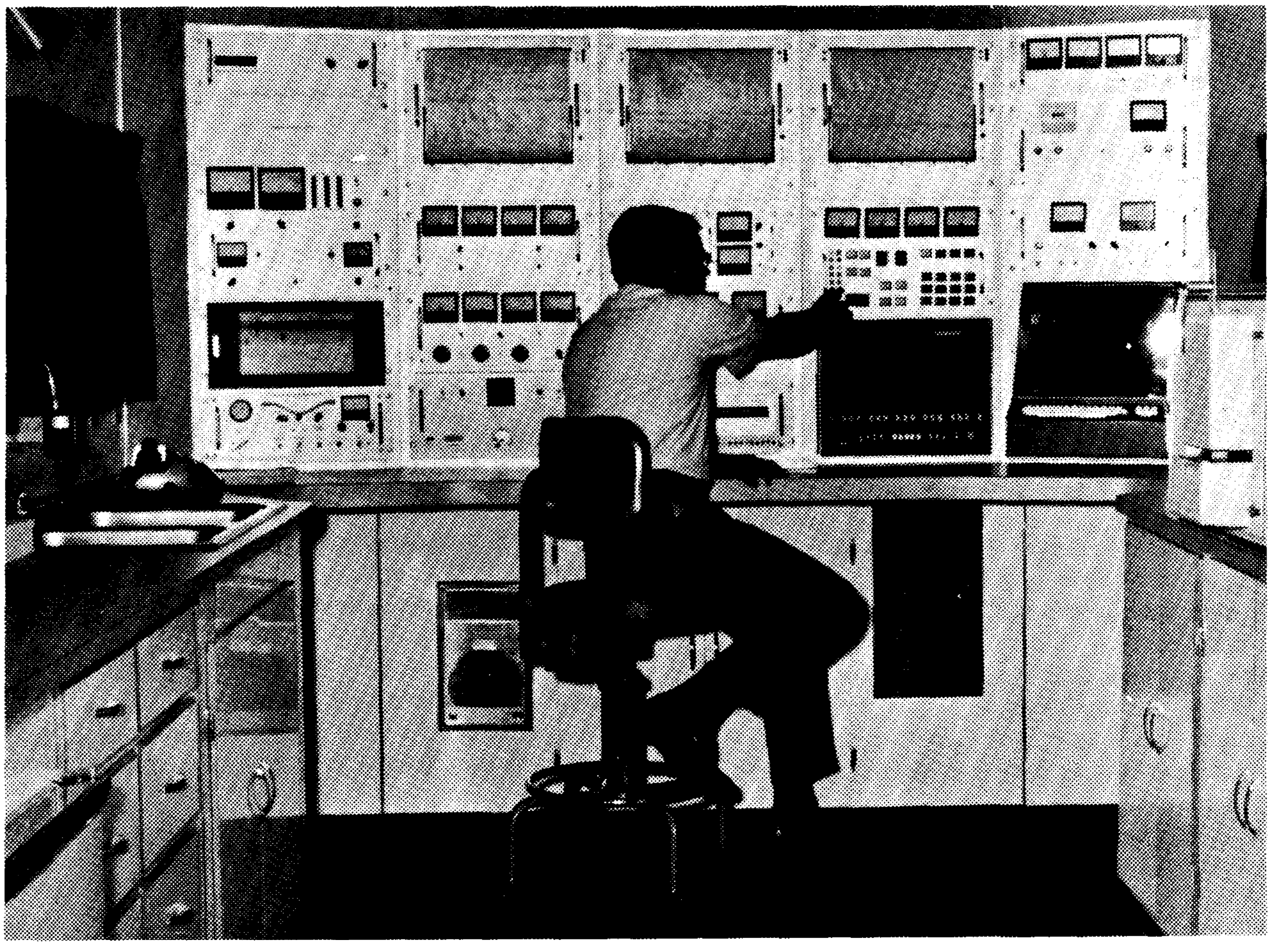


FIGURE 5
CDC UNIT

and react by algorithyms, to certain logical drilling operations.

