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FULL-SCALE LABORATORY DRILLING TESTS ON SANDSTONE AND DOLOMITE—FINAL REPORT

By

Terra Tek, Inc.
Performed for DOE Under Contract No. EY-76-C-02-4098

Date Published—December 1977

Bartlesville Energy Research Center
Department of Energy
Bartlesville, Oklahoma

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FULL-SCALE LABORATORY DRILLING TESTS ON SANDSTONE AND DOLOMITE

FINAL REPORT

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Prepared for the Department of Energy
Under DOE Contract No. EY-76-C-02-4098

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FOREWORD

This report covers the work performed under DOE Contract No. EY-76-C-02-4098 (formerly E(34-1)-0038.

The contract was approved by the Division of Oil, Gas and Shale Technology, Mr. Hugh D. Guthrie, Director, and was funded by the Branch of Drilling, Exploration and Offshore Technology, Mr. Don Guier, Branch Chief. The work was supervsied by the Bartlesville Energy Research Center, Mr. John S. Ball, Director.

The contract resulted from an unsolicited proposal from Terra Tek, Inc., dated July 1975, which was entitled, "Optimization of Deep Drilling Parameters." Both the proposal and the contract anticipated simulating depths below 20,000 feet with the deepest simulated depth being controlled by a borehole pressure of 15,000 psi; however, the maximum simulated depth was 13,000 feet because of equipment limitations and inadequate funds.

DOE's objective in funding the contract was to obtain drilling information which might prove useful to the petroleum industry in improving efficiency while drilling deep wells. The work was successfully performed on dolomite and sandstone rocks. The data show why the penetration rates become slower at depth.

Although this report completes the existing contract, it is anticipated that additional work will be performed in the future to simulate depths below 20,000 feet for both roller cone bits and diamond bits. Additional efforts will also be made to obtain shale samples and determine its drilling characteristics.

C. Ray Williams
Technical Project Officer
Bartlesville Energy Research Center

ABSTRACT

Full-scale laboratory drilling experiments were performed under simulated downhole conditions to determine what effect changing various drilling parameters has on penetration rate. The two rock types, typical of deep oil and gas reservoirs, used for the tests were Colton Sandstone and Bonne Terre Dolomite. Drilling was performed with standard 7 7/8 inch rotary insert bits and water base mud. Variations in drilling parameters are as follows:

Weight on Bit	5,000-40,000 pounds
Rotary Speed	40-100 RPM
Mud Flow	80-220 gpm
Mud Pressure	100-5,000 psi
Confining Pressure on Rock	0-9,000 psi

Penetration rates from about three feet per hour to about 90 feet per hour were obtained.

The results showed the penetration rate to be strongly dependent on bit weight, rotary speed and borehole mud pressure. There was only a small dependence on mud flow rate. The drilling rate decreased rapidly with increasing borehole mud pressure for borehole pressures up to about 2,000 psi. Above this pressure, the borehole pressure and rotary speeds had a smaller effect on penetration rate. The penetration rate was then dependent mostly on the bit weight. Penetration rate per horsepower input was also shown to decrease at higher mud pressures and bit weights.

The ratio of horizontal confining stress to axial overburden stress was maintained at 0.7 for simulated overburden stresses between 0 and 12,800 psi. For this simulated downhole stress state, the undrilled rock sample was within the elastic response range and the confining pressures were found to have only a small or negligible effect on the penetration rate. Visual examination of the bottomhole pattern of the rocks after simulated downhole drilling, however, revealed ductile chipping of the Sandstone, but more brittle behavior in the Dolomite.

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INTRODUCTION

This report summarizes the results of full-scale laboratory drilling of rock types typically found in deep oil and gas reservoirs in the United States. The need for full-scale drilling, as opposed to small scale tests, is generally recognized because of the complex phenomena involved when bits cut into rock. At deep hole drilling conditions where rock plasticity and hydraulic hold-down of cuttings impede chip removal, the need for full-scale drilling is even more apparent. In a study by J.B. Cheatham (Appendix A), it is pointed out that actual drilling rates fall below theoretically achievable rates and that a study of the kinematics of drilling is needed to utilize the fundamental knowledge to achieve faster drilling.

The object of the work reported here was to determine the effects of changing various drilling parameters on the drilling rate while drilling at simulated depths. To accomplish this objective, a study was first performed to identify rock types typical of deep oil and gas reservoirs in the United States. This study, given in Appendix B, identified four rock types typical of deep oil and gas reservoirs. These were sandstone, shale, dolomite and limestone. Samples of Colton Sandstone, Mancos Shale and Bonne Terre Dolomite were selected as representative of the rock types encountered in oil and gas reservoirs and then obtained from surface outcrops. The shale samples proved to be unusable, so the study was conducted with drilling data obtained only from the Colton Sandstone and Bonne Terre Dolomite.

The drilling tests were performed at the Drilling Research Laboratory in Salt Lake City, Utah. The large drill rig and wellbore simulator were used so that full-scale simulation of bit size and downhole pressure could be achieved. A description of the facility is given in Appendix C. The rock samples drilled under pressure were 13.5 inches in diameter and approximately three feet long. This sample size allowed drilling with a standard 7 7/8 inch insert roller bit without the sample failing under the applied pressure.

This work, done under contract to ERDA, required effort to get the equipment operational in order to obtain the specified test conditions, as well as acquiring the test data. Although the data obtained forms an important base of information, it is also recognized that continuation of this type of work is needed to obtain a more complete body of data.

ROCK SELECTION

From the rock selection study (Appendix B), it was decided that the rock types representing a large percentage of the drilling found in the deep reservoirs consisted of shales, sandstones, limestones and dolomites. Based on the physical and mechanical properties typical to these rock types, a list of candidate rocks was compiled (Table VII in Appendix B). For the full-scale drilling tests there was an additional constraint that the rock samples be obtained in large sizes and from quarries or other locations free from surface weathering. From the candidate list the Colton Sandstone, Bonne Terre Dolomite and Mancos Shale satisfied both the requirements to be representative of the deep oil and gas wells and samples were available in large sizes.

The Colton Sandstone was selected from the stock of building stone at Hansen Stone Quarries, Sandy, Utah. Blocks approximately three feet by three feet by five feet were selected by visual inspection to be as homogeneous as possible. The Bonne Terre Dolomite was obtained from Valley Mineral Products Company, Bonne Terre, Missouri, and was also received in building stone blocks approximately three feet by three feet by five feet by visual inspection to be as uniform as possible. The Mancos Shale was obtained from a home construction site near Price, Utah, where an excavation was being made in the shale. At this excavation site, sample points were identified where large irregular samples were broken loose specifically for this study.

ROCK PROPERTIES

The mechanical and physical properties of the blocks of rock received for the drilling tests were determined on small (3/4 inch diameter by 2 inch long) samples cut from the blocks. These small samples were tested in the Rock Mechanics Laboratory at Terra Tek. Table 1 summarizes the test results. Note that the properties measured by Terra Tek are reasonably close to the typical values, where properties are are available, used for the rock selection (Table VII in Appendix B).

Triaxial compression tests at three different confining pressures were also done at Terra Tek to define the volume strain relationships and the failure points. In these tests the samples were gaged so the axial and radial strains in the sample could be measured as the pressures were applied. The axial pressure and confining pressure were independently controlled so the desired stress difference between the two pressures could be obtained. To perform the triaxial test the sample is first loaded along the hydrostatic path (where the axial and confining pressure are equal) until the specified confining pressure is reached. From this point, the confining pressure is held constant and the axial pressure is increased until the sample fails. This test determines the compressibility of the rock and manner of failure (failure envelope) resulting from large differential stresses.

The data obtained from the triaxial compression of the sandstone and dolomite are shown in Figures 1 through 5. The axial and transverse strains in these figures are used to obtain the volume change curves

TABLE 1

MECHANICAL AND PHYSICAL PROPERTIES OF TEST ROCK

	COLTON SANDSTONE	BONNE TERRE DOLOMITE	MANCOS SHALE
TOTAL POROSITY (% of Total Volume)	10.9%	8.4%	7.9%
AIR VOIDS (% of Total Volume)	8.4%	8.1%	4.7%
INITIAL SATURATION (% of Pore Volume)	18.4%	4.8%	41%
DENSITY (As Received)	2.38 gm/cm^3	2.66 gm/cm^3	
DRY DENSITY (Sample Dried 24 hrs @ 105°C)	2.35 gm/cm^3	2.656 gm/cm^3	2.52 gm/cm^3
GRAIN DENSITY	2.65 gm/cm^3	2.90 gm/cm^3	2.70 gm/cm^3
PERMEABILITY (With P_{conf} @ 5,000 psi)	40×10^{-6} darcies	47×10^{-9} darcies	
UNCONFINED COMPRESSIVE STRENGTH	7,600 psi	25,500 psi	
COMPRESSIONAL WAVE VELOCITY	2880 M/Sec	6510 M/Sec	
SHEAR WAVE VELOCITY	1960 M/Sec	3590 M/Sec	
APPARENT YOUNG'S MODULI	2.8×10^6 psi	12.7×10^6 psi	

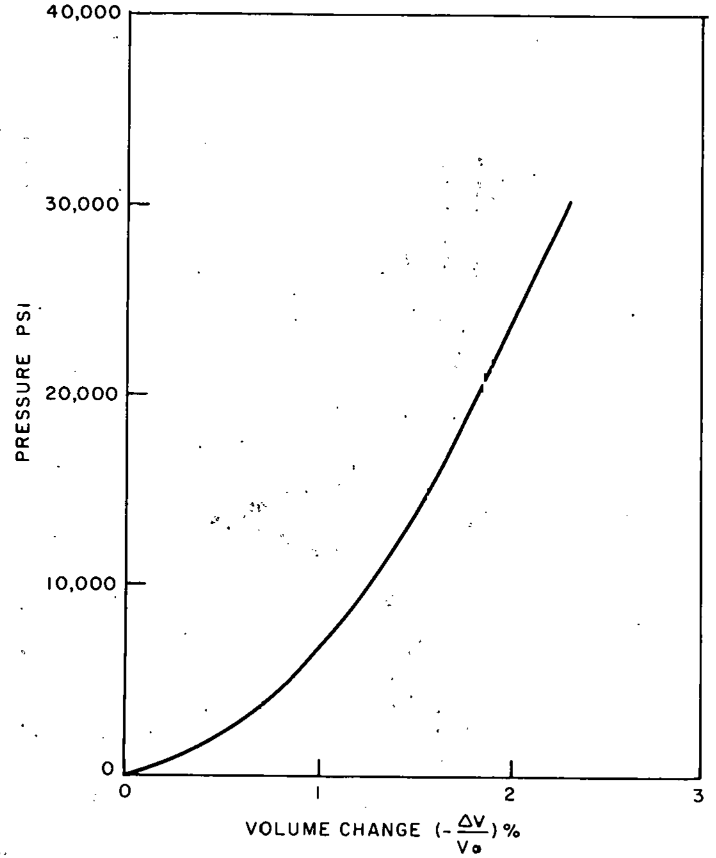

FIGURE 1

Hydrostatic Compression of
Dry Colton Sandstone

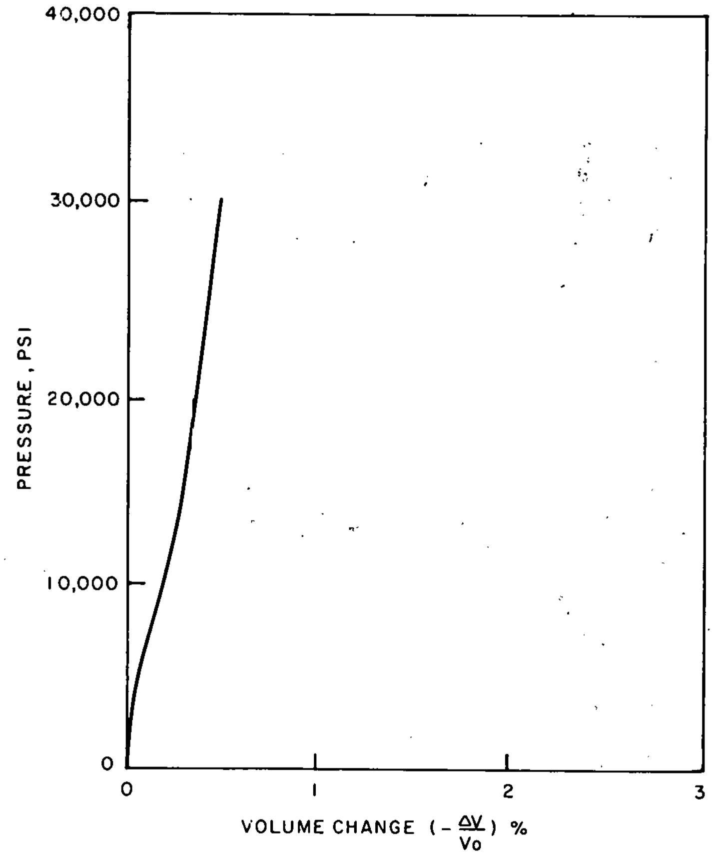

FIGURE 2

Hydrostatic Compression of
Dry Bonne Terre Dolomite

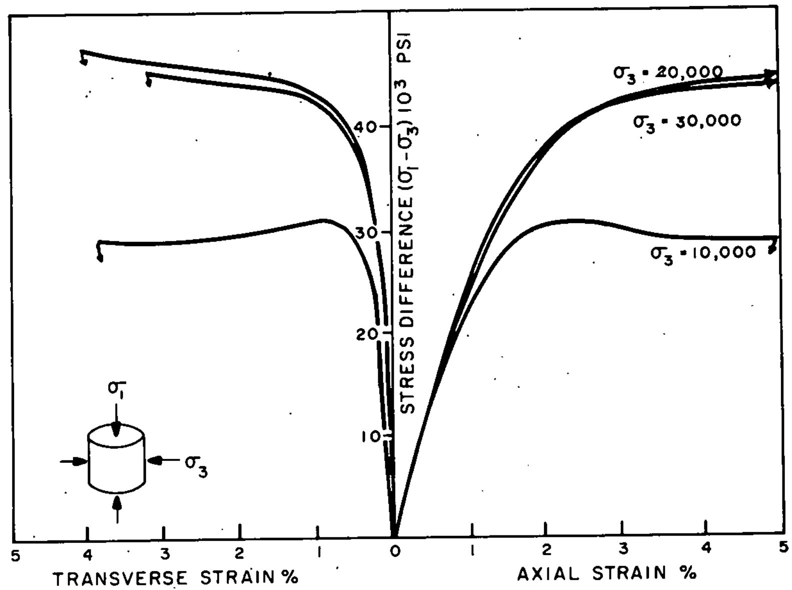

FIGURE 3

Shortening Strain Under Confining Pressure for Colton Sandstone without Pore Pressure

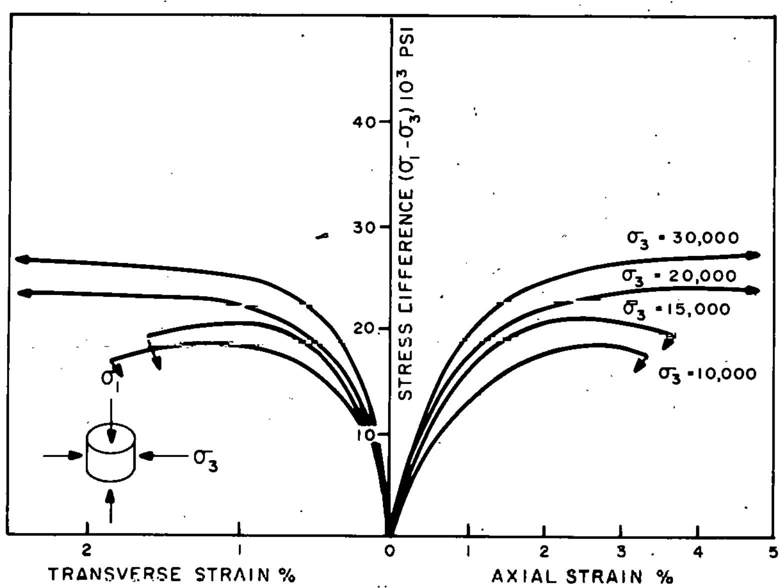

FIGURE 4

Shortening Strain Under Confining Pressure for Colton Sandstone with Pore Pressure ($P_{pore}=\sigma_3/2$)

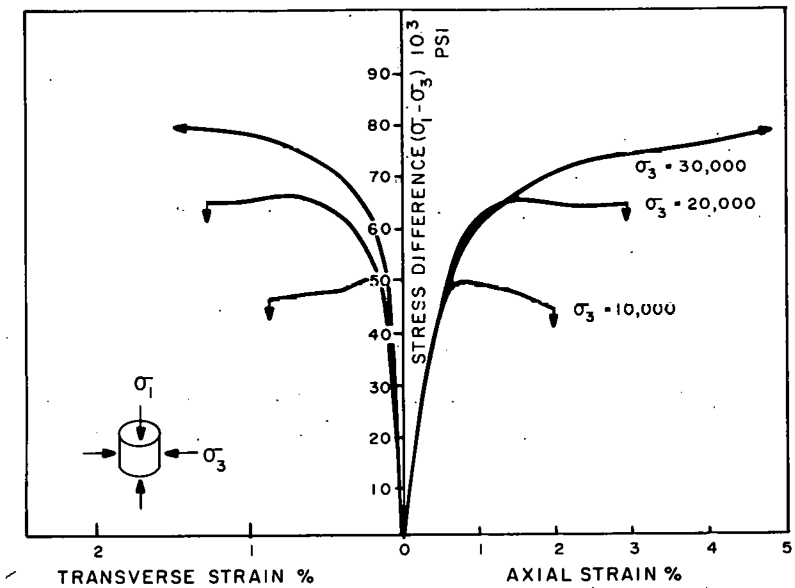

FIGURE 5

Shortening Strain Under Confining Pressure for Bonne Terre Dolomite without Pore Pressure shown in Figures 6-8 and the Failure Envelope curve in Figure 9.

Also shown on Figures 6-9 are the stress states, or range of stress states, which the samples where placed under in the solid sample ahead of the drill bit. It is thus apparent that the undrilled rock is in its elastic response region. The stress state in the annular rock ring left after the center is drilled out is under a larger stress difference state, but the stress in this region of the sample is only of interest in relation to maintaining sample integrity during the drilling tests.

An attempt was made to saturate the samples with water so that pore pressure could be controlled during the tests, but after soaking the sandstone samples for nearly a month in water, a limiting saturation of only 60% was reached. With this partial saturation, the time required to equalize fluid pore pressure throughout the sample was much too long for pore pressure control during drilling. The long time arises since fluid must flow through the extremely low permeability of the rock matrix to compress the gas trapped in the matrix. After one experimental test where it was verified that pore pressure could not be achieved in reasonable time limits, no further attempt was made to control pore pressures during the drilling tests.

To check the uniformity of the large samples, several holes were drilled through the blocks at constant drilling parameters. Figure 10 shows the penetrated rate as a function of the penetrated depth in the sample for the Shale; Figure 11 shows a similar plot for Sandstone. Because of the highly variable penetration rate in the shale, which reflected the non-

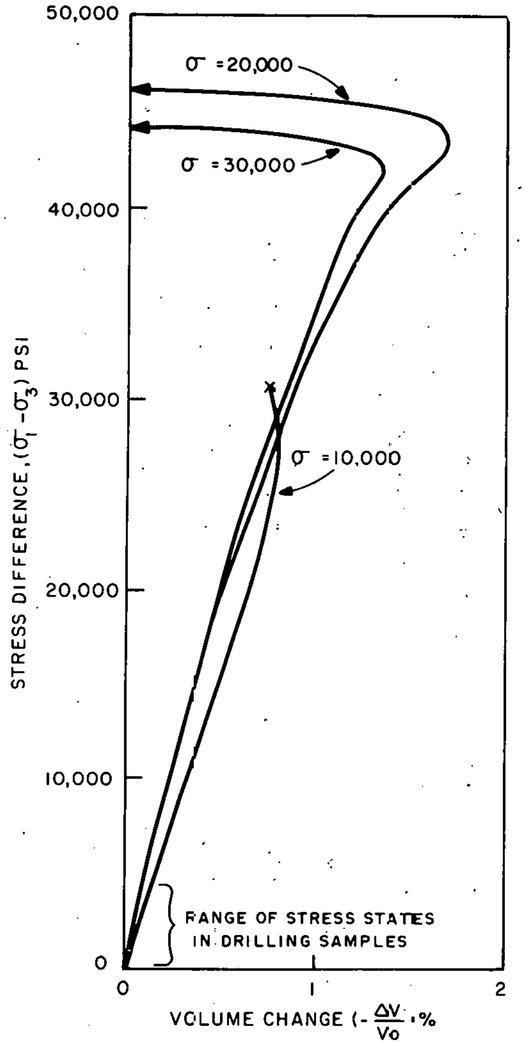

FIGURE 6

Incremental Volume Strain for Triaxial Compression under Confining Pressure for Colton Sandstone without Pore Pressure

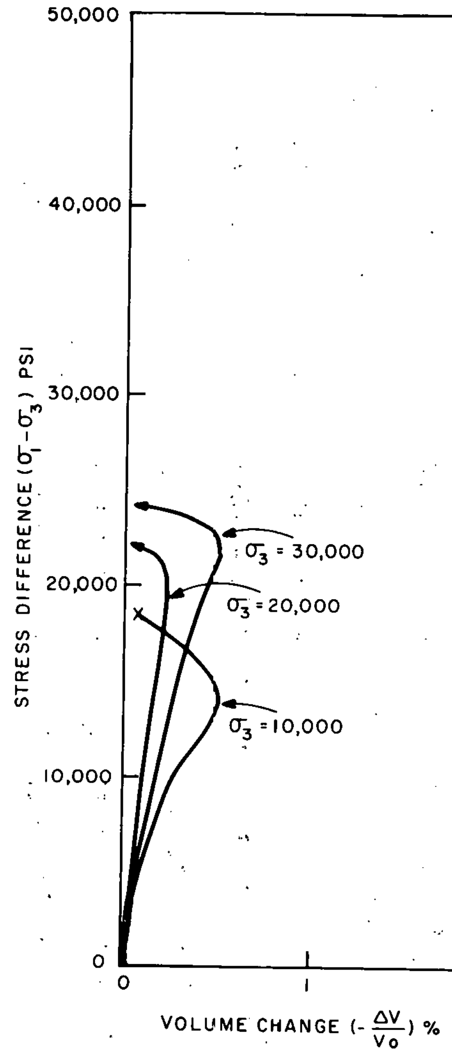

FIGURE 7

Incremental Volume Strain for Triaxial Compression under Confining Pressure for Colton Sandstone with Pore Pressure ($P_{pore}=\sigma_3/2$)

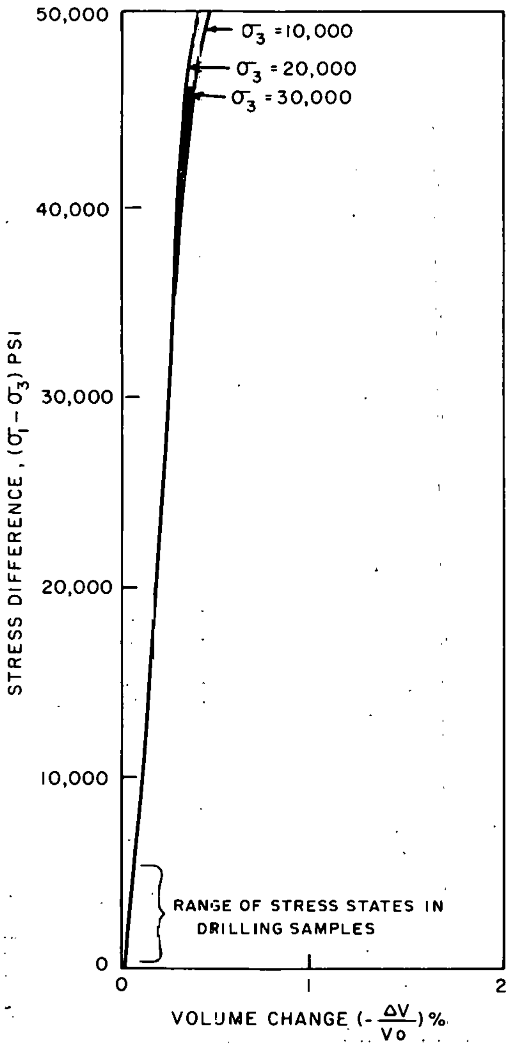

FIGURE 8

Incremental Volume Strain for Triaxial Compression under Confining Pressure for Bonne Terre Dolomite without Pore Pressure

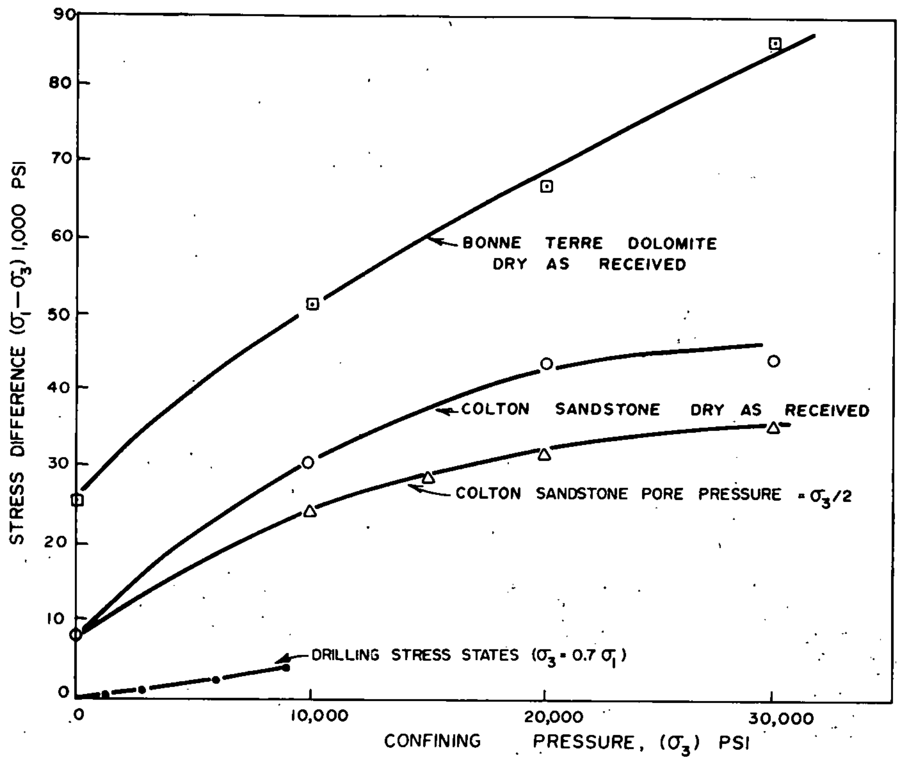

FIGURE 9

Failure Envelopes for Colton Sandstone and Bonne Terre Dolomite

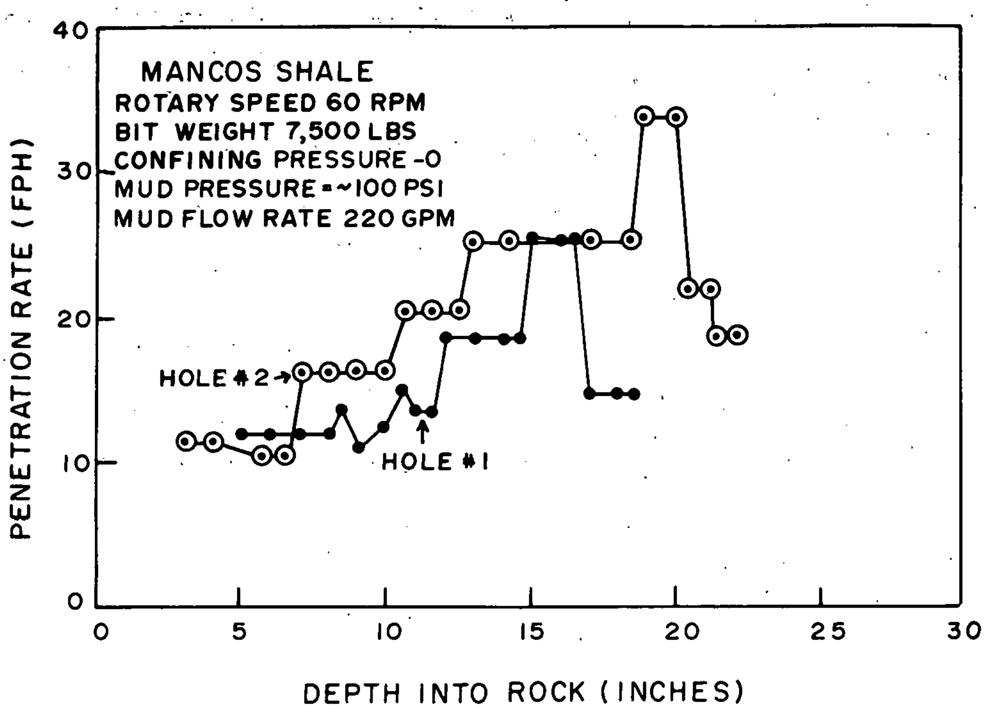

FIGURE 10
Uniformity Test of Mancos Shale. Entire Hole Drilled with Constant Drilling Parameters

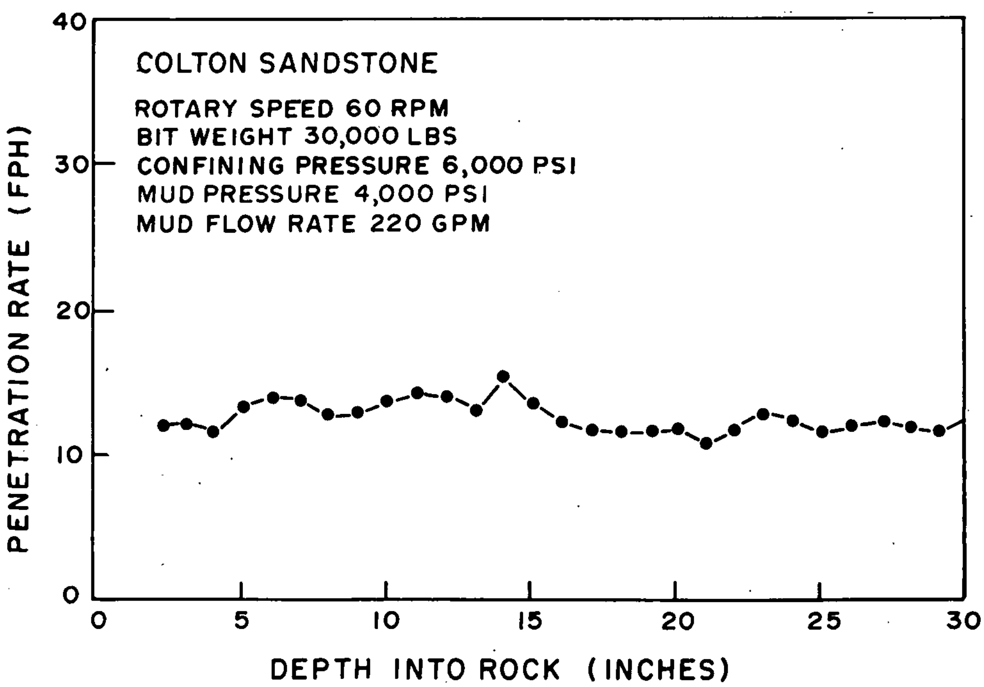

FIGURE 11

Uniformity Test of Colton Sandstone. Entire Hole Drilled with Constant Drilling Parameters uniformity of the sample, it was decided to delete this shale sample from the test program. Funding limitations precluded obtaining further shale samples, so after consultation and direction by the ERDA Contract Coordinator, the program was continued without doing drilling tests in shale. Similar atmospheric drilling tests for uniformity in the dolomite samples showed it to be reasonably uniform, except for occasional vugs or defects. The dolomite was used, but if a defect was encountered during the drilling tests as evidenced by a sudden jump in drill rates, that data was deleted from the reported results.

DRILL BIT AND MUD SELECTION

The bits used were selected on the basis of recommendations solicited from the major bit manufacturers. The recommendations were obtained by first holding a meeting where the bit manufacturers were invited to learn about the program. The attending manufacturers were requested to make recommendations as to which bits should be used along with any other comments they might have on the program. Recommendations and comments were received from Reed Tool Company, Smith Tool Company, Hughes Tool Company, Dresser Industries (Security Division), and Christensen, Inc. A collection of the correspondence pertaining to the meeting and the subsequent replies is given in Appendix D. The recommendations were reasonably consistent and three manufacturers furnished bits at no charge for use in the drilling program. Based on a comparative analysis of the recommendations, the following bit types were selected for the program.

MANUFACTURER	TYPE*	RECOMMENDED FOR
Smith Tool	F3	Sandstone or Shale
Reed Tool	FP52	Sandstone or Shale
Security	M89TF	Sandstone or Dolomite

* Manufacturers specifications for these bits are tabulated in Appendix D.

The bit size selected, also based on the recommendations, was 7 7/8 inches. This size is very popular for the drilling of oil and gas wells for which this drilling program is simulating. Also, most experimental bits are made in this size and the results of this program will be directly comparable to much of the current research being done in the industry. The goal of this project was to study the drilling rates with currently available bits, consequently no experimental bits or bits not available from normal purchasing were considered.

The drilling fluid selected was to be typical of the fluid used in drilling oil and gas wells. Since muds are commonly used for well stability and pressure control, mud was selected for this program. A waterbase, weighted mud was selected to be representative of typical drilling. Table 2 tabulates the constituants and basic properties of the mud. Percentage compositions of the solids are not given since they changed throughout the drilling as drill solids accumulated and small additions of the other constituants were made from time to time to keep the weight, viscosity and gel properties reasonably constant throughout the test. The same mud was used for both the atmospheric drilling and the pressure drilling.

TABLE 2

MUD PROPERTIES

BASE: Water

PHASES: (i) Water
(ii) Solids
(a) Bentonite
(b) Barite
(c) Drill Solids

WEIGHT: 9.3 pounds/gallon

APPARENT VISCOSITY: 12 cp

PLASTIC VISCOSITY: 7 cp

YIELD POINT: 10 pounds/100 square feet

INITIAL GEL: 5 pounds/100 square feet

10 MINUTE GEL STRENGTH: 14 pounds/100 square feet

pH: 7.85

API FILTRATE: 14.2 cc/30 minutes

EXPERIMENTAL METHOD

The tests were performed with the Drilling Research Laboratory drill rig. For atmospheric conditions, the drill rig was positioned over rock blocks placed in the drilling pit. Samples to be drilled under simulated downhole conditions were first cored from the large quarried blocks with a 13 5/8 inch thin-walled core drill and then fitted with a urethane jacket and steel end caps prior to placement in the pressure vessel.

To simulate downhole stress conditions, the overburden, or vertical stress gradient was assumed to be 1.0 psi per foot and the horizontal stress was assumed to be 70% of the vertical stress. These are typical values, for normally pressured reservoirs, although local conditions in specific wells may be somewhat different. For the laboratory tests, the pore pressure was essentially zero.

One of the critical aspects of the experimental procedure was to determine what combinations of confining pressure, axial pressure, and borehole pressures could be exerted on the rock specimens to both simulate downhole conditions and not cause the specimen to fail. To accomplish this, a model predicting specimen failure was developed (Appendix E) and used as a guide in specifying the test conditions. The final selection of the operating conditions and the test matrix was made under the direction of the ERDA contract coordinator. The various parameters were chosen to be typical of actual field conditions and to provide a basic set of data. In the selection of conditions, some emphasis was placed on mud pressure in addition to rotary speed and thrust (weight) on the bit.

The actual drilling of the samples was done using the servocontrolled equipment so that the drilling conditions could be rapidly changed and then held constant. With this arrangement, it was possible to obtain many data points on each three foot long specimen. Changing from one set of conditions would then take only a few minutes. During these stabilized drilling periods, the computerized data acquisition program would be invoked to gather a set of digitized data in addition to the continuous strip chart record being made throughout the test. Some of the data reduction and analysis was done with the digitized data and computer programs.

EXPERIMENTAL DATA AND RESULTS

The experimental data obtained is tabulated in Tables 3 and 4. Actually, considerably more drilling was done than is reported in Tables 3 and 4, but lack of homogeneity in some of the test samples, particularly the dolomite, and some operational problems resulted in some bad tests or unreliable data. The questionable results were thus omitted from the reported results.

For the Colton Sandstone tests, the penetration rate as a function of rotary speed, weight on bit, borehole mud pressure, mud flow rate, confining pressure and overburden pressure is shown in Figures 12 to 18. The data were generally fit to a power curve ($y = ax^b$) for these plots. From these curves, it is readily apparent that the penetration rate is highly dependent on rotary speed, weight on the bit and borehole mud pressure. Mud flow rate had a small influence whereas confining pressure and axial pressure had an apparent negligible effect. These results are in accord with expectations based on drilling theory.

The borehole mud pressure was particularly significant in controlling the drilling rate. As the mud pressure was raised, the drilling rate dropped rapidly until the pressure reached about 2,000 psi. At borehole mud pressure above this value, the increased pressure had a small effect. Evidently, the chip hold-down and imperfect cleaning effects resulting from the differential between the mud and pore pressures tended to reach a critical level. Once this critical level was reached, the drilling rate was then dependent primarily on bit weight. Neither rotary

TABLE 3
EXPERIMENTAL DATA FOR COLTON SANDSTONE

BIT	CONFINING PRESSURE (psi)	AXIAL PRESSURE (psi)	MUD PRESSURE (psi)	MUD FLOW (gpm)	ROTARY SPEED (rpm)	BIT WEIGHT (1000 lbs)	DRILLING RATE (ft/hr)	TORQUE (ft. lbs)
SMITH F-3 7 7/8 Inch w/3- 11/32 Nozzles	Atmos.	Atmos.	100	220	40	5	6.1	400
						10	20.6	830
						15	30.1	1320
						20	36.4	1950
						25	47.0	- -
						30	57.5	- -
						35	64.5	- -
					60	5	8.0	400
						10	23.8	800
						15	41.0	1200
						20	53.0	1800
						25	70.0	- -
						30	77.5	- -
					80	5	12.0	350
						10	30.5	730
						15	52.0	1070
						20	75.5	1380
					100	5	14.1	230
						10	37.3	580
						15	65.0	960
						20	93.5	1240
	1500	σ_1 = 2140	275	220	60	10	7.7	440
						20	22.2	1000
						30	31.8	1600
						40	44.9	- -
			500	220	60	10	7.4	420
						20	15.8	1000
						30	27.4	1700
						40	35.4	2200
			1000	220	60	10	5.3	400
						20	9.9	940
						30	16.9	1600
						40	21.3	2100
	3000	σ_1 = 4285	1000	220	60	10	4.8	400
						20	9.2	880
						30	17.6	1440
						40	22.6	2040
			2000	220	40	10	3.4	400
						20	6.5	900
						30	9.0	1480
						40	17.8	2280
					60	10	3.9	380
						20	7.8	840
						30	10.4	1400
						40	14.6	2000
					80	5	5.4	200
						10	9.0	400
						20	11.5	880
						30	19.0	1460

Table 3 Continued

BIT	CONFINING PRESSURE (psi)	AXIAL PRESSURE (psi)	MUD PRESSURE (psi)	MUD FLOW (gpm)	ROTARY SPEED (rpm)	BIT WEIGHT (1000 lbs)	DRILLING RATE (ft/hr)	TORQUE (ft. lbs.)
SMITH F-3 7 7/8 Inch w/3-11/32 Nozzles	3000	σ_1 = 4285	2000	220	80	40	27.4	2160
					100	5	5.8	200
						10	7.6	400
						20	14.1	880
						30	20.5	1400
						40	28.0	2000
				80	60	10	7.1	400
						20	9.9	950
						30	11.6	1500
						40	16.9	2150
				150	60	10	4.8	440
						20	9.1	950
						30	13.8	1560
						40	17.8	2200
				220	60	10	7.9	400
						20	11.1	840
						30	13.8	1500
						40	20.2	2100
		σ_1 = 3330	2000	220	60	20	9.8	900
						40	21.6	2150
		σ_1 = 4000	2000	220	60	20	11.8	1000
						40	22.0	2200
		σ_1 = 4660	2000	220	60	20	9.7	940
						40	19.8	2150
	6000	σ_1 = 8570	2000	220	60	5	3.2	200
						10	3.6	400
						10	4.8	400
						20	11.0	840
						20	7.8	1000
						30	12.8	1600
						30	14.6	1500
						40	22.7	2200
						40	21.7	2200
			4000	220	40	5	3.2	230
						5	2.7	--
						5	3.6	240
						10	5.1	400
						10	5.2	480
						15	4.8	650
						20	6.1	900
						20	8.0	960
						30	11.2	1440
						40	13.8	2000
					60	5	3.0	200
						5	4.0	--
						10	4.7	--
						10	4.6	400
						20	7.1	800
						20	9.0	--
						30	10.6	1400
						30	12.8	--
						30	12.5	1600

Table 3 Continued

BIT	CONFINING PRESSURE (psi)	AXIAL PRESSURE (psi)	MUD PRESSURE (psi)	MUD FLOW (gpm)	ROTARY SPEED (rpm)	BIT WEIGHT (1000 lbs)	DRILLING RATE (ft/hr)	TORQUE (ft lbs)
SMITH F-3 7 7/8 Inch	6000	σ_1 =8570	4000	220	60	40	13.8	2000
					100	5	3.5	200
						10	5.1	400
						20	8.6	820
						30	12.7	1360
						40	17.8	1900
	9000	σ_1=12860	4000	220	60	10	4.6	400
						20	9.6	800
						30	11.4	1500
						40	18.7	2100
			5000	220	60	10	9.2	480
						20	10.7	1000
						30	12.9	1550

TABLE 4

EXPERIMENTAL DATA FOR BONNE TERRE DOLOMITE

BIT	CONFINING PRESSURE (psi)	AXIAL PRESSURE (psi)	MUD PRESSURE (psi)	MUD FLOW (gpm)	ROTARY SPEED (rpm)	BIT WEIGHT (1000 lbs)	DRILLING RATE (ft/hr)	TORQUE (ft lbs)
SECURITY M89TF 7 7/8 Inch w/3 - 11/32 Inch Nozzles	Atmos.	Atmos.	50	220	40	5	3.8	90
						10	12.6	320
						20	33.4	800
					60	5	4.2	70
						10	14.2	260
					80	5	6.4	70
						10	20.7	260
					100	5	8.4	70
						10	26.6	260
	3000	σ_1 = 4285	1000	220	60	10	16.0	360
						20	41.1	800
						30	67.5	1200
			1500	220	60	5	5.3	100
						10	13.8	300
						20	33.0	750
						30	58.3	1220
						40	82.5	1800
			2100	220	60	5	3.9	100
						10	8.9	310
						20	27.0	780
						29	54.7	1200
						38	70.5	1800
	6000	σ_1 = 8570	4100	220	40	5	4.8	220
						5	4.7	260
						10	10.1	400
						10	10.4	500
						20	24.5	940
						20	25.1	1100
						30	37.8	1490
					60	5	6.6	--
						5	6.9	300
						5	6.6	310
						10	14.6	--
						10	14	430
						10	13.5	430
						20	34.2	1020
						20	34.0	900
						28	54.6	1430
						28	53.6	1540
					80	5	7.4	100
						10	17.2	390
						20	37.8	820
						26	52.3	1220
					100	5	7.0	180
						10	16.4	440
						21	50.3	600
						26	59.0	880

