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Results of Field Verification Tests in the Tight Mesaverde Group: Piceance Basin, Colorado

Final Report

G.C. Kukal
E.H. Price
R.E. Hill
E.R. Monson

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For
U.S. Department of Energy
Office of Fossil Energy
Morgantown Energy Technology Center
P.O. Box 880
Morgantown, West Virginia 26507-0880

By
CER Corporation
950 Grier Drive
Las Vegas, Nevada 89119

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EXECUTIVE SUMMARY

Overview

The Piceance Basin of western Colorado contains a major potential natural gas resource in Mesaverde blanket and lenticular low permeability gas sands. The basin has been a pilot study area for government sponsored tight gas sand research for over 20 years. This work culminated in the Multiwell Experiment (MWX), a field laboratory consisting of three closely spaced wells, designed by the Department of Energy to study the reservoir and production characteristics of the low permeability sands of the Mesaverde Group in the Rulison Field near Rifle, Colorado.

The purpose of this study is to compare geologic, production and reservoir characteristics of the existing Mesaverde producing areas in the Piceance Basin with those same characteristics at the Multiwell site. This study has been performed in two sequential parts, Phase I and Phase II. In Phase I the geologic, production and reservoir engineering parameters were developed for the existing Mesaverde gas producing areas through analysis of log suites, well completion information and production histories. The southern part of the basin was partitioned into three areas having similar geologic and production characteristics. Phase II consisted of field verification tests with cooperative industry partners in which new subsurface geologic and production information was collected in the partitioned areas to be compared with that at MWX. This report presents the results of Phase II investigations.

Summary of Findings - Phase II

The Phase II studies resulted in a successful program to further characterize the geologic and production aspects of the Mesaverde formation in the Piceance Basin.

The natural fracture system identified at MWX and the subsequent Slant Hole Completion Test (SHCT) was also found in the Central Basin area. This fracture system is important to gas production and could be a contributor to gas production in parts of the Southwest Flank.

Production potential of the paludal and fluvial intervals in the Central Basin area was further verified.

The Southeast Uplift area was determined to be distinctly different from other southern Piceance Basin producing areas. This is due to production from limited structural traps as opposed to the large basin-centered gas trap. The Ragged Mountain Field was removed from the Southeast Uplift area.

The gas/water distribution in the marine section of the Mesaverde is still not fully understood. Test wells have encountered unexpected water production from marine sandstones in the Central Basin area and near the Southwest Flank.

The Southwest Flank area was expanded to the Northwest with the potential for further expansion to the north and east along the western and southern basin limbs.

Acknowledgements

The following operators participated in cooperative data collection programs for this study: Barrett Resources, Fuelco, Mobil Oil, and Meridian Oil. Other active companies contributed well information to the study or provided useful discussions related to operations or geology. These included Oryx, Nassau Resources, Petro-Energy, Dekalb, Unocal, and Berry Petroleum.

1.0 INTRODUCTION

The Mesaverde Group of the Piceance Basin in western Colorado has been a pilot study area for government sponsored tight gas sand research for over 20 years. Early production experiments included both nuclear stimulations and massive hydraulic fracture treatments. These studies left many unanswered questions which were addressed by the Multiwell Experiment (MWX).

MWX was a field laboratory, consisting of three closely spaced wells, designed by the Department of Energy (DOE) to study the reservoir and production characteristics of the low permeability sands of the Mesaverde Group. The location of the MWX site with respect to the Piceance Basin Mesaverde gas producing areas is shown in Figure 1. The stratigraphic nomenclature used in this report, and as correlated with earlier reports, is shown in Figure 2. Much knowledge has been gathered through MWX in many disciplines including geology, log analysis, core analysis, stress testing, well testing, reservoir characterization and stimulation technology. Insights and contributions gained from MWX are summarized in Northrop and Frohne, 1988.

During 1990 and 1991, the Slant Hole Completion Test (SHCT) was drilled at the MWX site. The SHCT is a DOE-funded production test of the Mesaverde Group sandstones utilizing a 60° slant borehole through the paludal Mesaverde section and a horizontal open hole in the naturally fractured Cozzette sandstone. This well is presently being tested. The coring program in the SHCT contributed valuable information on natural fracture density as described by Lorenz and Hill, 1991.

This study provides a critical comparison of the geologic, production and reservoir characteristics of existing Mesaverde gas producing areas within the basin to those same characteristics at the MWX site near Rifle, Colorado. The southern Piceance Basin is emphasized in this study because of the greater quantity of production and geologic data available. There may be Mesaverde gas production potential in northern areas, but because of the lack of production and relatively few penetrations, the northern Piceance Basin was not included in this study.

The study was performed in two sequential parts, Phase I and Phase II. In Phase I the geologic, production and reservoir engineering parameters were developed for the existing Mesaverde gas producing areas through analysis of log suites, well completion information and production histories. The southern part of the basin was partitioned into three areas having similar geologic and production characteristics.

Phase II is based on the gathering and interpretation of new geologic and engineering data within the three partitioned areas. One cost-effective mechanism for gathering data for government sponsored natural gas research is to cooperate with individual operators in cost-shared wells of opportunity. The term "wells of opportunity" or "cooperative wells" is applied to a well where DOE and the well operator jointly participate in gathering data and evaluating the tight gas resource. Cooperative programs have been found to be a valuable approach to performing tight gas sands research and also have the added benefit of maximizing technology transfer from these programs to industry. In a typical cooperative well arrangement, the operator assumes the responsibility and risk of drilling the well and is responsible for all data acquisition costs, including cost of the DOE programs implemented.

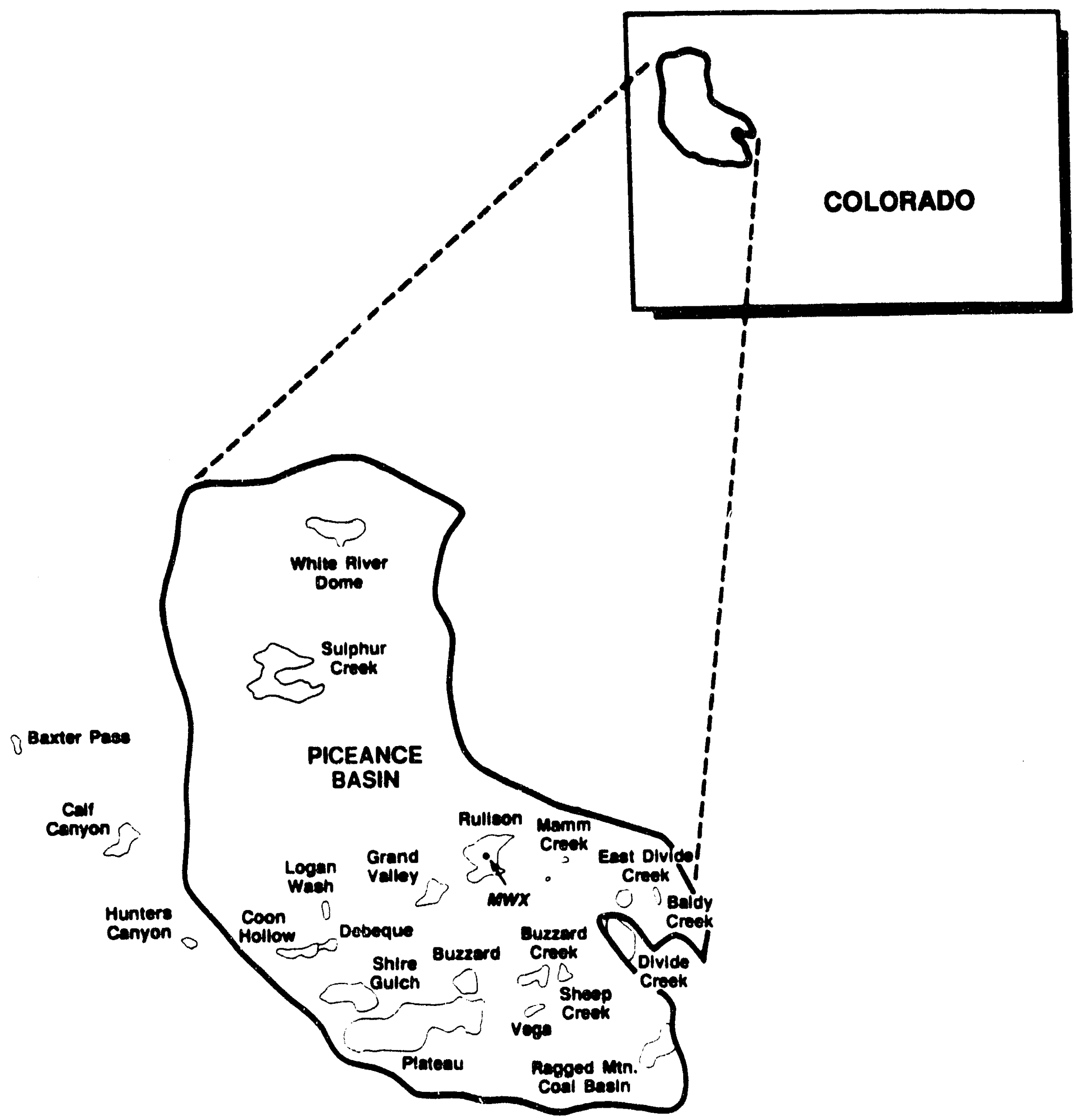


Figure 1 Piceance Basin of Colorado Showing Mesaverde Gas Fields and MWX Location

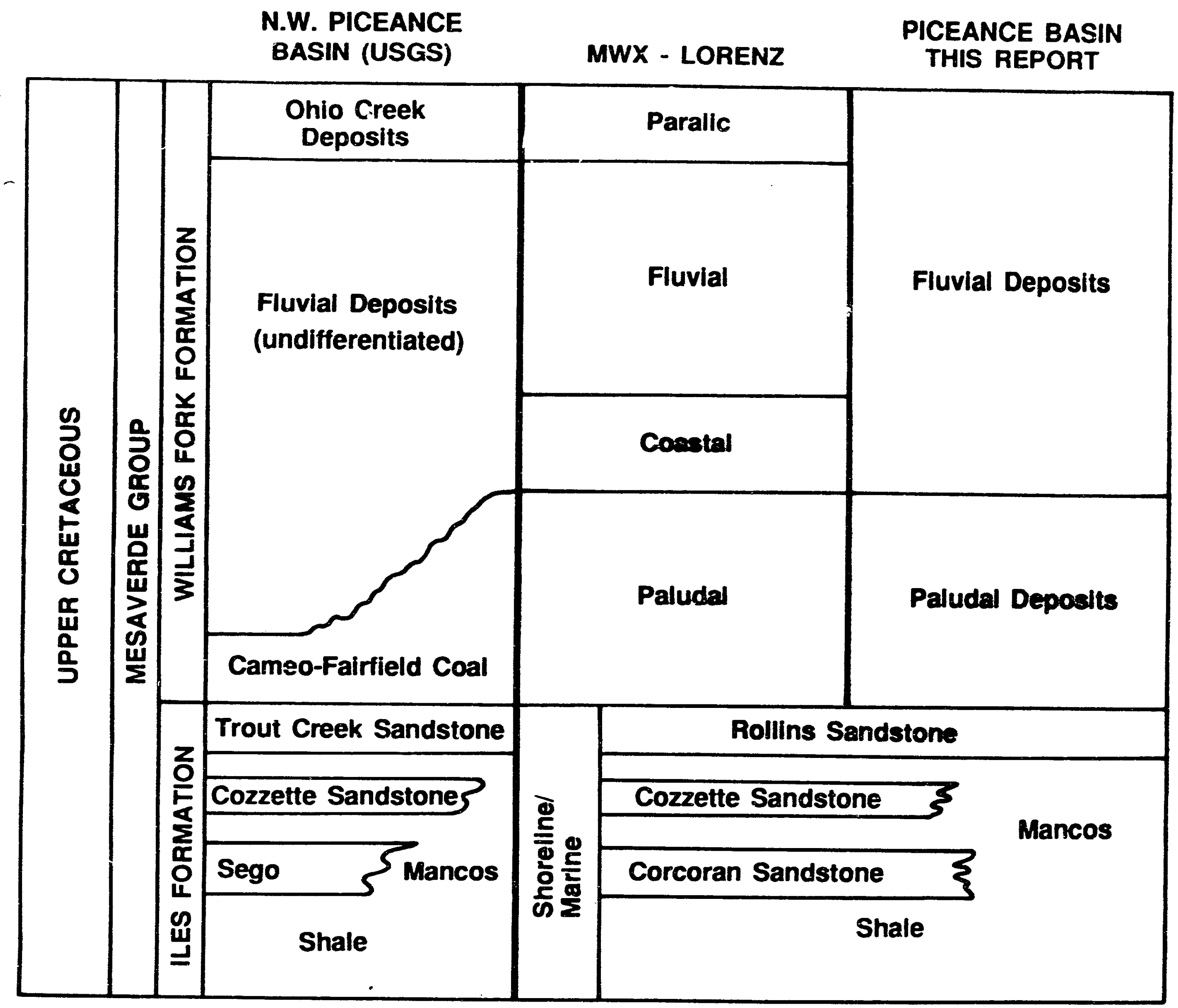


Figure 2 Stratigraphic Nomenclature Used in This Report Compared With That of Lorenz (1983) and Johnson (1987)

The operator is subsequently reimbursed for a portion of the data acquisition costs and receives the benefit of specialized data analysis.

Supplemental well information was contributed to this study by operators or organizations with activities in the Piceance Basin. This supplemental information includes basic data analyses from other related studies, geologic information, and production information from significant recent wells. This supplemental information significantly expanded the database from which conclusions about the partitioned areas in this report were based.

1.1 PURPOSE OF STUDY

The purpose of this study is to:

- Compare and contrast the geologic and production characteristics at MWX with the characteristics of other areas in the partitioned areas to determine the general extrapolation potential of MWX observations and conclusions.

- Develop an optimum methodology for exploiting the tight gas resource.

The overriding goal of this investigation is to transfer the technology developed at MWX to the gas producers who can implement it on a scale that will significantly increase economically recoverable gas reserves from tight, naturally fractured reservoirs.

1.2 REVIEW OF PHASE I RESULTS

During Phase I, a series of Mesaverde gas productivity maps and geologic cross sections were prepared for the basin. These maps included gross interval and sand thickness maps, permeability-thickness (kh) maps, thermal maps (indicating areas of active gas generation), a natural fracture intensity map, and ultimate recoverable gas production maps. Stimulation techniques were reviewed to determine the most effective stimulation technique for the Mesaverde in each gas producing field.

Results of the Phase I work were compiled in a report prepared by CER Corporation for the DOE titled "Geologic and Production Characteristics of the Tight Mesaverde Group: Piceance Basin, Colorado", DOE publication DOE/MC/24120-2769, July, 1989. The report is available to the public from the National Technical Information Service, U.S. Department of Commerce, 5285 Port Royal Rd., Springfield, VA 22161.

1.2.1 Phase I Major Conclusions

Extrapolation of detailed geological and engineering data from MWX into the surrounding Piceance Basin resulted in the following conclusions:

- Large areas of marine and paludal source rocks are presently hotter than 190°F, the temperature above which gas is believed to be generated in source rocks. Source rocks at gas generating temperatures are shallower in the southern part of the basin.

- Log data norms determined for MWX can be used to normalize data in the Rulison Field and fields in the central Piceance Basin trough; however, these norms cannot be extrapolated basin wide.

- The TITEGAS log analysis model developed at MWX is able to characterize reservoir parameters basin wide by adjusting some of the constants input to the program.

- Trapped gas is downdip of water in each stratigraphic unit as proposed by Masters (1979). The transition zone between water and gas cuts across stratigraphy near the edges of the basin.

- The subsurface in the Mesaverde Group has two distinct unidirectional, regional fracture systems. These fracture systems occur in different parts of the basin but may overlap in some areas.

- Log analysis of natural fractures detected the greatest density of natural fractures in the Southeast Uplift partitioned area followed by fewer detected fractures in the Central Basin and Southwest Flank partitioned areas, respectively.

- The higher rates of gas production are in areas of known fractures and are believed to be the result of enhanced permeability along fractures. The highest production rates are probably the result of cross fracturing of multiple sets developed during late Laramide uplift.

- The best wells were completed with minimal or no stimulation.

- Vast regions of the Piceance Basin have little well control and unproved Mesaverde gas production. In many cases, entire townships are still undrilled. This is particularly true for the northern Piceance Basin where data is too sporadic for adequate mapping control. Topography and pipeline distribution are also important factors explaining the lack of drilling in some areas.

A major product of Phase I was the division of the basin into three discrete areas having similar geologic and production characteristics: the Central Basin, the Southeast Uplift, and the Southwest Flank. These partitioned areas are shown in Figure 3. Each area is believed to have considerable gas production potential. Areas in the Piceance Basin outside of the three partitioned areas were judged to have insufficient data to define geologic and production characteristics.

1.2.2 Central Basin Area

The Central Basin partitioned area occupies the central basin trough and includes the following fields: Rulison, Grand Valley, Mamm Creek, Buzzard Creek, Sheep Creek and Vega. The producible reservoirs in the Central Basin partitioned area include fluvial, paludal and marine sandstones. Production in the marine interval is confined to the Cozzette and Corcoran sandstones. The Rollins sandstone shows some gas content; however, the blanket character of this sand results in poor trapping, and the water saturation is higher than irreducible water saturation.

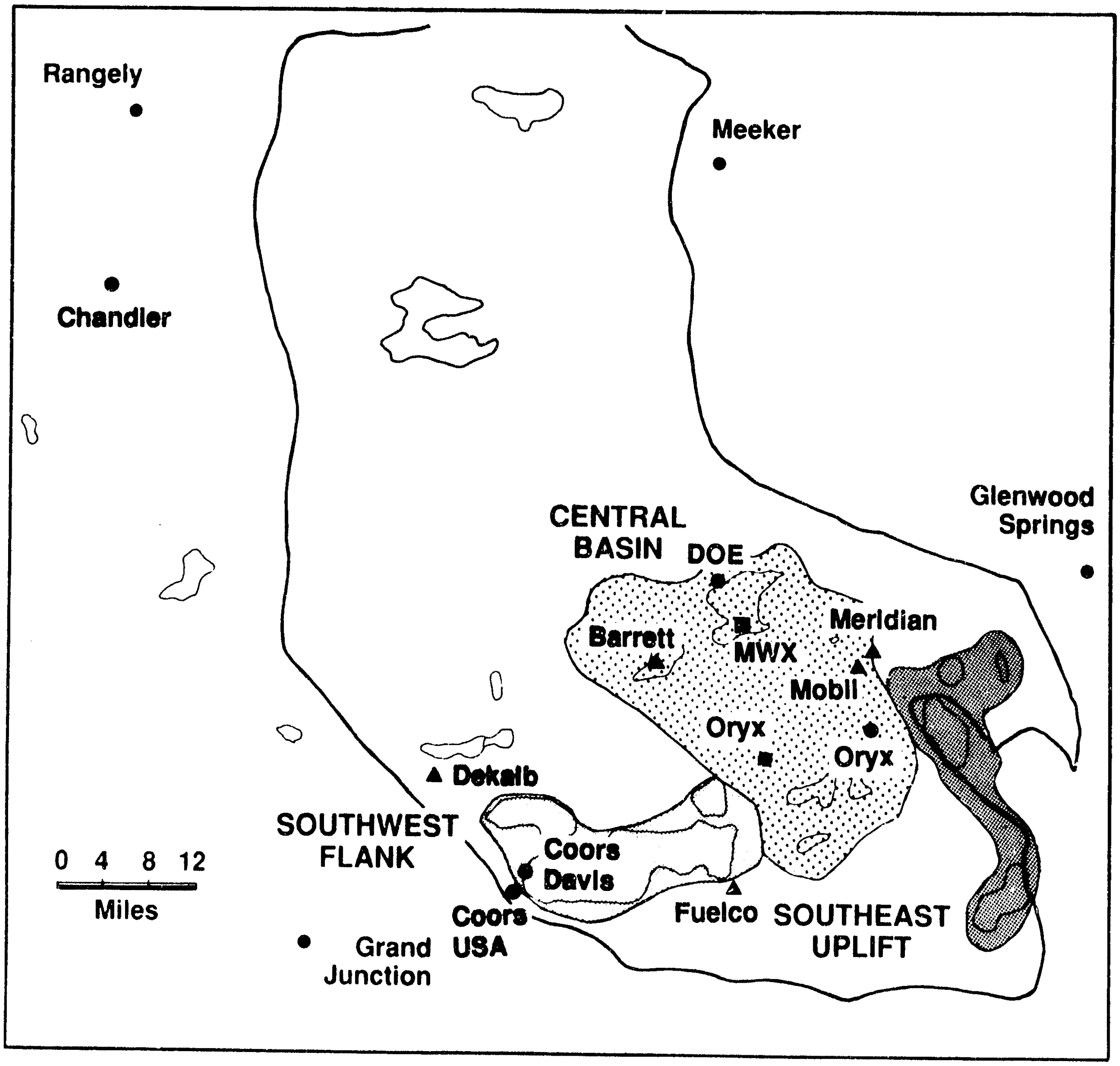


Figure 3 Map Showing the Three Selected Partitioned Areas: Central Basin, Southeast Uplift and Southwest Flank from the Phase I Study and the Well Locations for Phase II Investigations. Triangles are Cooperative Wells. Dots are Supplemental Information Wells

The production potential of the paludal sandstones at MWX appears to be anomalous. There is a high percentage of sandstone in the MWX paludal section and the sands appear to have better reservoir quality than adjacent wells. There is some potential for gas production from coal seams in both the Rulison and Grand Valley Fields. Some wells in the Grand Valley Field are producing primarily from coal seams.

There is good potential for gas production from fluvial sands in the Central Basin partitioned area. The gas saturated fluvial section averages about 1,500 ft thick. The gas saturated interval thickens downdip from southwest to northeast; however, there is also a downdip trend for lower porosity. Better quality sands can be recognized by their greater degree of flushing (i.e., shallow water saturation is greater than deeper saturation on logs), higher porosity and lower overall water saturation. Better quality sands appear to occur randomly both vertically in the section and laterally in the area. The percentage of sand in the interval decreases east of the Rulison Field toward Mamm Creek.

Natural fractures are an important gas production mechanism in the Central Basin. Natural fractures have been observed in core taken at MWX in all Mesaverde intervals and were also described in core from the Barrett Energy Grand Valley No. 2 well. The presence of a highly anisotropic, natural fracture system at the MWX site was inferred through extensive, highly instrumented well tests and pressure interference tests in the marine, paludal and fluvial intervals (Lorenz and others, 1986). The fracture system was confirmed by cores from the SHCT Well (Lorenz and Hill, 1991).

Historical records indicate that the best fluvial production is either unstimulated or from nitrogen-based foam propped fractures. The best paludal zone completions are from assisted gelled water and cross-linked gelled water fracture treatments.

1.2.3 Southeast Uplift Area

The Southeast Uplift partitioned area is located in T7S and T8S, R90W and R91W and in T10S and T11S, R90W and includes the following fields: Divide Creek, East Divide Creek, Baldy Creek, Ragged Mountain and Coal Basin. Eighteen wells produce from the Corcoran, Cozzette or Rollins sandstones of the marine interval of the Mesaverde, and two wells, are completed in the paludal Mesaverde.

The major potential for gas production in the Southeast Uplift partitioned area is from the regressive marine sands. The productive units include the Corcoran and Cozzette sands. In some cases, good production is achieved even though the particular sand does not appear to be well developed.

Paludal sands are poorly developed in the Southeast Uplift partitioned area; however, there appears to be some potential for paludal gas production in the Ragged Mountain Field. In general, updip fluvial wells are water saturated, indicating a lack of structural closure on the Divide Creek anticline. There appears to be some potential for fluvial production downdip at the Ragged Mountain and Baldy Creek Fields.

The wells that have the highest average production were those that did not require stimulation. Natural fractures are inferred to be important to production.

1.2.4 Southwest Flank Area

The Southwest Flank partitioned area encompasses T9S and T10S, R94W to R97W and includes the following fields: Shire Gulch, Brush Creek, Buzzard and Plateau. The majority of wells in the area are completed in the Corcoran and Cozzette sandstones of the marine Mesaverde.

Wells on the eastern side of the Southwest Flank partitioned area are gradational to the Central Basin area and have the potential to produce gas from the fluvial interval. In general, however, sands in this interval have been swept by meteoric water. Sands of the paludal interval are not well developed.

The highest average production is from wells that were unstimulated or hydraulically fractured with gelled weak acid or gelled diesel carrying proppant.

2.0 PHASE II - FIELD VERIFICATION TESTS IN WELLS OF OPPORTUNITY

Following the initial characterization of the Mesaverde reservoirs, field technology verification tests with industry partners were undertaken in the partitioned areas. The purpose of these "wells of opportunity" or cooperative tests was to verify or compare and contrast the geologic, reservoir, and production characteristics previously determined for the Mesaverde reservoirs at the MWX site with those in other areas. Specifically, tests were designed to examine reservoir matrix quality, natural fracture characteristics, stress orientation and production quality. These tests supplemented the operators' data collection plans with data from oriented coring, borehole image logs, and pressure transient tests, as was practical. At least one cooperative well in each of the three partitioned areas was sought.

To collect the requisite data from each partitioned area for comparison to MWX, the following procedure was followed:

1. **Locate wells of opportunity.** The southern Piceance Basin was monitored for drilling activity within the areas of interest. Contacts were made with individual operators to determine their interest in participating in the cooperative well program.

2. **Develop field test plans.** For those interested operators, data acquisition programs and operations procedures were designed and approved by the operator, the DOE, and CER Corporation. Cost reimbursement or co-funding agreements were negotiated and formalized between CER Corporation and the operators on behalf of the DOE.

3. **Coring activities.** In those wells involving core acquisition, the core intervals were selected in consultation with the operator. Coring logistics, handling, marking and orientation were performed by CER. Cores were analyzed for natural and drilling induced fracture distribution and orientation, and lithologic and sedimentological features.

4. **Logging and log analyses.** Logging programs were designed to evaluate basic reservoir parameters such as porosity, water saturation and matrix permeability. The minimum logging suites included Gamma Ray, Dual or Phasor Induction, Compensated Neutron, and Litho-Density. Also included was either a Borehole Televiewer or a Formation Microscanner, primarily for fracture and breakout detection and orientation. Wellsite logging quality was strictly monitored and controlled. Log analysis was done with TITEGAS, a customized system designed to identify producible gas zones in marginally productive sandstone gas reservoirs. TITEGAS identifies zones that are impermeable, permeable and wet, or permeable and gas bearing. A description of the log analysis model and the format for presentation of log analysis results in this report are included in Appendices 1 and 2.

5. **Pre-Frac Pressure Transient Testing.** The pre-frac well tests were designed and executed to provide the following: sufficient clean-up, pre-frac production capacity, average reservoir flow capacity, influence and characterization of the natural fractures, determination of boundary conditions, and damage estimates from drilling and/or completion. Test intervals were selected with regard to the operators' completion objectives and the results of the log analysis. Real time modeling and various analytic techniques, such as derivative analysis, were used to minimize test periods as well as reservoir evaluation. A downhole shut-in device was used to minimize wellbore storage and to obtain early time pressure data.

2.1 COOPERATIVE AND SUPPLEMENTAL WELLS

During 1990 and 1991 there was only moderate drilling activity in the Piceance Basin, primarily targeting the coals in the paludal Mesaverde interval. Several operators were willing to cooperate with this study and five cooperative well programs were conducted. Three wells were within the Central Basin partitioned area, one was in the Southwest Flank area, and one in an Undefined area. Unfortunately, no co-op wells were located in the Southeast Uplift partitioned area; however, two wells near the boundary with the Central Basin provide insights into parts of the Southeast Uplift area. Table 1 is a list of the cooperative wells, the operators, locations, and data collection activities with respect to the areas. The activities, results and implications of these field verification tests are described in detail below. Table 2 is a summary of the supplementary wells, including the type of data and analyses that contributed to this report.

In the Southwest Flank partitioned area, direct reservoir information was obtained in a cooperative well with Fuel Resources Development Company (Fuelco). In addition, the Gas Research Institute funded TITEGAS log analyses of the Corcoran and Cozzette sandstone intervals in two Coors Energy wells. These wells (Figure 3) are important in that they define geographic limits of production in the Southwest Flank.

Table 1 Cooperative Wells and Activities

Partitioned Area	Operator	Well Name	Location	Data Collection Activities
Central Basin	Barrett Resources	MV 8-4	NE/4 Section 4, T7S, R96W Garfield County	Oriented coring Core analysis Geophysical logs Formation Microscanner Pressure transient test
	Mobil	Mamm Ranch T45-29P	NE SW Section 20, T7S, R92W, Garfield County	Conventional coring Core analysis Geophysical logs Formation Microscanner
	Meridian	MOI Lyons 12-14	SW NW Section 14, T7S, R92W	Geophysical logs Formation Microscanner
Southwest Flank	Fuelco	FEE E-22-10-94S	NW Section 22, T10S, R94W, Mesa County	Oriented coring Core analysis Geophysical logs Borehole televiewer Pressure transient test
	Dekalb	14-11 Wagon Train Federal	Section 11, T9S, R98W, Mesa County	Log analysis only

Table 2 Supplemental Wells and Activities

Well	Location	Activities and Data Contributed
DOE 1M-17	Sec. 17, T6S, R94W	Log analysis Production data
Coors USA 1-27	Sec. 27, T10S, R97W	Log analysis
Coors Davis 1-24	Sec. 24, T10S, R97W	Log analysis
Oryx Acapulco Federal Unit #1 HD	Sec. 16, T8S, R92W	Fracture data Production data
Oryx Collier Creek	Sec. 25, T8S, R94W	Fracture data Production data

2.2 BARRETT RESOURCES MV 8-4

The Barrett Resources MV 8-4 well is located in Section 4, T7S, R96W, Garfield County, Colorado, in the Grand Valley Field. The MV 8-4 was drilled to a total depth of 6,900 ft, which is approximately 200 ft below the top of the Rollins. Figure 3 shows the location of the well with respect to the partitioned areas. Barrett Resources has been actively developing the gas resource in the Grand Valley Field for several years. The MV 8-4 well was targeted to produce gas from two objectives. One objective was the gas producing coal seams in the paludal Mesaverde interval, and a second objective was the roughly 1,500 ft of sand/siltstone/shale sequence of the fluvial Mesaverde that contains about 20 potentially productive individual gas reservoirs. A field verification test program was designed to determine reservoir parameters including the significance of natural fractures to production. The test program consisted of oriented coring of selected fluvial sandstone intervals, analyzing logs with the TITEGAS program, running and analyzing a borehole image log, and pressure transient testing of a selected fluvial sandstone.

2.2.1 Summary of Core Data

The cored interval for this well is 5,760.0 to 5,869.0 ft. The interval was selected by well-to-well correlations with six other wells in T7S, R96W and T6S, R96W. From these correlations, the MV 8-4 well was expected to penetrate reservoir quality fluvial gas sands 300 to 200 ft above the top of the paludal Mesaverde interval.

Figure 4 shows the depth shifted core gamma ray curve plotted with the wireline gamma ray curve. The core gamma is discontinuous because only core intervals of reservoir interest were measured. Unfortunately, the lowermost sand between 5,820 and 5,866 ft is not well developed as a reservoir unit. A total of 35 plug samples were chosen for core analysis. The core analysis data is presented in Table 3.

The core analyses consisted of stressed dry Klinkenberg corrected air permeability, stressed Boyles Law helium porosity and grain density. The confining stress selected for the analysis was 3,000 psi. A confining stress of 800 psi was also used; it is instructive to compare this data to the 3,000 psi data to determine the stress sensitivity of the porosity and permeability measurements. Figure 5 graphically compares the core porosity data. The figure shows that porosity is not very stress sensitive. Porosity reduction is generally less than a few tenths of 1 percent. By contrast, Figure 6 shows that permeability measurements are sensitive to stress. The findings are consistent with petrophysical observations made on MWX core and with many other tight gas sandstones. It is interpreted that this extreme permeability stress sensitivity is due to the closure of intergranular cracks or slot-like grain boundaries of the remnant primary porosity system with added confining stress. Porosity is not very stress sensitive because the majority of pore space consists of relatively large secondary pores that are supported by matrix. The remnant primary pores control gas flow through matrix; however, they do not contribute much to gas storage.

2.2.2 Formation Evaluation

The log suite for the MV 8-4 well consists of Phasor Induction, SFL, Density, Caliper, Compensated Neutron, Gamma Ray and Formation MicroScanner (FMS). Three separate FMS

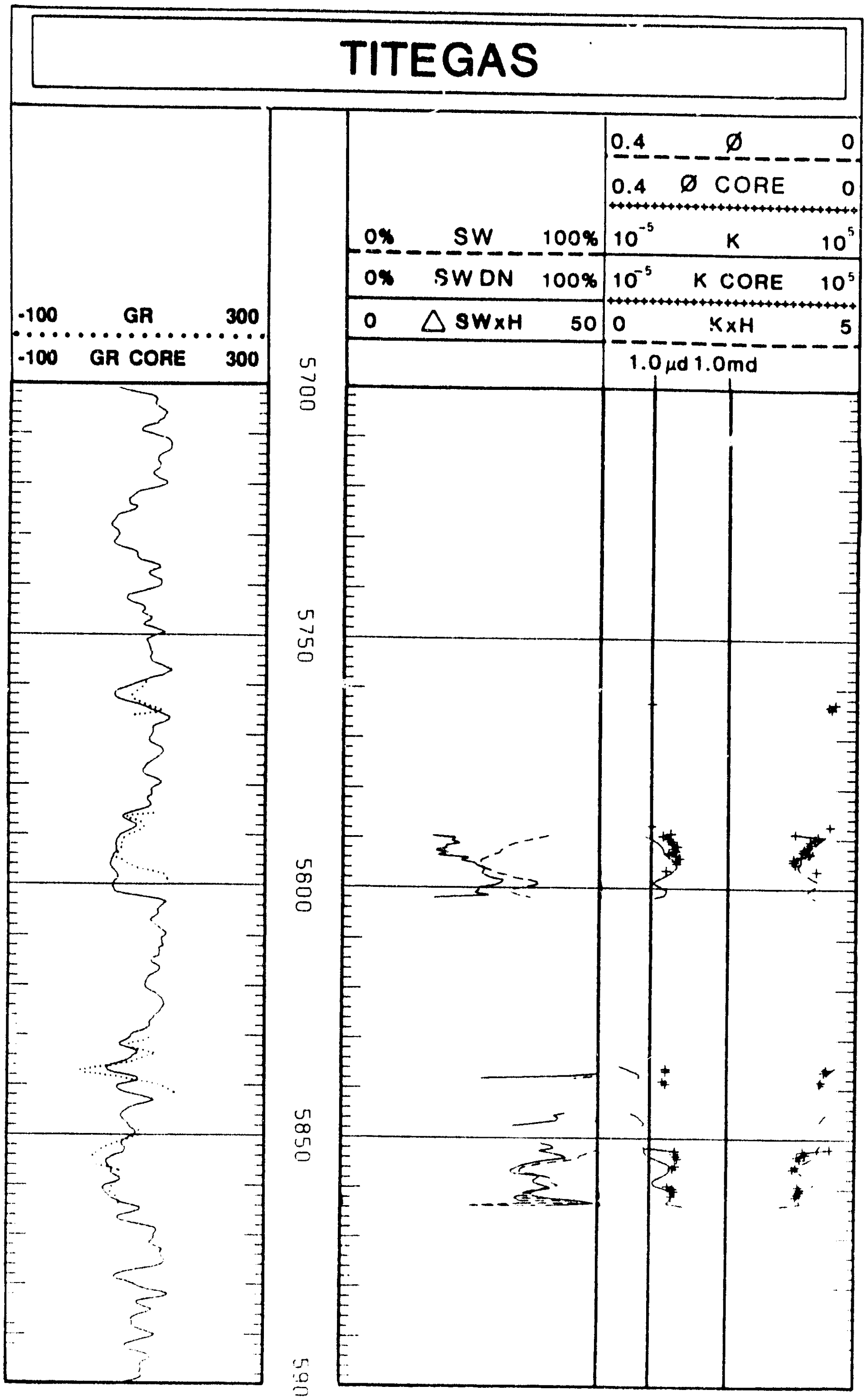


Figure 4 Trace Plot of Depth-Shifted Core Gamma Ray (GR CORE) and Log Gamma Ray (GR) Curves, Barrett MV 8-4

Table 3 Core Petrophysical Data for the Barrett MV 8-4

Depth, ft	Porosity 800 psi, percent	Porosity 3000 psi, percent	Perm. 800 psi, md	Perm. 3000 psi, md	Grain Density, gm/cc
5,766.5	3.2	2.6	0.005	0.001	2.70
5,767.0	4.2	3.2	0.015	---	2.71
5,767.5	3.8	2.7	0.009	---	2.73
5,791.0	4.1	3.4	0.006	0.001	2.71
5,792.5	9.4	8.9	0.018	0.006	2.81
5,793.0	5.9	5.4	0.007	0.003	2.69
5,793.5	6.3	5.9	0.013	0.005	2.69
5,794.0	7.1	6.7	0.015	0.006	2.69
5,794.5	7.0	6.4	0.027	0.007	2.69
5,795.0	7.4	6.9	0.034	0.011	2.69
5,795.5	8.0	7.4	0.039	0.008	2.69
5,796.0	8.2	7.7	0.043	0.009	2.69
5,796.5	7.2	6.7	0.026	0.005	2.70
5,797.0	8.5	8.0	0.042	0.010	2.69
5,797.5	9.6	9.0	0.045	0.013	2.69
5,798.0	9.7	9.3	0.037	0.010	2.69
5,798.5	9.4	8.9	0.053	0.010	2.69
5,800.0	6.2	5.7	0.019	0.004	2.74
5,834.0	4.6	4.1	0.023	0.004	2.69
5,834.5	4.9	4.5	0.019	0.004	2.74
5,835.0	5.5	5.1	0.044	0.004	2.73
5,837.5	5.4	4.9	0.031	0.003	2.72
5,838.0	5.6	5.1	0.032	0.004	2.70
5,851.0	3.9	3.0	0.014	0.001	2.70
5,851.5	8.0	7.5	0.037	0.010	2.70
5,852.0	7.7	7.2	0.037	0.009	2.69
5,852.5	8.9	8.4	0.050	0.010	2.69
5,853.0	8.5	8.0	0.075	0.012	2.67
5,853.5	9.1	8.5	0.059	0.010	2.68
5,854.0	9.6	8.8	0.047	0.008	2.71
5,856.5	8.8	8.4	0.025	0.005	2.71
5,857.0	8.6	8.1	0.045	0.008	2.69
5,857.5	8.5	8.0	0.048	0.009	2.69
5,858.0	9.0	8.4	0.049	0.007	2.69
5,858.5	9.2	8.6	0.045	0.007	2.70

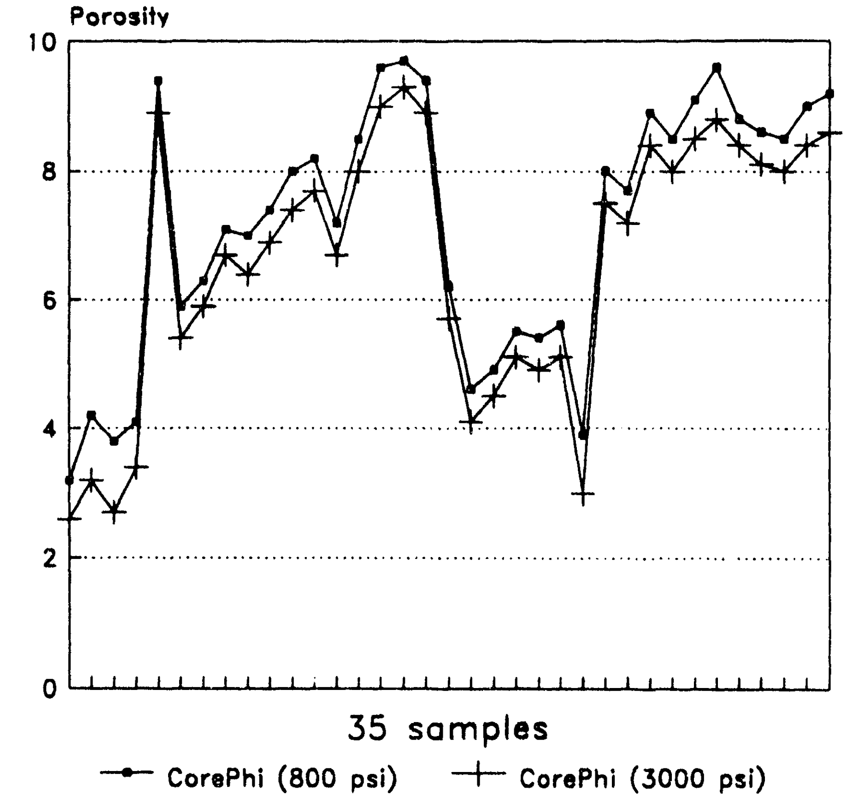


Figure 5 Comparision of Core Porosity Measurements at 800 and 3,000 psi, Barrett MV 8-4

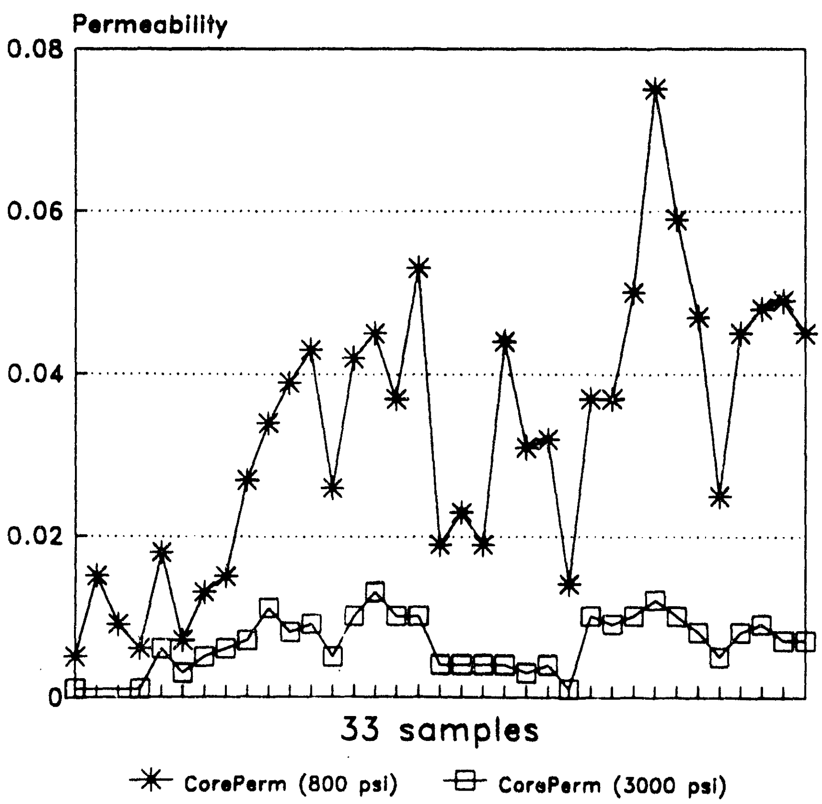


Figure 6 Comparison of Core Permeability Measurements at 800 and 3,000 psi, Barrett MV 8-4

passes were made over the interval of interest in an attempt to achieve full wellbore coverage. Even so, in the upper part of the hole, the tool tended to lock into an elliptical borehole and wellbore coverage was sometimes as little as 40 percent.

The gross interval analyzed was from 6,818 to 3,661 ft which includes the upper marine, paludal and fluvial depositional series of the Mesaverde Group. The analysis was broken into four sub-intervals to account for changes in formation constants across the gross interval. The lower sub-interval is from 6,818 to 6,054 ft and includes the Rollins and paludal section. The lower fluvial sub-interval is from 6,054 to 4,912 ft. Water saturations within this sub-interval are interpreted to be at irreducible. The fluvial transition sub-interval is from 4,912 to 4,348 ft. Water saturations within this sub-interval are interpreted to be greater than irreducible while still having some gas content. For completeness, the water-saturated Mesaverde sub-interval is analyzed from 4,348 to 3,661 ft, which coincides with the top of the Ohio Creek.

Following depth shifting and environmental corrections of log data, histograms of log data were prepared over each sub-interval for use in log data normalization. Log data norms developed in the Phase I portion of this study were used to normalize log data. It was determined that the MV 8-4 log data is in good agreement with Central Basin Mesaverde log data norms.

Comparisons of computed matrix density with core grain density showed that the log analysis could be improved by varying the matrix density with measured bulk density. These results are consistent with the results observed using MWX data.

Tabular log analysis results for the MV 8-4 well are presented in Table 4. Each zone in the analyzed interval is numbered from bottom to top, i.e., Zone 1 is from 6,774.5 to 6,801.0 ft and Zone 52 is from 3,676.5 to 3,685.0 ft. Refer to Appendix 2 for a description of each reservoir parameter that is presented in the table. Also included in the table is an estimate of early time gas production from a matrix-permeability dominated flow system (QMCFD). For an individual sandstone to be designated as a zone, it must have at least three ft of continuous valid log data above cutoff values, (i.e. an interpreted porosity that is greater than 3 percent, and an interpreted clay volume that is less than 25 percent).

The computed log for the MV 8-4 well is presented in Figure 7. Appendix 2 describes the format of the TITEGAS computed log.

A semi-log crossplot of MV 8-4 core porosity vs. dry core Klinkenberg-corrected (absolute) permeability is presented in Figure 8. Both sets of core data are measured at 3,000 psi net stress. A best fit line through this data is expressed by the following exponential equation:

$$k = 0.00065 \times 10^{0.1383\phi}$$

where ϕ = porosity in percent. The correlation coefficient is 0.77 which is higher than is generally observed for tight gas sand porosity and permeability data.