An extensive amount of engineering and programming time was required to develop the computer software. Individual programs were written in either assembly level or FORTRAN language, depending upon the amount of arithmetic involved. Most logical programming of routine hardware functions is written in assembly language. All mathematical equations, however, which require floating point arithmetic, are written for solution in FORTRAN. This language allows added flexibility in that the relationships programmed may be easily modified. The combination of assembly and FORTRAN programs have been inter-

Detailed logs and reports are prepared daily from all of these previously described sources of information. These logs include the standard mud log showing drill rate, gas in mud, lithology, and ppm analysis of mud hydrocarbons. Other data useful for detecting pressure transition zones are plotted with depth, including rock drillability, formation base exchange capacity, mud temperatures, cuttings density, and mud conductivity. A detailed morning report form is used to summarize other operating information, including circulating system hydraulics, equivalent mud circulating density, bit information (rotating times, cost per foot, footage drilled, and condition of cuttings structure and bearings), and routine mud analysis.

faced to a real-time operating executive program, and are resident in the 16K core during drilling.

On trips or on other occasions when the rig is not on bottom drilling, the computer may be used for other purposes. A library of conversational programs has been developed for use during these times by the operator's personnel. This library includes programs for:

1. Well pressure control
2. Calculation of bit constants
3. Analysis of hole problem such as lost returns
4. Free point calculation
5. Drill bit cost analysis
6. Annular velocity/slip velocity/hydraulics

This computer software is constantly undergoing modification and updating as new features are added. The importance of this effort is tangible, for without it the capabilities of these units are limited.

DATA ANALYSIS

A two-fold problem in developing a concept such as that described here is: (1) Which parameters should be monitored, and (2) Which methods of data analysis should be employed. In general, the first part of the problem has been solved by the conventional oilfield method: measure everything you can think of. This is good, because the more one measures, the higher the probability of measuring the correct parameter. However, this procedure creates some confusion and satellite problems. For example, geologists, drilling engineers, and operations personnel all want, and should have, the information which interests them most. Geologists desire accurate sample analysis, whereas the tool pushers want to know more about pump operation, to cite one case. This confusion can be minimized, or in some cases avoided, if proper reporting methods are utilized. Successful application of these units requires close cooperation among all representatives on the location.

The second part of the problem is more complex, for the economic success of the operation may depend upon it. Methods of data analysis will be discussed next.

Geological Data

Whereas much new information is being generated from the well site for drilling cost minimization, the basic function of geological data collection remains fundamental to these units. An accurate analysis of cuttings not only identifies formation tops, but confirms what the engineer is observing on drillability plots. The detection of gas in the mud identifies potentially productive zones, and a study of background connection and trip gas is a qualitative measure of pore pressure. Of course, a quantitative analysis of the hydrocarbons in the gas may be used to predict productivity. Because of the importance of this information, and the fact that many older wells used for correlation purposes were mud logged, the collection and interpretation procedures used for geological information remain unchanged.

Monitor and Alarm

The successful application of technology to the drilling operation begins with a selection of mud weight, for the pressure exerted on the hole bottom by the annular fluid column not only controls drilling rate, but also the quality of data recorded on the surface.[7,8,9] Since the use of a minimum mud weight is so desirable, special care should be taken to assure that the weight selected is adequate for control of formation pressure. This means not only during the drilling operation, but on trips as well. Most pressure control problems develop during trips on development wells.[10]

Equipment which will monitor, and alarm for out-of-limit operations, forms an integral part of CDC units. The following parameters are continuously monitored by the CDC computer:

Mud weight in
Mud weight out
Total surface pit volume
Rate of change of surface pit volume
Catalytic gas
Thermal gas
Flow rate in
Flow rate out
Fill-up on trips

For each parameter, a safe deviation may be defined. If the feedback information varies beyond the deviation limit, visual and audible alarms are activated. The computer scans these variables five times per second, so that reaction time is essentially instantaneous. This automatic feature conserves manpower, freeing personnel to perform other duties.