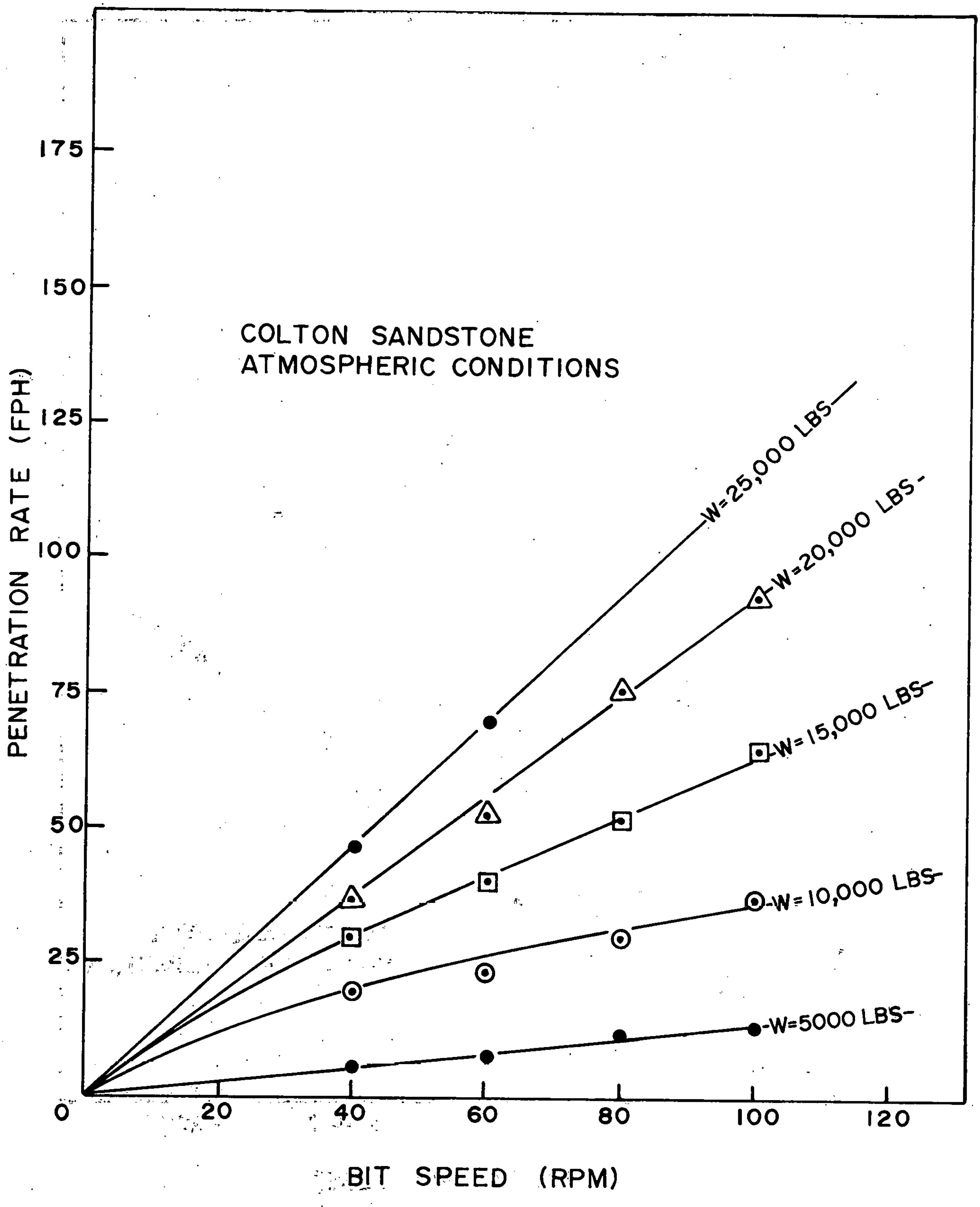

FIGURE 12

Penetration Rate versus Bit Weight and Rotary Speed for Colton Sandstone at Atmospheric Conditions

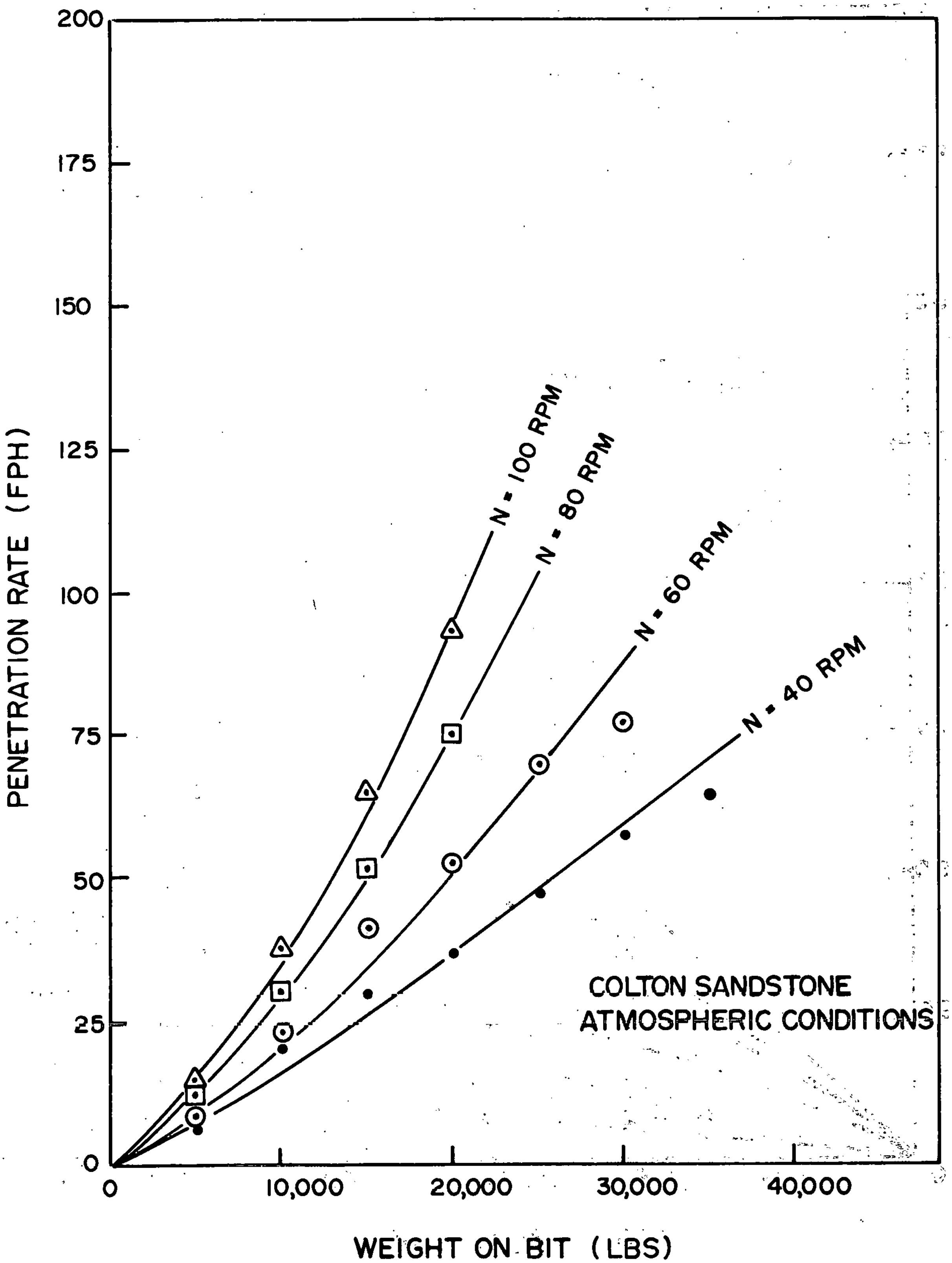

FIGURE 13

Penetration Rate versus Bit Weight and Rotary Speed for Colton Sandstone at Atmospheric Conditions

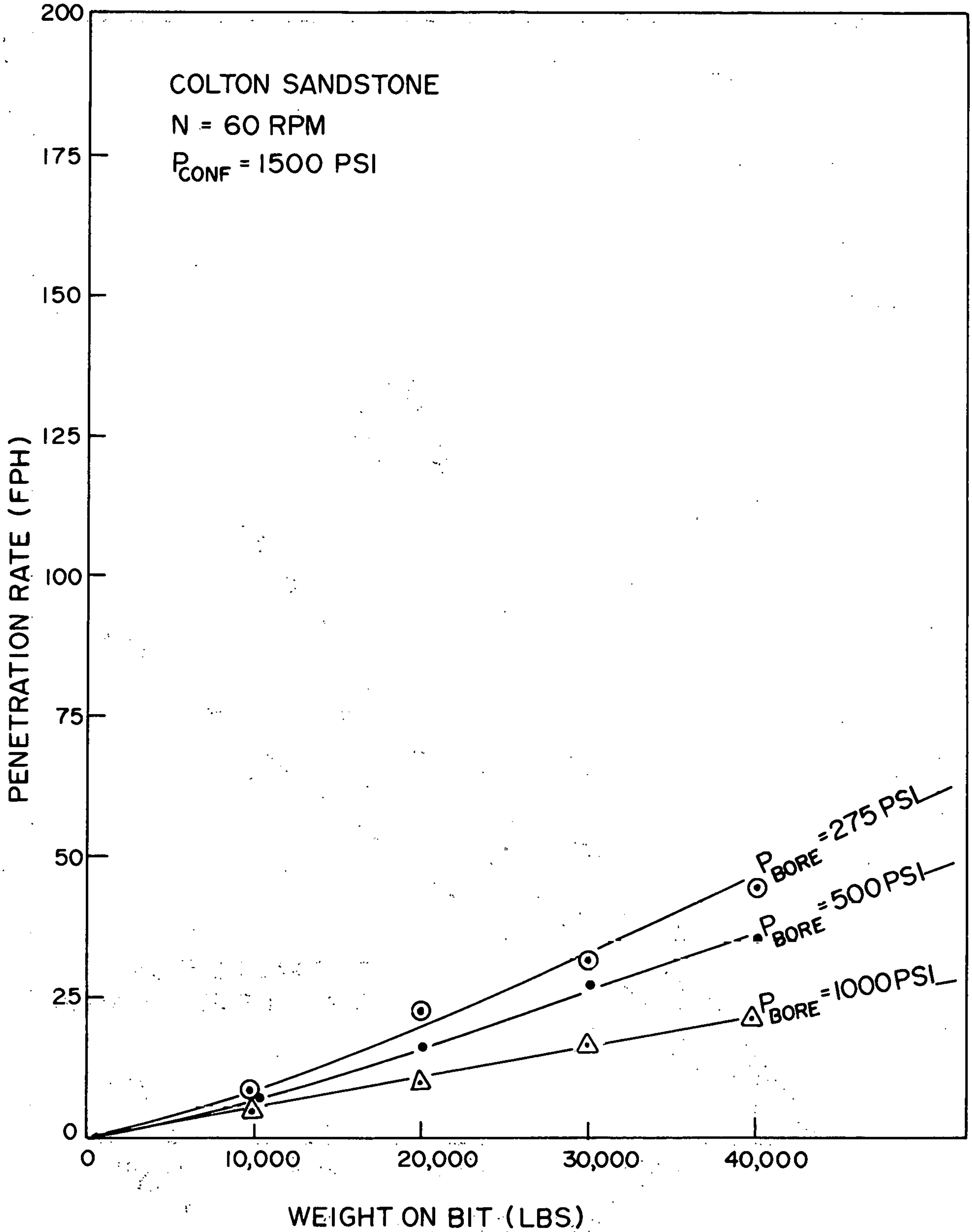

FIGURE 14

Penetration Rate Versus Bit Weight and Mud Pressure for Colton Sandstone at Confining Pressure of 1,500 psi and Rotary Speed of 60 RPM

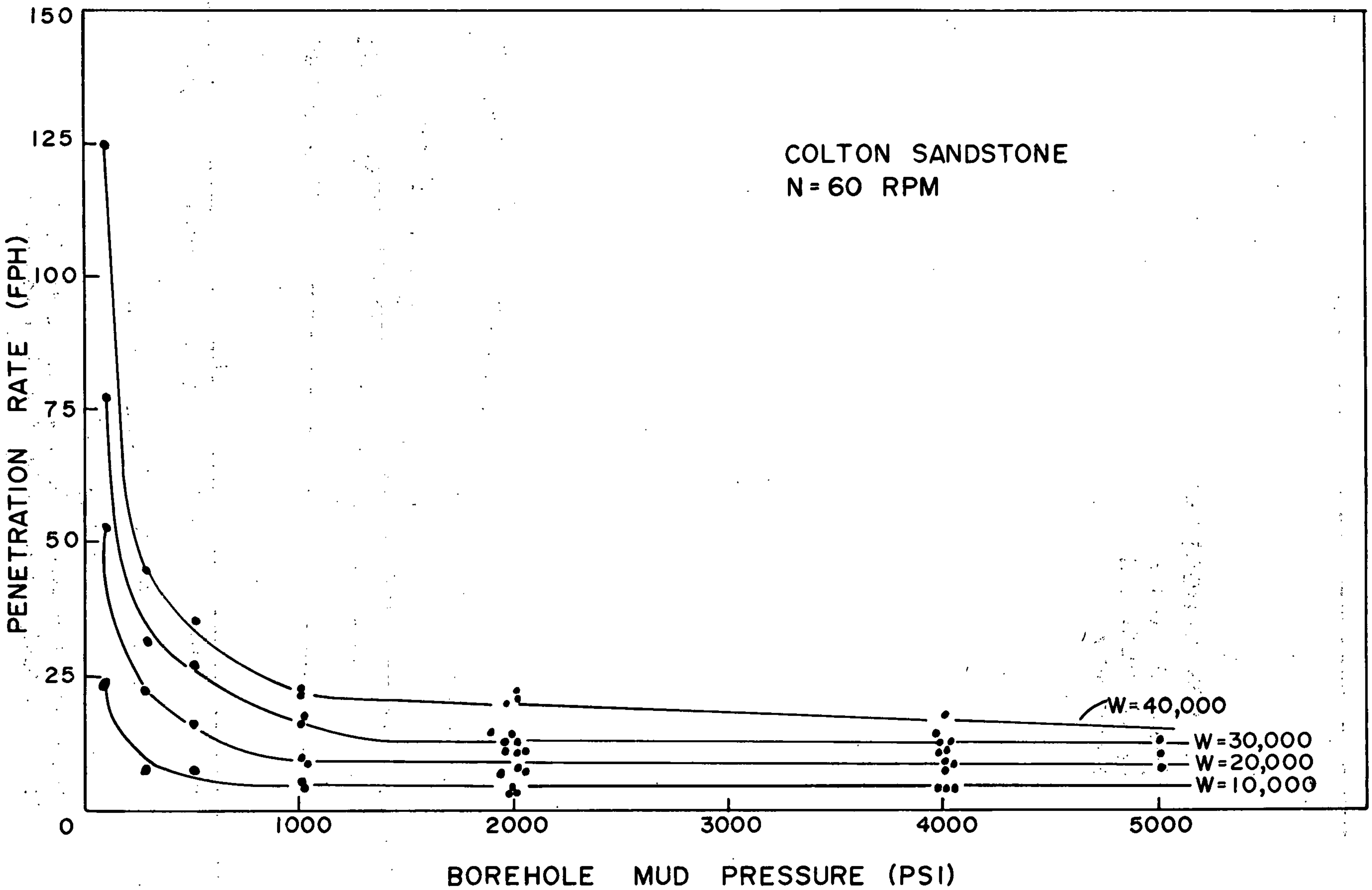

FIGURE 15

Penetration Rate Versus Mud Pressure and Bit Weight for Colton Sandstone at Simulated Downhole Conditions

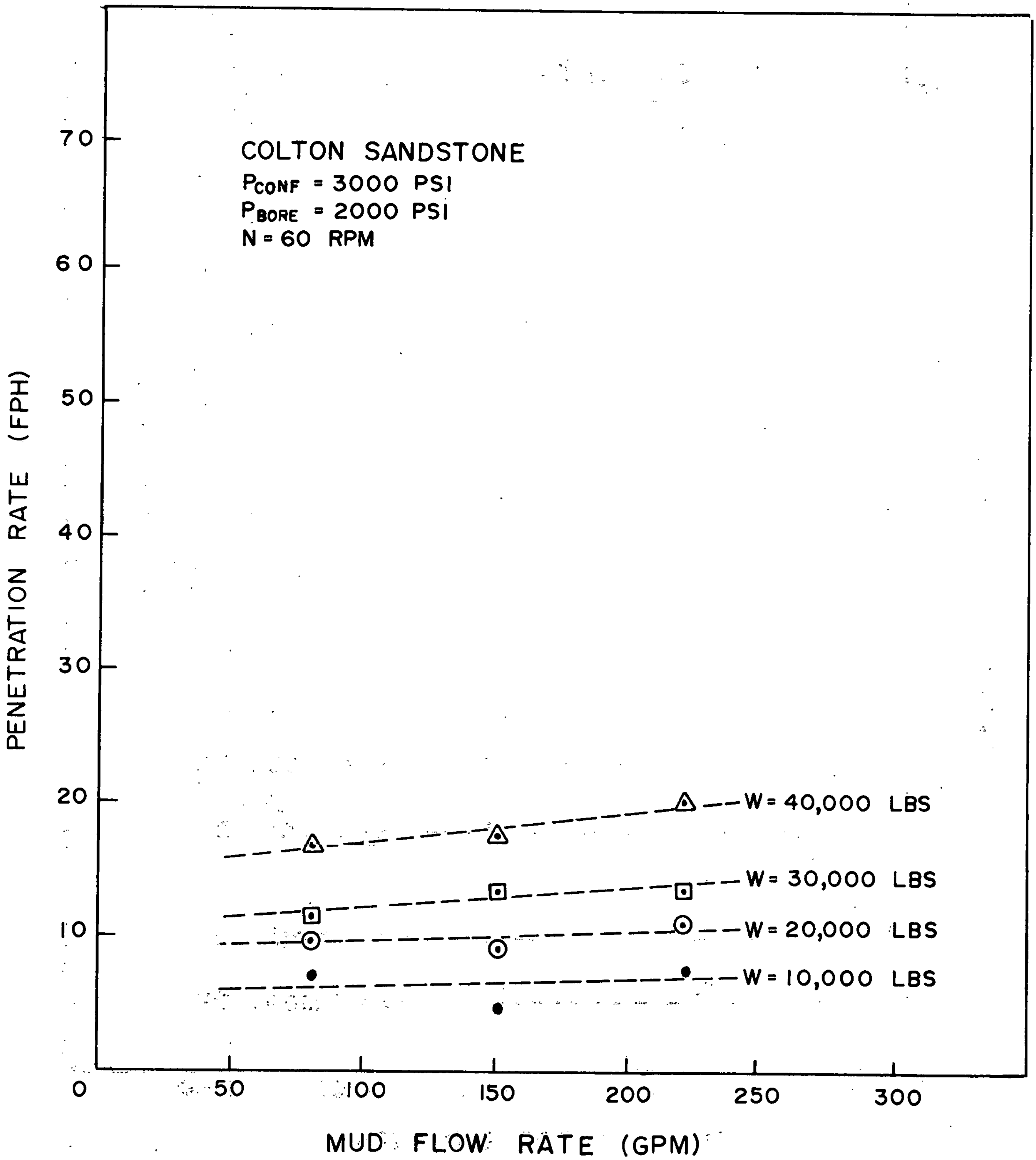

FIGURE 16

Penetration Rate versus Mud Flow Rate and Bit Weight for Colton Sandstone at Simulated Downhole Conditions

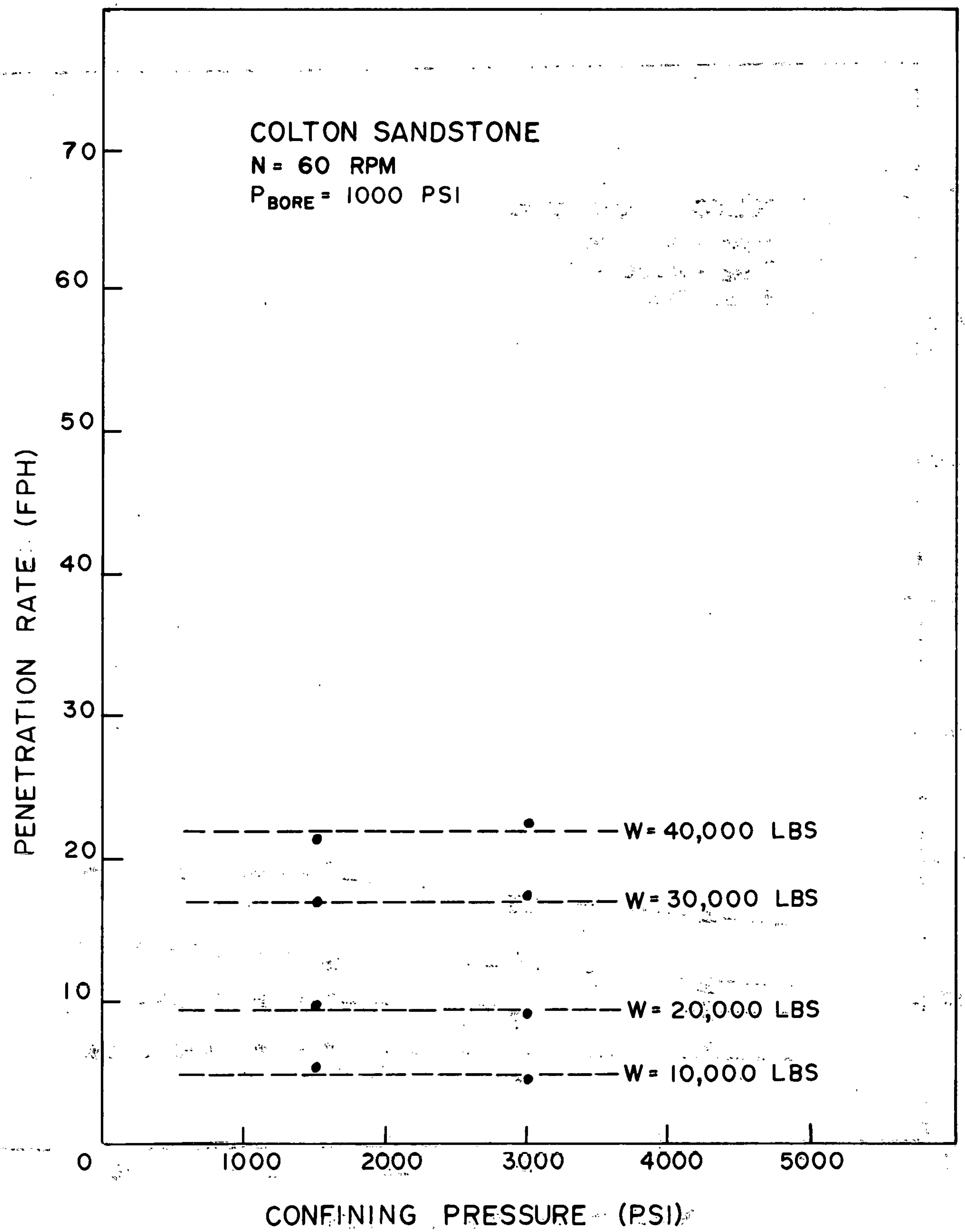

FIGURE 17

Penetration Rate versus Confining Pressure and Bit Weight for Colton Sandstone at Simulated Downhole Conditions

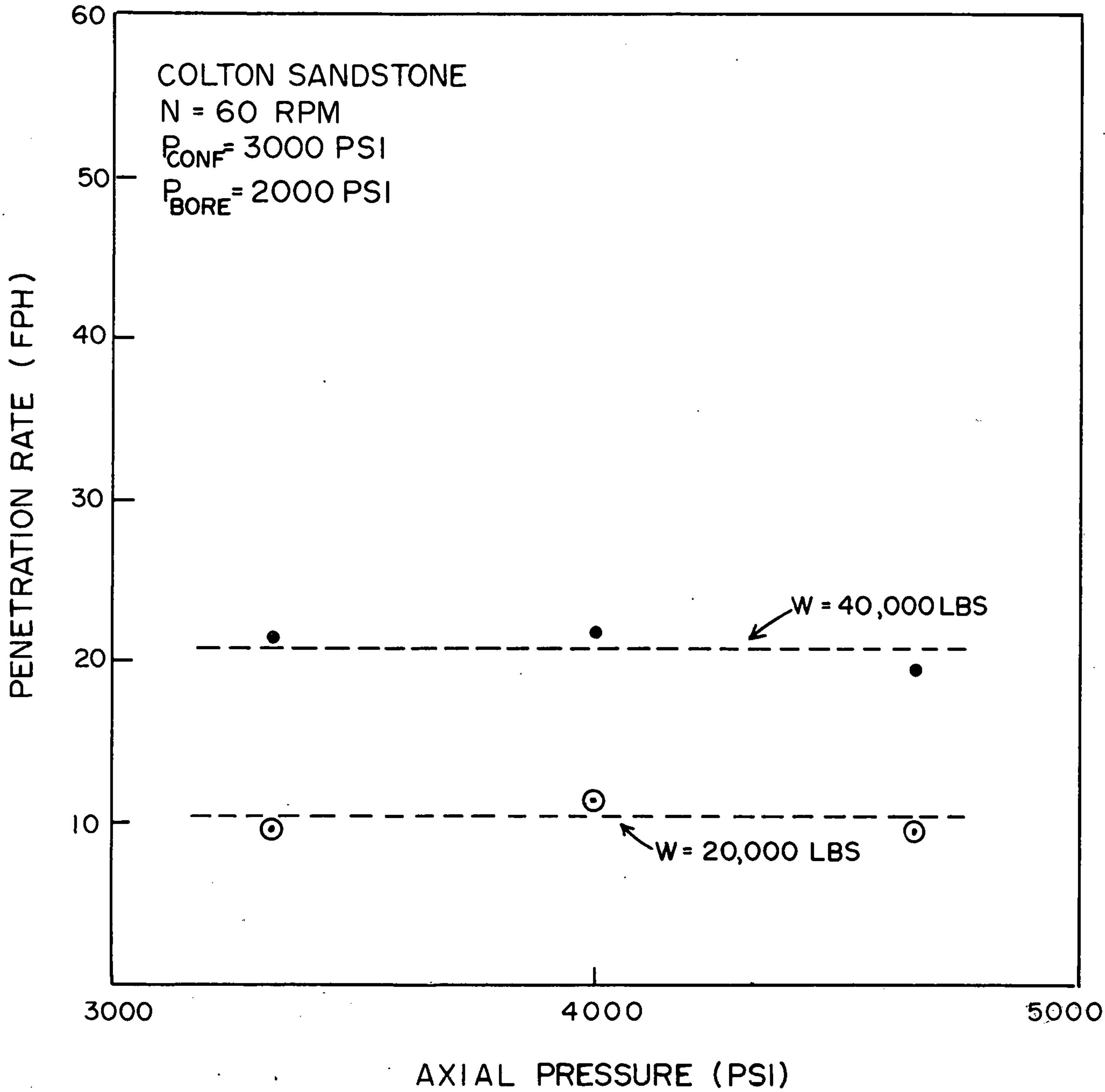

FIGURE 18

Penetration Rate versus Axial Pressure (Overburden) and Bit Weight for Colton Sandstone at Simulated Downhole Conditions speed nor mud pressure have the degree of effect on penetration rate as they did when the mud pressure was below the critical value.

For the Bonne Terre Dolomite, plots of penetration rate as functions of the other parameters are shown in Figures 19 to 21. From these curves it is also seen that the qualitative results of the Dolomite drilling are similar to the Sandstone drilling. The effect of the borehole mud pressure is less in the Dolomite than in the Sandstone, however.

Although the stress state in the rock being drilled was well below the failure point and presumably in the elastic range as seen in Figure 9, the bottomhole drilling pattern for Sandstone drilled at high pressures visually appeared to have been ductilly deformed. No detailed examination of the chips or the drill patterns was made, however. Figure 22 is a photograph of one of the Colton Sandstone bottomhole patterns after drilling at pressure and Figure 23 is a similar photograph for a Bonne Terre Dolomite sample.

An indication of drilling efficiency was made by plotting the penetration rate/rotary power as a function of bit weight and borehole pressure in Figures 24 and 25. This shows that the drilling efficiency drops significantly between atmospheric conditions and downhole pressure conditions. Also, the Dolomite is behaving somewhat differently than the Sandstone.

To make a preliminary evaluation of the functional relationships between the variables, a few regression analyses were made on selected portions of the data. Table 5 gives the coefficients determined for penetration rate as a function of rotary speed and bit weight for different conditions of confining pressure and mud pressure. Note that in the Colton Sandstone, the coefficients for both RPM and bit weight are drastically reduced as the combined confining and mud pressures are increased. This contrasts with the same coefficients for the Bonne Terre Dolomite which remain about the same with a similar change in confining and mud pressure.

TABLE 5

Coefficients from Multiple Linear Correlation Analyses

Drilling Rate = $C_o + C_1x(RPM) + C_2x(Bit\ Wt.)$

	C_o	C_1	C_2	R^2 Correlation
Colton Sandstone				
Atmosphere Conditions	-39.3	.592	.00271	.86
3,000 psi confining 2,000 psi mud	-11.2	.159	.00053	.90
6,000 psi confining 4,000 psi mud	- .05	.0325	.00032	.95
Bonne Terre Dolomite				
Atmosphere Conditions	-16.8	.171	.00223	.95
6,000 psi confining 4,100 psi mud	-18.7	.228	.00194	.95

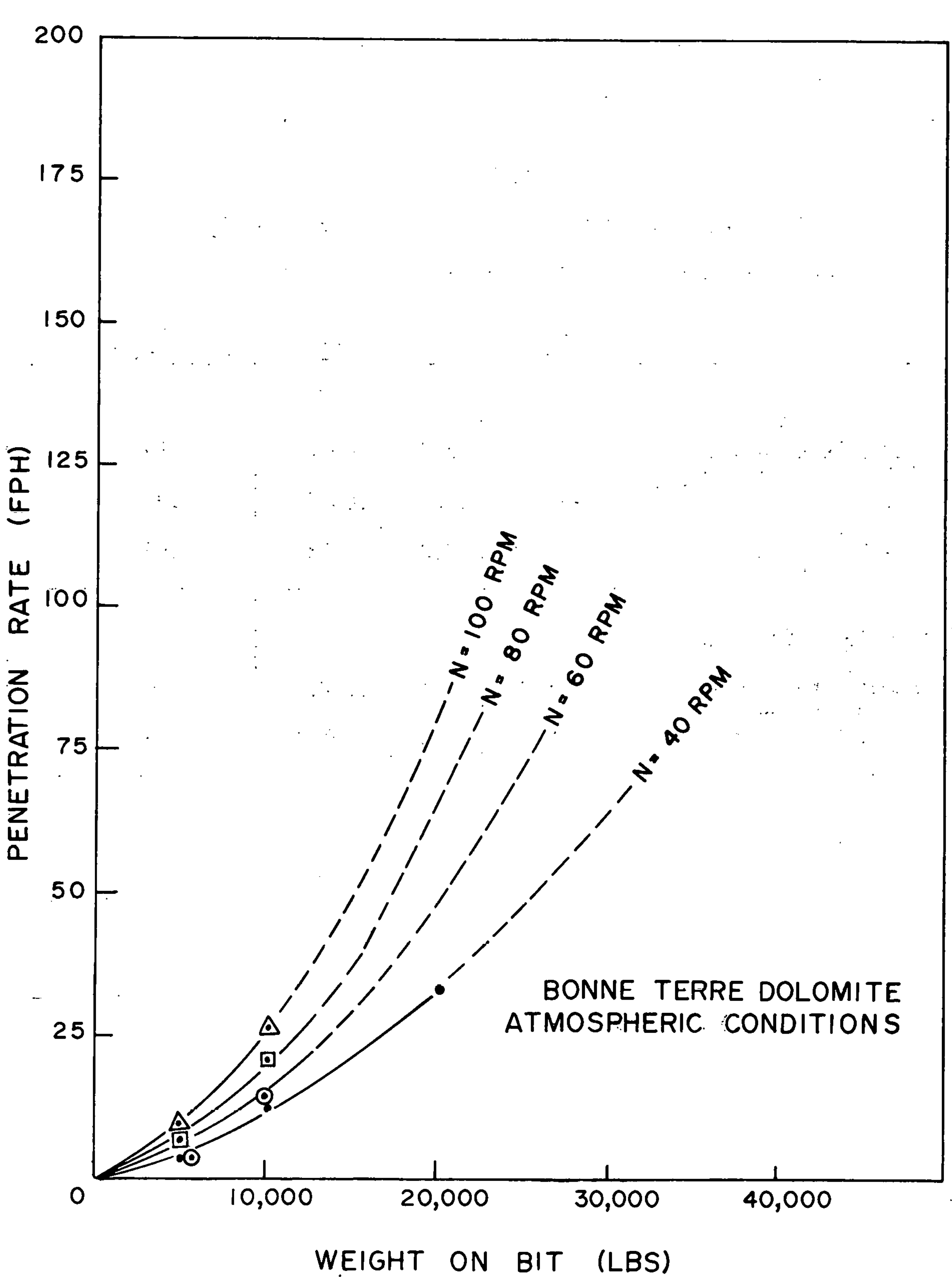

FIGURE 19

Penetration Rate versus Bit Weight and RPM for Bonne Terre Dolomite at Atmospheric Conditions

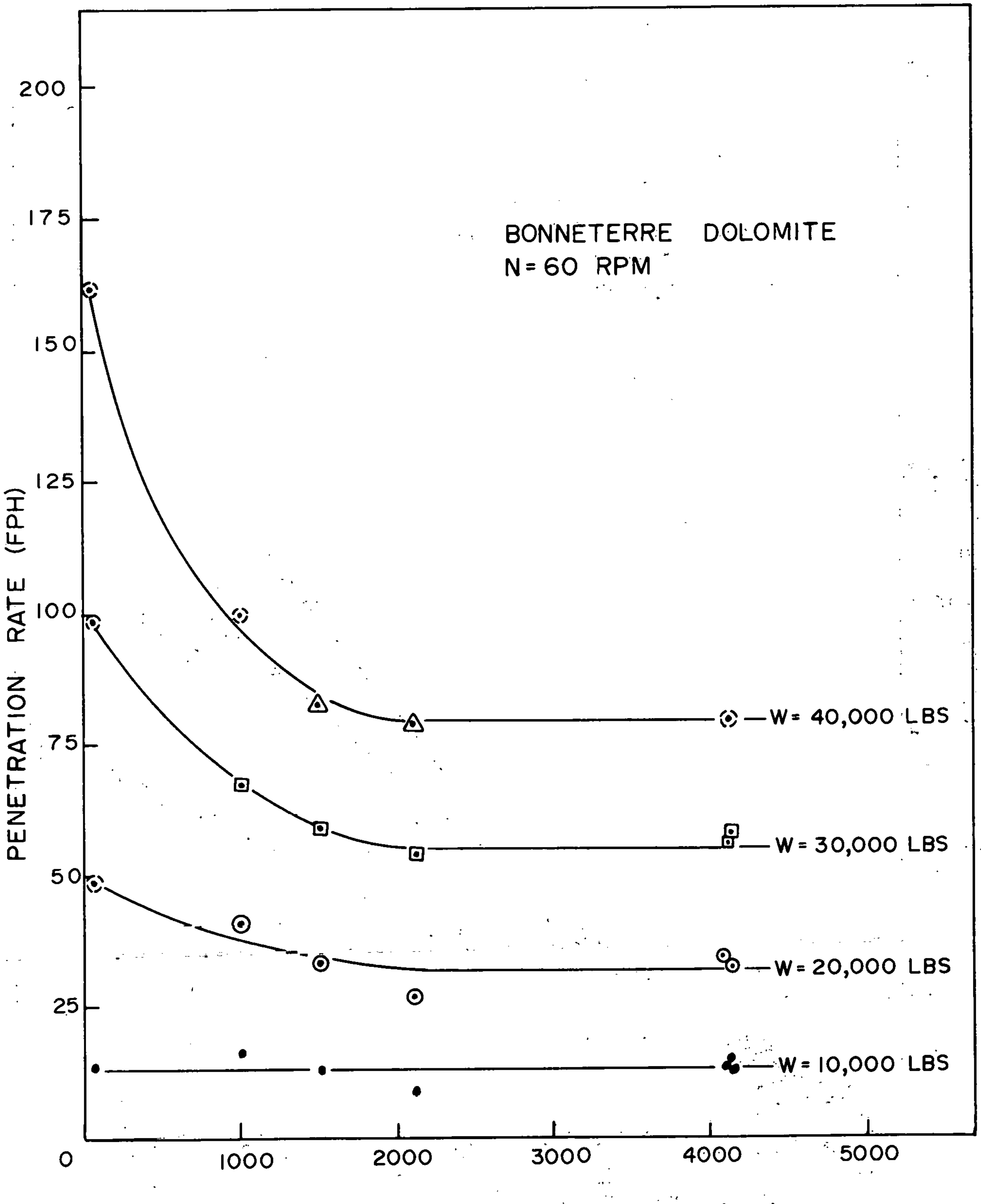

FIGURE 20

Penetration Rate versus Mud Pressure and Bit Weight for Bonne Terre Dolomite at 60 RPM and Simulated Downhole Conditions

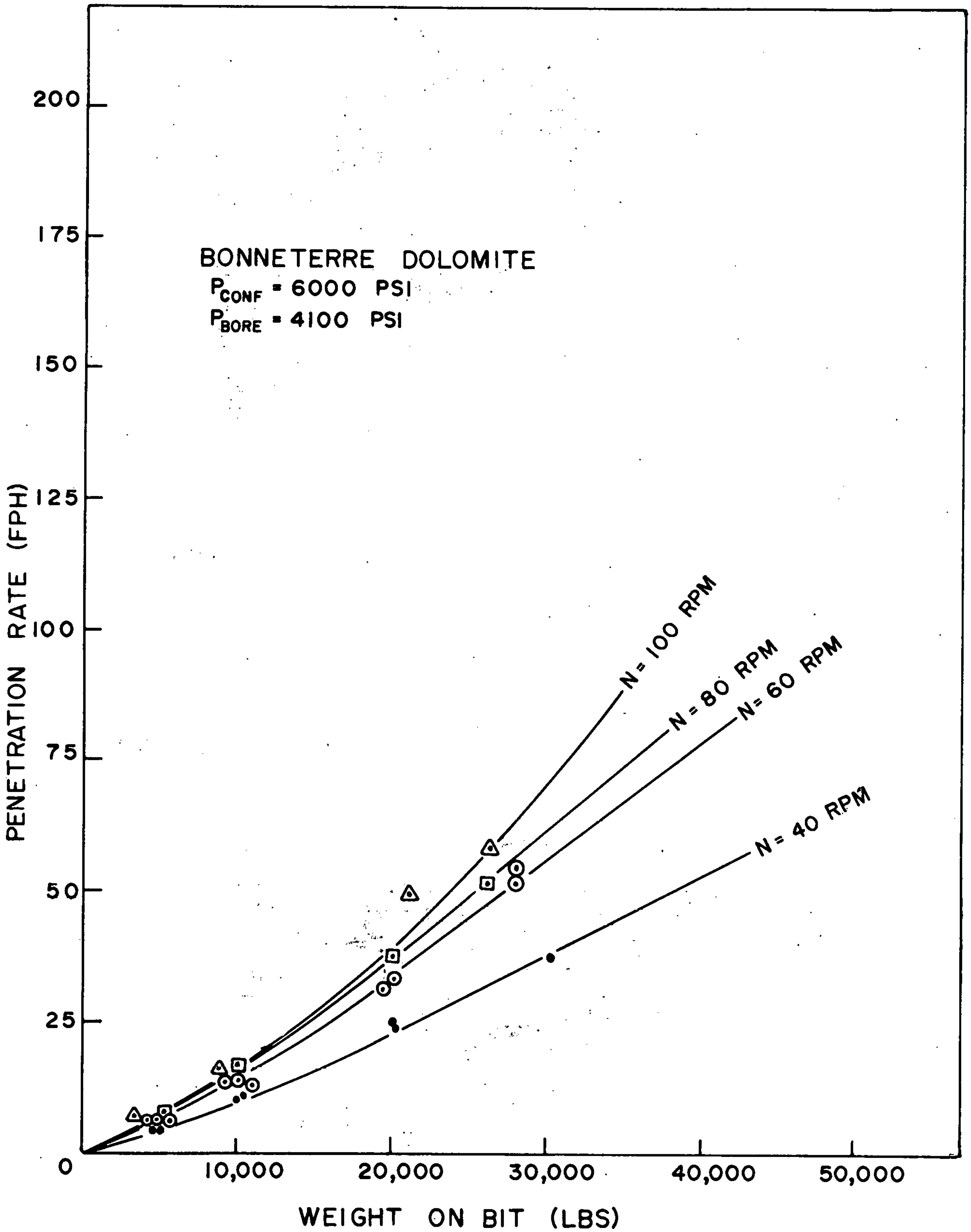

FIGURE 21

Penetration Rate versus Bit Weight and Mud Pressure for Bonne Terre Dolomite at 60 RPM and Simulated Downhole Conditions

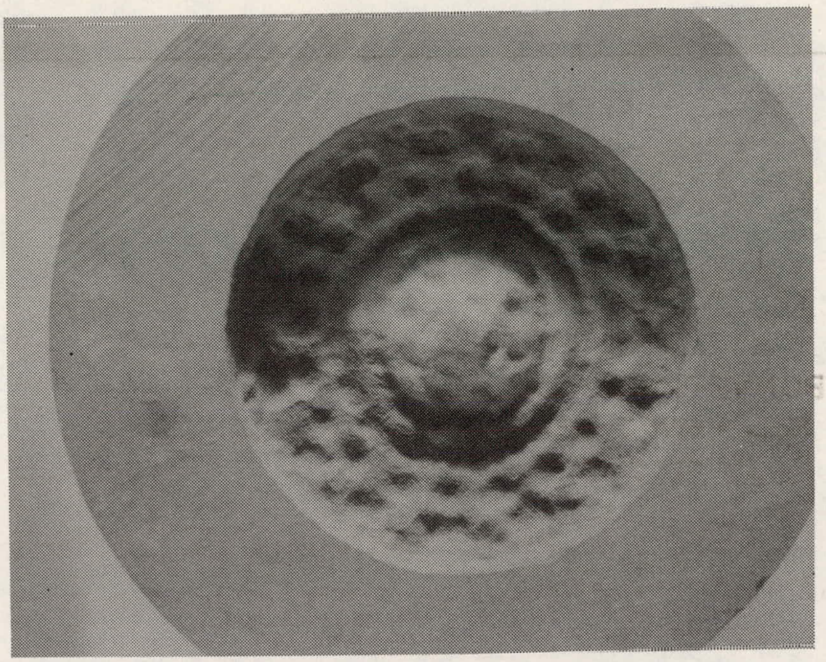

FIGURE 22

Bottomhole Patterns of Colton Sandstone after Drilling at Simulated Downhole Conditions

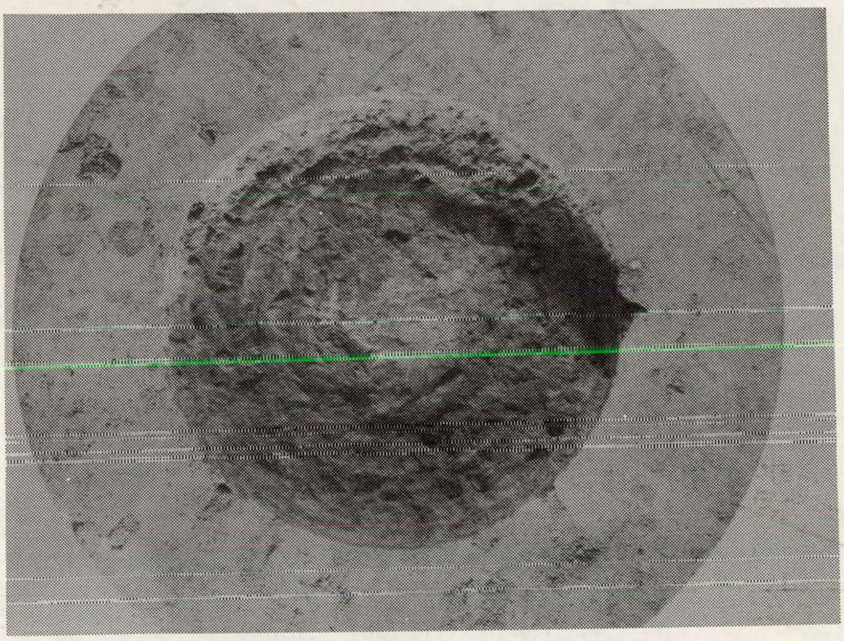

FIGURE 23

Bottomhole Patterns of Bonne Terre Dolomite after Drilling at Simulated Downhole Conditions