To better compare MV 8-4 porosity-permeability relationships with the relationships observed at MWX, core porosity at 800 psi net stress is plotted vs. absolute permeability at 3,000 psi net stress. This is necessary because MWX core porosities were not routinely measured at in-situ stress, whereas a fairly large database was developed for permeability at in-situ stress (261 samples). Figure 9 shows the best fit line for the MV 8-4 data and also shows the best

Table 4 Key Reservoir Parameters and Zone Designations for the Barrett MV 8-4

INTERVAL (FEET)	ZONE	GROSS H (FT)	NET H (FT)	AVG Ø (%)	MAX Ø (%)	AVG SW (%)	MIN SW (%)	HCFT (FT)	KH (MD-FT)	MAX K (MD)	AVG CLAY (%)	MIN CLAY (%)	QMCFD (MCFD)
6774.5-6801.0	R - 1	27.0	24.0	5.0	6.7	98.9	77.1	0.017	0.025	0.001	19.8	12.1	3.5
6699.0-6761.0	R - 2	62.5	52.0	7.3	11.1	77.8	47.7	0.935	0.654	0.027	12.7	4.9	96.8
6518.5-6521.5	P - 1	3.5	3.5	4.3	5.1	97.9	92.6	0.004	0.002	0.001	19.3	15.1	0.5
6437.0-6440.5	P - 2	4.0	4.0	6.3	7.8	70.9	61.9	0.079	0.012	0.005	9.1	5.5	5.4
6394.5-6401.5	P - 3	7.5	7.0	7.0	8.3	79.7	70.2	0.104	0.018	0.004	21.4	16.8	6.7
6375.0-6386.5	P - 4	12.0	12.0	7.4	9.2	72.1	62.3	0.275	0.071	0.007	15.9	11.6	26.3
6298.5-6344.0	P - 5	46.0	42.0	9.2	11.2	62.6	40.8	1.516	0.957	0.030	16.6	12.3	155.7
6277.0-6289.0	P - 6	12.5	12.5	8.8	11.2	67.1	54.6	0.379	0.080	0.016	17.3	9.0	31.2
6188.0-6197.0	P - 7	9.5	9.5	8.9	11.4	78.7	61.3	0.200	0.043	0.012	21.9	18.2	16.2
6172.5-6175.5	P - 8	3.5	3.5	7.1	8.1	94.7	87.1	0.014	0.006	0.003	14.5	9.9	1.7
6016.5-6053.5	FG-1	37.5	29.5	8.3	10.1	81.2	61.7	0.496	0.233	0.012	15.1	8.6	44.5
5973.0-5978.5	FG-2	6.0	6.0	7.0	9.6	77.5	60.8	0.113	0.028	0.012	7.8	5.1	10.7
5835.5-5863.5	FG-3	28.5	19.0	6.7	8.9	86.4	67.3	0.219	0.063	0.007	14.8	4.5	20.8
5789.5-5802.0	FG-4	13.0	13.0	7.0	9.0	65.2	53.5	0.328	0.053	0.012	14.5	10.1	21.9
5696.5-5699.5	FG-5	[illegible]	3.5	6.4	9.7	84.5	60.8	0.042	0.008	0.009	17.6	15.7	2.9
5624.0-5671.0	FG-6	47.5	42.5	6.7	8.6	63.3	49.7	1.087	0.324	0.011	15.4	9.0	66.9
5577.5-5580.5	FG-7	3.5	3.5	5.7	6.2	78.7	75.4	0.042	0.004	0.002	17.5	13.8	1.9
5556.0-5558.5	FG-8	3.0	3.0	5.1	7.0	93.7	84.2	0.011	0.002	0.001	18.8	15.1	0.7
5539.5-5542.0	FG-9	3.0	3.0	4.9	5.6	86.6	82.3	0.020	0.003	0.001	18.3	13.2	1.1
5473.0-5488.0	FG-10	15.5	13.0	7.9	8.9	62.8	57.9	0.385	0.131	0.009	13.9	8.6	25.1
5407.5-5424.5	FG-11	17.5	14.5	6.9	8.7	67.5	53.0	0.350	0.084	0.009	15.5	6.1	24.2
5371.5-5374.5	FG-12	3.5	3.5	5.9	6.7	81.7	65.4	0.041	0.005	0.002	17.8	12.9	1.9
5340.0-5357.5	FG-13	18.0	18.0	8.3	9.3	56.1	47.9	0.669	0.160	0.015	11.4	7.9	50.6
5289.0-5292.0	FG-14	3.5	3.5	4.7	5.1	73.6	69.9	0.044	0.013	0.001	19.1	15.0	4.6
5278.0-5280.5	FG-15	3.0	3.0	8.9	10.3	56.5	51.3	0.117	0.034	0.002	10.6	6.0	10.4
5246.0-5265.5	FG-16	20.0	16.0	6.7	9.0	64.3	47.8	0.405	0.085	0.007	13.6	9.4	27.5
5229.5-5232.5	FG-17	3.5	3.5	6.7	8.1	80.8	59.8	0.049	0.009	0.006	12.4	9.9	3.0
5104.0-5110.5	FG-18	7.0	7.0	8.0	10.0	72.0	54.0	0.165	[illegible]	0.014	13.1	6.9	11.0
5034.0-5058.0	FG-19	24.5	19.5	9.8	10.1	69.3	46.2	0.846	0.215	0.021	11.5	4.7	56.8
4912.0-4921.5	FG-20	10.0	9.5	6.4	10.4	60.9	41.1	0.246	0.047	0.032	8.0	3.9	13.5
4829.0-4852.5	FT-1	24.0	18.5	10.1	13.1	55.6	45.8	0.844	0.640	0.033	18.7	9.9	65.2
4800.5-4807.5	FT-2	7.5	7.5	9.3	10.5	44.4	37.6	0.387	0.134	0.031	10.2	6.8	27.4
4777.0-4779.5	FT-3	3.0	3.0	10.5	13.1	49.8	41.4	0.161	0.250	0.043	16.4	13.4	52.1
4698.0-4700.5	FT-4	3.0	3.0	7.7	10.0	66.8	55.0	0.080	0.017	0.012	14.1	11.6	4.0
4668.5-4687.0	FT-5	19.0	19.0	7.5	10.8	71.5	57.1	0.447	0.094	0.012	13.1	9.2	20.7
4621.5-4634.0	FT-6	13.0	13.0	5.8	7.7	58.7	47.8	0.322	0.039	0.007	13.5	5.9	10.0
4567.0-4589.0	FT-7	22.5	22.5	6.3	10.1	64.6	44.[illegible]	0.531	0.093	0.023	13.5	3.5	20.4
4523.5-4526.5	FT-8	3.5	3.5	6.3	6.8	56.1	54.[illegible]	0.097	0.009	0.003	21.7	17.7	2.6
4471.0-4494.0	FT-9	23.5	21.5	7.9	10.6	59.8	48.2	0.697	0.338	0.025	10.9	0.8	32.6
4445.5-4461.5	FT-10	16.5	11.0	7.5	9.2	68.3	56.7	0.276	0.063	0.014	9.5	0.0	12.4
4383.5-4390.5	FT-11	7.5	7.5	8.1	8.6	72.2	53.3	0.176	0.066	0.012	4.7	1.3	10.7
4348.5-4351.0	FT-12	3.0	3.0	6.5	7.2	81.7	70.2	0.036	0.006	0.004	9.7	9.0	1.3
4319.0-4333.0	FW-1	14.5	14.5	6.2	7.4	89.2	72.3	0.103	0.036	0.004	12.5	7.1	6.0
4161.5-4171.0	FW-2	10.0	10.0	5.0	6.1	93.5	71.8	0.032	0.012	0.002	9.8	4.8	1.4
4151.0-4153.5	FW-3	3.0	3.0	5.4	6.1	74.4	68.5	0.042	0.004	0.002	14.8	9.2	1.0
4081.0-4091.5	FW-4	11.0	11.0	7.3	12.9	89.8	56.1	0.102	0.091	0.038	5.9	0.0	11.4
4039.5-4052.5	FW-5	13.5	13.5	5.8	8.9	89.7	69.7	0.091	[illegible].032	0.011	10.2	3.8	4.6
4019.0-4022.0	FW-6	3.5	3.5	6.4	8.5	92.2	75.0	0.021	[illegible]010	0.006	11.5	8.9	1.3
3786.0-3807.5	FW-7	22.0	18.0	6.3	8.5	91.3	79.1	0.098	0.067	0.007	17.7	11.6	5.1
3772.5-3779.0	FW-8	7.0	7.0	6.3	9.6	98.9	88.4	0.005	0.025	0.014	7.7	2.8	1.2
3736.5-3753.5	FW-9	17.5	15.5	7.1	9.3	88.9	73.9	0.162	0.196	0.017	6.5	0.0	16.3
3676.5-3685.0	FW-10	9.0	9.0	8.7	11.4	57.0	50.1	0.342	0.079	0.016	16.5	10.1	11.2

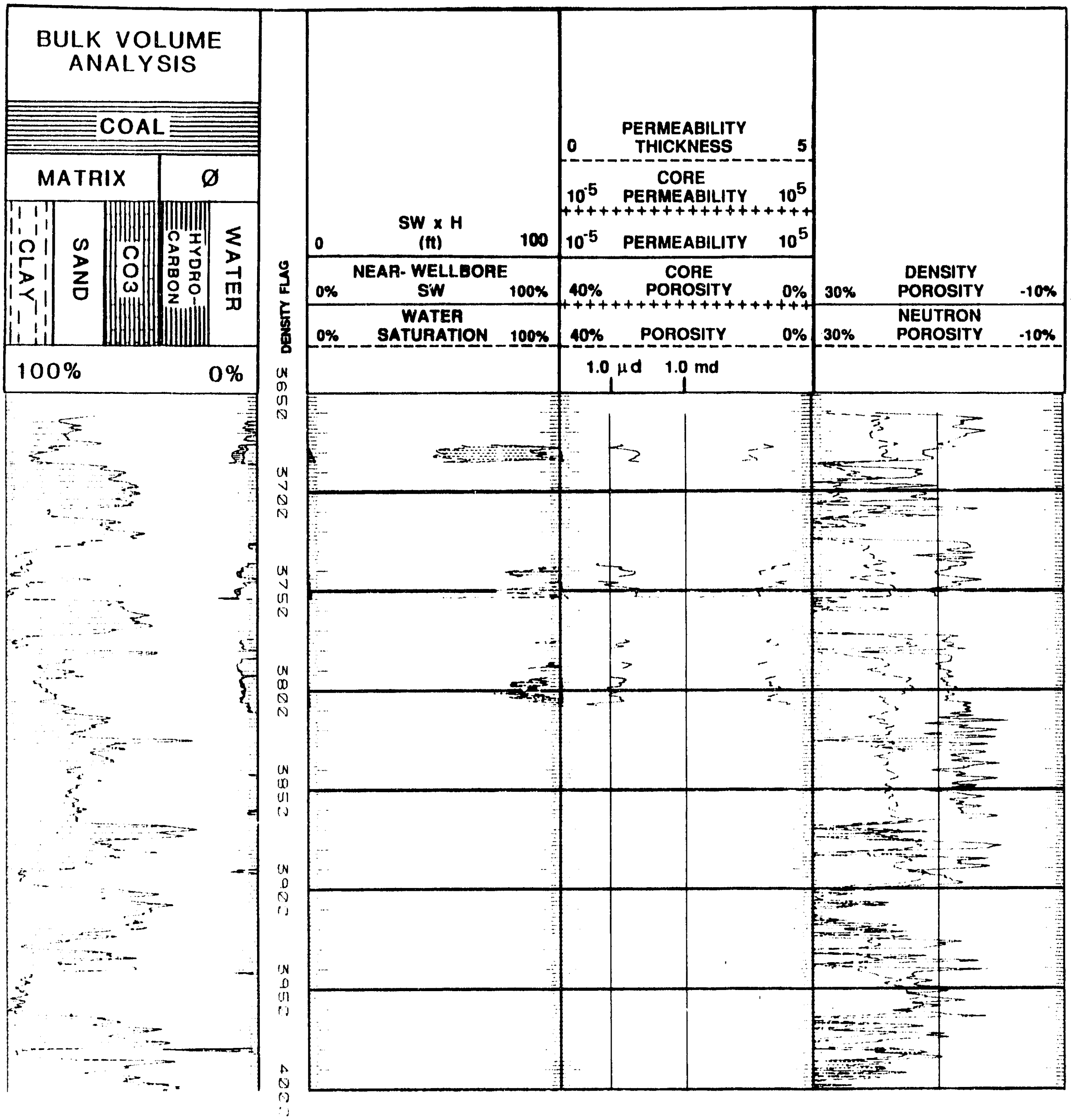
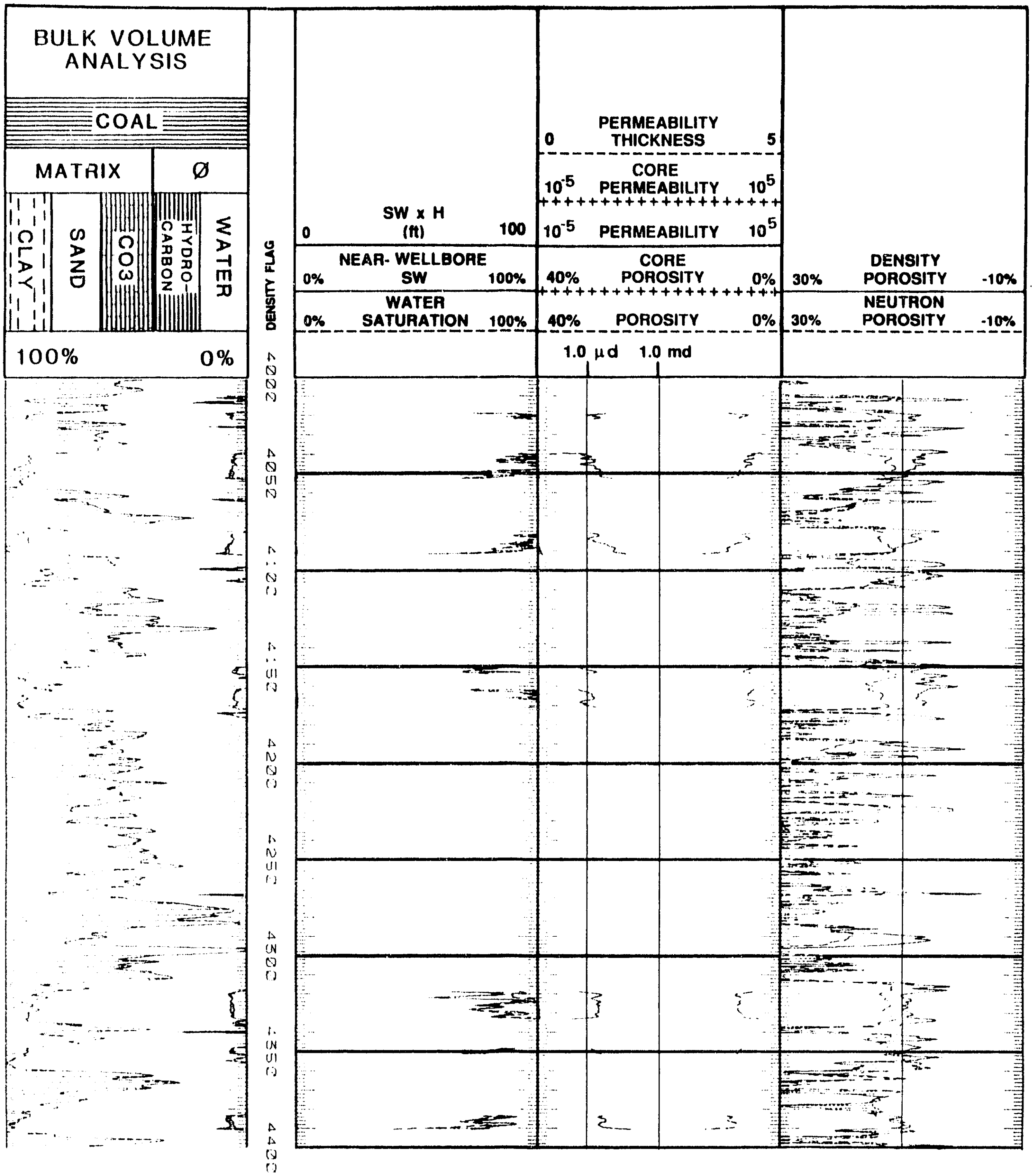


Figure 7 TITEGAS Computed Log, Barrett MV 8-4



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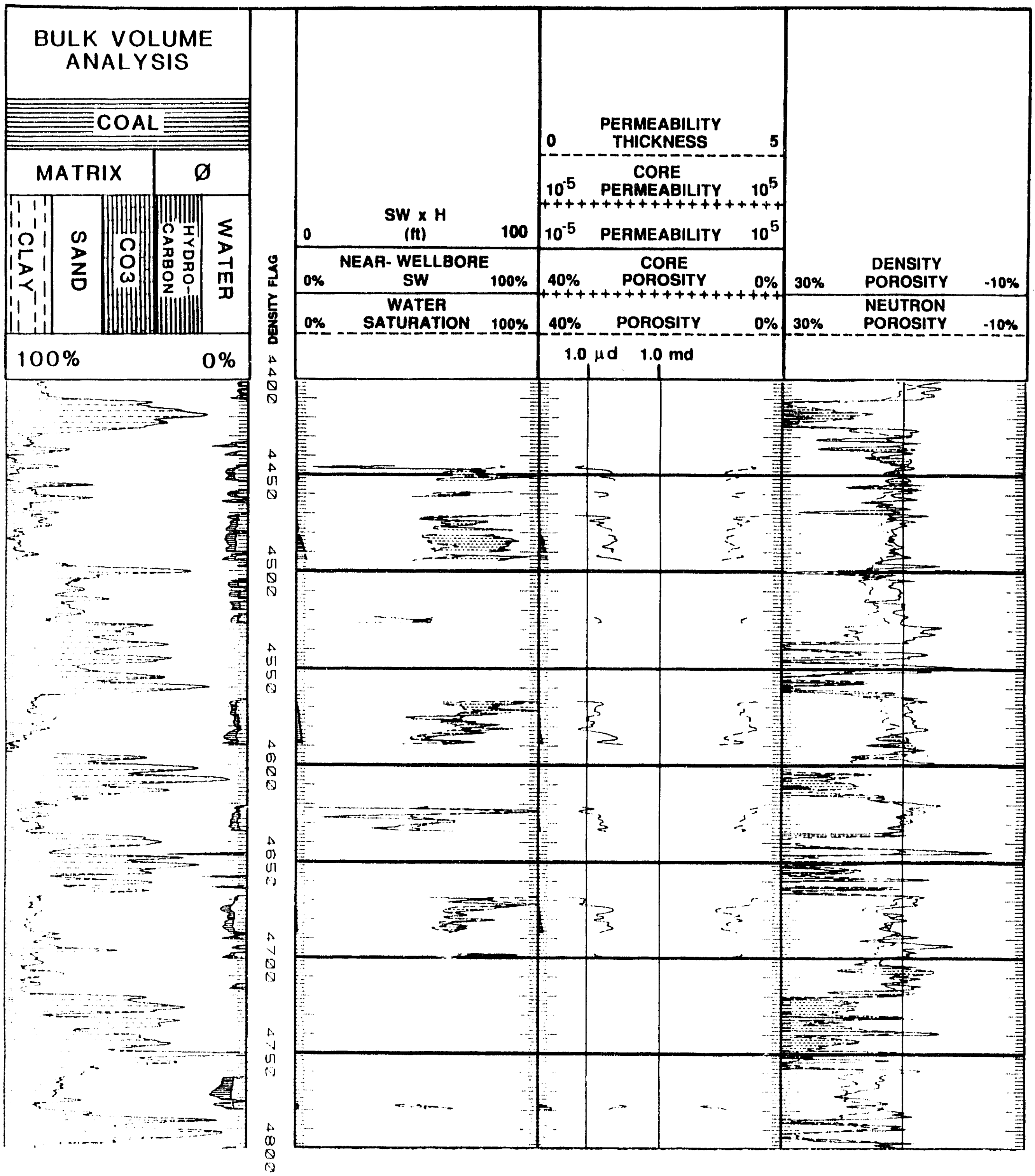

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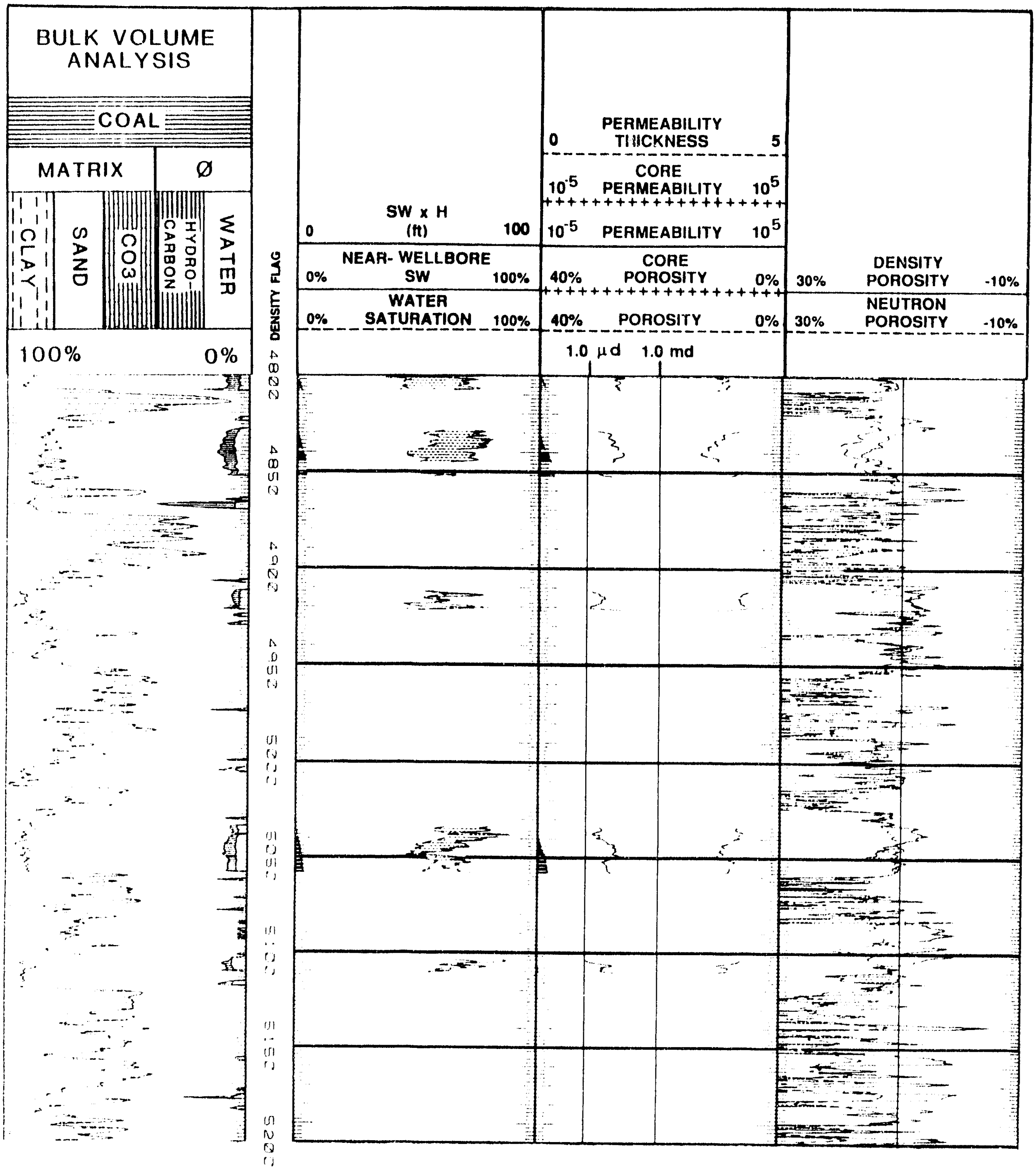

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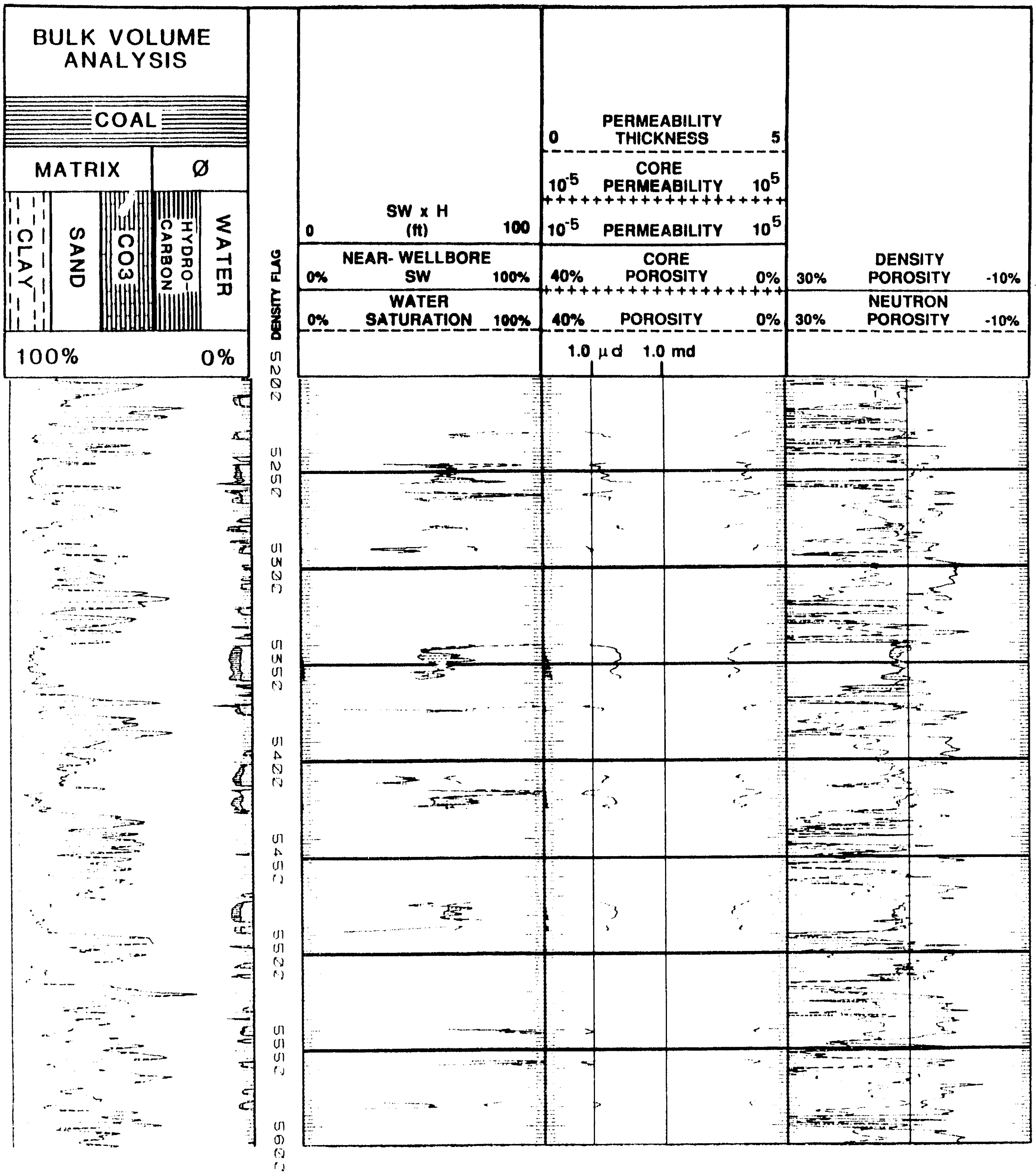

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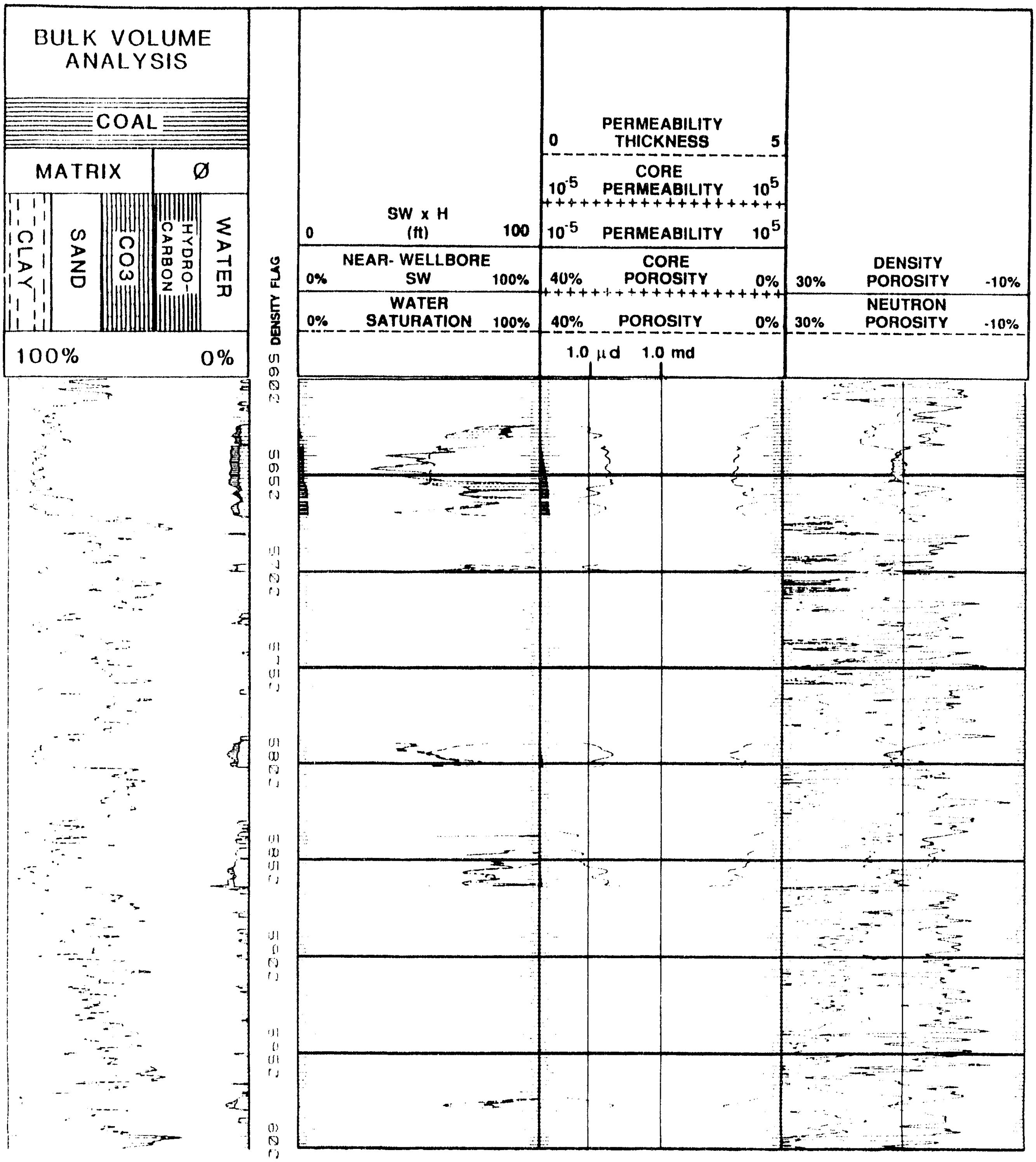

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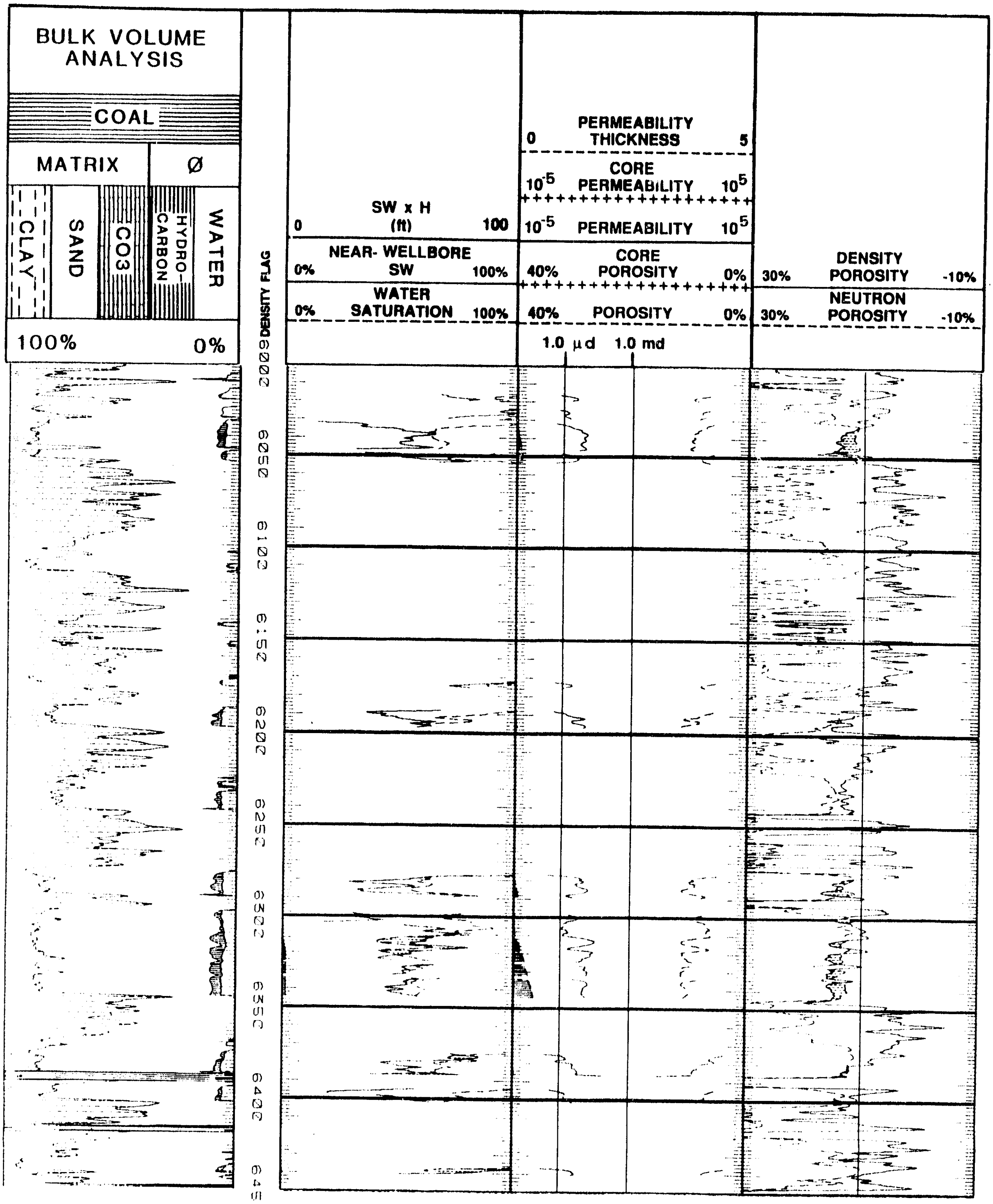

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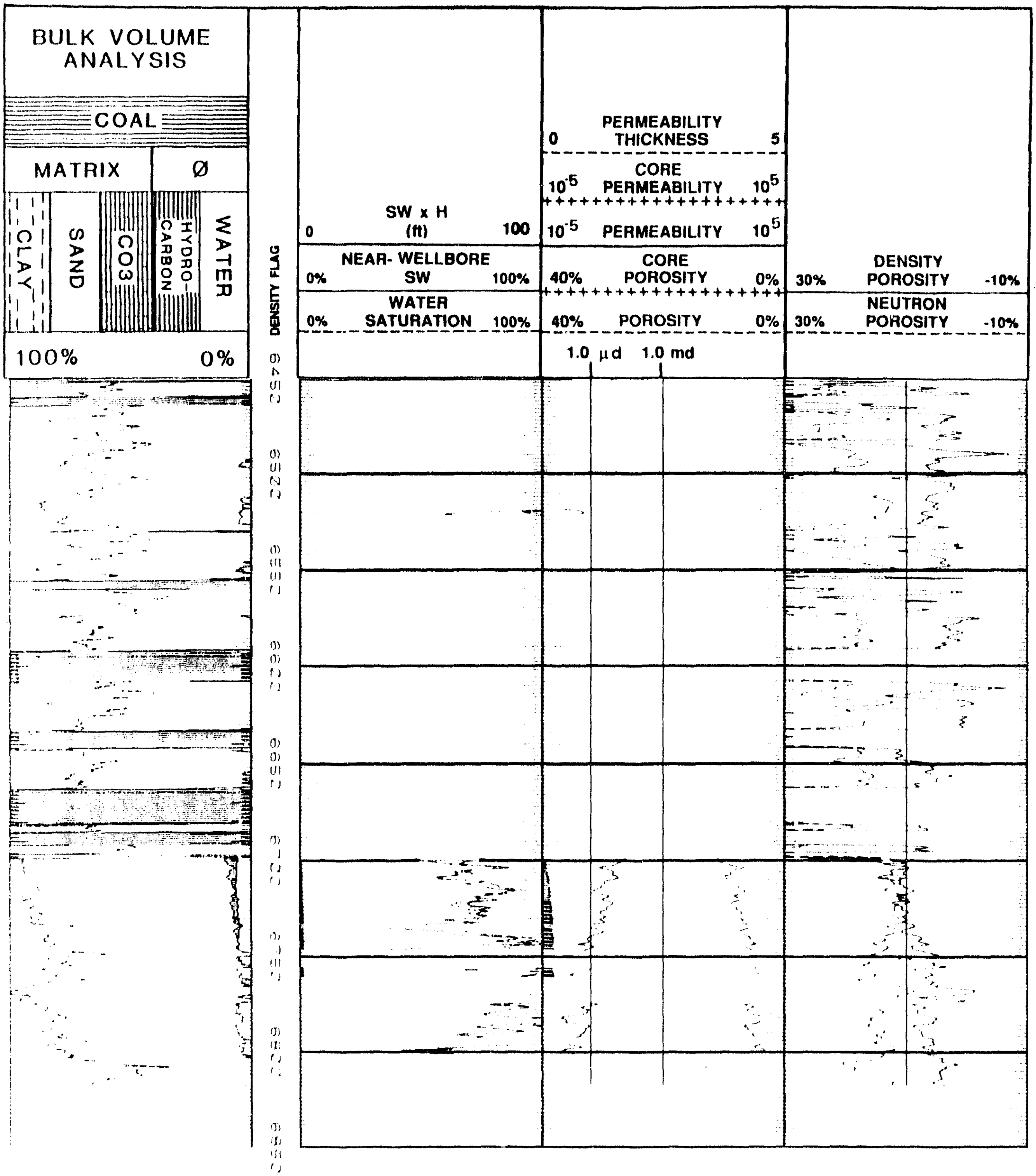

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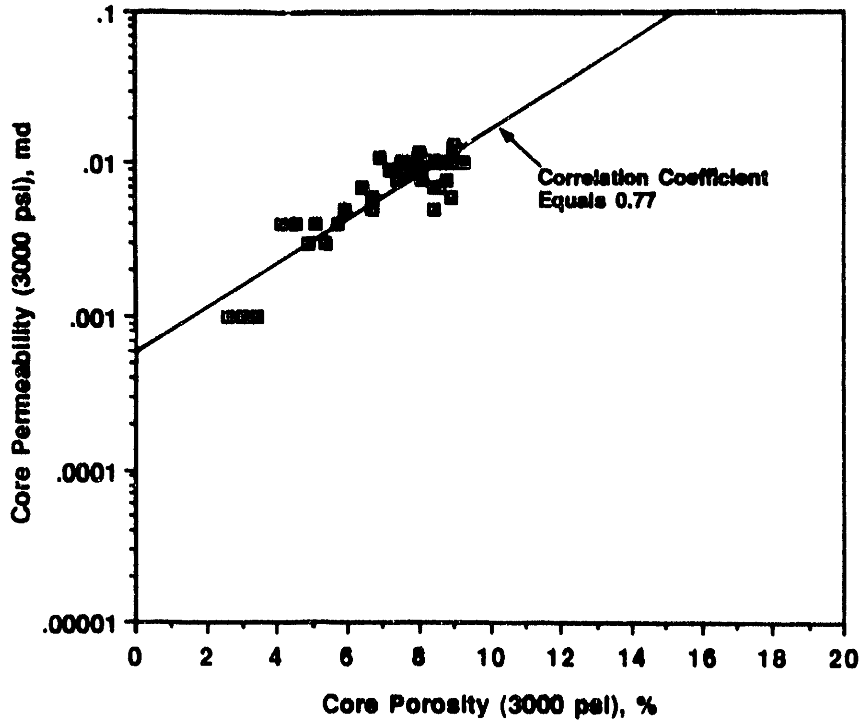


Figure 8 Core Porosity versus Dry Core Klinkenberg-Corrected Permeabiltiy at Net Stress, Barrett MV 8-4

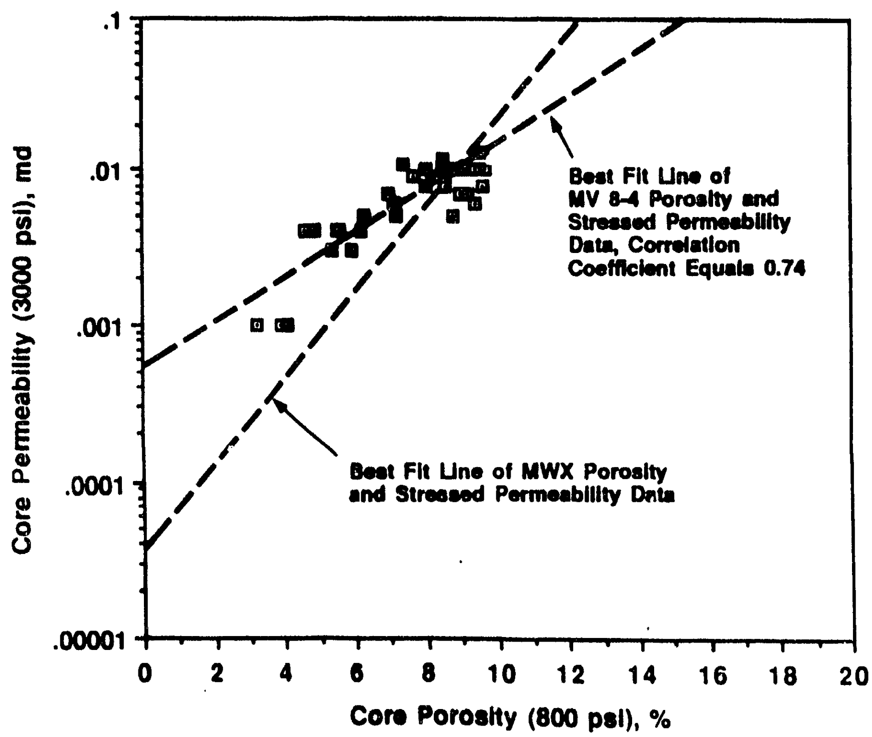


Figure 9 Core Porosity versus Dry Core Klinkenberg-Corrected Permeabiltiy at Hybrid Net Stresses to Simulate MWX Core Data, Barrett MV 8-4

fit line for MWX data. A comparison of the MV 8-4 data to the MWX best fit line indicates that the permeabilities that are associated with porosities over the range of 7 to 10 percent are similar. This is interpreted to mean that the pore structure of MV 8-4 and MWX Mesaverde sandstones are similar in that range.

MV 8-4 sandstones that have porosities ranging from 3 to 7 percent have higher associated absolute permeabilities than do MWX sandstones over that porosity range. This indicates that a higher portion of the MV 8-4 primary pore structure survives as compared to MWX lower fluvial sandstones over the 3 to 7 percent porosity range. This may relate to a shallower depth of burial for the MV 8-4 sandstones.

MV 8-4 sandstones having higher absolute permeability generally have lower grain density. The trend of data shown in Figure 10 has a correlation coefficient of -0.58. Most of this effect can be explained by the clay content. Lower clay content of MV 8-4 sandstones is associated with higher absolute permeability and lower grain density. The inverse relation of MV 8-4 clay content (as indicated by the gamma ray log) with absolute permeability has a correlation coefficient of -0.36. This suggests that other factors must come into play in both reducing permeability and increasing grain density. At MWX, higher absolute permeabilities are associated with lower carbonate mineral content. The higher grain densities that are associated with the lower permeability sandstones are in part due to the presence of the higher density carbonate minerals.

Log analysis results for porosity and permeability are compared directly to core porosity and permeability on the TITEGAS computed log (Figure 4). There is generally a good agreement for both porosity and permeability. Direct comparison of log and core porosities are also shown in Figure 11. Mean log calculated porosity is 6.52 percent and mean core porosity is 6.89 percent. The correlation coefficient is 0.71. The correlation coefficient of log calculated permeability vs. core permeability is 0.59. Log calculated permeability has good agreement to core permeability over the higher permeability range and tends to be less than core permeability for the lower permeability range.

The basis for the log-derived permeability presented in Figures 4 and 7 and Table 4 is the MWX Mesaverde core and log data. This data was used to develop empirical equations which are meant to approximate humidity-dried Klinkenberg-corrected absolute permeability at net stress (Kukal and Simons, 1986). That study also extrapolated MWX equations to other tight gas formations and concluded that the petrophysical relationships observed at MWX are generally applicable to Variety II tight gas reservoirs (Spencer, 1985) — i.e., those reservoirs that have undergone extensive diagenesis where most of the porosity is secondary and the pores are interconnected by narrow box-like pore systems.

Absolute permeability is ideally independent of the type of fluid in the rock. The absolute permeability is a base permeability from which effective permeability can be calculated when more than one fluid is present. In conventional gas reservoirs, effective gas permeability is approximately equivalent to absolute permeability when the reservoir is at irreducible water saturation. However, in low permeability gas reservoirs at irreducible water saturation, the effective gas permeability is apparently much less than absolute permeability. A question remains as to whether this characteristic of tight gas reservoirs is an in-situ phenomenon or rather that it is an artifact of the physical problems inherent in the core analysis of low permeability rock. For example, it is difficult to resaturate a tight rock to achieve original fluid

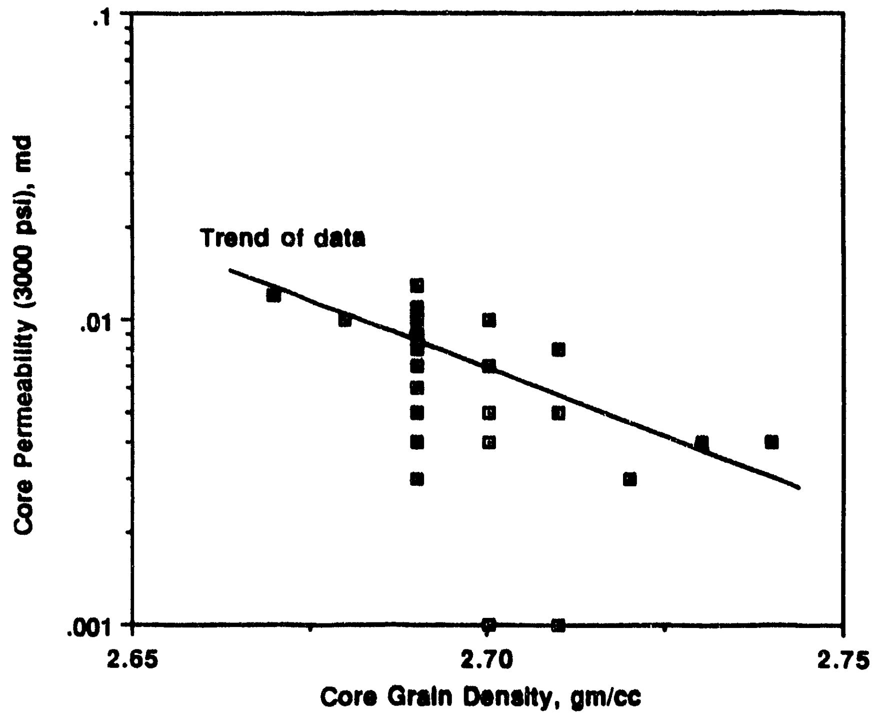


Figure 10 Core Grain Density versus Absolute Permeability, Barrett MV 8-4

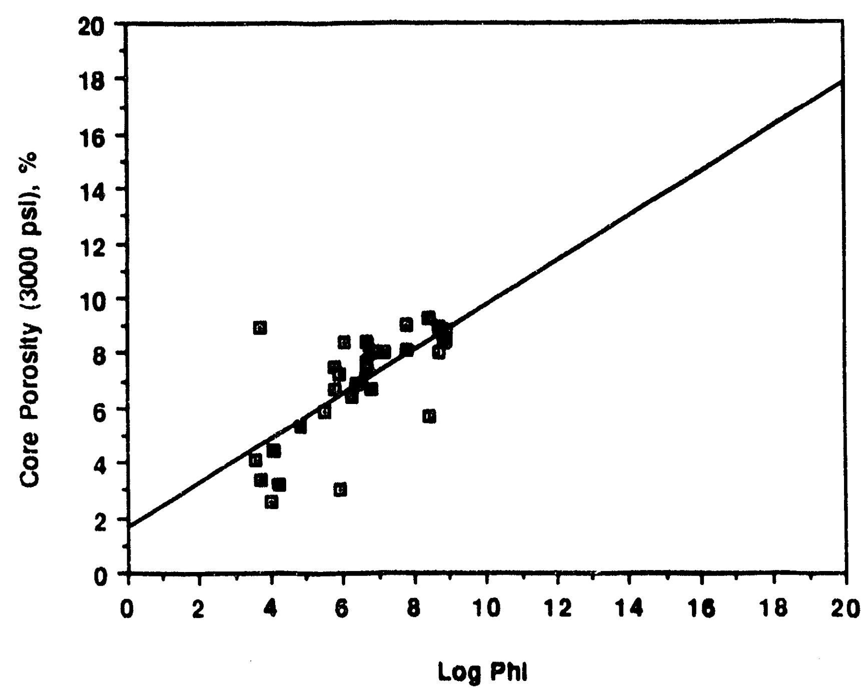


Figure 11 Log Calculated Porosity versus Core Porosity at Reservoir Net Stress, Barrett MV 8-4

distributions. This fluid distribution problem casts doubt on the validity of tight gas sand relative permeability curves.

One of the goals of Phase II is to ascertain the importance of natural fracture systems as a gas production mechanism in different areas of the Piceance Basin. Evidence for natural fracture permeability enhancement may involve direct comparisons of the effective gas permeability of in-situ simulated core samples with the effective gas permeability that is interpreted from pressure build-up data. However, since neither special core data nor pressure build-up data are generally available, it is useful to make comparisons of log derived calculations of short-term gas production potential with actual short-term gas production data. A natural fracture control to gas production is indicated when the actual gas production is much greater than the predicted flow (which is based upon only matrix permeability).