Pressure Prediction

The early detection of increasing pore pressure is desirable, because the volume and density of influx determine the severity of surface conditions as the influx is circulated. While surface measurements can be used to detect an influx, much effort has been expended to predict increasing pore pressure before a permeable zone is drilled. These methods rely on wireline log measurements [11,12] and surface-measured drilling relationships. [13,14]. Four methods of interpretation are utilized by the CDC unit personnel to predict pore pressure while drilling:

1. Qualitative analysis of recorded data
2. Regression analysis of offset data
3. Formation drillability
4. Gas porosity correlation

The data which are recorded to predict increasing pore pressure include:

1. Normalized drilling rate
2. Gas in mud
3. Formation density
4. Formation base exchange capacity
5. Corrected flowline temperature (bottomhole gradient)
6. Differential mud conductivity
7. Formation lithology

A suite of curves is plotted with depth, with appropriate lag introduced for the measurements which are dependent upon samples from bottom. Significant trends in these curves, when analyzed together, provide a qualitative measure of overbalance. Corrected flowline temperature is the stabilized mud temperature observed after several hours of circulation. A bottomhole temperature is estimated from surface measurements using a linear heat flow balance.[15] This formulation assumes the drill pipe-annulus-earth system represents a steady-state heat exchanger. A plot of bottomhole temperatures with depth provides a means of estimating the temperature gradient, which increases near abnormally pressured zones.[16]

The previously recorded curves can be quantitatively interpreted in most areas by the development of overlays. These overlays are now available for the Gulf Coast, Anadarko Basin, and West Texas Areas.

The second interpretation method is based upon an object analysis of offset data by means of a regression analysis.[17] Where appropriate offset data are available, regression equations relating the measured variables to pore pressure can be developed. As the new well is drilled, the CDC computer reads the input data, solves the regression equations and plots the results. Statistically meaningful variances may be applied to the results to predict a rapidly increasing bottomhold pressure. This technique has the advantage of automatically relating each parameter to its historical importance in arriving at pore pressure predictions. This method has promise in development areas where many wells are to be drilled.

While it is difficult to predict the effect of differential pressure (mud volume pressure-formation pore pressure) on drillability in the field, laboratory measurements make it possible to empirically curve fit differential pressure vs. drill rate data, and utilize the derived relationships in a drilling rate equation. [1,14] By use of this new equation, the component of rock drillability attributed to pressure effects may be estimated. Thus, "rock drilling strength"[18] becomes a function of rock density, porosity, and compressive strength (and possibly other factors). Since formation porosity and lithology can be determined from an analysis of drilled cuttings, their inclusion into a predictive drill rate equation more clearly defines true rock drillability. During drilling, apparent rock drillability differs from true drillability by the magnitude of the difference in equivalent circulating density (ECD) and formation pore pressure. This is only true, however, when formation changes can be verified by sample analysis. Thus a true rock drillability determined from offset drilling can be compared on a footage basis with apparent rock drillability, the difference being attributed to differential pressure effects.

The gas porosity correlation is a relatively new concept being tested in hard rock areas. Plots of rock porosity (calculated from formation density) plotted against gas readings in units will establish a normal pressure trend line. As formation pressures increase abnormally, rock porosity also increases. A measurable increase in background gas yields meaningful data. While dependent upon drill rate, flow rate, and mud properties, the observed phenomenon appears promising.

Each of the above methods is now being field tested, some in different parts of the world. The technique of pressure prediction while drilling, although now in relatively early stages of development, will soon become a well-established science.

Optimization

The terms "optimization" and "minimum cost drilling" are synonymous. Drilling optimization is simply the process of applying all known technology to the drilling operation to reduce cost per foot. While "optimized drilling" in earlier times meant varying bit weight and rotary speed to reduce cost per foot, [19,20] the term now denotes a wider definition.[21] To optimize a drilling well, the engineer today relies upon his knowledge of circulating system hydraulics, bit selection, mud system type and density, and weight speed practice; all tempered by his experience and rig capabilities. The CDC units have been designed by knowledgeable engineers to provide the basic information necessary for optimized drilling. With special emphasis on a penetration model, the CDC computer is programmed to recommend optimum drilling conditions at all times, and provide the flexibility of investigating alternative practices. Thus, the units provide a means for reducing footage costs while getting the hole down as trouble-free as possible.