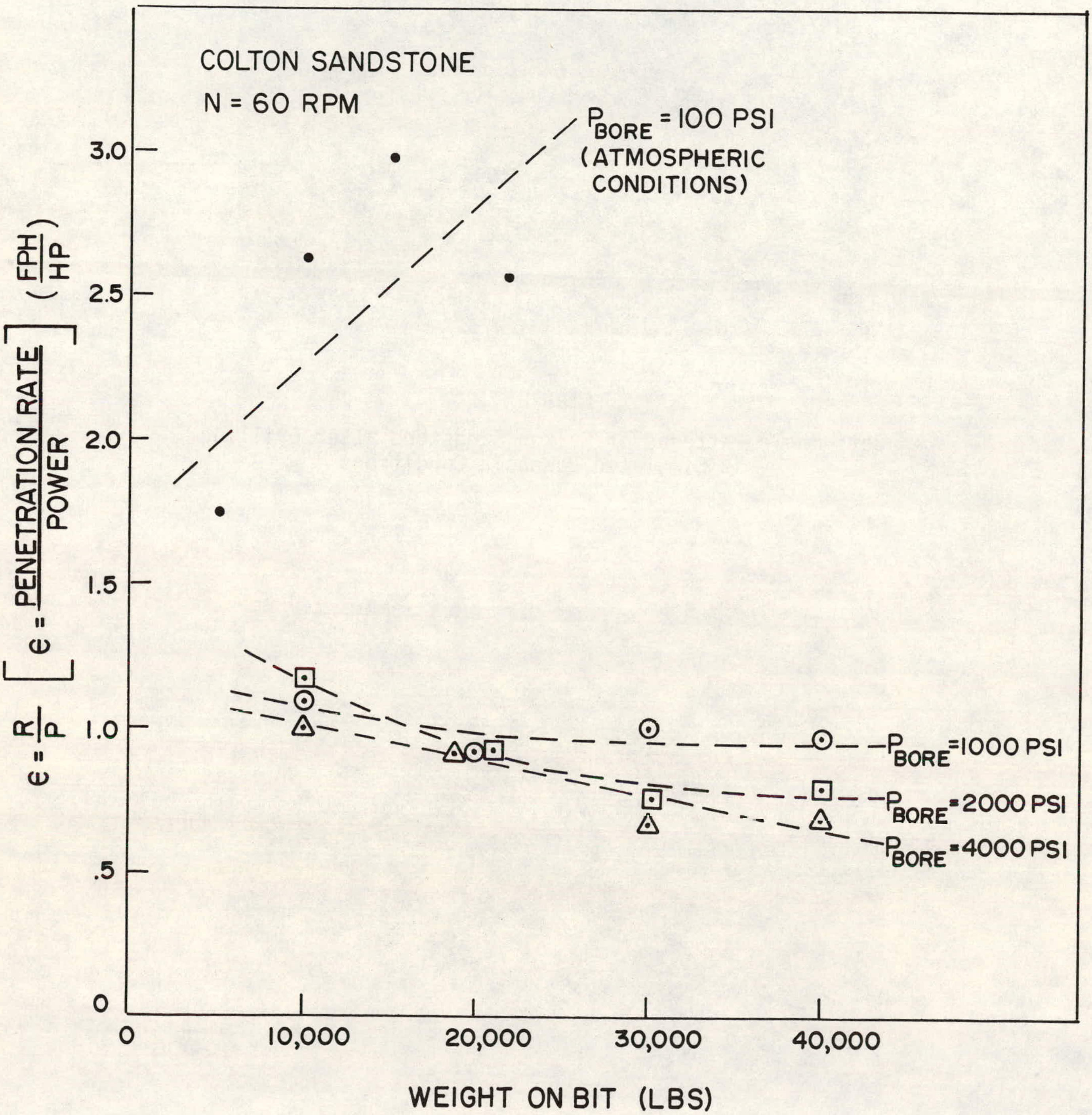

FIGURE 24

Efficiency of Drilling Rate versus Bit Weight and Mud Pressure for Colton Sandstone at 60 RPM and Simulated Downhole Conditions

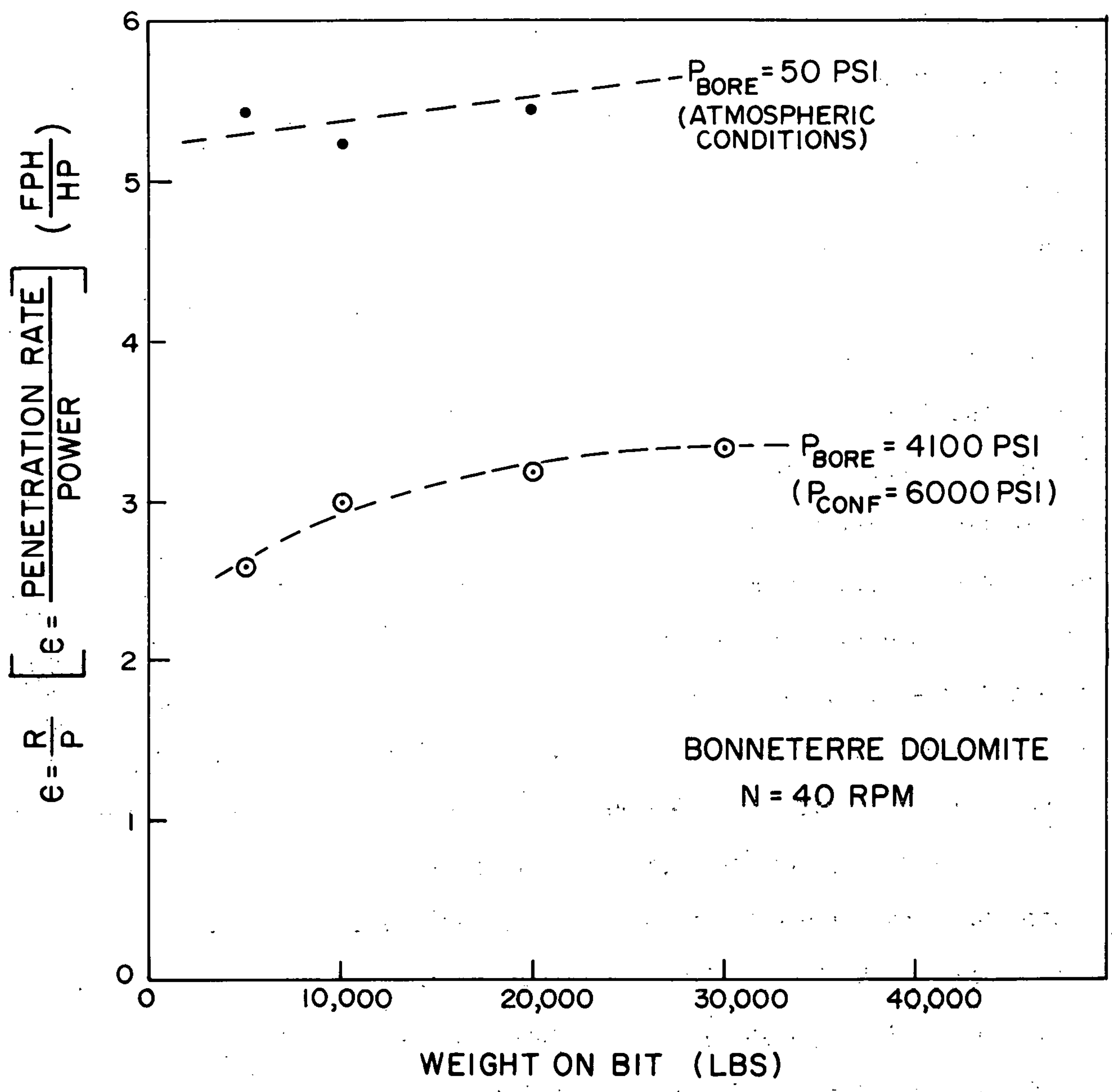

FIGURE 25

Efficiency of Drilling Rate as a Function of Bit Weight and Mud Pressure for Bonne Terre Dolomite at 40 RPM and Simulated Downhole Conditions

CONCLUSIONS

The goals of the project to select rocks typical of deep oil and gas wells and drill them under full-scale simulated downhole pressures were accomplished. The amount of special effort needed to make the equipment operational for the simulated downhole conditions did limit somewhat the number of tests that could be performed within the time and budgetary constraints. A significant amount of data was, nevertheless, obtained to provide an important base for future full-scale drilling tests.

The study to determine typical rocks for deep gas wells in the United States identified four different types; Shales, Sandstones, Limestones and Dolomites. From examination of the physical properties of these rock types in the major petroleum provinces in the United States, particular varieties of each of these rock types were selected as typical of their rock type. From the typical varieties, selections were made where large blocks could be obtained for the laboratory tests. The rocks selected were Colton Sandstone, Bonne Terre Dolomite and Mancos Shale. The Shale samples received were too inhomogeneous, so the program was completed using only the Sandstone and Dolomite.

Commercially available bits were selected based on manufacturers' recommendations. The bit size of 7 7/8 inch was selected because of its common use and the fact that most new experimental bits are made this size.

The drilling fluid was a water based mud selected to be typical of fluids commonly used to drill oil and gas wells. The drilling parameters were selected to cover the ranges of rock stresses, borehole pressure, rotary speeds, and weight on bit that are typical of actual drilling conditions. The results obtained thus provide data on the functional relationships of the basic drilling parameters and are a basic body of data.

The drilling penetration rate was found to be primarily dependent on the rotary speed, weight on the bit and borehole fluid pressure. There was a small dependency on mud flow rate. The dependence on the mud pressure was particularly significant since the penetration rate decreased rapidly until the differential mud pressure reached approximately 2,000 psi. Above this value, additional mud pressure and rotary speed had only a minor effect on penetration rate. The effect was more pronounced in the Sandstone than the Dolomite. Visual examination of the rock bottom-hole pattern under the bit after drilling at simulated downhole conditions revealed much ductility in the Sandstone and more chipping and cratering in the Dolomite. The stress state in the undrilled rock ahead of the bit was well within the elastic response range so that the only non-elastic deformations were those of the bit action on the rock. The confining stresses, within the range of these tests, had no apparent effect on the drilling rate.

ACKNOWLEDGMENTS

Acknowledgment is given to John Sandstrom, Gordon Tibbitts, Jim Wilson and Gary Wright for their effort in getting the equipment operational and in running the tests and to the ERDA Contract Coordinator, C. Ray Williams, for his positive comments which were a significant part of making this test program a success. Acknowledgment is also given to William Maurer and others at Maurer Engineering for their assistance in this program.

APPENDIX A

THE STATE OF KNOWLEDGE OF ROCK/BIT TOOTH INTERACTIONS UNDER SIMULATED DEEP DRILLING CONDITIONS

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ABSTRACT

This report presents a survey of factors that influence drilling rates with emphasis on the theoretical and experimental work relating to rock/bit tooth interactions under pressures associated with conditions encountered during the drilling of deep oil and gas wells. Studies which attempt to explain the effects of various parameters associated with the rock/bit tooth interactions are described with an objective of correlating bit-tooth force and chip generation with rock properties determined from triaxial tests.

A review is given of laboratory drilling results relating to the effects of down hole pressures on drilling rates. These studies include the effects of bottom-hole cleaning and the so called "chip hold down" effect. The variations of roller-cone bit designs for drilling different types of rocks is also described.

Finally, suggested means for achieving increased drilling rates in deep holes are summarized. This discussion includes means for increasing overall drilling rates as well as instantaneous drilling rates. It is concluded that a study of the kinematics of roller-cone bit drilling is needed to utilize the fundamental knowledge of rock/bit tooth interactions in order to design bits for faster drilling in ductile rock.

APPENDIX A

TABLE OF CONTENTS

INTRODUCTION

The primary objective of this report is to summarize the state of knowledge of the rock/bit tooth interaction under conditions of pressures associated with deep well drilling. Specifically, results of theoretical and experimental work relating rock properties, fluid pressures, and bit tooth configurations to bit-tooth forces and chip configurations are described. Although not a primary purpose of this present report, a discussion of laboratory drilling studies of the effects of drilling fluids in removing cuttings from the bottom of the hole is given since ineffective bottom-hole cleaning and chip hold down can result in low drilling rates and these effects might be confused with the pressure effects related to increased rock strength and ductility.

The effects of confining pressures on rock properties are well known (Griggs and Handin, 1960). As the confining pressure is increased, both the strength and the ductility of rock increase. In drilling porous rock, the effective confining pressure is the differential pressure across a mud filter cake at the bottom of the hole (i.e., the difference between the mud pressure and the formation fluid pressure). Laboratory drilling tests under simulated deep hole drilling conditions have shown that drilling rates can be decreased as much as 80% at high bore hole pressures compared with atmospheric drilling results. Part of the effect of the high down hole pressures is related to rock strength increase and ductility while an important part is related to the inefficient bottom-hole cleaning under high differential pressures. Since these effects are interrelated, it is difficult to separate the influence of the various factors causing the decreased drilling effectiveness.

Bit designs have taken into account the formation strength and ductility by changing the bit-tooth configuration and the drilling action of roller-cone bits whereby soft formation bits have both rolling and scraping action. Jet bits have been introduced to facilitate the removal of cuttings from beneath the bit and to promote cleaning of both the bit and the bottom of the hole.

It is common knowledge that if it were possible one would drill with gas or air as a first choice, and with clear water as a second choice followed by water with few solids; and from a drilling standpoint, the last choice would be the most usual situation of drilling with mud having high density and many solids. However, because of hole stability problems and high formation fluid pressures, it is not frequently possible to drill with the desired drilling fluids that would promote rapid drilling rates. These problems are particularly critical in shales.

Theoretical and experimental studies have been conducted to examine and explain the effects of the various parameters related to rock/bit tooth interaction problem. The factors involved include the mechanical motion, shape, and configuration of the bit-tooth; the mechanical behavior of the rock and response to the penetration of the bit-tooth when subjected to a state of stress induced by mud column pressures, pore pressures, and overburden stresses; and the drilling fluid composition and flow properties as well as the pressure effects. In these studies efforts have been made to correlate the indentation behavior which simulates the action of a bit-tooth with the rock properties measured by triaxial tests. Studies have been aimed at describing and predicting the behavior of both brittle and ductile rock under the action of bit teeth. Also, data have been collected on the transition from brittle to ductile behavior of rock during indentation by single bit teeth. Specifically, effects of bit-tooth angle, the cohesive strength and angle of internal friction of the rock, and the fluid pressure differential across the cutting depth on the force required for indentation and for producing chips have been studied. A theory of chip formation in ductile rocks along with experimental evidence of the validity of this theory has also been developed.

Both theoretically derived and experimentally determined drilling rate equations are presented for the purpose of establishing a description of instantaneous drill bit performance. The potential for improving drilling rates in deep holes is considered from both the instantaneous penetration rate as well as the overall drilling rate point of view. Research and development needed to increase these drilling rates is summarized.

BIT DESIGN CONSIDERATIONS

The first roller-cone bit was patented in 1909 and today most oil and gas wells are drilled using three cone roller bits (Estes, 1970; Gravley, 1975; Laird, 1976); however, a significant footage is drilled with diamond bits and a minor amount with drag type bits. Figure 1 illustrates the history of roller bit development showing how teeth and bearings have been modified and improved. Roller-cone bit designs are classified according to soft formation bits, medium formation bits, and hard formation bits (See Table I). These bits are also classified according to tooth material and tooth height, cone angle offset, and journal angle. Teeth may be hard faced, case hardened, or made of inserts of tungsten carbide and bearings in the cones may be sealed or nonsealed. Cone offset called skewness is measured by the offset of the center line of the cone with respect to the center of the bit (Figure 2).

Soft formation bits, for very soft formations, will have three to four degrees cone offset and have hard-tipped faces on the bit teeth with long, widely-spaced teeth. Hard facing applied to the teeth on soft formation bits is applied in such a manner that a self-sharpening effect is produced as the bit teeth wear (Figure 3). The cutting action of these bits is described as scraping and gouging. Medium formation bits are intermediate between the soft formation bits and the hard formation bits. Hard formation bits have no cone offset thereby resulting in pure rolling contact with the bottom of the hole. The teeth are very short and blunt with more steel on the bottom than in the soft formation bits and these bits require higher weights on bit to produce the desired drilling action. The cutting action of the hard formation bits is described as a crushing action. These bits, with shorter teeth, have greater bearing capacity and, therefore, can withstand higher bit weights. Design variations are illustrated by Figure 4 and Figure 5.

A considerable part of the formation bottom (as much as 50%) is uncut by the direct crushing action of the bit teeth for hard formation bits and these bits depend upon formation friability to cause the breakup of the uncut hole bottom (Figure 6). Soft formation bits, on the other hand, produce cutting action on approximately 70% of the hole bottom and introduce a ploughing action caused by the cone skewness or offset. At depths below 7,000 feet, many rocks are believed to be nonfriable and tend to become somehwat plastic (Estes, 1970). Suggested practice under these circumstances is to use the softer formation bits.

Drag bit cutting action is illustrated by Figure 7. These bits are fixed-blade rotary drills which cut and scrape the rock in a manner similar to the cutting action of metal cutting tools. The drilling rate potential of drag bits is greater than that of roller bits; however, rapid wear in hard abrasive formations and high torque requirements limit their usefulness.

Diamond bits are used frequently for coring and with high speed downhole motors. These bits also drill by a drag or scraping action. High costs of diamond bits is one important factor that limits their applications.

EFFECT OF ROCK PROPERTIES ON CONDITIONS AT DEPTHS

Since this report is concerned with interaction of the bit and rock, attention will now be focused on rock behavior under simulated down hole conditions. The overburden pressure increases approximately 1 psi/ft. (230 bars/km) and the average fluid pore-pressure gradient is about 0.45 psi/ft. (100 bars/km). Furthermore, the geothermal gradient is sometimes as high as 1.6°F/100 ft. (30°C/km). Laboratory simulation of these parameters has shown that the strength and ductility of rock increase with depth (Handin, et. al., 1963).

The combined effects of temperature, confining pressure, and pore pressure on the mechanical behavior of Berea sandstone are illustrated by Figure 8. These triaxial test results show that the strength and ductility increase with an increase of the effective confining pressure (defined as actual confining pressure less the pore pressure), and the strength decreases and ductility increases with higher temperatures. Ultimate strengths and ductilities of a number of rocks tested at simulated depth conditions are shown in Fiugre 9. From these data large increases of strength are expected for sandstones, limestones, and dolomites, and greatly increased ductility for shales and limestones at great depths in the earth.

Results of tests on Solenhofen limestone at confining pressures to 20,000 psi, temperatures from 78°F to 300°F, and strain rates from 10^{-3} to 100%/sec are shown in Figure 10 (Serdengecti and Boozer, 1961). This study showed that a decrease of temperature from 300°F to 78°F was approximately equivalent to increasing the strain rate by a factor of 10^5. In Figure 10 the dashed lines indicate regions representing changes from brittle to transitional to ductile failure. Solenhofen limestone has a relatively high transition from brittle to ductile behavior at a confining pressure of 15,000 psi at room temperature while at atmospheric pressure the transition occurs at a temperature of 900°F (Griggs and Handin, 1960).

Fortunately during drilling at great depths the rock is subjected to a mud column pressure which is considerably less than the overburden pressure. In fact, under ideal conditions the mud pressure would be only slightly greater than the formation fluid pore pressure and the resulting effective confining pressure at the bottom of the hole would be relatively small.

ROCK/BIT TOOTH INTERACTION

This section contains a review of experimental and theoretical studies concerned with the interaction of bit teeth and rock. Experimental results are described which simulate downhole conditions while drilling with air, water, and mud under both static and impact conditions. Theoretical results are discussed for penetration of rock in both the brittle and ductile states. These theories are concerned with predicting the force and chip configuration as functions of bit-tooth shape, rock surface geometry, rock properties, and confining pressure. Finally, the results of the analyses are compared with experimental results.

Single Bit-Tooth Experiments

Experiments have been conducted in which blunt teeth were forced into rock under simulated downhole conditions (Maurer, 1965). These tests indicate that a wedge of compressed material beneath the bit-tooth will form a crater at a threshold force which depends on tooth dullness, rock strength, confining fluid properties and pressure, and rate of loading. The threshold pressure is of the order of 300,000 to 600,000 psi in stronger rocks such as granite and basalt.

Effects of borehole fluid pressure and kind of fluid on threshold pressure and crater volume are shown in Figure 11 for a 1/32" x 1/2" tooth flat acting on Berea Sandstone. The crater volumes were formed at a constant static load of 6,500 lbs. Neither the threshold pressure nor crater volume are appreciably influenced by an increase of air pressure. A small increase of threshold pressure and a 50% decrease of crater volume are observed when water pressure is increased from atmospheric to 5,000 psi. However, when mud pressure is increased to 5,000 psi, there is an approximate linear increase of threshold pressure and a crater volume decrease of about 90%. These tests demonstrate one of the advantages of drilling with air or water compared with mud.

In tests Maurer refers to as "static" the time for crater formation is 0.01 to 5 seconds and in his "impact" tests craters are formed in 0.001 to 0.005 seconds. Craters under roller bit teeth are formed in 0.01 to 0.1 seconds which is more nearly approximated by the static tests. Static and impact force-displacement curves with drilling mud (differential pressure) are similar although the threshold force is somewhat greater for impact loading at a given pressure (Figure 12). The impact curves with water (hydrostatic pressure) are nearly identical to the impact tests with mud. In both cases the confining fluid apparently does not have sufficient time to equalize the pressure beneath the freshly cut chip. Hydrostatic pressure (equal borehole water pressure and formation fluid pressure) had no influence on the static force curves and brittle craters were produced at all pressures. The brittle-to-ductile transition pressures are given in Table II for static and impact tests on Indiana limestone and Berea sandstone. It can be seen that the transition occurs at lower pressures in the impact tests.

Static tests have also been conducted using sharp wedge-shaped teeth indenting rock subjected to a confining pressure through an impermeable membrane (Gnirk and Cheatham, 1965). Typical force-displacement curves are shown in Figure 13 as dependent on confining pressure with constant 60^{o} tooth angle and in Figure 14 as dependent on tooth angle with constant confining pressure of 1,000 psi. At low confining pressures or at moderate confining pressure with small tooth angles the force-displacement curves are irregular as a result of much fracturing and chipping taking place. As the confining pressure is increased (or for large tooth angles at moderate pressure), the curves become smooth and nearly linear. This correlation between the shape of the force-displacement curve and the nature of the mode of failure is illustrated by Figure 15.

Analysis of the Penetration of Brittle Rock

Penetration of a bit-tooth into brittle rock has been described as follows (Sikarskie and Cheatham, 1973). With increasing force, the bit-tooth is forced into the material and crushes rock beneath the tooth forming a zone of crushed material and extension fractures beneath the wedge-shaped tooth (Figure 16). Extension fractures form into virgin material as the stresses are increased in the surrounding mass of material until a fracture grows in a stable manner with increasing load and finally a point of crack instability is reached whereupon rapid crack growth, with little increase in force, extends the fracture to the free surface and results in a rock chip being formed. After the chip is formed, the load on the bit-tooth decreases abruptly thereby resulting in an irregularly shaped force-displacement curve. The crushed phase of the penetration process is actually not a brittle fracture problem but is more nearly associated with the plasticity penetration problem since material in a pulverized zone tends to behave more like a soil than a brittle solid. The actual loading process is thought to be bounded by two idealized situations; one involving a constant load test and the other a constant rate test as shown in Figure 17.

The chip formation process is the most difficult part to describe analytically and it is sometimes theorized that the fractures which produce the chips propagate along stress trajectories which intersect the maximum principal stress trajectories at about 30°. Sikarskie suggests that this theory does not explain the fracture in terms of the current understanding of the brittle fracturing of rock and he suggests a theory which first locates incipient fracture and then follows the fracture through to the formation of the chip (Figure 18). This theory is based upon a general Coulomb-Mohr theory of fracture and is believed to be consistent with recent research on the brittle fracture of rock. Based upon computation of the elastic stress field, a fracture function is computed and it is postulated that the fracture path follows a line which represents the minimum gradient of the fracture function (Figure 19). The transition from stable to unstable fracture growth is believed to occur at the inflection point of the crack velocity versus crack length plot (Bieniawski, 1963). Current work by Sikarskie is being conducted in analyzing the rock/bit tooth interaction and chip formation in anisotropic rock (Sikarskie and Cheatham, 1973).

Analysis of the Penetration of Ductile Rock by a Single Tooth

The penetration of a single bit-tooth into ductile rock has been analyzed using plasticity theory. Most of the analyses have been concerned with sharp, wedge-shaped teeth; however, results for blunt or rounded teeth have also been obtained (Cheatham, 1958). The rock is assumed to be isotropic, homogeneous, and rigid/perfectly-plastic and to yield when stresses satisfy Mohr's theory of failure. Linear (Coulomb) yield envelopes have been considered as well as parabolic envelopes (Cheatham, 1964). The bit-tooth is modeled by a long two-dimensional wedge under the assumption of plane strain. A typical plasticity slip line field is shown in Figure 20 where the effect of a lip (displacement of free surface) is neglected but the influence of friction at the rock/bit tooth interface is considered, and a linear yield envelope is illustrated by Figure 21 (Cheatham, 1963).

A linear increase of force with increasing depth of penetration is predicted for a sharp wedge. The slope of the force-displacement curve can be given in the following form for a Coulomb material:

$$\frac{F}{bh} = \text{Function } (\beta, c, \phi, p)$$

where

F = force on sharp bit-tooth

b = width of tooth

h = depth of penetration

β = half wedge angle

c = cohesive strength of rock

ϕ = angle of internal friction of rock

p = confining pressure on free surface

The above parameter in dimensionless form $F/bh\ \sigma_p$ (where σ_p is triaxial compressive strength at confining pressure p) is plotted as a function of bit-tooth angle including effects of a linear-parabolic yield envelope and tooth-rock friction in Figure 22 (Cheatham and Gnirk, 1966). Experimental results for Carthage marble shown in Figure 22 compare favorably with the theoretical perfectly rough tooth-rock interface curve. Experimental results for other rocks (Gnirk and Cheatham, 1963, 1965) generally give good agreement between theory and experiments for indentations at confining pressures above the transition pressures.

From Table III it can be seen that the brittle-to-ductile transition during indentation occurs at pressures as low as 250-500 psi for salt to pressures greater than 5,000 psi for dolomite. For a given confining pressure, the transition is furthermore influenced by tooth angle. In Figure 14 it can be seen that the indentation behavior becomes more ductile as the wedge angle is increased. A comprehensive study to correlate the transition pressures from triaxial tests with the transitions observed during indentation has not been performed to the author's knowledge; however, from typical triaxial tests shown in Figure 23, it appears that the transition from brittle-to-ductile behavior occurs at considerably higher pressure during triaxial tests than during indentation tests.

Work is currently under way to extend the above analyses to include effects of anisotropy, strain hardening, rate of loading and fluid flow through porous rock on rock/bit tooth interaction (Sikarskie and Cheatham, 1973).

Multiple Bit-Tooth Contacts

A single, sharp bit-tooth penetrating normal to a smooth surface of rock is obviously a greatly oversimplified model of rock/bit tooth interaction. Actually there are many bit-tooth contacts with a rough hole bottom by blunt teeth that rotate as the cone rolls.

The interaction of a bit-tooth with a previously formed crater has been referred to as "indexing". Experiments similar to the single bit-tooth studies described above have been conducted with multiple bit-tooth contacts for the purpose of studying indexing (Gnirk, 1966; Gnirk and Musselman, 1967). Results from these experiments are shown in Figure 24 for sharp 30^0, 60^0, and 90^0, one-half inch long wedges penetrating Carthage marble at atmospheric pressure and 5,000 psi confining pressure for indexing distances of 0.25" and 0.50". Figure 25 illustrates the general features of the tests results for an indentation depth of 0.10". The depth of indentation at which interaction occurs is indicated by a change of slope of the force-displacement curves in Figure 24. At atmospheric pressure rock is broken free between successive penetrations for indexing distances as great as five times the penetration depth; however, at confining pressures above the transition pressure, the rock will flow into the previous crater at indexing distances of two or three times the penetration depth.

The critical indexing distance at which interaction occurs for a given penetration depth increases as the bit-tooth angle is increased. Thus, the interaction of a bit-tooth with a previously formed crater depends on tooth angle, depth of penetration, indexing distance, rock properties and confining pressure. The transition pressure from brittle to ductile behavior is approximately the same for multiple bit-tooth contacts as for a single bit-tooth penetration.

A theory of indexing in ductile rocks has been proposed based on plastic limit analysis (Cheatham and Pittman, 1966). In this approach the plasticity slip line field near the bit-tooth is extended by a straight line of discontinuity as shown in Figure 26. It is hypothesized that the failure will follow a path requiring the least work or minimum power of dissipation. A plot of loci of constant power of dissipation is given in Figure 27. When a free surface such as that shown in Figure 26 intersects a line of constant power of dissipation, failure is assumed to be possible. All points on a given curve require the same bit-tooth load and are equally probable failure paths.

The above theory has been verified by experiments on Carthage marble where slots were cut into the rock surface to force the chip geometry into an approximately two dimensional configuration (Musselman and Cheatham, 1972). This configuration and the idealization of the indexing problem are illustrated by Figure 28. Typical force-penetration curves are shown in Figure 29 for Carthage marble penetrated by a 1/8 inch by 1/2 inch flat punch at various distances from a surface with inclination of 60°. The decrease of force for indexing distances $I \leq 4$ w (where w is width of the punch) indicates that a chip is formed by interaction with the inclined surface. For an indexing distance of 10 times the punch width, no chip is formed and interaction takes place with the horizontal surface rather than the sloping face.

The critical indexing distance which is the minimum distance from the inclined surface at which interaction occurs with that surface is indicated by the point at which the dimensionless force versus dimensionless indexing distance curve changes slope as shown in Figure 30. The theoretical curve has been corrected for the force necessary to cause failure of the rock at the ends of the punch. It can be seen from these curves that the theoretically predicted critical indexing distance of I = 5 w agrees well with the experimental results and that the theoretical force approximates the measured force values rather well. Comparison of the actual chip configuration at the midpoint of the punch length with the theoretical failure path based on the upper bound analysis also shows relatively good agreement (Figure 31). From these results it can be concluded that plasticity theory offers a valid method for computing tooth forces and chip configurations for rock at pressures above the brittle-to-ductile transition pressure.

DRILL BIT PERFORMANCE

Drilling rate for a given bit drilling under specified conditions in a particular rock can depend on a large number of factors. These parameters include the following: bit design, bit-tooth wear, weight-on-bit, rotary speed, rock properties (strength, permeability, and porosity), drilling fluid properties, circulation rate, mud pressure, and formation pore pressure.

The problem of relating the above parameters to drilling rate has been approached both theoretically and experimentally. Results of some of these studies are summarized in this section.

Theoretical Drilling Rate Equations

Theoretically derived drilling rate equations have generally been based on restrictive assumptions in attempts to establish upper limits on drilling rate. Outmans (1960) based his theory on a single-tooth plasticity model and related chip volume to drilling rate, hydraulic horsepower at the bit and drilling mud pressure. His equations express drilling rate as a function of the above variables, rotary speed and bit weight for various limiting conditions of mud flow and chip removal below the bit.

Maurer (1962) derived a theoretical drilling rate equations for roller-cone bits under perfect bottom hole cleaning conditions. His equation for drilling rate is:

$$R = k \frac{N(W - W_o)^2}{D^2S^2}$$

where R = drilling rate

N = rotary speed

W = weight-on-bit

W_o = threshold weight required for cratering

D = bit diameter

S = rock drillability strength

He pointed out that under imperfect hole cleaning, such as usually found in the field, the drilling rates fall below those for perfect cleaning because of regrinding of cuttings under the bit. Maurer gave the following approximate relation for field drilling results under these conditions:

$$R = aN^{0.5}W/D$$

A theoretical drilling rate equation for roller-cone drilling has been derived based on the indexing studies described above for plastically deforming rock (Gnirk and Cheatham, 1969). In this analysis the rock chips are assumed to be removed instantaneously. The teeth are taken to be wedge shaped (45^{o}) with flat apexes, and the bit weight is assumed to that weight required for optimum indexing (maximum volume for minimum energy). This dimensionless optimum weight is a function of the dimensionless indexing distance and differential pressure. Their equation for drilling rate with optimum bit weight can be written as follows:

$$R = 1.872\ m\ N\ l\left(\frac{w^2}{D}\right)\left[\left(\frac{W}{w\ l\ n_t \sigma_p}\right)^2 - 75.69\right]\ \text{ft/min}$$

where l = length of cutting edge of single bit-tooth (in)

m = number of bit-tooth penetrations per bit revolution

n_t = average number of bit teeth in contact with bottom

w = bit-tooth flat width (in)

σ_p = strength of rock at differential pressure p (psi)

The other parameters have been defined previously and the angle of internal friction was taken as 30^{o}. This equation based on perfect cleaning and minimum energy per unit volume of rock drilled gives numerical values for the optimum drilling rate. It can be seen that the theoretically predicted drilling rate dependence on rotary speed (N), bit weight (W), bit diameter (D), and rock strength (S or σ_p) is the same for the above theories.

Appl and Rowley (1963) have analyzed drag bit drilling using plasticity theory. They found that the load on the leading edge of the bit depends on the ultimate compressive strength and angle of internal friction of the rock and is independent of the radius of the leading edge.

Appl, Rowley, and Bridwell (1967) have developed a theory of the cutting action of diamonds in diamond bits. Their analysis which assumes a rigid/perfectly-plastic Coulomb material determines stresses on the diamond cutting surface, the components of cutting force, and the volume of material removed by the diamonds. Their theoretical results agree reasonably well with experimental data.

Experimental Drilling Results

In the above theoretical studies upper limits to drill bit performance were sought. In experimental drilling studies attempts have been made to simulate actual down hole drilling conditions.

Test results using 1¼" diameter two-cone microbits indicate that drilling rates decrease with increased drilling fluid pressure as shown in Figure 32 (Murray and Cunningham, 1955). Drilling tests with equal mud and pore pressures show the influence of permeability and drilling fluid (Figure 33). In these tests by Garnier and Van Lingen (1955) there was no influence of pressure when water was used as the drilling fluid in fairly permeable rock whereas the drilling rate decreased with pressure when either water or mud was used to drill the low permeability Belgian limestone. Drilling rates also decreased with mud pressure for the more permeable rocks. They explain these results as being due to chip hold down.

After a chip has been formed by the bit, they suggest that a vacuum is created when the chip is lifted unless sufficient liquid can be supplied to fill the opening crack. This liquid can be supplied through the crack or through the pores of permeable rock by mud filtrate or pore fluid. Additional tests results by Garnier and Van Lingen (Figure 34) indicate their interpretation of the influence of differential mud pressure on rock strength and chip hold down. According to these results, chip hold down effects can account for a greater decrease of drilling rate than the effects of rock strength increase due to pressure.

An empirical approach to predicting drilling performance has been developed by Bingham (1964) based on both laboratory and field drilling data. He proposes a linear approximation for the relationship between drilling rate and bit weight given by

$$R/N = M\ (W-W_0)/D$$

where m = performance line slope

W_0/D = performance line intercept

The performance line slope is greatest for a drag bit and lowest for hard-formation roller bits as shown in Figure 35. Imperfect hole cleaning causes the drilling rate to drop below the performance line. A bit capability number relates the performance line intercept and slope as follows:

$$K = m\ (W_0/D)^{\frac{1}{2}}$$

The performance for most bits have a common intercept for a given rock strength and this intercept can be correlated with rock shear strength as shown in Figure 36.

Bingham states that most field drilling takes place below the performance line because of inadequate chip removal. The deviation from the ideal performance line increases with higher rotary speeds (because of less time available for hole cleaning between tooth contacts), with higher mud weight, and with decreased tooth height caused by tooth wear. The effect of bit skewness is shown by increased drilling potential for bits having more drag action.

POTENTIAL FOR IMPROVEMENTS OF DRILLING RATES IN DEEP HOLES

Increased drilling rate can refer to faster instantaneous penetration rate or improved overall drilling rate. The instantaneous rate depends on the rock/bit interaction and cuttings removal efficiency while the overall rate depends on many factors not related to actual drilling such as trip time. A comprehensive review of developments aimed at improving drilling methods has been given by Ledgerwood (1960). These methods are summarized in Table IV.

Increased Instantaneous Penetration Rates

Instantaneous drilling rates generally increase with higher bit weight and rotary speed. Methods aimed at improving instantaneous penetration rates generally attempt to increase the power delivered to the rock. With conventional rotary drilling, only approximately 50 horsepower is available at the bit because of torque-transmitting limitations of the drill pipe. Since mud pumps may require 1,000 horsepower, it follows that a small part of the power on a drilling rig is utilized for rock fracture. Furthermore, rock comminution by a rock bit is an inefficient process.

Bailey and Dean (1967) report that a man with a pick and hammer is 10 to 100 times more efficient than a machine in drilling ice because of his ability to pick and pry and to locate favorable geometry. In general, larger chips require less energy than smaller ones.

A two-channel drill pipe has been used with reverse circulation and continuous coring. This procedure requires cutting only an annulus, then breaking the cores and circulating them up the drill pipe. Such drill pipe would also permit drilling with a fast drilling fluid and protecting the borehole with another fluid by having a downhole packer between the two fluids. Air on gas would be an ideal drilling fluid if high pressure formation fluids could be controlled. And, of course, water is a better drilling fluid than high density drilling mud.

Increased downhole power can be obtained by means of percussive and vibratory drills or downhole motors or turbines. Methods of drilling by other than mechanical means have been investigated. These include thermal, electrical, magnetic, and chemical drilling. Many of these methods have been known for many years (Table V). The use of high pressure hydraulic jets is currently under development for use in rock drilling.

Increased Overall Drilling Rate

A most significant cost reduction in drilling of deep holes can be obtained by decreasing the time that the rig is not actually being used for drilling. Time spent on round trips to replace bits, logging, and surveying hole direction is nonproductive time from a hole-making point of view. It has been estimated that operating time spent in actual drilling is only about 40 percent for onshore wells and 25 percent for offshore wells where more directional drilling occurs (National Research Council, 1976). In directionally drilled holes, approximately equal time is frequently spent drilling and surveying.

Much effort has been devoted to decreasing trip time. These efforts have included retractable bits for replacement without a round trip, reelable drill pipe for rapid round trips, and automatic drill rigs for more efficient pipe handling (Ledgerwood, 1960). To date none of these systems has gained widespread use.

Currently, however, there is considerable industry work toward development of a commercialized downhole telemetry system (Heilhecker, 1975). The successful development of reliable telemetry systems should greatly decrease time required for surveying and logging. Additional advantages of these systems are that they can permit measurement of downhole drilling parameters, detection of incipient bit bearing failures, and early detection of gas zones that could lead to blowouts.

Fundamental Drilling Research

The state of knowledge of rock/bit tooth interactions has been summarized above and it can be seen that it is not possible at present to predict the effects of all of the parameters associated with the drilling process. Additional work is necessary to understand the interactions of the parameters in an actual three-dimensional situation where the hole bottom is irregular, there are chip removal interactions with rock cutting, bit teeth on different rows of a single cone interact, and there are interactions with teeth on other cones. This involves the kinematics of drilling as well as dynamics and rock failure considerations.

However, much of the necessary background theoretical and experimental work has been done. With adequate effort it should be possible to develop a mathematical model of the drilling process by properly modeling the important parameters. From such a model (verified by experiments), it would then be possible to predict the effects of modifications of bit design on drilling rates in different rocks under specified conditions of mud pressures and properties.

It is interesting to note that the fundamental understanding of drilling has not progressed significantly since Ledgerwood published his paper in 1960. The following quotation from Ledgerwood appears to apply as well today as when he wrote it:

> "In spite of these efforts to discover new and improved systems, rotary drilling maintains its economic leadership. Undoubtedly, rotary drilling costs will continue to be reduced by rigid application of the best available technology and by development of new rotary technology. In view of the extensive past development programs, however, significant long-range improvement appears to be a research, not a development problem. Research must postulate and prove theories and principles governing various subsurface rock-failure processes pertinent to both rotary and new systems. Also, research must produce physical and engineering data relative to these processes. When such information is available, earth boring will graduate from an art to a science. Major improvements in rotary drilling can then be expected, and the systematic evolution of an improved drilling method can be initiated--with a strong probability for success."

Possible Bit Modifications for Drilling Ductile Rocks

Very little work has been published relating to bit modifications for drilling ductile rocks. Feenstra and Van Leeuwen (1963) reported results of drilling tests in which the bit nozzles were extended nearer to the hole bottom. Better chip removal and less "bit balling" from optimum nozzle placement can improve drilling performance.

The brittle-to-ductile transition pressure for a given rock depends on bit-tooth angle; however, a detailed study of the influence of tooth angle, rock properties, and crater geometry on transition pressure has not been made to the author's knowledge. If the differential pressure at cutting depth is very high, it is not likely that changing tooth geometry would cause the rock to fail in a brittle manner.

If the rock is in a truly ductile state, then drilling with a roller-cone bit having pure rolling contact is ineffective. The author found that lead could not be drilled effectively with a 1¼ inch diameter microbit that produced pure rolling contact. The microbit teeth indented the lead but as the bit was rotated the indentations moved to follow the bit-tooth pattern without actually breaking free any chips that could produce a drilling action. So-called "soft formation" bits have long teeth and cone offset or skewness to produce some translation as well as rolling. Ideally, from a purely drilling action point of view, a very ductile rock could be drilled more effectively by a drag bit. This type of bit more nearly simulates the type of tools used in cutting of ductile metals. In order to use such bits, wear and "bit balling" problems must be overcome.

From the theoretical studies of ductile rocks a theory of indexing has been developed. If the bit-tooth spacing and configuration could be designed to take advantage of optimum indexing, greatly improved drilling action could occur in ductile rocks. This is not an easy task, however. In order to develop bits with teeth that produce optimum indexing, a comprehensive study of the kinematics of roller bit drilling action would be required. Such a study would involve the indexing behavior of the rock, the interaction of all teeth on all cones, and the rolling and translational motion of the cones. Without such a combined theoretical and experimental effort the present state of knowledge of rock/bit tooth interaction cannot be applied effectively to engineering computations involved in roller-cone bit design for ductile rocks.

SUMMARY AND CONCLUSIONS

A survey of factors that influence drilling rates in deep holes has been presented. These factors include bit design, rock behavior and cuttings removal. In general, drilling rates decrease with depth because the differential pressure between the mud column and formation fluid causes increased rock strength and ductility as well as so-called "chip hold down". Reduced down hole pressure by drilling with air or water increases the drilling rates compared with those obtained using drilling mud. However, drilling mud is usually necessary to maintain hole stability and control high pressure formation fluids.

Theoretical and experimental work relating rock/bit tooth interactions to rock properties and bit-tooth configuration has been reviewed and drilling rate equations developed from this theory have been given. These ideal drilling rate equations provide an upper limit on drilling performance. Actual drilling rates usually fall below the optimum rates because of inefficient cuttings removal.

In a discussion of ways of improving drilling performance in deep wells, it is pointed out that the overall drilling rate is the most significant factor and actual on-bottom drilling frequently occurs less than half of the operating time because of trip time, logging, surveying, etc. Instantaneous penetration rates are limited by the amount of power available at the bit plus the inefficiencies in the drilling process itself.

Fundamental knowledge of the drilling process is not currently sufficient to properly model the overall drilling problem; however, from the knowledge of bit-tooth interaction and indexing a program could be instituted to study the kinematics of roller bit drilling. From such a study, it should be possible to determine optimum bit-tooth spacing and configuration.

The following list summarizes suggested means for achieving increased drilling rates in deep wells.

1. Increased overall drilling rates:

   a) Development of reliable downhole telemetry systems will decrease non-drilling time required for logging and surveying.

b) Reduce number of round trips or decrease time required for round trips by providing longer bit life or more rapid replacement of bits.