The predicted gas flow is accumulated through the zone and is presented in Table 4. The predicted flow assumes an infinitely acting volumetric gas reservoir, radial and laminar flow and only horizontal matrix permeability. The production time is assumed to be 24 hours. The bottomhole wellbore pressure while producing is assumed to be 500 psi. The effective wellbore radius is assumed to be one foot. Average gas viscosity, gas compressibility and gas deviation factor are computed for each analysis interval based upon assumed pressure gradients, temperature gradients and gas compositions. The gas flow model has the capability of reducing absolute permeability to effective gas permeability; however, no reduction was done in this analysis.

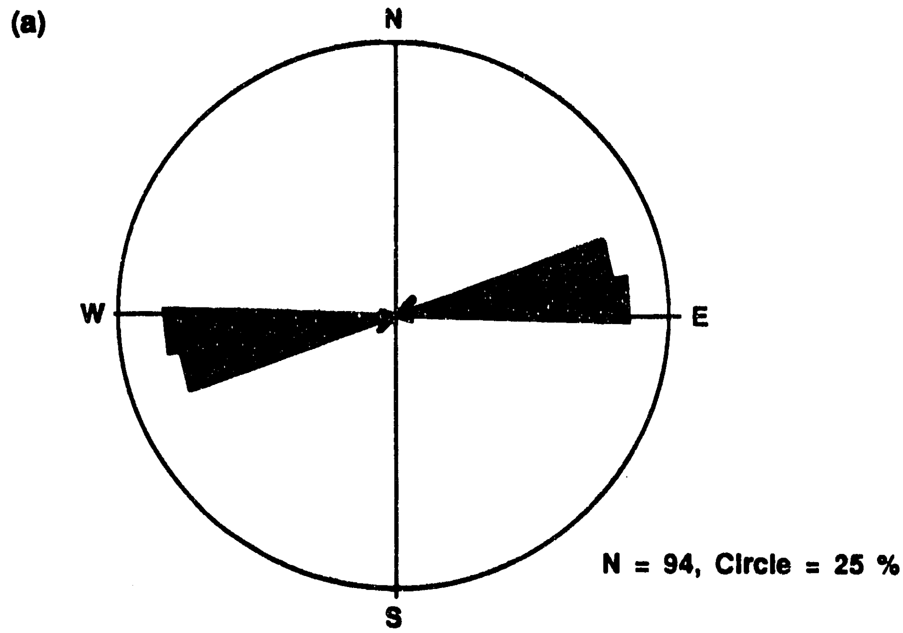
The maximum gas flow predicted for any zone in the MV 8-4 well is about 156 MCFD. There is considerable uncertainty about the reduction factor in going from absolute permeability to effective gas permeability. However, the calculated flow volumes should be useful in a qualitative or relative sense, and represent the maximum production that should be expected from an unfractured reservoir.

2.2.3 Fracture Characterization Summary

In this section, the interpretation of the FMS log will be discussed. The log was used for fracture detection, core orientation and borehole breakout analysis. The results of this analysis are compared with the fracture description and velocity anisotropy data from the core. From this data, in-situ stress orientations are inferred.

Two types of fractures are usually present in Piceance Basin cores, natural and induced. Natural fractures are believed to have a significant impact on gas production in the Piceance Basin (Finley and Lorenz, 1988; Myal et al., 1989). These fractures are usually mineralized to some extent with quartz or calcite. A description of natural fractures in the Piceance Basin and a model for their origin is presented by Lorenz et al. (1990) and Lorenz and Finley (1990).

Induced fractures, on the other hand, are caused by the drilling process. These fractures are created ahead of the bit and usually form in an orientation parallel with the present maximum principal stress. Therefore, the strike of these fractures is the same direction in which hydraulic fractures will form (Laubach and Monson, 1988; Lorenz and Finley, 1988; Kulander, 1990).



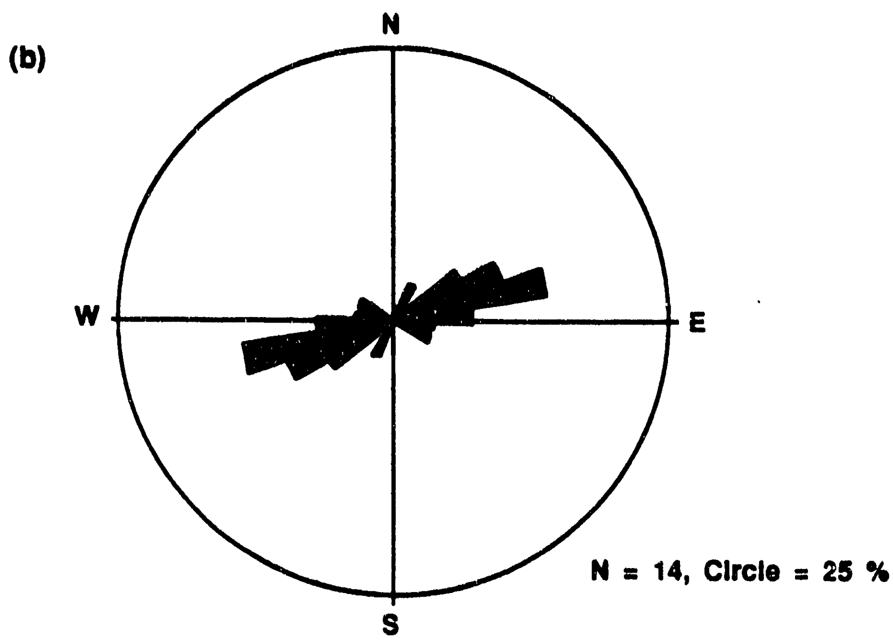


Figure 12 Rose Diagrams Showing the Strikes of FMS-Imaged Fractures (a), and Induced Fractures Measured in Core (b), Barrett MV 8-4

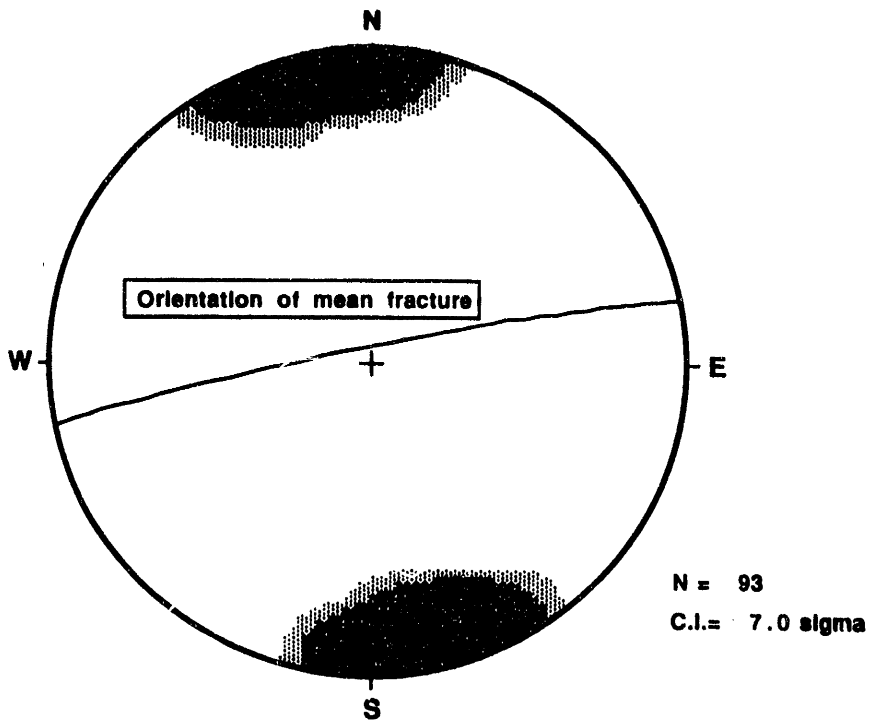


Figure 13 Kamb-Contoured Stereographic Projection of Poles to Planes of Fractures Measured on the FMS Imagery, Barrett MV 8-4

2.2.4 FMS Fracture Analysis

A rose diagram showing the fracture strikes measured on the FMS log for the Barrett Energy MV 8-4 well is shown in Figure 12a. Figure 13 is an equal area stereographic projection on which poles to the fracture planes have been contoured using the Kamb (1959) contouring method. The Kamb method uses a variable area counting circle and calculates the number of standard deviations from a uniform distribution of points on the projection (Allmendinger, 1987). The darker shading indicates a higher concentration of poles. The advantage to this plot is that variation in dip angle is shown as well as the fracture strike. The mean orientation of the induced fractures is N78°E, dipping 85° to the north, and the 99 percent confidence range is within 10° of the mean orientation. Because all of the FMS fractures are interpreted as drilling induced fractures, this is the predicted strike for hydraulic fractures.

2.2.5 Core Fracture Analysis

In the cored interval, 21 fractures were described: two natural fractures and 19 coring induced fractures. Five of the coring-induced fractures could not be oriented. Figure 12b is a rose diagram of the coring-induced fracture strikes noted in core. Figure 14 shows the core fractures plotted on an equal area net for comparison with the FMS log measured fractures (Figure 13). The distribution of core data was too widely scattered for the mean orientation to be considered valid; therefore, an estimated median fracture plane is shown.

2.2.6 Borehole Breakouts

Borehole breakouts form as a result of unequal maximum and minimum horizontal stresses acting on the wellbore thus causing high shear stress concentrations on opposite sides of the wellbore. Preferentially oriented caved holes in the borehole wall results. Wellbore breakouts (long axis) occur perpendicular to the direction of maximum horizontal stress, the direction in which an induced fracture will propagate. They can, therefore, be used to interpret the horizontal in-situ stress directions in boreholes (Gough and Bell, 1982; Plumb and Cox, 1987; Zoback, 1985).

The oriented caliper log data from the FMS log was used to analyze borehole breakouts. The analysis technique employs a computer model which implements criteria for recognizing true breakouts from other types of borehole elongations described by Plumb and Hickman (1985). The breakout azimuths were then plotted on the rose diagram shown in Figure 15. To facilitate direct comparison with the fracture data shown in Figure 12, the rose diagram shows the interpreted maximum horizontal stress (σ_H) direction (i.e., Breakout Azimuth plus 90°). The mean azimuth of σ_H interpreted from breakouts is N88°E, and the standard deviation is 7°.

This interpreted direction for σ_H was supported by two velocity anisotropy measurements performed by Sandia National Labs. Their results indicated a σ_H direction of N74°E to N83°E (Warpinski and Lorenz, 1990).

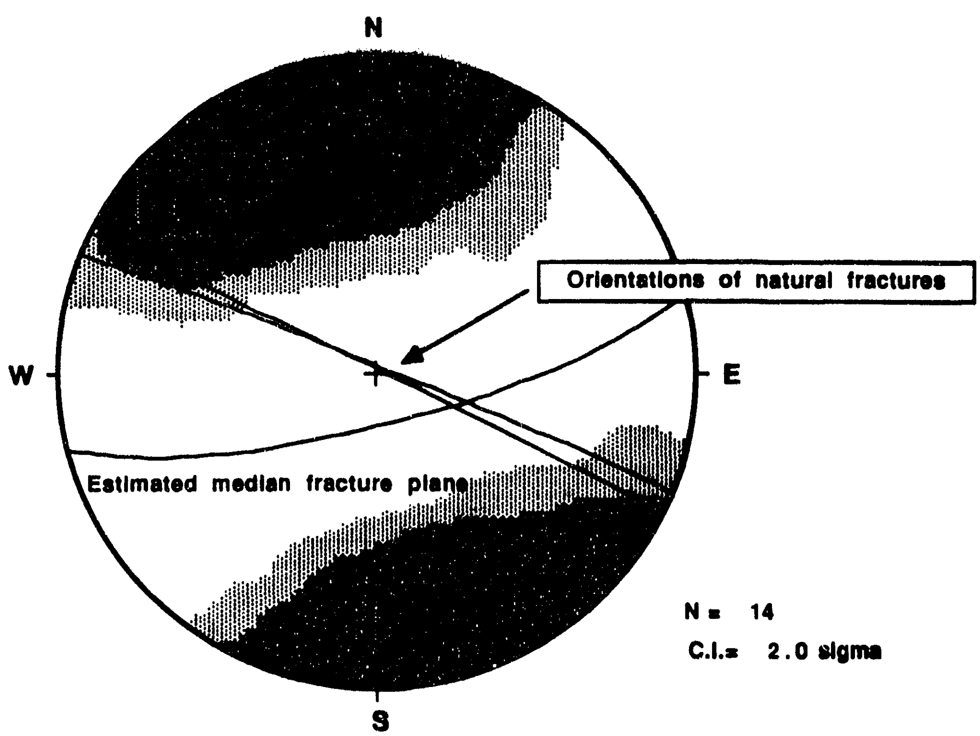


Figure 14 Kamb-Contoured Stereographic Projection of Poles to Planes of Induced Fractures Measured in Core and Great Circles of the Two Oriented Natural Fractures, Barrett MV 8-4

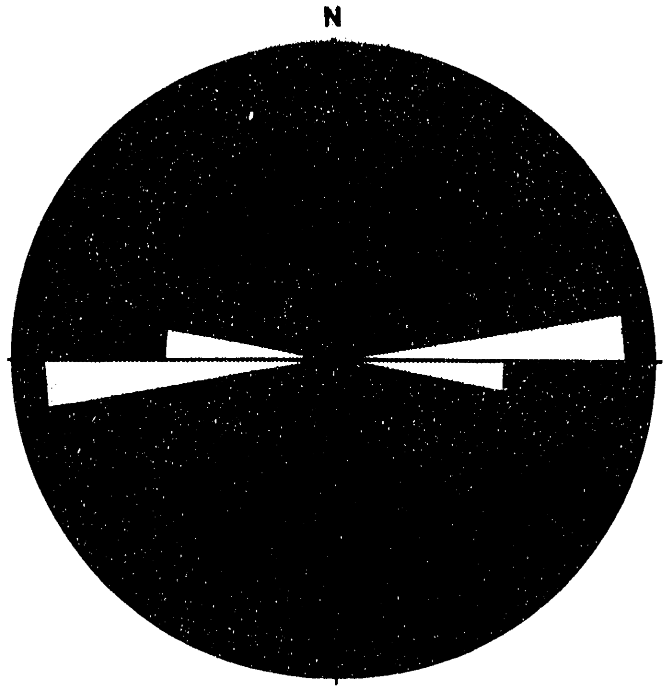


Figure 15 Rose Diagram of Maximum Horizontal Stress Directions Indicated by Borehold Breakouts Interpreted from the FMS Calipers, Barrett MV 8-4

2.2.7 Pressure Translent Test

A pressure buildup test of a 14 ft thick fluvial sandstone was done in the Barrett well. A sandstone at 5,638 to 5,652 ft in depth was selected because it looked to be one of the better reservoirs penetrated in the fluvial section (see Table 4 for reservoir characteristics). The sandstone was perforated with one shot per foot and broken down under high nitrogen pressure differential toward the formation. Following the nitrogen breakdown, the well was flowed for a period of 14 days. Initial flow was slightly over 800 MCFG/D which declined to less than 200 MCFG/D in four days. Flow stabilized at about 200 MCFG/D for several days but had declined to 100 MCFG/D at the end of the 14th day.

The well was shut in for thirteen days with a downhole shut-in tool. The Horner plot of the pressure buildup is shown in Figure 16. Initially, an attempt was made to analyze the buildup test using conventional analytical solutions to pressure buildup curve shape. However, due to the lack of a clear straight line region of the curve and the ever increasing slope it was not possible to determine the reservoir characteristics analytically. Therefore, a computer simulation approach was employed to analyze the buildup. A single-phase three-dimensional simulator was used to model the bottomhole pressure response. A reasonable match in both the Horner coordinates and the log-log plots was achieved.

The shape of the buildup curve strongly indicates boundary effects. Since the slope of the Horner plot is constantly increasing, more than one boundary may be expected. Many different reservoir geometries were examined with the well located at various distances from the boundaries. The final match was achieved by locating the well at the center line of a 32-ft wide channel with infinite length.

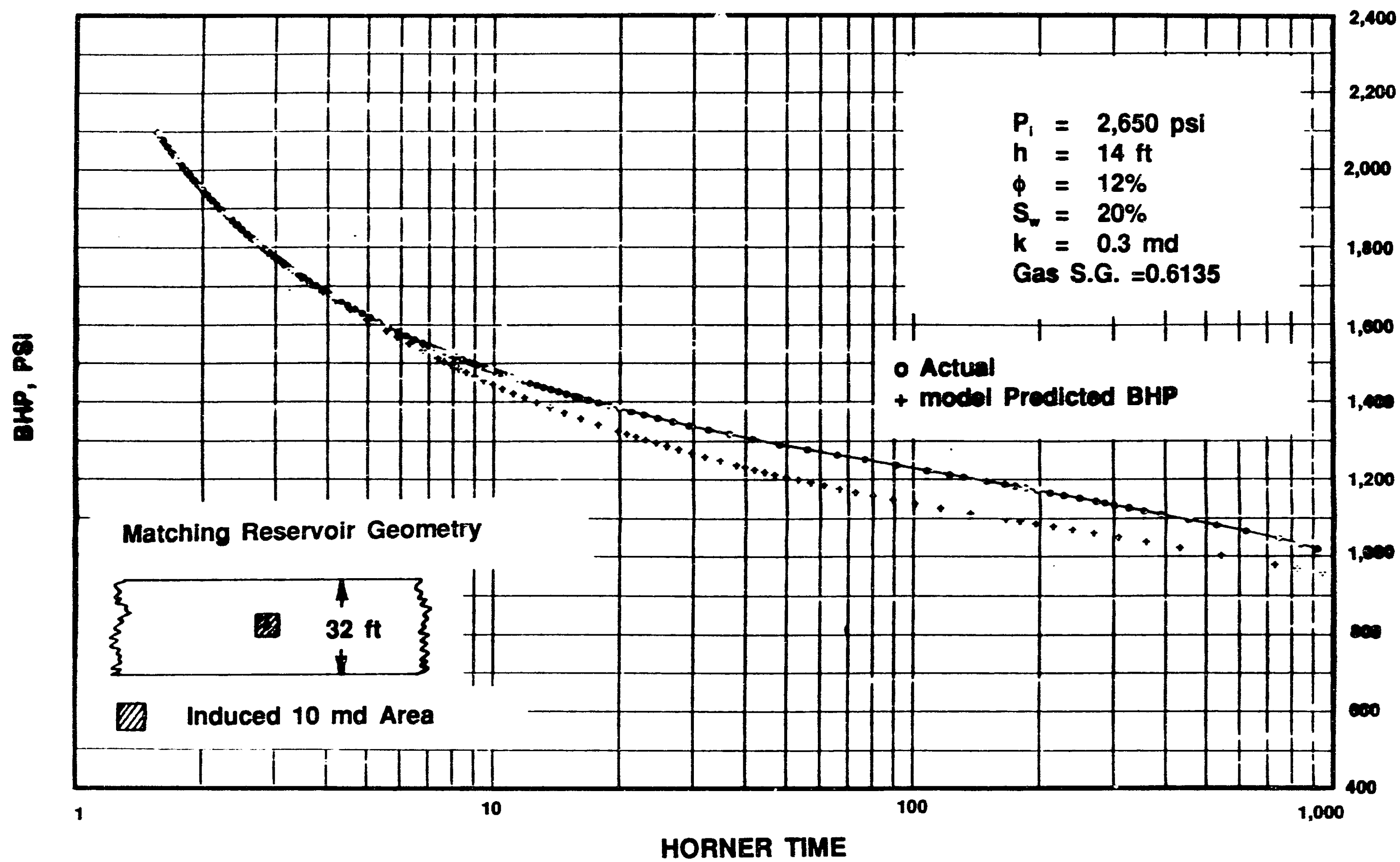


Figure 16 Horner Plot of Pressure Buildup Showing the Actual (o) and the Model Predicted (+) Results, Barrett MV 8-4

Because there was insufficient data to substantiate vertical layering that could affect gas flow behavior of the MV 8-4 well, a single-layer system was used in this analysis. A zone extending six ft from the wellbore with an increased permeability of 10 md was used in the model to represent the reservoir stimulation as a result of high pressure nitrogen perforation/breakdown.

Figure 16 compares the simulated Horner curve with the actual Horner plot, and Figure 17 is a similar comparison for pressure and pressure derivative curves. A schematic representation of the reservoir geometry and a list of parameters used in the model are also shown in these two figures.

The model-predicted pressure behavior and curve shapes are very similar to the actual data, indicating the channel geometry is a possible shape of the reservoir. Other reservoir heterogeneities, such as the presence of natural fractures or reservoir layering, can probably produce similar pressure response in a buildup test; however, there was not enough information to perform a computer analysis. No natural fractures were interpreted on the FMS log in the test interval. It should also be noted that the term "channel" does not necessarily mean the modelled reservoir is actually a river channel, although the test interval was in the Mesaverde fluvial section. It only indicates the pressure buildup process can be reproduced by using this bar-shaped reservoir with two parallel boundaries 32 ft apart.

2.2.8 Completion, Initial Production, and Well Status

Following the pressure transient test, Barrett stimulated the test interval sandstone with 220,000 lb of 20/40 mesh sand in 2,114 bbls of cross-linked gelled KCl water. After a 14 day cleanup period, production stabilized at just under 400 MCFG/D. At 14 days Barrett completed in additional paludal and fluvial sandstones and commingled the production.

2.2.9 Summary and Conclusions Barrett MV 8-4 Well

The Barrett well showed some important consistencies in reservoir parameters in the Central Basin with those at MWX, but there were also some differences.

The gas/water distribution in the Barrett MV 8-4 is consistent with the east-west cross section across the basin (Myal et al., 1989, Figure 13). The Rollins sandstone has a water saturation that is greater than irreducible. The paludal Mesaverde sandstones from 6,521.5 to 6,172.5 ft and the fluvial Mesaverde sandstones from 6,053.5 to 4,912 ft are interpreted to be at irreducible water saturation. The fluvial sandstones from 4,852.5 to 4,348.5 ft are interpreted to have a water saturation that is greater than irreducible. Fluvial sandstones above 4,333 ft are water saturated.

Several paludal Mesaverde sandstones in the MV 8-4 well are relatively well developed. Twenty individual gas saturated fluvial sandstones were identified in the MV 8-4 well and several appear to have good gas production potential. Paludal and fluvial sandstones are also well developed at MWX and the potential to produce gas from these two depositional intervals is characteristic of the Central Basin partitioned area.

The coring program and borehole image log suggests that the MV 8-4 location might be less naturally fractured than MWX, but a vertical hole cannot be conclusive about fracture density.

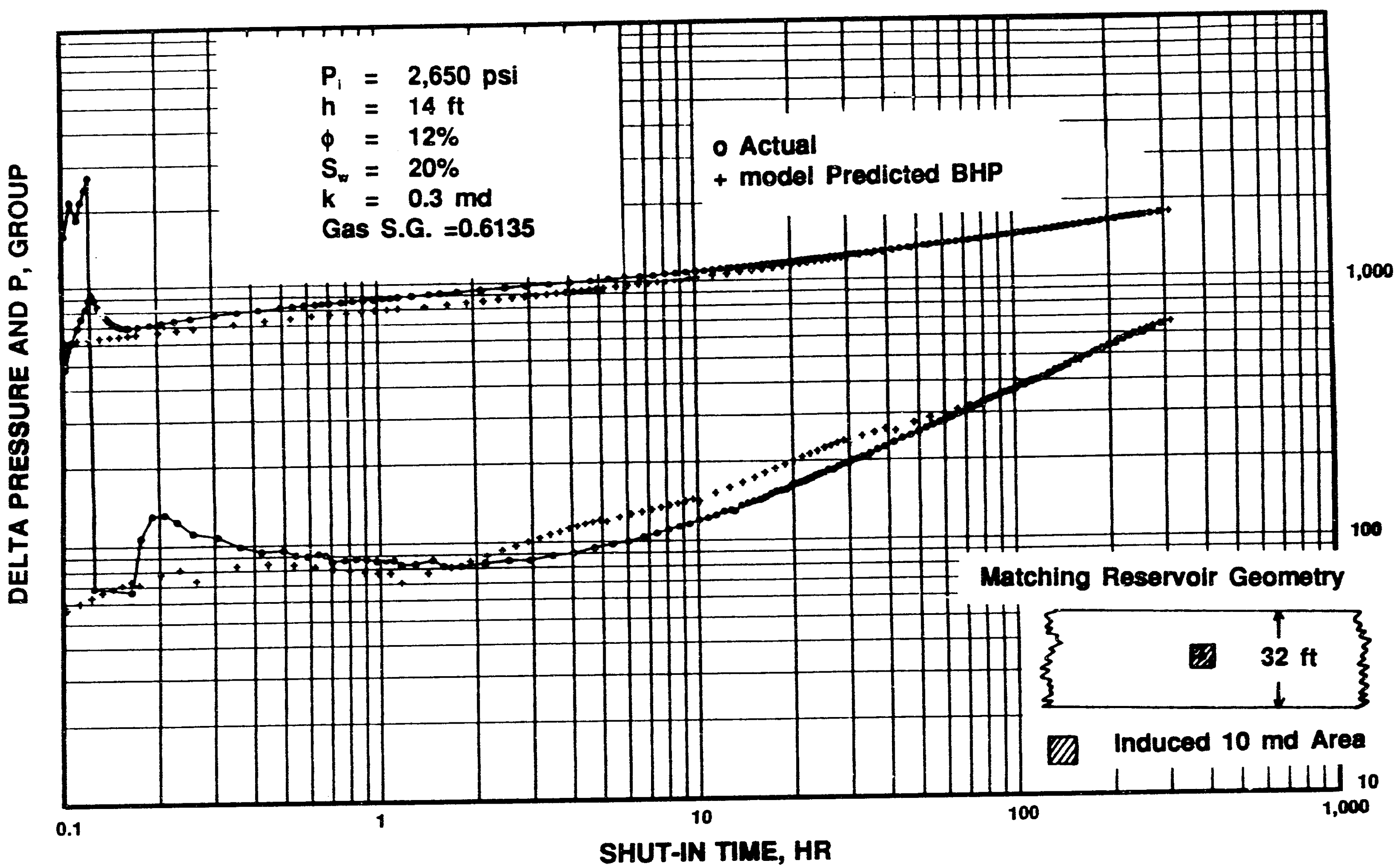


Figure 17 Pressure and Pressure Derivative Curves Showing the Actual (o) and Model Predicted (+) Results, Barrett MV 8-4

Two natural fractures were found to have orientations similar to the dominant set in MWX, whereas in-situ stress is oriented 20 to 30 degrees counterclockwise compared to MWX.

The MV 8-4 sandstones have probably had a shallower depth of burial than MWX equivalent sandstones and they have higher absolute permeabilities. The production test interval was calculated to have a matrix gas flow potential of 67 MCFD. Because of the initial flow rate of 800 MCFG/D and the stabilized rate of 200 MCFG/D for several days following the nitrogen breakdown, the breakdown is believed to have provided access to natural fractures in the lenticular sandstone. Natural fractures are thus believed to be an important production mechanism in the western part of the Central Basin area, just as they were in MWX reservoirs. Barrett's stimulation of the production test interval demonstrated the initial production from their propped fracture treatment is about four times higher than unstimulated production.

2.3 MOBIL T45-20P MAMM RANCH

Mobil Oil Company drilled a Mesaverde coalbed methane test through the paludal section in Garfield County, Colorado, in Section 20, T7S, R92W. The Mamm Ranch T45-20 well is located three miles south of the Mamm Creek Field where there is fluvial zone production, and eight miles north of the Divide Creek Field where there is Cameo coal and Cozzette production. The location is shown in Figure 3 and is near the extrapolated boundary between the Central Basin and the Southeast Uplift partitioned areas. The data acquisition and analysis program included approximately 600 ft of unoriented paludal core, TITEGAS log analysis, and FMS analysis for fracture characterization. Sections of the core could be oriented with the FMS.

2.3.1 Formation Evaluation

Mobil provided CER log data and core analysis data for the Mamm Ranch T45-20P well for inclusion in this study. The logging program was as follows:

	Service	Logged Interval
1.	Phasor Induction/SP/GR	6,794 to 2,013 ft
2.	Lithodensity/Caliper	6,798 to 2,000 ft
3.	Compensated Neutron	6,780 to 2,000 ft
4.	Gamma Ray Spectrometry	6,768 to 1,981 ft
5.	Array Sonic	6,752 to 1,885 ft
6.	Formation Microscanner	6,797 to 5,696 ft
7.	Dipmeter	6,798 to 2,000 ft
7.	Repeat Formation Tester	Selected stations

TerraTek Core Services collected the cores from this well and selectively sampled the core as directed by the Mobil wellsite geologist. Whole core analysis was performed on a total of 16 samples by TerraTek. Vertical and horizontal air permeability was measured at 300 and 3,500 psi net stress. Boyle's Law helium porosity was measured at 400 and 3,500 psi net stress.

The well was analyzed using the TITEGAS log analysis model over the gross interval 6,752 to 3,653 ft. A brief description of the TITEGAS log analysis model is provided in Appendix 1. The gross interval was divided into three sub-intervals and constants were refined individually for each sub-interval. The lowermost sub-interval includes the gas-saturated paludal Mesaverde section over the depths 6,752 to 5,782 ft. The middle sub-interval includes the fluvial Mesaverde gas-saturated section over the depths 5,782 to 4,270 ft. The upper sub-interval includes the fluvial Mesaverde gas-water transition section over the depths 4,270 to 3653 ft. Histograms of environmentally corrected log data were made for the principal log curves through each sub-interval. These histograms were compared to the log data norms that were developed for the Central Basin partitioned area during the Phase 1 TETWGS study. The Mamm Ranch T45-20P log data is of good quality and no log data normalizations were required. The formation water resistivities that were interpreted through the paludal sub-interval varied with temperature from 0.120 to 0.134 ohm-m from 6,752 to 5,782 ft, respectively. The formation water resistivities for the fluvial-gas sub-interval varied with temperature from 0.134 to 0.163 ohm-m from 5,782 to 4,270 ft, respectively. The formation water resistivities for the fluvial-transition sub-interval varied with temperature from 0.272 to 0.299 ohm-m from 5,782 to 4,270 ft, respectively.

The log analysis results for porosity and permeability are compared directly to core porosity and permeability through the cored interval of this well on the TITEGAS computed logs shown in Figures 18 and 19. A description of the format for log analysis results is provided in Appendix 2. These results are also shown in Figures 20 and 21 as crossplots comparing log calculated porosity to core porosity and log calculated permeability to core permeability. Some of the core data is excluded from these comparisons because they are coal or they are not a part of the net reservoir. The crossplots show ideal best fit lines. Figure 20 shows that most of the log and core porosities compare favorably. The correlation coefficient is only 0.251, however, there is a low standard error for log porosity to predict core porosity (0.62 p.u.). The statistical results are affected significantly by one data point at 6,651.5 ft which shows a higher core porosity (0.079) than log porosity (0.030). The correlation coefficient for permeability is 0.639. Log calculated permeability predicts core permeability with a standard error of 0.097 order of magnitude. The equations that were used to calculate stressed absolute permeability from log data were developed by Kukal and Simons (1986) using the MWX petrophysical database. The least squares relationship shown in Figure 22 for the Mamm Ranch core data is nearly identical to the MWX porosity-permeability transform.

The log analysis results for the entire analyzed interval of Mamm Ranch T45-20P well are presented in Table 5 and Figure 23.

The paludal Mesaverde sub-interval is subdivided into 9 individual sandstone zones over the gross interval 6,696 to 6,239 ft. These zones are numbered sequentially from P-1 to P-9, starting with the deepest zone. Most of the zones have a net thickness of only three to five feet. The only zone that appears to have any production potential is the P-8 sandstone. The P-8 zone has a net thickness of 24.5 ft. The maximum porosity is 11.9 percent and averages 7.9 percent. The log calculated kh is 0.164 md-ft. Maximum log calculated permeability is 0.034 md. The minimum clay volume is 6.9 percent and averages 15.3 percent. The minimum water saturation is 39.7 percent and averages 57.6 percent.

The gas saturated fluvial Mesaverde sub-interval is subdivided into 23 individual sandstone zones over the gross interval 5,666.5 to 4,416 ft. These zones are numbered sequentially

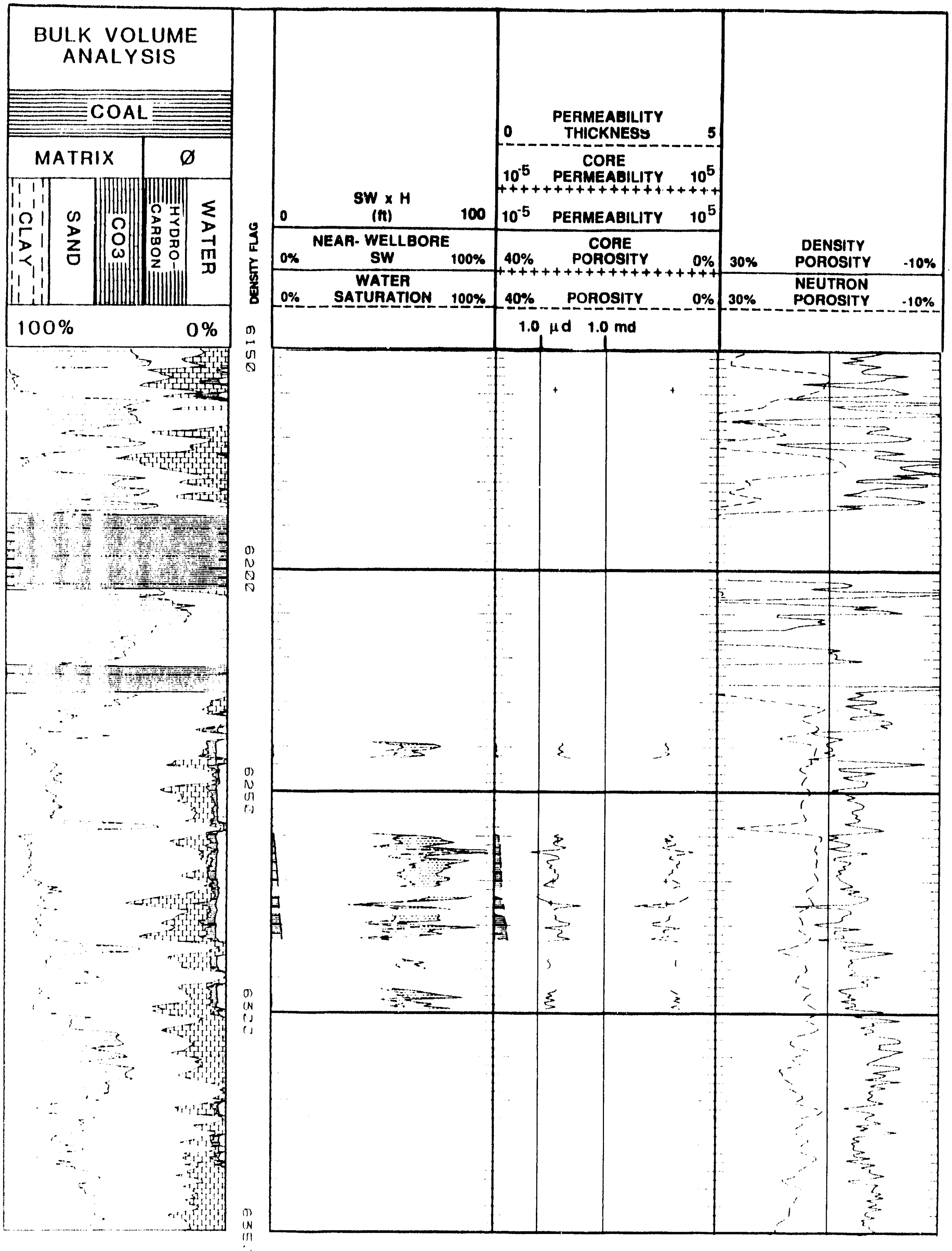


Figure 18 TITEGAS Computed Log Through Cored Interval 6,150 to 6,350, Mobil T45-20P

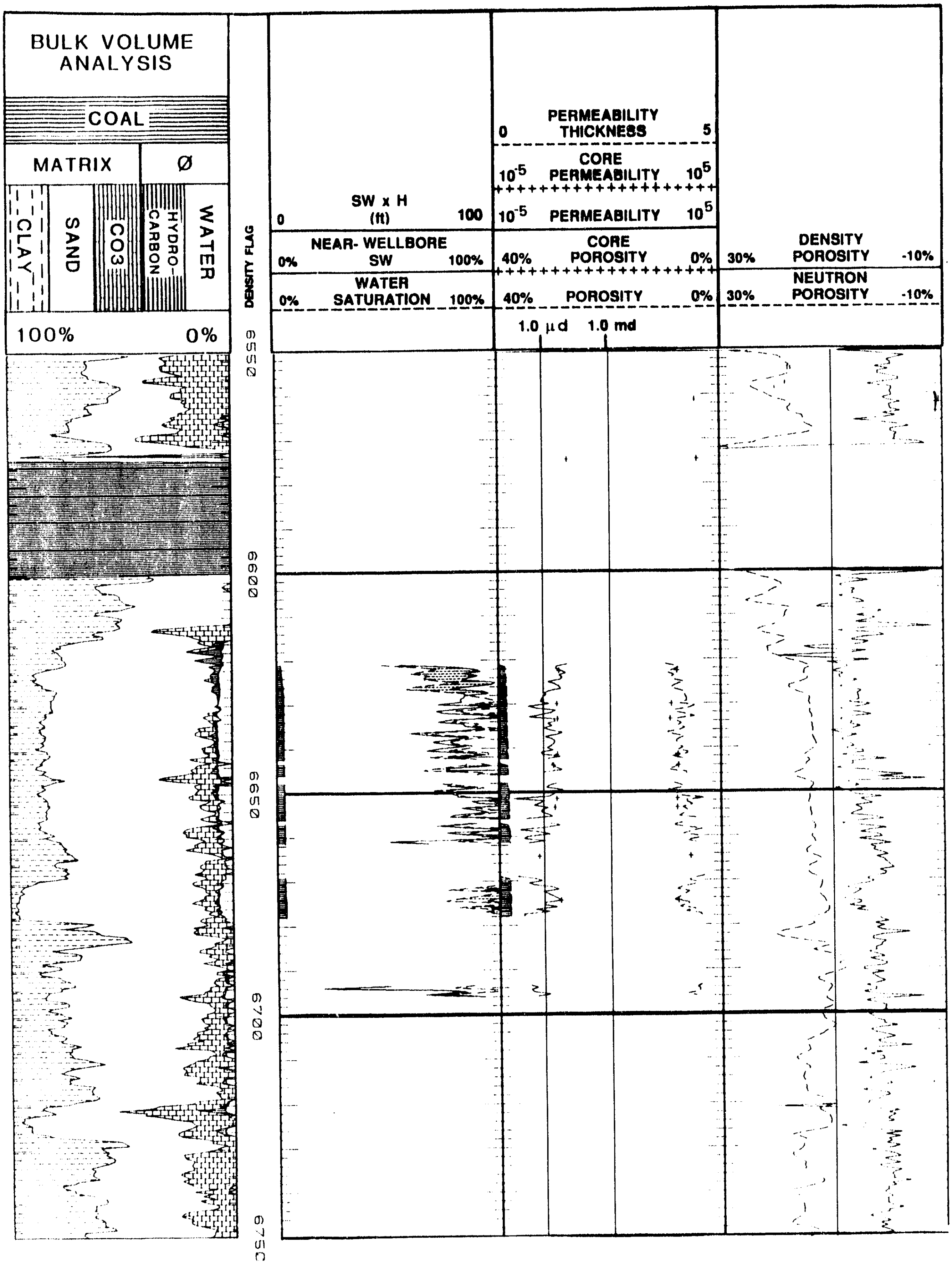


Figure 19 TITEGAS Computed Log Through Cored Interval 6,550 to 6,750, Mobil T45-20P

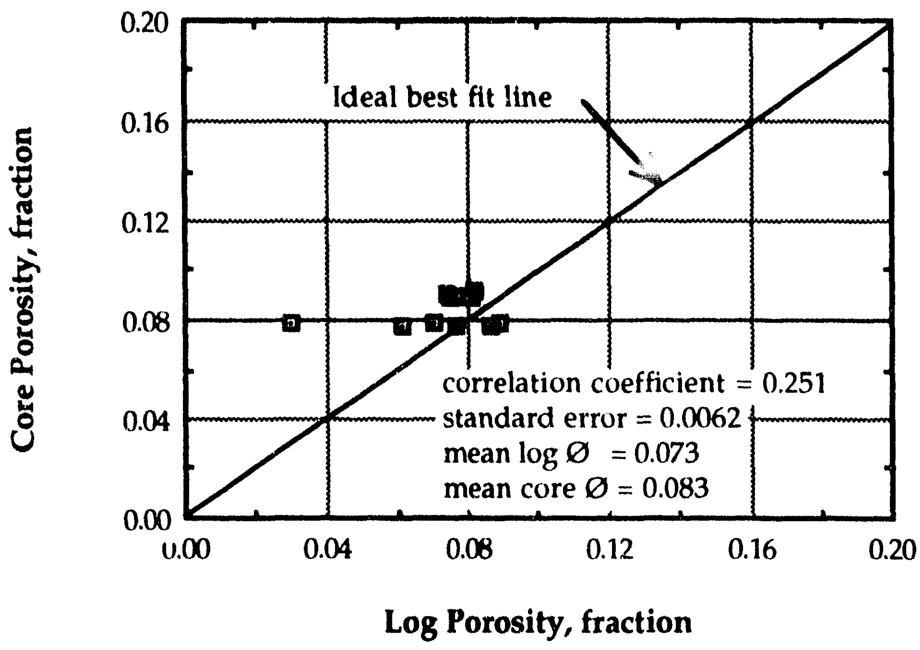


Figure 20 Log Porosity versus Core Porosity, Mobil T45-20P

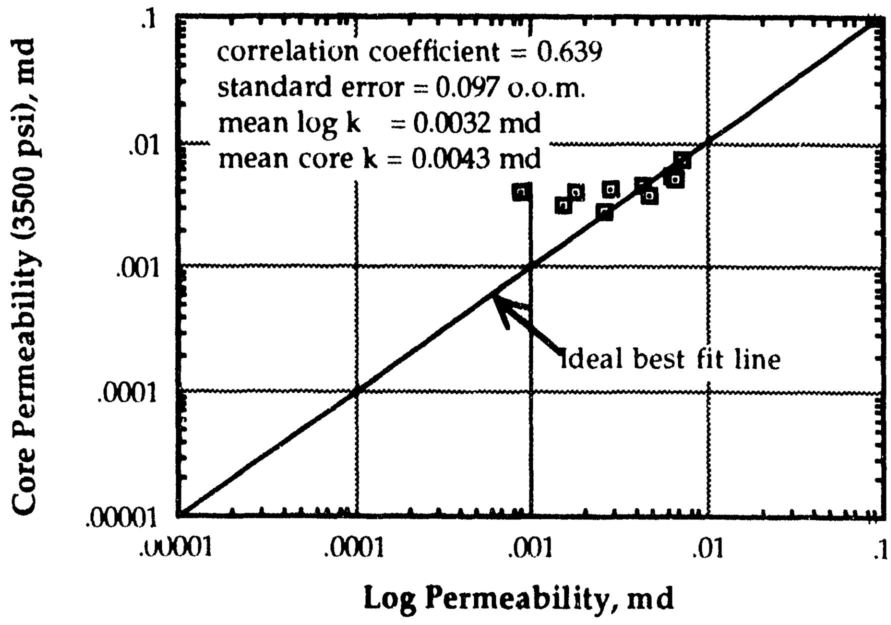


Figure 21 Log Permeability versus Core Permeability, Mobil T45-20P

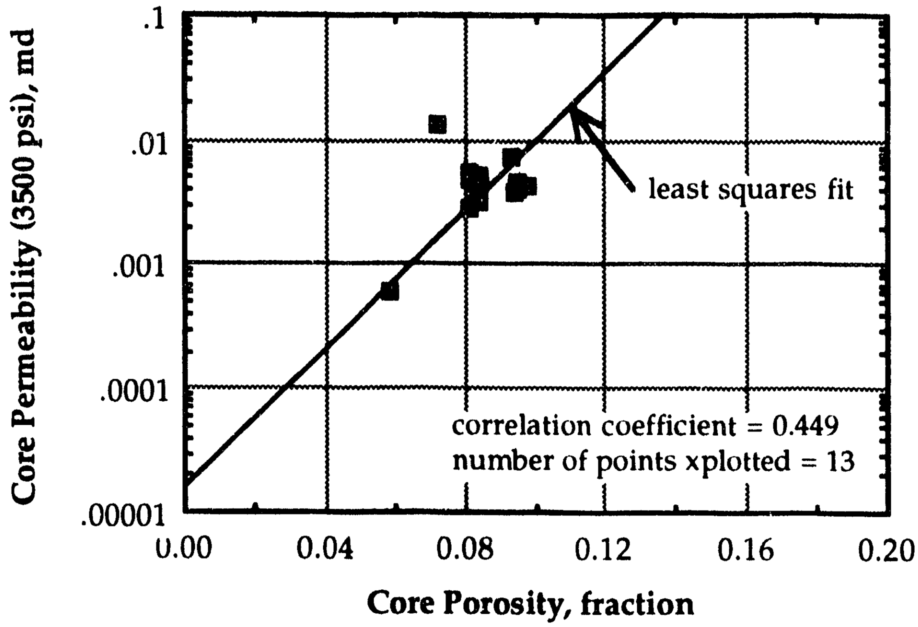


Figure 22 Core Porosity versus Core Permeability, Mobil T45-20P

from FG-1 to FG-23, starting with the deepest zone. Most of the designated FG zones have a net thickness less than ten feet, an average porosity less than 7 percent, and a log calculated kh less than 0.1 md-ft. The best zones indicated from log analysis are the FG-20 and FG-23 sandstones. The FG-20 zone has a net thickness of 12.5 ft. The maximum porosity is 11.7 percent and averages 9.9 percent. The log calculated kh is 0.280 md-ft. Maximum log calculated permeability is 0.041 md. The minimum clay volume is 6.8 percent and averages 9.7 percent. The minimum water saturation is 40.0 percent and averages 48.4 percent. The FG-23 zone has a net thickness of 16.5 ft. The maximum porosity is 14.3 percent and averages 9.9 percent. The log calculated kh is 0.295 md-ft. Maximum log calculated permeability is 0.058 md. The minimum clay volume is 5.9 percent and averages 12.1 percent. The minimum water saturation is 40.7 percent and averages 58.8 percent. A third potential FG target from 4,619.5 to 4,602.5 ft was totally overlooked by the log analysis. It is mentioned here because of a significant mud log gas show while drilling through this interval. The logic of the log analysis accumulation model requires at least three continuous feet of clean sandstone (having a clay volume less than 25 percent) be present before the interval is considered a zone. The overlooked interval calculates just over 25 percent clay. The interval has an average porosity of 9.4 percent and a log calculated kh of 0.20 md-ft.

The fluvial-transition Mesaverde sub-interval is interpreted as having a water saturation that is greater than irreducible. Zones completed in this sub-interval would likely produce gas with significant water cut. The fluvial-transitional Mesaverde is subdivided into 14 individual zones over the gross interval 4,257.5 to 3,665 ft. These zones are numbered sequentially from FT-1 to FT-14, starting with the deepest zone. The zone with the best gas production potential is the FT-1 sandstone. It has a net thickness of 30.5 ft. The maximum porosity is 15.7 percent and averages 11.6 percent. The log calculated kh is 0.90 md-ft. Maximum log calculated permeability is 0.073 md. The minimum clay volume is 7.6 percent and averages 14.0 percent. The minimum water saturation is 42.2 percent and averages 60.1 percent. Sandstones above 3,650 ft are interpreted as being wet in this well.