ECONOMICS OF MONITORING UNITS

Economic justification for use of on-site monitoring units involves some accepted values and some not so tangible. It involves an estimate of their total cost to the operator as related to the benefits derived. In the following discussion, an attempt will be made to list the tangible service provided by these units, assign a value where possible, and then attempt to assess a total value of the services performed, including the avoidance of drilling problems.

The analysis discussed was prompted by a desire to assess the market and economic justification for such services, and to establish any long range plans. The serious development of units such as have been described is a very costly and time-consuming process. Only by careful and frequent reexamination of progress can such a development evolve. While the criteria to be used in evaluation are sometimes nebulous, it is hoped the conclusions are meaningful.

To assess the value of any advanced logging tool and fit it to the needs of a specific application, a value must be assigned to each service performed. The capabilities of the unit described may be classified as follows:

1. Geological data collection
2. Monitor and alarm
3. Drilling optimization
4. Avoidance of problems
5. Drilling data collection

The value of each will now be developed.

Geological Data Collection

This service may be equated to conventional mud logging services. It consists of sample collection, analysis, and the logging of gas in mud. Since 1939, mud logging units have been used on most wildcat exploratory wells, and the services performed are well recognized. The value of this service is established at about $200/day.

Monitor and Alarm

The basic mud logging unit may be easily upgraded to a monitor and alarm unit by adding more instrumentation. Compact, easily installed panels and recorders are available for measuring:

1. Pit level total/change
2. Flow in/out
3. Mud density in/out
4. Mud temperature in/out
5. Differential mud conductivity
6. Bit weight/rotary speed

The daily rental cost of this equipment, if leased individually, totals over $100/day. A logging unit upgraded as described would approach in capability an Applied Drilling Technology (ADT) unit. Average revenue for the ADT units in 1970 was approximately $375/day. While this is more than the mud logging unit cost plus auxiliary equipment, the ADT service is provided with more personnel. Thus the basic value of units capable of mud logging, monitoring and alarming is in excess of $300/day.

Optimization

The implementation of optimization may be carried out by several methods as discussed by Lummus.[22] A summary of various methods and cost per day is shown in Table 3. Complete on-site computer control of rig operation would cost about $1,000/day. Area office time sharing would

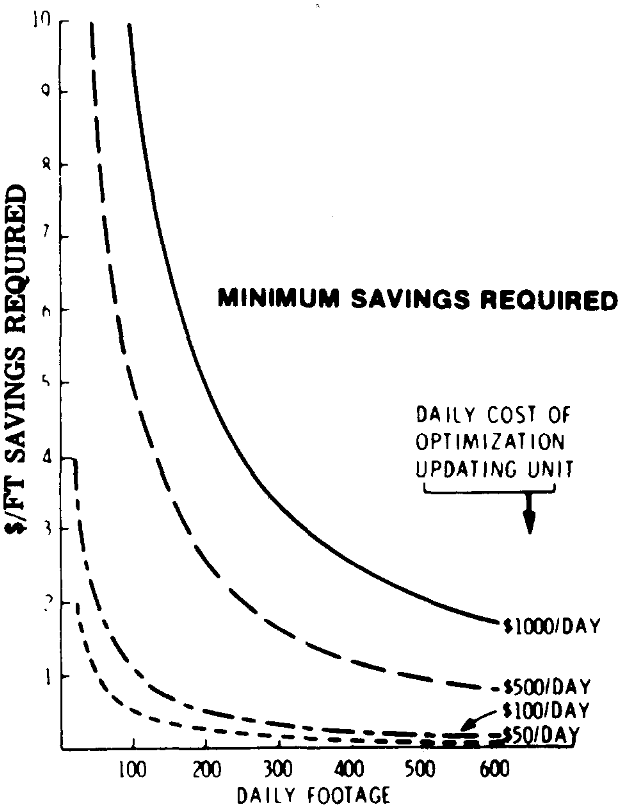
TABLE 3

THE ECONOMICS OF OPTIMIZATION

Various Methods of Implementing Optimization

Method	Cost Per Day
Complete On-Site Computer Control of Rig	$1,000
On-Site Computer Calculations and Warnings Only	500
On-Site Time-Sharing Terminal with Radio/Phone	100
Area Office Time-Sharing Terminal with Phone to Rig	50

cost about $50/day. A CDC unit would cost between $100 and $500/day, depending upon personnel requirements. Figure 6 shows the cost per foot savings required to justify an optimization unit for various amounts of hole drilled per day.