2. Development of drilling fluids or fluid systems for faster drilling can improve instantaneous penetration rates. Possibilities include fluids with delayed filter cake build up at bottom of hole or concentric pipe with two fluids (one circulating for fast drilling and one in outer annulus for hole stability).
3. Bit nozzles designed for more effective cuttings removal such as extended nozzles near hole bottom could increase instantaneous penetration rates by overcoming chip hold down.
4. Drag bits have a greater drilling potential in ductile rocks, but the wear and "bit balling" problems must be overcome.
5. Roller bits currently have long teeth and offset cones to produce drag action for drilling ductile rocks. In order to make use of the fundamental knowledge currently available, a program could be instituted to study the kinematics of roller-cone bits combined with optimum indexing. This work would be aimed at fast drilling by means of improved bit-tooth configuration and spacing.

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I. Description of Rock-Bit Classes
(After Estes, 1971)

TYPE	CLASS	FORMATION TYPE	TOOTH DESCRIPTION	OFFSET
STEEL	1 - 1, 1 - 2	VERY SOFT	HARD-FACED TIP	$3^\circ - 4^\circ$
CUTTER	1 - 3, 1 - 4	SOFT	HARD-FACED SIDE	$2^\circ - 3^\circ$
MILL-	2 - 1, 2 - 2	MEDIUM	HARD-FACED SIDE	$1^\circ - 2^\circ$
TOOTH	2 - 3	MEDIUM HARD	CASE HARDENED	$1^\circ - 2^\circ$
BITS	3	HARD	CASE HARDENED	0
	4	VERY HARD	CASE HARDENED, CIRCUMFERENTIAL	0
TUNGSTEN-	5 - 2	SOFT	64° LONG BLUNT CHISEL	$2^\circ - 3^\circ$
CARBIDE	5 - 3	MEDIUM-SOFT	$65 - 80^\circ$ LONG SHARP CHISEL	$2^\circ - 3^\circ$
INSERT	6 - 1	MEDIUM SHALES	$65 - 80^\circ$ MEDIUM CHISEL	$1^\circ - 2^\circ$
BITS	6 - 2	MEDIUM LIMES	$60 - 70^\circ$ MEDIUM PROJECTILE	$1^\circ - 2^\circ$
	7 - 1	MEDIUM - HARD	$80 - 90^\circ$ SHORT CHISEL	0
	7 - 2	MEDIUM	$60 - 70^\circ$ SHORT PROJECTILE	0
	8	HARD CHERT	90° CONICAL OR HEMISPHERICAL	0
	9	VERY HARD	120° CONICAL OR HEMISPHERICAL	0

II. Brittle-to-Ductile Transition Pressures (psi) for Dull Bit-Tooth Indentation
(After Maurer, 1965)

Pressure, psi	Indiana Limestone Static	Indiana Limestone Impact	Berea Sandstone Static	Berea Sandstone Impact
Confining (air)	*	*	*	*
Hydrostatic (water)	*	250-500	*	1000-2000
Differential (mud)	1250-1500	250-500	3000-4000	1000-2000

* Brittle behavior occurs at all pressures.

III. Brittle-to-Ductile Transition Pressures for Sharp Bit-Tooth Indentation Under Static Load
(After Cheatham and Gnirk, 1966)

Rock	Transition Pressure, Psi
Salt	250-500
Indiana limestone	500-750
Carthage Marble (limestone)	750-1500
Berea sandstone	2000-2500
Ohio sandstone	2500
Virginia Greenstone (schist)	2500-3000
Danby marble	4000-5000
Kasota dolomite	5000-6000
Hasmark dolomite	>5000

IV. Drilling System Efforts to Improve Drilling Rates (After Ledgerwood, 1960)

PART I—ROCK-ATTACK DEVELOPMENTS (DRILLING RATE AND/OR BIT LIFE)

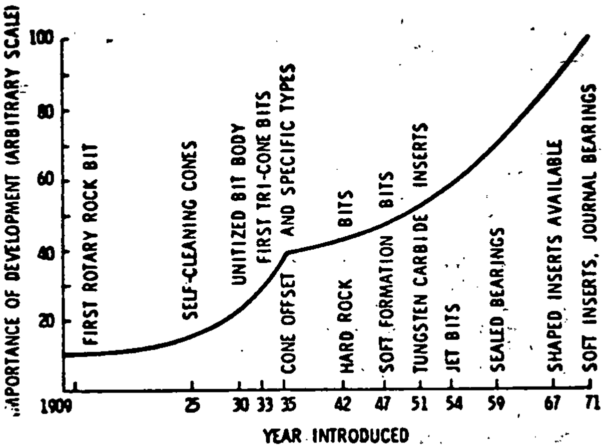
1. MECHANICAL ROCK ATTACK
   - A. Emphasis on Force Normal to Rock
   - B. Emphasis on Rotation Means
2. THERMAL ROCK ATTACK
3. ABRASION-EROSION ROCK ATTACK
4. CHEMICAL ROCK ATTACK
5. ELECTRIC CURRENT ROCK ATTACK
6. MAGNETIC FIELD ROCK ATTACK

PART II—EFFORTS NOT RELATED TO ROCK ATTACK (TRIP TIME)

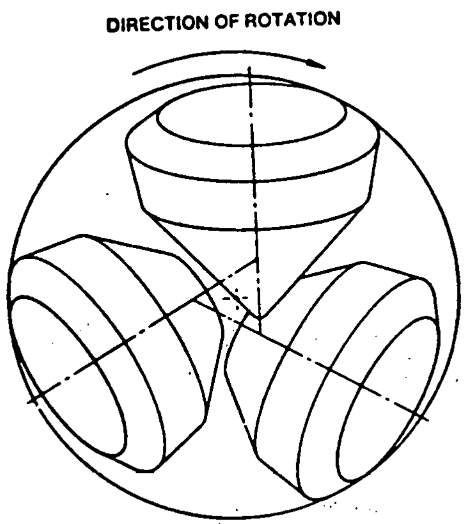
1. RETRACTABLE BITS
2. REELABLE DRILL PIPE
3. CONTINUOUS CORING
4. AUTOMATIC RIGS

V. Dates of Initial Patents Pertaining to "New" Drilling Systems (After Ledgerwood, 1960)

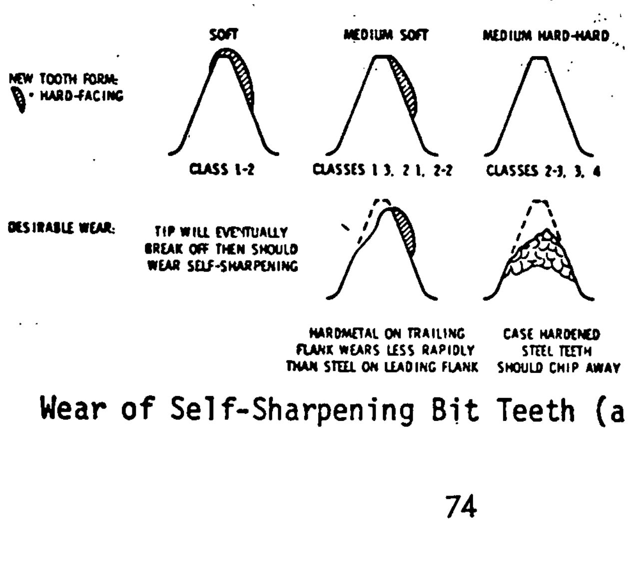
Flame Drill	1853*
Bottom Hole Rotary Hydraulic Motor	1873
Electric Arc (British Patent)	1874
Conventional Rotary	1884
Chemicals to Soften Rock	1887
Bottom Hole Electric Percussor	1890
Bottom Hole Electric Motor	1891
Bottom Hole Hydraulic Percussor	1900
Retractable Bit & Bottom Hole Motor	1902
Reelable Drill Pipe	1935
Abrasive Laden Jets	1941
Shaped Explosive Charge	1954
Pellet Impact Drill	1955



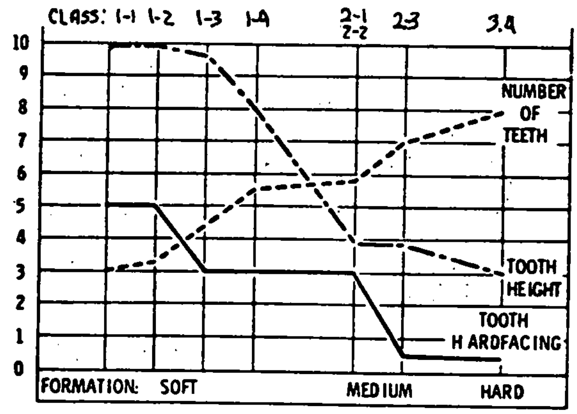
1. Development History of Rotary Rock Bits (after Estes, 1961)



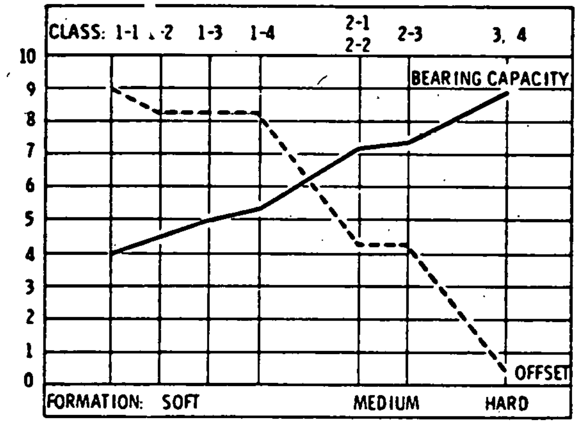
2. Cone Offset of Roller Cone Bit (after Laird, 1976)



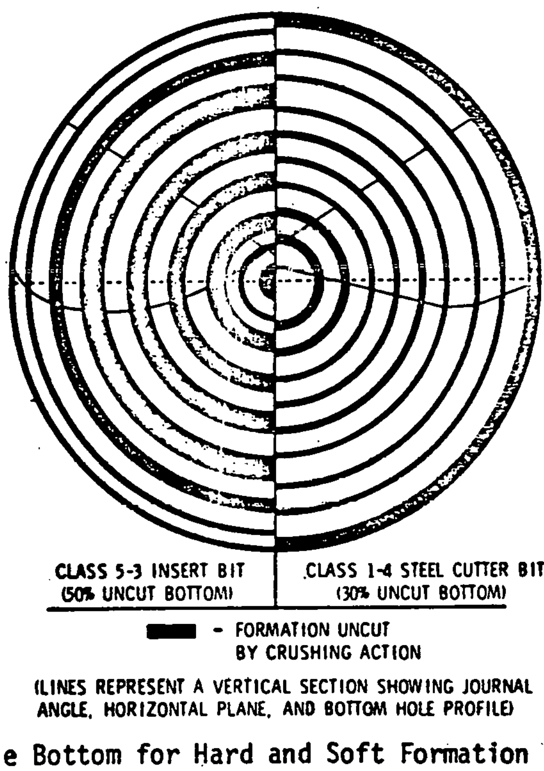
3. Wear of Self-Sharpening Bit Teeth (after Estes, 1971)



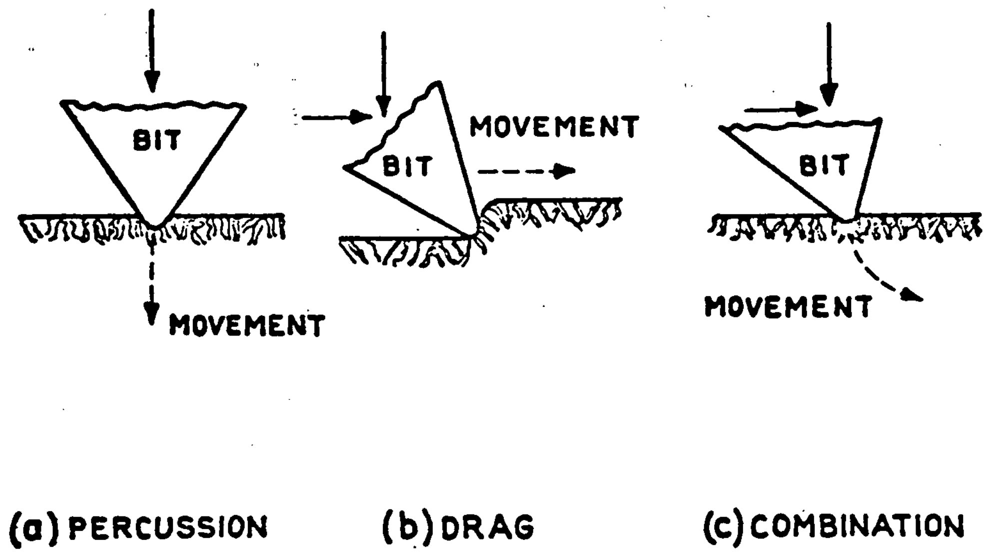
4. Tooth-design Variations for Different Bit Types (after Estes, 1971)



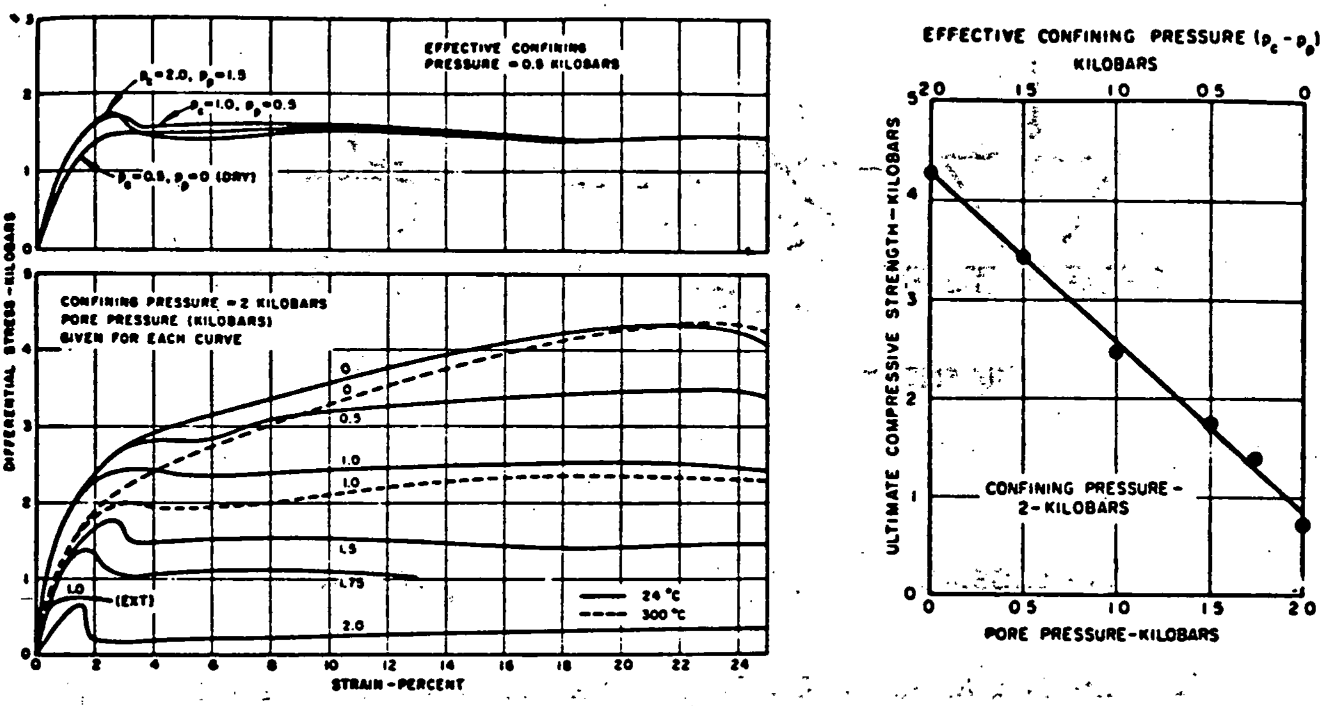
5. Cone Offsets and Bearing Capacities of Different Bit Types (after Estes, 1971)



6. Uncut Hole Bottom for Hard and Soft Formation Bits (after Estes, 1971)



7. Drilling Action of Bit Teeth (after Sikarskie and Cheatham, 1973)

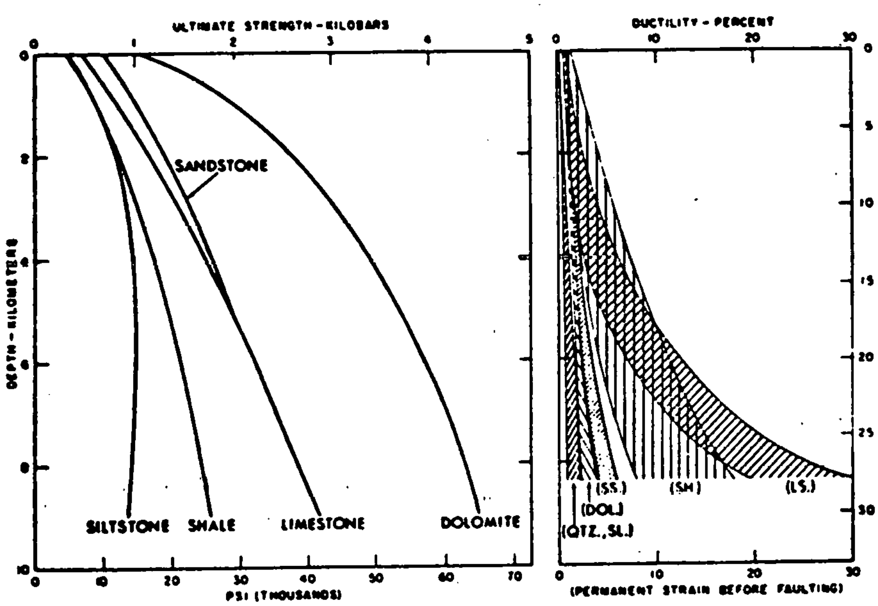


p_c = CONFINING PRESSURE (KB.)

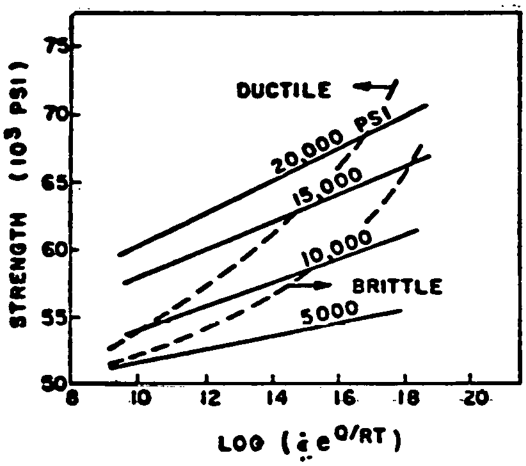
p_p = PORE PRESSURE (KB.)

TEMP. = 24°C

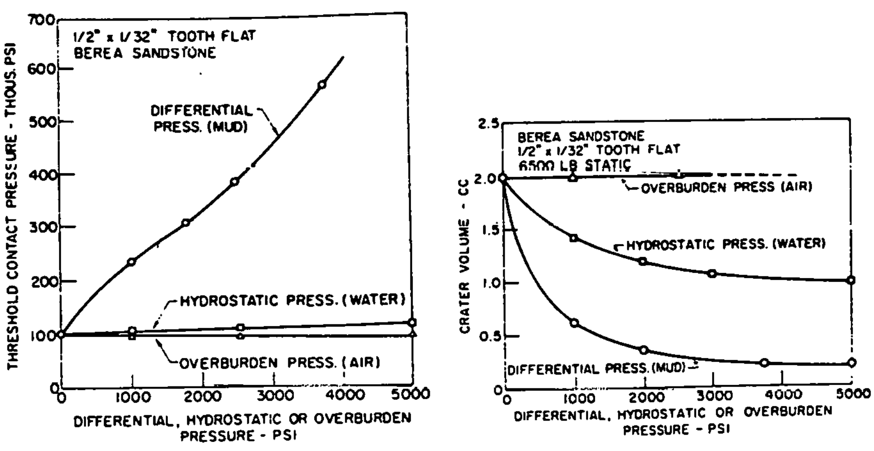
8. Effects of Confining Pressure, Pore Pressure and Temperature of the Compressive Strength of Berea Sandstone (after Handin and Hager, 1957)



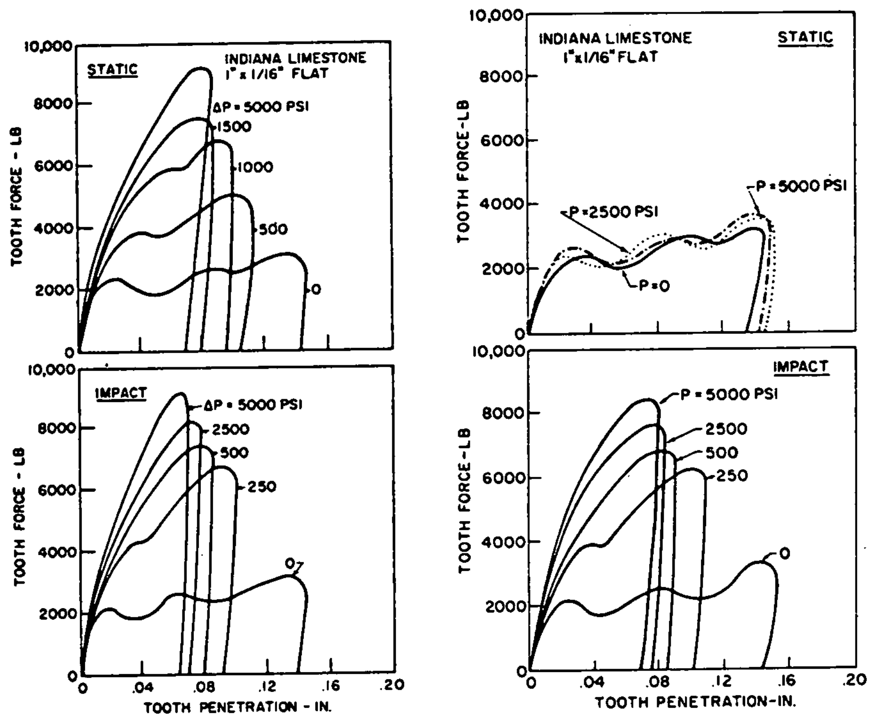
9. Strengths and Ductilities of Rocks Under Simulated Depths (after Handin and Hager, 1957)



10. Strength and Ductility of Solenhofen Limestone at Various Confining Pressures as Functions of Strain Rate ($\dot{\varepsilon}$) and Absolute Temperature (T) (after Serdengecti and Boozer, 1961)

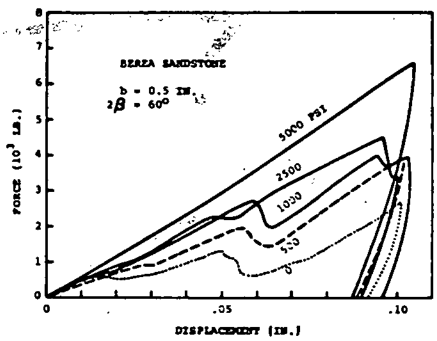


11. Effects of Bottom-Hole Pressure on Threshold Force and Crater Volume for Dull-Tooth Indentation of Berea Sandstone (after Maurer, 1965)

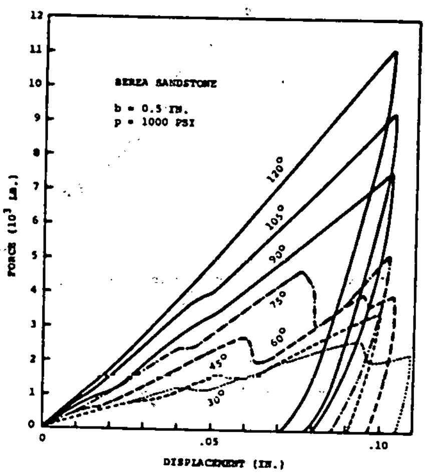


(a) *Differential pressure.* (b) *Hydrostatic pressure.*

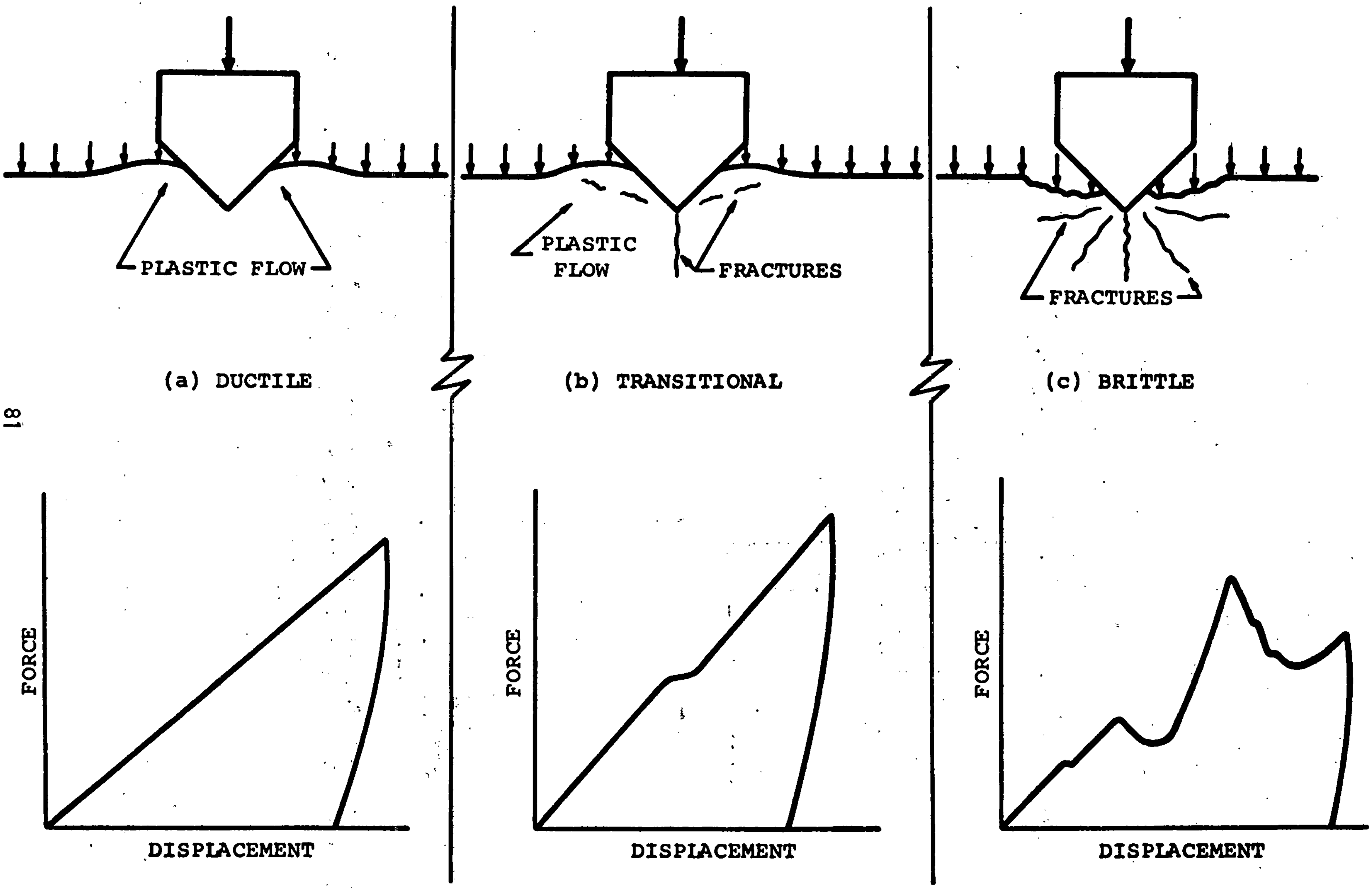
12. Effects of Confining Pressure and Loading Rate on Force-Penetration Curves for Indiana Limestone (after Maurer, 1965)



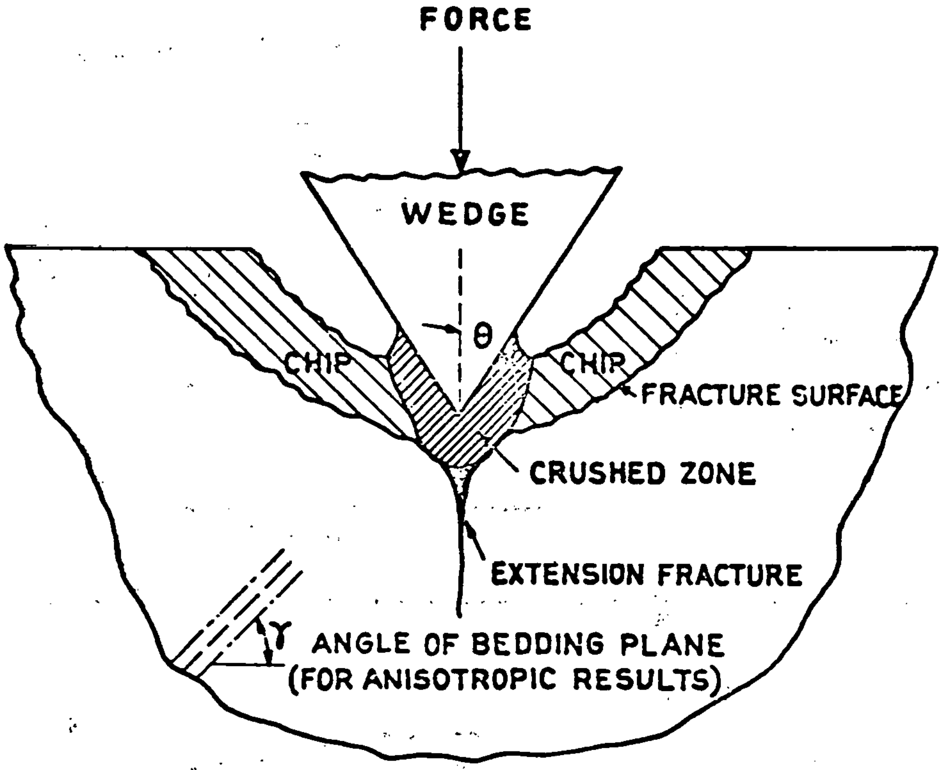
13. Force-Penetration Curves for Berea Sandstone at Various Confining Pressures for Sharp 60° Bit-Tooth (after Cheatham and Gnirk, 1965)



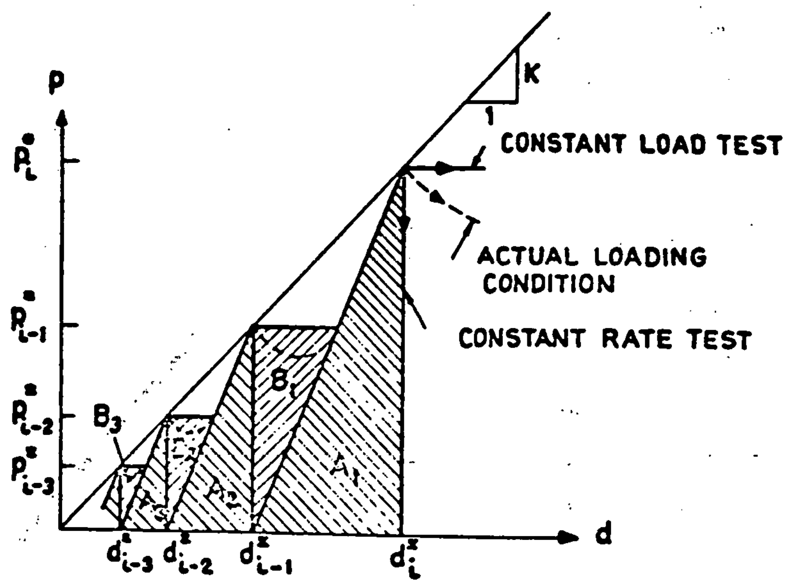
14. Force-Penetration Curves for Berea Sandstone at 1,000 psi Confining Pressure with Various Tooth Angles (after Cheatham and Gnirk, 1965)



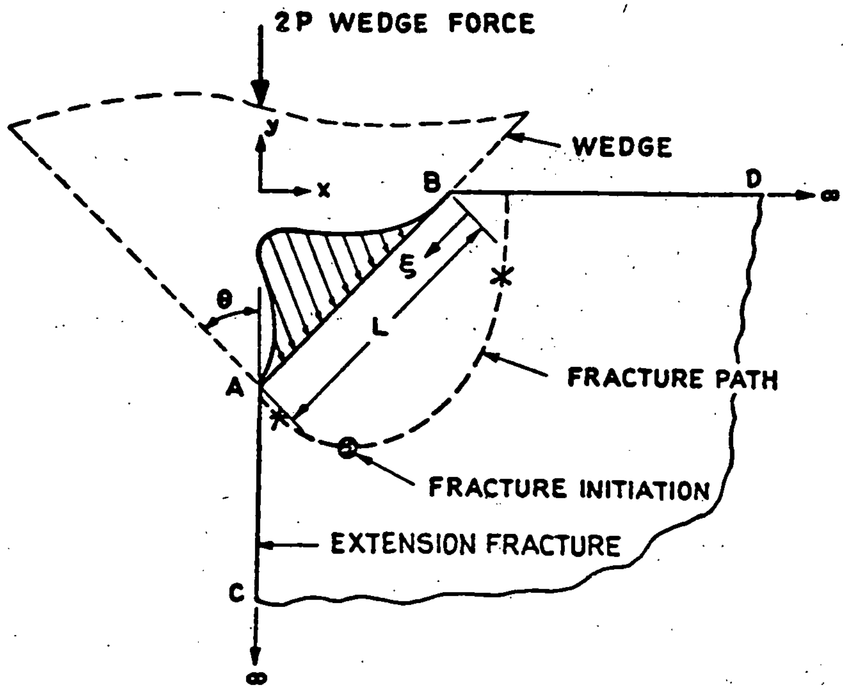
15. Correlation Between the Mode of Rock Failure for Sharp Bit-Tooth Indentation and the Shape of the Force-Displacement Curve (after Cheatham and Gnirk, 1965).



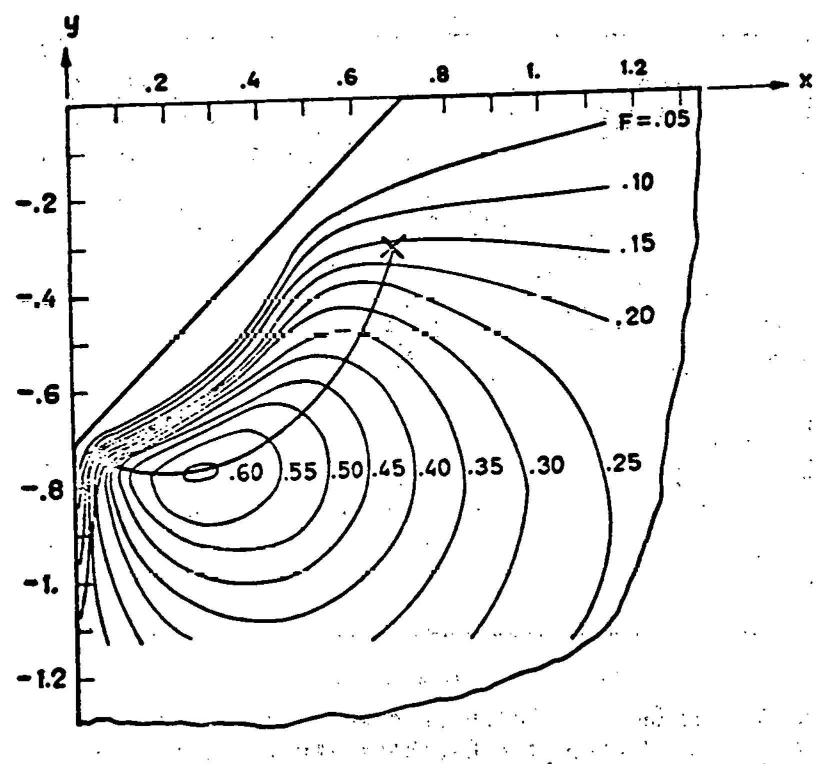
16. Model of Sharp Bit-Tooth Penetration into Brittle Rock (after Sikarskie and Cheatham, 1973)



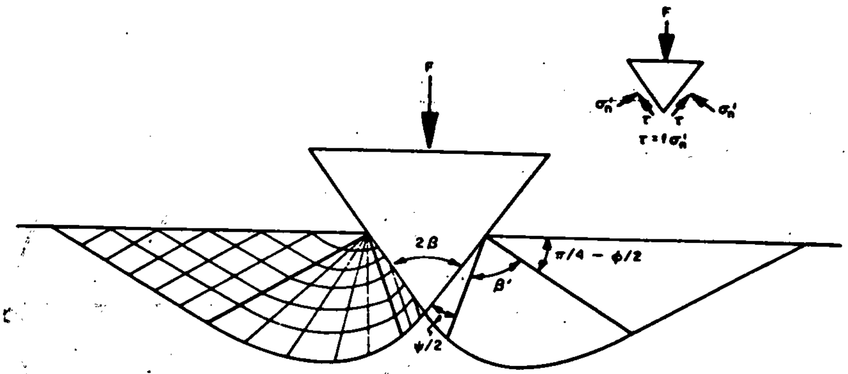
17. Actual Force-Penetration Curve for Brittle Rock Compared with Idealized Constant Load Test and Constant Rate Test (after Sikarskie and Cheatham, 1973)



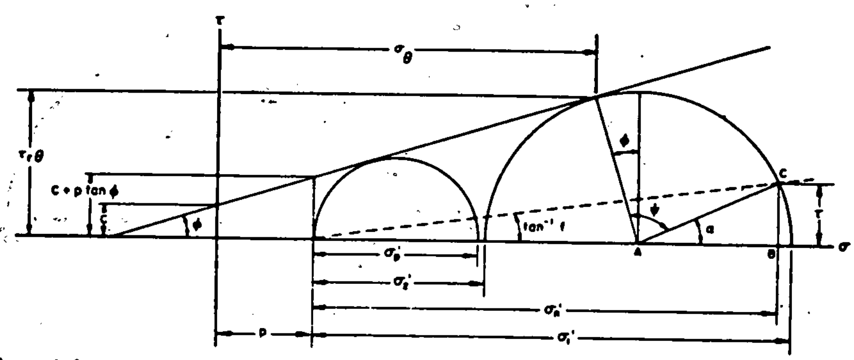
18. Idealized Fracture Path for Brittle Rock Penetration (Points X Denote Transition Points from Stable to Unstable Fracture Growth) (after Sikarskie and Cheatham, 1973)



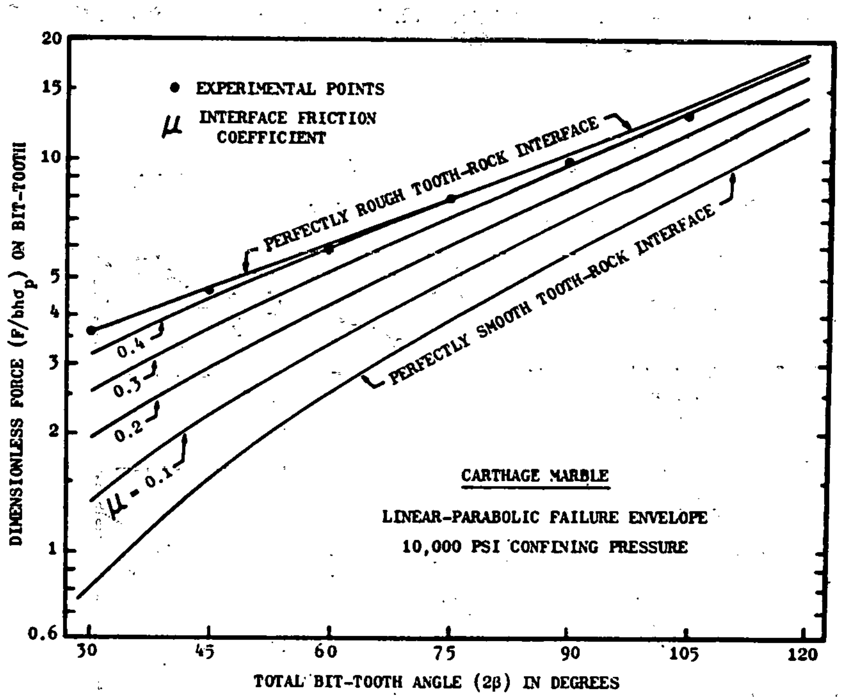
19. Contour Map of the Fracture Function F (after Sikarskie and Cheatham, 1973)



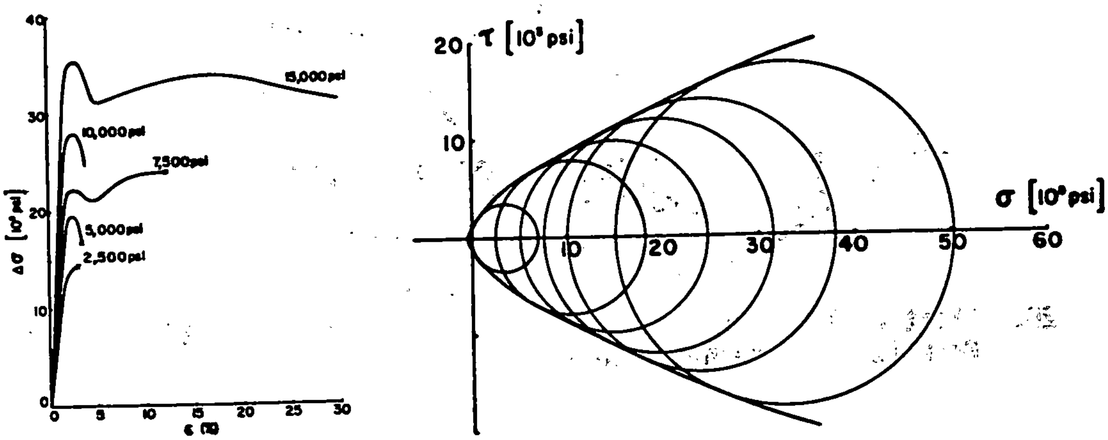
20. Plastic Slip-Line Field for Sharp Bit-Tooth Penetration of Ductile Rock (after Cheatham, 1963)



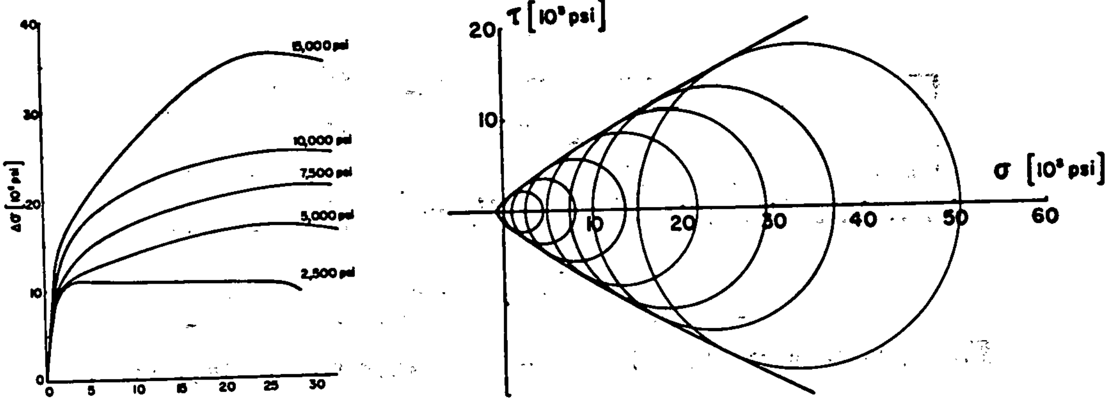
21. Linear Mohr-Coulomb Failure Envelope (after Cheatham, 1963)



22. Comparison Between Calculated and Experimental Slopes of Force-Penetration Curves for Carthage Marble Using Parabolic Failure Envelope (after Cheatham and Gnirk, 1966)