Table 5 Key Reservoir Parameters and Zone Designations for Mobil T45-20P

INTERVAL (FEET)	ZONE	GROSS H (FT)	NET H (FT)	AVG Ø (%)	MAX Ø (%)	AVG SW (%)	MIN SW (%)	HCFT (FT)	KH (MD-FT)	MAX K (MD)	AVG CLAY (%)	MIN CLAY (%)
6693.5-6696.0	P-1	3.0	3.0	4.6	6.3	88.9	73.9	0.017	0.002	0.002	18.7	15.9
6621.0-6678.0	P-2	57.5	48.0	6.9	10.1	86.4	47.1	0.531	0.115	0.012	15.0	2.6
6505.5-6509.0	P-3	4.0	4.0	8.0	10.2	51.5	41.6	0.165	0.049	0.026	13.7	10.4
6498.5-6502.5	P-4	4.5	4.5	4.7	6.1	67.9	49.4	0.071	0.005	0.003	16.8	11.2
6393.5-6397.0	P-5	4.0	4.0	8.5	10.1	39.0	32.6	0.210	0.054	0.025	22.6	20.5
6294.5-6299.0	P-6	5.0	5.0	7.1	8.3	56.9	49.2	0.154	0.021	0.007	18.8	14.4
6287.5-6290.0	P-7	3.0	3.0	7.0	7.3	58.3	56.3	0.088	0.010	0.004	21.6	20.6
6259.5-6283.5	P-8	24.5	22.0	7.9	11.9	57.6	39.7	0.760	0.164	0.034	15.3	6.9
6239.0-6242.5	P-9	4.0	4.0	9.4	11.7	52.9	44.2	0.178	0.048	0.029	14.5	10.7
5662.0-5666.5	FG-1	5.0	5.0	5.1	6.6	73.7	54.5	0.072	0.007	0.004	15.6	9.2
5627.0-5634.0	FG-2	7.5	7.5	6.7	8.9	68.9	47.6	0.172	0.032	0.012	13.3	7.7
5477.5-5486.0	FG-3	9.0	9.0	7.5	9.4	58.1	40.3	0.295	0.063	0.016	12.4	8.6
5440.0-5450.5	FG-4	11.0	10.5	7.7	10.4	56.3	41.9	0.370	0.102	0.028	8.3	3.7
5329.5-5341.0	FG-5	12.0	12.0	6.8	9.0	62.9	49.3	0.318	0.051	0.011	13.5	9.8
5322.0-5325.0	FG-6	3.5	3.5	8.1	12.5	57.5	38.9	0.128	0.036	0.036	12.5	9.7
5187.0-5190.5	FG-7	4.0	4.0	6.6	7.7	62.8	52.3	0.101	0.011	0.005	19.6	12.5
5152.5-5154.5	FG-8	2.5	2.5	6.0	7.4	57.9	43.3	0.067	0.010	0.009	12.3	11.6
5045.0-5059.0	FG-9	14.5	14.5	6.3	8.1	56.4	44.8	0.405	0.054	0.009	16.1	10.3
4988.5-4995.0	FG-10	7.0	7.0	6.6	9.6	56.6	41.5	0.208	0.046	0.024	9.6	3.8
4967.0-4979.5	FG-11	13.0	13.0	5.8	8.3	55.9	43.1	0.341	0.054	0.013	9.0	5.0
4890.0-4894.5	FG-12	5.0	5.0	5.3	7.1	56.3	43.1	0.118	0.014	0.004	8.9	6.3
4871.0-4875.0	FG-13	4.5	4.5	6.6	7.8	43.5	32.8	0.169	0.026	0.011	21.0	18.4
4794.0-4797.5	FG-14	4.0	4.0	6.0	7.4	60.6	46.6	0.093	0.011	0.005	13.6	10.3
4767.5-4771.5	FG-15	4.5	4.5	7.1	7.9	48.5	44.0	0.165	0.021	0.007	22.2	18.9
4754.5-4761.0	FG-16	7.0	7.0	7.3	8.4	46.0	37.1	0.281	0.077	0.019	7.9	4.4
4712.5-4715.5	FG-17	3.5	3.5	4.5	5.3	74.0	52.1	0.044	0.004	0.002	11.5	9.3
4665.5-4680.0	FG-18	15.0	9.5	7.2	10.8	59.6	47.9	0.290	0.051	0.016	19.5	15.3
4553.5-4561.5	FG-19	8.5	7.5	8.4	12.6	57.7	43.2	0.282	0.088	0.046	12.6	6.7
4514.5-4527.0	FG-20	13.0	12.5	9.9	11.7	48.4	40.0	0.656	0.280	0.041	9.7	6.8
4480.0-4486.5	FG-21	7.0	7.0	7.4	10.3	58.1	45.5	0.227	0.037	0.016	20.7	16.9
4472.0-4475.0	FG-22	3.5	3.5	7.1	7.7	60.7	55.2	0.098	0.012	0.005	19.6	18.0
4416.0-4433.5	FG-23	18.0	16.5	9.9	14.3	58.8	40.7	0.728	0.295	0.058	12.1	5.9
4227.0-4257.5	FT-1	31.0	30.5	11.6	15.7	60.1	42.2	1.470	0.900	0.073	14.0	7.6
4155.5-4158.5	FT-2	3.5	3.5	4.6	6.0	87.4	72.1	0.023	0.002	0.002	17.9	13.1
4105.0-4137.5	FT-3	33.0	33.0	7.6	12.2	82.2	58.4	0.467	0.221	0.031	13.9	7.7
4069.5-4073.0	FT-4	4.0	4.0	8.9	11.7	84.2	62.8	0.060	0.053	0.034	10.1	5.5
4056.5-4065.0	FT-5	9.0	9.0	8.9	10.3	78.1	64.0	0.179	0.085	0.021	14.1	5.9
4015.0-4017.5	FT-6	3.0	3.0	7.7	9.0	70.3	63.5	0.070	0.011	0.007	21.2	18.7
3981.0-3983.5	FT-7	3.0	3.0	9.2	11.9	76.2	57.8	0.071	0.033	0.031	15.5	9.9
3867.5-3870.5	FT-8	3.5	3.5	6.7	7.5	78.3	57.1	0.051	0.011	0.007	13.0	4.1
3831.5-3834.5	FT-9	3.5	3.5	8.3	9.7	67.3	54.2	0.098	0.020	0.010	19.0	14.0
3797.5-3809.0	FT-10	12.0	12.0	12.1	15.3	60.7	49.4	0.580	0.392	0.081	12.7	8.0
3790.0-3793.5	FT-11	4.0	4.0	7.9	10.1	65.6	48.3	0.118	0.027	0.014	17.8	13.4
3747.0-3759.0	FT-12	12.5	12.5	9.5	11.8	50.7	41.5	0.585	0.130	0.022	17.4	11.0
3717.0-3720.5	FT-13	4.0	4.0	7.8	9.8	71.4	53.6	0.097	0.017	0.008	22.6	20.1
3665.0-3680.0	FT-14	15.5	15.5	8.9	12.3	90.4	67.0	0.162	0.178	0.030	14.1	8.0

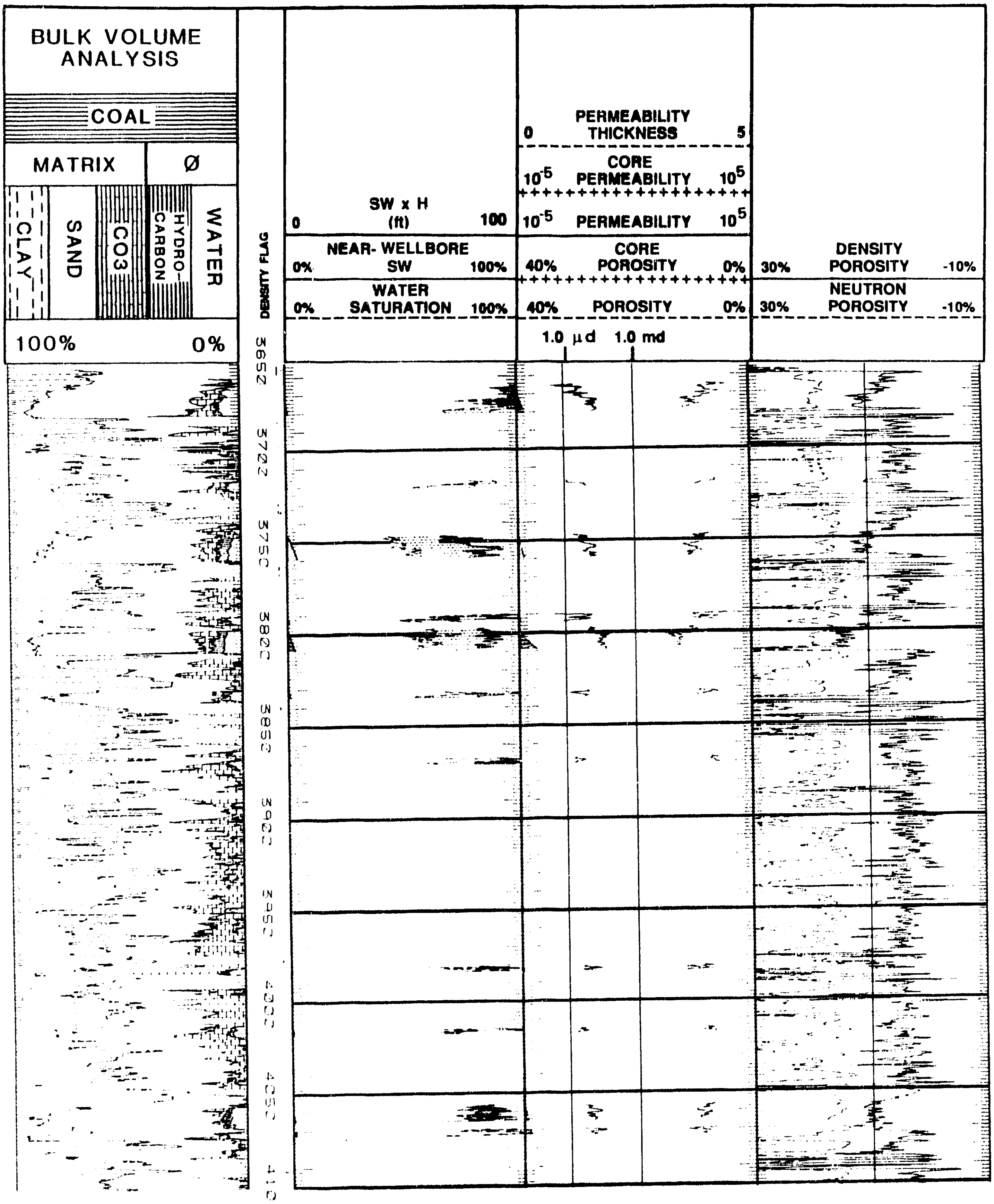


Figure 23 TITEGAS Computed Log of Entire Well, Mobil T45-20P

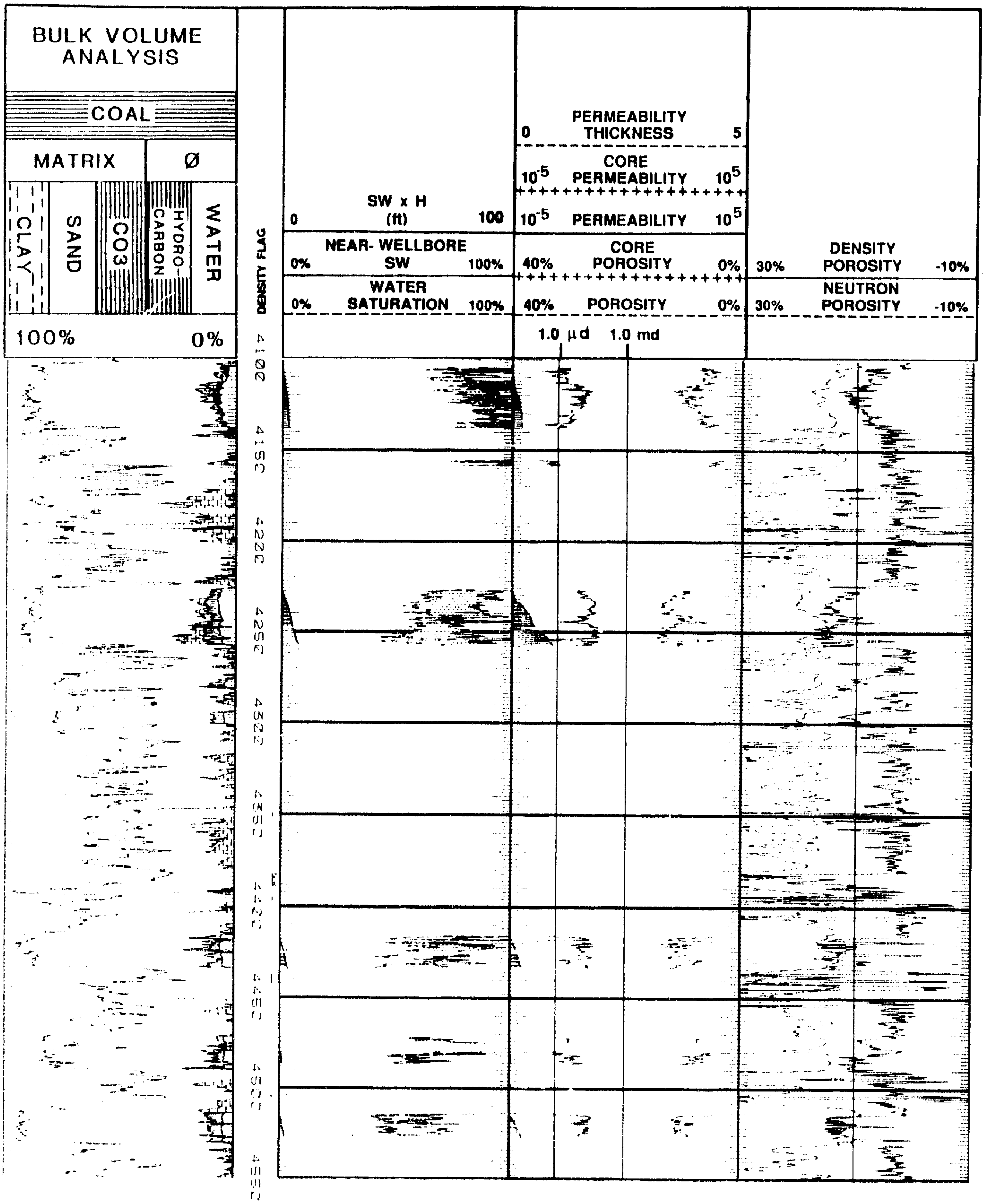
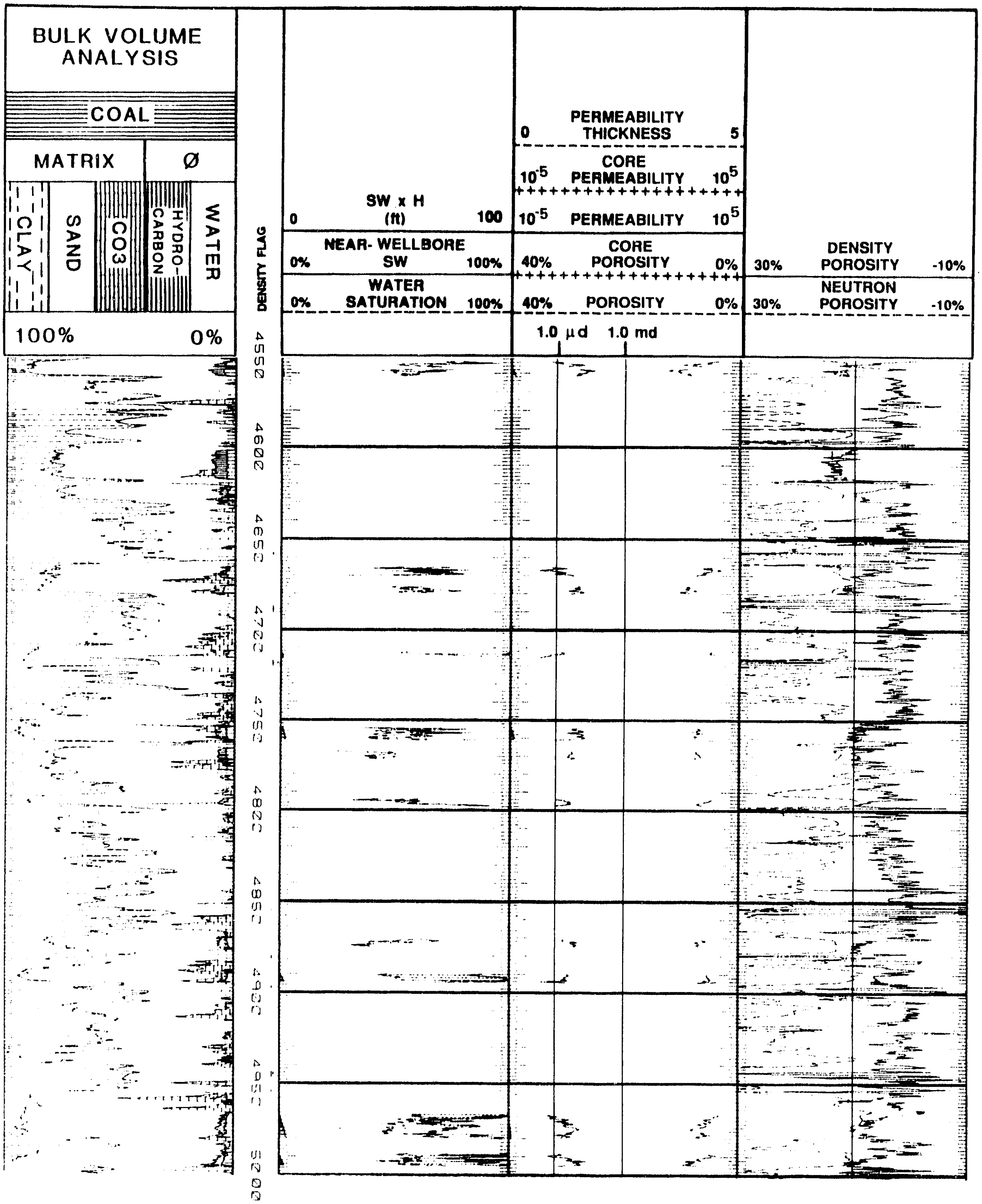


Figure 23, Continued



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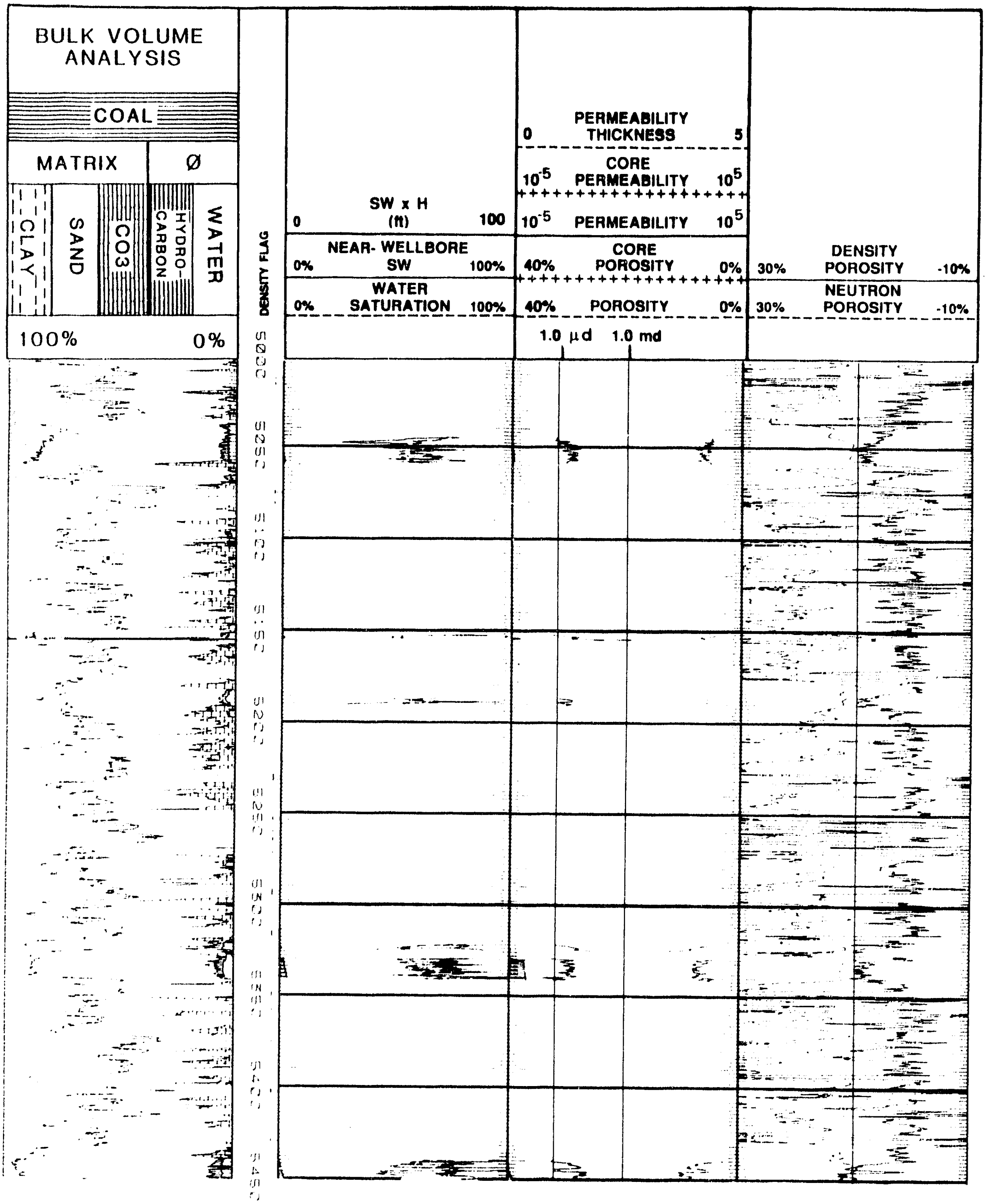

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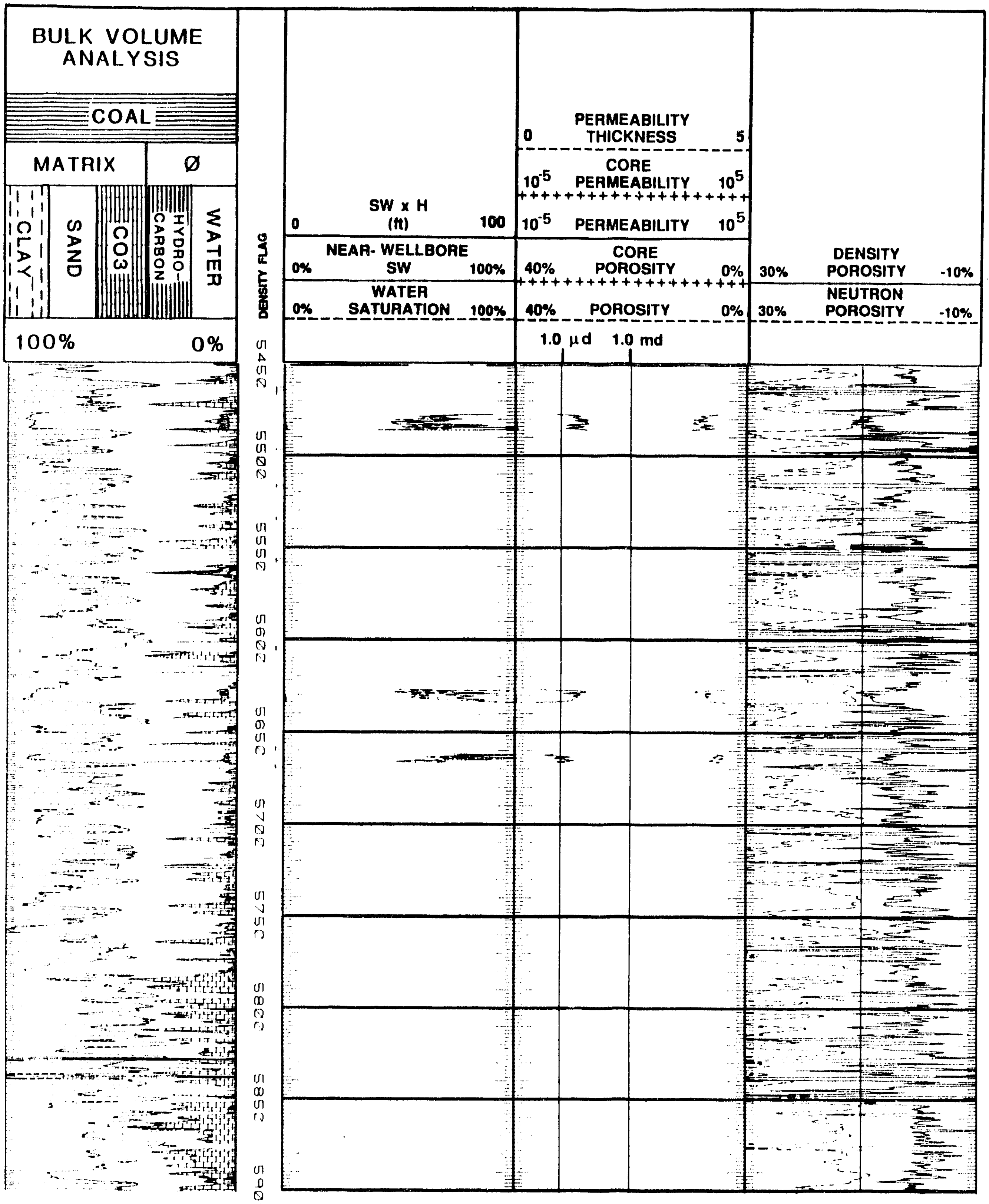


Figure 23, Continued

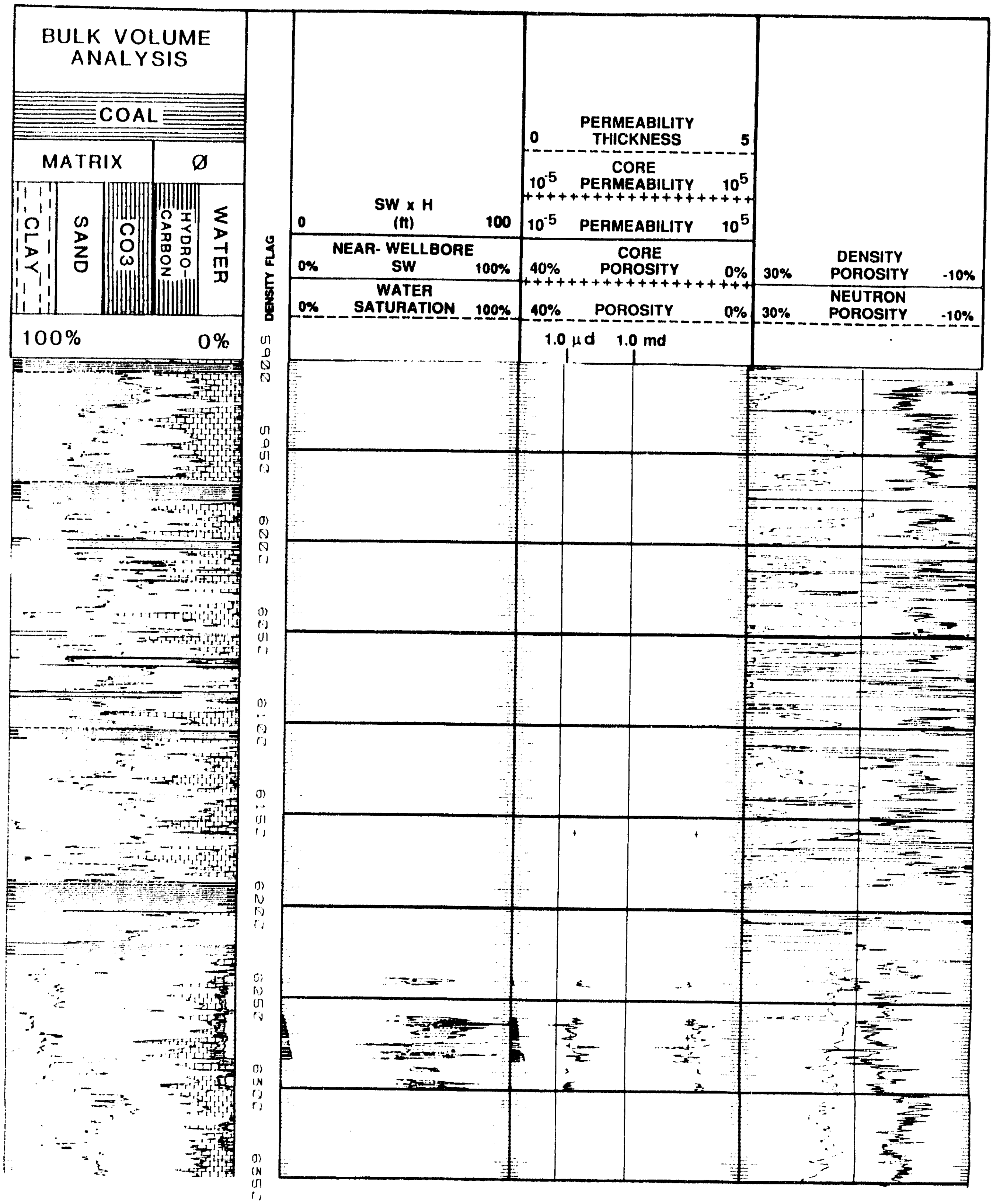


Figure 23, Continued

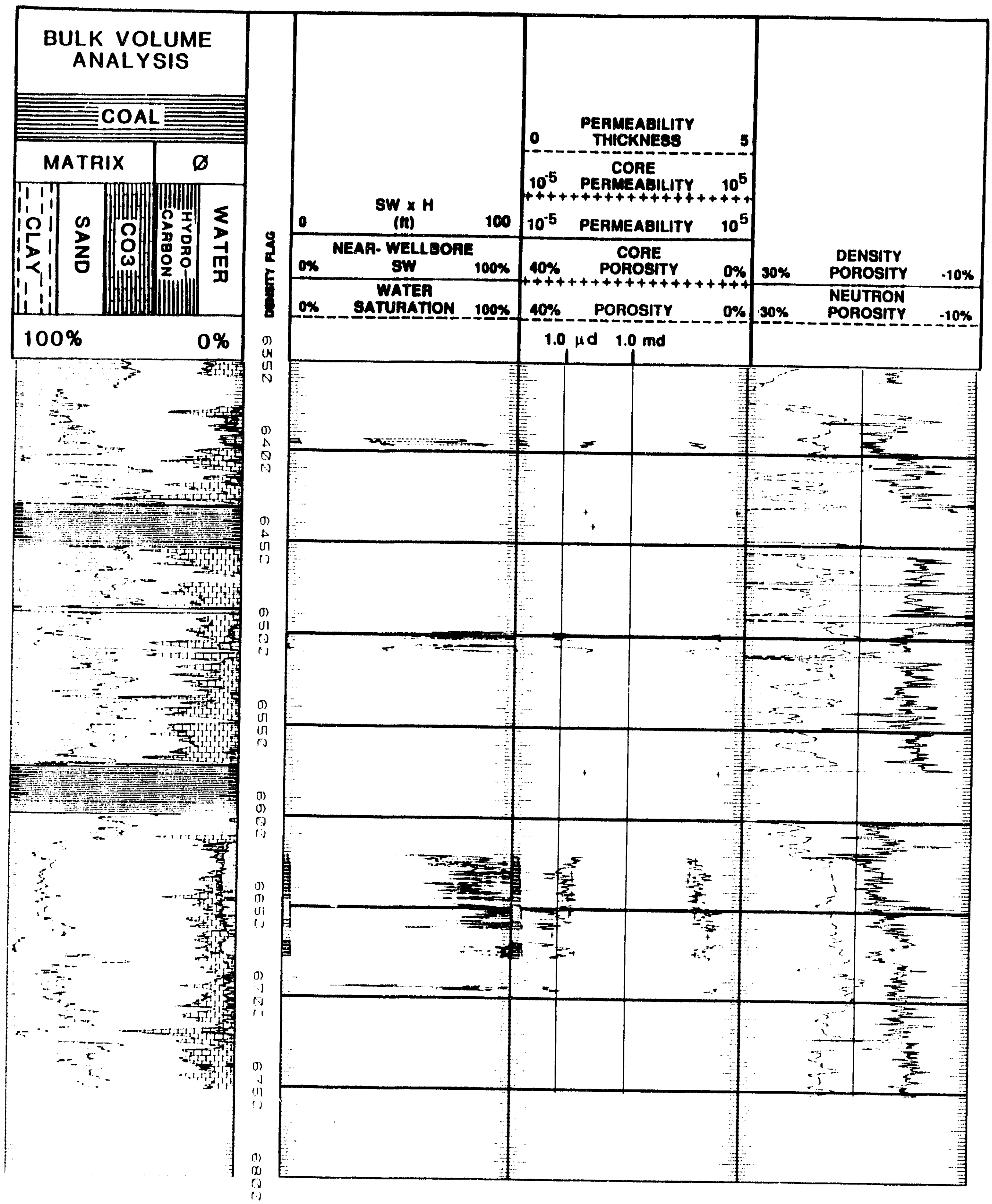


Figure 23, Continued

Overall, the Mamm Ranch area appears to have poor gas production potential compared with many other areas in the Central Basin. There is only one paludal Mesaverde sandstone with good potential. The gas saturated fluvial Mesaverde sands in this part of the Central Basin partitioned area are also noticeably thinner than in the western part of the Central Basin. While gas trapping is effective in this area, the percentage of sand in the gross interval is significantly less than in the Rulison Field. The finding of a lower sand percentage in the Mamm Ranch well is consistent with the Phase I TETWGS study which found a similar result for the Atlantic Richfield No. 1-36 Arco-Exxon well at Mamm Creek, approximately 4 miles northwest of the Mamm Ranch area.

2.3.2 Core Fractures

A total of 63 natural fractures were recognized in the core. Six of the natural fractures were present in mudstone and exhibited slickensides. Some of the natural fractures were either partially or completely mineralized. Two sets of steeply dipping natural extension fractures with different strikes were recognized locally. Figure 24 is a photograph of sandstone core at 6,515 ft showing the two fracture sets intersecting in an acute angle.

In the interval 6,514 to 6,715 ft, five fractures (four natural and one induced) were oriented by the FMS image log. The true orientation of bedding planes in this zone were determine from the image log. The measured spatial relationship between the fractures and bedding planes were employed to orient the fractures. The four natural fractures had strikes of 212°, 185°, 233° and 281°. True strike of the induced fracture was 268°.

2.3.3 Borehole Image Log

A Schlumberger Formation Microscanner (FMS) was run in the open-hole over the paludal interval for fracture characterization. Classification of fracture type is very interpretative using image logs, but it is believed that most fractures identified on the FMS are induced fractures because of the great heights, and non-crossing character. Several natural fractures in the core had a similar appearance, but most do cut across the core and lack the greater vertical extent of induced fractures. A total of 114 steeply inclined fractures were observed. Figure 25 is a rose diagram of the true fracture strikes. The preferential strike for most fractures is 90° to 120°. A minor preferential strike was also observed at 70° to 80°. This interpreted induced fracture orientation implies a maximum horizontal in-situ stress orientation similar to that determined at MWX.

2.3.4 Borehole Breakouts

The FMS oriented calipers were analyzed for borehole breakouts. Calculated maximum horizontal in-situ stress orientations inferred from breakout azimuths were plotted in a rose diagram in Figure 26. The majority of stress azimuths are between 130° and 140°, and the vector mean for all azimuths is 135°. Interpreted stress orientation from the breakouts is about 20° clockwise from that determined from the induced fractures. Because the breakouts are determined from calipers which can easily be rotated in a rugose borehole, the actual induced fractures are believed to be the more accurate stress indicator.

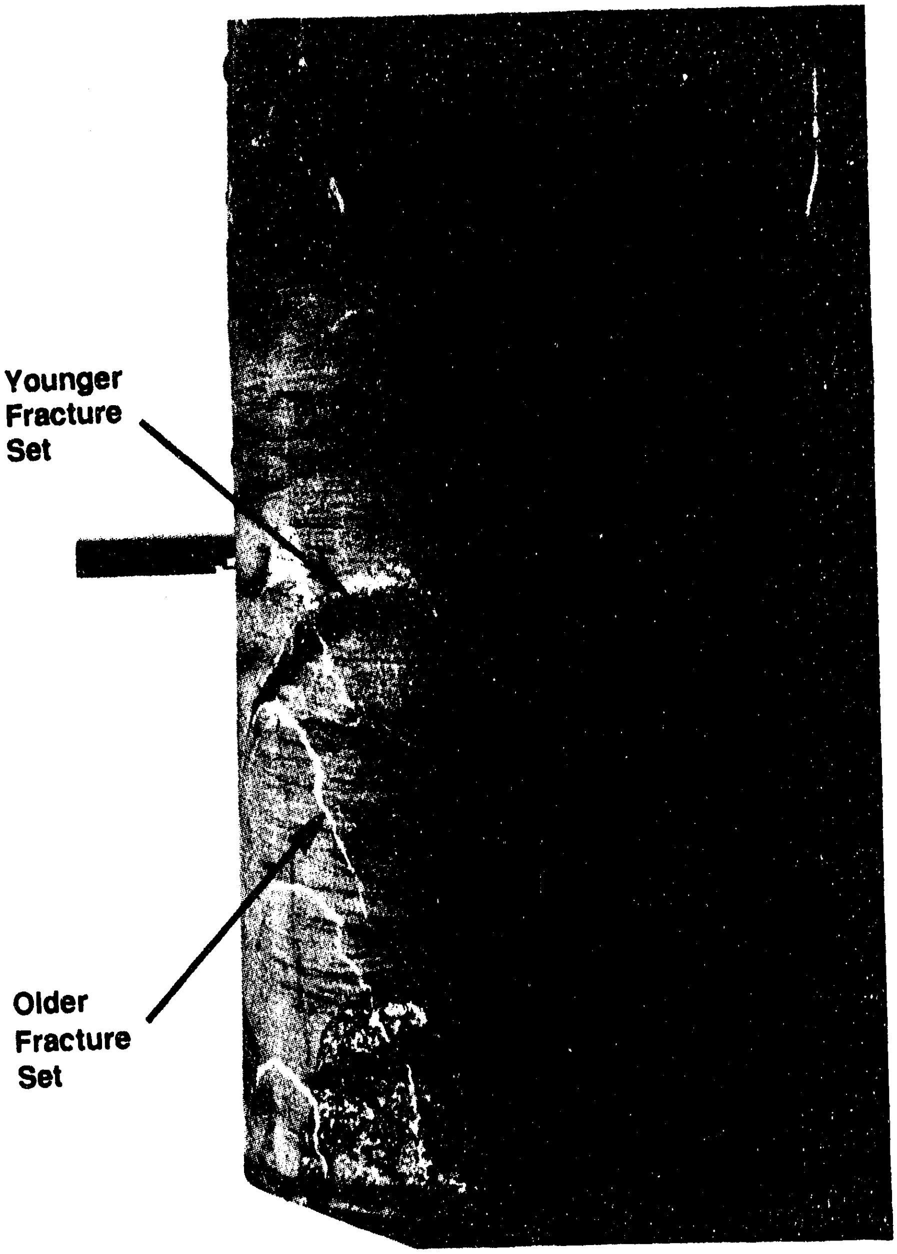


Figure 24 Photograph Showing Two Sets of Natural Fractures in Core, Mobil T45-20P

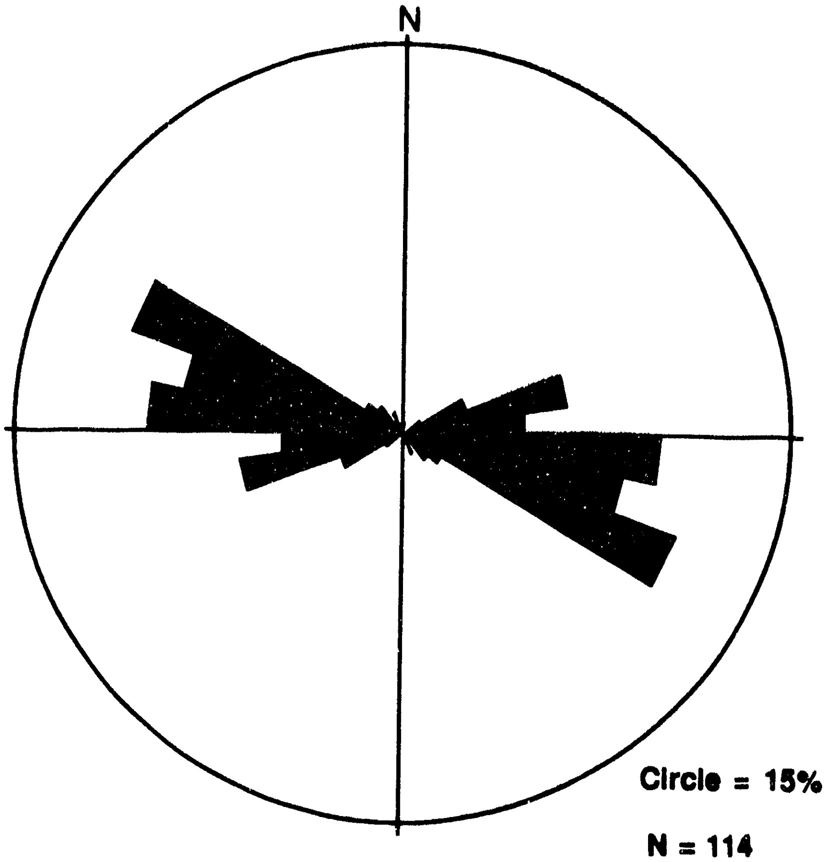


Figure 25 *Rose Diagram Showing the Strikes of Fractures Interpreted from the FMS Log, Mobil T45-20P*

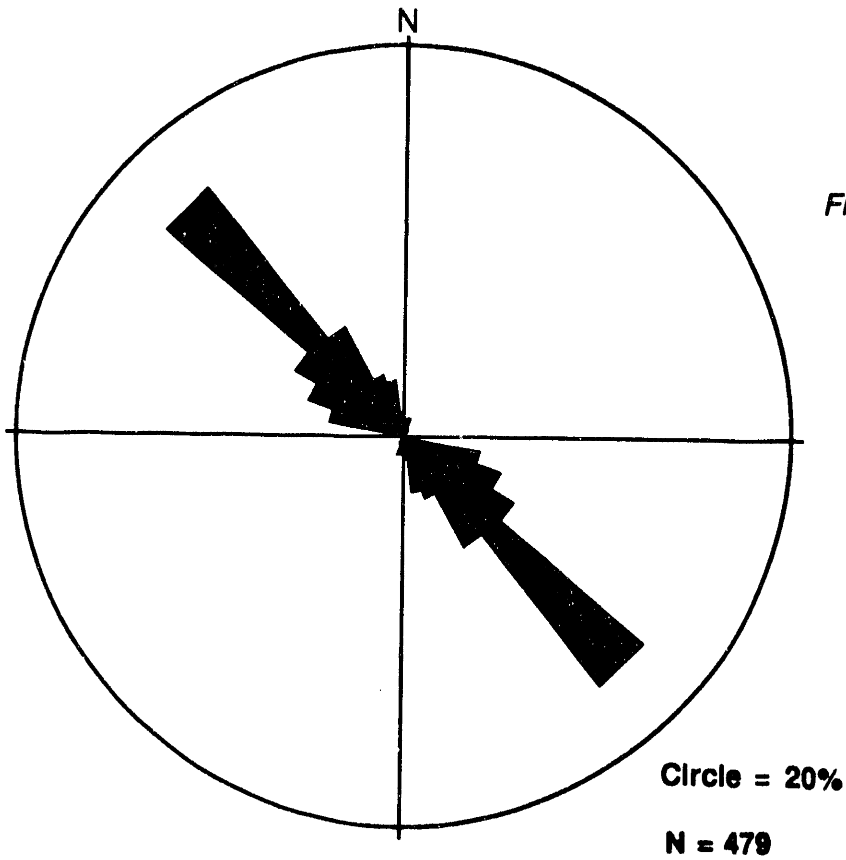


Figure 26 *Rose Diagram of Maximum Horizontal Stress Directions Indicated by Borehole Breakouts Interpreted from the FMS Calipers, Mobil T45-20P*

2.3.5 Well Status

Mobil's primary targets in this well were the coal seams. Because of mechanical problems in testing the lower coals, poor production in the upper coals, and lack of paludal and fluvial sand development, the well has been plugged.

2.3.6 Summary and Conclusions Mobil T45-20P Well

The log analysis of the Mobil well demonstrated gas production potential in the fluvial and paludal sandstones, although not as good as in the Rulison area. Open natural fractures were found in the fluvial and paludal intervals.

2.4 MERIDIAN 12-14 LYONS

From April to June 1991, Meridian Oil Inc. drilled the Moi Lyons 12-14 well in Section 14, T7S, R92W, about 15 miles southeast of MWX. This well is on the eastern boundary of the Central Basin partitioned area as shown on the Phase I partitioned area map (Figure 3). Meridian's primary targets were the coal seams in the paludal Mesaverde section.

Figure 27 shows the gross structural relationships of the wells included in the Phase II study. The Meridian well is located on the nose of the plunging Divide Creek anticline while the Mobil well is near the basin axis. The Meridian well is approximately 1,500 ft structurally higher than the Mobil well. Reverse faulting associated with the anticline is possible between the wells. One objective of this study was to examine the nature of fracturing on the anticline nose to determine if there was any recognizable influence of the Divide Creek anticline that might differentiate this area from other areas of the Central Basin. The studies done in the Meridian well were TITEGAS log analysis and analysis of the FMS log. No cores were taken.

2.4.1 Formation Evaluation

Meridian provided CER log data for inclusion in this study. CER witnessed the Run 2 logging operation. The logging adhered to the DOE tight gas sand log quality control standards. The logging program was as follows:

	Service	Logged Interval
1.	Phasor Induction/SP/GR	5,453 to 1,334 ft
2.	Lithodensity/Caliper	5,424 to 1,322 ft
3.	Compensated Neutron	5,406 to 1,322 ft
4.	Gamma Ray Spectrometry	5,395 to 1,291 ft
5.	Array Sonic	5,441 to 3,404 ft
6.	Formation Microscanner	5,457 to 3,991 ft

The well was analyzed using the TITEGAS log analysis model over the interval 5,394 to 3,250 ft. A brief description of the TITEGAS log analysis model is provided in Appendix 1. The analyzed interval includes the gas saturated paludal and fluvial Mesaverde sub-intervals. These two sub-intervals were analyzed separately, and log analysis constants were refined separately.