From Lummus, J. L. "Acquisition and Analysis of Data for Optimized Drilling" Journal Pet. Tech., Nov 1971

FIGURE 6

DAILY FOOTAGE VS SAVINGS FROM OPTIMIZATION

Figure 7 relates optimization savings to rig cost, $/day, at various levels of rotating activity. It is assumed that 10 percent of intangible drilling costs can be "saved." This is a well established value.[20,21] By way of example, Fig. 7 shows that with 40 percent rotating activity, a $3500/day rig would yield slightly under $150/day in "savings" due to this feature of optimization. It appears that a rig cost in excess of $12,000/day would be required to justify a $500/day unit on the basis of optimization alone. While this figure appears large, it is not uncommon to find daily rig costs in excess of $20,000 in remote offshore areas. However, in many high cost areas, rotary time is much less than 40 percent, negating the value of optimization. In general, for large land rigs drilling the deeper holes, a value of $100/day savings due to optimization does not appear unreasonable.

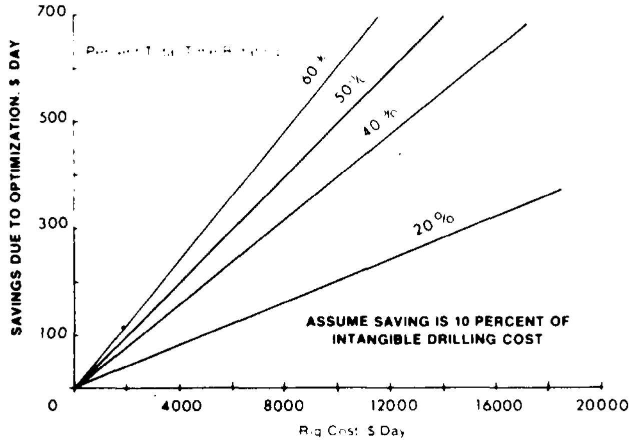
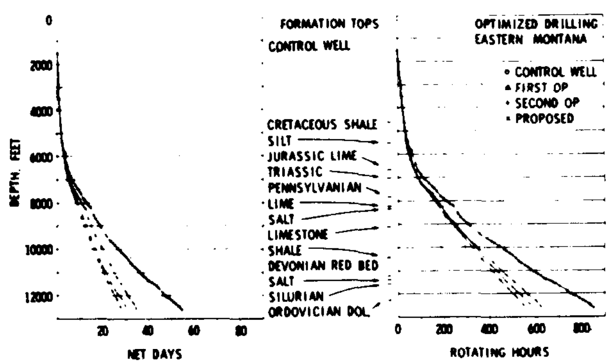


FIGURE 7

RIG COST VS SAVINGS DUE TO OPTIMIZATION

Figure 8 shows Eastern Montana experience gained by Lummus.[22] Of interest is the fact that successive attempts to optimize appear to yield positive, though diminishing, results. It is well established that if after optimizing several wells, strict supervision is not maintained, the depth-time curve (and cost) will flatten, and approach the reference curve.

SAVINGS DUE TO OPTIMIZATION ARE TANGIBLE



Eastern Montana Well

From Lummus, J. L. "Acquisition and Analysis of Data for Optimized Drilling" Journal Pet. Tech., Nov 1971

FIGURE 8

EASTERN MONTANA OPTIMIZATION EXPERIENCE

Figure 9 reflects Baroid's experience. After drilling two 12-¼-in. holes to 8000 ft., the same rig drilled a third. The optimized well shows a reduction in cost of more than $25,000 over a three-week period.