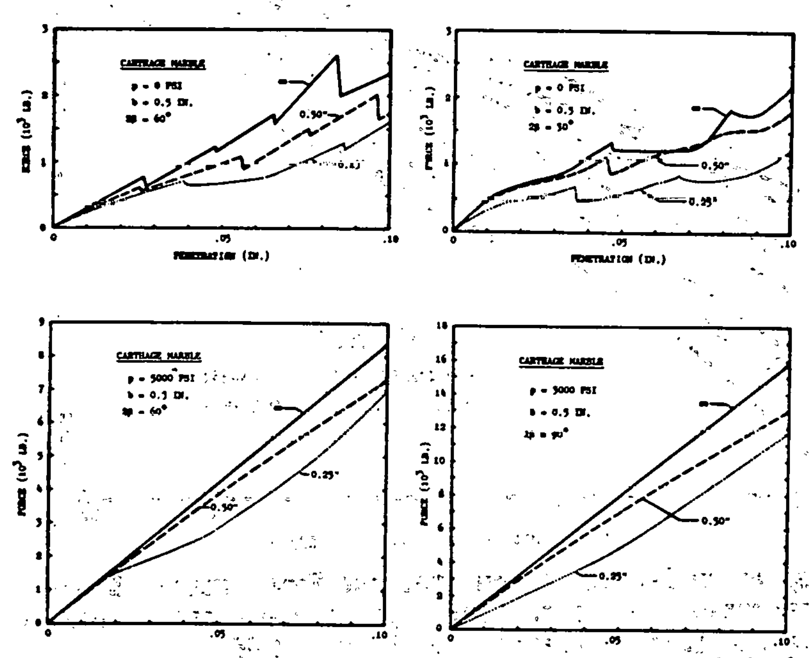


(A) Berea Sandstone

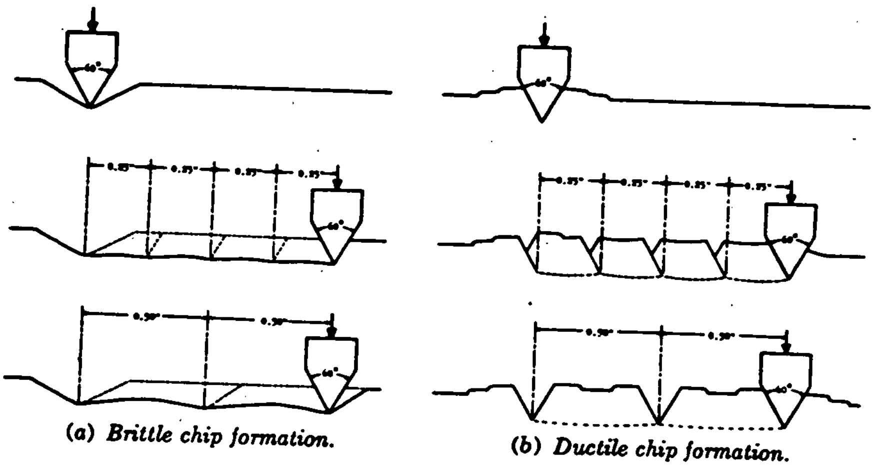


(B) Indiana Limestone

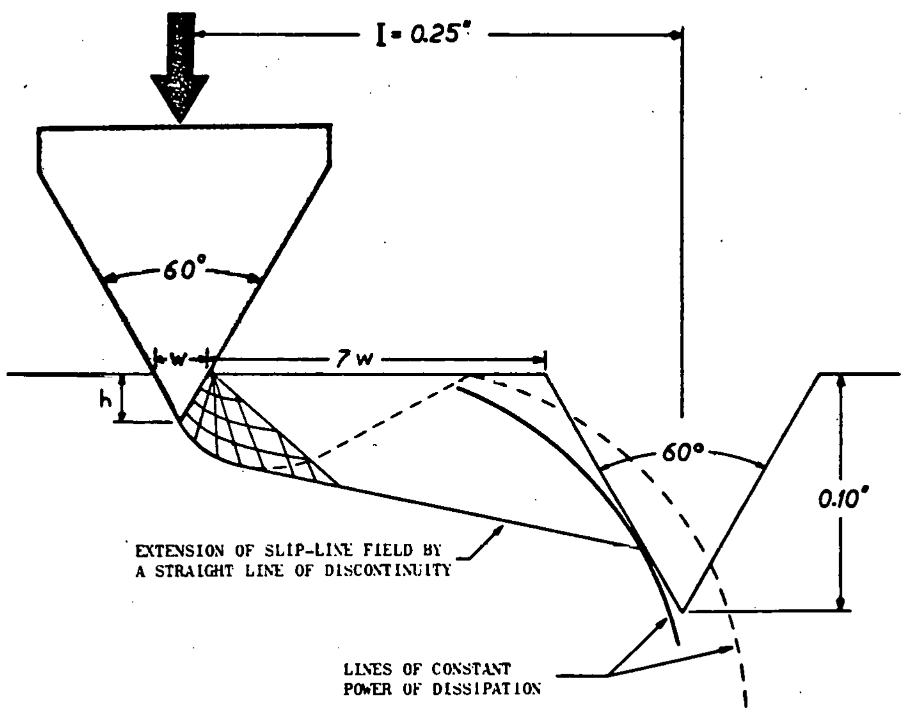
23. Triaxial Test Results for Berea Sandstone and Indiana Limestone (after Cheatham and Gnirk, 1966)



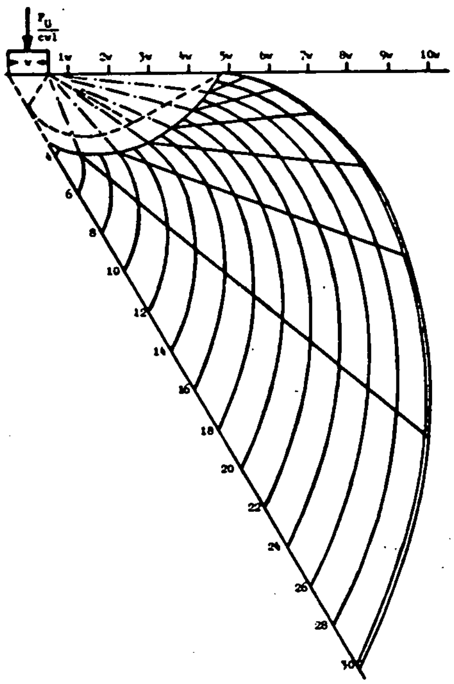
24. Force-Penetration Curves for Carthage Marble with Indexing (after Gnirk, 1966)



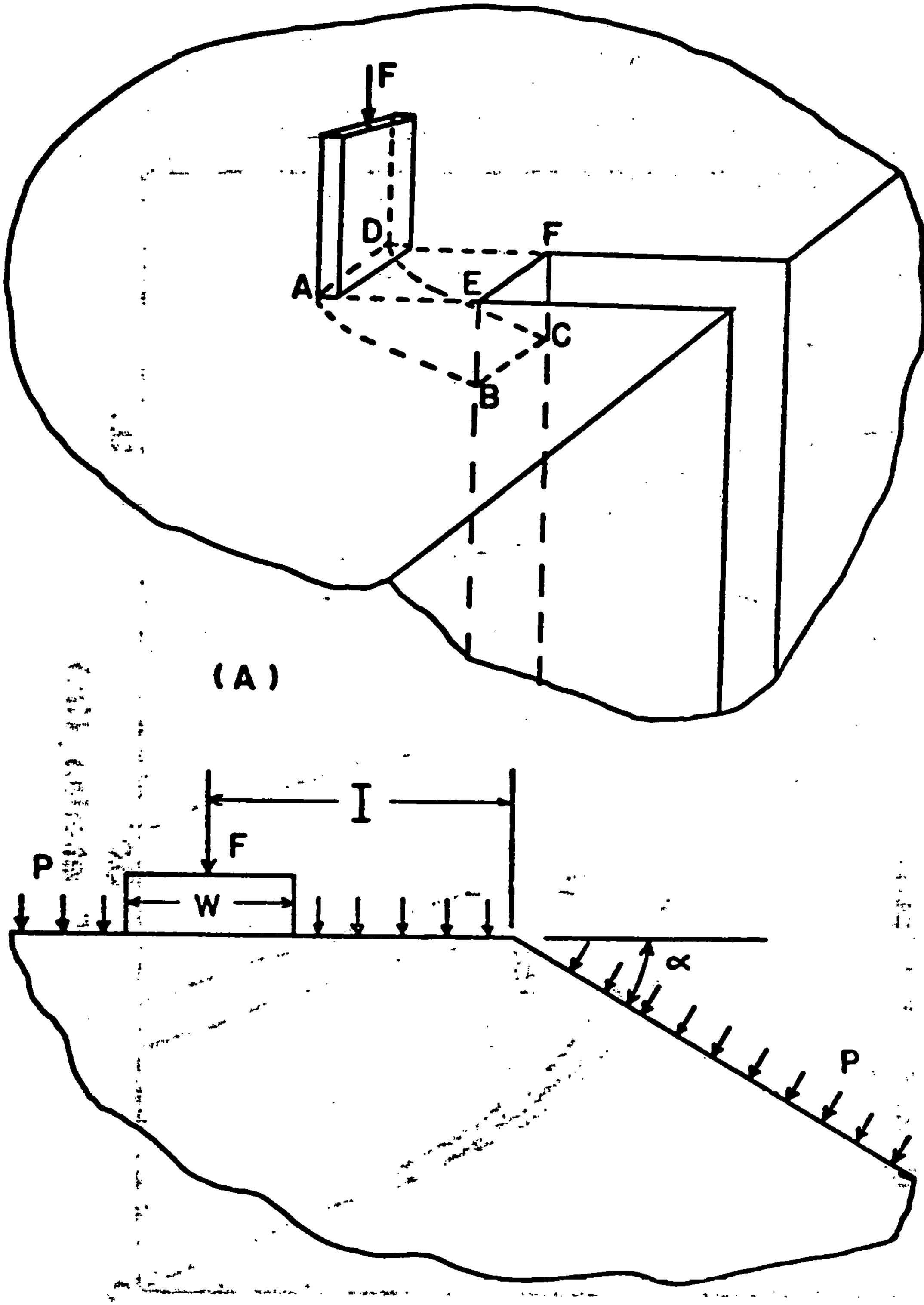
25. Features of Indexing for Brittle and Ductile Chip Formation (after Gnirk, 1966)



26. Minimum Power of Dissipation Concept Applied to Indexed Penetration by a Sharp Bit-Tooth (after Cheatham and Gnirk, 1966)

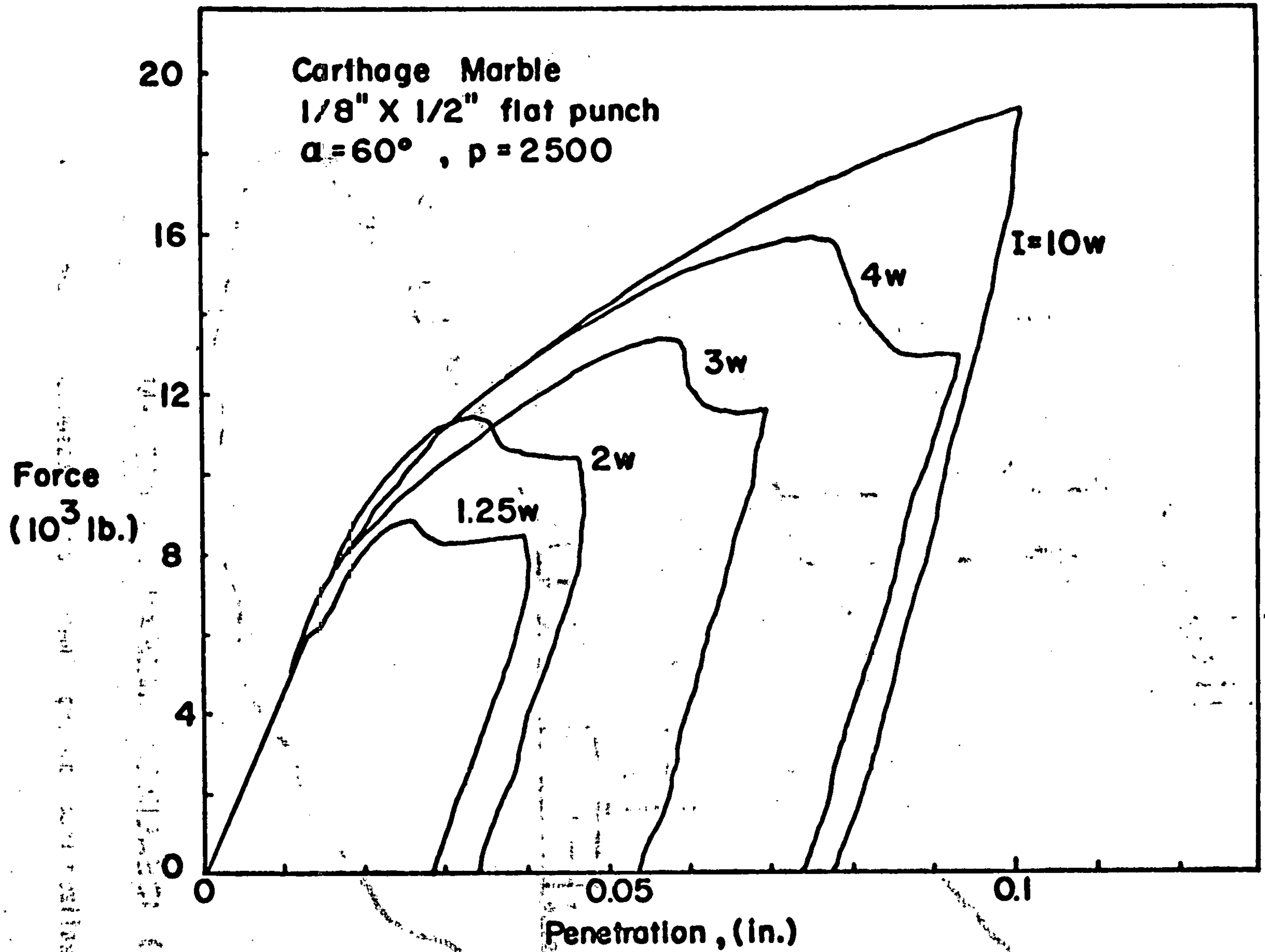


27. General Plot for the Power of Dissipation Corresponding to a Flat Punch and Rock with an Angle of Internal Friction of 30° (after Cheatham and Pittman, 1966)

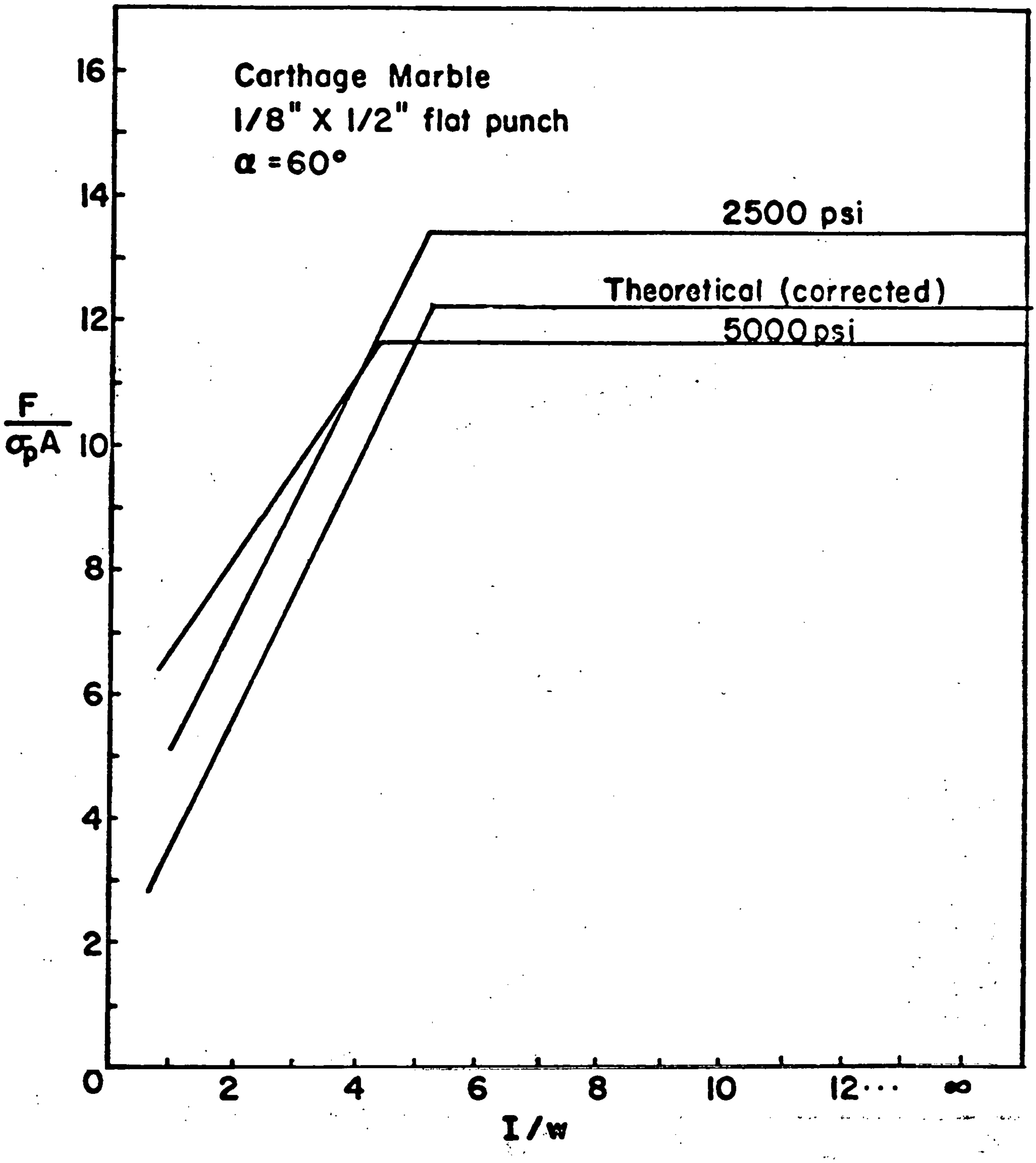


(B) IDEALIZED INDEXING PROBLEM

28. Idealized Indexing Experiments (after Musselman and Cheatham, 1972)

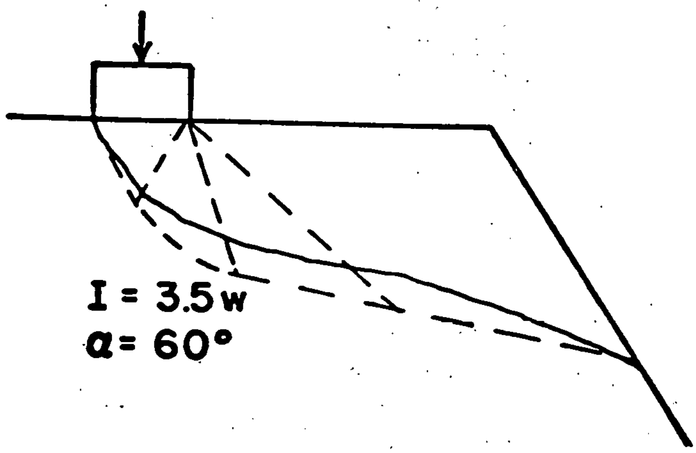


29. Force-Penetration Curves for Indexing Experiments on Carthage Marble (after Musselman and Cheatham, 1972)

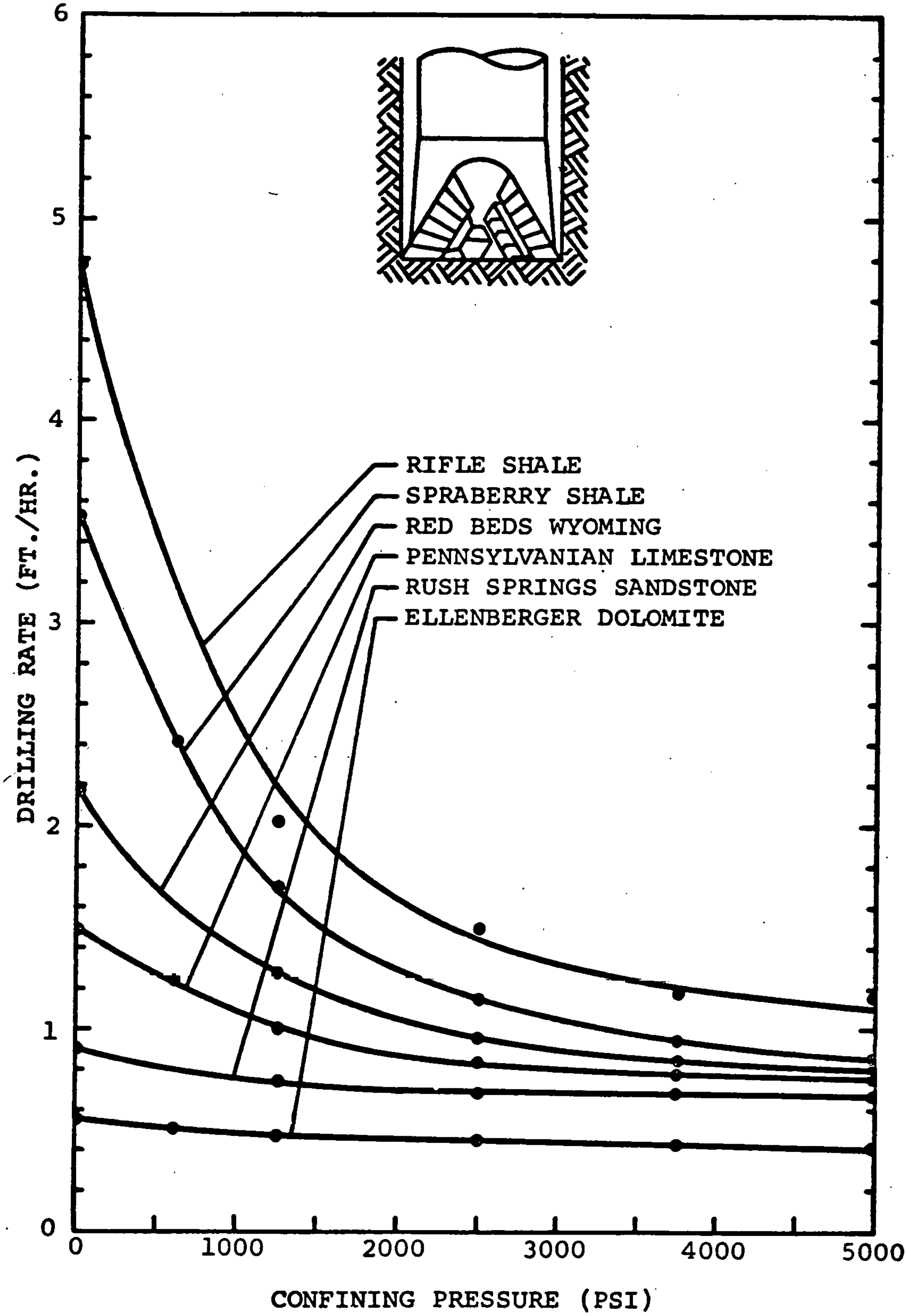


DIMENSIONLESS FORCE – INDEXING DISTANCE.

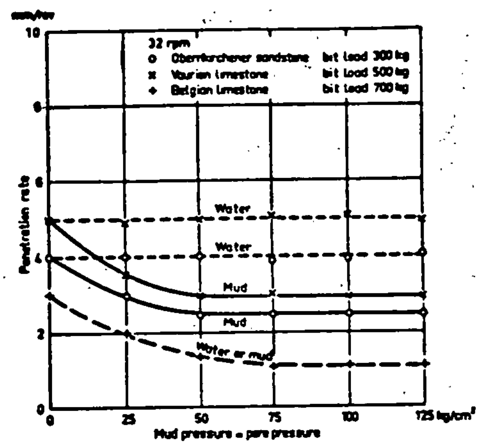
30. Comparison of Experimental Indexing Results for Carthage Marble with Calculations Corrected for End Effects (after Musselman and Cheatham, 1972)



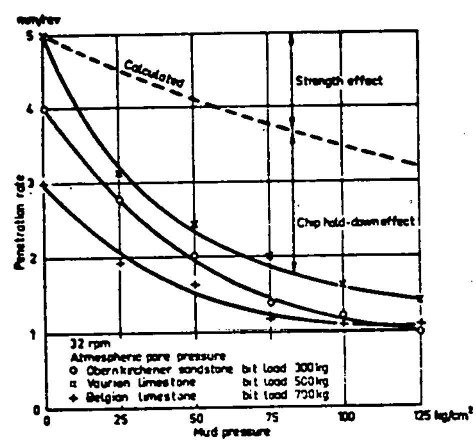
31. Comparison of Actual Failure Path with Path Predicted by Theory (Musselman and Cheatham, 1972)



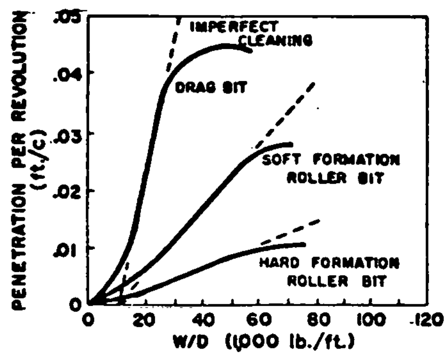
32. Microbit Drilling Results for Impermeable Rocks Subjected to Water Pressure (50 RPM and 1,000 lb. weight-on-bit)



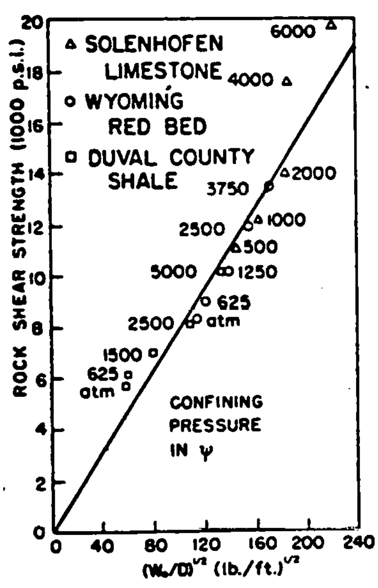
33. Drilling Penetration Rate as a Function of Pressure (after Garnier and Van Lingen, 1959)



34. Drilling Penetration Rate as a Function of Mud Pressure at Atmospheric Pore Pressure (after Garnier and Van Lingen, 1959)



35. Comparison of Drilling Performance of Various Bit Types (after Bingham, 1964)



36. Correlation Between Shear Strength and Drilling-Performance Line Intercept (after Bingham, 1964)

APPENDIX B

DEFINITION, JUSTIFICATION AND SELECTION OF ROCK

A TOPICAL REPORT ON THE LITHOLOGY AND PHYSICAL PROPERTIES OF DEEP OIL AND GAS RESERVOIR ROCKS

by

H. R. Pratt

ABSTRACT

A program to select formations representative of rock drilled during the exploration and exploitation of deep oil and gas reservoirs was conducted. The lithology, mechanical and physical properties, geologic structure and physical conditions of the formations penetrated during deep drilling were investigated. Candidate rock types were collected and their physical and mechanical properties determined. On the basis of this study, representative rocks of a variety of lithologies including sandstones, shales and carbonates (limestone and dolomite) were selected for this drilling program.

INTRODUCTION

In order to obtain rock samples for the ERDA Drilling Optimization Program that realistically simulate those in deep reservoirs, a study was performed to determine the lithology, structure, physical and mechanical properties of rock from major oil and gas fields in the continental United States. The important properties affecting drilling process included porosity, density, and strength. The physical conditions at reservoir depths were investigated and include pressure, temperature and the chemistry of pore fluids.

The major oil and gas fields in the United States included in this study were those with oil and/or gas production at depths of 10,000 feet or greater. These included 1) the mid-continent area, Oklahoma and Texas, 2) the west Texas area, 3) the Gulf Coast area and 4) the Rocky Mountain area.

On the basis of data obtained from these deep oil and gas fields a list of candidate rock types of appropriate lithologies was selected for use in the program. The final selection of the rock types used in the program was based on their availability and suitability as representative of lithologies occurring in deep oil and gas fields.

DEEP RESERVOIRS

Petroleum Provinces

Petroleum and natural gas provinces having deep reservoirs are located in several areas in the continental United States. For the purpose of this study deep reservoirs are defined as those with depths of 10,000 feet or greater. While several areas were given initial consideration for study, four major fields were selected for detailed analysis. These are 1) Mid-continent field, Texas and Oklahoma, 2) West Texas field, 3) Gulf Coast field, Texas, Louisiana and Mississippi and 4) the Rocky Mountain field, Colorado, Utah and Wyoming. The lithology and material properties of the formations in both the reservoir and rock penetrated above the reservoir will be discussed in detail. In addition, the geologic structure will play an important role in drilling. The physical conditions at depth including pressure, temperature and the chemistry of the fluids at depth were also considered. The object of this study is to delineate the basic rock types and physical conditions that are encountered during deep drilling for the production of oil and gas.

Mid-Continent Field

The mid-continent field in Oklahoma and Texas consists of a series of basins lying to the north of the Ouchita Mountains, Witchita Mountains and Amarillo Uplift[1]. The producing zones, in places, are located at depths up to 30,000 feet in some areas of the Anadarko Basin, Arkoma Basin and Dalhardt Basin (Figure 1). Production from oil and gas from these deep basins has been significant over the past several years. Cross sections of the Anadarko Basin (Figures 2 and 3) and the Dalhardt Basin (Figure 4) show wells that have penetrated the Cambrian Arbuckle dolomite at depths of greater than 20,000 feet. The world's record Lone Star Producing, Baden No. 1, 31,441 feet deep, was drilled in 1974. The formations penetrated in these deep wells consist mostly of limestone, sandstone and dolomite with only minor shale. The deep reservoir strata, the Simpson and Arbuckle formations, consist of sandstone and dolomite, respectively, while production from the upper part of the section consists primarily of limestone as exemplified by the Chester and Pre-Chester Mississippian formations and sandstone-shale sequences exemplified by the Morrow Formation. Future potential oil and gas fields in the area of the Anadarko Basin and surrounding areas are shown in Table I and illustrate that producing zones range in age from the Cambrian Arbuckle dolomite in the deep basin up through the Morrow sandstone located on the basin shelf to the Leonardian sandstone at shallow depths. These potential reserves are found in both structural and stratigraphic traps. Table II shows reservoir rocks of varying lithologies that have been tested by Terra Tek. The shales and sandstones from the Atoka and Morrow formations from depths of 14,000 to 18,500 feet have porosity in range between 3.0 and 7.3 percent. The porosity in the limestone and dolomite units at great depth will primarily be fracture porosity rather than pore porosity unless these carbonates are of a highly vuggy nature. The strengths of the reservoir rocks from the Mid-continent and Rocky Mountain fields indicate that strength varies significantly depending on parameters such as porosity, the composition of the matrix, and the composition of the cement (see Figure 5). It appears that representative rocks from the Mid-continent field are well indurated sandstones, limestones and dolomites with minor shales.

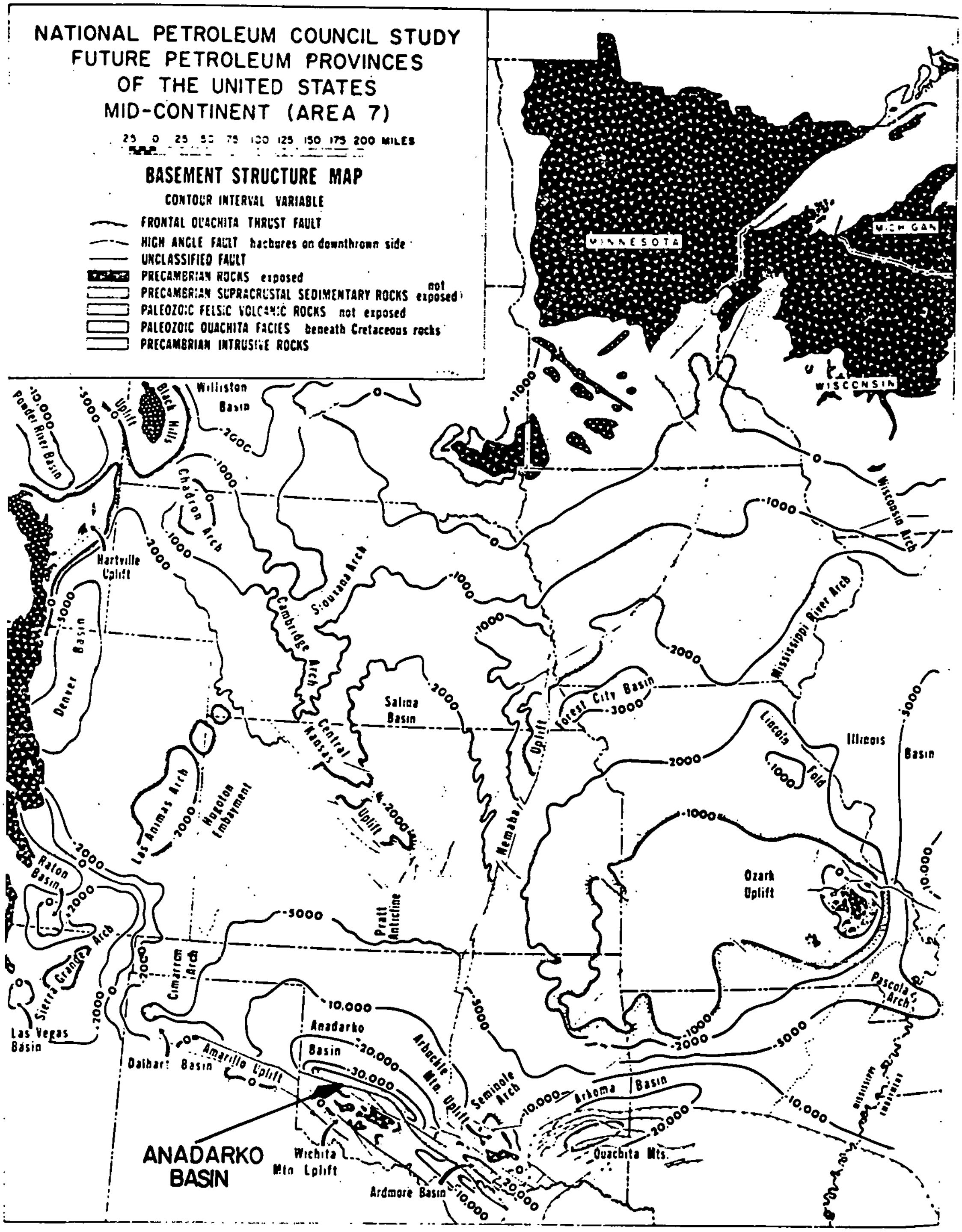


Figure 1. Basement structure map of the Mid-continent region[1].

TABLE I

Future Potential Oil and Gas Areas

Rock Unit	*Prospective Area(s)*	*Type Trap*	*Oil or Gas*	*Estimate of Potential*[1]
Leonardian & Wolfcampian ss.	S. Anadarko basin	Structural	Gas, oil	Insignificant
Virgilian & Missourian ss. & ls.	NW Anadarko shelf (ls.-ss.)	Struct. & strat.	Gas	Significant (ls.) Insignificant (ss.)
	S. Anadarko basin (ss.)	Structural	Oil	Insignificant (ss.)
Desmoinesian & Atokan (ls. & ss.)	Anadarko shelf (ls.-ss.)	Stratigraphic	Gas, oil	Significant (ss.) Significant (ss.)
	E. flank Nemaha ridge and Seminole arch (ss.)		Oil	Insignificant (ss.)
Morrowan (ss.)	Anadarko basin shelf and deep basin	Stratigraphic	Gas	Significant
	Seminole arch	Structural	Oil	Insignificant
Chesteran (ls.)	Anadarko shelf	Stratigraphic	Gas	Insignificant
Springer (ss.)	S. Anadarko basin	Struct. & strat.	Gas, oil	Significant
Pre-Chesteran Miss. (ls.)	Anadarko shelf	Fract. reservoir	Oil	Insignificant
Hunton (dol.)	Anadarko shelf and deep basin	Structural & stratigraphic	Gas, oil	Significant
Viola (dol.)	Anadarko shelf Seminole arch	Structural	Oil	Insignificant
Simpson (ss.)	W. Anadarko shelf and deep basin	Structural	Gas, oil	Significant
	Seminole arch		Oil	Insignificant
Arbuckle (dol.)	Deep Anadarko basin Seminole arch	Structural & poss. strat.	Gas Oil	Insignificant (struct.) Possibly significant (strat.)

[1]Significant potential is more than 25 million bbl of oil or 500 billion cu ft of gas.

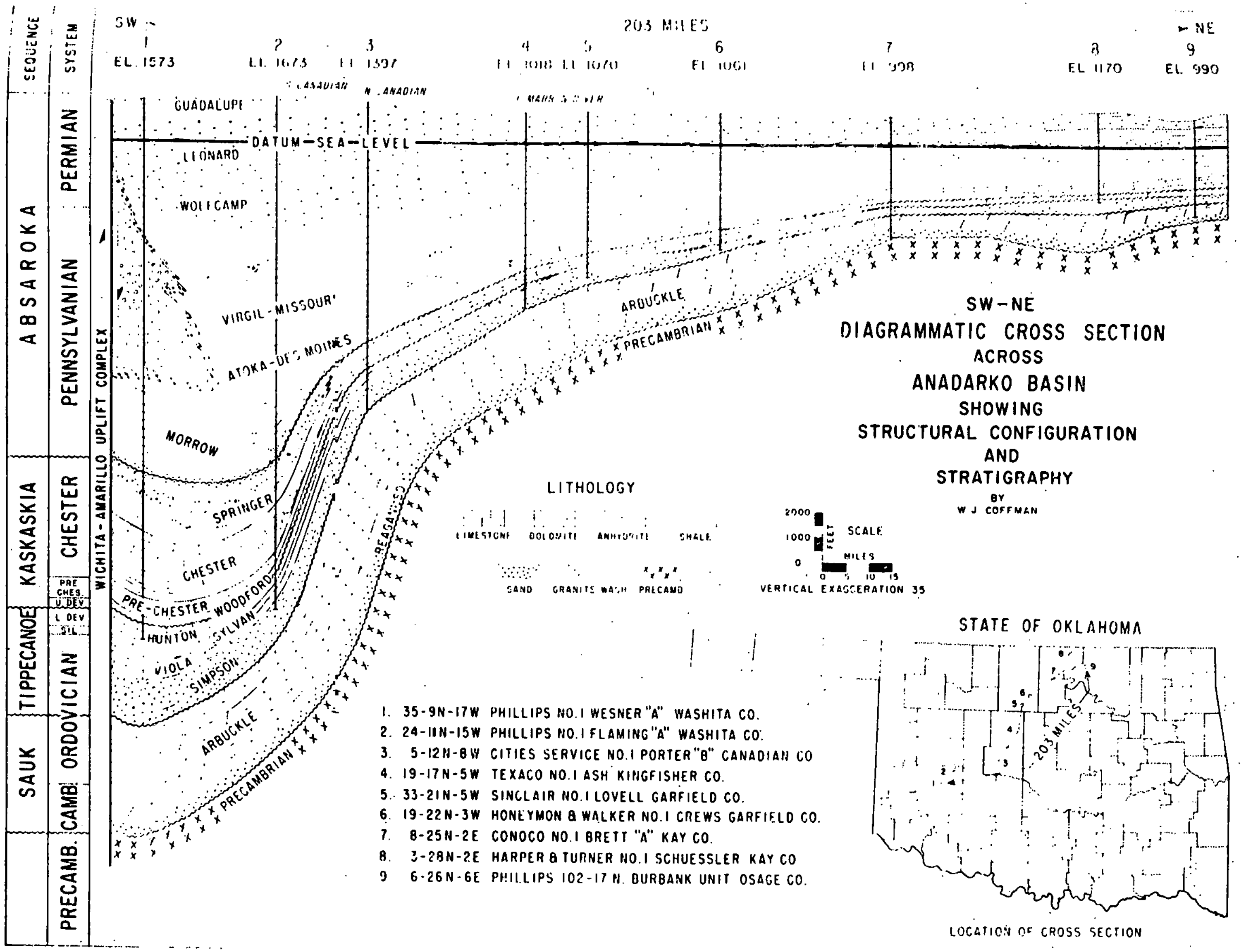


Figure 2. Diagrammatic cross section of the Anadarko Basin showing structural configuration and stratigraphy[1].

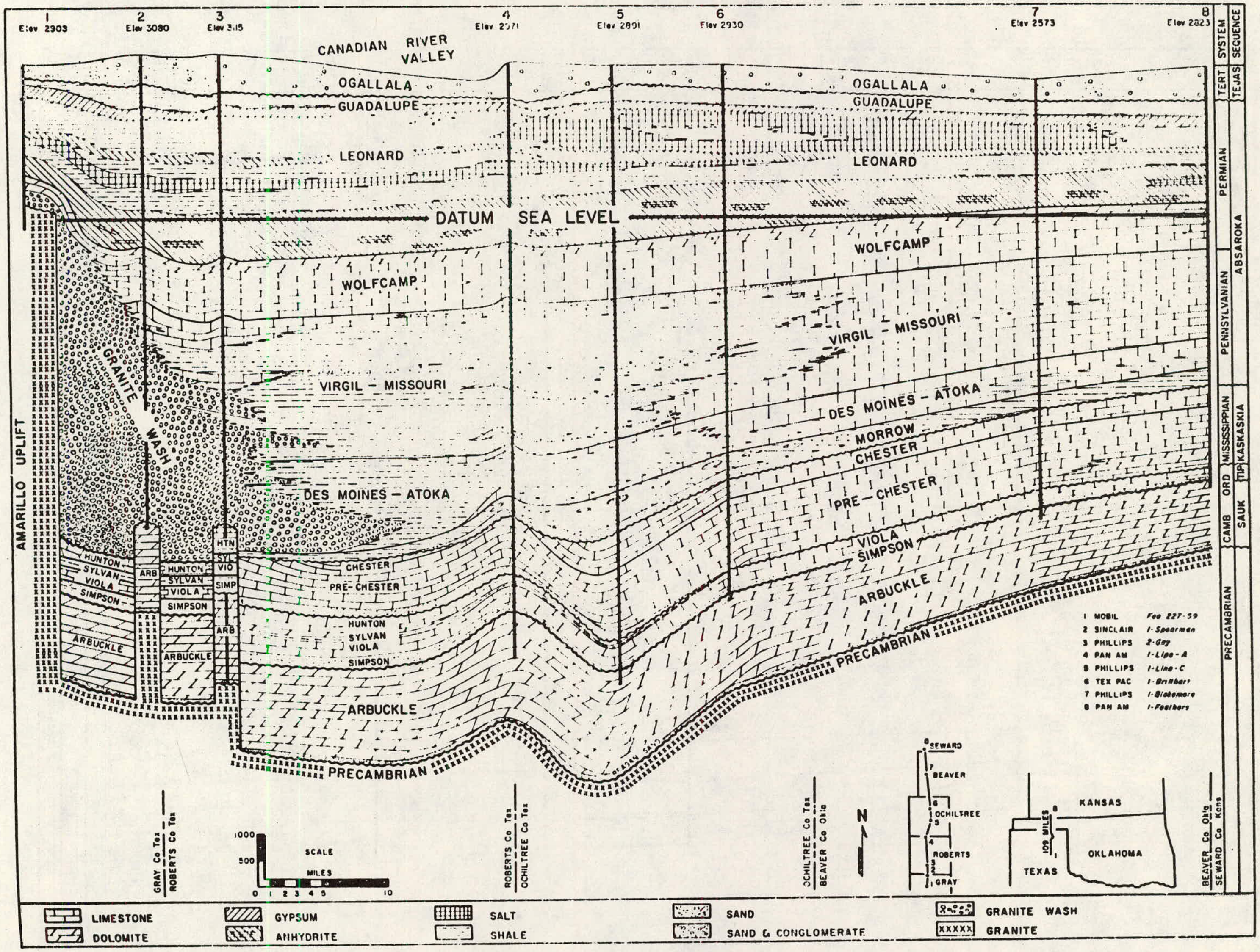


Figure 3. Diagrammatic cross section of Anadarko Basin in Texas and Oklahoma panhandle[1].