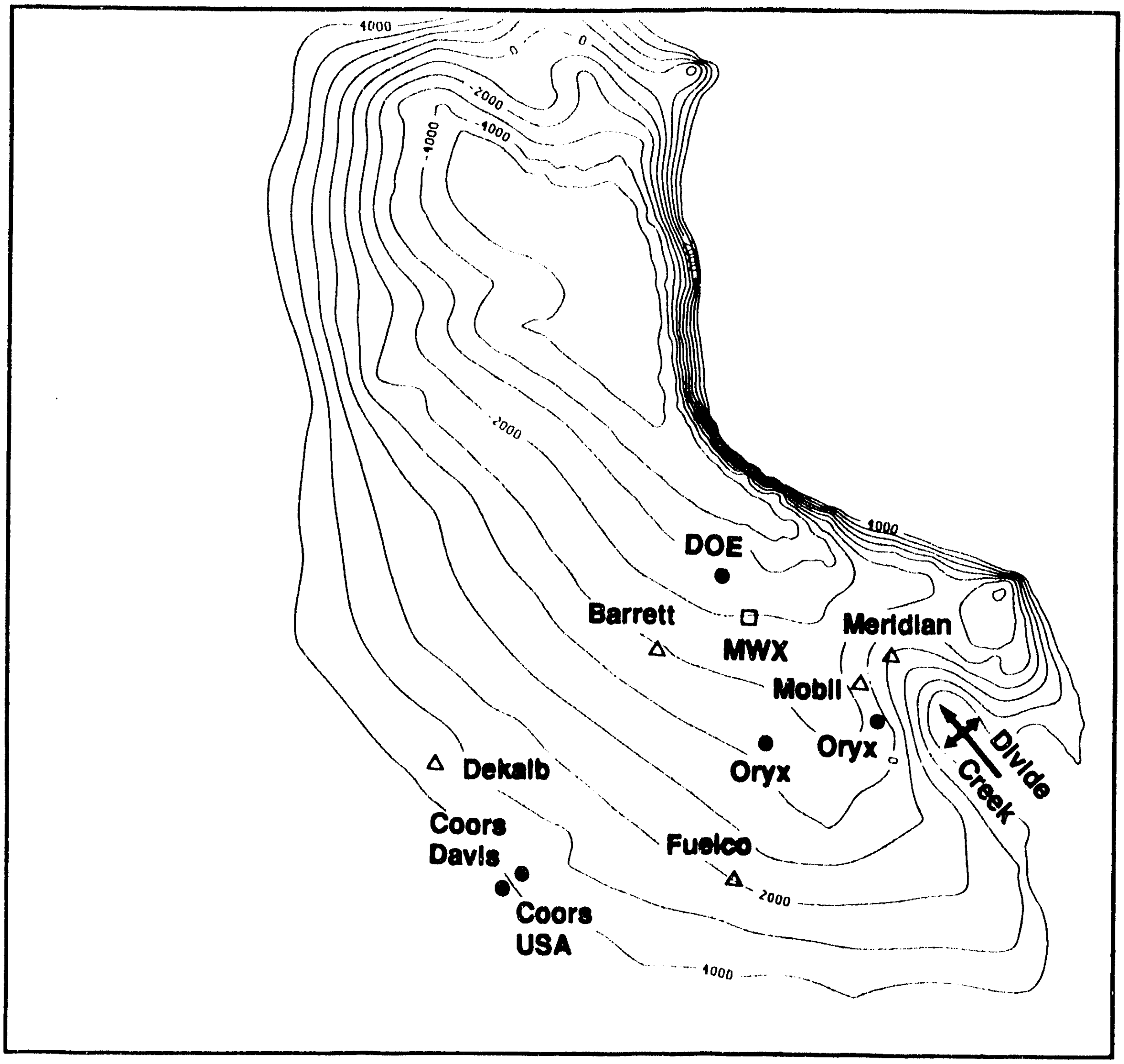


Figure 27 Structure Contour Map on Top of the Rollins Sandstone Showing the Structural Relationship of the Wells in This Study. Triangles are Cooperative Wells. Dots are Supplemental Information Wells.

Histograms of environmentally corrected log data were made for the principal log curves through each sub-interval. These histograms were compared to the log data norms that were developed for the Central Basin partitioned area during the Phase I TETWGS study. It was determined that the Meridian Moi Lyons 12-14 log data is of good quality and no log data normalizations were required. The formation water resistivities that were interpreted through the paludal sub-interval varied with temperature from 0.170 ohm-m to 0.198 ohm-m from 5,394 to 4,188 ft, respectively. The formation water resistivities for the fluvial gas sub-interval varied with temperature from 0.173 ohm-m to 0.198 ohm-m from 4,188 to 3,250 ft, respectively.

The log analysis results for the Moi Lyons 12-14 well are presented in Table 6 and Figure 28. A description of the format for log analysis results is provided in Appendix 2.

The paludal Mesaverde sub-interval is subdivided into 19 individual sandstone zones over the gross interval 5,355 to 4,344 ft. These zones are numbered sequentially from P-1 to P-19, starting with the deepest zone. Some of these zones have fair gas production potential. The most notable are the P-7 and P-9 sandstones. The P-7 zone has a net thickness of 19.0 ft. The maximum porosity is 11.1 percent and averages 8.3 percent. The log calculated kh is 0.156 md-ft. Maximum log calculated permeability is 0.024 md. The minimum clay volume is 7.1 percent and averages 15.6 percent. The minimum water saturation is 46.8 percent and averages 57.3 percent. The P-9 zone has a net thickness of 31.5 ft. The maximum porosity is 9.4 percent and averages 7.2 percent. The log calculated kh is 0.191 md-ft. Maximum log calculated permeability is 0.015 md. The minimum clay volume is 8.6 percent and averages 17.7 percent. The minimum water saturation is 43.2 percent and averages 51.0 percent.

The fluvial Mesaverde sub-interval is subdivided into 10 individual sandstone zones over the gross interval 4,186.5 to 3,286.5 ft. These zones are numbered sequentially from FG-1 to FG-10, starting with the deepest zone. The fluvial section also has some gas production potential. The best zones indicated from log analysis are the FG-1, FG-8 and FG-9 sandstones. The FG-1 zone net thickness is 65.5 ft. The maximum porosity is 9.8 percent and averages 6.5 percent. The log calculated kh is 0.383 md-ft. Maximum log calculated permeability is 0.021 md. The minimum clay volume is 2.0 percent and averages 10.4 percent. The minimum water saturation is 42.5 percent and averages 58.8 percent. There is some uncertainty that the water saturation is at irreducible, and it is likely that this zone would also produce some water. The FG-8 zone has a net thickness of 27.0 ft. The maximum porosity is 9.6 percent and averages 7.4 percent. The log calculated kh is 0.148 md-ft. Maximum log calculated permeability is 0.012 md. The minimum clay volume is 5.7 percent and averages 16.8 percent. The minimum water saturation is 42.5 percent and averages 58.1 percent. The FG-9 zone has a net thickness of 31.5 ft. The maximum porosity is 11.3 percent and averages 9.5 percent. The log calculated kh is 0.411 md-ft. Maximum log calculated permeability is 0.032 md. The minimum clay volume is 9.4 percent and averages 18.0 percent. The minimum water saturation is 44.1 percent and averages 50.1 percent.

The porosities and permeabilities of the paludal and fluvial sandstones on the eastern margin of the Central Basin partitioned area are comparable to those observed in the correlative section at MWX. The original depth of burial at the Moi Lyons location was probably similar to that at MWX. The Moi Lyons 12-14 logs were visually examined through the remainder of the logged interval within the fluvial section. Sandstones above 3,286.5 ft are interpreted as being wet in this well. This means that less of the overall fluvial Mesaverde section is gas saturated as compared to MWX. Also it appears that some of the paludal and fluvial sands

Table 6 Key Reservoir Parameters and Zone Designations for Meridian Moi Lyons 12-14

INTERVAL (FEET)	ZONE	GROSS H (FT)	NET H (FT)	AVG Ø (%)	MAX Ø (%)	AVG SW (%)	MIN SW (%)	HCFT (FT)	KH (MD-FT)	MAX K (MD)	AVG CLAY (%)	MIN CLAY (%)
5353.0-5355.0	P-1	2.5	2.5	7.8	8.9	49.7	43.5	0.098	0.016	0.011	21.0	17.2
5284.5-5308.0	P-2	24.0	24.0	7.1	10.1	77.4	53.2	0.478	0.194	0.016	9.7	2.8
5261.0-5273.5	P-3	13.0	12.0	5.6	7.5	72.5	46.4	0.213	0.028	0.007	15.2	11.6
5245.0-5257.0	P-4	12.5	12.0	5.5	8.1	67.5	42.8	0.231	0.024	0.010	21.1	16.5
5166.5-5180.5	P-5	14.5	14.5	6.6	7.8	57.4	48.6	0.412	0.051	0.007	16.6	13.1
5119.5-5122.5	P-6	3.5	3.5	5.7	8.2	70.8	47.3	0.069	0.009	0.008	17.1	13.1
5078.5-5097.0	P-7	19.0	19.0	8.3	11.1	57.3	46.8	0.691	0.156	0.024	15.6	7.1
5052.5-5062.0	P-8	10.0	10.0	6.2	8.1	62.5	51.6	0.238	0.026	0.007	18.5	15.8
4986.5-5020.5	P-9	34.5	31.5	7.2	9.4	51.0	43.2	1.118	0.191	0.015	17.7	8.6
4954.5-4957.5	P-10	3.5	3.5	7.5	9.8	43.6	36.2	0.150	0.053	0.035	7.7	3.1
4902.5-4927.5	P-11	25.5	20.5	7.4	10.2	56.1	41.3	0.691	0.118	0.018	18.0	12.2
4878.5-4881.0	P-12	3.0	3.0	4.5	5.3	72.7	54.5	0.038	0.002	0.002	15.9	12.4
4732.0-4736.5	P-13	5.0	5.0	7.5	4.3	77.2	58.2	0.044	0.002	0.001	22.7	20.1
4691.0-4702.0	P-14	11.5	11.5	5.1	6.7	72.8	59.0	0.167	0.013	0.002	16.5	10.4
4631.5-4653.0	P-15	22.0	18.5	5.2	7.2	82.6	74.4	0.174	0.017	0.002	18.3	10.7
4538.5-4560.5	P-16	22.5	22.0	5.2	7.1	72.9	51.0	0.325	0.031	0.004	14.6	8.3
4468.0-4471.0	P-17	3.5	3.5	6.2	6.4	75.5	70.0	0.053	0.005	0.002	17.3	14.3
4352.0-4369.0	P-18	17.5	17.5	6.4	10.0	64.9	43.4	0.415	0.072	0.025	13.4	3.3
4344.0-4348.0	P-19	4.5	4.5	7.4	11.5	58.3	43.6	0.144	0.028	0.028	18.2	15.1
4120.5-4186.5	FG-1	66.5	65.5	6.5	9.8	58.8	42.5	1.849	0.383	0.021	10.4	2.0
4061.5-4081.5	FG-2	20.5	19.5	6.9	9.2	58.5	45.6	0.586	0.096	0.012	16.0	7.8
4002.0-4021.5	FG-3	20.0	20.0	6.5	8.6	60.5	48.0	0.525	0.082	0.011	12.5	8.4
3942.5-3946.5	FG-4	4.5	4.5	5.0	6.3	72.8	56.8	0.057	0.005	0.002	11.9	5.0
3884.0-3905.5	FG-5	22.0	20.0	6.4	7.9	62.9	52.3	0.487	0.078	0.009	9.2	4.5
3851.5-3855.5	FG-6	4.5	4.5	7.7	9.4	73.9	51.6	0.092	0.020	0.012	11.2	5.9
3545.0-3550.5	FG-7	6.0	6.0	8.8	10.6	52.7	45.9	0.252	0.055	0.017	17.7	12.3
3504.0-3532.0	FG-8	28.5	27.0	7.4	9.6	58.1	42.5	0.858	0.148	0.012	16.8	5.7
3414.0-3445.5	FG-9	32.0	31.5	9.5	11.3	50.1	44.1	1.506	0.411	0.032	18.0	9.4
3286.5-3293.0	FG-10	7.0	7.0	8.6	9.7	54.2	48.2	0.277	0.056	0.013	16.8	12.2

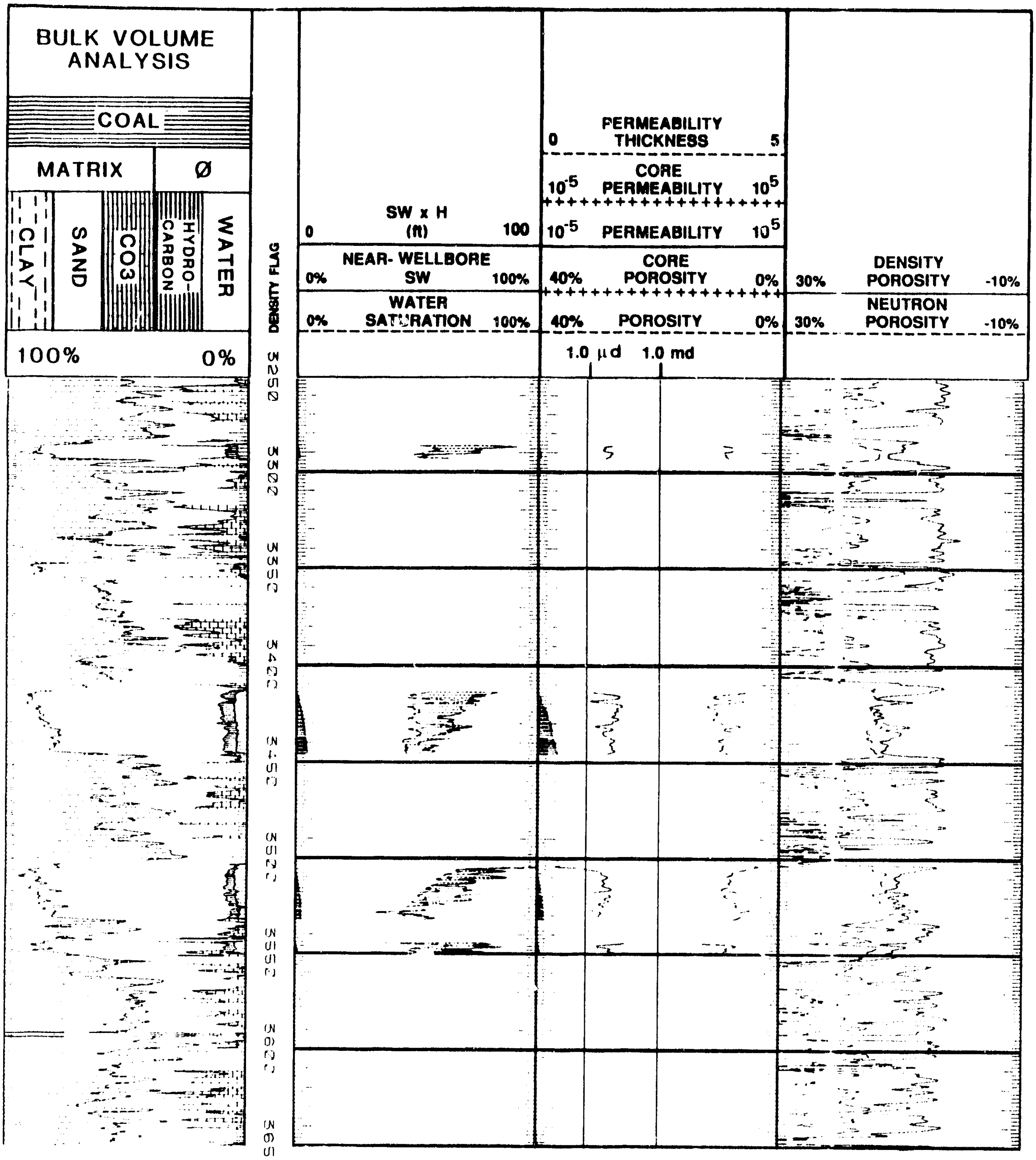
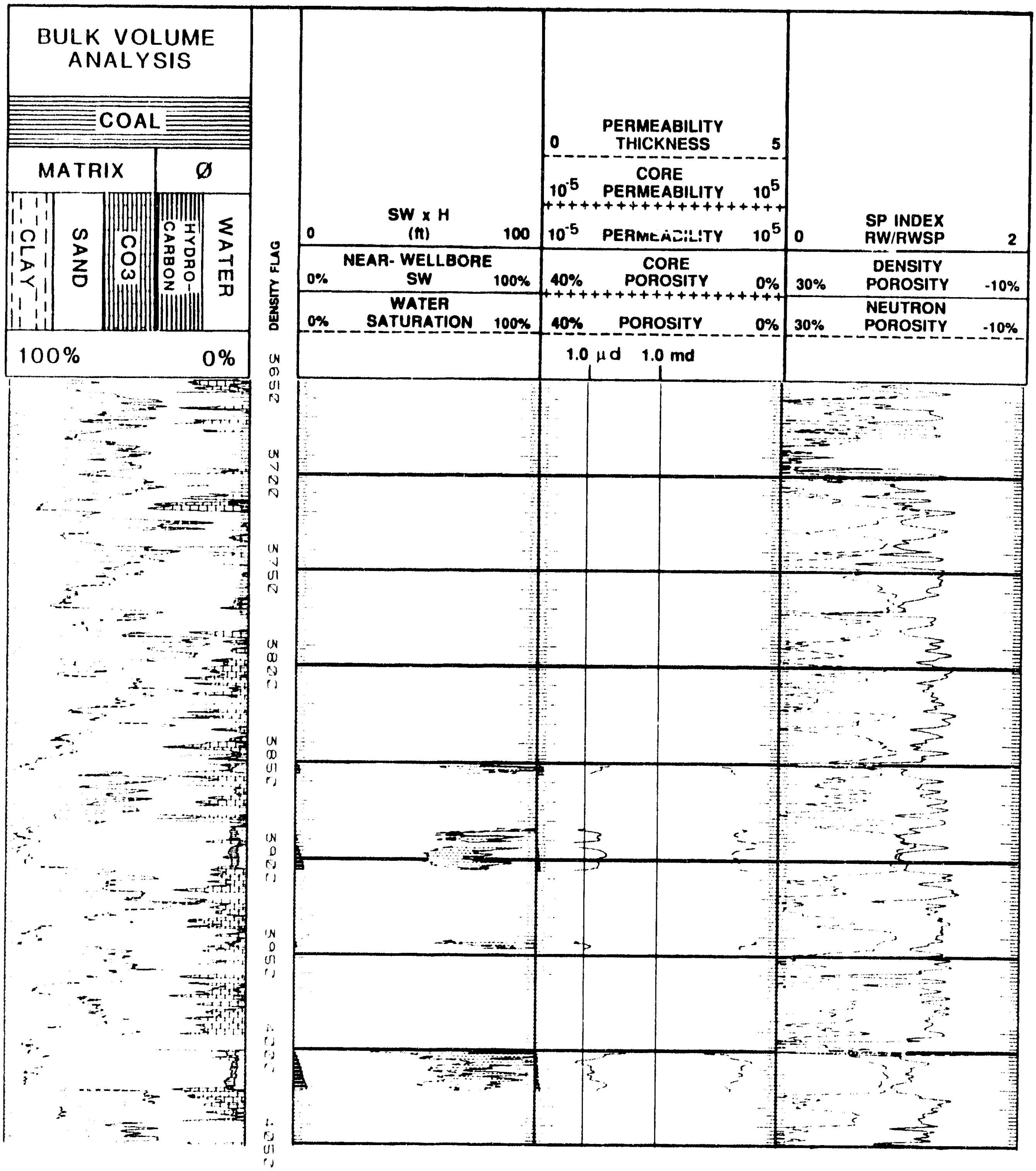


Figure 28 TITEGAS Computed Log, Meridian 12-14



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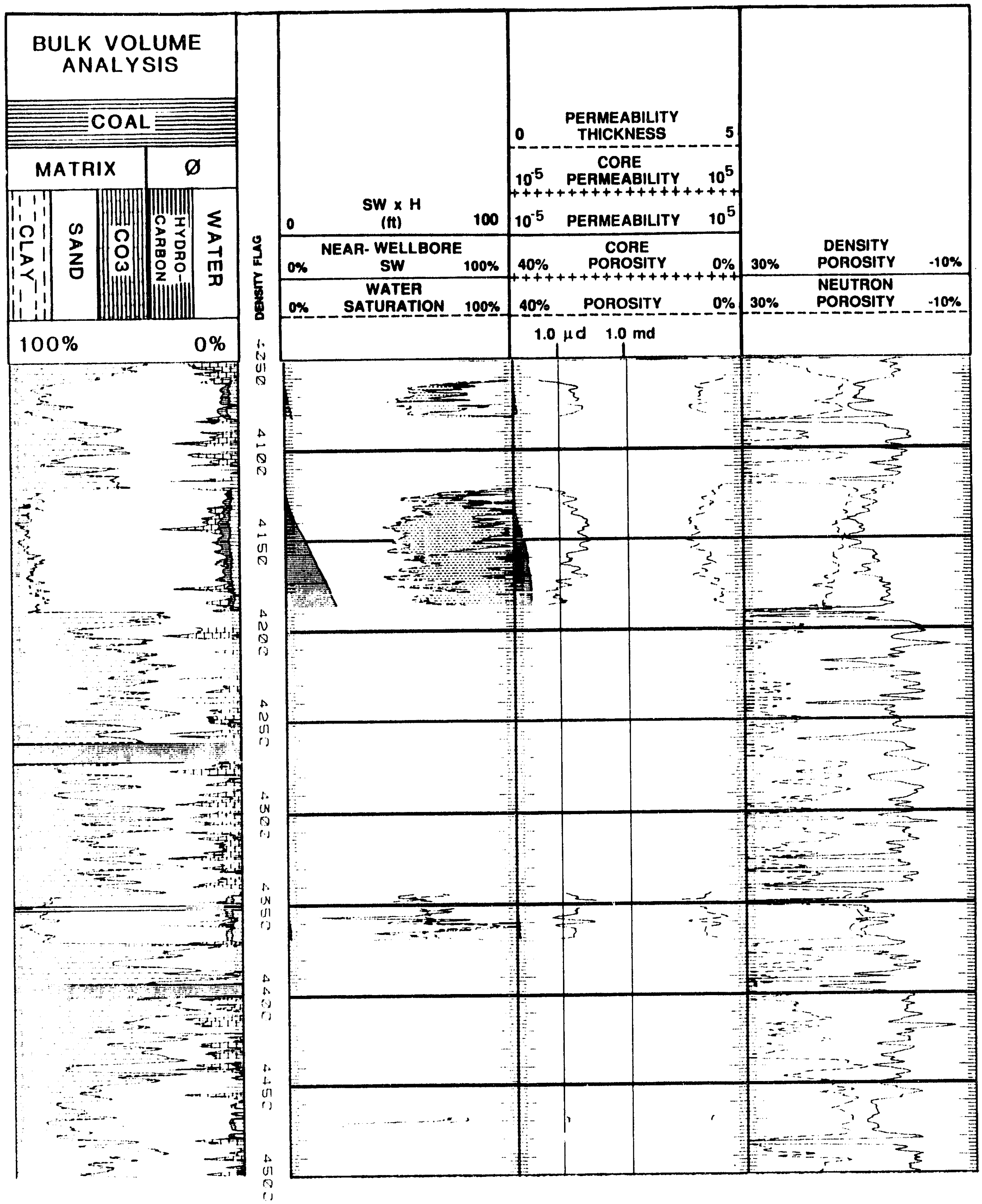

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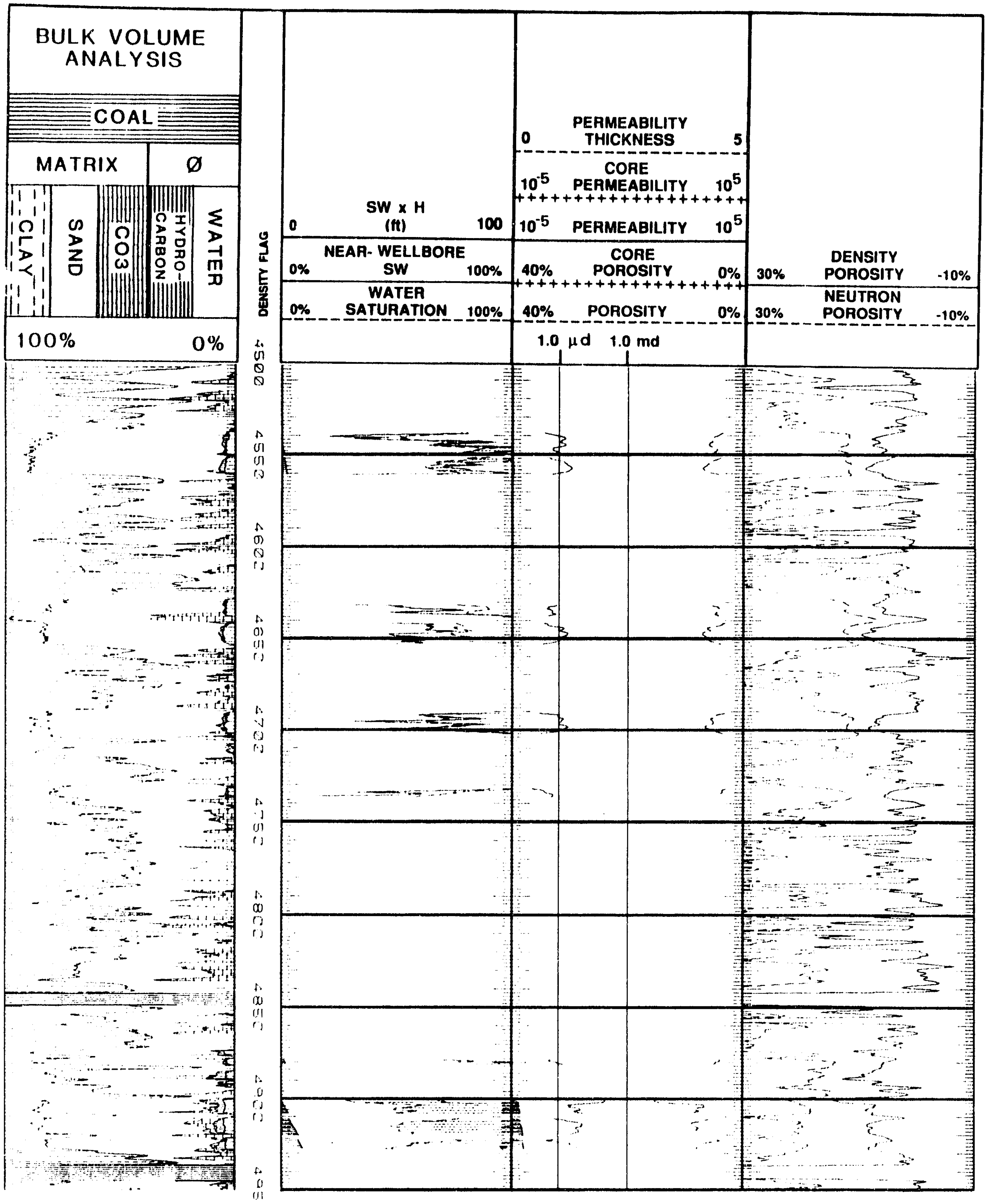

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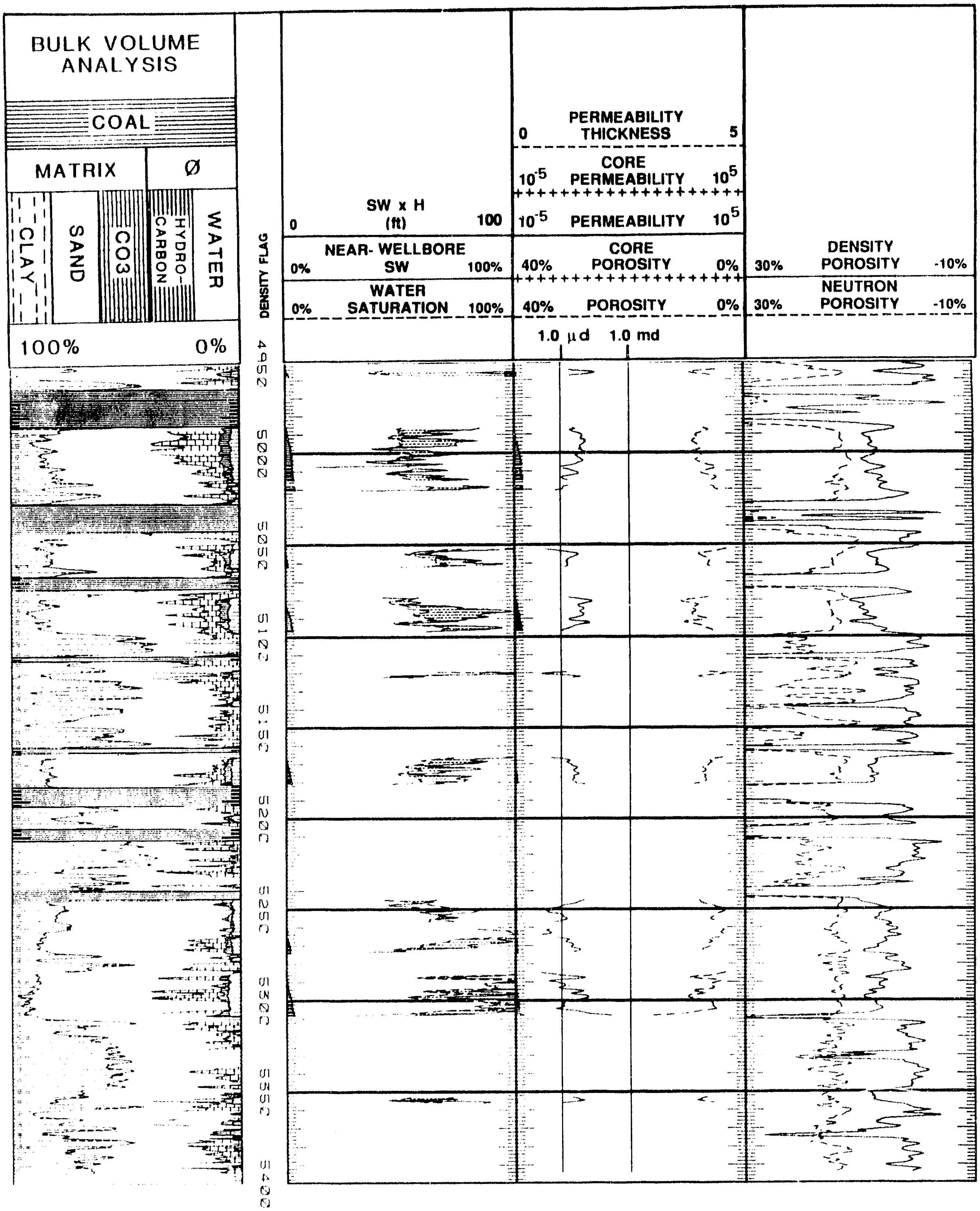


Figure 28, Continued

in the Moi Lyons analyzed interval have water saturations that are greater than irreducible. This gas/water distribution scenario is consistent with the position of the Moi Lyons well in the basin. Gas trapping along the eastern edge of the Central Basin partitioned area is not as effective as in the Rulison Field. It appears that gas escapes updip along the Divide Creek anticlinal axis.

2.4.2 FMS Analysis

A Formation MicroScanner (FMS) was run over the interval 3,400 to 5,448 ft. The FMS image log was manually analyzed for fractures over this entire interval. A total of 190 fractures were visible on the image log. Top and bottom depth were noted for each occurrence and orientation data were acquired for 113 fractures. All fractures are steeply dipping.

The distinction of natural versus induced fractures on the FMS log, without corroborating core, is difficult. Several criteria were employed to distinguish natural fractures from induced fractures.

Criteria for natural fractures included but was not limited to the following:

- relay or enechelon traces;
- narrow width; and
- short length (< two ft)

Criteria for induced fractures included but was not limited to the following:

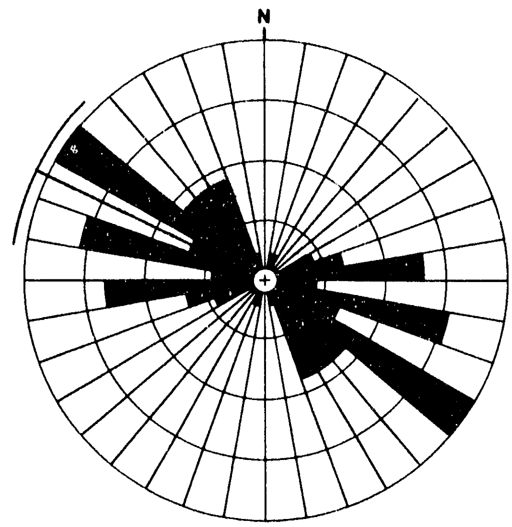
- length extending over a relatively long section (several or more ft) of the wellbore;
- large aperture; and
- petal-centerline configuration (e.g. fractures that exit the wellbore wall into the borehole);

A rose diagram with strikes of the 47 interpreted natural fractures is shown in Figure 29. Preferential strike orientation is trimodal at 70° to 80°, 100° to 110°, and 120° to 130°. The vector mean of all the natural fracture strikes is 116°. Fracture strikes in the range of 100° to 110° are similar to those found at the MWX location.

Figure 30 is the rose diagram of strikes of the 55 interpreted induced fractures. Induced fracture strikes range from 120° to 140°. The vector mean of all induced fracture strikes is 129°. These observations indicate that an induced fracture will parallel the set of natural fractures oriented at 120° to 130° but will be oblique to the other sets. However, because of the difficulty in differentiating induced from natural fractures on the FMS log, it is possible that some of the interpreted natural fractures that have the same orientation as the induced fractures are actually induced.

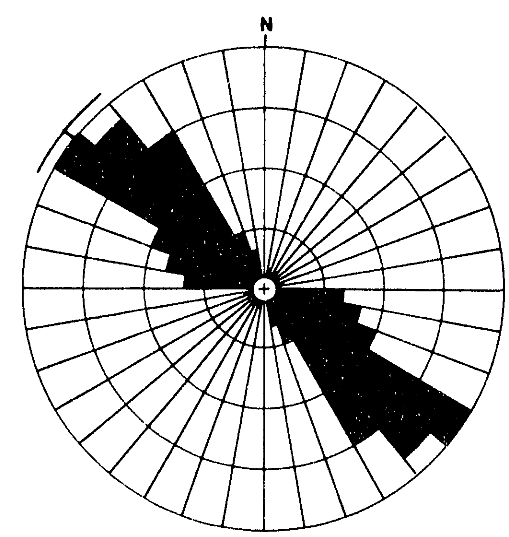
2.4.3 Production Test Results

Casing was set at 5,456 ft, and the well was then drilled to a total depth of 5,528 ft. The Cameo coals were tested and produced 1,700 BWPD. This test condemned gas production from coal seams in this well. The well was subsequently plugged and abandoned because



Meridian Lyons 12-14 Natural Fractures	Statistics
N = 47	Vector Mean = 295.9
Class Interval = 10 degrees	Conf. Angle = 18.41
Maximum Percentage = 19.1	R Magnitude = 0.566
Mean Percentage = 7.69 Standard Deviation = 5.14	Rayleigh = 0.0000

Figure 29 Rose Diagram Showing the Strikes of FMS-Interpreted Natural Fractures, Meridian 12-14



Meridian Lyons 12-14 Induced Fractures	Statistics
N = 55	Vector Mean = 308.7
Class Interval = 10 degrees	Conf. Angle = 11.61
Maximum Percentage = 21.8	R Magnitude = 0.743
Mean Percentage = 9.09 Standard Deviation = 7.19	Rayleigh = 0.0000

Figure 30 Rose Diagram Showing the Strikes of FMS-Interpreted Induced Fractures, Meridian 12-14

Meridian did not believe that it would be economic to complete the paludal or fluvial sandstones.

2.4.4 Summary and Conclusions Meridian 12-14 Lyons Well

The TITEGAS log analysis shows that the Meridian well has some potential in the fluvial and paludal sandstones. There are interpreted open natural fractures in the Meridian well that are similarly oriented to those at MWX. The natural fracture data suggests that other fracture sets are also present. However, without corroborating core, the FMS study could not definitively define the number of fracture sets, nor their relationship to the Divide Creek structure.

2.5 LOG ANALYSIS AND PRODUCTION TESTING OF THE DOE NO. 1-M-17 WELL

CER reviewed the production testing data and performed log analysis for the DOE No. 1-M-17 well in Section 17, T6S, R94W, Garfield County, Colorado. The well is located on the edge of Anvil Points approximately 4 miles northwest of MWX on the Naval Oil Shale Reserve No. 3 and was drilled during 1991 by John Brown E&C. The well is important because of the high gas flow rates experienced during completion.

During the drilling of the DOE No. 1-M-17 well, the operator experienced lost circulation of drilling fluids into the Rollins Sandstone and well flowing problems from multiple overpressured zones above the Rollins. These problems persisted over several days. The hole was stabilized for logging by spotting a "pill" of higher weight drilling fluid over the interval that was thought to be flowing. This procedure resulted in quiet well conditions during logging.

The logging program was as follows:

	Service	Logged Interval
1.	Phasor Induction/SFL/SP	8,454 to 816 ft
2.	Lithodensity/Caliper	8,425 to 816 ft
3.	Compensated Neutron	8,406 to 816 ft
4.	Gamma Ray	8,391 to 20 ft
4.	X-Y Caliper	8,417 to 816 ft

Histograms of environmentally corrected log data were made for the principal log curves through each depositional interval. These histograms were compared to histograms of the Multiwell Experiment (MWX) environmentally corrected log data to determine the validity of each log. The DOE No. 1-M-17 log data histograms were in good agreement with MWX histograms for each depositional interval. Log data normalizations were therefore not required for this well.

The KCl drilling fluid resulted in good borehole conditions in the lower section of the well. Above 6,000 ft the hole is rugose and borehole breakouts have apparently occurred in some of the upper sands. This condition makes the acquisition of valid density data impossible over these intervals, and in some cases log calculations were not performed in these poor data intervals. Fortunately, sandstones above 6,000 ft are not considered to be of good reservoir quality in this well. Several sandstones below 6,000 ft have thin intervals where density data is invalid. These include the intervals 6,908.5 to 6,912.5, 6,724.5 to 6,726.5 and 6,558.5 to

6,566.0 ft. Since each of these intervals is in the main gas package, density data was reconstructed by using the SP curve.

The computer log analysis of the DOE No. 1-M-17 well subdivides the gross Mesaverde interval from 4,715 to 8,390 FT into five sub-intervals as follows:

1. Paludal (including Rollins sandstone), 7,400 to 8,390 ft.
2. Coastal, 6,880 to 7,400 ft.
3. Fluvial, 6,000 to 6,880 ft.
4. Fluvial transition, 5,350 to 6,000 ft.
5. Water saturated (including Ohio Creek), 4,715 to 5,350 ft.

The log analysis results are presented in Figure 31. The results are also summarized in Tables 7 and 8. Each zone in each sub-interval is numbered from bottom to top. The zone numbering system uses the letter prefixes P, C, F, FT and W which correspond to the sub-intervals listed above. Following the refinement of constants for each sub-interval and the completion of the TITEGAS analysis, the NATUFRAC computer program (NATUFRAC is a variation of TITEGAS which uses basic log data to help detect the presence of natural fractures), was run over the gas package from 5,700 to 8,390 ft. The TITEGAS and NATUFRAC logs were then compared with mud log data to identify possible natural fractures. A computer program was then run to accumulate and average the reservoir parameters and a table was made to summarize the reservoir characteristics of each zone. The tabular results and the computed logs were then used to interpret the gas productive characteristics of each zone.

The formation water resistivities (Rw) were interpreted as follows:

Paludal:	(7,400-8,390 ft)	Rw @75°F=0.37ohm-m
Coastal:	(6,880-7,400 ft)	Rw @75°F=0.29ohm-m
Fluvial:	(6,000-6,880 ft)	Rw @75°F=0.29ohm-m
Fluvial Transitional:	(5,350-6,000 ft)	Rw @75°F=0.37ohm-m
Water Saturated:	(4,715-5,350 ft)	Rw @75°F=0.54ohm-m

The TITEGAS program corrects Rw to the formation temperature. These Rw values are fairly consistent with the water resistivities interpreted at MWX.

Zones above 5,800 ft have water saturations that are greater than irreducible water saturation. Gas trapping is more effective below 6,000 ft. With the exception of the Rollins sandstone, all sands below 6,000 ft appear to contain over-pressured gas. Water saturations are interpreted to be irreducible. Most of the better quality sands occur in the fluvial sub-interval over the gross interval 6,050 to 6,867 ft.

Fracture analysis was performed over the interval 8,390 to 5,700 ft. Fractures were interpreted in the following zones: P-4, C-2, C-5, C-7, F-3, F-6, F-7, F-8, F-11, F-17, F-18 and FT-5. Natural fracture permeability is known to be an important gas production mechanism at MWX and it appears that natural fractures are also important in the DOE No. 1-M-17 well. The NATUFRAC analysis confirms the presence of natural fractures in the above zones, however it does not necessarily deny the presence of fractures in other zones. The encounter of a

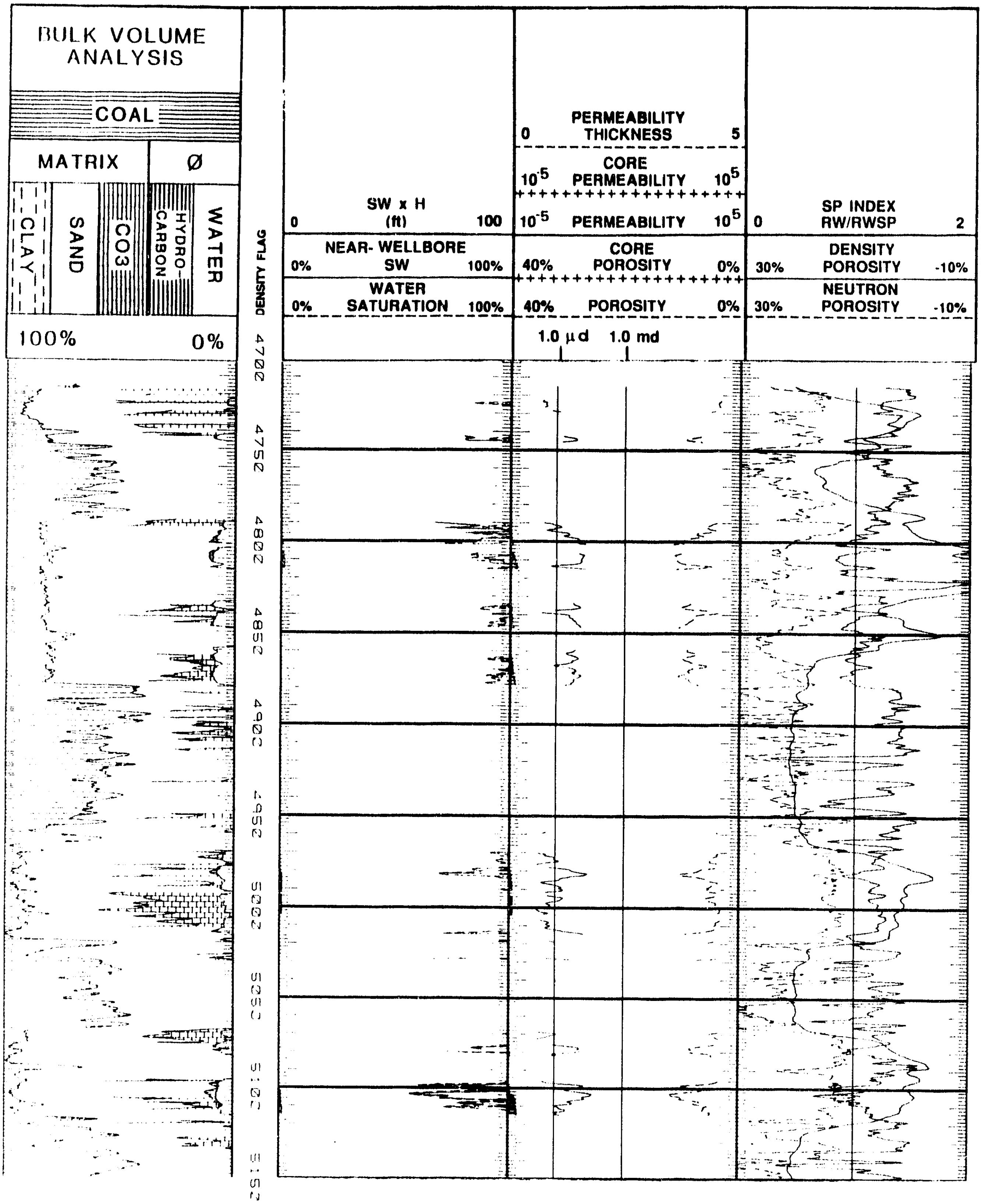
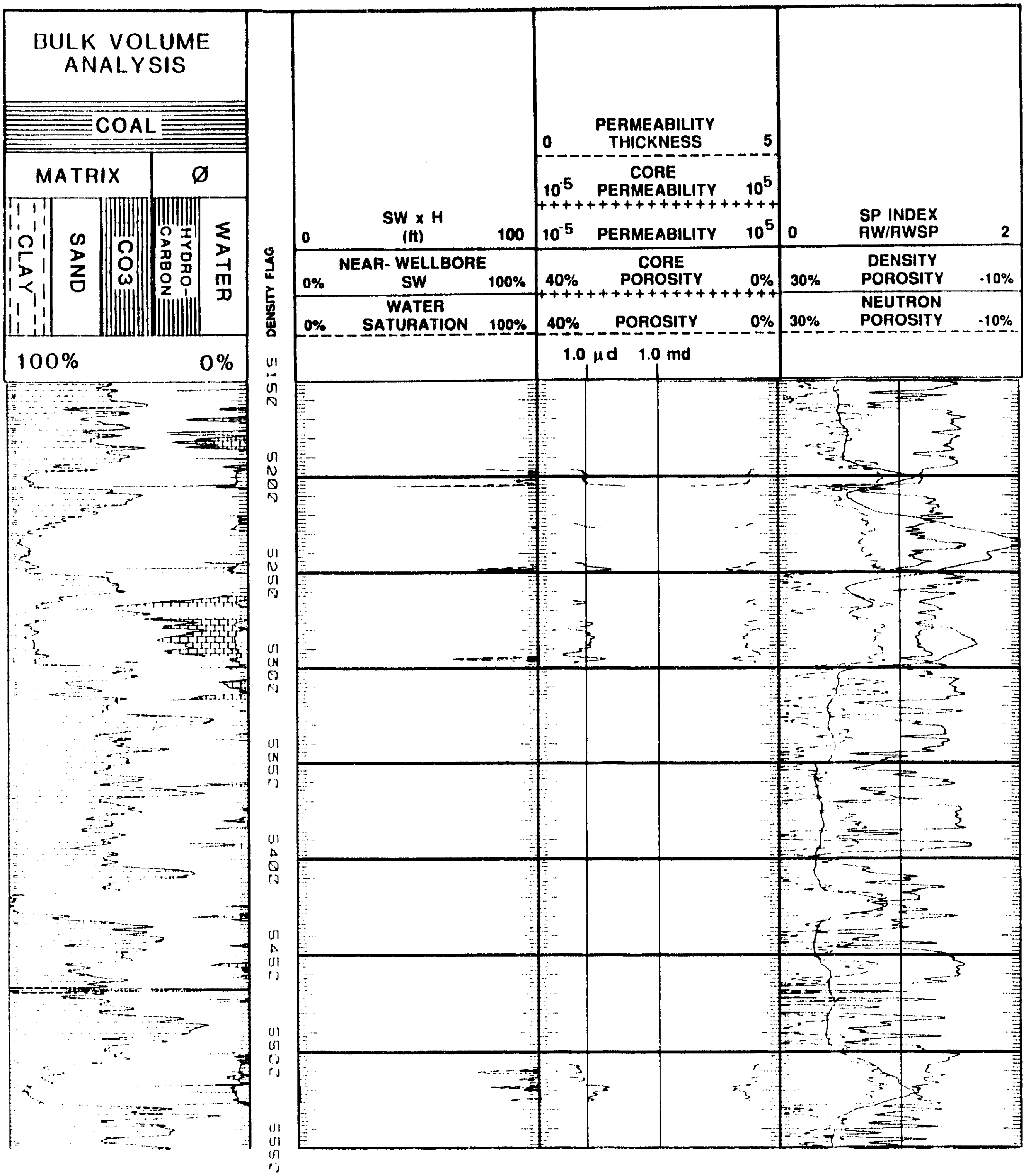