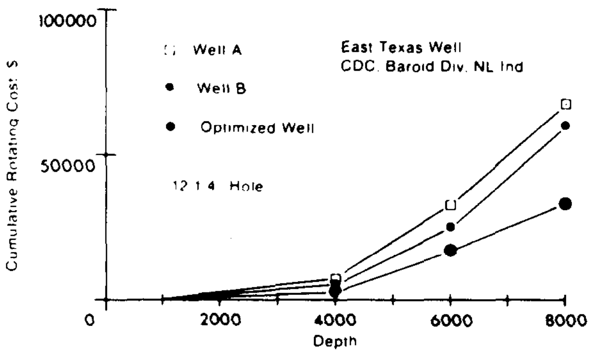


FIGURE 9

EAST TEXAS OPTIMIZATION EXPERIENCE

Avoidance of Problems

This capability—the avoidance of problems—is the most difficult to assess, because the dollar value of hole trouble must first be determined, and then a fraction thereof for avoidable error must be assumed.

To determine the amount of money spent by the industry on hole trouble, several companies were canvassed for statistics on the number of trouble-days per well. One major operator reported that in a 40-well program, there was an average of seven trouble days/well at a total cost of $2 x 10^6$. This is approximately $50,000/well. Four other operators reported that they add 10 percent to an AFE for hole trouble, and that if the well is to be drilled in a known trouble area, an additional 10 percent is added. From analysis of 1970 wildcat statistics, it appears that $794 x 10^6$ was spent on drilling. If 10 percent of that money was spent on unscheduled trouble days, the cost to industry approached $80 x 10^6$ in 1970, or $10,000 per well. Thus, in this informal survey, five operators reported spending from $10,000-$50,000/well for unscheduled trouble. The partial explanation for this variation is that the $50,000 figure represented mostly offshore operations where costs were high. This does not account for the cost of redrilling the hole, which should be included.[10]

In a more quantitative and wide-spread survey, Baroid's Area Engineers were asked to examine well files for the period 1965-1971 and to report total unscheduled days for three depth categories:

0-10,000 feet
10-15,000 feet
15,000 feet and deeper

Six geographical areas, including Canada were surveyed; and records from over 1000 wells were tabulated. A map of the areas is shown in Fig. 10. The survey covers a composite of over 12 million feet of drilled hole. Results of the survey are shown in Table 4.

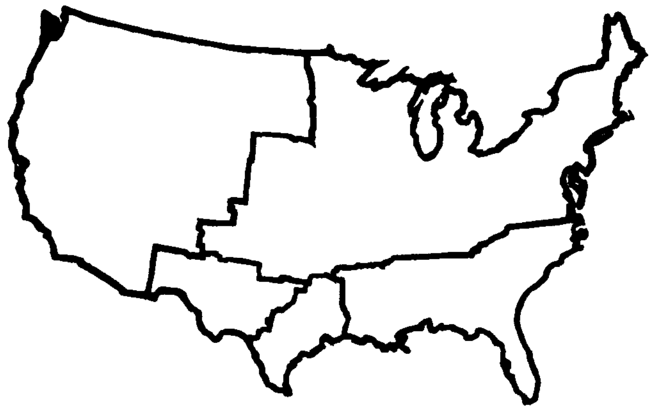


FIGURE 10

AREAS SURVEYED

The data in Table 4 show that the average days/1000 ft of hole drilled varies greatly from one area to the next. Canadian drilling is slowest, and as would be expected, the younger coastal formations drilled fastest. In Canada the average drilling time was 20 days/1000 ft for wells drilled below 15,000 ft; in the coastal formations, this average was 4.6 days/1000 ft. Percent of trouble days/well varies by geographical area in each depth category, but the average percent of unscheduled days for all three depths is nearly the same—8.3 to 9.7 percent. Since for trouble-time, cost is conservatively equal to rig cost, this survey confirms the earlier findings that approximately 10 percent of well cost is represented by unscheduled trouble costs; over $10,000/well, on the average, is spent on trouble. Since the average days per well is 12.77 (Joint Association Survey 1970), this study has shown that nearly $800/day is being spent by the drilling industry on unscheduled trouble, and it is believed that this amount is very conservative.