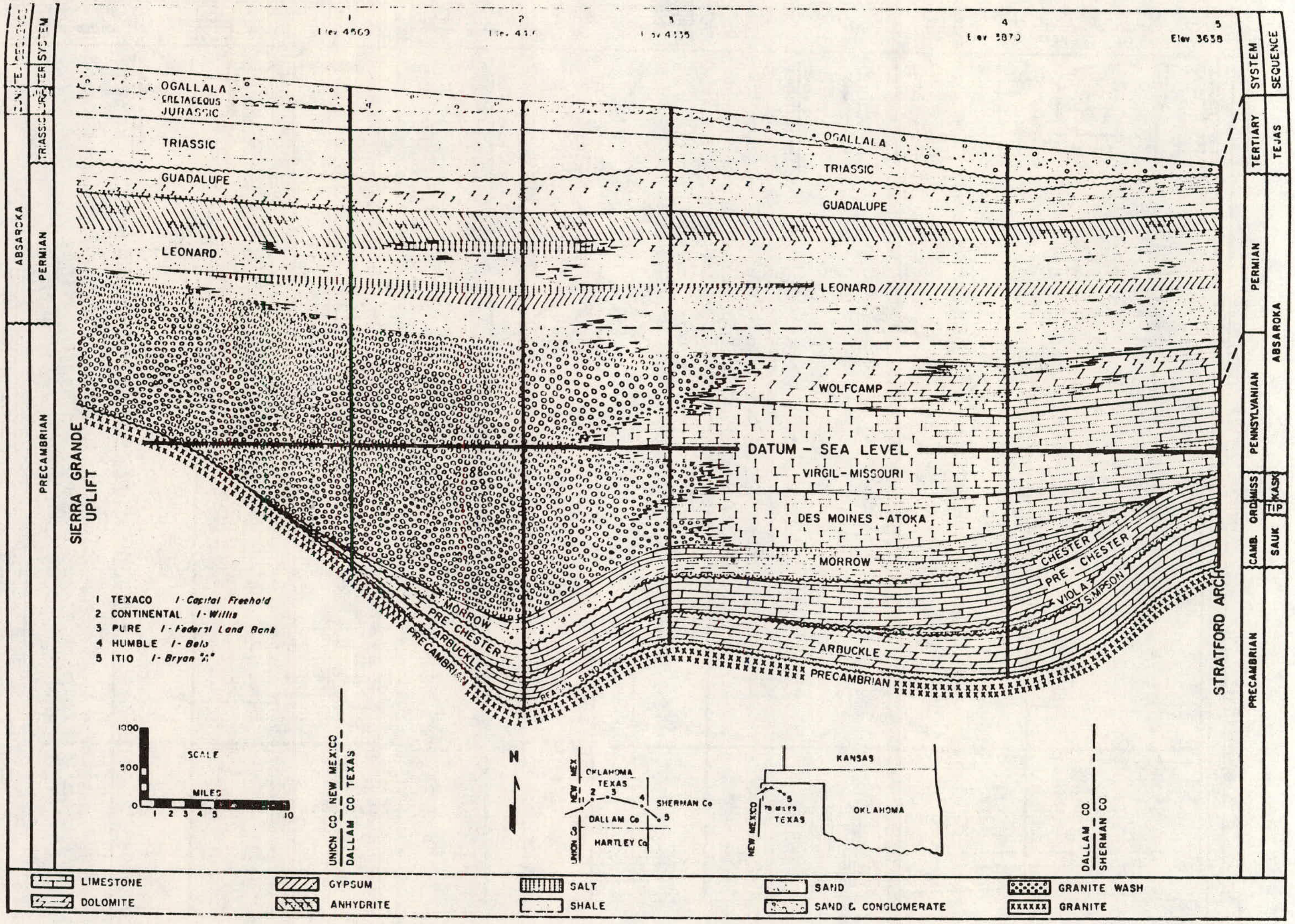


Figure 4. Diagrammatic cross section of Dalhardt Basin in Texas showing structure and stratigraphy[2].

TABLE II

Lithology and Porosity of Reservoir Rocks[3,4]

Rock Type	Formation	Depth (ft)	Porosity (%)
Shale	Atoka	14,616	3.2
Sandstone	Morrow	17,982	3.0
Shale	Morrow	18,490	7.3
Sandstone	Lance	10,812	8.6
Sandstone	Lance	8,995	5.7
Sandstone	Muddy J	7,978	9.5
Sandstone	Fort Union	6016-6032	4.4-7.9
Sandstone	Mesa Verde	6795-6797	6.8-8.2
Silty sandstone	Mesa Verde	6,838	1.8
Sandstone	Mesa Verde	6,263	13.7
Limestone and dolomite	Ellenberger	Outcrop	3.0
Dolomite	Beekmantown	11,945	0.4
Limestone	Smackover	8000-20,000	5-30

West Texas Field

The West Texas gas and oil field contains several basins which have produced vast quantities of oil and gas. In particular, the Central Basin Platform, the Midland and Delaware Basins (Figure 6)[5]. Typical sections of the rocks penetrated are shown in Figures 7 and 8[5,6]. Figure 7 is a composite log from several wells in the Keystone Field showing the complete stratigraphic section from the Permian to top of the Precambrian. The Ellenburger dolomite located at a depth of 10,100 feet in Figure 7 (Keystone Field) and at a depth of greater than 13,500 feet in Figure 8 (Pegasus Field) is one of the primary reservoir rocks. Production in both of these fields is primarily from limestones and dolomites with minor reservoirs occurring in sandstones. Structural traps dominate the Keystone Field. Most of the traps are associated with anticlinal folding, sometimes terminated by faulting as exemplified by the Ellenburger dolomite reservoirs. Occasionally stratigraphic traps are present as exemplified by some of the Wolfcampian rocks. A structure cross section (Figure 9) for the Keystone illustrates the relatively simple structure found in the West Texas area[5]. Note that in both of these sections (Figures 7 and 8) the large footage of carbonate rock (limestone and dolomite) penetrated during drilling. In fact, only a small portion of the section consists of sandstones, shales and evaporites. Figure 10 is a composite section from a Verhalen field in the Delaware Basin showing a higher percentage of clastic rocks and a lower percentage of carbonate rocks[7]. The Verhalen field has had only marginal production and is located at the southwest edge of the Delaware Basin. This section is higher in the stratigraphic column than the rocks in the Keystone and Pegasus fields with only the Permian and Pennsylvanian formations penetrated. Production is from the permeable

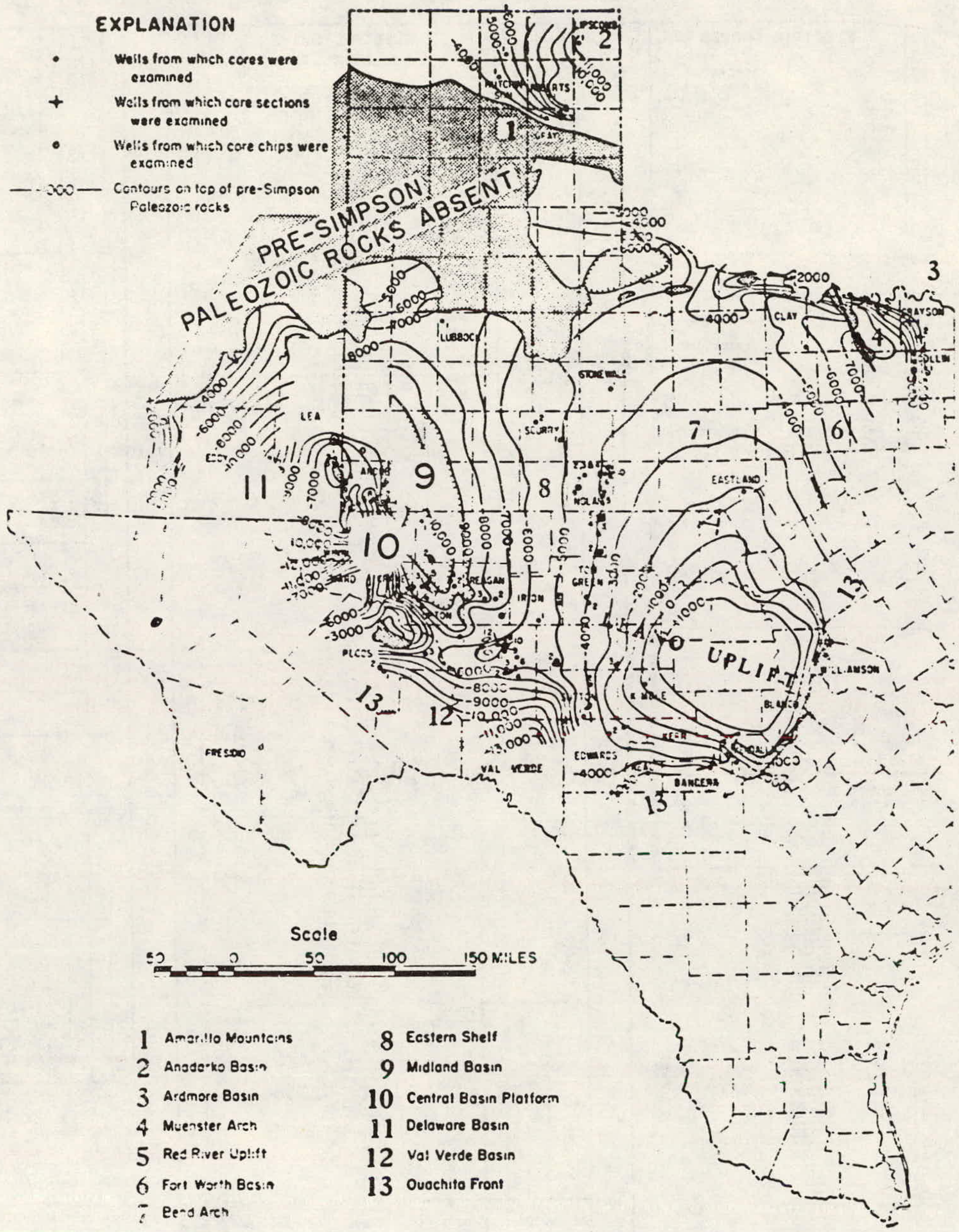


Figure 6. Map showing present configuration on top of Pre-Simpson sequence of Paleozoic rock in Texas and location of primary producing basins[5].

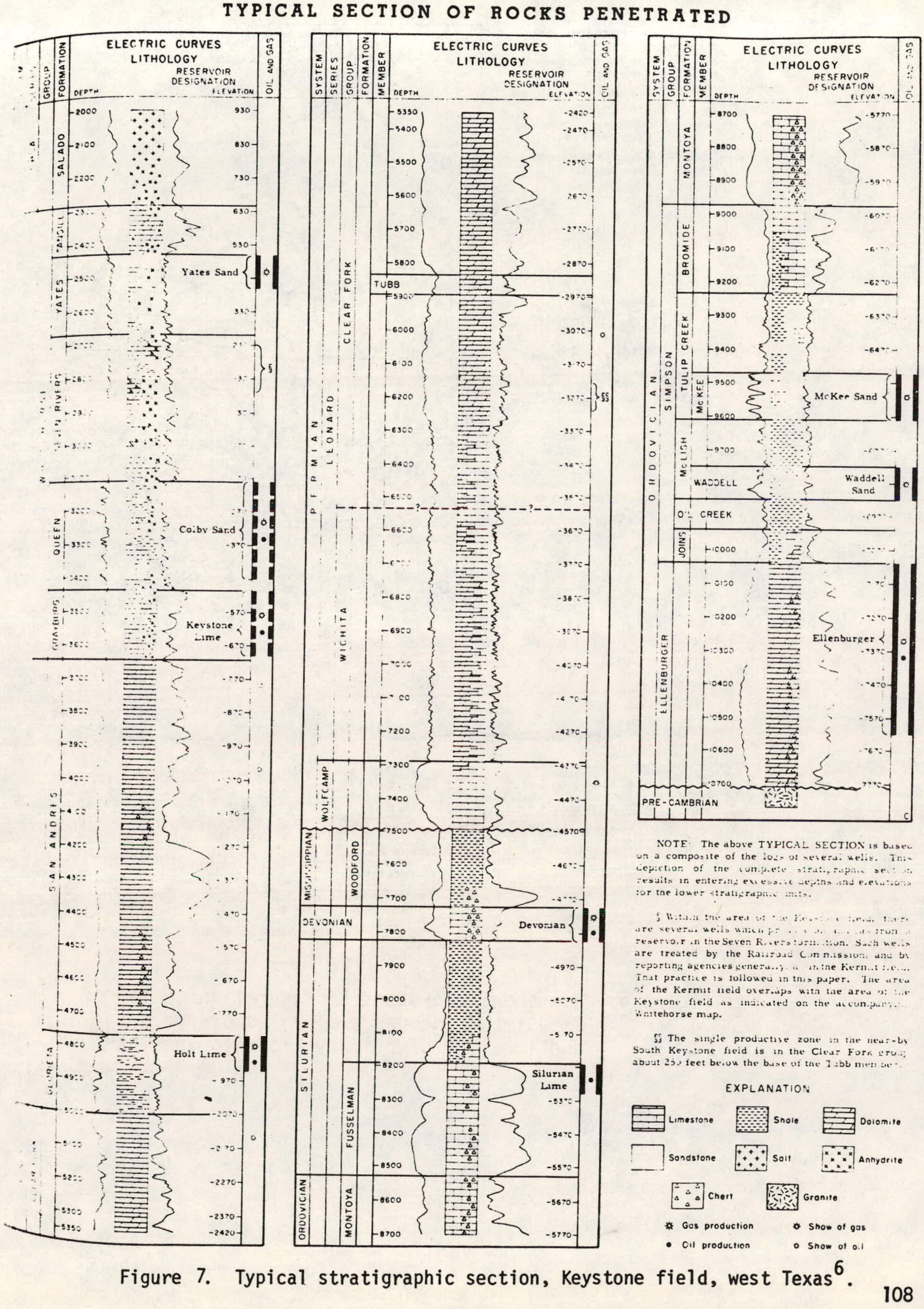
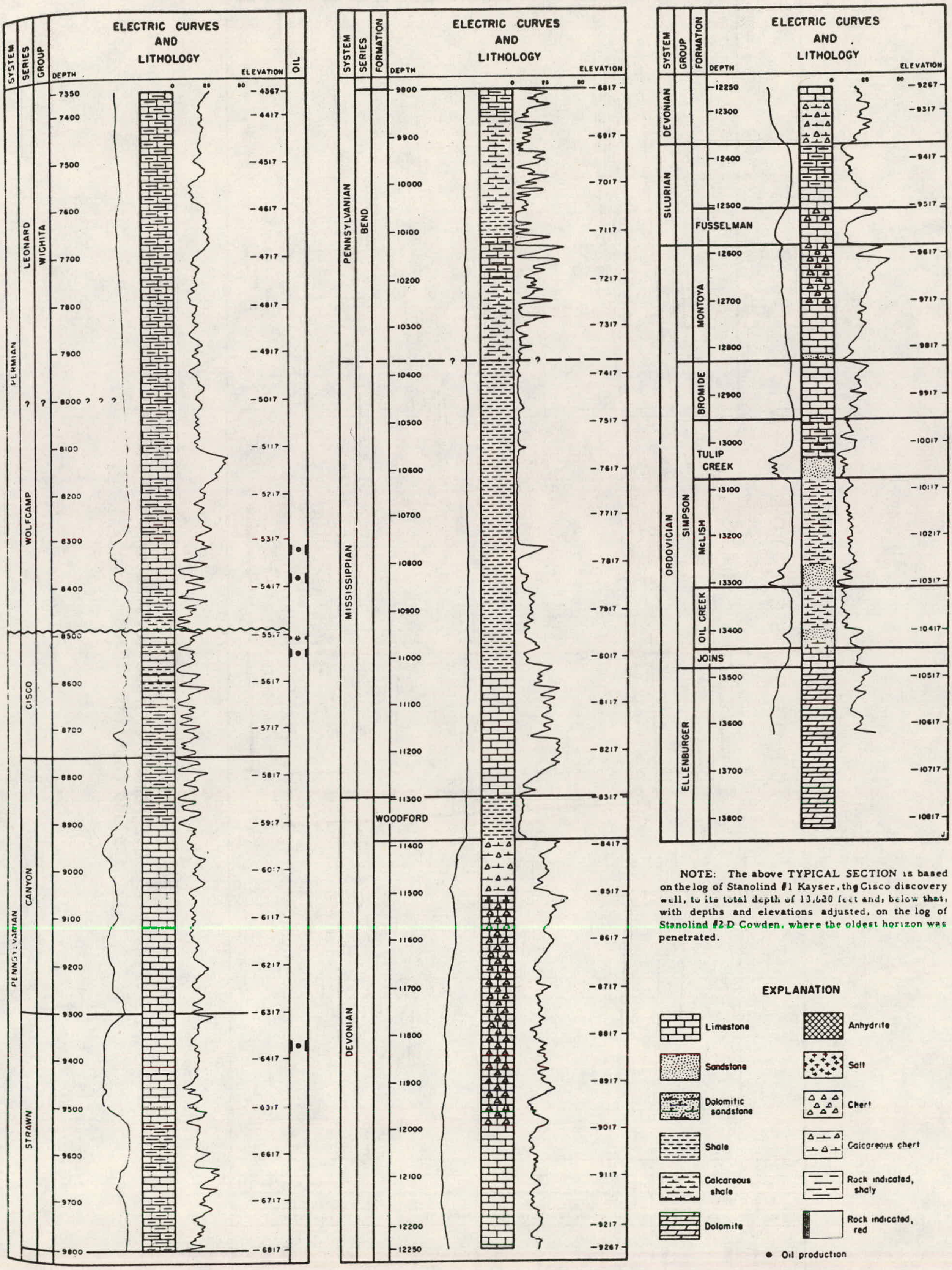


Figure 7. Typical stratigraphic section, Keystone field, west Texas[6].

TYPICAL SECTION OF ROCKS PENETRATED



NOTE: The above TYPICAL SECTION is based on the log of Stanolind #1 Kayser, the Cisco discovery well, to its total depth of 13,620 feet and, below that, with depths and elevations adjusted, on the log of Stanolind #2 D Cowden, where the oldest horizon was penetrated.

Figure 8. Composite section from Pegasus field, west Texas.

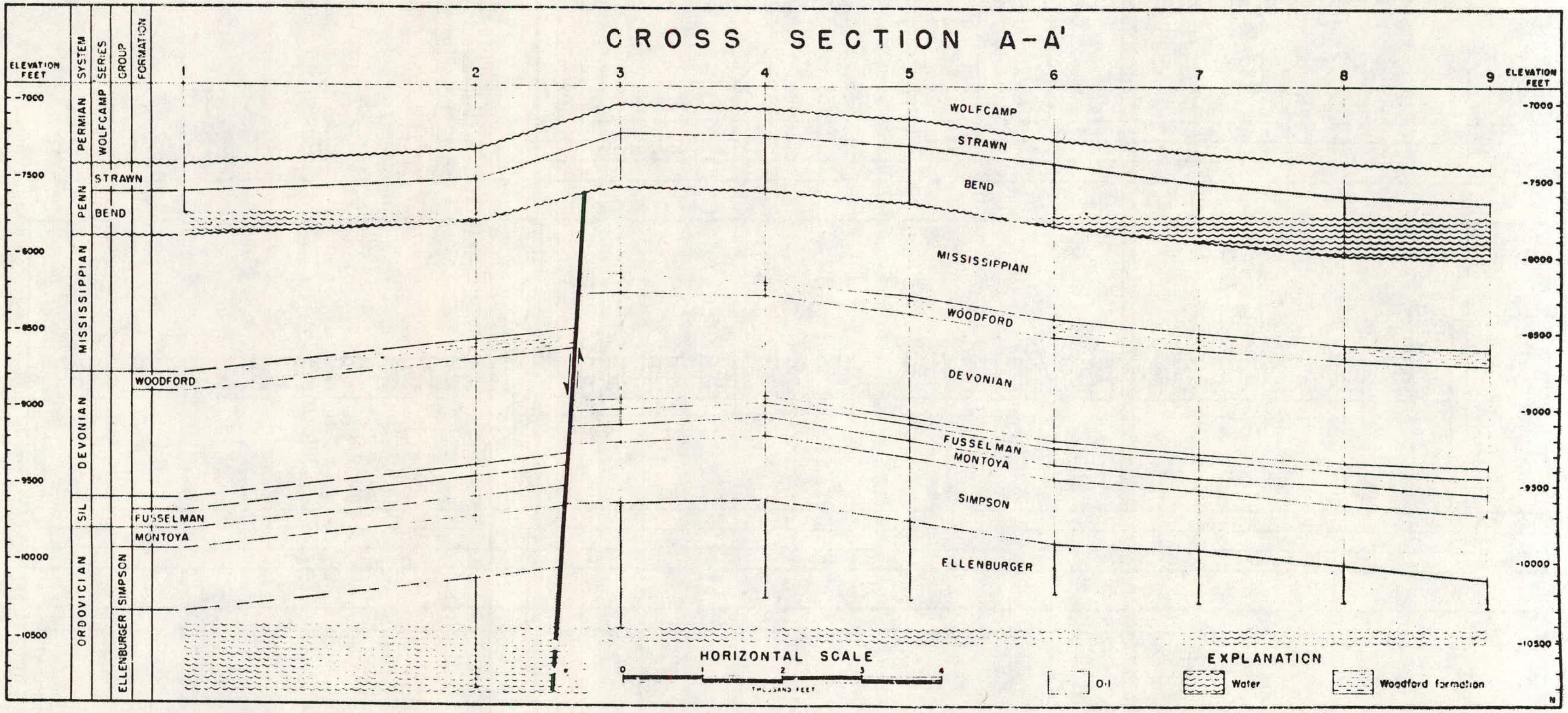


Figure 9. Diagrammatic cross section of the Pegasus field in Middle and Upland counties, Texas[7].

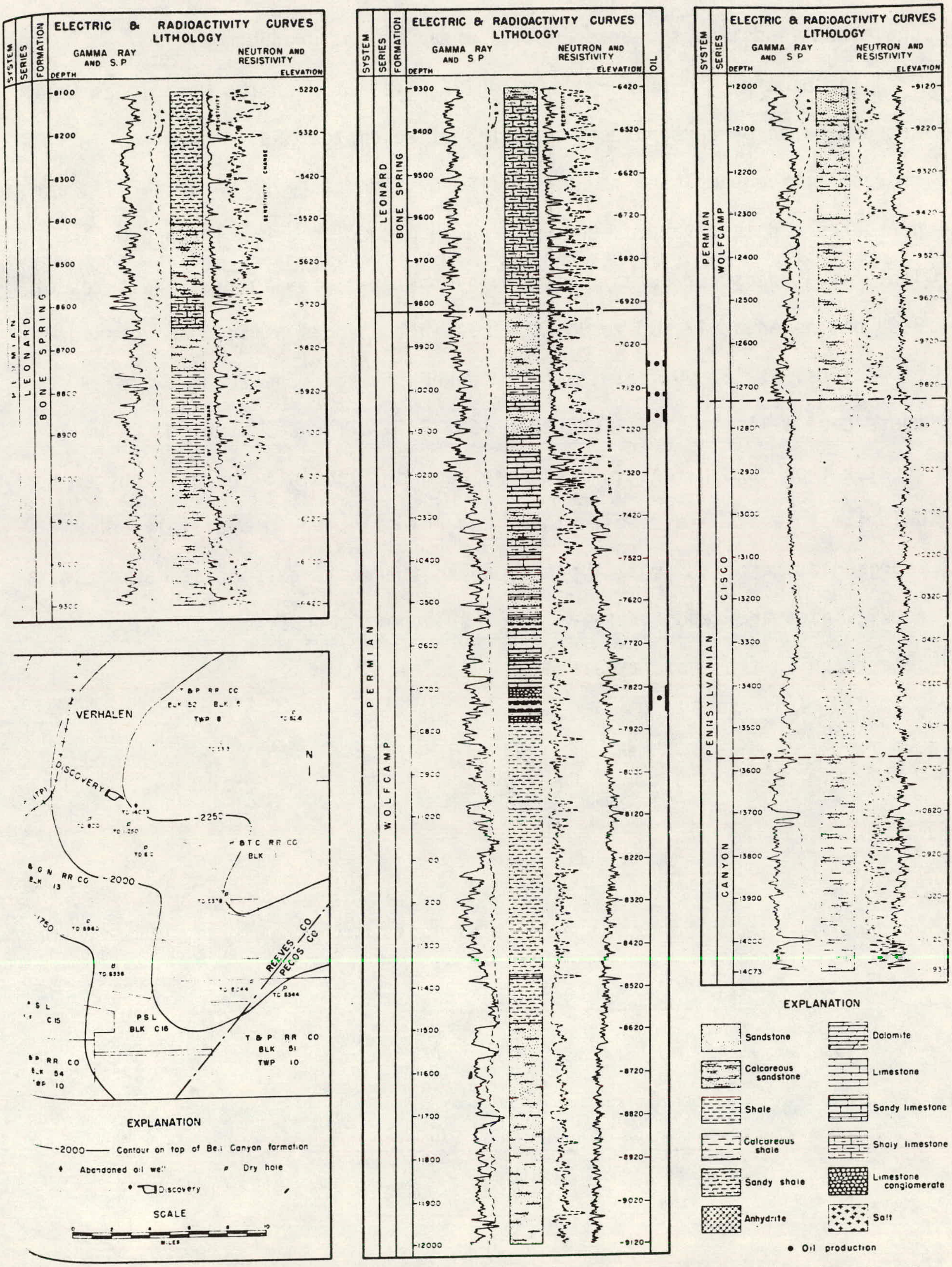


Figure 10. Typical stratigraphic section in the Verhalen field, Reeves County, Texas. This section shows the significant section of sandstones and shales and minor limestones[8].

Wolfcampian series at depths on the order of 10,000 feet. The Pennsylvanian shale and sandstone sequence in this area was not productive.

In summary, the primary lithologies penetrated in the West Texas Basin are dominated by carbonates consisting of dolomites and limestones. A representative sample of the deep wells drilled is given in Table III, and pressures and temperatures encountered in producing zones in deep wells in Table IV. Pressures appear to be subhydrostatic with initial pressures of 5668 psi noted at 12,500 to 13,000 feet in the Pegasus Field and pressures of 4664 psi at 11,800 feet in the Deep Rock Field. The temperature of these deep wells are low, less than 160° F in all cases studied. A well greater than 30,000 feet in depth has been drilled into the Ellenburger dolomite in West Texas. Limestones and dolomites would certainly be representative of the rock types found in the West Texas area. Some clastic rock, shales and sandstones, as well as evaporite deposits, are also penetrated in the West Texas area.

TABLE III

Key Well Summary, West Texas Area

Company	Lease	County	Total Depth
Gulf Oil Corporation	#1 John Haggard	Roberts	12,597
Gulf Oil Corporation	#1 McElroy-State	Upton	12,762
Gulf Oil Corporation	#1 Mitchell Bros.--State	Presidio	15,996
Gulf Oil Corporation	#1-E Porter "A"	Lipscomb	14,278
Gulf Oil Corporation	#1-E State "AM"	Andrews	12,924
Humble Oil & Refining Company	#1 Miller	Collin	11,407
Magnolia Petroleum Company	#1 Nobles	Midland	13,538
Magnolia Petroleum Company	#2-A Windham	Midland	13,099
Phillips Petroleum Company	#1 Glenna	Pecos	14,522
Phillips Petroleum Company	#1 Wilson	Val Verde	16,456
Richardson & Bass	#1 Federal-Cobb	Eddy, N.M.	16,469
The Superior Oil Company	#1-36-A University	Andrews	12,637
Wilshire Oil Company	#14-130 McElroy	Upton	12,235
Wilshire Oil Company	#23-118 Windham	Upton	12,868

TABLE IV

Reservoir Data from West Texas Fields

Field	Formation	Lithology	Depth	Pressure (i)[1]	Pressure (p)[2]	Temp.° (F)
Dollarhide	Fusselman	Dolomite	8700	3555	2655	-
	Ellenburger	Dolomite	10,300	3630	2730	
Keystone	Devonian	Limestone	7800	3388	-	125
	Fusselman	Limestone	8200	3377	-	120
	McKee	Sandstone	9500	4128	-	140
	Ellenburger	Dolomite	10,300	4283	-	145
Pegasus	Bend	Limestone	10,300	4567	3000	-
	Ellenburger	Dolomite	12,500-13,300	5668	3600[3]	
Shafter Lake	Shafter Lake	Dolomite (Sandy)	6900	2210	-	108
Deep Rock	Wolfcamp	Limestone	8400	3414	-	125
	Pennsylvanian	Limestone	8700	2825	-	127
	Devonian	Limestone	9600	4200	-	135
	Ellenburger	Dolomite	11,800	4664	-	152

1. Initial pressure in reservoir (psi)

2. Pressure at time of publication (1955).

3. Reinjection at 3500 psi @ 13,000 feet was a record (1955).

Gulf Coast Field

Production of oil and gas from deep wells in the Gulf Coast area comes primarily from the Upper Jurassic clastic section (Haynesville and Schuler formations) and the lower Jurassic Smackover limestone formation (Figure 11[9]). The structure contour map on the top of the Smackover formation shows that depths 15,000 to 20,000 feet are required to reach the top of the formation in central Louisiana, Mississippi and Texas (Figure 12). The lithology of the producing zones in the Smackover formation is dominated by carbonate material consisting of dense limestones, oolitic carbonates and mixed carbonates (Figure 13)[9]. In some areas of the northeastern Louisiana and Mississippi the lithology is mixed carbonates and clastics.

Holes are now being drilled in the western Gulf Basin through the Jurassic section into pre-Jurassic formations[10]. These deep holes, drilled to depths as great as 20,000 feet, have pentrated lower Paleozoic formations (Table V). Other shallower wells have penetrated Jurassic and upper Paleozoic units. Cross sections in Arkansas and Southern Louisiana and Southeast Mississippi (Figures 14a and 14b) show the location of the Smackover lime and underlying Louann evaporite deposits composed of salt and anhydrite. The lithologies penetrated in the Gulf Coast area will consist of a significant section of shale in the upper part of the section. These shales, because of high montmorillonite content, are responsible for borehole stability problems[11,12].

The porosities and densities of these reservoir rocks vary over a wide range. The Smackover reservoir rock, for example, has porosity ranging from 5 to 30 percent and permeabilities ranging from 2 to 1400 md[9].

In summary, based on the general lithology of the section found in the Gulf Coast area, large sections of sandstone, shale and porous limestone will be representative for some of the very deep sections. Evaporite deposits of salt and anhydrite also comprise a portion part of the section.

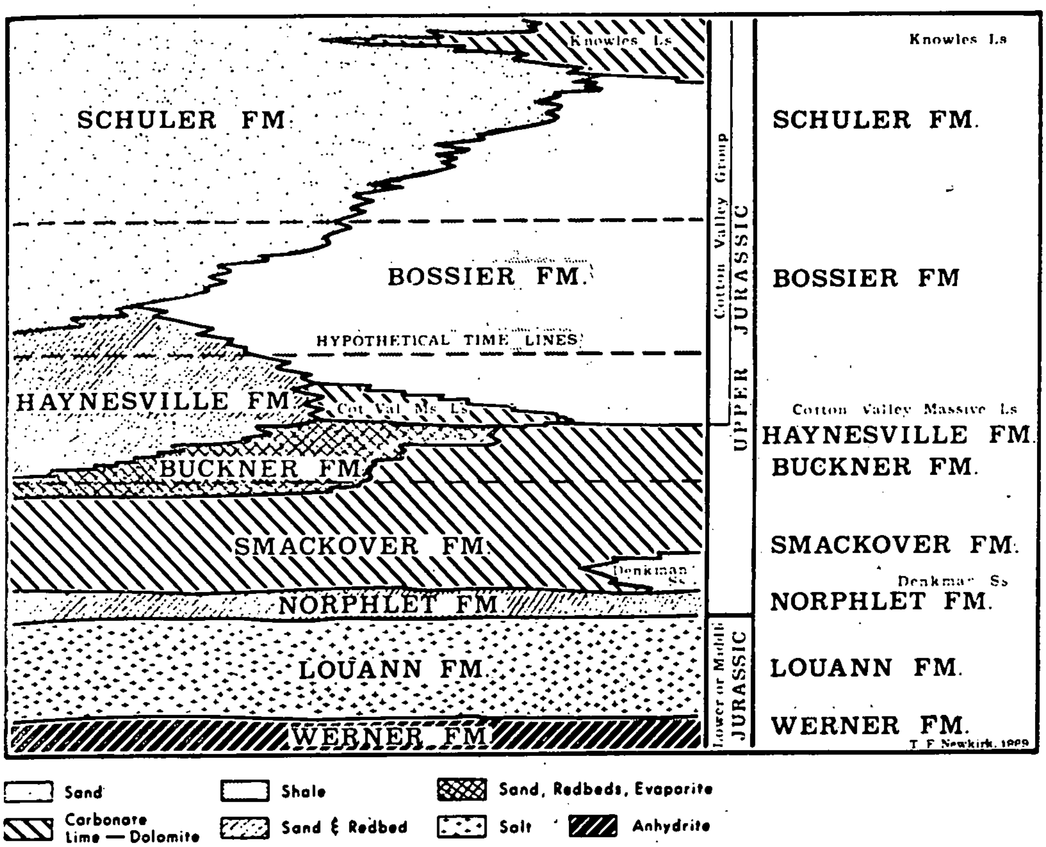


FIG. 1.—Geologic column. Schematic representation of Gulf Coast Jurassic section showing formation relations and hypothetical time correlations.

Figure 11. Schematic representation of Jurassic Gulf Coast stratigraphy showing formation relations[9].

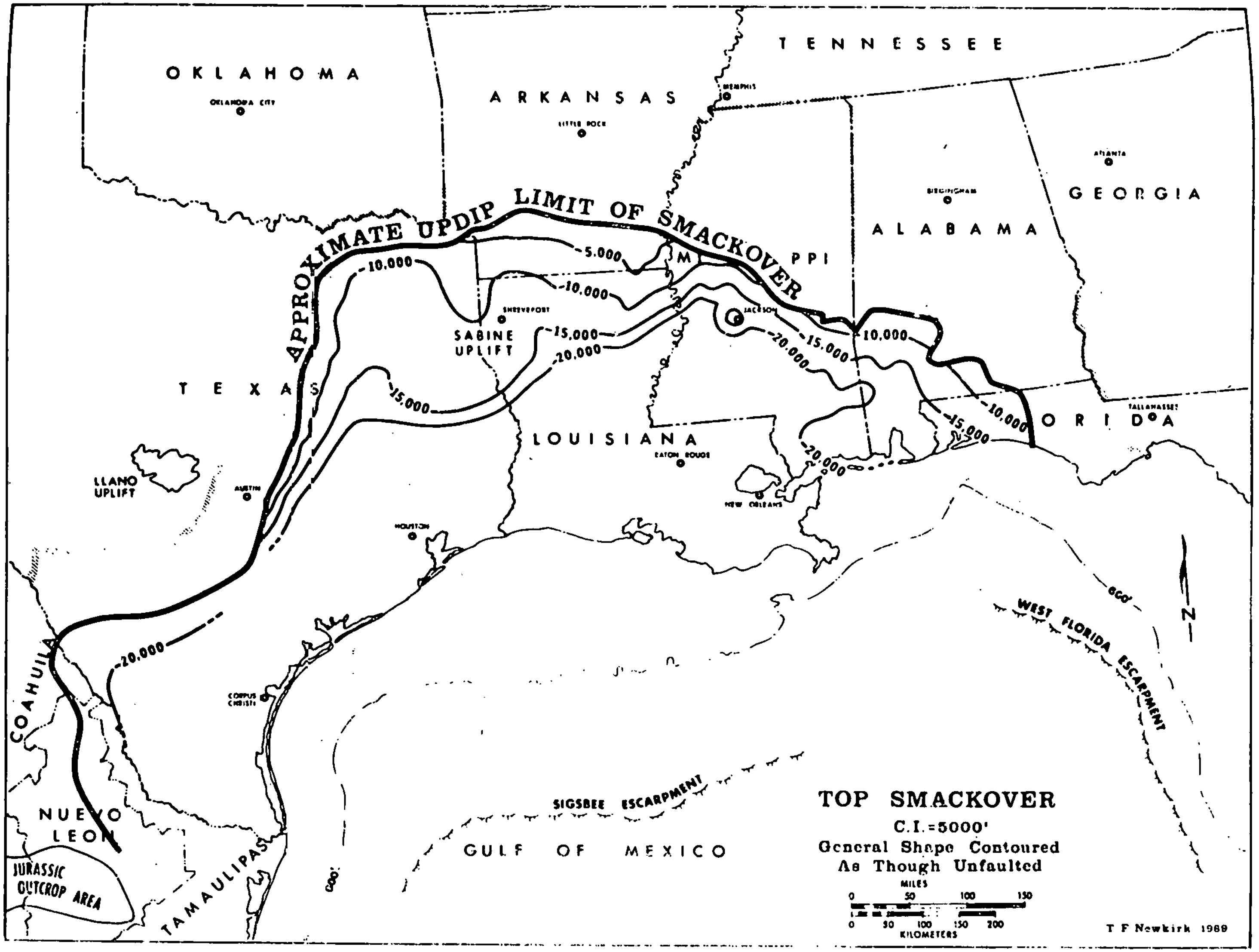


Figure 12. Regional contour map on top of Smackover formation, western Gulf Basin[9].

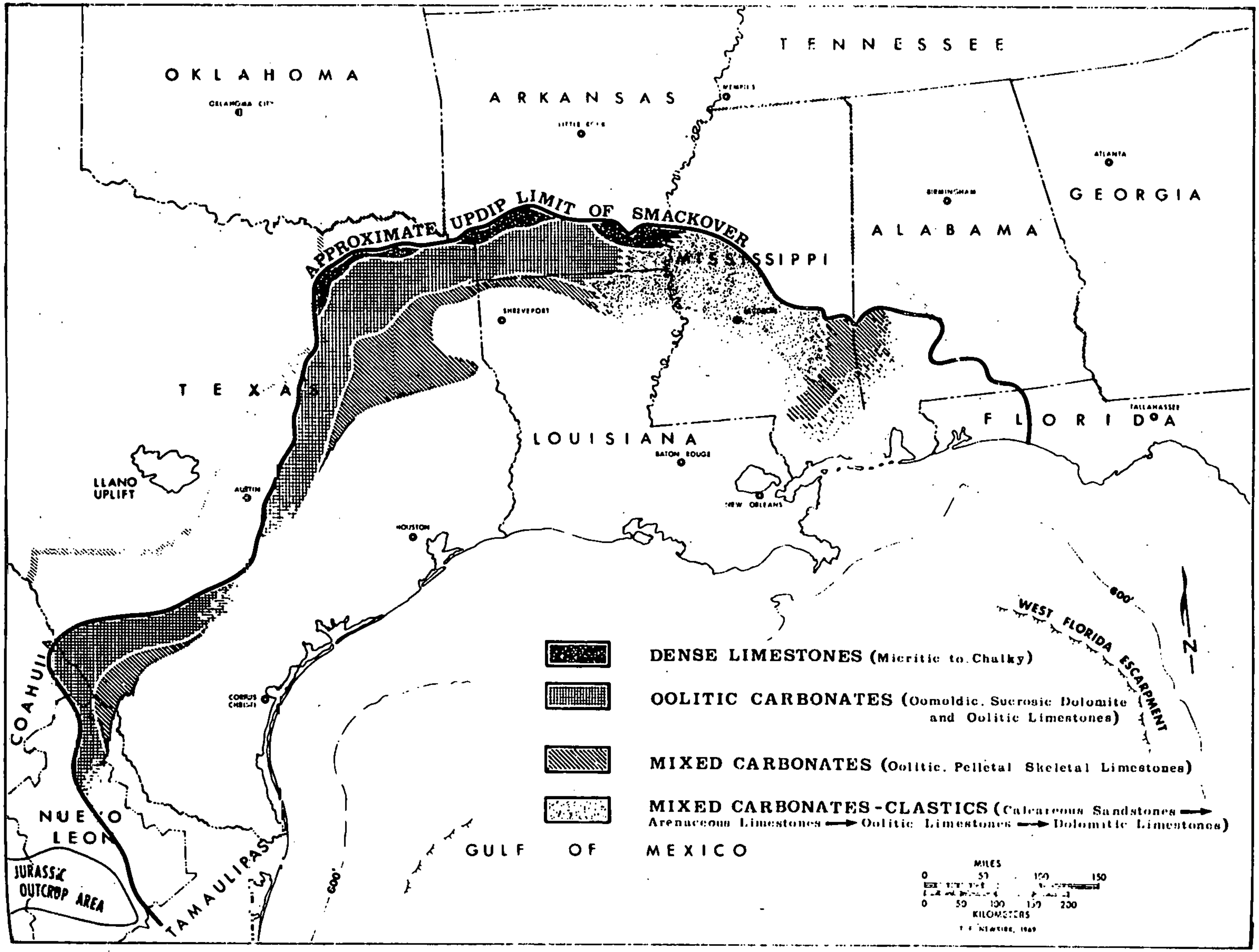


Figure 13. Region lithologic variation in the Smackover limestone, a major production zone in the Gulf Coast area[9].

TABLE V

Key Well Summary, West Gulf Pre-Jurassic Basin[10]

MAP NO.	WELL NAME	TOP (FT.) PRE-JURASSIC	TOTAL DEPTH (FT.)	COMMENTS
1	Humble, Bandera School Land No. 1	13,462 (-12,553)	13,869	Jur. (?) red beds on metavolcanics at TD (Flawn et al., 1961).
2	Mobil, Byrne No. 1	15,705 (-14,959)?	16,152	TD in intbd. red bds and lava flows-Triassic (?)
3	Pan Am., Buerger No. 1	16,528 (-15,883)?	17,483	Jur. on Triassic (?) red bds and basalt.
4	Magnolia, McKinley No. 1	11,910 (-11,296)	11,951	Jur. gravels on metamorphics. Pebbles contain fusulinids.
5	Pagenkopf, Blum No. 1	4,580 (- 3,867)	7,197	Cret. on Permian red beds.
6	Mobil, Bundick No. 1	10,500 (-10,100)	14,285	Cret. on Triassic (?) red beds. No palynology.
7	Texas Gulf Sulphur, Baker No. 1	9,302 (- 8,857)	12,593	Triassic on non-folded red beds, on Ouachita metased.
8	Cockburn, Buie No. 1	5,980 (- 5,578)	7,045	Jurassic on Triassic variegated shales.
9	Stanolind, Norris No. 1	9,892 (- 9,364)	9,950	Werner on Triassic (?) red beds. No palynology.
10	Humble, Marberry No. 1	13,266 (-12,807)	13,595	Jurassic on Triassic (?) red beds with igneous flows.
11	Humble, Geiger No. 1	9,134 (- 8,803)	10,527	Jurassic on Triassic (?) red beds—TD in red beds.
12	Humble, Calfee No. 1	9,608 (- 9,232)	11,012	Same-both tests drilled along Talco fault zone.
13	Placid, Dunn No. 2	13,840 (-13,516)	14,283	Werner on Permian (?) red beds.
14	Humble, Johnson No. 1	13,820 (-13,319)	16,824	Werner on Permian (?) red beds. Perm. alluvial on "flysch" at 15,600.
15	Amerada, Strickland No. 1	11,715 (-11,382)	12,533	Werner on igneous. Drilled 818 ft. diabase to TD.
16	Humble, Angelina Lumber No. B-1	17,780 (-17,525)	17,829	Acc. to Humble, TD is about 50 ft. below base Louann salt.
17	Humble, Royston No. 1	1,832 (- 1,360)	10,335	Penet. 6968 ft. Triassic red beds. Top Paleozoic at 8,800 ft.
18	Stanolind, Dillon Heirs No. 131	11,405 (-11,163)	11,419	Werner anhydrite on diabase.
19	Humble, Georgia Pacific Corp. No. 1	7,756 (- 7,632)	16,610	Penet. 1,596 ft. Triassic red beds; 7,258 ft. undiff. Paleozoic.
20	Union, Tensas Delta No. A-1	9,220 (- 9,149)	10,475	Jurassic on marine, Mid Penn.-Perm., Morehouse fm.
21	Shell, Barrett No. 1	3,904 (- 3,324)	20,310	6,050 ft. L. Paleoz. meta-carbonates beneath interior Ouachitas.