Figure 31 TITEGAS Computed Log, DOE 1-M-17



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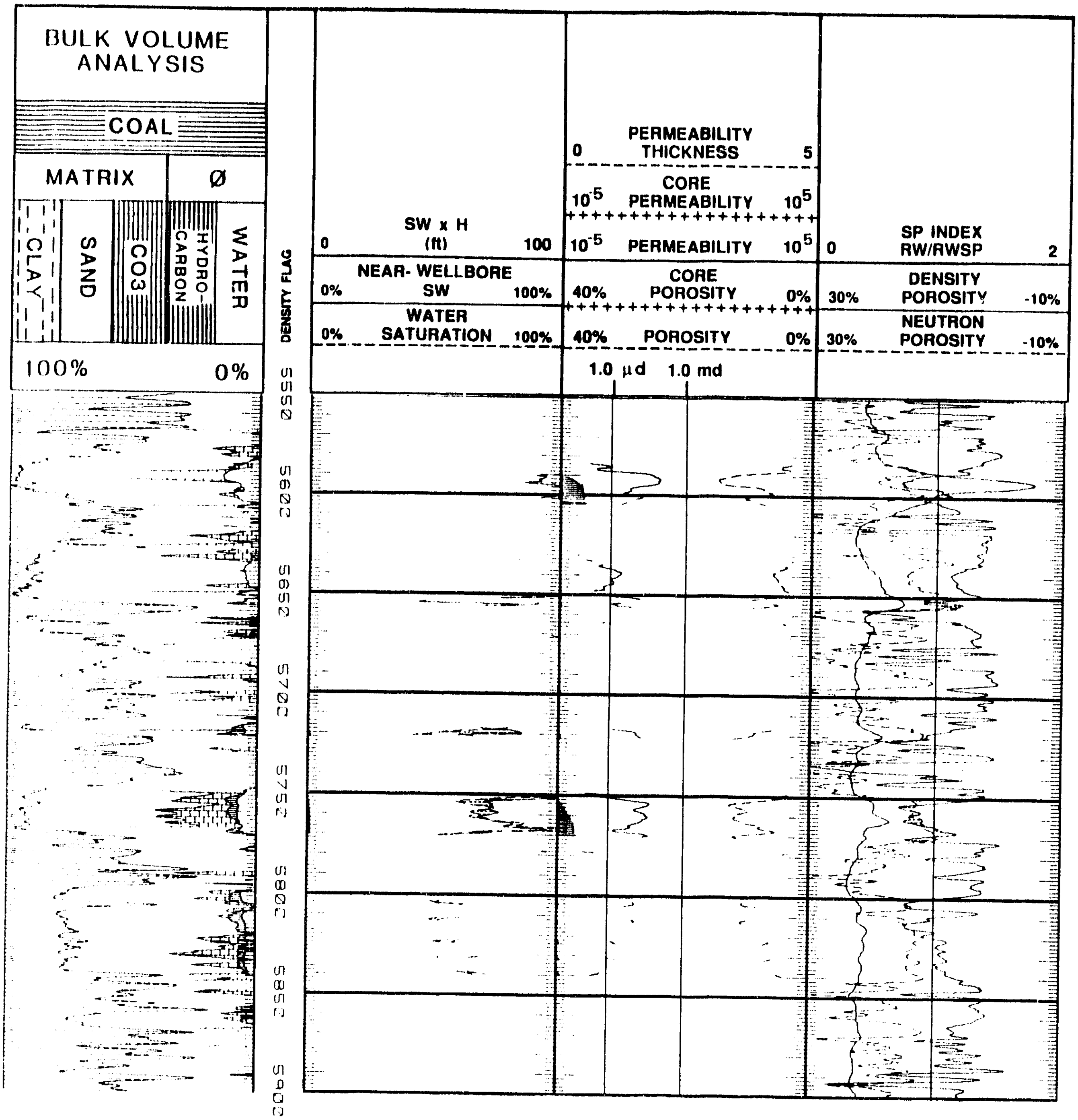

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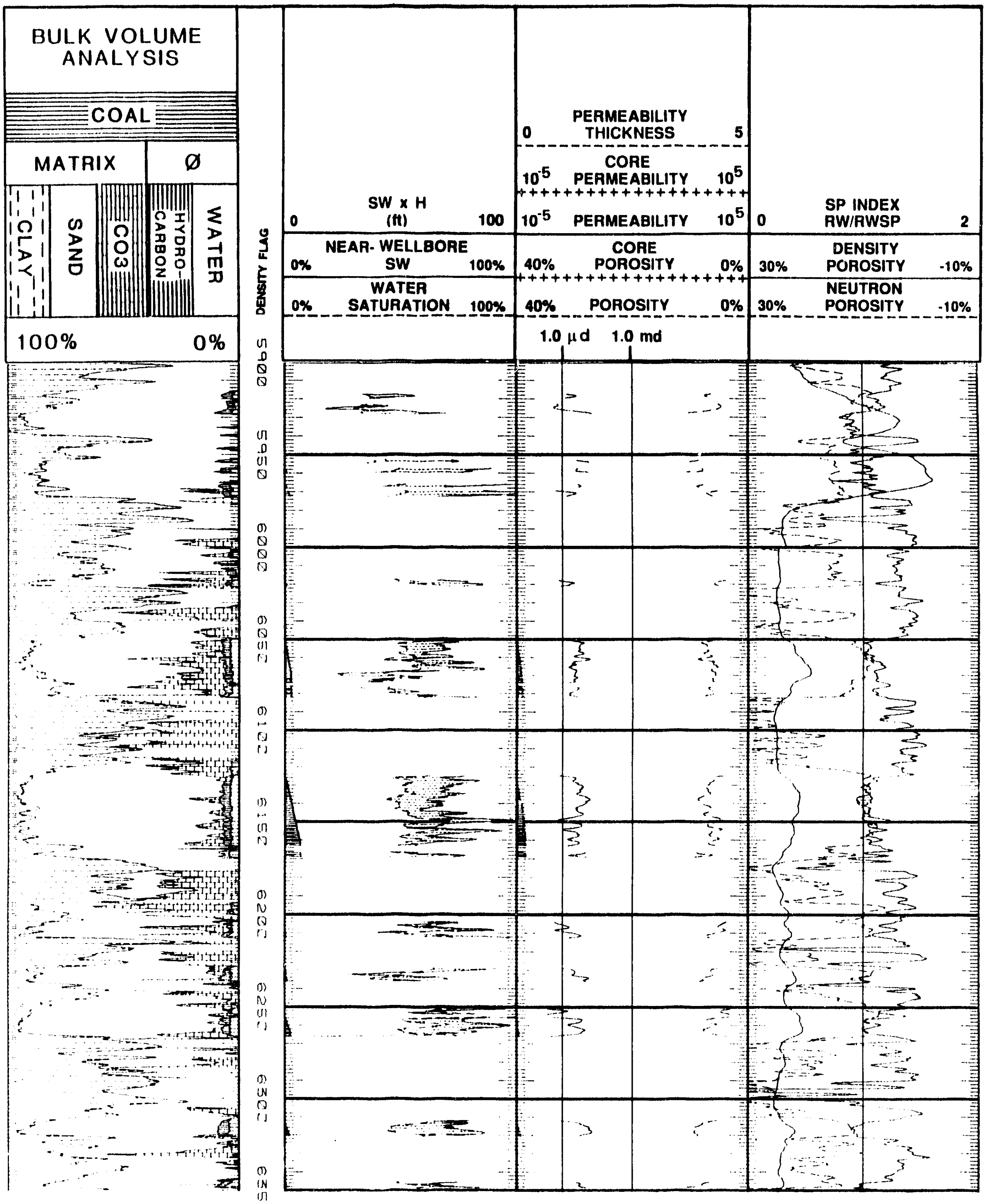

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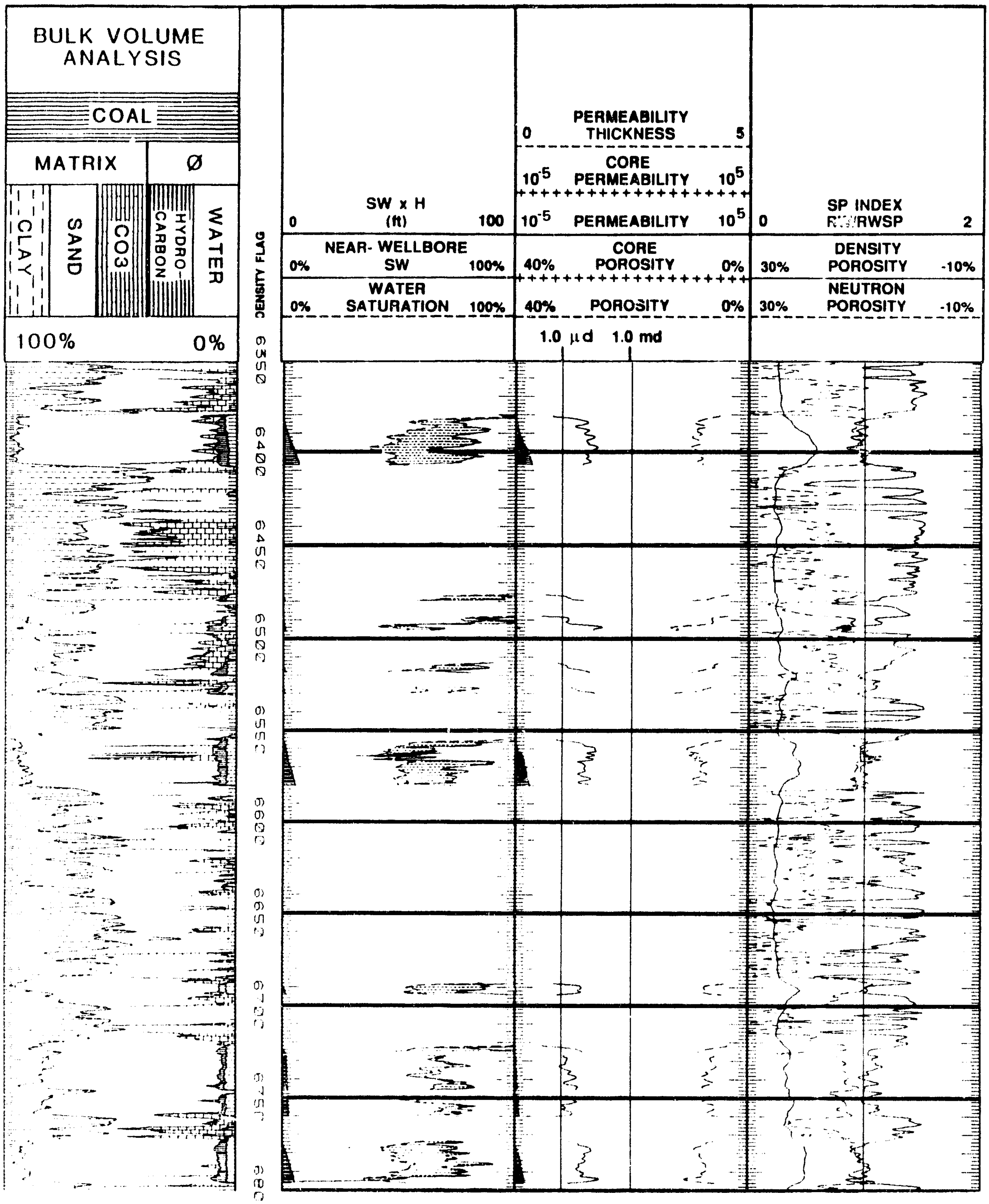

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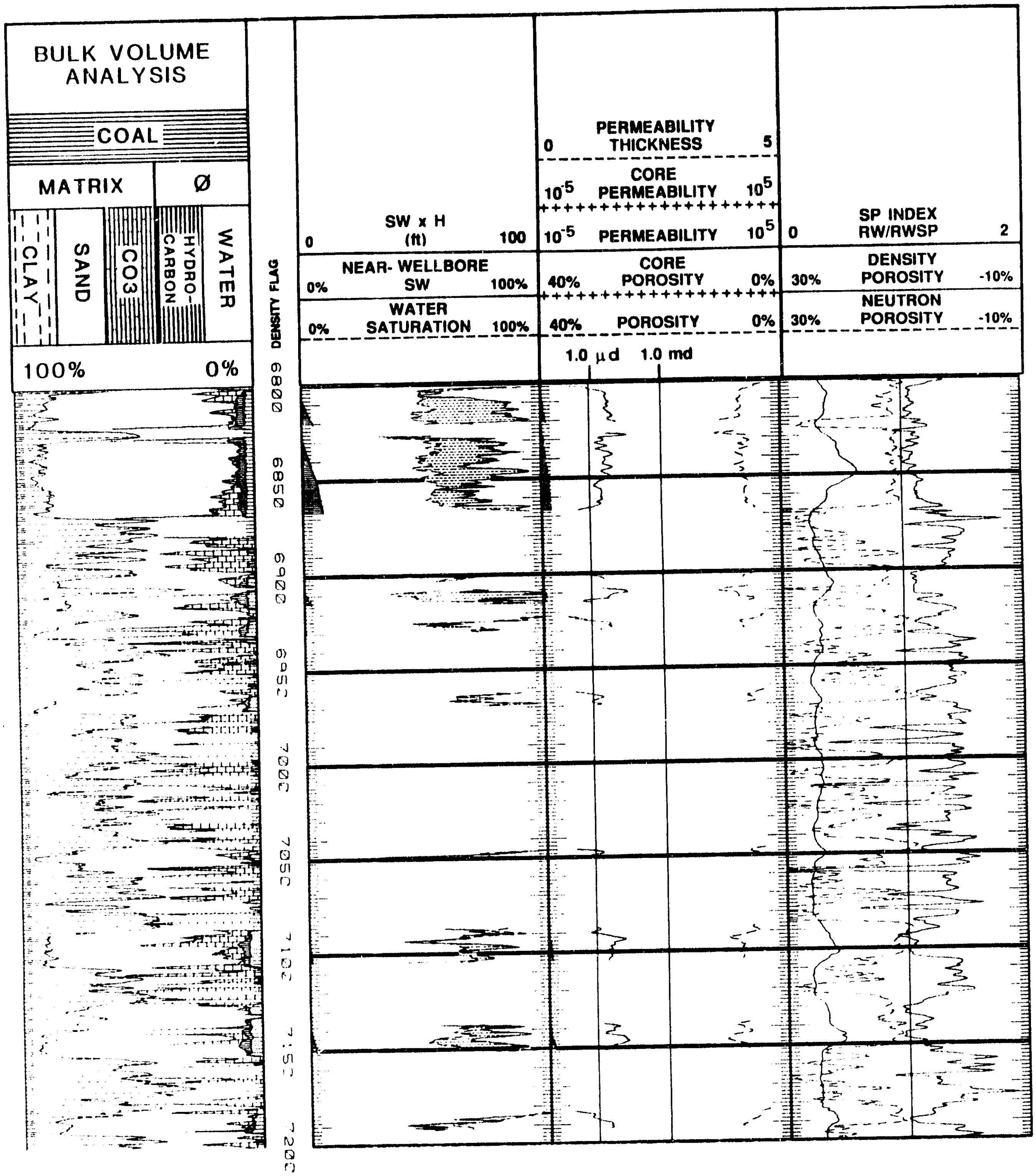

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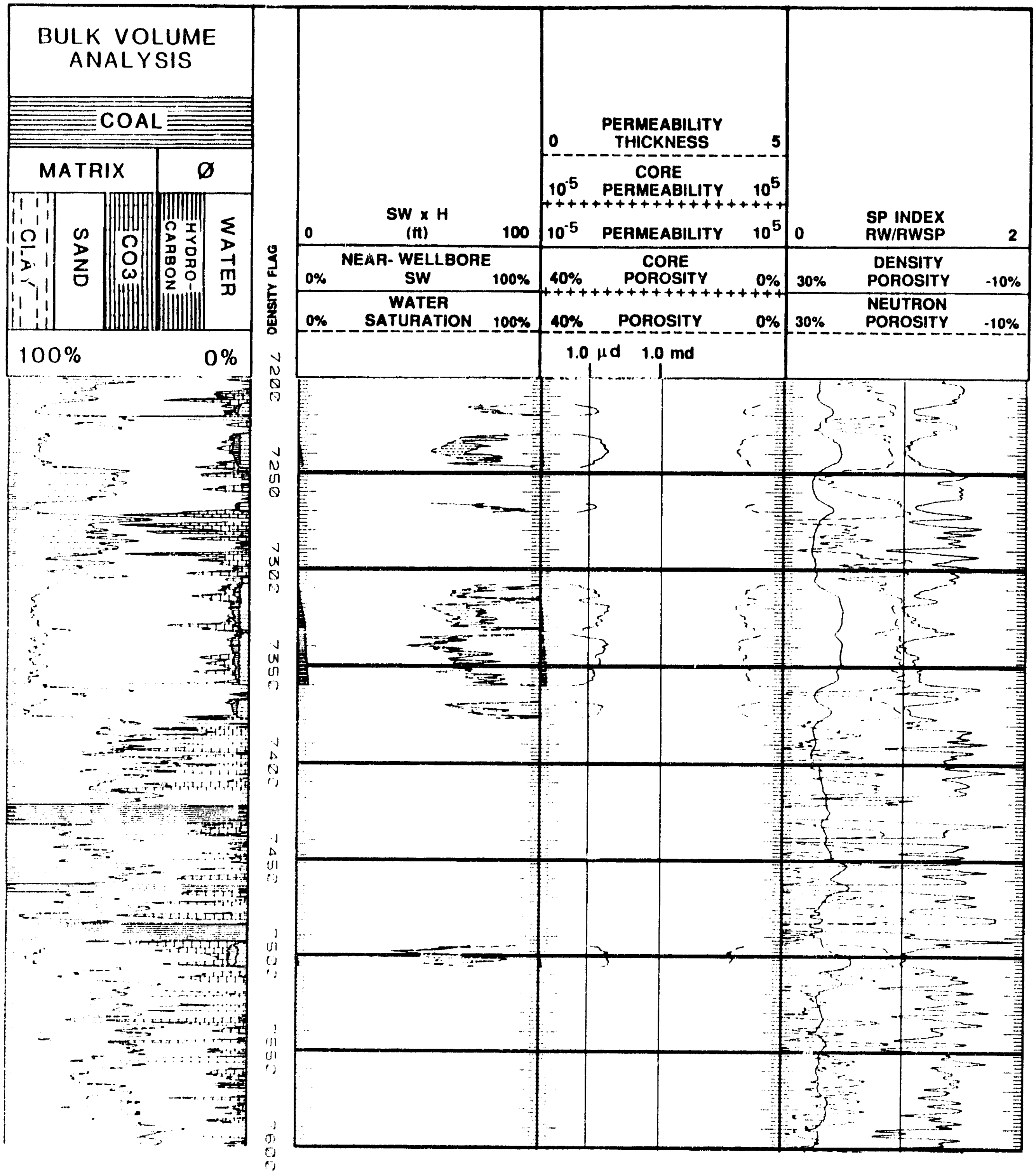

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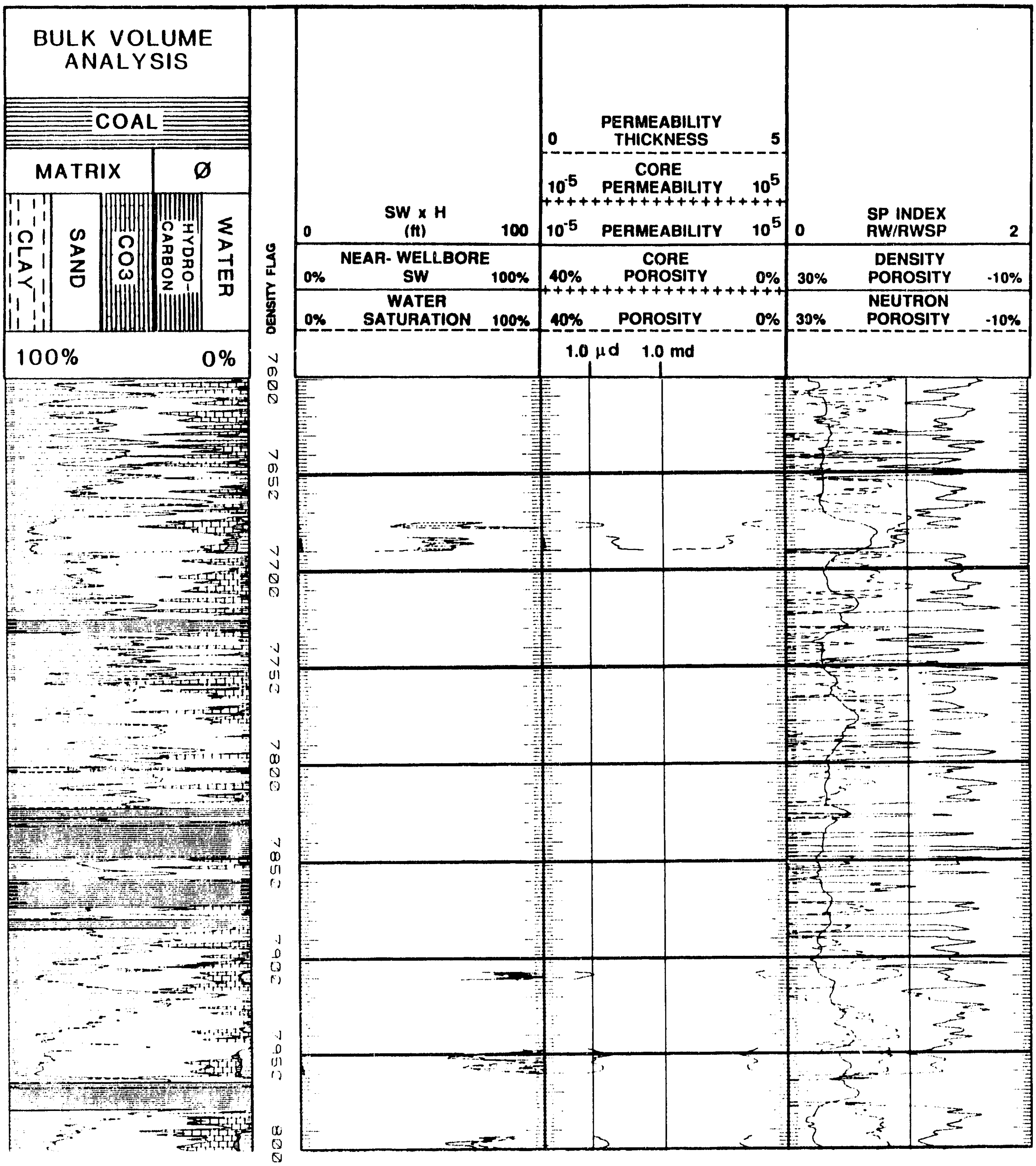

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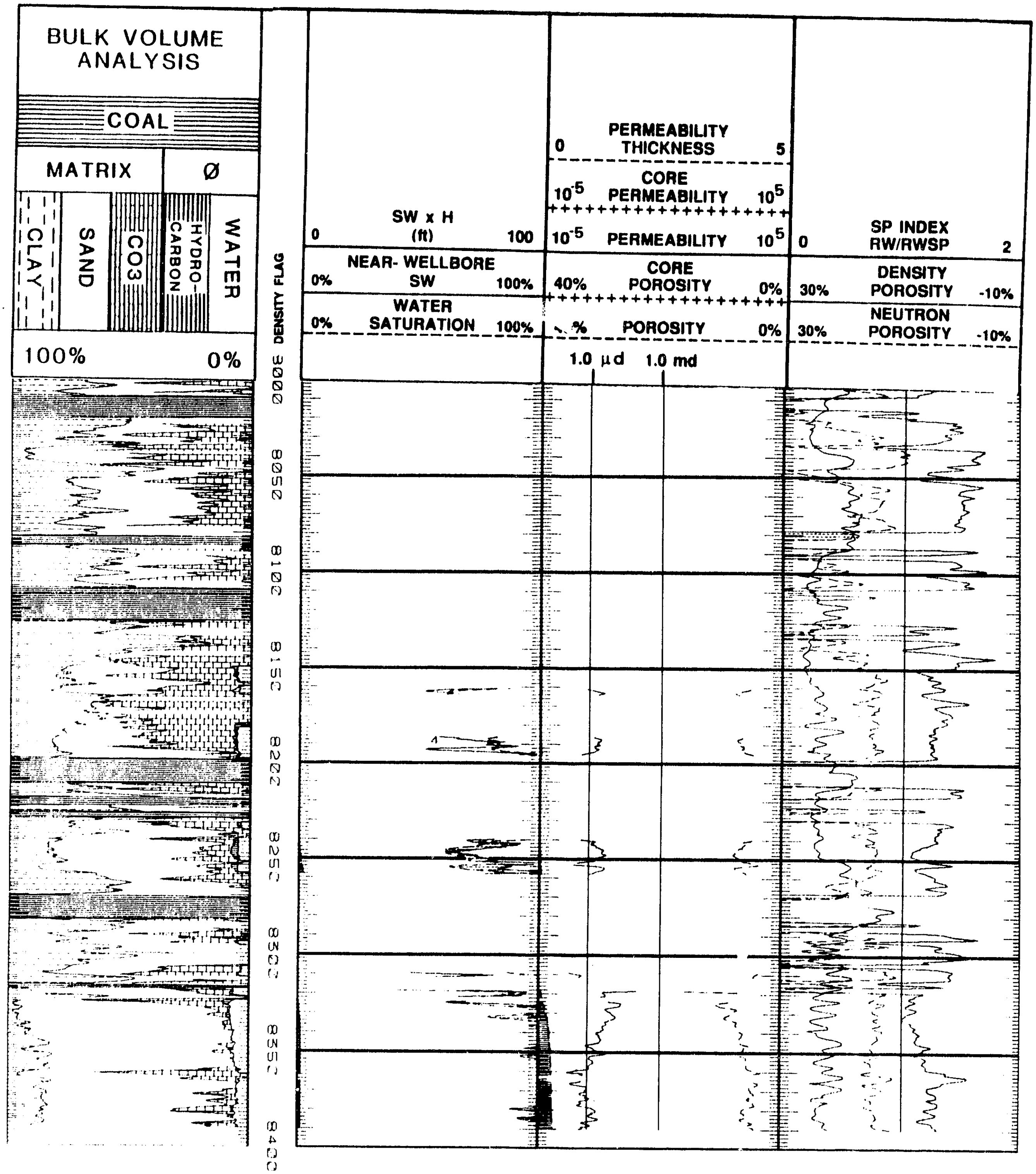


Figure 31, Continued

Table 7 Key Reservoir Parameters and Zone Designations for John Brown E&C Inc. DOE No. 1-M-17, 8,390.0 to 6526.5 ft

INTERVAL (FEET)	ZONE	GROSS H (FT)	NET H (FT)	AVG Ø (%)	MAX Ø (%)	AVG SW (%)	MIN SW (%)	HCFT (FT)	KH (MD-FT)	MAX K (MD)	AVG CLAY (%)	MIN CLAY (%)	SP INDEX
8318.5-8390.0	P-1	72.0	67.5	6.3	10.9	96.7	60.4	0.219	0.299	0.025	12.3	2.2	***
8309.0-8311.5	P-2	3.0	3.0	4.2	4.7	95.3	86.1	0.005	0.001	0.001	20.5	15.1	***
8240.0-8258.0	P-3	18.5	18.0	6.6	8.2	71.7	60.7	0.349	0.044	0.005	10.6	13.3	***
8186.5-8195.5	P-4	9.5	9.5	6.5	7.5	84.0	77.1	0.103	0.019	0.003	20.6	18.8	***
8161.0-8164.0	P-5	3.5	3.5	6.7	7.9	69.5	61.4	0.074	0.008	0.004	21.0	18.2	***
7993.5-8000.0	P-6	7.0	7.0	7.0	8.0	79.0	69.5	0.107	0.020	0.004	20.2	16.9	***
7947.5-7960.5	P-7	13.5	13.5	6.0	8.7	81.0	62.7	0.169	0.027	0.006	16.1	12.0	***
7907.0-7911.0	P-8	4.5	4.5	4.4	5.3	89.4	79.0	0.022	0.003	0.001	16.4	12.0	***
7675.5-7690.0	P-9	15.0	11.0	8.6	11.1	50.5	31.4	0.482	0.167	0.020	12.7	9.0	***
7495.0-7506.0	P-10	11.5	11.5	7.9	9.0	58.0	44.8	0.386	0.065	0.009	14.4	8.7	***
7368.0-7377.0	C-1	9.5	9.5	6.1	7.5	76.6	61.7	0.148	0.021	0.004	12.5	7.4	0.409
7308.0-7360.0	C-2	52.5	51.0	6.0	7.9	67.9	51.2	1.035	0.132	0.008	13.5	9.4	0.498
7266.0-7270.5	C-3	5.0	5.0	5.3	6.1	80.6	71.8	0.054	0.006	0.002	11.5	8.3	0.421
7229.5-7247.0	C-4	18.0	18.0	6.5	7.8	68.6	55.3	0.386	0.052	0.006	15.1	11.5	0.479
7214.0-7220.0	C-5	6.5	6.5	5.7	6.9	82.6	72.4	0.069	0.009	0.003	14.9	11.7	0.412
7183.0-7192.0	C-6	9.5	9.5	5.8	8.1	78.0	58.8	0.138	0.016	0.004	17.9	12.9	0.393
7137.5-7151.0	C-7	14.0	14.0	7.9	10.3	63.3	48.9	0.425	0.102	0.020	11.2	7.2	0.472
7087.0-7104.5	C-8	18.0	18.0	7.3	10.1	67.4	49.6	0.446	0.081	0.017	12.4	9.0	0.426
7046.0-7049.0	C-9	3.5	3.5	5.1	6.1	78.2	67.0	0.041	0.004	0.002	10.1	6.1	0.316
6962.5-6969.5	C-10	7.5	7.5	5.3	6.5	73.9	62.0	0.107	0.010	0.003	12.8	6.2	0.304
6922.5-6929.5	C-11	7.5	7.5	5.9	7.4	69.5	53.0	0.150	0.023	0.007	13.6	7.1	0.325
6907.5-6915.0	C-12	8.0	8.0	7.4	10.7	53.4	33.1	0.300	0.073	0.031	20.1	12.3	0.412
6899.5-6903.0	C-13	4.0	4.0	5.5	6.6	66.8	55.2	0.077	0.007	0.003	18.7	17.1	0.371
6827.0-6867.0	F-1	40.5	40.5	6.3	11.2	55.3	36.0	1.176	0.187	0.039	12.8	6.6	0.633
6802.0-6821.0	F-2	19.5	19.5	6.7	10.3	53.1	44.8	0.629	0.106	0.010	13.1	6.7	0.395
6773.5-6796.0	F-3	23.0	23.0	7.9	11.0	48.7	35.4	0.947	0.259	0.020	10.4	4.4	0.509
6721.5-6760.0	F-4	39.0	35.0	6.5	8.5	67.3	44.0	0.767	0.091	0.009	18.2	6.7	0.399
6688.0-6694.0	F-5	6.5	6.5	6.6	7.8	59.7	51.4	0.180	0.032	0.008	9.1	3.0	0.451
6555.0-6580.0	F-6	25.5	25.5	8.3	10.5	51.8	41.1	1.053	0.315	0.030	8.5	4.2	0.449
6526.5-6530.0	F-7	4.0	4.0	9.0	13.3	57.1	50.5	0.157	0.038	0.026	19.8	15.8	0.315

Table 8 Key Reservoir Parameters and Zone Designations for John Brown E&C Inc. DOE No. 1-M-17, 6,518.5 to 4,723.0 ft

INTERVAL (FEET)	ZONE	GROSS H (FT)	NET H (FT)	AVG Ø (%)	MAX Ø (%)	AVG SW (%)	MIN SW (%)	HCFT (FT)	KH (MD-FT)	MAX K (MD)	AVG CLAY (%)	MIN CLAY (%)	SP INDEX
6513.0-6518.5	F-8	6.0	6.0	6.9	9.9	62.8	40.0	0.165	0.029	0.016	19.4	13.9	0.387
6488.0-6495.5	F-9	8.0	8.0	8.4	13.4	66.8	40.4	0.263	0.108	0.055	12.0	5.2	0.294
6476.5-6479.5	F-10	3.5	3.5	6.2	9.7	71.7	57.9	0.067	0.009	0.009	14.4	11.6	0.252
6380.5-6407.0	F-11	27.0	27.0	8.3	10.0	52.8	36.2	1.092	0.355	0.034	6.6	2.3	0.586
6345.5-6348.5	F-12	3.5	3.5	8.4	10.9	56.3	48.0	0.127	0.021	0.011	20.1	16.7	0.312
6312.0-6320.5	F-13	9.0	9.0	8.3	9.4	53.5	44.3	0.356	0.097	0.020	11.7	4.5	0.410
6251.0-6266.0	F-14	15.5	14.5	5.7	7.7	62.2	48.3	0.334	0.054	0.010	8.6	4.8	0.476
6229.0-6236.0	F-15	7.5	7.5	6.7	8.4	51.7	36.7	0.246	0.045	0.015	12.6	8.5	0.420
6204.0-6212.5	F-16	9.0	9.0	5.2	7.6	62.6	47.1	0.179	0.019	0.006	13.1	5.1	0.380
6125.0-6169.0	F-17	44.5	41.5	6.5	9.3	53.9	43.9	1.273	0.224	0.016	9.4	4.4	0.450
6050.0-6082.0	F-18	32.5	30.5	6.5	8.7	51.5	42.4	0.959	0.141	0.017	14.3	4.5	0.546
6018.0-6021.0	F-19	3.5	3.5	5.1	6.0	59.2	48.0	0.072	0.006	0.004	14.6	24.2	0.282
5953.0-5972.5	FT-1	20.0	9.5	7.7	10.6	46.7	37.9	0.397	0.050	0.015	17.2	12.7	1.540
5917.5-5928.0	FT-2	11.0	8.0	6.5	10.5	35.9	29.0	0.334	0.029	0.020	18.3	9.3	1.224
5811.5-5840.0	FT-3	29.0	7.5	7.1	10.9	60.6	48.9	0.223	0.027	0.012	23.6	23.0	0.459
5803.0-5805.0	FT-4	2.5	2.5	10.0	10.7	54.1	52.4	0.116	0.023	0.012	22.3	21.1	0.435
5749.0-5770.5	FT-5	22.0	22.0	9.3	12.7	75.9	50.5	0.568	0.392	0.047	10.2	4.1	0.644
5717.0-5721.5	FT-6	5.0	5.0	9.1	12.7	58.6	41.6	0.200	0.055	0.020	13.5	6.6	0.584
5632.5-5656.0	FT-7	24.0	19.5	5.3	9.5	97.4	77.8	0.041	0.039	0.016	10.0	3.1	0.835
5584.0-5604.5	FT-8	21.0	20.0	9.1	14.9	99.9	98.5	0.001	0.055	0.094	9.1	2.8	1.771
5506.5-5525.5	FT-9	19.5	17.0	5.3	8.4	94.8	74.0	0.051	0.031	0.008	13.4	5.9	1.109
5275.0-5297.5	W-1	23.0	22.5	4.9	8.1	97.7	64.1	0.037	0.028	0.002	12.0	7.5	1.643
5245.0-5249.5	W-2	5.0	5.0	5.9	8.9	94.3	75.4	0.024	0.016	0.001	10.5	8.0	1.621
5196.5-5204.5	W-3	8.5	8.5	5.0	8.1	94.9	72.9	0.025	0.010	0.006	10.9	7.4	1.123
5096.0-5115.0	W-4	19.5	19.5	7.4	12.2	82.9	60.3	0.302	0.179	0.044	7.7	2.9	1.548
5069.0-5082.0	W-5	13.5	11.0	5.5	9.1	95.2	65.9	0.045	0.037	0.013	8.1	1.9	1.476
4970.5-5019.0	W-6	49.0	40.0	5.0	10.4	96.5	68.5	0.115	0.097	0.024	8.3	3.2	1.692
4790.0-4878.5	W-7	89.0	54.0	8.4	11.6	95.1	69.0	0.263	0.337	0.018	20.3	16.2	2.151
4723.0-4745.5	W-8	23.0	8.5	5.6	9.3	96.8	83.1	0.017	0.019	0.008	13.8	6.9	1.544

single natural fracture in a wellbore appears to be happenstance and says little about the relative importance of natural fractures to the gas production from any given zone.

A comparison of log-derived permeability indicators for the thicker zones in the coastal and fluvial sub-intervals is presented in the following figures. There is a positive correlation between the maximum permeability that is calculated in a zone and the SP Index of that zone as shown in Figure 32. There is a positive correlation of the permeability-feet (kh) that is calculated for a zone and the flushing index of that zone as shown in Figure 33. There is also a positive correlation of the zonal flushing index and the zonal SP Index as shown in Figure 34.

The SP analysis above 6,000 ft is not reliable as a permeability indicator. The theory of this index assumes that 100% of the SP development is due to the electrochemical component of the SP. Above 6,000 ft the SP Index is frequently greater than 1.0. This is interpreted to mean that there is a large electrokinetic SP component or "streaming potential". This phenomenon is often observed in cases of unusually large pressure differential such as when heavy drilling mud is used. The higher SP Index above 6,000 ft indicates that the shallower sands have lower pressure. This is further interpreted to mean that these sands do not trap gas as effectively as in the more overpressured reservoirs.

Completions of the DOE No. 1-M-17 to date have been performed in five stages. The first stage included the lower Cameo coals over the interval 8,280 to 8,083 ft. The perforations were isolated and broken down through tubing. This interval did not appear productive. No fracture treatment was performed over this interval.

The second stage treatment included hydraulic fracturing of the middle Cameo coals and P-9. These multiple coal and sandstone reservoirs extend vertically over the interval 8,041 to 7,646 ft. Refer to tables 7 and 8 for the individual coal and sandstone designations. Prior to fracturing, the perforations were broken down using ball sealers to sequentially isolate perforations, assuring that each reservoir would be adequately connected to the wellbore during the main fracture treatment. The main fracture treatment was performed using a gel-water hydraulic fluid and 20/40 mesh sand as a fracture propping agent. After 72 hours of flow testing these intervals were capable of producing at a rate of 784 MCFD against a surface tubing pressure of 560 psi.

The third stage treatment included hydraulic fracturing of three individual reservoirs, the upper Cameo coal, P-10, and two Mesaverde sandstones, C-1 and C-2. These reservoirs extend vertically over the interval 7,503 to 7,315 ft. Prior to fracturing, the perforations were broken down using ball sealers to sequentially isolate perforations assuring that each reservoir would be adequately connected to the wellbore during the main fracture treatment. The main fracture treatment was performed using a gel-water hydraulic fluid and 20/40 mesh sand as a fracture propping agent. There were indications of probable communication with the stage two completion during the stage three treatment. After 142 hours of flow testing, these three intervals were capable of producing at a rate of 1,252 MCFD against a surface tubing pressure of 200 psi.

The fourth stage treatment involved only Mesaverde sandstones C-3, C-4, C-5, C-6, C-7, C-8, C-9, C-10, and C-11. These nine reservoirs extend vertically over the interval 7,269 to 6,925 ft. Prior to performing a breakdown of the perforations, dry gas was readily flowed from

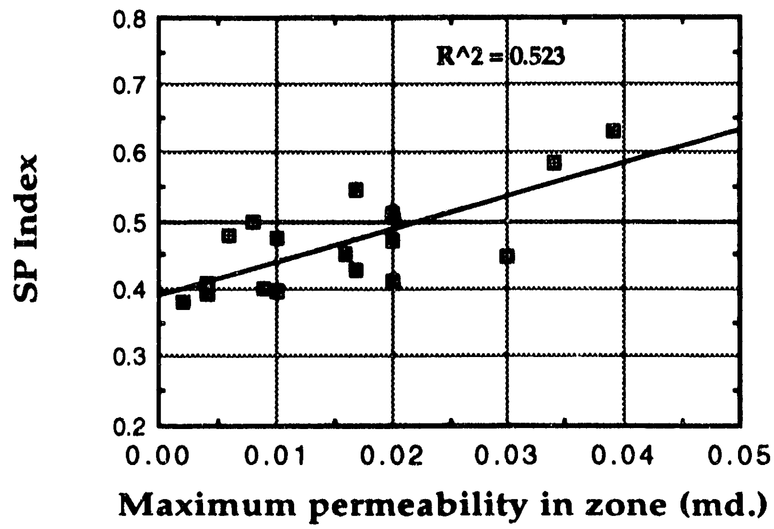


Figure 32 Maximum Permeability in Zone versus SP Index, DOE 1-M-17

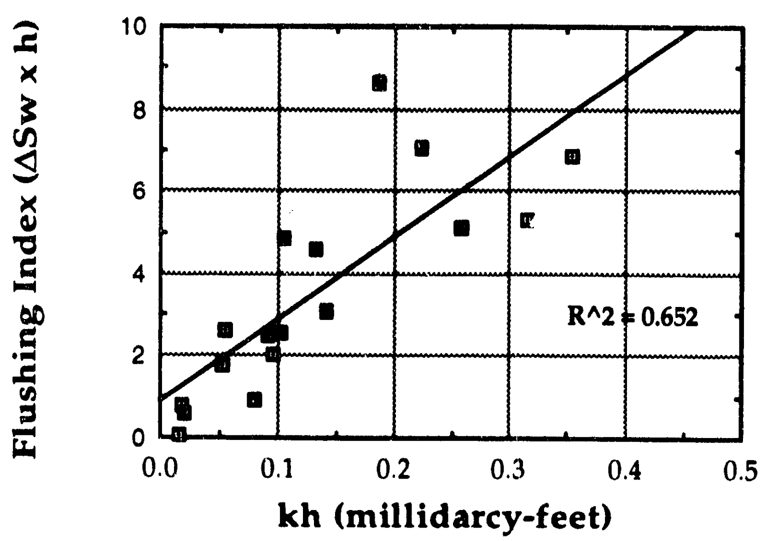


Figure 33 Permeability-Feet (kh) versus Flushing Index (ΔSw x h), DOE 1-M-17

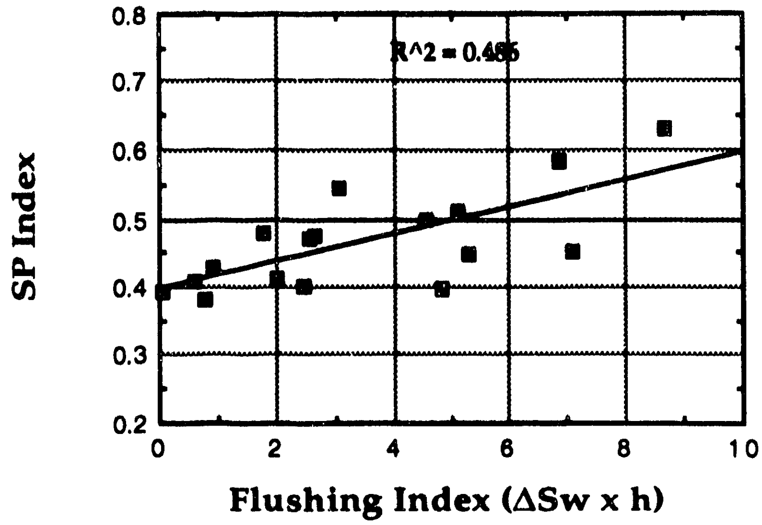


Figure 34 Flushing Index versus SP Index, DOE 1-M-17

the well. Subsequently these perforations were broken down using ball sealers to sequentially isolate the nine perforated intervals assuring that each reservoir would be adequately connected to the wellbore during the main fracture treatment. The main fracture treatment involved a 70 quality (percent volume) nitrogen, N_2, foam with a 40# linear gel water based fluid. The created frac was propped with 20/40 mesh sand. Following 170 hours of flow testing these intervals were capable of producing at a rate of 1,753 MCFD against a surface tubing pressure of 280 psi.

The fifth and final stage treatment was directed at 5 Mesaverde sandstones, F-1, F-2, F-3, F-4, and F-5. These reservoirs extend over the vertical interval 6,860 to 6,688 ft. Prior to performing a breakdown of the perforations, dry gas was readily flowed from the well. Subsequently these perforations were broken down using ball sealers to sequentially isolate the five perforated intervals assuring that each reservoir would be adequately connected to the wellbore during the main fracture treatment. The main fracture treatment involved a 70 quality N_2 foam with a 40# linear gel water based fluid. The created frac was propped with 20/40 mesh sand. After 311 hours of flow testing these intervals were capable of producing at a rate of 3,196 MCFD against a surface tubing pressure of 940 psi.

The DOE No. 1-M-17 well shows high production potential, especially in the fluvial Mesaverde section. The high potential reinforces the importance of natural fractures as a control to the production of gas in the Central Basin partitioned area. CER interprets that the high production potential is also reflective of the local development of relatively thick, clean and porous fluvial sands.

2.6 ORYX ACAPULCO FEDERAL UNIT NO. 1

During 1991, Oryx drilled a significant Central Basin horizontal test of the Cozzette sandstone. This well was the Acapulco Federal Unit #1 HD in Section 16, T8S, R92W, in Mesa County

(Figure 3). The well is positioned near the Piceance Basin axis to the west of the Divide Creek anticline. It is approximately 1,500 ft structurally higher than MWX.

In the Acapulco well, Oryx initially drilled a vertical pilot through the Corcoran interval and cut three oriented cores in the Mancos shale and Cozzette and Corcoran sandstones. The well was then plugged back, and a high angle lateral of 1,745 ft was drilled toward N20°E. A Formation Microscanner (FMS) was run in the lateral open hole in the Corcoran and Cozzette for fracture characterization.

2.6.1 Fracture Orientations and Spacing

Strikes of both drilling-induced and natural fractures in the Cozzette and Corcoran sandstones are shown in Figures 35 and 36 respectively. In both units, both natural and drilling induced fractures are essentially parallel, near vertical, and strike west-northwest. The induced fractures indicate the principal in-situ stress is oriented parallel to the natural fracture strikes. Oryx reports that the strike of virtually all fractures identified on the FMS (believed to be mostly induced fractures) was within 20° of N70°W and dips are near vertical. Both the natural fracture and in-situ stress orientations are therefore very similar to those at the MWX site about 14 miles toward the northwest.

The FMS data in the lateral wellbore also showed an average of 62 fractures per 100 ft. Fractures with high relative intensity on the log were noted at an average spacing of one every 3.3 ft. Maximum spacing between fractures is 16 ft. This fracture spacing is similar to that at the MWX location, as reported by Lorenz and Hill, 1991.

2.6.2 Test for Productivity

Because of problems with bottomhole pressure measurement, Oryx flowed the well to establish a rate. After swabbing for two hours the well began flowing ten barrels of water per hour, increasing steadily to 76 barrels per hour. After 16 days the well had produced over 20,000 barrels of drilling fluid and water with only a small amount of gas.

Salinity analyses taken throughout the flow period indicated that the chloride levels were typical of formation water in the area. An Oxygen Activation Log indicated that the majority of the water entry was from the upper Cozzette. This zone correlated to a zone of high water loss during drilling. Oryx thus decided that the formation water saturation was above irreducible and the well was subsequently plugged and abandoned.

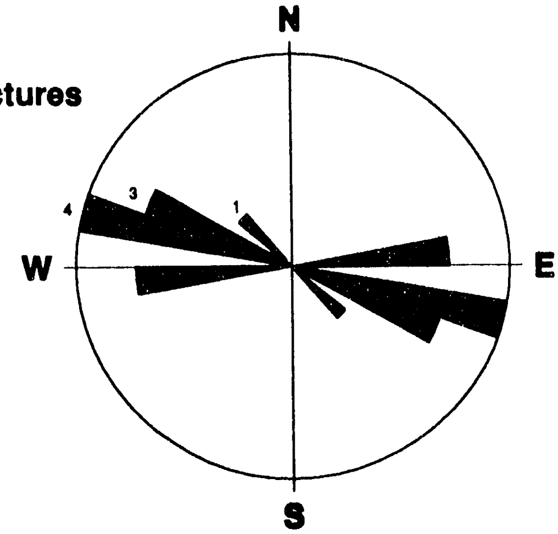
2.7 ORYX COLLIER CREEK WELL

Oryx drilled their second horizontal Cozzette attempt in the Central Basin area in Section 25, T8S, R94W, in Mesa County. The well is approximately eleven miles south of the MWX site and 1,500 ft updip. The Collier Creek well was also drilled in a N20°E direction. An FMS log was run in the lateral but no cores were taken.