In summary, the net worth of a drilling monitor unit can be established from the data presented. For deep, high pressure wells which would otherwise be mud logged:

Mud logging service	$200.00
Monitor and alarm	100.00
Optimize	100.00
Trouble x frac.	800(x)
Total value =	$400 + 800(x)

where: x = fraction of trouble-days avoidable

Thus, if 25 percent of unscheduled trouble-days is avoidable, a unit is worth $600/day. The amount one should spend for $600/day value will depend upon the degree of risk he is willing to undertake. Not included in this figure is the worth of the drilling data for planning nor the capabilities of the personnel on location.

SUMMARY AND CONCLUSIONS

Following many months of research and development, a new well-site monitoring system has evolved. This well monitoring system performs many functions, including the collection of geological information, monitor and alarm, pore pressure prediction, and drilling optimization.

The new units utilize an on-site digital computer to perform the monitor, alarm, and computations functions. Use of the computer facilitates the application of advanced drilling technology at the well site for minimizing drilling costs. An improved technology of logging wells while drilling is evolving, and based upon sound engineering principles, will yield meaningful data for the prediction of pore pressure while drilling.

An economic analysis of these units has been presented. The value of the service to the operator was estimated based upon the value of individual capabilities. Results of a survey conducted to evaluate the cost of drilling trouble was discussed. From the data obtained, it was concluded

TABLE 4

DRILLING STATISTICS
U. S. & CANADA BY AREA

Area	Total Wells In Survey	Av. Depth of Wells	Total Days on Wells	Total Unscheduled Trouble Days	Average Days/Well	% Unscheduled Trouble Days	Av. Days /1000 ft. of Hole	Av. Days/1000 ft. Hole Adjusted for Unscheduled Trouble Days
Wells Drilled to 10,000 ft. or Less								
Gulf Coast East	61	8,270	909	148	14.9	16.3	1.80	1.51
Texas Gulf Coast Area	250	7,880	2,800	210	11.2	7.5	1.42	1.31
Mid-Continent Area	16	8,828	432	29	27.0	6.6	3.06	2.85
West Texas Area	11	7,691	392	22	35.6	5.6	4.63	4.37
Western Area	36	7,150	792	74	22.0	9.4	3.08	2.79
Canada	55	7,392	2,601	122	47.3	4.7	6.40	6.10
Sub Total	429	3,364,279*	7,926	605				
Averages		7,842			18.5	8.29	2.36	2.18
Wells Drilled to a TD of 10,000-15,000 ft.								
Gulf Coast East	102	12,280	3,559	534	34.9	15.0	2.84	2.42
Texas Gulf Coast Area	132	11,620	5,148	463	39.0	9.0	3.36	3.05
Mid-Continent Area	17	12,511	986	73	58.0	7.4	4.64	4.29
West Texas Area	22	12,122	917	104	41.7	11.3	3.44	3.05
Western Area	55	11,425	3,905	219	71.0	5.6	6.21	5.87
Canada	32	12,431	5,152	520	161.0	10.1	12.95	11.64
Sub Total	360	4,291,938*	19,667	1,913				
Averages		11,922			53.1	9.73	4.58	4.14
Wells Drilled to 15,000 ft. or Deeper								
Gulf Coast East	57	16,290	4,275	658	75.0	15.4	4.60	3.90
Texas Gulf Coast Area	42	16,403	3,183	395	75.8	12.4	4.62	4.05
Mid-Continent Area	17	18,722	3,247	575	191.0	17.7	10.20	8.40
West Texas Area	116	19,899	23,084	1,293	199.0	5.6	10.00	9.44
Western Area	20	16,050	2,680	300	134.0	11.2	8.35	7.41
Canada	8	15,930	2,640	251	330.0	9.5	20.72	18.75
Sub Total	260	4,692,454*	39,105	3,472				
Averages		18,048			150.4	8.88	8.33	7.59

* Total footage for depth category
Total well evaluated 1,049
Total footage evaluated 12,348,671
% unscheduled trouble days—all depths 8.98

Source—Drilling Fluid Records 1965-1971

that nearly 10 percent of all well-days are unscheduled trouble-days. The cost of this trouble was conservatively estimated as $800/day. The economic justification of these new units is a function of the unscheduled trouble-days anticipated. The units can be justified solely on the basis of optimization capabilities in extremely high-cost areas.