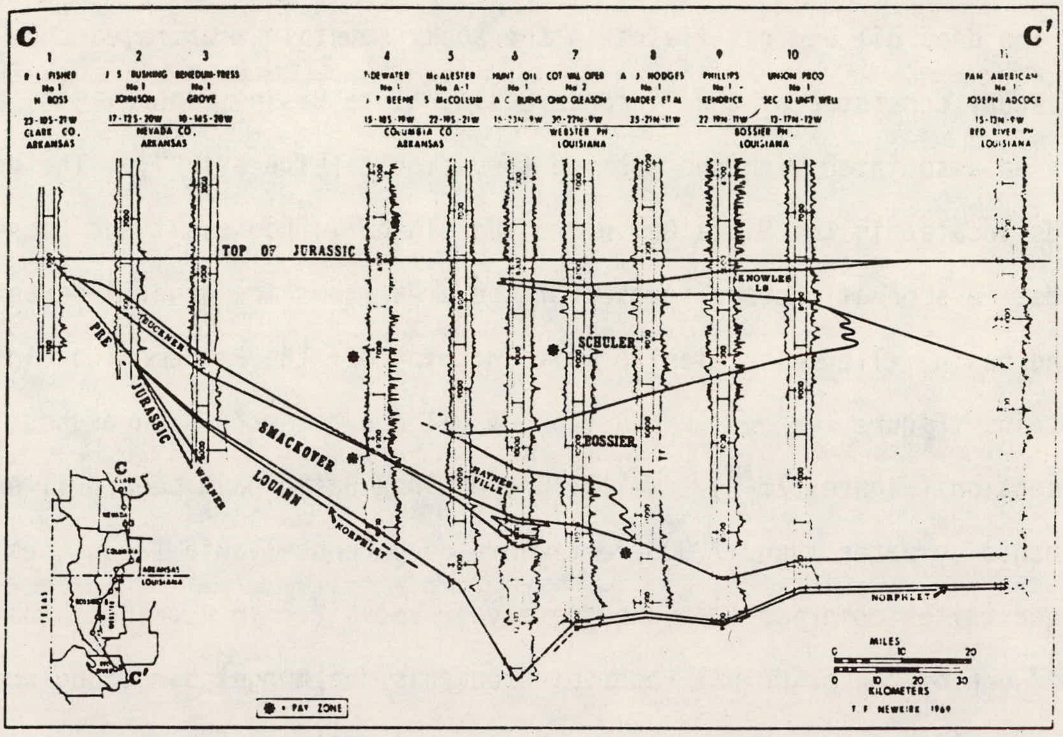


Figure 14a. Stratigraphic sections, southern Arkansas and northern Louisiana[9].

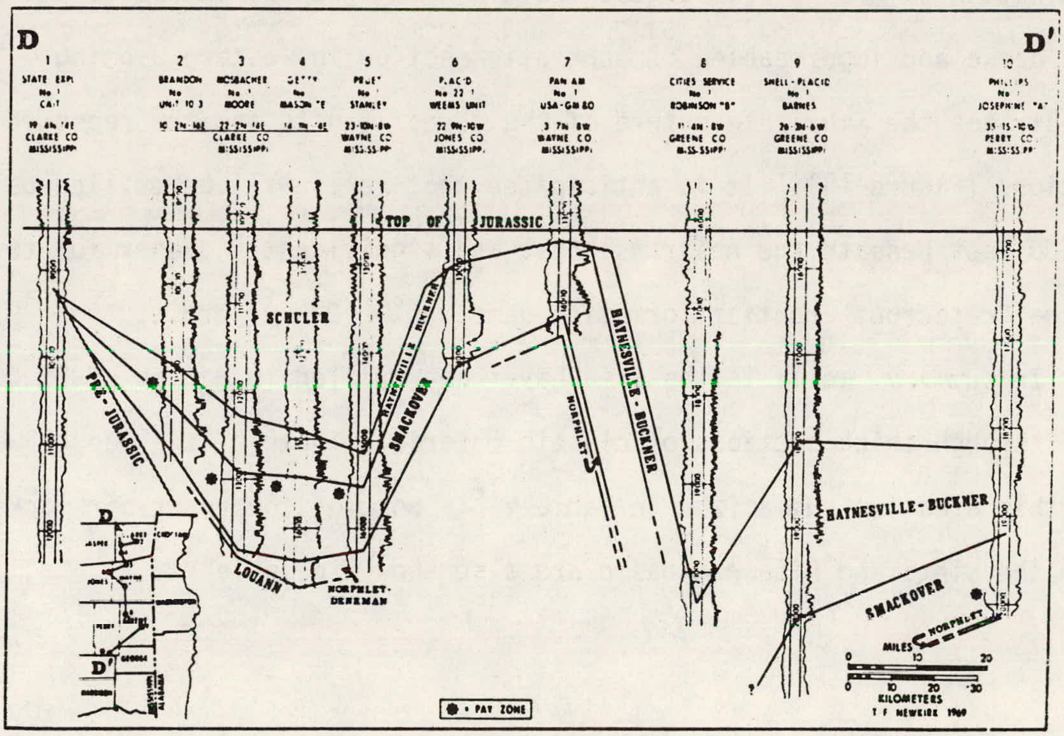


Figure 14b. Stratigraphic section, southeast Mississippi, Gulf Coast region[9].

Rocky Mountain Area

The deep oil and gas fields in the Rocky Mountain area researched in this study consisted of the Piceance Basin, Uinta Basin (Figure 15[13]) and the area associated with the Wyoming thrust belt (Figure 16[14]). The deep fields located in the Uinta Basin are the Bluebell, Roosevelt and Duchesne fields. A schematic cross section of the area shows the general structure of the basin filled with clastic units dipping off the Precambrian Uinta Mountains (Figure 17a[13]). Production of oil and gas occurs throughout the section (Figure 17b[13]). Wells in the Uinta Basin have been drilled to a depth of greater than 17,000 feet where deep Pennsylvania sandstones and quartzites comprise the lower reservoir rocks[13]. In Wyoming thrust belt area[14] one of the principal reservoir rocks is the Nugget sandstone which varies in lithology from a relatively porous sandstone with porosity of 10 percent to a highly quartzitic sandstone with low porosity and permeability[15]. Examination of a core from 22,000 feet in Wyoming shows the Nugget to be very dense and impermeable. A schematic section in western Wyoming illustrates the imbricate nature of the thrust faults and the repeated sections (Figure 18). It is anticipated that wells will be drilled below 14,500 feet beneath the Absorka Thrust and significantly deeper for tests of the Cretaceous Frontier formation beneath the Darby Thrust.

In summary, wells in the area have been drilled to depths of 22,000 feet through thick sections of clastic material. Some of the deeper wells for this area are summarized in Table V[16]. Some of the reservoir rocks from the Uinta and Piceance basin are also shown in Table VI.

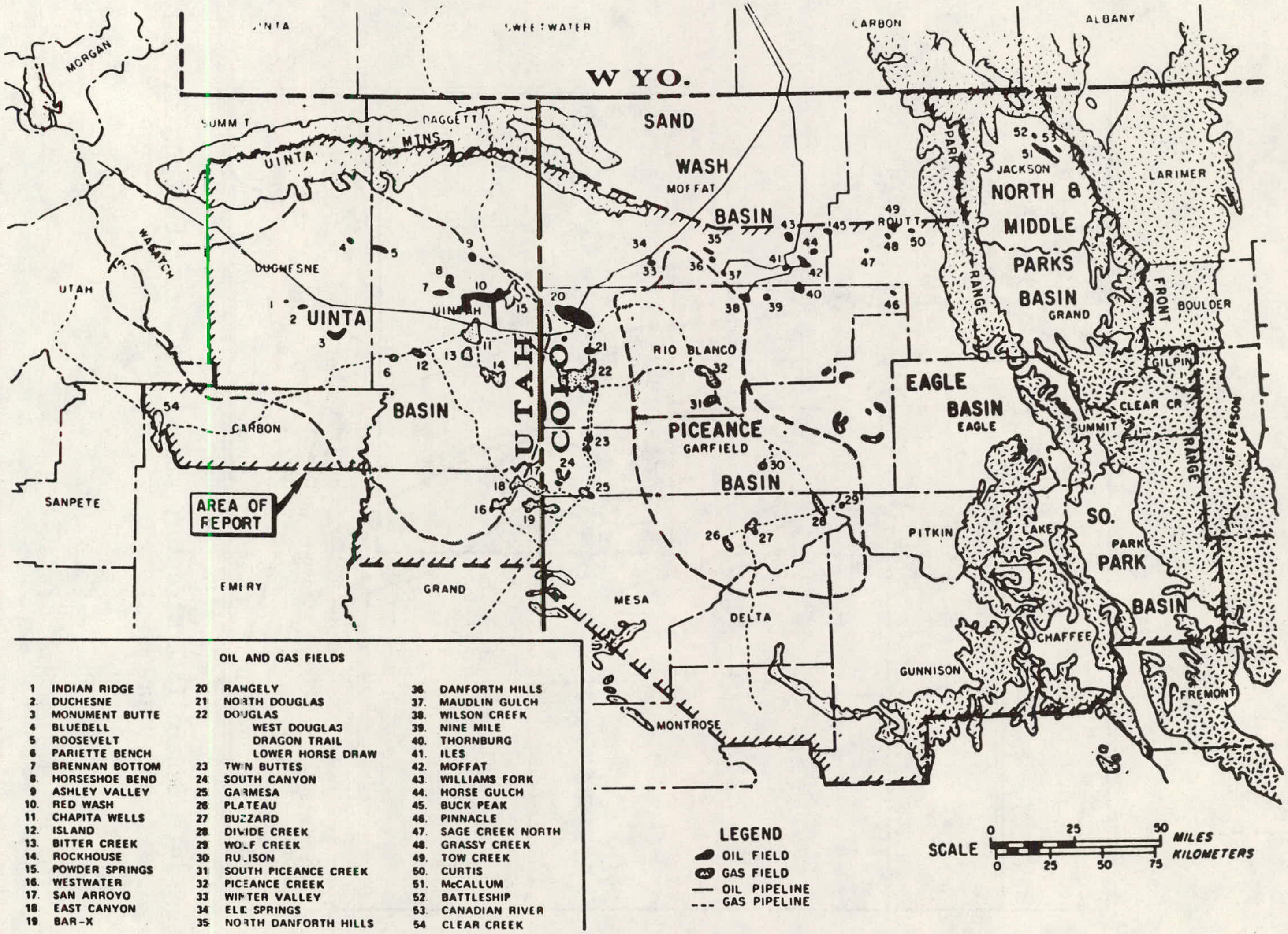


Figure 15. Tectonic map showing principal Rocky Mountain oil and gas fields in Utah and Colorado[13].

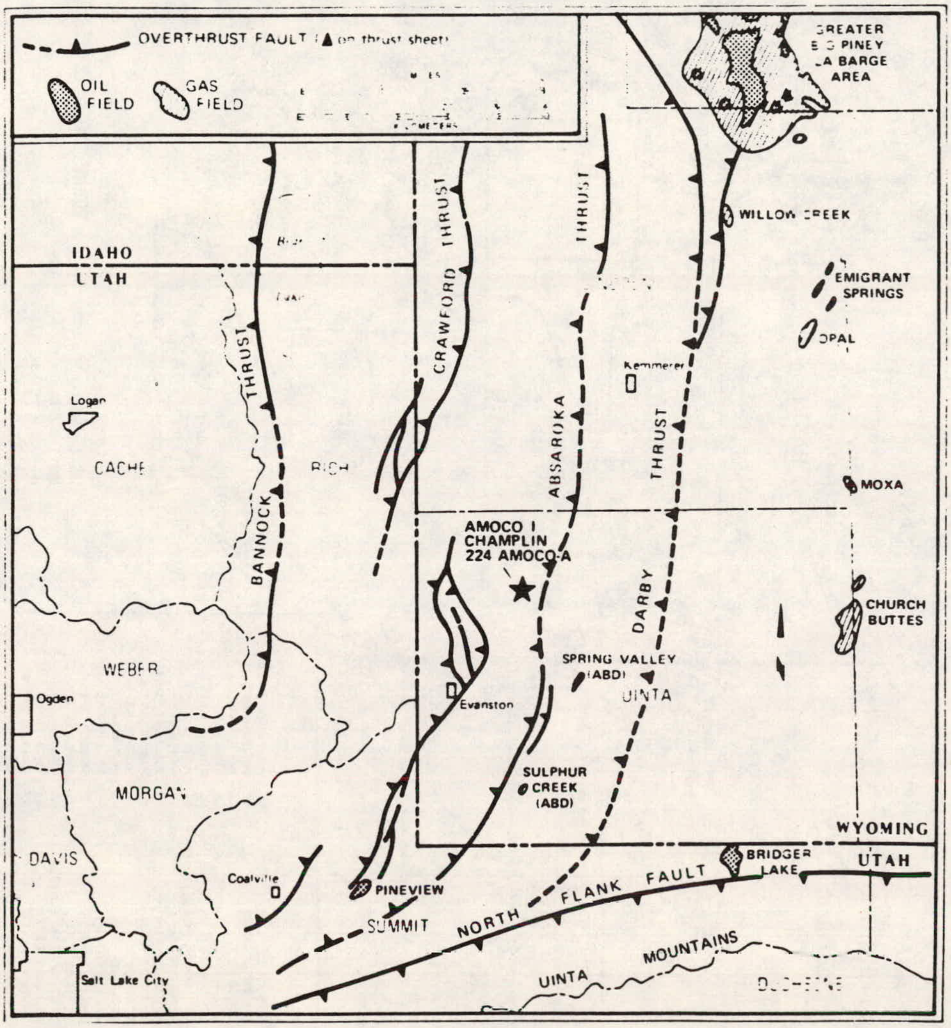


Figure 16. Generalized structure map of the thrust belt, Wyoming, Idaho and Utah.

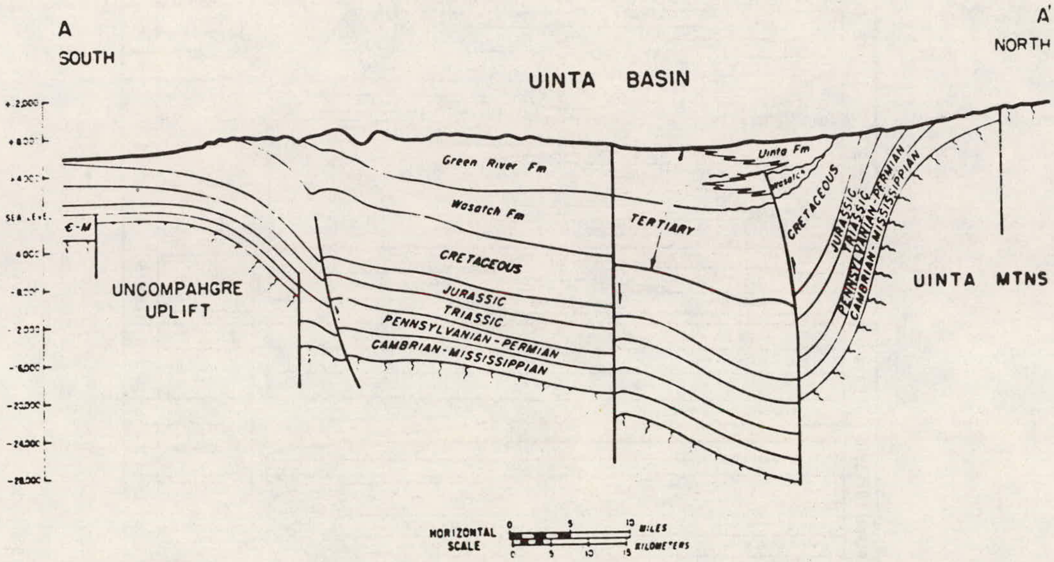


Figure 17a. Structure cross section Uinta Basin. The deepest production well in the Uinta Basin is from the Altamont field 17,732 feet.

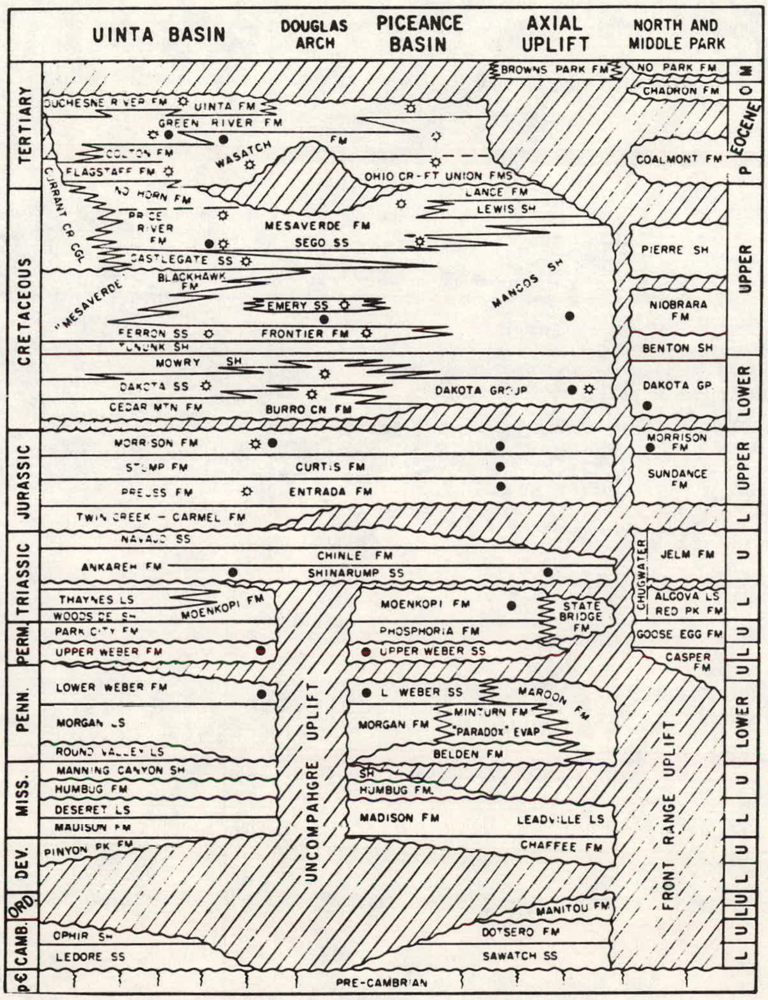
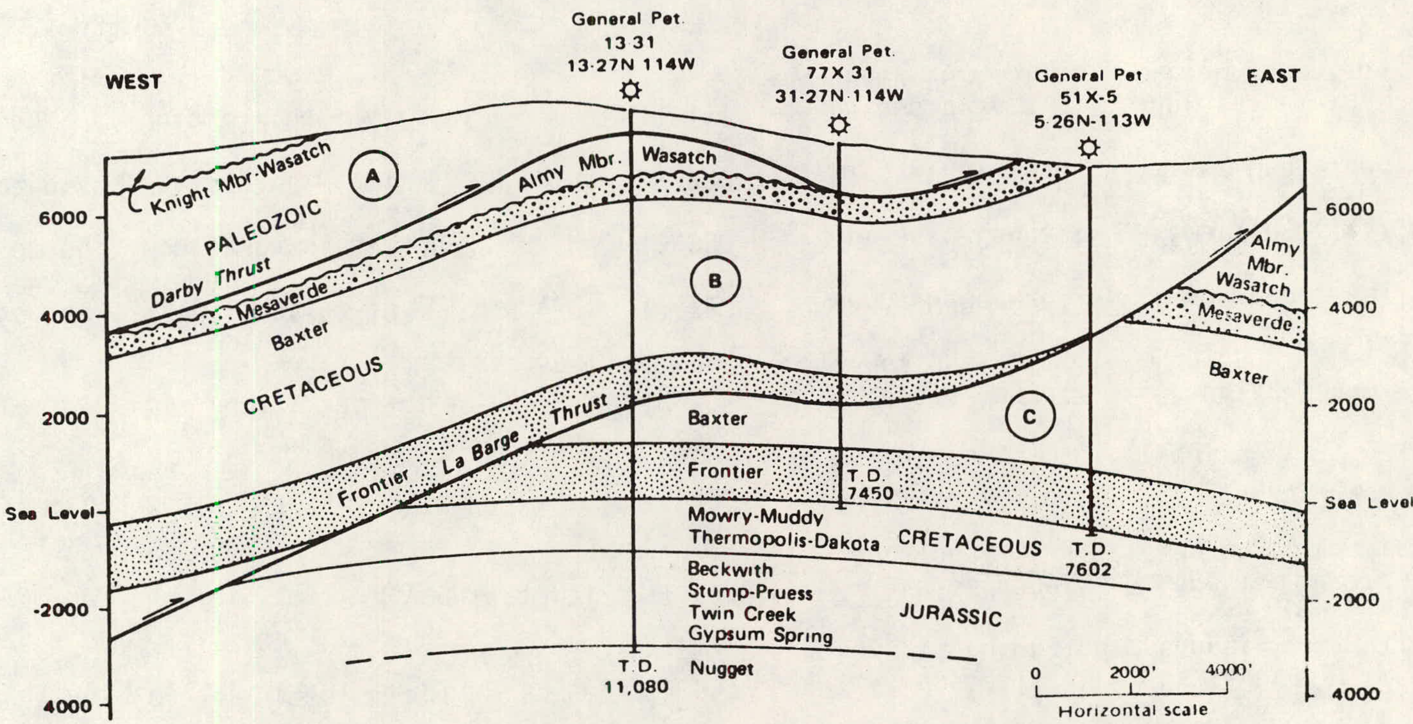


Figure 17b. Correlation diagram, northeast Utah and northwest Colorado.
● Oil producing formations.



After Michael: Wyoming Geological Association Guidebook, 1960, p. 215.

Figure 18. Generalized section in the Wyoming thrust belt. This section is from the Greater Big Piney La Barge field[14].

TABLE VI

Summary of Deep Wells, Rocky Mountain Area, Utah and Wyoming

State	Well Name	Total Depth	Term Formation	Oldest Formation Tested
Wyoming	Phillips, For A-1	17,345	Triassic-Nugget Sandstone	Cambrian-Park Formation
Wyoming	Carter, Meridian Ridge 1	14,397	Cret-Jurassic Cannett Formation	Cret-Jurassic Cannet Formation
Wyoming	Belfer, Dry Piney Unit 4	11,474	Triassic-Nugget Sandstone	Canbriam-Death Canyon Formation
Wyoming	Mobil, Tip Top Unit 22-19	15,435	Cambrian-Gallatin	Cambrian-Gros Ventre
Wyoming	Mt. Fuel, Deadline Ridge 1	12,605	Triassic-Nugget Sandstone	Cambrian-Death Canyon
Wyoming	G. P. Gout 43-19	14,720	Penn. Weber-Wells	Penn. Weber-Wells
Wyoming	Mobil, Camp Davis R-22-3G	13,336	Jurassic-Cannett	Cambrian Gallatin
Idaho	Phillips Dewey 1	12,720	Miss.-Undivided	Miss.-Undivided
Utah	Ohio Oil Co., Wilde 1	11,444	Jurassic-Twin Creek Formation	Jurassic-Twin Creek Formation

CANDIDATE ROCK TYPES

The candidate rocks for the drilling optimization program were selected on the basis of the rock types found in deep oil and gas field reservoirs. In summary, the rock types representing a large percentage of the footage found in these deep reservoir areas consisted of sandstones, carbonates, both limestones and dolomites, and shales. Typical porosities of some of these rocks are outlined in Table I. The compressibilities of typical reservoir rocks in general as a function of porosity are given in Figures 19a and 19b[17]. Limestone and sandstone reservoir rocks range in porosity from 2 to approximately 14 percent and from 4 to 30 percent, respectively. The higher porosity reservoir rocks are generally from shallow depths. The porosities from deep reservoir sandstones range between 3 and approximately 11 percent for sandstones[3].

On the basis of our findings, candidate sandstones, shales, limestones and dolomites were sought and evaluated. The final candidate list is shown in Table VII with a summary of the material properties for these rocks. A more detailed presentation of the physical and mechanical properties of these rocks will be presented in another report. The candidate rock types within each rock type were chosen based on criteria relevant to the drilling process. The similarity in properties indicate that the rocks chosen are representative of the material to be found at depth. We, of course, had constraints, in that samples required for the program needed to be blocks approximately 1 meter on a side. Therefore, it was necessary that these rocks be obtained in large quantities from quarry locations or excavation sites. The final selection of rock types include the following media:

1. Colton sandstone with a porosity of 10.8 percent was chosen as a greywacke typical of deep reservoir rocks. This rock was similar in physical and mechanical properties to typical deep reservoir rocks such as the Morrow and Atoka formations in the deep Mid-Continent basins, and similar to the Lance formation (Table I) found in deep gas reservoirs in western Wyoming[18].
2. The Mancos shale was chosen because of its similarity to the Gulf Coast shales which present very difficult drilling problems. It was also similar to the Atoka shales found in the Mid-Continent basins.
3. Burlington limestone was selected because it was representative of the limestones found in Mid-Continent basins. In fact, this Mississippian limestone correlates well with the Mississippian limestones found in the basins of Oklahoma and west Texas. The density, porosity and strength correlate well with existing data from the oil patch.
4. The Bonneterre dolomite was selected as being representative of the dolomitic rocks from the deep reservoir rocks found in the Mid-Continent and west Texas areas as exemplified by the Ellenberger and Arbuckle formations. The strengths, densities and porosities are similar.

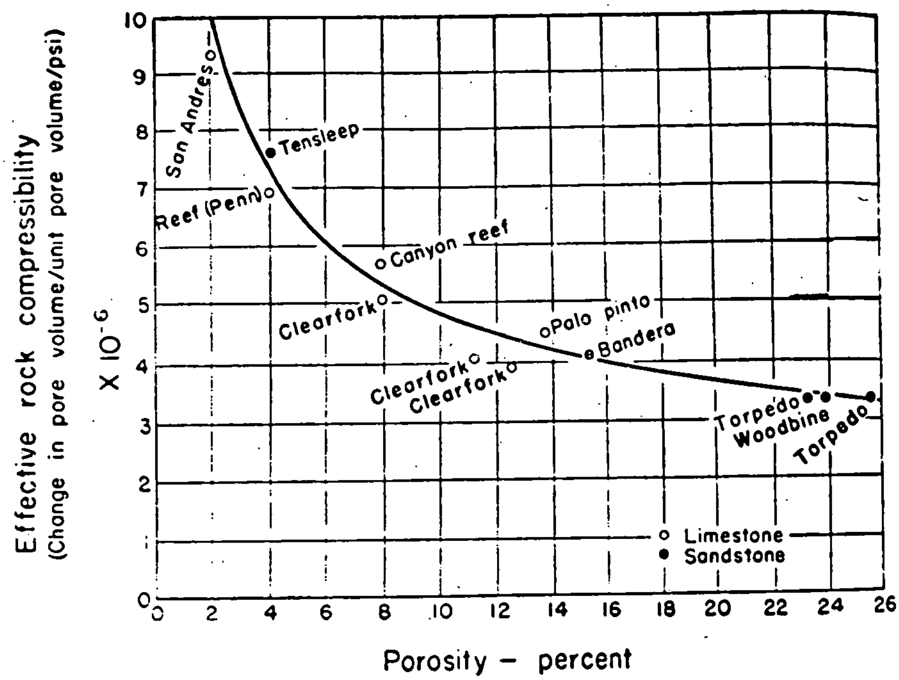


Figure 19a. Effective compressibility as a function of porosity for a group of reservoir rocks[16].

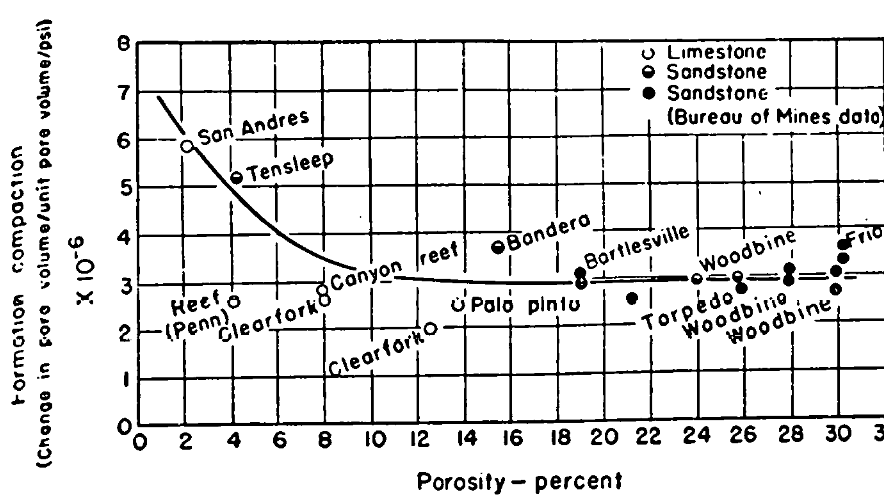


Figure 19b. Formation compaction as a function of porosity[16].

TABLE VII

Candidate Rock Types for ERDA Drilling Optimization Program

Rock Type	Formation	Porosity (%)	Density (gm/cc)	Strength (kbr, psi)	Comments
Sandstone	Nugget (Jurassic) Utah	2.55	2.59	1.45 21,000	Found 8000-17,000' in Utah, Wyoming oil and gas fields
Sandstone	Colton (Eocene)	10.8	2.37	.40 5800	Graywacke, typical of deep reservoir rocks
Shale	Mancos (Cretaceous) Utah	9.5	2.48	.64	Roadcut excavation 10% Montmor. Typical of Gulf Coast shale
Shale	Mancos (Cretaceous) Utah	8.7	2.55	.52 7540	Quarry very available 16% Montmor. Typical of Gulf Coast shale
Limestone	Green River (Eocene) Utah	25.8	2.07	.421 6100	Quarry very available, 3-4 md permeability
Limestone	Burlington (Mississippian) Missouri	3-5	2.67	1.0 14,500	Available from quarry
Dolomite	Bonneterre (Cambrian) Missouri	3.11	2.67	1.5 22,000	Quarry

CONCLUSIONS

Candidate rocks were chosen for the ERDA drilling optimization program based on their lithology, physical and mechanical properties that are representative of deep reservoirs and the formations that will be drilled to get to these reservoirs. These rocks (shales, sandstones, limestones and dolomites) are similar in lithology, structure, physical and mechanical properties to the rocks found at depth.

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APPENDIX C

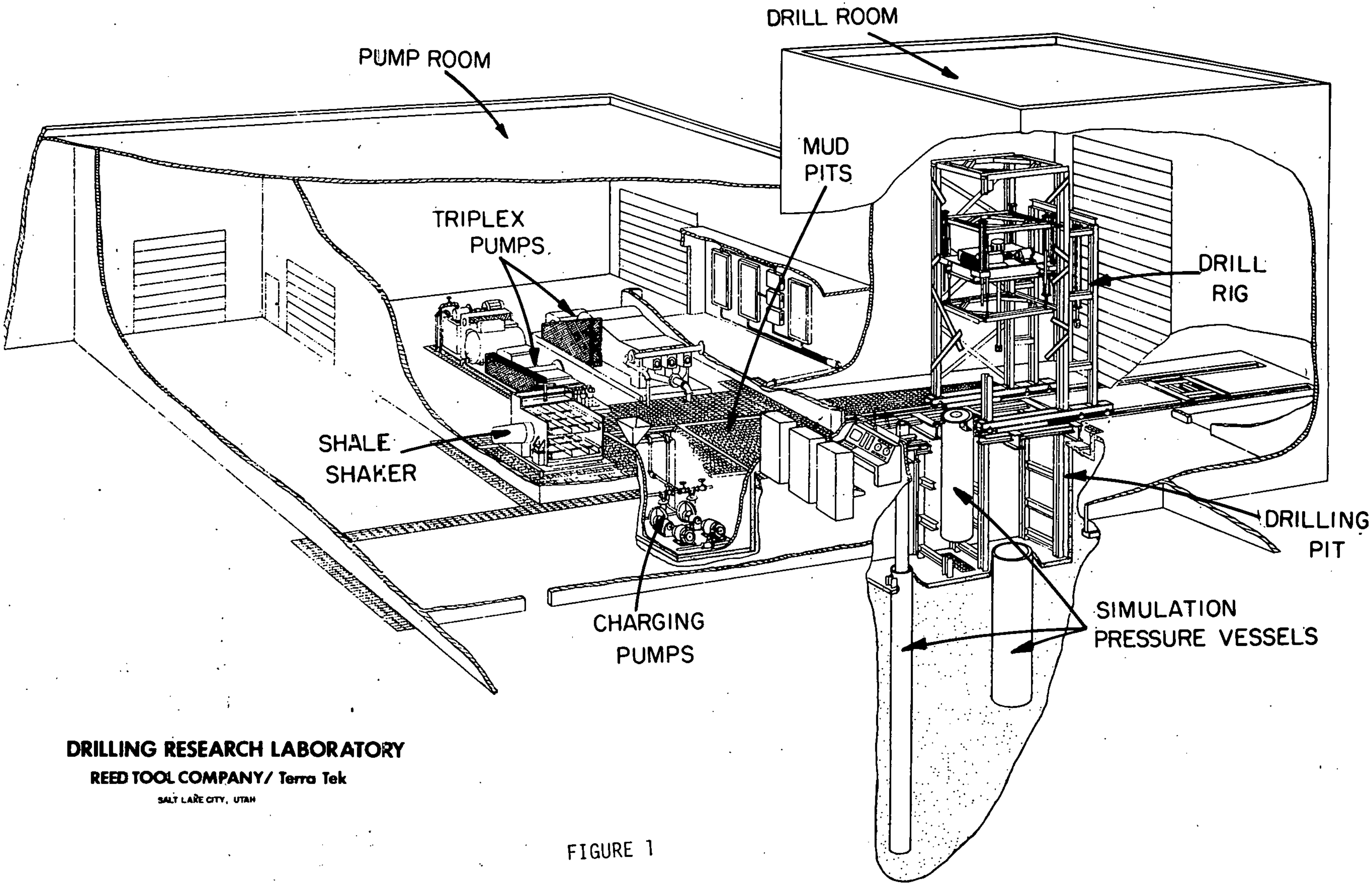
DESCRIPTION OF FACILITIES
DRILLING RESEARCH LABORATORY

The main areas and components of the laboratory, shown in Figure 1, are the rig room, drill rig, drilling pit with depth simulation pressure vessels; mud pumps and mud handling room; controls area; and service corridor where rock specimens are prepared and the seal test facilities are located.

Rig Room - The rig room is a 1500 square foot, 40 foot high bay housing the drill rig, drilling pit, simulation pressure vessels and a rock storage pit. A 10-ton overhead crane allows the handling of laboratory vessels and equipment, rocks and downhole tools.

Drill Rig - The drill rig (Figure 2) is a rail-mounted movable gantry that can be positioned over various stations for atmospheric and pressure drilling. The drilling platform can be located at a number of heights and is adjustable within the main frame of the rig to accommodate various length tools. The platform contains a rotary table with DC motor drive to allow continuously variable rotation from 0 to 500 RPM and torques up to 5,000 foot-pounds. Hydraulic cylinders and a servocontrolled hydraulic power supply provides a drilling stroke of six feet at penetration rates up to 100 feet per hour. Thrust can be applied up to 400,000 pounds as required to supply bit weight and overcome the pressure reaction from simulated wellbore pressure.

Drilling Pit and Simulators - The drilling pit is a 23 foot deep reinforced concrete sub-floor structure with two additional cased holes extending 16 feet and 36 feet from the bottom of the pit floor. Reaction frames in the drilling pit provide mounting and force coupling



DRILLING RESEARCH LABORATORY
REED TOOL COMPANY/ Terra Tek
SALT LAKE CITY, UTAH

FIGURE 1

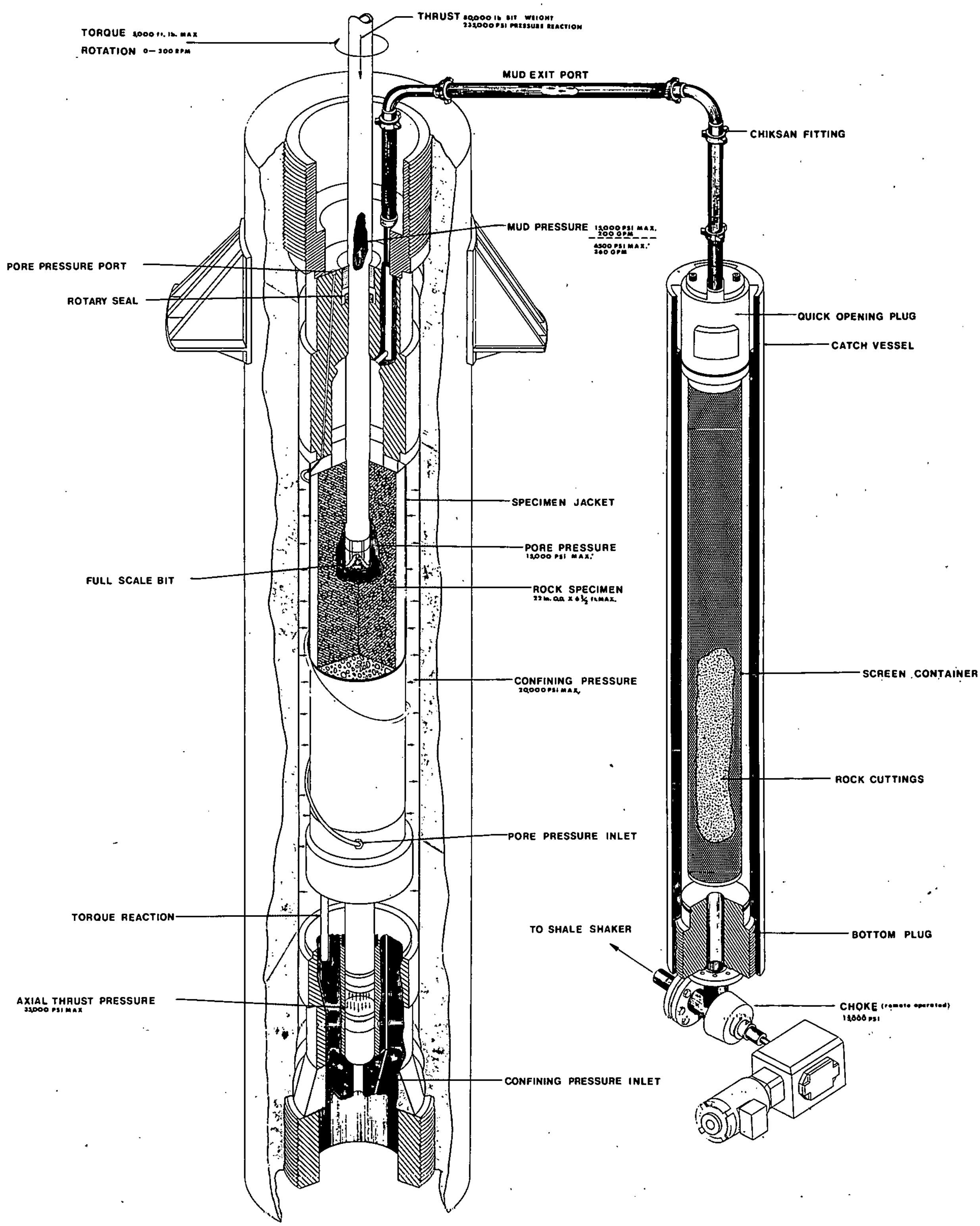
of the various pressure vessels to the drill rig. Large blocks of rock can be located here for atmospheric drilling and testing of long tools such as shock-subs and downhole motors at atmospheric conditions. Three pressure vessels are housed in the drilling pit, including the wellbore simulator, geothermal vessel and the long downhole tool vessel.

The wellbore simulator (Figure 3) is the converted breech end of a naval gun barrel with a 23 inch inside diameter, 18 foot overall length, working pressure of 20,000 psi and a working length of 7 feet. Cylindrical rock specimens up to 20 inch diameter by 7 feet long can be subjected to independently controlled confining pressure, overburden stress and pore pressure simulating well depths to 30,000 feet.

The wellbore pressure is maintained by pumps and a choke system. A specially developed rotary seal around the polished drill shaft allows the shaft to rotate under pressure. High pressure drilling mud and rock cuttings flow out of the wellbore into a second long vessel before pressure is relieved. There the cuttings are screened out before the mud passes through a remotely adjustable choke to reduce pressure prior to returning to the mud pit. Several rock specimens are prepared in advance with metal end caps and sealing jackets to be inserted and removed from the wellbore simulator as part of the vessel's top sealing plug.

The geothermal vessel is a 16 inch inside diameter by 5 foot overall length pressure chamber made from the muzzle end of a naval gun barrel. It has a working inside diameter of eight inches and a working length of 24 inches. It has been operated at 5,000 psi and 600^{0}F. The vessel is equipped with 24 kilowatts heating capacity and ceramic insulation inside the vessel.

Two 12 inch inside diameter by 25 foot long extruded forgings coupled together constitute the 50 foot long downhole tool vessel. This vessel hangs vertically in the drilling pit and is rated at 15,000 psi



DRILLING RESEARCH LABORATORY - WELLBORE SIMULATOR

FIGURE 3

at 200°F and 5,000 psi at 600°F. A programmable dynamic actuator is being designed and fabricated and will be installed to the vessel end closure to allow simulation of downhole dynamics in the axial direction of sealed bearing packages or full-scale downhole drilling motors. Also, a thrust bearing and dynamometer will be provided for reacting and measuring torque and dissipating the horsepower generated by downhole motors. The vessel will also be equipped with inlet and outlet ports and a choke system for creating simulated wellbore pressure.

Mud Pump and Mud Handling Room - The laboratory is equipped with complete mud handling equipment and mud pumps, including a 20,000 gallon mud storage capacity; two 40-HP centrifugal circulating and charging pumps; a 58P Oilwell Triplex mud pump driven by a 125-HP DC motor rated at 600 psi at 360 gpm; and an FA 1600 Continental Emsco triplex mud pump driven by two 900-HP DC motors presently equipped with 5 inch liners and rated at 5,000 psi and 360 gpm. Currently, new fluid ends based on the Exxon high pressure fluid end design are being fabricated to provide the capability of 12-15,000 psi and 200 gpm needed to create wellbore pressure for simulating wells to 30,000 feet. The DC motor drives allow continuously variable flow rate at constant pressure.

Instrumentation and Controls - The drill rig and wellbore simulator are instrumented with numerous transducers to measure the various pressures and temperatures, as well as bit weight, torque, rotary speed, penetration, penetration rate and flow rate. These measured parameters are recorded on analog X-Y-Y' and strip chart recorders and a digital computer. The operation is controlled from the remote instrumentation station. The servocontrolled drill rig allows automatic control of either constant bit weight, constant penetration rate or constant torque.

The seal and sealed bearing test facilities have independent data acquisition systems.

The data acquisition system incorporated in the set-up consists of a Hewlett Packard 7046A X-Y-Y' recorder and a Brush 260 six-channel strip chart recorder for the purpose of recording selected analog information continuously, and a Digital Equipment Corporation PDP 11/34 disc operating computer with RSX-11M time sharing option and a sixty-four channel analog to digital converter for data acquisition. the HP7046A reocreder is used to record penetration and weight on bit with clarity, as the drilling operator relies mainly on these two inputs to control the drilling. The following parameters are recorded periodically with the computer:

(1) Penetration Rate
(2) Penetration*
(3) Weight on Bit*
(4) Torque*
(5) Shaft Speed
(6) Mud Flow Rate*
(7) Mud Pressure at Swivel*
(8) Mud Pressure at Borehole*
(9) Axial Ram Pressure
(10) Confining Pressure
(11) Pore Pressure

* Also recorded on the analog recorders.