2.7.1 Fracture Orientations and Spacing

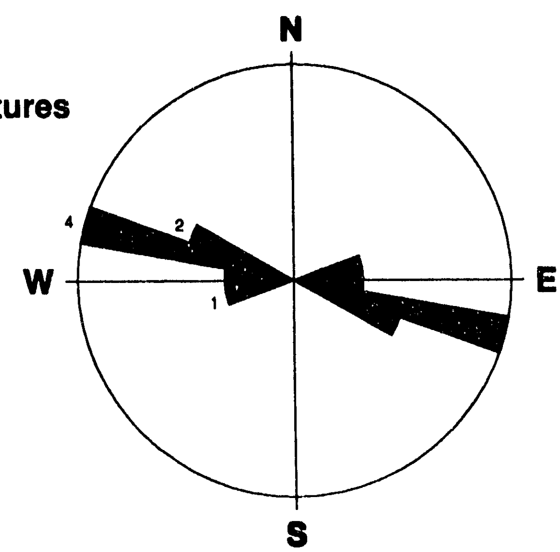
Strikes of fractures identified on the FMS log are shown in Figure 37. The interpretation from the FMS imagery reveals a dominant strike of near vertical fractures (probably natural fractures) of approximately N85°W. The number of fractures observed on the FMS was high, but not nearly as high as the Acapulco or SHCT walls. Oryx reports that average fracture spacing is ten feet. Apparent fracture aperture was considered less than those imaged at the

A. Induced Fractures



Oryx Alcapulco Fed #1	
Core 2	N = 11
Depth = 8,654 - 8,684 ft	Class Interval = 10°

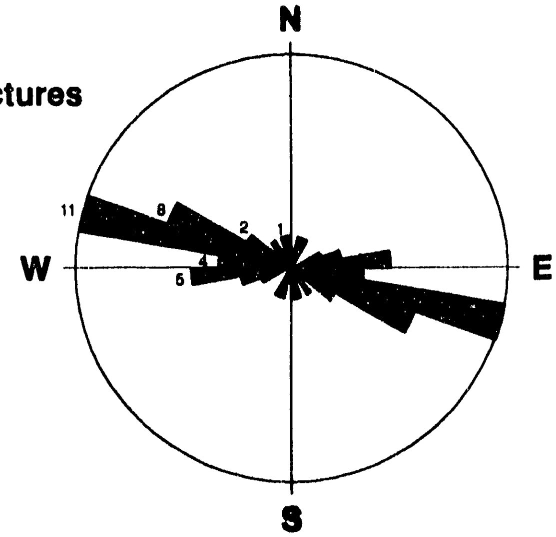
B. Natural Fractures



Oryx Alcapulco Fed #1	
Core 2	N = 8
Depth = 8,654 - 8,684 ft	Class Interval = 10°

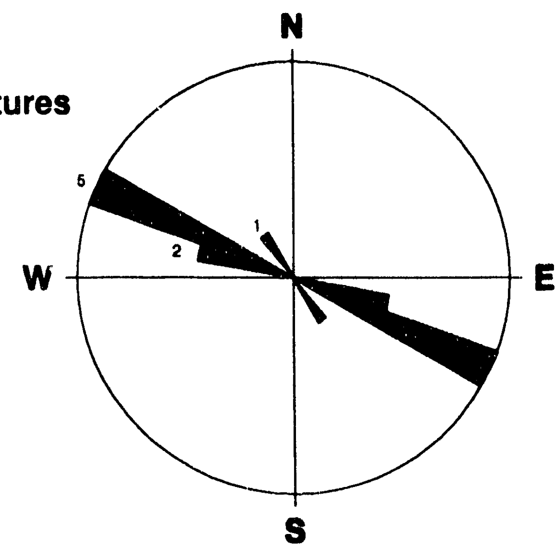
Figure 35 Strikes of Induced Fractures (A) and Mineral Filled Natural Fractures (B) in Cozzette core, Oryx Acapulco Fed. No. 1

A. Induced Fractures



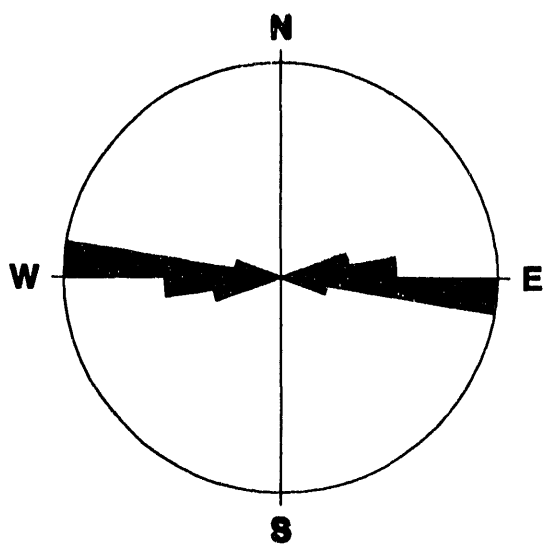
Oryx Alcapulco Fed #1	
Core 3	N = 36
Depth = 8,854 - 8,885 ft	Class Interval = 10°

B. Natural Fractures



Oryx Alcapulco Fed #1	
Core 3	N = 8
Depth = 8,854 - 8,885 ft	Class Interval = 10°

Figure 36 Strikes of Induced Fractures (A) and Mineral Filled Natural Fracture (B) in Corcoron Core, Oryx Acapulco Federal No. 1



Oryx Collier Creek	
	N = 196
Depth = 8,990 - 10,857 ft	Class Interval = 10°

Figure 37 Strikes of Near Vertical Fractures Identifed on the FMS in the Interval 8,990 ft to 10,857 ft, Oryx Acapulco Federal No. 1

Acapulco well. Although fracture classification is not certain on the FMS log, the similarity of these results to those at the Acapulco well indicates that natural fractures are probably similar to those at the MWX site.

2.7.2 Test for Productivity

While drilling the lateral hole in the Cozzette, there were numerous "flares of gas", especially on trips and connections. The largest flare was estimated to be 100 ft. The 4-1/2 in. liner was run across the Cozzette and the well was flow tested three days. Highest gas rate was a brief surge at 1.5 MCFD. Flow stabilized at 150 MCFD and 12.2 barrels of water per hour. The well was subsequently plugged and abandoned.

2.8 FUELCO E-22-10-94-S

The Fuelco FEE-E-22-10-94-S E-22-10-94-S cooperative well was drilled in Section 22, T10S, R94W, in Mesa County. The objectives were the Corcoran and Cozzette sandstones and secondarily the Mesaverde paludal coals. The well is a southeastward stepout from the eastern part of the Plateau Field which predominately produces from the Corcoran and Cozzette.

Projected ultimate production in the Plateau Field, from the Phase I report, is shown in Figure 38. The best production in the field is along the eastern edge which contains four wells that will each have cumulative production greater than 1 BCF, and one of these may produce more than 2 BCF. These wells had never been directly offset to the east because of the rugged topography, so the field limits were not known. The Fuelco location, shown in Figure 3, was

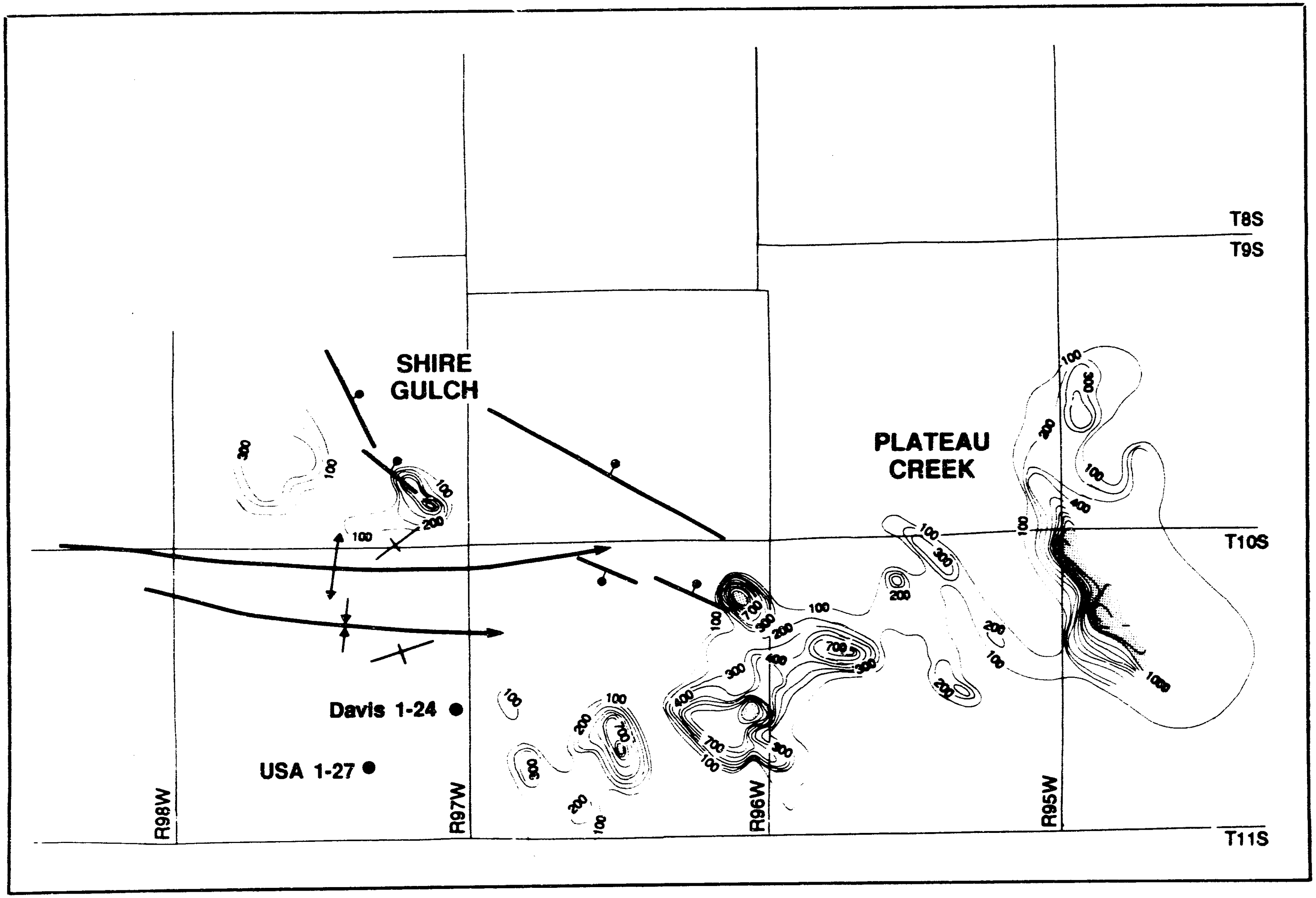


Figure 38 Projected Ultimate Production from the Plateau Field with Areas Greater than 1 BCF Shaded (from Myal et al., 1989)

selected as a co-op well to examine the nature of this better production. TITEGAS log analysis of offsetting wells in the Phase I study suggested that the production can be attributed, in part, to the better matrix quality of the reservoir. It was also believed that natural fractures could have an influence on production. There was no fracture information in the Plateau Field on which to base this conclusion. A field verification test program was designed to determine the significance of natural fractures to production. The test program consisted of oriented coring of the two marine sandstone intervals, analyzing logs with the TITEGAS log analysis model, running and analyzing borehole image logs, and pressure transient testing of the Cozzette interval.

2.8.1 Formation Evaluation

The formation evaluation of the Fuelco E-22-10-94-S well (E-22) includes the integration of core data with log data. The logging program was as follows:

	Service	Logged Interval
1.	Dual Induction Guard Log/SP/GR	7,259 to 1,802 ft
2.	Microlog	7,240 to 5,240 ft
3.	Spectral Density/Caliper	7,248 to 3,091 ft
4.	Dual Spaced Neutron Log	7,222 to 3,091 ft
5.	Circumferential Acoustic Scanning Tool	7,204 to 5,320 ft
6.	Formation Microscanner	Selected intervals
7.	Nuclear Magnetic Log	Selected intervals

The borehole imaging logs were funded by DOE. The remainder of the expanded logging program was funded by the Gas Research Institute to support the GRI formation evaluation research that was conducted by Bergeson and Associates. CER witnessed the logging operation. The logging adhered to the DOE tight gas sand log quality control standards.

CER selected sample depths of the Corcoran and Cozzette core in the field. Following the lithologic and fractographic field descriptions, CER sealed the core in saran wrap and Protec Core. The core was then sent to Core Laboratories, Inc. for analysis. Core gamma was run over the entire core. The core analysis included unsteady state (CMS 300) gas permeability and porosity at minimal net stress (800 psi) and at the approximate in-situ net stress (3,500 psi). A total of 45 plug samples were cut for this analysis (18 from the Corcoran and 27 from the Cozzette).

The well was analyzed using the TITEGAS log analysis model over the gross interval 7,214 to 5,100 ft. A description of the TITEGAS log analysis model is provided in Appendix 1. The gross interval was divided into 4 sub-intervals, and constants were refined individually for each sub-interval. The lowermost sub-interval includes the Corcoran and Cozzette section over the depths 7,214 to 6,750 ft. The second sub-interval includes the Rollins sandstone and paludal Mesaverde section over the depths 6,750 to 6,077 ft. The third sub-interval includes the fluvial Mesaverde gas-saturated section over the depths 6,077 to 5,500 ft. The upper sub-interval includes the fluvial Mesaverde gas-water transition section over the depths 5,500 to 5,100 ft. Core data was depth shifted to log data by correlating the core gamma with the wireline gamma ray log. Histograms of environmentally corrected log data were made for the principal log curves through each sub-interval. These histograms were compared to the log data norms that were developed for the Southwest Flank partitioned area during the Phase I TETWGS study. The log data is of good quality and no log data normalizations were required.

The formation water resistivities that were interpreted from log analysis through the marine Corcoran and Cozzette sub-interval varied with temperature from 0.117 to 0.123 ohm-m from 7,214 to 6,750 ft, respectively. This well subsequently produced water from the Cozzette and the log interpreted Rw was confirmed to be approximately correct. Water samples were collected from the separator over a one week period and showed that the formation water resistivity corrected to formation temperature is 0.140 ohm-m. The formation water resistivities for the Rollins and paludal Mesaverde sub-interval varied with temperature from 0.145 to 0.156 ohm-m from 6,750 to 6,077 ft, respectively. The formation water resistivities for the fluvial-gas sub-interval varied with temperature from 0.127 to 0.135 ohm-m from 6,077 to 5,500 ft, respectively. The formation water resistivities for the fluvial-transition sub-interval vary across the section. It is interpreted that this section is saturated with fresh water that is of meteoric origin. It is hypothesized that the meteoric water moves downdip from outcrop, interfingers with and mixes with the connate formation water. Over the interval 5,500 to 5,450, Rw is interpreted to be 0.90 ohm-m. Over the interval 5,450 to 5,300, Rw is interpreted to be 1.90 ohm-m. Over the interval 5,300 to 5,100, Rw is interpreted to be 1.10 ohm-m.

The log analysis results for porosity and permeability are compared directly to core porosity and permeability through the cored interval of this well on the TITEGAS computed logs shown in Figure 39. A description of the format for log analysis results is provided in Appendix A2. These results are also shown in Figures 40 and 41 as crossplots comparing log calculated porosity to core porosity and log calculated permeability to core permeability. Some of the core data is excluded from these comparisons because they are not a part of the net reservoir. The crossplots show ideal best fit lines. Figure 40 shows that most of the log and core porosities compare favorably. The correlation coefficient for porosity is 0.689. Log porosity predicts core porosity with a standard error of 1.79 p.u. The data shows unusually large scatter over the interval 6,944 to 6,955 ft because of the laminated character of the Cozzette through this section. This results in four points which plot significantly lower core porosity than log porosity. These differences relate to the vertical resolution of log data compared to small core plug samples. The correlation coefficient for permeability is 0.518. Log calculated permeability predicts core permeability with a standard error of 0.327 order of magnitude. This plot is also being affected by the laminated character of the reservoir. The equations that were used to calculate stressed absolute permeability from log data were developed by Kukal and Simons (1986) using the MWX petrophysical database. The least squares relationship shown in Figure 42 for the E-22 core data is very similar to the MWX porosity-permeability transform.

The log analysis results for the entire analyzed interval of the Fuelco E-22-10-94-S well are presented in Table 9 and Figure 43.

The Corcoran sandstone is subdivided into two individual zones over the gross interval 7,196 to 7,104 ft. These zones are identified on Table 9 as COR-1 and COR-2. The Corcoran is extremely shaly in this well and the reservoir characteristics are poor. For the COR-1 and COR-2 zones combined, the net thickness is 28.5 ft. Average porosity is 4.7 percent with a maximum log porosity of 6.6 percent and a maximum core porosity of 6.9 percent. Average water saturation is 72.4 percent with a minimum water saturation of 51.6 percent. The kh is 0.015 md-ft with a maximum log calculated permeability of 0.003 md and a maximum stressed core permeability of 0.002 md. Average clay volume is 25.0 percent with a minimum clay volume of 14.1 percent.

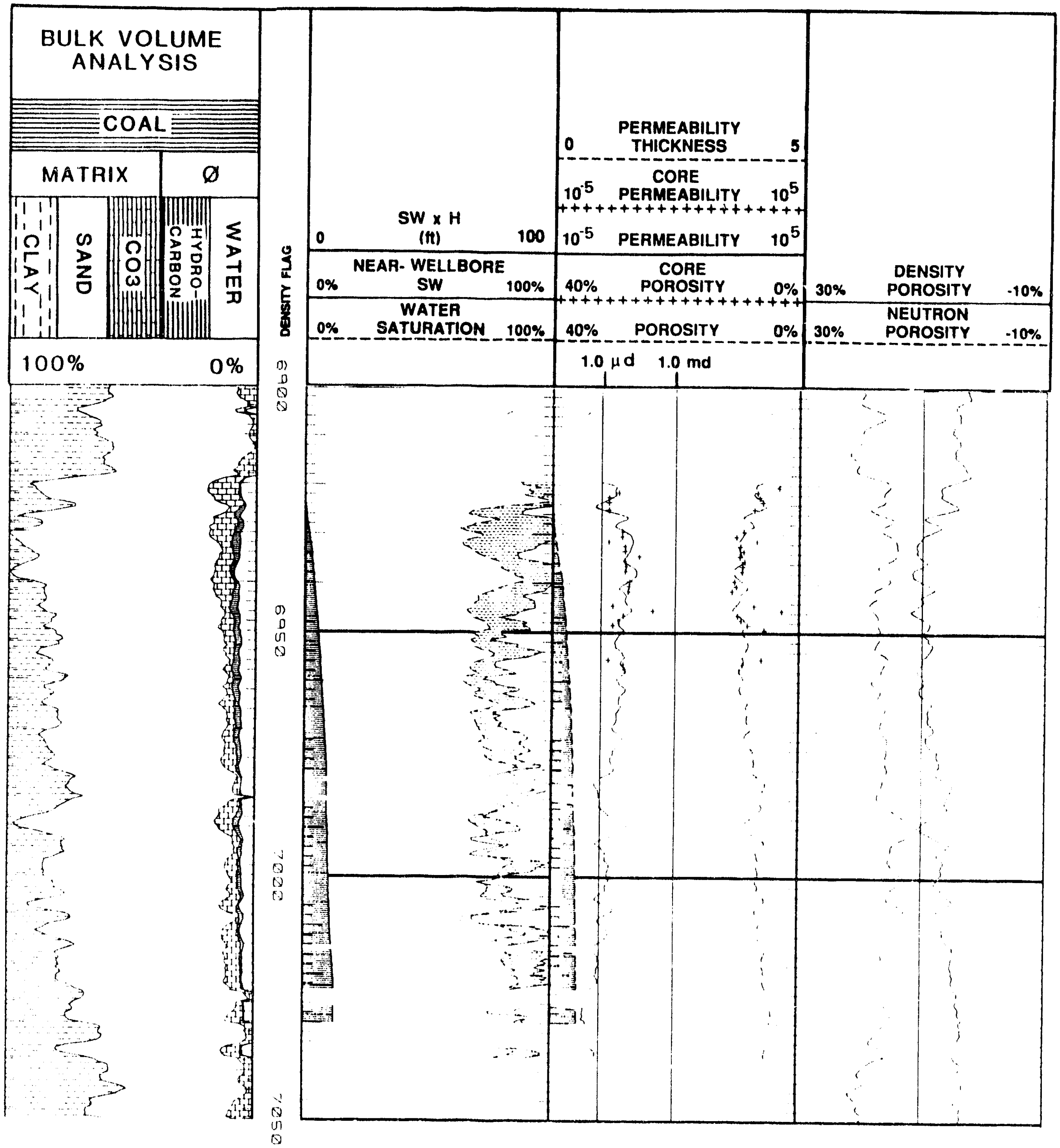


Figure 39 TITEGAS Computed Log Through Cored Interval, Fuelco E-22-10-94-S

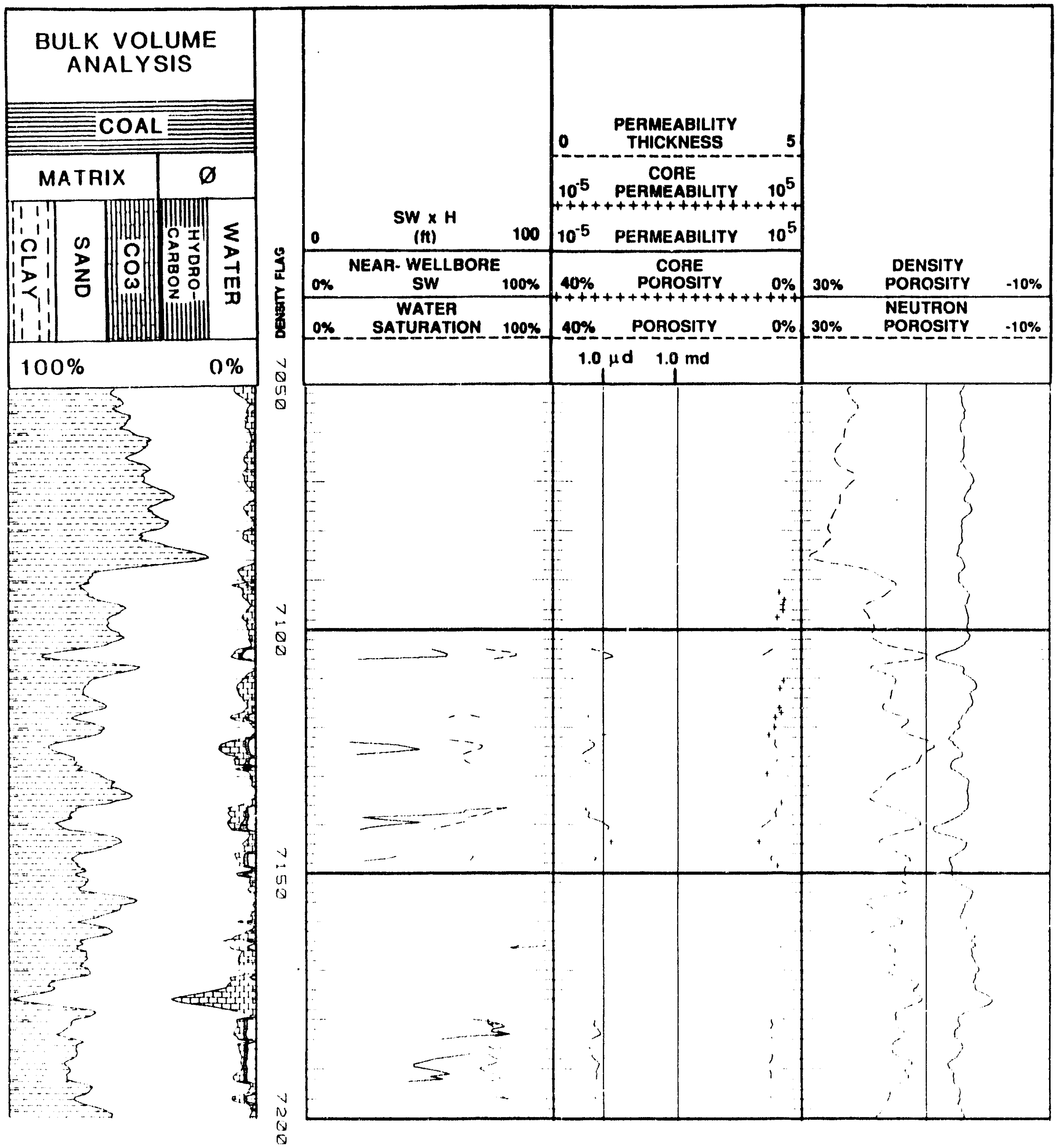


Figure 39, Continued

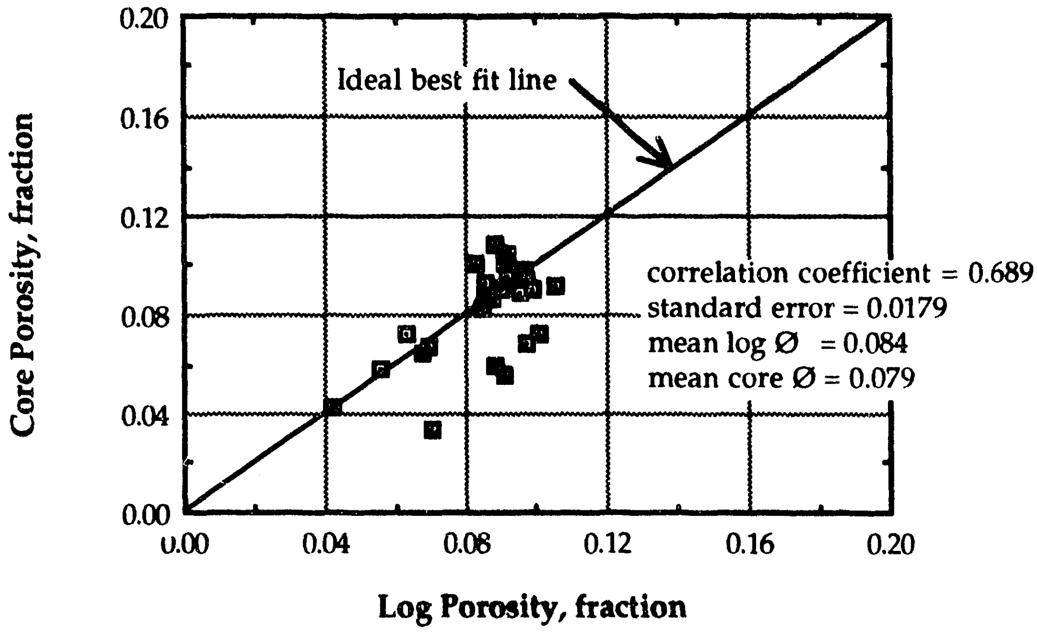


Figure 40 Log Porosity versus Core Porosity, Fuelco E-22-10-94-S

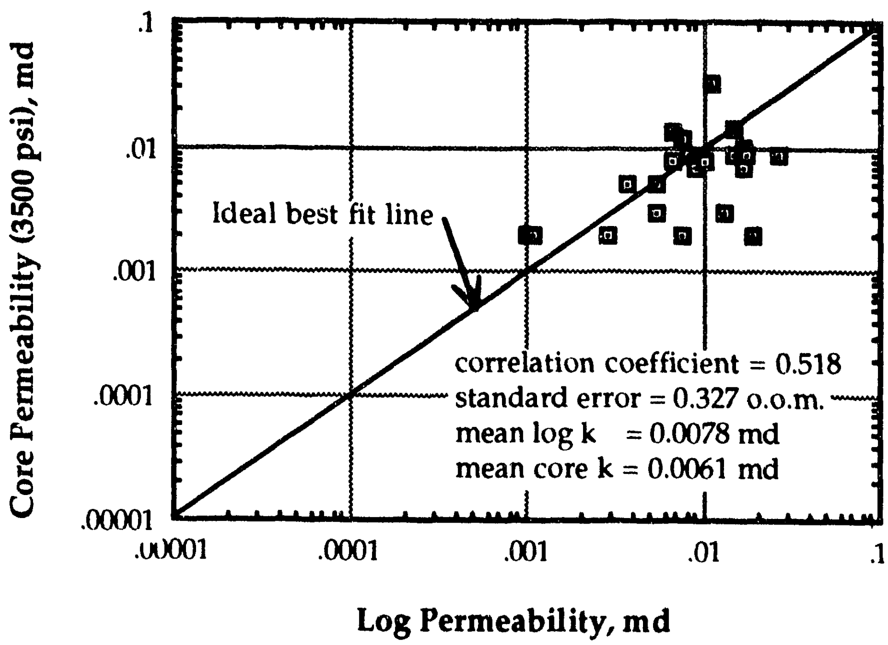


Figure 41 Log Permeability versus Core Permeability, Fuelco E-22-10-94-S

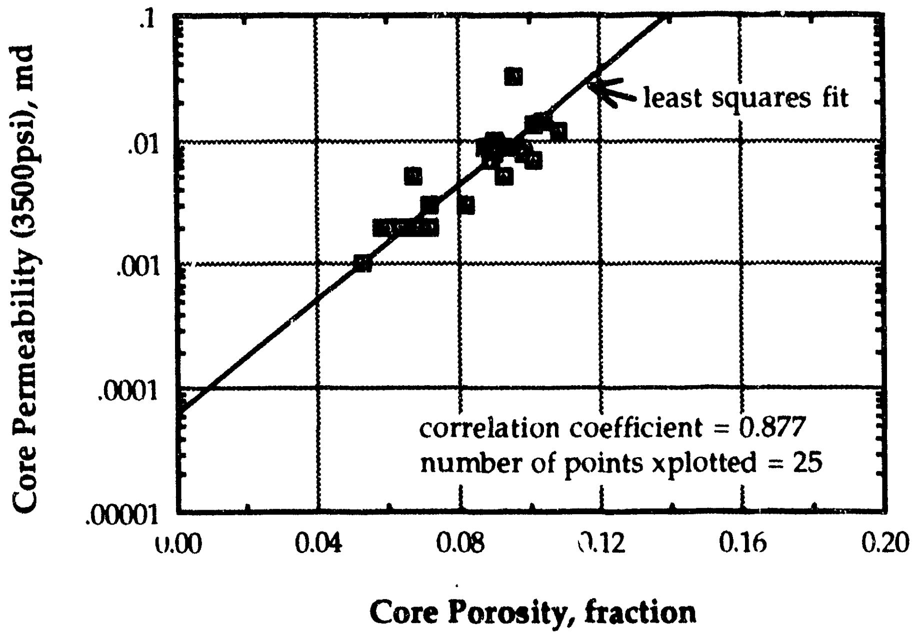


Figure 42 Core Porosity versus Core Permeability, Fuelco E-22-10-94-S

The TITEGAS analysis normally uses a clay volume cutoff of 25 percent, however since the Corcoran is very shaly and since there is core data, the clay volume cutoff was relaxed to 29 percent for the marine sub-interval of this well in order to gain additional points for log vs. core comparison. Increasing the clay volume cutoff adds to the net thickness of the Corcoran in this well, however it decreases the average porosity, increases the average water saturation and increases the average clay volume.

The Cozzette sandstone is subdivided into two zones over the gross interval 7,037 to 6,919.5 ft. These zones are numbered COZ-1 and COZ-2. The combined net thickness of the Cozzette is 109.0 ft. Average porosity is 7.3 percent with a maximum log porosity of 10.8 percent and a maximum core porosity of 10.8 percent. Average water saturation is 77.3 percent with a minimum water saturation of 62.8 percent. The kh is 0.549 md-ft with a maximum log calculated permeability of 0.027 md and a maximum stressed core permeability of 0.033 md. Average clay volume is 18.1 percent with a minimum clay volume of 0.1 percent. The water saturation of the Cozzette is interpreted to be greater than irreducible.

The Rollins sandstone is subdivided into four zones, numbered R-1 through R-4 over the gross interval 6,651 to 6,490 ft. The combined net thickness of the Rollins is 89.0 ft. Average porosity is 7.8 percent. A maximum porosity of 18.6 percent occurs at a depth of 6,578.5 ft. This porosity is anomalously high for any Mesaverde sand at this depth. The Nuclear Magnetic Log verifies that porosity is high. The corrected free fluid index measures between 9 and 10 p.u. It is probable that 18.6 percent represents both matrix porosity and fracture porosity. The borehole imaging logs at this depth show multiple intersecting fractures. Average water saturation is 89.5 percent with a minimum water saturation of 44.8 percent. The kh is 0.95 md-ft with a maximum log calculated permeability of 0.155 md. The anomaly at 6,578.5 ft is also responsible for the minimum water saturation value and the maximum log calculated permeability. Average clay volume is 13.9 percent with a minimum clay volume of

Table 9 Key Reservoir Parameters and Zone Designations for Fuelco FEE E-22-10-94-S

INTERVAL (FEET)	ZONE	GROSS H (FT)	NET H (FT)	AVG Ø (%)	MAX Ø (%)	AVG SW (%)	MIN SW (%)	HCFT (FT)	KH (MD-FT)	MAX K (MD)	AVG CLAY (%)	MIN CLAY (%)
7165.0-7196.0	COR - 1	31.5	13.5	4.8	5.3	76.6	70.1	0.153	0.006	0.001	26.2	20.3
7104.0-7147.5	COR - 2	44.0	15.0	4.7	6.6	68.7	51.6	0.223	0.009	0.003	24.0	14.1
6984.5-7037.0	COZ - 1	53.0	45.0	5.9	8.6	79.8	67.0	0.555	0.084	0.012	20.4	3.1
6919.5-6983.5	COZ - 2	64.5	64.0	8.3	10.8	75.5	62.8	1.350	0.465	0.027	16.5	0.1
6637.0-6651.0	R - 1	14.5	13.5	4.2	6.1	99.4	92.3	0.005	0.006	0.002	22.7	15.4
6544.0-6614.0	R - 2	70.5	38.5	8.5	18.6	89.4	44.8	0.451	0.480	0.155	16.6	7.2
6503.0-6538.0	R - 3	35.5	30.5	8.1	10.6	89.2	66.1	0.320	0.312	0.029	8.1	0.1
6490.0-6496.0	R - 4	6.5	6.5	10.3	11.5	70.4	66.0	0.200	0.152	0.040	6.7	0.0
6430.5-6436.0	P - 1	6.0	6.0	6.1	16.0	82.8	28.9	0.128	0.041	0.047	19.0	13.4
6405.0-6407.5	P - 2	3.0	3.0	5.8	6.7	76.5	67.6	0.042	0.003	0.002	22.7	21.4
6243.0-6254.0	P - 3	11.5	9.0	6.9	8.6	74.4	55.6	0.176	0.034	0.008	16.5	13.5
6218.5-6228.0	P - 4	10.0	7.0	5.3	6.3	78.4	71.9	0.084	0.006	0.002	21.9	19.7
6201.5-6205.5	P - 5	4.5	4.5	7.4	7.9	66.6	63.2	0.112	0.014	0.004	21.2	19.3
6064.0-6073.5	FG - 1	10.0	10.0	7.4	9.3	79.9	67.1	0.165	0.058	0.011	11.4	8.0
6052.0-6057.5	FG - 2	6.0	6.0	8.2	9.0	71.7	64.0	0.147	0.036	0.008	16.5	11.2
6009.0-6016.0	FG - 3	7.5	7.5	7.3	8.3	84.6	73.2	0.091	0.033	0.007	16.0	10.6
5988.5-5997.0	FG - 4	9.0	9.0	9.0	9.8	69.5	61.7	0.253	0.103	0.017	9.8	6.4
5876.0-5879.0	FG - 5	3.5	3.5	5.2	7.0	99.0	96.2	0.002	0.006	0.004	12.3	7.4
5731.5-5732.5	FG - 6	1.5	1.5	4.6	6.2	79.3	60.5	0.017	0.001	0.001	23.6	21.7
5543.5-5547.0	FG - 7	4.0	4.0	7.1	7.9	69.1	55.5	0.088	0.017	0.006	10.5	5.1
5457.5-5486.5	FT - 1	29.5	26.5	11.8	14.2	81.8	70.0	0.612	1.050	0.067	9.6	5.1
5392.5-5419.5	FT - 2	27.5	24.0	13.2	16.8	87.0	68.1	0.382	1.641	0.140	8.9	5.2
5331.5-5374.5	FT - 3	43.5	42.5	16.0	18.4	81.4	55.7	1.237	4.775	0.199	8.9	2.4
5226.5-5233.5	FT - 4	7.5	7.5	8.8	9.8	96.6	89.6	0.022	0.071	0.013	14.0	10.3
5194.0-5197.5	FT - 5	4.0	4.0	5.7	7.2	100.0	100.0	0.000	0.007	0.004	15.7	11.1
5133.5-5156.5	FT - 6	23.5	22.0	11.4	13.9	93.6	79.9	0.163	0.728	0.069	7.5	2.1

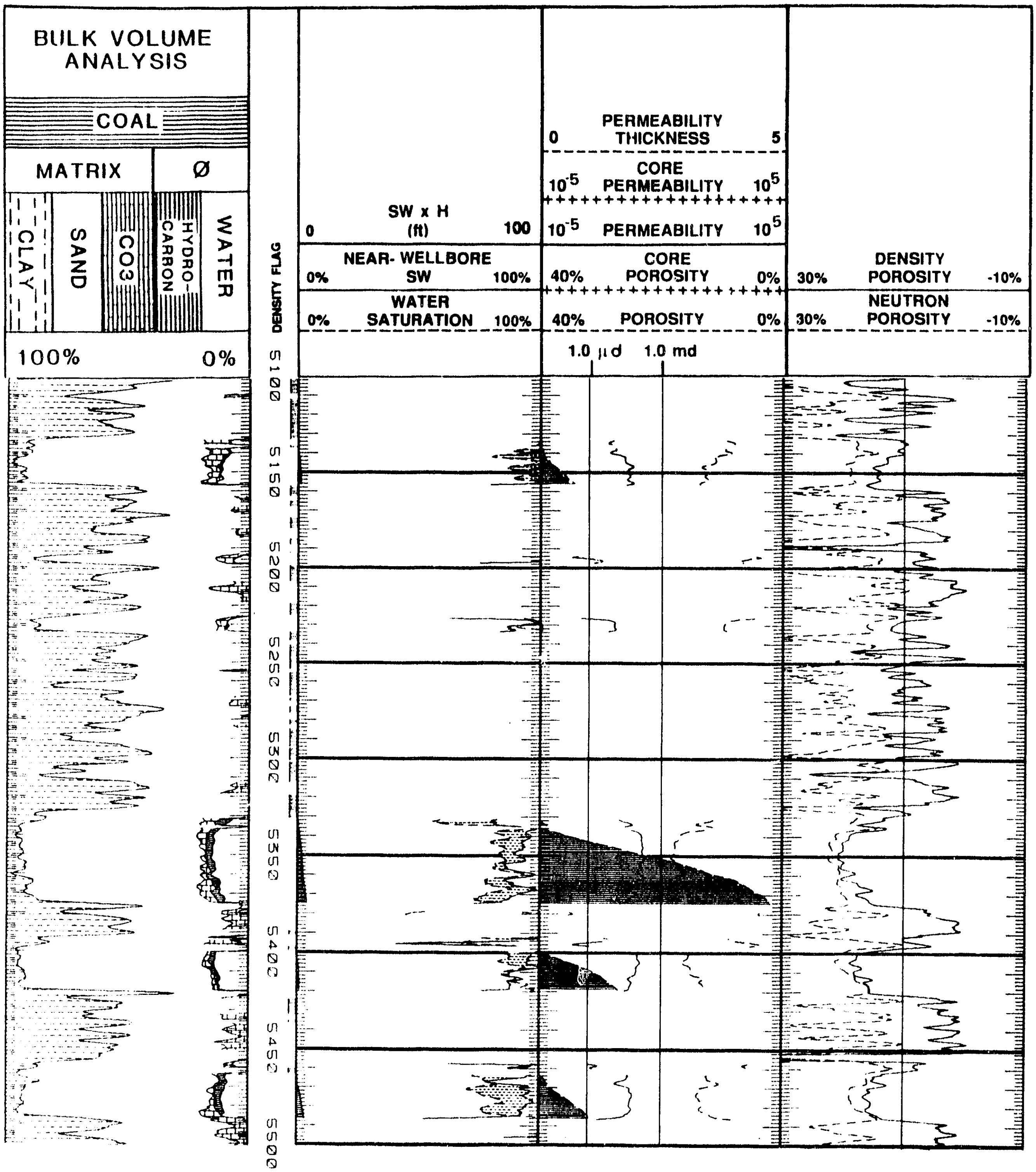


Figure 43 TITEGAS Computed Log, Fuelco E-22-10-94-S

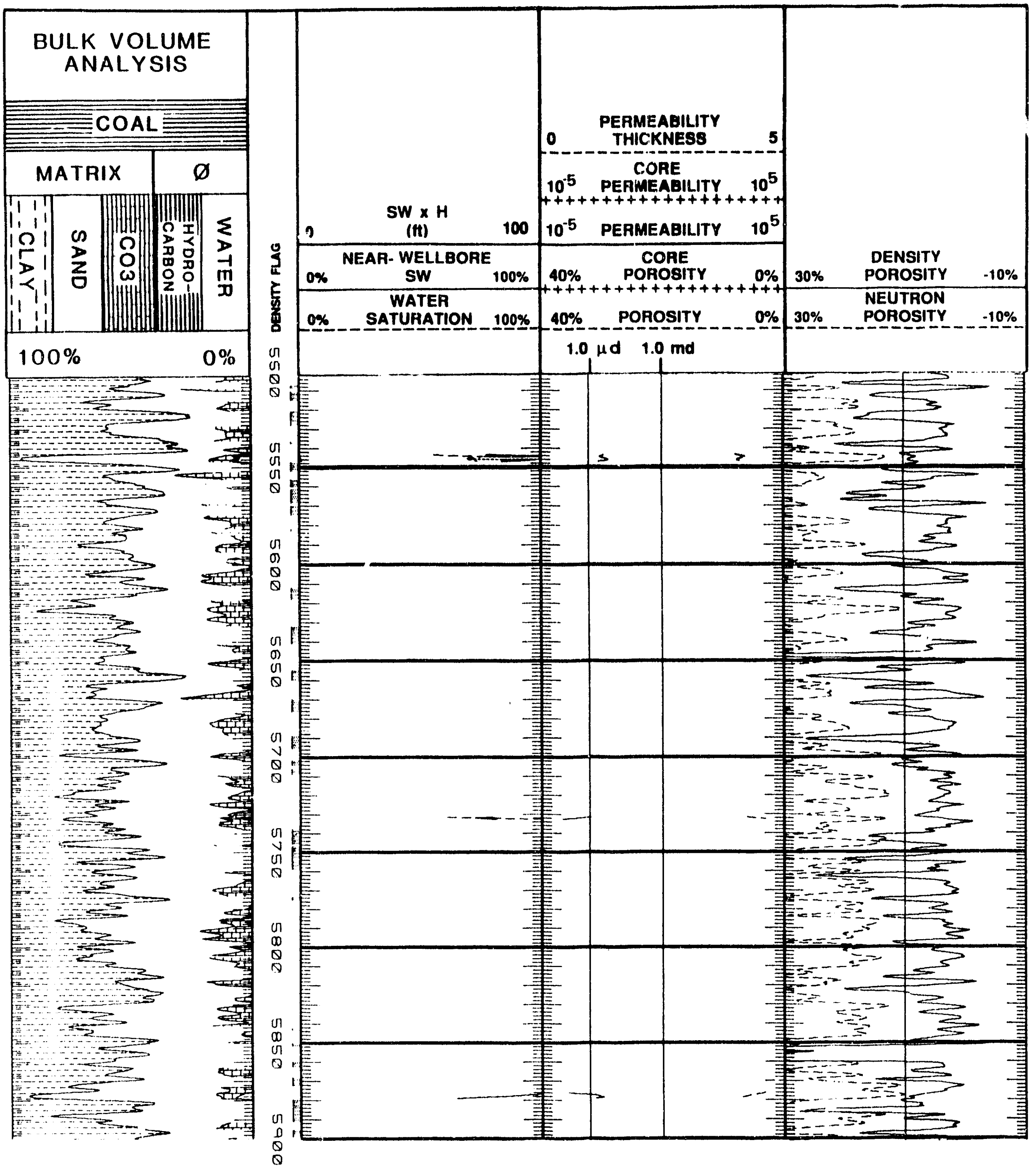


Figure 43, Continued

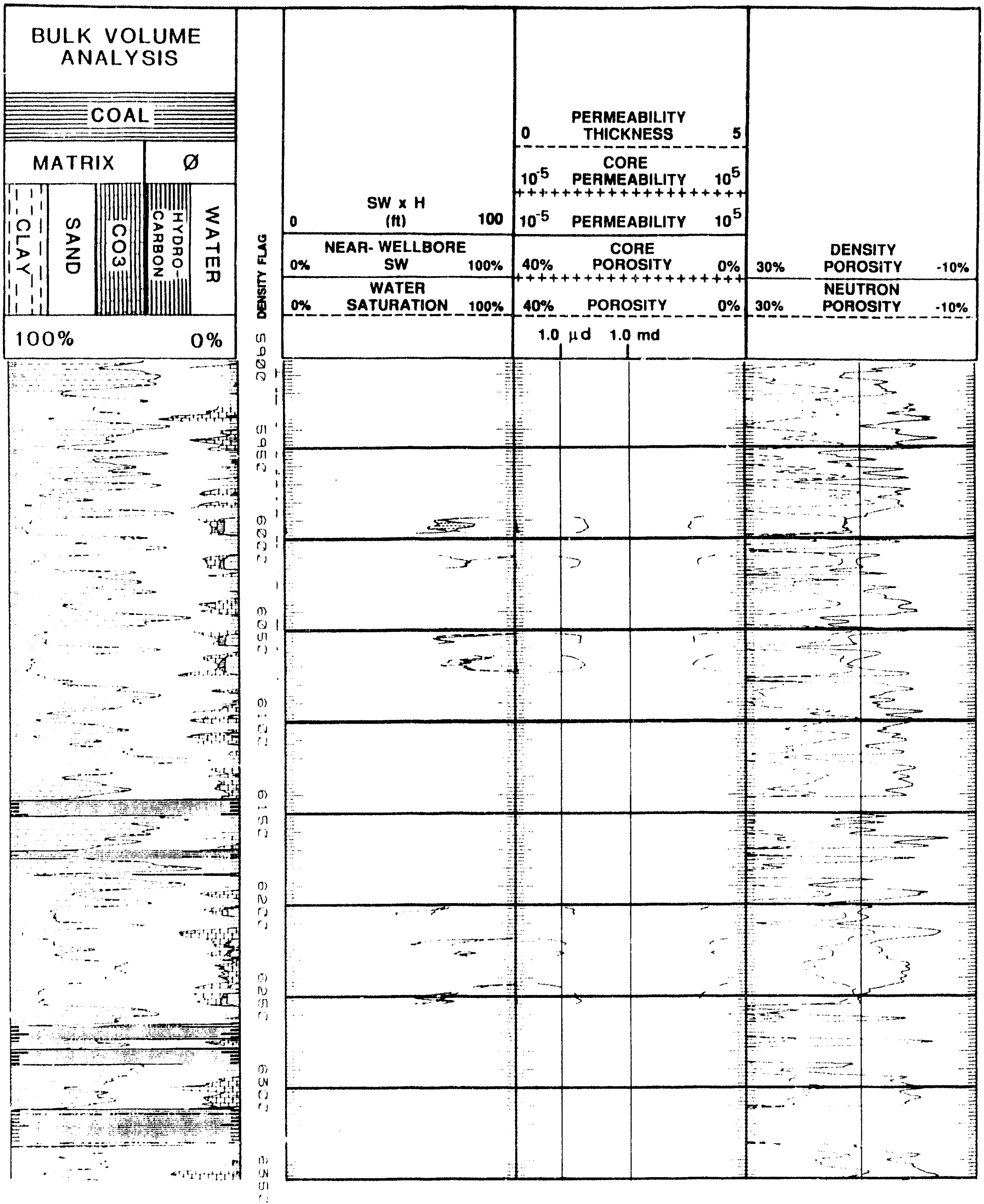
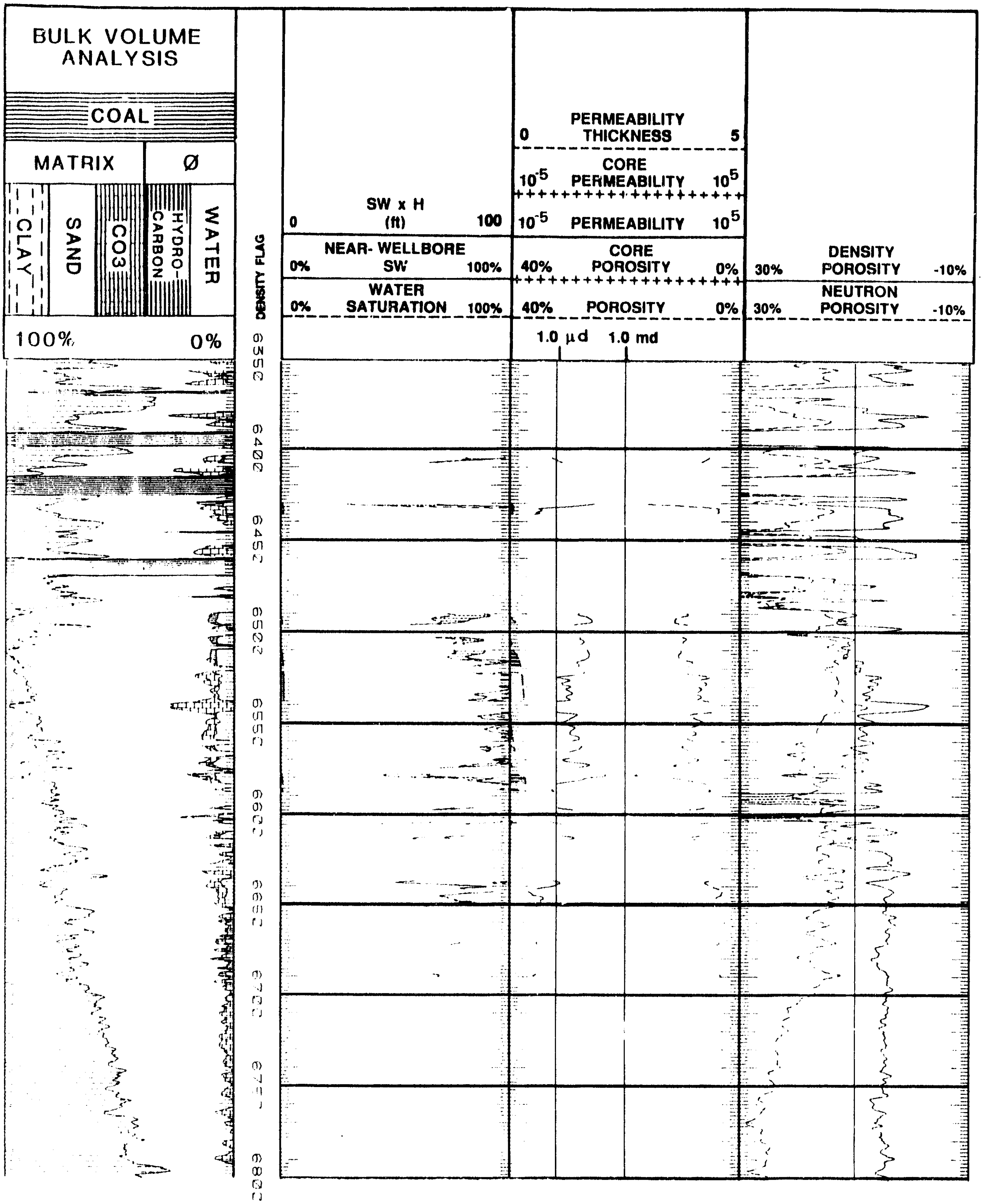


Figure 43, Continued



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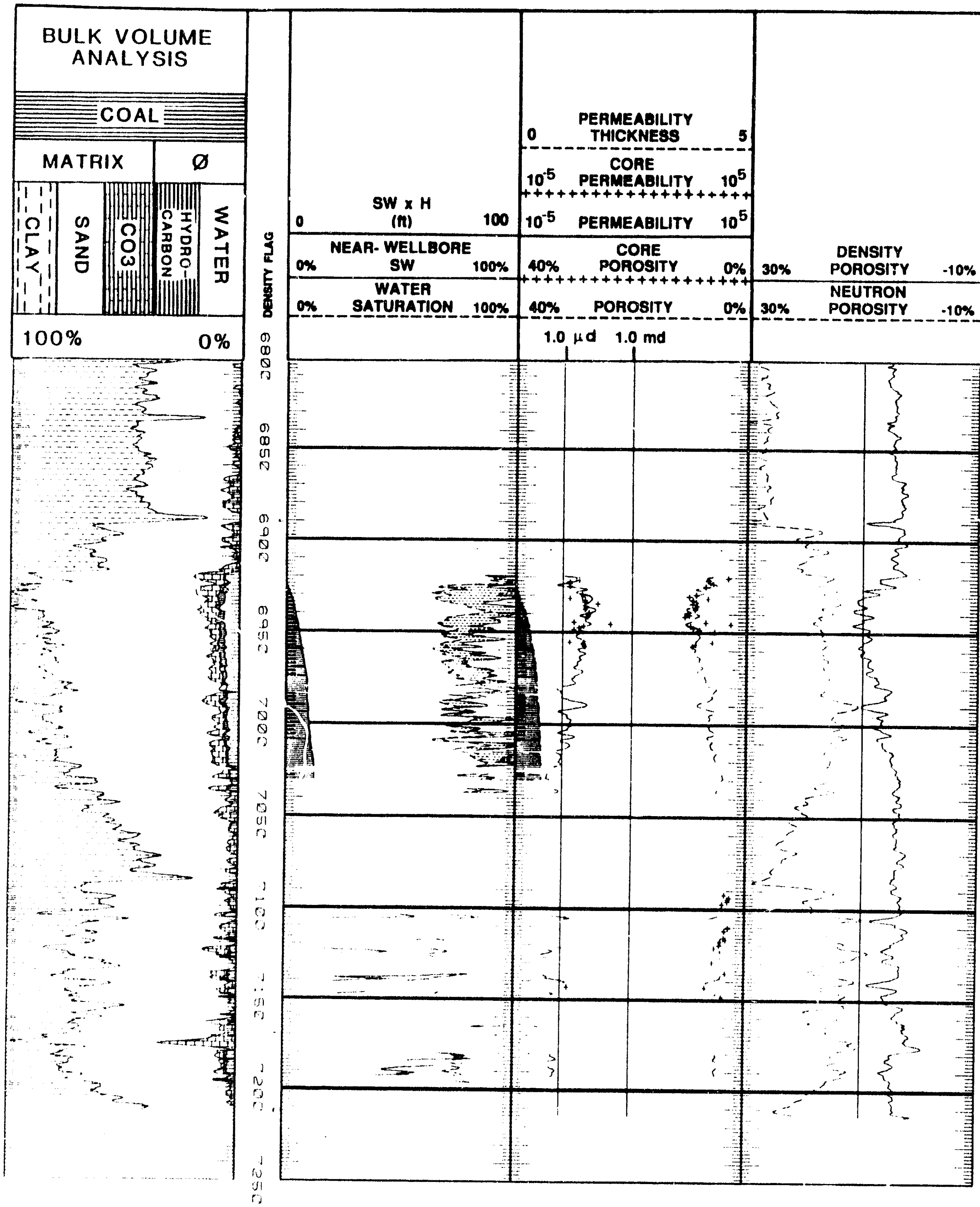


Figure 43, Continued

0.0 percent. The water saturation of the Rollins is interpreted to be much greater than irreducible.