REFERENCES

1. Gray,G. R. and Young, F. S., Jr.: Drilling Fluids For Deep Wells In The United States in 8th World Petroleum Congress Pre-print Panel Discussion 7: "Problems, Techniques, and Possible Solutions in Drilling and Producing Very Deep Wells," Elsevier Publishing Co., London, 17 pp.
2. Wilson, R. W.: Mud Analysis Logging and Its Use in Formation Evaluation; *AIME Tech Paper* 587-G, Presented University of Houston, Oct. 1955.
3. Pixler, B. O.: Mud Analysis Logging *Jour. Petr. Tech.*, April 1961, pp. 323-326.
4. Pixler, B. O.: Formation Evaluation by Analysis of Hydrocarbon Ratios, *Jour. Petr. Tech* June 1969 pp. 665-670.
5. Gill, J. A.: Applied Drilling Technology, The Drilling Contractor, March-April 1968.
6. Young, F. S., Jr.: Computerized Drilling Control *Trans. AIME,* Vol. 246, 1969, pp 483-496.
7. Eckel, John R.: Effect of Pressure on Rock Drillability *Trans. AIME,* Vol. 213, 1958, pp. 1-6.
8. Vidrine, D. J. and Benit, E. J.: Field Verification of the Effect of Differential Pressure on Drilling Rate, *Jour. Petr. Tech.* July 1968 pp. 676-682.
9. Murray, A. S. and Cunningham, R. A.: Effect of Mud Column Pressure on Drilling Rates, *Jour. Petr. Tech.,* Vol. 7, No. 11, 1955 pp. 196-204.
10. Kennedy, John L.: Losing Control While Drilling: A 32-well Look At Causes and Results, *Oil & Gas Jour.* Sept. 20, 1971, pp. 121-128.
11. Hoffman, C. E. and Johnson, R. K.: Estimation of Formation Pressures From Log-Derived Shale Properties, *Trans. AIMIE,* Vol. 234, 1965 pp. 771-772.
12. Ham, H. H.: A Method of Estimating Formation Pressures From Gulf Coast Well Logs, *Trans. Gulf Coast Assoc. Geol. Soc.,* Vol. 16, pp. 185-197.
13. Jordan, J. R. and Shirley, O. J.: Application of Drilling Performance Data to Overpressure Detection, *Jour. Petr. Tech.,* Vol. 18, Nov. 1966, pp. 1387-94.
14. Combs, George D.: Prediction of Pore Pressure From Penetration Rate, SPE 2162, Presented at 39th Annual California Fall Meeting, Bakersfield, California, November 7-8, 1968.
15. Holmes, C. S. and Swift, S. C.: Calculation of Circulating Mud Temperatures, *Jour. Petr. Tech.,* June 1970 pp. 670-674.
16. Lewis, C. R. and Rose, S. C.: A Theory Relating High Temperatures and Overpressures, *Jour. Petr. Tech.* Jan. 1970, pp. 11-16.
17. Hebert, W. E. and Young, F. S.: Estimation of Formation Pressure With Regression Models of Drilling Data, *Jour. Petr. Tech.,* Jan. 1972 pp. 9-15.
18. Maurer, W. C.: The "Perfect-Cleaning Theory" of Rotary Drilling, *Jour. Petr. Tech.,* Nov. 1962 p 1270.
19. Speer, John W.: A Method For Determining Optimum Drilling Conditions, Paper No. 1242-G presented at SPE Drilling and Production Practices Symposium in Lafayette, La., April 24, 1959.
20. Galle, E. M. and Woods, H. B.: Variable Weight and Rotary Speed for Lowest Drilling Cost, 20th AAODC Meeting, New Orleans, La., Sept. 25-27, 1960.
21. Lummus, J. L.: Drilling Optimization, *Jour. Petr. Tech.* Nov. 1970 pp. 1379-1389.
22. Lummus, J. L.: Acquisition and Analysis of Data For Optimized Drilling, *Jour. Petr. Tech.* Nov. 1971, pp. 1285-1293.