APPENDIX D

SELECTION OF ROCK BITS

To select rock bits representative of those used in deep drilling and oil and gas wells, a meeting of industry representatives was held at Rice University, Houston, Texas, on June 25, 1976. At this meeting, the industry representatives were requested to respond with comments concerning the program and recommendations on the bits which should be used. The following pages are copies of the request and comments received from the industry representatives. Following these pages are copies of the appropriate pages of the manufacturer's sales brochures in the Composite Catalog of Oil Field Equipment and Services which describe the bits used for this project.

REED TOOL COMPANY
DRILLING EQUIPMENT DIVISION
P.O. BOX 2119, HOUSTON, TEXAS 77001
(713) 926-3121

July 8, 1976

Mr. Sid Green, President
Terra Tek
University Research Park
420 Wakara Way
Salt Lake City, UT 84108

Dear Mr. Green:

SUBJECT: Drilling Parameter Optimization Program

The Reed Tool Company is pleased to respond to your request for inputs to your program "Drilling Parameter Optimization." It became obvious in the meeting at Rice University on June 25, 1976 that a wide diverse opinion existed within the industry as to the type of program it should be, or even if the program should be executed.

First, to us, this wide diverse opinion, itself, indicates the program is needed. We are not dealing with an exact science, and the drilling industry surely will benefit from some data obtained under controlled conditions. Specifically, let us address some of the points:

It is true that previous work under high borehole pressure has been done, all with Microbits. For the first time, data will be generated at full scale and with better simulation of actual down hole conditions. Two very important differences will characterize your tests:

1.) No unknown scale effects.

2.) Real cutting structure configurations, that are not possible on Microbits.

Furthermore, a data bank of performance on today's best bits under controlled conditions gives the industry a "tool" to design and test new configurations and test them under the same controlled conditions. In this manner, the experimenter can detect those design improvements of 10 or 20 percent which make a significant difference in drilling costs. Today's method of field testing often "mask" these improvements due to difference in formation, drilling parameters, or even inaccurate rig records. Thus, the manufacturer does not commit to the expensive re-tooling of a new configuration.

SUBJECT: Drilling Parameter Optimization Program

We urge Terra Tek to consider the use of 7-7/8" bits in this program. A lion's share of experimental bits are manufactured in this size for the simple reason that it is the best selling size and more holes are available for test. Moreover, the factory builds this size more days of the year; and, therefore, experimental bit production in this size creates less disruption of the production line. In actual deep drilling, the most predominant sizes are 6-1/2", 7-7/8", 8-1/2", 9-7/8", and 12-1/4". We at Reed feel that we can extrapolate best from the 7-7/8" bit size, where a full range of types are available.

To give meaning to these tests, the environmental and drilling conditions should be set as near as possible to actual conditions at depths normally drilled. It is not necessary to retest the effects of various overburden pressures and various well bore mud pressure vs. pore pressure (ΔP). This has been well established both from the laboratory and field studies. In the real world, some overbalance of mud pressure to pore pressure is usually necessary to varying amounts, depending on unknown transient pressure conditions.

What is needed is to test the effects of bit design, hydraulics, weight, and rotary speed on drilling rate at typical overburden and ΔP conditions.

A typical deep hole would be 14,000 feet deep requiring 13.5# drilling mud. This would establish a good test condition for overburden pressures and well bore mud pressure. A typical pore pressure to set for the various formations is difficult to estimate, so a realistic approach to do this would be to vary pore pressure for each formation until a typical drilling rate results using average drilling conditions of weight, RPM, and hydraulics.

For 7-7/8" insert bits drilling under the above conditions, typical drilling parameters would be:

Rock	Weight (1000#)	RPM	Hydraulics	R.O.P.
Shale	30-35	50-60	250 G.P.M.-1500 psi	8-15 ft./hr.
Carbonates (Porous)	30-35	50-60	250 G.P.M.-1500 psi	8-15 ft./hr.
Sand (Porous)	30-35	50-60	250 G.P.M.-1500 psi	8-15 ft./hr.

I hope that this information will be of some benefit to your program. If there are any questions or you desire more detail, do not hesitate to call on us. We are looking forward to evaluating the data generated on this program and will consider it a challenge to develop a new faster penetrating rock bit where performance can be compared realistically.

Sincerely,

REED TOOL COMPANY
Drilling Equipment Division

Dewey A. Thiessen
Vice-President - Engineering

DAT/asd

TerraTek

July 26, 1976

Dewey Thueson, Reed Tool Company
Bob Jackson, Dresser Industries (cc to Lyman Edwards)
Dr. Raymond Chia, Smith Tool Company (cc to Robert Evans)
Robert Cunningham, Hughes Tool Company (cc to Ed Galley)

Dear

We would again like to express appreciation for your participation in the recent ERDA-Fossil Energy Program Planning Meeting held at Rice University on June 25, 1976. We found the comments appropriate, and as a result, the program will place greater emphasis on: a) expansion of the available knowledge and "data base" for deep-well drilling under fully controlled conditions; b) drilling in shale; c) overall characterization of the rocks drilled; d) possible use of penetration rate or other drilling variables to obtain more information on formation pore pressure; and e) use of a full scale field drill bit for our experiment.

We are proceeding with specimen preparation of three rock types: Mancos Shale, Colton Sandstone and Bonne Terre Dolomite. These rocks represent media typically found in deep oil and gas fields. The drill bits to be used must be selected and comments on the range of drilling parameters are desired. As background, the following information is given.

UNIVERSITY RESEARCH PARK · 420 WAKARA WAY · SALT LAKE CITY, UTAH 84108 · (801) 582-2220

The physical and mechanical properties of the rocks to be drilled are given in Table 1, and include density, porosity and strength. A drill bit size of 7 7/8 inch diameter has been selected, mainly because of the great percentage of usage in the industry, the availability of a wide variety of bit types in this size, and the availability of field and laboratory data for comparison. Only one bit per rock type will probably be used for all depth simulation experiments, with a second or third bit used if time and money are available. We are leaning toward the use of insert bits because of their frequent use in deep well drilling. We also want to eliminate bit wear as a variable in this drilling program. The flow rate of our triplex pump will be 200 gpm or slightly above for the deepest well test simulation (at 15,000 psi well-bore pressure).

Provided is a data sheet for your comments on bit types, showing a first and second priority. Comments on the range of drilling parameters is also desired.

If you have any question regarding our request and/or clarification on the program, please call me at (801) 582-2220. Again, I extend our thanks and consider your commendations toward the selection of drill bits very valuable in meeting the objectives of our program.

Sincerely,

Alan D. Black

Alan D. Black
Director
Drilling Research Laboratory

cc: Sidney J. Green
Ray Williams
Arfon Jones
Howard Pratt

bcc: Don Guier

TABLE 1

SELECTED ROCK PROPERTIES

Properties	ROCK TYPES		
	Mancos Shale	Bonne Terre Dolomite	Colton Sandstone
Unconfined Strength	7.5 ksi	22.0 ksi	5.8 ksi
Strength at P_c = 7.25 ksi	16.0	---	22.5
Strength at P_c = 14.5 ksi	21.0	---	30.0
Strength at P_c = 29 ksi	26.0*	---	42.5*
Bulk Density	2.56 g/cc	2.67 g/cc	2.41 g/cc
Porosity (Atmos. Cond.)	8.7%	3.11%	10.8%

* Maximum Stress @ 5.7% strain; did not fail

PRIORITY	7 7/8" BIT	ROCK TYPES		
		MANCOS SHALE	BONNE TERRE DOLOMITE	COLTON SANDSTON
FIRST CHOICE	Bit #:			
	Nozzle Size:			
	Flow Rate:			
SECOND CHOICE	Bit #:			
	Nozzle Size:			
	Flow Rate:			
OTHER COMMENTS				

HUGHES TOOL COMPANY

5425 POLK AVENUE

HOUSTON, TEXAS

August 24, 1976

Mr. Alan D. Black
TerraTek
University Research Park
420 Wakara Way
Salt Lake City, Utah 84108

Dear Mr. Black:

Attached are my recommendations for bits in the Mancos Shale, Bonne Terre Dolomite, and the Colton Sandstone. As indicated, the flow rate and the nozzle size should be adjusted to give the desired hydraulic horsepower and jet velocity at the bit. We have found hydraulic horsepower to be the more reliable recorded parameter.

If I can be of any further help, please let me know.

Very truly yours,

R. A. Cunningham
Manager Product Research

RAC:bj

Attachment

PLEASE REPLY: P. O. BOX 2539 HOUSTON, TEXAS 77001 TEL: A/C 713 926-3101

		ROCK TYPES		
PRIORITY	7 7/8" BIT	MANCOS SHALE	BONNE TERRE DOLOMITE	COLTON SANDSTO
FIRST CHOICE	Bit #:	OSC-3	J55	J22
	Nozzle Size:			
	Flow Rate:	∿250 gallon/minute	same	same
SECOND CHOICE	Bit #:	OSC-1G	J44	J33
	Nozzle Size:			
	Flow Rate:	∿250 gallon/minute	same	same
OTHER COMMENTS		Nozzle size and flow rates need to be adjusted to give the desired jet velocity. A velocity of about 300 ft/sec will give cleaning.		

REED TOOL COMPANY
DRILLING EQUIPMENT DIVISION
P.O. BOX 2119, HOUSTON, TEXAS 77001
(713) 926-3121

August 13, 1976

Mr. Alan D. Black, Director D. R. L.
Terra Tek
University Research Park
420 Wakara Way
Salt Lake City, UT 84108

Dear Mr. Black:

<u>SUBJECT</u>: Drilling Mechanics in Deep Holes - ERDA Program

With reference to your letter of July 26, 1976 to Dewey Thiessen, I have indicated bit types and drilling parameters on the enclosed data sheet that you provided.

You may note that the bit types that I have indicated are not consistent with the bit types that we agreed to furnish in a letter from Mr. Dewey Thiessen to Mr. Sid Green dated July 12, 1976.

We would be pleased to furnish at no cost one bit of any of the types that we have recommended for your program.

If we can be of any further assistance to you, do not hesitate to call on us.

Sincerely,

P. W. Schumacher

P. W. Schumacher

PWS/asd
Enclosure
cc: Mr. D. A. Thiessen
Mr. S. J. Green

		ROCK TYPES		
PRIORITY	7 7/8" BIT	MANCOS SHALE	BONNE TERRE DOLOMITE	COLTON SANDSTON
FIRST CHOICE	Bit #:	FP-52	FP-63	FP-52
	Nozzle Size:	(3) 10/32	(3) 10/32	(3) 10/32
	Flow Rate:	250 G. P. M. 13.5# Mud	250 G. P. M. 13.5# Mud	250 G. P. M. 13.5# Mud
SECOND CHOICE	Bit #:	FP-54	FP-62	FP-54
	Nozzle Size:			
	Flow Rate:			
OTHER COMMENTS				
	Weight-Range	20,000-45,000#	30,000-60,000#	20,000-45,000
	RPM-Range	50-120	50-120	50-120

SMITH TOOL
Division of Smith International, Inc.

P. O. Box 15500
17871 Von Karman Ave.
Irvine, California 92705
Phone (714) 540-7010 Telex: 6-74575

August 13, 1976

Mr. Alan D. Black
Director, Drilling Research Laboratory
TerraTek
420 Wakara Way
Salt Lake City, Utah 84108

Dear Mr. Black:

In response to your letter dated July 26, 1976 I am glad to fill in the table for you toward the selection of rock bits.

Calculations were made based upon mud weight 10 ppg, flow rate 200 gpm, and related assumptions in addition to the information provided in your letter. Due to my limited knowledge of the test equipment and procedures in the Drilling Research Laboratory, it is suggested to use the table as a qualitative guide for your quantitative tests and optimization.

Bit type F3 in the table can be used as a reference bit since it is popular in the oilfield. Changes of different nozzle size during the tests are easily made to find the optimization of hydraulics effects. The related hydraulic calculations can readily be found in the Smith Tool Hydraulic Manual.

As a final comment or suggestion, the greatest project success can be reached by inviting the industry to review and present their own analysis on the test data base in some drilling conferences.

Please do not hesitate to call me if you need further help. I enjoy providing service to you.

Very truly yours,

Raymond Chia

Raymond Chia, Ph.D.
Research Engineer

RC/cb

cc: R. F. Evans

Attachment

		ROCK TYPES		
PRIORITY	7 7/8" BIT	MANCOS SHALE	BONNE TERRE DOLOMITE	COLTON SANDSTO
FIRST CHOICE	Bit #:	F3	F5	F3
	Nozzle Size:	$(\frac{7''}{32}, \frac{8''}{32}, \frac{8''}{32})$	$(\frac{8''}{32}, \frac{8''}{32}, \frac{9''}{32})$	$(\frac{8''}{32}, \frac{8''}{32}, \frac{8''}{32})$
	Flow Rate: (gpm)	200	200	200
SECOND CHOICE	Bit #:	F2	F7	F4
	Nozzle Size:	$(\frac{7''}{32}, \frac{8''}{32}, \frac{8''}{32})$	$(\frac{9''}{32}, \frac{9''}{32}, \frac{9''}{32})$	$(\frac{8''}{32}, \frac{8''}{32}, \frac{8''}{32})$
	Flow Rate: (gpm)	200	200	200
OTHER COMMENTS		See Letter		

Christensen
Diamond Technology Center
2532 South 3270 West Stree
Salt Lake City, Utah 84119 /
Telephone (801) 487-5371
Telex: 388-491

August 18, 1976

Alan D. Black,
Director
Drilling Research Laboratory
University Research Park
420 Wakara Way
Salt Lake City, Utah 84108

SUBJECT: Oil and Gas Well Drilling Parameter Optimization For Hostile Environments

Dear Alan:

Attached are the "best guess" estimates of bit types for the various rocks you expect to drill in your deep well drilling study. Because of very limited diamond bit laboratory data a more accurate selection is not possible. As soon as drilling data under confining pressure for either roller or diamond bits in these rocks is available, we could make a better selection.

The bit size selected is unusual for diamond bits, where the average size is in the 6 inch range, but the 7 7/8 inch size will present no real difficulties. The nominal flow rates and flow areas shown on the attachments are typical in the field.

The critical parameters needing study include the effect of bit weight 10-50,000 pounds, rotary speed 60 to 1000 rpm, and flow rate 100 to 400 gpm. This assumes the mud properties, another subject of great interest, will be held constant because of their extreme complexity.

A very interesting study would be to take one bit style and change the diamond size and possibly exposure to see the effects on penetration rate and pressure drop. If a more limited test is necessary, it would be possible to use one bit, MD-262, for all three rocks.

Please keep me informed on the status as the project develops.

Best regards,

Bruce H. Walker
Group Leader, Applied Research

Attachment as noted

BHW/cd

PRIORITY	7 7/8" BIT	ROCK TYPES		
		MANCOS SHALE	BONNE TERRE DOLOMITE	COLTON SANDSTON
FIRST CHOICE	Bit #:	MD-262	MD-41	MD-331
	TFA:	.20	.16	.40
	Flow Rate:	200	150	300
SECOND CHOICE	Bit #:	MD-34	MD-24	MD-262
	Nozzle Size:	.20	.16	.20
	Flow Rate:	200	150	200
OTHER COMMENTS				
	Diamond Size	1 to 4 stones per carat	8 to 15 stones per carat	2 to 4 ston per carat
	Hydraulic horsepower per square inch	2.4	1.6	2.0

DRESSER INDUSTRIES

OILFIELD PRODUCTS GROUP, DRESSER INDUSTRIES, INC. P.O. BOX 6504, HOUSTON, TEXAS 77005 713 784-6011 TELEX 76-2349; 76-2970

August 11, 1976

Mr. Alan D. Black
Director
Drilling Research Laboratory
TerraTek
University Research Park
420 Wakara Way
Salt Lake City, Utah 84108

Dear Mr. Black:

Reference your letter of July 26, 1976 concerning the ERDA-Fossil Energy Research project and your request for comments concerning bit type, operating parameters, etc. The attached information furnished by our Security Division should answer your questions.

We are looking forward to seeing the data generated by your project. In the interim, if you need additional information or if we can be of assistance, please advise.

Sincerely,

R. A. Jackson
Manager
Market Development & Planning

dge

Attachment

DRESSER INDUSTRIES | DRESSER

Oilfield Products Group
Inter-Office Correspondence

To: Bob Jackson

From: Steve Worford

Copy to: Ed Moerbe

Date: August 10, 1976

Subject: Terra Tek - Bit Recommendations

The rational used in the bit selection for each rock type was to minimize the possibility of cutting structure damage. Bearing life should not be a factor.

Their mud pump should be able to handle the pressure loss through 3 - 8/32" nozzles unless they use high density fluid. There is no mention of the density of the fluids to be used in the letter.

If you have any questions, give me a call.

Steve

kph

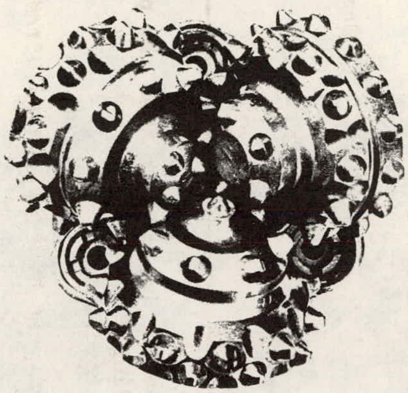
PRIORITY	7 7/8" BIT	ROCK TYPES		
		MANCOS SHALE	BONNE TERRE DOLOMITE	COLTON SANDS
FIRST CHOICE	Bit #:	S86F	M89TF	M89TF[2]
	Nozzle Size:	3 - 8/32"[1] (435 ft/sec. @ 1699 psi)	3 - 8/32"	3 - 8/32"
	Flow Rate:	200 GPM	200 GPM	200 GPM
SECOND CHOICE	Bit #:	S88F	M84F	H88F
	Nozzle Size:	Same	Same	Same
	Flow Rate:	Same	Same	Same

OTHER COMMENTS

1. Should the pressure loss through 3 - 8/32" nozzles be greater than the pressure rating for the liner being used, recommend using 3 - 9/32" nozzles (343 ft/sec. @ 1061 psi). This is based on a 10 ppg drilling fluid.

2. This appears to be a sharp, abrasive formation. An H88F may be required for thi formation.

TYPE 2



SOFT	MEDIUM SOFT	MEDIUM HARD	HARD

The Smith Type 2 bit drills soft formations, such as unconsolidated, sticky shales; soft shales; clays; red beds; salts; soft limestones; anhydrites; gypsum, and tough, waxy shales. It is especially effective where heavier weight drilling muds are used.

Large diameter tungsten carbide inserts offer maximum strength and resistance to wear. The chisel-crest configuration of the inserts, plus maximum cutter offset, provides for efficient gouging-scraping action and fastest penetration in soft formations.

Precise insert spacing ensures smooth rotation and prevents tracking. Bottom hole cleaning is aided by deeper relief grooves on the three cutters.

The recommended weight ranges between 2,000 and 4,500 pounds per inch of bit diameter, with corresponding rotary speeds of 50 to 70 rpm.

Available with roller-ball-friction bearings or solid journal bearings. IADC Code 527.

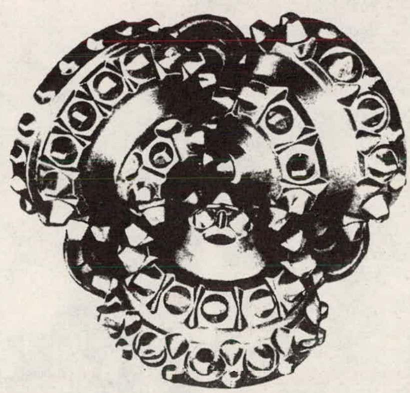
TYPE 3

The Smith Type 3 bit was developed primarily for use in medium soft formations. These, generally, include sandy shales and medium-hard shales with some softer streaks. Penetration rates are as high as with medium-soft formation milled tooth bits because of the chisel-crest inserts with maximum extension from the cone body. This feature, along with a large amount of cone offset, makes the Smith Type 3 the fastest drilling tungsten carbide insert bit in the field for medium-soft formation drilling.

Improved bottom-hole cleaning and flushing is made possible by use of long inserts and deep relief grooves on the cones. Inserts are made of selected grades of tungsten carbide to provide balanced wear resistance and strength. The cutters are machined from special quality steel for superior strength and insert retention.

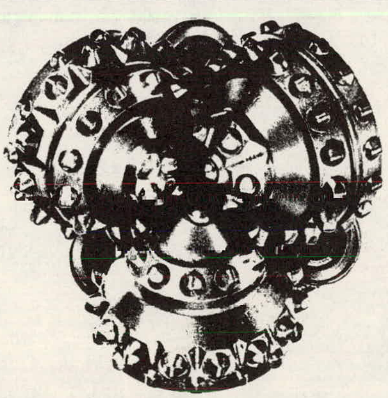
Recommended drilling weights are 2,500 and 5,000 pounds per inch of bit diameter with rotary speeds from 45 to 65 rpm.

Available with roller-ball-friction bearings or solid journal bearings. IADC Code 537.



SOFT	MEDIUM SOFT	MEDIUM HARD	HARD

TYPE 4



SOFT	MEDIUM SOFT	MEDIUM HARD	HARD

The Smith Type 4 bit was developed to drill in medium soft to medium hard formations. These include medium to medium-hard shales, limestone, dolomite and medium-hard sand. Chisel crest shaped inserts on the Type 4 offer deep penetration and fast drilling rates.

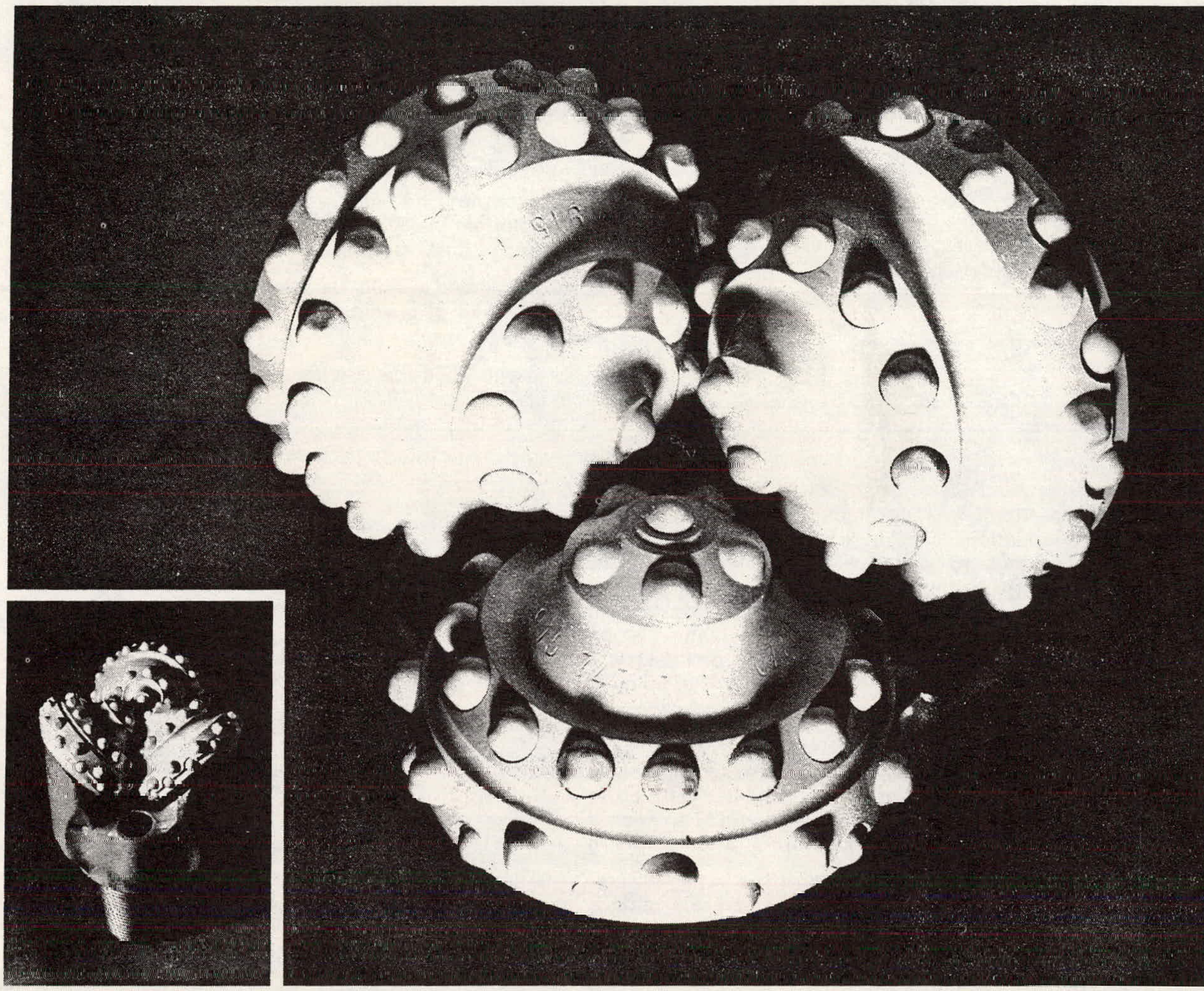
Medium gouging-scraping action is provided by medium cone offset. Varied insert pitch in all drive rows reduces tracking while deep relief milling speeds chip removal.

The Type 4 bit has built-in ruggedness based upon a larger journal diameter and a special quality cutter steel for superior strength and insert retention. Operating weights suggested are 3,000 to 5,500 pounds per inch of bit diameter with rotary speeds of 40 to 60 rpm.

Available with roller-ball-friction bearings or solid journal bearings. IADC Code 617.

M89TF

Medium Formation Insert Bits



M89TF This FerrAx bearing rock bit drills medium formations with numerous hard abrasive streaks.

The M89TF combines true rolling cones with tooth-shaped inserts with moderate extension. Close spaced inserts provide for smooth running with increased resistance to insert breakage.

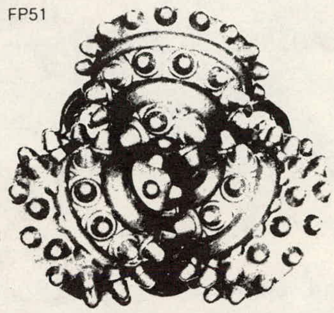
Recommended weight is 4,000 to 7,000 pounds per inch of bit diameter. Rotary speed should be in the range of 60 to 30 R.P.M.

SOFT			MEDIUM			HARD	VERY HARD
S84F	S86F	S88F	M88F		M89F	H88F	H100F

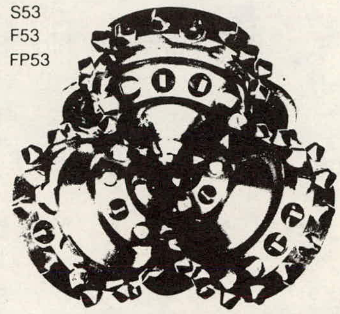
Rock Bits

Insert type

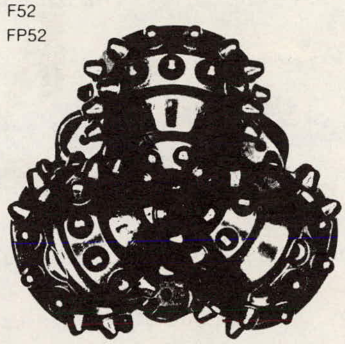
FP51



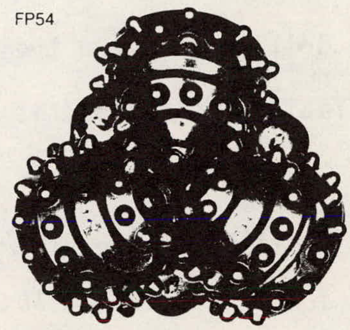
S53
F53
FP53



F52
FP52



FP54



Principal Application/Features	Recommendations: Bit Weight (Pounds per inch bit diameter)	Rotary Speed (RPM)
51 **Soft "top-hole" formations**—Designed to drill low-compressive-strength and high-drillability formations. Skew angle of cutter, insert shape and positioning provide optimum gouging-tearing-scraping action.	3500-4500	45-65
52 **Soft-to-medium soft**—Skew angle and insert shape and positioning yield cutting action for soft through medium-soft yet effectively handle inevitable hard streaks.	3500-4500	45-60
53 **Medium-soft to soft-medium**—Similar to 52 but slightly less insert protrusion. Handles both soft and hard streaks.	4000-5000	46-40
54 **Broken medium-soft to medium**—Blunt, conical-shaped inserts cut with high ROP through rough, broken medium-soft to medium formations. Particularly useful with light drilling fluids.	4000-5000	40-60

APPENDIX E

ROCK SAMPLE PRESSURE LOADING CONSTRAINTS

The axial stress at the top of the rock specimen usually differs from the axial stress at the bottom of the specimen. This occurs because a portion of the upper surface of the specimen (i.e., the borehole area) is subject only to reaction forces developed by the pressure of the circulating drilling mud and the load exerted by the drill bit. If no mud is circulating and no load is applied to the bit, the borehole area is open to atmospheric pressure. The remainder of the reaction forces act over the annular portion of the upper specimen surface external to the borehole area. Figure 1 illustrates the situation. The axial stress in the annular portion of the specimen is given the notation σ_z*. The relationship between σ_z* and the axial stress at the bottom of the specimen (σ_z) is given by

$$\sigma_z^* = \frac{P_{ram} A_{ram} + P_{conf} (A_{rock} - A_{ram}) - P_{bore} A_{bore}}{A_{rock} - A_{bore}}$$

where P_{ram} = Pressure applied to bottom of sample

A_{ram} = Area of ram

P_{conf} = Confining pressure

A_{rock} = Area of rock across diameter

P_{bore} = Borehole (mud) pressure

A_{bore} = Area of borehole

One of the critical aspects of the experiment design was to determine what combinations of confining, axial ram and borehole mud pressures could be exerted on a given rock specimen without failing the specimen. To

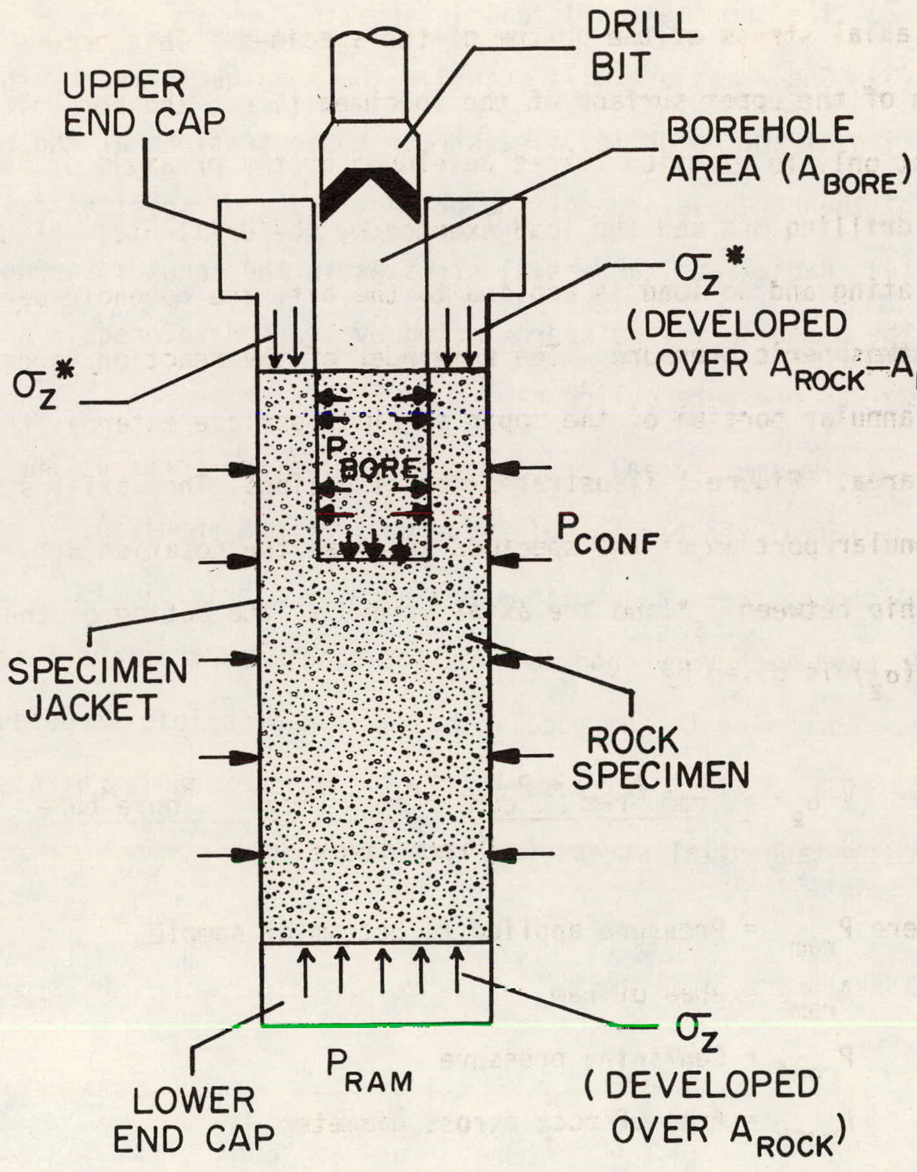

DRILL BIT
UPPER END CAP
BOREHOLE AREA (A_{BORE})
σ_z^*
(DEVELOPED OVER $A_{ROCK}-A_{BORE}$)
σ_z^*
P_{BORE}
P_{CONF}
SPECIMEN JACKET
ROCK SPECIMEN
σ_z
(DEVELOPED OVER A_{ROCK})
P_{RAM}
LOWER END CAP

FIGURE 1

accomplish this, a model predicting specimen failure was developed according to the following assumptions about a given specimen:

(1) No large imperfections, such as cracks or fissures exist in the specimen, i.e. the specimen is completely homogeneous;

(2) The specimen will fail in shear;

(3) Shear failure will occur in the annulus formed by the drilling of the borehole, i.e. stress concentrations at the bottom of the borehole are not the primary cause of specimen failure;

(4) Radial and tangential stresses in the annulus surrounding the borehole may be approximated by those developed in a thick-walled pressure cylinder;

(5) Maximum radial and tangential stresses occur at the outer radius of the borehole (inside wall of the annulus).

Although these assumptions are perhaps overly simple, the model has been used with very good success for specimens that are fairly homogeneous. According to the model, the maximum principle stresses in a specimen (i.e. maximum axial stress (σ_z*), maximum radial stress (σ_r) and maximum tangential stress (σ_θ) are given by

$$\sigma_z = \sigma_z{}^*$$

$$\sigma_r = -P_{bore}$$

$$\sigma_0 = \frac{b^2 + a^2}{b^2 - a^2} P_{bore} - \frac{2b^2}{b^2 - a^2} P_{conf}$$

where a is the radius of the borehole (four inches) and b is the radius of the specimen. With the ratio of P_{conf} to σ_z set at -.7, the axial ram pressure P_{ram} may be expressed as a function of P_{conf}, and the above stresses become (using the dimensions given):

$$\sigma_z^* = .541\ P_{bore} - 2.202\ P_{conf}$$

$$\sigma_r = -\ P_{bore}$$

$$\sigma_\theta = 2.082\ P_{bore} - 3.082\ P_{conf}$$

In Figure 2, a hypothetical stress situation is plotted according to Mohr's circle conventions. According to Mohr's theory of failure, the maximum shear stress is equal to the radius of the largest circle, or

$$2\ \tau_{max} = \text{Maximum Difference of } (\sigma_z^*, \sigma_r, \sigma_\theta)$$

where τ_{max} is the maximum shear stress. Thus, the maximum shear stress in a specimen is a function of P_{conf} and P_{bore}, since σ_z^*, σ_r and σ_θ are each functions of P_{conf} and P_{bore} (see above). The maximum shear stress in a 13.5 inch diameter by three foot long specimen is plotted as a function of confining pressure and borehole mud pressure in Figure 3. The curves are based on the specification that the ratio of horizontal to vertical stress is .7. Each line in Figure 3 shows the maximum shear stress in the annulus of a specimen that exists at a particular confining pressure and a given borehole mud pressure.

The dotted tensile stress limiting line shown in Figure 3 is a warning that any stresses developed to the left of the line will induce tensile tangential stresses in the specimen. A strength curve for each rock type (determined by triaxial strength tests) may be superimposed

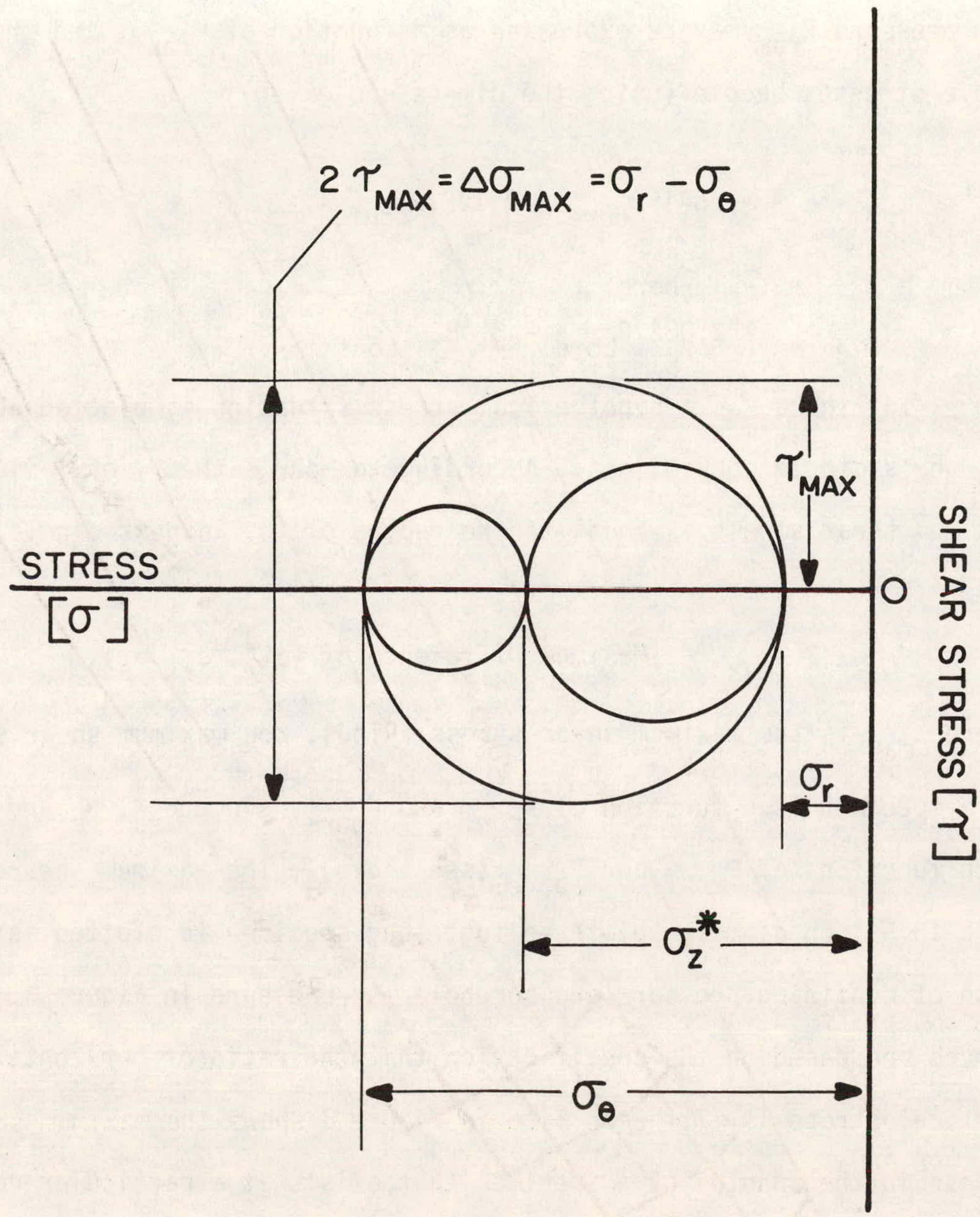


FIGURE 2
The Maximum Principle Stresses in a Specimen are Plotted on a Common Axis for a Hypothetical Situation. The Maximum Shear Stress, according to Mohr's Theory of Failure, is the Radius of the Largest Circle.

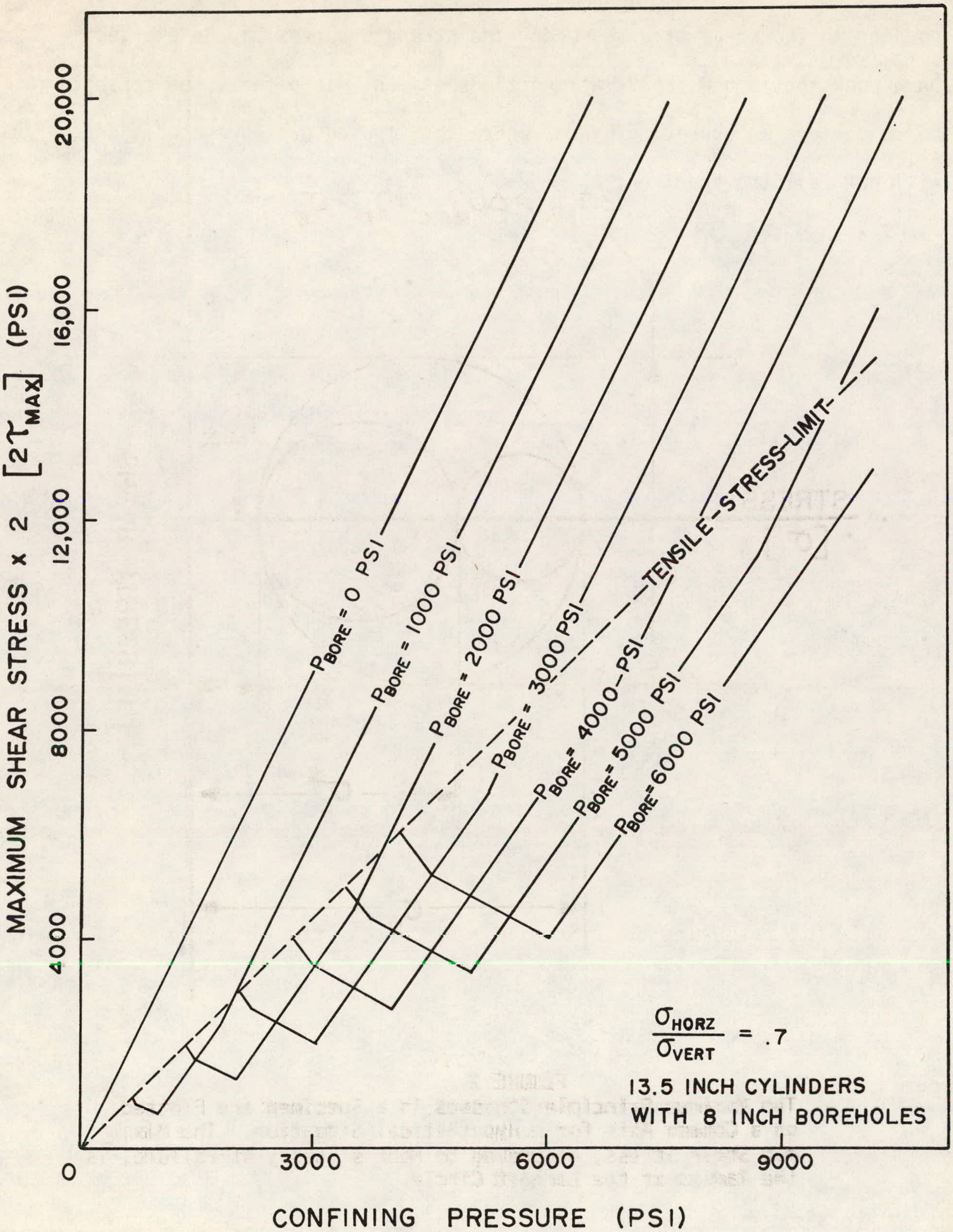


FIGURE 3
Maximum Shear Stress in a 13/5 inch diameter by 36 inch Specimen is Plotted as a Function of Confining Pressures and Borehole Mud Pressure - P_{bore}.

on the stress curves of Figure 3 and the pressure conditions corresponding to the shear stresses under the strength curves may be exerted on a rock specimen without failing the specimen. In effect, the strength curve defines an operating window where the imposed pressure conditions will not fail the specimen.