The paludal Mesaverde is subdivided into five zones over the gross interval 6,430.5 to 6,201.5 ft. These sands are thin and very tight. The best of the paludal sandstone zones is P-3 which has a net thickness of 9.0 ft. The maximum porosity is 8.6 percent and averages 6.9 percent. The log calculated kh is 0.034 md-ft. Maximum log calculated permeability is 0.008 md. The minimum clay volume is 13.5 percent and averages 16.5 percent. The minimum water saturation is 55.6 percent and averages 74.4 percent. Water saturation is believed to be at irreducible.

The gas-saturated fluvial Mesaverde sub-interval is subdivided into seven individual sandstone zones over the gross interval 6,073.5 to 5,543 ft. These zones are numbered sequentially from FG-1 to FG-7. These zones are thin and tight and none are interpreted as having any significant gas production potential. The best of these zones is FG-4 which has a net thickness of 9.0 ft. The maximum porosity is 9.8 percent and averages 9.0 percent. The log calculated kh is 0.103 md-ft. The maximum log calculated permeability is 0.017 md. The minimum clay volume is 6.4 percent and averages 9.8 percent. The minimum water saturation is 61.7 percent and averages 69.5 percent.

The fluvial-transition Mesaverde sub-interval is interpreted as having a water saturation that is much greater than irreducible. The fluvial-transition Mesaverde in this well is subdivided into 6 zones over the gross interval 5,486.5 to 5,133.5 ft. None of these zones are viewed as having any gas production potential because this section of the fluvial Mesaverde does not effectively trap gas and has apparently been swept by meteoric water.

The Cozzette sandstone shows a good net thickness in the E-22 well, however it calculates a high water saturation and produces a significant volume of water. The Colorado Land No. 1 and No. 2 wells in Section 17, and the Colorado Land No. 3 well in Section 7 T10S, R94W, are all excellent producers from the Cozzette. The E-22 well is just 2 miles southeast of this gas productive area. The Mesaverde Formation outcrops 15 miles south of the well, and hypothetically, gas trapping would be related to the proximity of outcrop. In order to better understand the gas trapping mechanism in the southern Piceance Basin and the reason that the Cozzette sandstone in the E-22 well produces water, log analysis was performed through the marine interval of the Exxon Old Man Mountain No. 1 well in Section 33, T10S R94W, approximately 2 miles south of the E-22 well. The TITEGAS log for the Old Man Mountain Cozzette section is shown in Figure 44. The Old Man Mountain Cozzette is more shaly than the E-22 well, particularly in the lower part of the section. Using the same cutoffs as in the E-22 well, net thickness is 45.5 ft compared to 109 ft in E-22. The average water saturation is 89.9 percent is compared to 77.3 percent in the E-22 Cozzette. These findings are consistent with the hypothesis that gas from the E-22 Cozzette is escaping south and updip approximately 15 miles to the Mesaverde outcrop. It is also probable that this outcrop is the source of what is interpreted to be fresh meteoric water in the upper fluvial Mesaverde sands in this area.

In summary, the Fuelco E-22 well would appear to have poor gas production potential compared with many other areas in the Southwest Flank partitioned area. The Corcoran is shaly and has low porosity. The Cozzette has a water saturation that is greater than

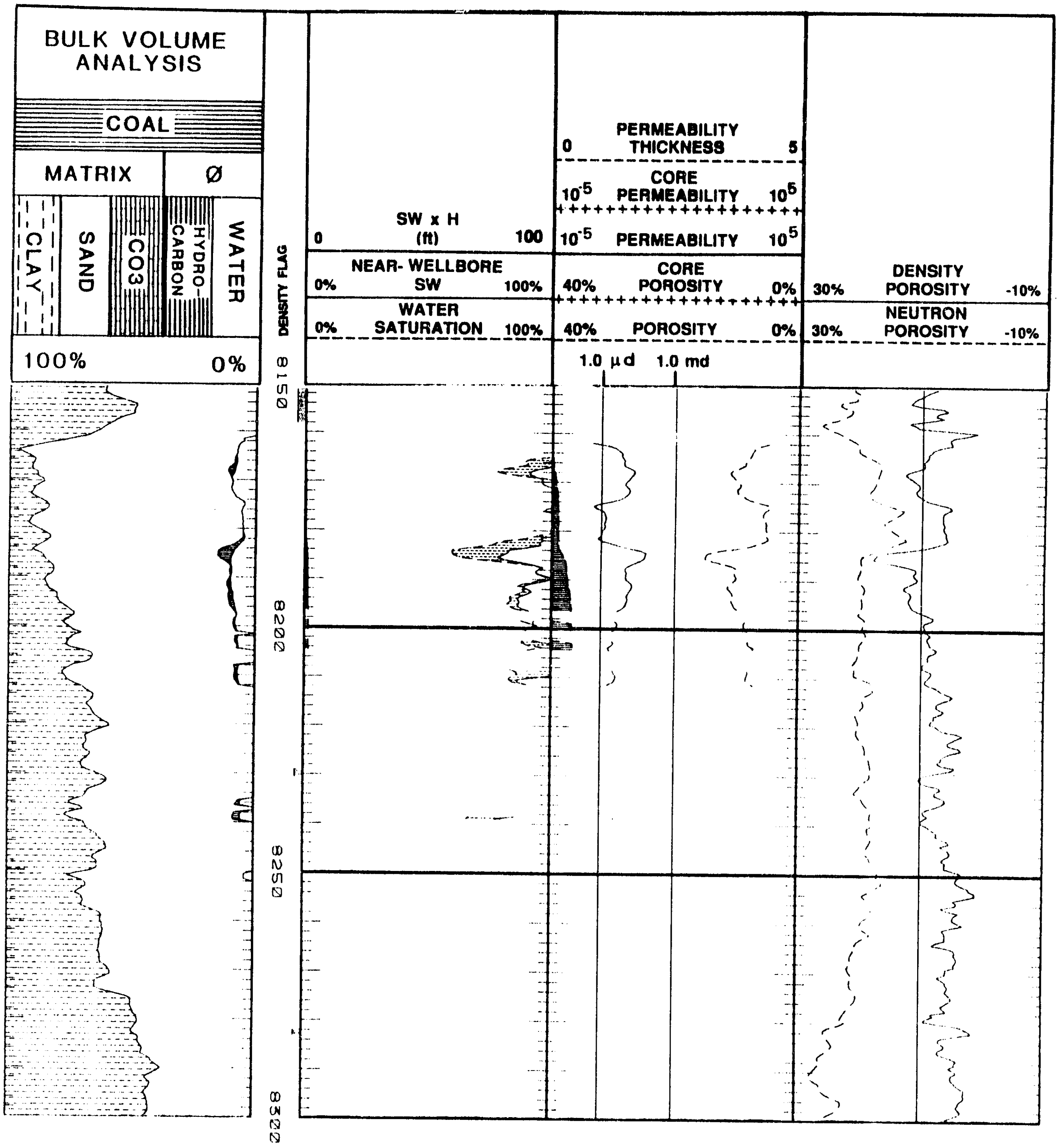


Figure 44 TITEGAS Computed Log, Exxon Old Man Mountain No. 1

irreducible. Sands in the gas-saturated paludal and fluvial Mesaverde sections are too thin and tight to be considered drilling targets in this area. The E-22 well, therefore, would appear to define and limit the southern boundary of the Southwest Flank partitioned area.

2.8.2 Oriented Coring

A total of 118.1 ft of core was cut from two intervals at 6,904.0 to 6,964.0 ft (Cozzette) and 7,092.0 to 7,150.1 ft (Corcoran); 112.2 ft (95 percent) was recovered. Core lithologic and fracture descriptions are included in Appendix 4. Downhole core orientation data was acquired continuously throughout both intervals but only 79.6 ft of the total cored interval was oriented. The intervals that were oriented using downhole orientation data were: 6,904.3 to 6,930.4; 7,092.0 to 7,107.0; 7,111.1 to 7,119.2; and 7,120.0 to 7,150.4 ft.

2.8.3 Core Fractures

A total of 37 fractures were observed in the core; 23 in the Cozzette and 14 in the Corcoran. There were 21 fractures classified as induced fractures; 17 in the Cozzette and 4 in the Corcoran. There were 16 natural extension fractures; 6 in the Cozzette and 10 in the Corcoran. Natural fractures were completely to partially mineral filled.

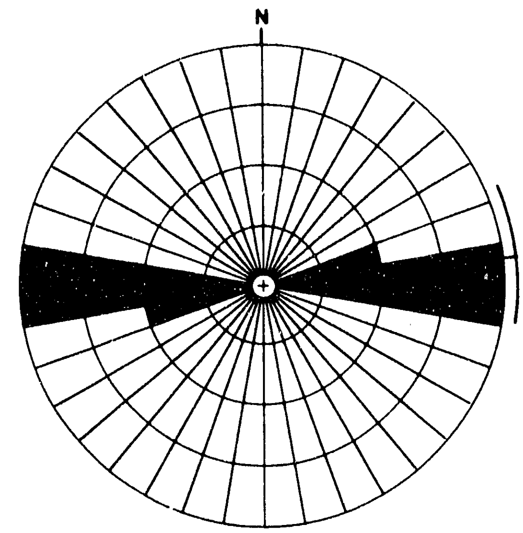
Thirteen natural extension fractures were oriented. In the Cozzette there were 5 oriented natural fractures with a vector mean strike of 83°. In the Corcoran there were 8 oriented natural fractures with a vector mean strike of 90°. Fractures are near vertical. Strikes of natural fractures in the Cozzette and Corcoran are shown in Figures 45 and 46, respectively. Cozzette and Corcoran natural fractures at the Fuelco location have a 10° to 20° counter clockwise orientation from those at the MWX location.

There were eight oriented induced fractures. True fracture strike ranged from 70° to 93° with a vector mean of 80°. Strikes of all orientable induced fractures in cores are shown in Figure 47. Induced fractures are near vertical. The orientation of the in-situ principal stress from the induced fractures is 80°. This orientation of stresses in also a 10° to 20° counter clockwise difference from that determined at the MWX location.

2.8.4 Borehole Image Logs

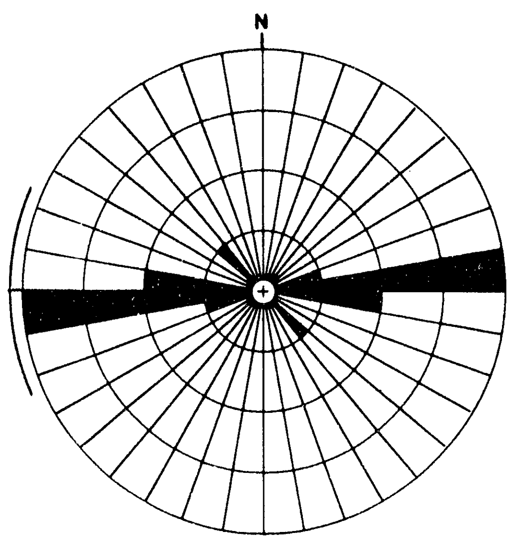
In the Fuelco well, two borehole imaging logs, the Schlumberger Formation Microscanner (FMS) and the Halliburton Logging Services Circumferential Acoustic Scanning Tool (CAST), were run.
Analysis of the FMS data for fractures was performed over the interval 6,849.6 to 7,239.5 ft. Fracture images were classified into two groups, vertical or inclined, and true fracture strike and dip were determined. Forty near vertical fractures were identified. These fractures had a preferential true strike between 70° and 80°. The preferential true strike direction of the 15 inclined fractures ranges from 80° to 90° with variable high to low dips both to the northwest and to the southeast. On the borehole image logs, the differentiation of natural and induced fractures cannot be made.

The FMS oriented calipers were analyzed for borehole breakout directions in the Fuelco E-22-10-94-S. A mean breakout azimuth of 56°, shown in Figure 48, and an inferred maximum horizontal stress direction of 146°, was determined.



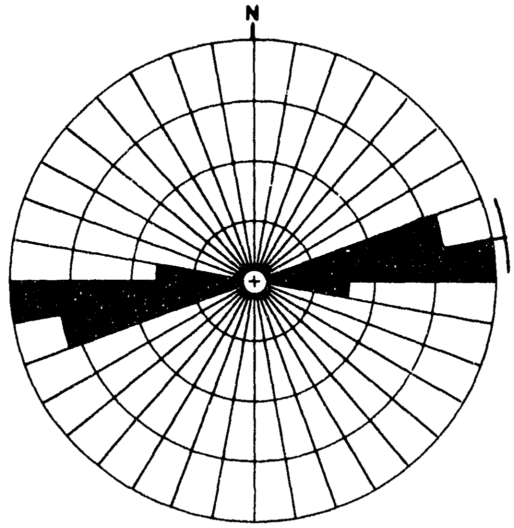
Fuelco, Cozzette Natural Fractures	Statistics
N = 5	Vector Mean = 83.2
Class Interval = 10 degrees	Conf. Angle = 16.05
Maximum Percentage = 40.0	R Magnitude = 0.953
Mean Percentage = 33.33 Standard Deviation = 10.33	Rayleigh = 0.0106

Figure 45 Rose Diagram Showing the Strikes of Natural Fractures in the Cozzette, Fuelco E-22-10-94-S



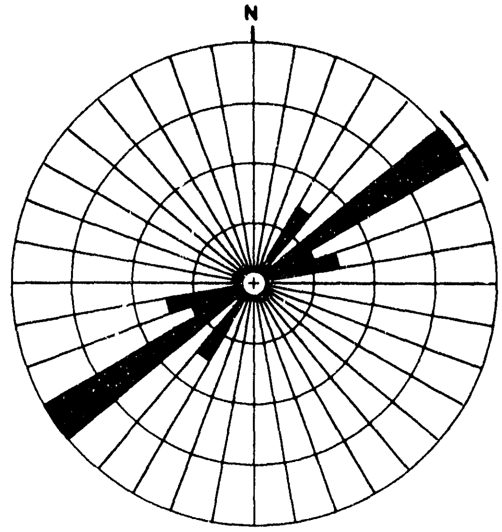
Fuelco, Corcoran Natural Fractures	Statistics
N = 8	Vector Mean = 270.3
Class Interval = 10 degrees	Conf. Angle = 23.98
Maximum Percentage = 50.0	R Magnitude = 0.831
Mean Percentage = 25.00 Standard Deviation = 16.37	Rayleigh = 0.0040

Figure 46 Rose Diagram Showing the Strikes of Natural Fractures in the Corcoran, Fuelco E-22-10-94-S



Fuelco, All Coring Induced Fractures	Statistics
N = 11 Class Interval = 10 degrees Maximum Percentage = 45.5 Mean Percentage = 33.33 Standard Deviation = 12.42	Vector Mean = 79.7 Conf. Angle = 8.36 R Magnitude = 0.970 Rayleigh = 0.0000

Figure 47 Rose Diagram Showing the Strikes of Coring-Induced Fractures, Fuelco E-22-10-94-S



Fuelco E-22-10-94-5, Bolehole Breakouts	Statistics
N = 23 Class Interval = 10 degrees Maximum Percentage = 47.8 Mean Percentage = 20.00 Standard Deviation = 15.50	Vector Mean = 56.3 Conf. Angle = 9.57 R Magnitude = 0.916 Rayleigh = 0.0000

Figure 48 Rose Diagram of Maximum Horizontal Stress Directions Indicated by Bore-hole Breakouts Interpreted from the FMS Calipers, Fuelco E-22-10-94-S

Because this inferred in-situ stress orientation is different from that inferred from the induced fractures seen in core, the distribution of breakouts was further examined. In Figure 48, all but two of the recorded breakouts are above 5,542 ft in depth; whereas, the fractures in core are below 6,904 ft. This distribution was verified with the CAST log. These data may be

displaying a local rotation of stress with depth, as has been reported at the MWX location by Sattler, 1988.

2.8.5 Circumferential Velocity Analysis

Circumferential Velocity Analysis (CVA) was performed on 2 core samples by Sandia National Laboratories. Sample depths were 6,937 and 6,940 ft. Results of these measurements, 94° and 87°, respectively, indicates a hydraulic fracture would propagate in an east-west direction, similar to that indicated by the induced fracture orientations.

2.8.6 Pressure Transient Test

A pressure transient test of the Cozzette was conducted in the Fuelco E-22-10-94-S. Casing was perforated under nitrogen pressure and the well was flowed for a period of 14 days. Flow consisted of gas and water at average rates of 80 MCFD and 24 BWD. The well was then shut in for a period of six days utilizing a down hole shut in tool.

Figures 49 and 50 are the Horner plot and the pressure-square & derivative log-log plots, respectively, for the Fuelco test. The pressure derivative curve indicates that radial flow developed about 50 hours after shut in which corresponds to the Horner time of about 8. The slope of the linear section on the Horner plot was graphically determined to be 170 psi/cycle.

Gas formation volume factor is estimated to be 1.44 reservoir barrels per MCF at 2,100 psi, which is the average pressure during the buildup test.

Based on the above information, the average formation permeability was estimated to be 0.076 md, assuming a net pay thickness of 25 ft. The extrapolation of the straight line on the Horner plot to one hour after shut in, or 337 on Horner time scale, yields a pressure of 2,140 psi. Assuming the average producing pressure was 1,800 psi, the skin factor is estimated to be -2.5. The negative skin indicates that the high pressure nitrogen breakdown may have created micro-fractures which penetrated the damaged zone and stimulated the reservoir near the wellbore.

The above analysis does not take into account the water that is in the formation. Water production indicates that the reservoir permeability is probably somewhat greater than calculated in the pressure buildup because more barrels of fluid were actually produced than just the equivalent of the gas. The highest permeability measured in core analysis is 0.033 md and most measurements are in the range of 0.01 md or less. The test therefore indicates that natural fractures contribute to the production.

Well Status Fuelco decided the Cozzette interval was uneconomic separately and commingled Cozzette production with gas from the paludal coals. Fuelco reported a commingled IPF of 510 MCFD and 264 BWD.

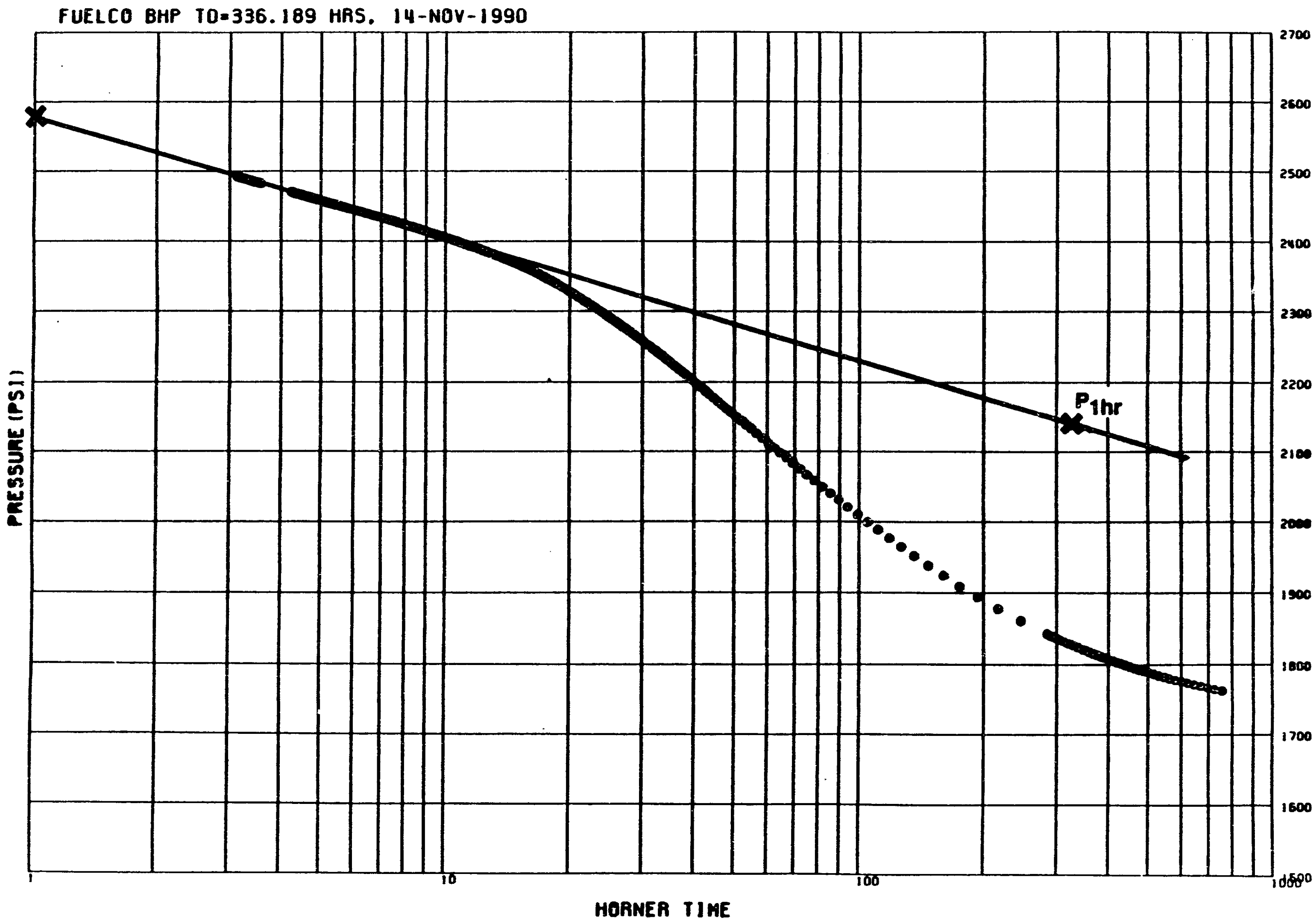


Figure 49 Horner Plot of Pressure Buildup Showing the Actual (o) and the Model Predicted (+) Results, Fuelco E-22-10-94-S

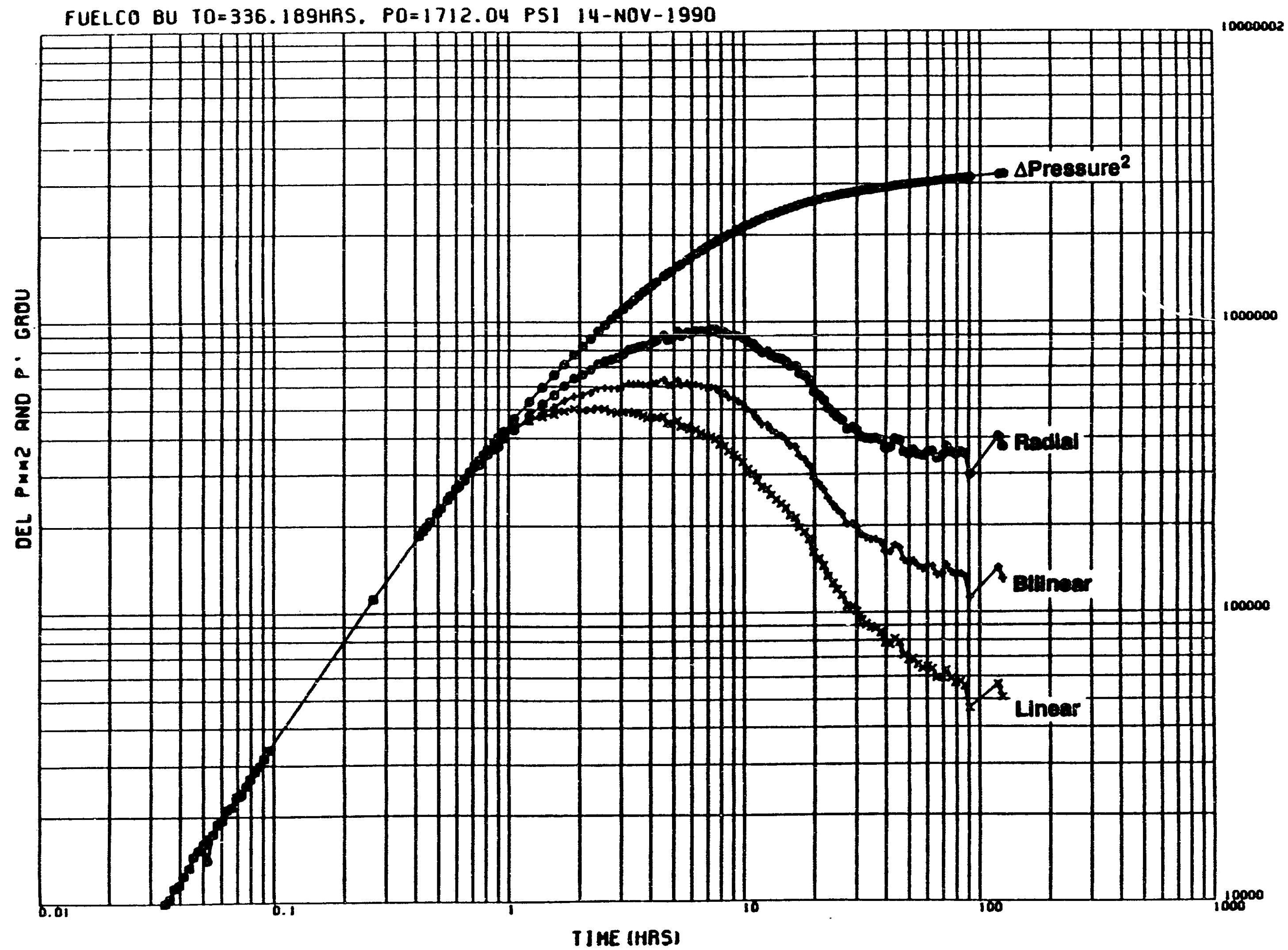


Figure 50 *Pressure and Pressure Derivative Curves Showing the Actual (o) and Model Predicted (+) Results, Fuelco E-22-10-94-S*

2.8.7 Summary and Conclusions Fuelco E-22-10-94-S Well

Partially open natural fractures are present in the marine sandstones in the Fuelco well. This is the first verification that natural fractures may contribute to production in the east Plateau field area. The fractures appear to be similar to the fracture system found at the MWX location, however their orientation is different by 20° to 30°. The pressure transient test analysis indicates that natural fractures contribute to the production. Because the marine sandstones were found to produce uneconomic quantities of formation water with the gas, and because the paludal interval has poor potential, the Fuelco well designates a southern limit to the Southwest Flank partitioned area.

2.9 THE SOUTHWESTERN LIMIT OF THE PLATEAU FIELD

This section details the analysis of the Coors USA 1-27 CM well and the Coors Davis 1-24 well in Sections 27 and 24 of T10S, R97W, respectively. The principal objective of the analysis was to characterize the Cozzette and Corcoran sandstones to determine the southwestern limit of the Plateau Field.

The USA well was drilled through the Dakota to 8,277 ft and was subsequently completed in the Dakota. It has not been completed in the Corcoran or Cozzette. The well is on the southwest (updip) margin of the Plateau Field which produces principally from the Corcoran and Cozzette sandstones. The Davis well is part of the Plateau Field and was completed in the Corcoran and Cozzette. From 1977 through 1990 the well produced 63 MMCF.

Tables 10 and 11 and Figures 51 and 52 present the log analysis results for the Davis I-24 and USA 1-27 CM wells, respectively. The log analysis of the Davis and USA wells, when combined with the Phase I studies that CER performed in the Plateau Field, indicates that the gas-trapping mechanism in this area is stratigraphic, and the gas-package is basin-centered. It is interpreted that gas is passing through the Corcoran and Cozzette sands from downdip sources and is migrating to Corcoran and Cozzette outcrops southwest of the field.

The Davis well, in Section 24, T10S, R97W, is on the western margin of the Plateau Field. Porosities of Corcoran and Cozzette sands in this well average between 8.5 to 10.6 percent, and the maximum calculated matrix permeability is about 0.03 md. The low permeability is confirmed by a lack of flushing in the near-wellbore zone. No SP permeability analysis was attempted because there is no contrast between R_{mf} and R_w (two percent KCl mud). The reservoirs are shaly, with clay volumes averaging between 20.1 to 23.1 percent. Average water saturations range between 47.2 to 80.7 percent. The water saturations, although high, are interpreted to be at or near irreducible.

Two and a quarter miles southwest and 550 ft updip from the Davis Well in Section 24, the Corcoran and Cozzette in the USA Well (Section 27) are interpreted to lie in a gas-water transition zone. Porosities are higher, averaging between 10.4 to 12.4 percent. Matrix permeability improves to a maximum of about 0.07 md. The formation is well flushed, and the electrochemical component of the SP is developed to its full potential. The sands are cleaner, with clay volumes averaging between 13.4 to 18.3 percent. Water saturations are interpreted to be greater than irreducible, averaging between 52.3 to 73.8 percent. There is no evidence of gas-water contacts in these reservoirs.

Table 10 Key Reservoir Parameters and Zone Designations for Coors Energy Company Davis 1-24

INTERVAL (FEET)	ZONE	GROSS H (FT)	NET H (FT)	AVG Ø (%)	MAX Ø (%)	AVG SW (%)	MIN SW (%)	HCFT (FT)	KH (MD-FT)	MAX K (MD)	AVG CLAY (%)	MIN CLAY (%)	SP INDEX
2736.5-2745.0	U. COZ	9.0	8.5	8.5	9.1	80.7	72.0	0.140	0.042	0.006	21.7	18.5	-----
2786.0-2808.5	L. COZ	23.0	18.5	10.2	13.0	61.9	49.1	0.724	0.186	0.029	22.2	18.9	-----
2888.5-2892.0	U. COR	4.0	4.0	10.6	11.2	47.2	44.1	0.225	0.044	0.014	23.1	22.1	-----
2946.5-3000.0	L. COR	54.0	31.5	9.6	12.3	72.8	50.3	0.850	0.296	0.028	20.1	14.9	-----

Table 11 Key Reservoir Parameters and Zone Designations for Coors Energy Company USA 1-27 CM

INTERVAL (FEET)	ZONE	GROSS H (FT)	NET H (FT)	AVG Ø (%)	MAX Ø (%)	AVG SW (%)	MIN SW (%)	HCFT (FT)	KH (MD-FT)	MAX K (MD)	AVG CLAY (%)	MIN CLAY (%)	SP INDEX
3304.5-3335.5	U. COZ	31.5	13.0	10.4	14.6	68.6	51.1	0.511	0.287	0.056	16.7	11.7	0.792
3357.0-3391.0	L. COZ	34.5	34.5	10.4	13.5	62.5	45.2	1.389	0.492	0.033	18.3	13.8	0.857
3477.5-3485.0	U. COR	8.0	8.0	12.4	14.4	52.3	41.7	0.482	0.275	0.052	13.4	9.8	0.721
3514.5-3554.0	L. COR	39.5	37.5	11.9	14.5	73.8	55.0	1.250	1.141	0.072	13.9	4.9	1.387

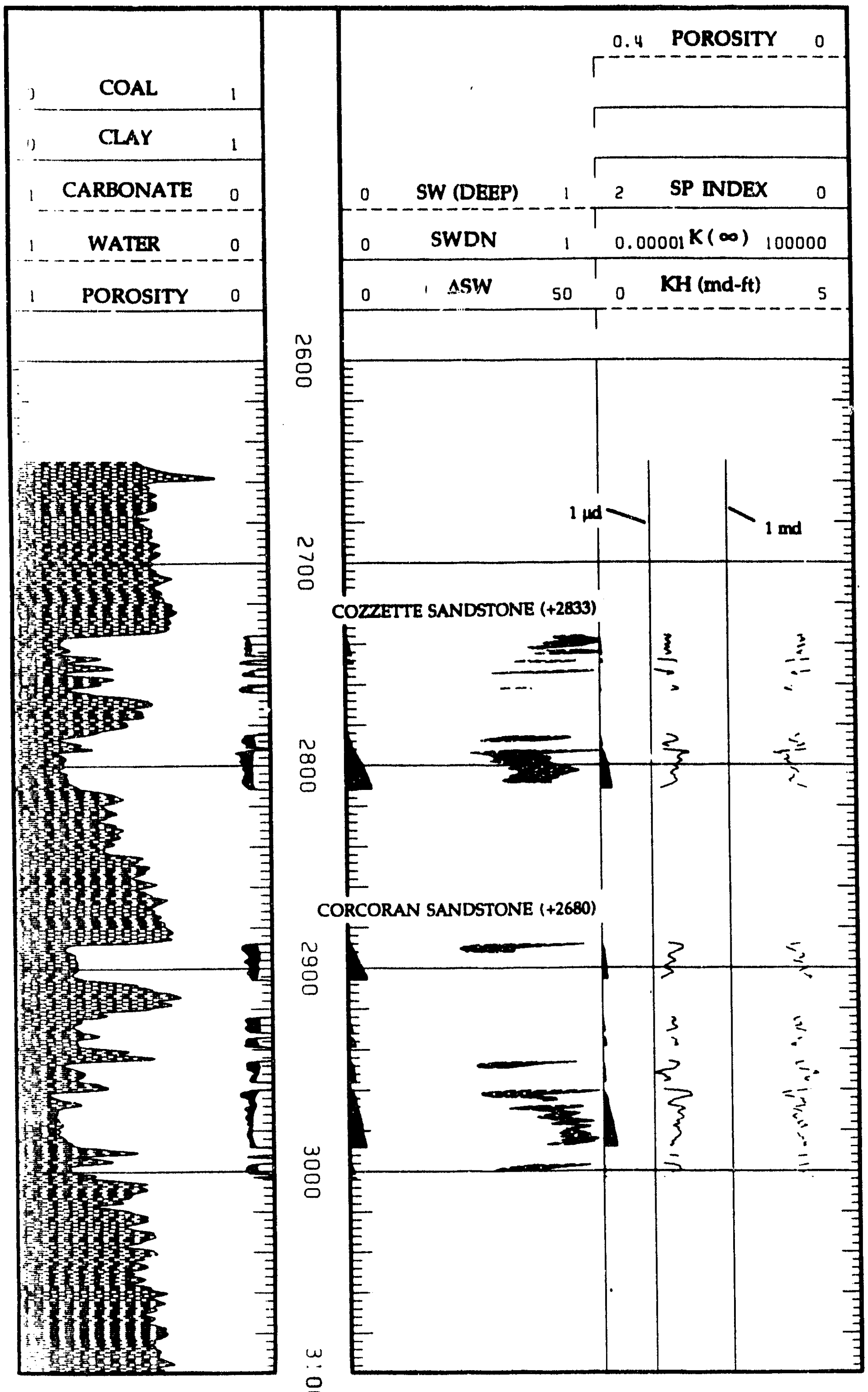


Figure 51 TITEGAS Computed Log, Coors Davis No. 1-24

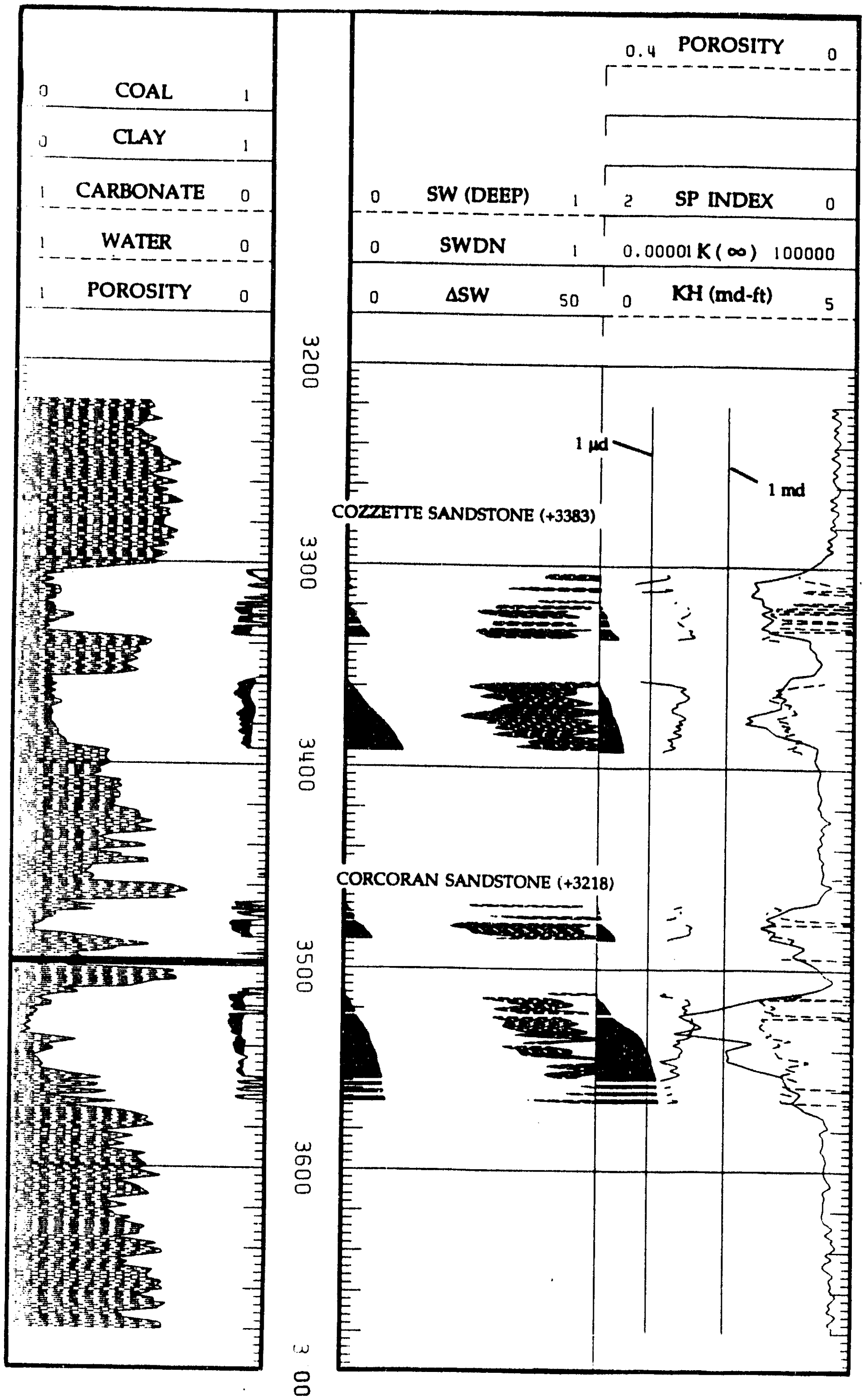


Figure 52 TITEGAS Computed Log, Coors USA No. 1-27 CM

Extrapolating further west and updip and assuming that the depositional character remains unchanged, it is anticipated that the reservoir would have a slightly higher porosity and permeability than in the USA well. Also, it is expected that water saturations increase moving updip.

2.10 THE DEKALB NEW FIELD DISCOVERY

In November, 1990, Dekalb Energy Company drilled the Wagon Trail Federal No. 44-11, a wildcat well in Section 11, T9S, R98W, in Mesa County. The target was the marine Mesaverde section. The well is in the undefined area with respect to partitioned areas. At the operator's request, the Dekalb well was included in this study to compare its potential with that of wells of the Southwest Flank area.

The Corcoran Sand was completed over the interval 2,790 to 2,763 ft. Following a fracture treatment with 70,000 pounds of 20/40 sand, the initial potential was 471 MCFD at 137 psi FTP (CP 203 psi) on a 3/8 in choke. Production stabilized at about 200 MCFD at 60 psi FTP on a 3/4 in choke.

Dekalb provided CER log data for inclusion in this study. The logging program was as follows:

	Service	Logged Interval
1.	Dual Induction/SFL/ SFL/SP	2,890 to 342 ft
2.	Lithodensity/Caliper	2,887 to 1,356 ft
3.	Compensated Neutron	2,869 to 1,356 ft
4.	Gamma Ray Spectrometry	2,885 to 1,912 ft
5.	Gamma Ray	2,860 to 273 ft
6.	Geochemical Log (GST)	2,895 to 1,950 ft

The well was analyzed using the TITEGAS log analysis model over the interval 2,300 to 2,862 ft. Refer to Appendix 1 for a description of the TITEGAS log analysis model. This interval includes the Corcoran, Cozzette and Rollins sandstones. The analysis was broken down into two sub-intervals, with the Rollins being a separate sub-interval. Histograms of environmentally corrected log data were made for the principal log curves through each sub-interval. These histograms were compared to log data norms that were developed for the Debeque and Shire Gulch fields during the Phase I TETWGS study to determine the validity of each log. It was determined that the Wagon Trail Federal No. 44-11 log data is of good quality and no log data normalizations were required. Formation water resistivities were interpreted as 0.153 ohm-m for the Corcoran, 0.158 ohm-m for the Cozzette and 0.166 ohm-m for the Rollins.

The log analysis results for the Wagon Trail Federal No. 44-11 well are presented in Table 12 and Figure 53. Refer to Appendix 2 for a description of the format for log analysis results.

The Corcoran sandstone is subdivided into two zones. The net thickness is 39.0 ft. The maximum porosity is 14.0 percent and averages 11.7 percent. The log calculated kh is 0.898 md-ft. Maximum log calculated permeability is 0.072 md. The minimum clay volume is 4.6 percent and averages 17.4 percent. The minimum water saturation is 34.9 percent and averages 45.1 percent.

Table 12 Key Reservoir Parameters and Zone Designations for Dekalb Energy Co. Wagon Trail Fed No. 44-11

INTERVAL (FEET)	ZONE	GROSS H (FT)	NET H (FT)	AVG Ø (%)	MAX Ø (%)	AVG SW (%)	MIN SW (%)	HCFT (FT)	KH (MD-FT)	MAX K (MD)	AVG CLAY (%)	MIN CLAY (%)
2838.5-2840.0	COR-1	2.0	2.0	11.6	11.9	42.6	42.1	0.133	0.033	0.020	21.5	19.5
2752.0-2795.0	COR-2	43.5	37.0	11.7	14.0	45.2	34.9	2.385	0.865	0.072	17.2	4.6
2626.5-2637.0	COZ-1	11.0	7.5	9.5	11.6	41.1	32.2	0.429	0.060	0.014	22.4	16.9
2555.0-2589.0	COZ-2	34.5	32.5	11.0	14.5	42.2	31.4	2.074	0.639	0.070	16.8	8.3
2535.0-2537.0	COZ-3	2.5	2.5	13.1	13.6	41.1	39.6	0.193	0.092	0.049	15.3	11.1
2523.0-2526.0	COZ-4	3.5	2.0	9.5	9.8	62.8	54.4	0.071	0.015	0.010	22.3	18.3
2335.0-2408.5	R-1	74.0	71.5	10.2	15.5	82.0	48.4	1.470	1.288	0.092	16.1	4.6

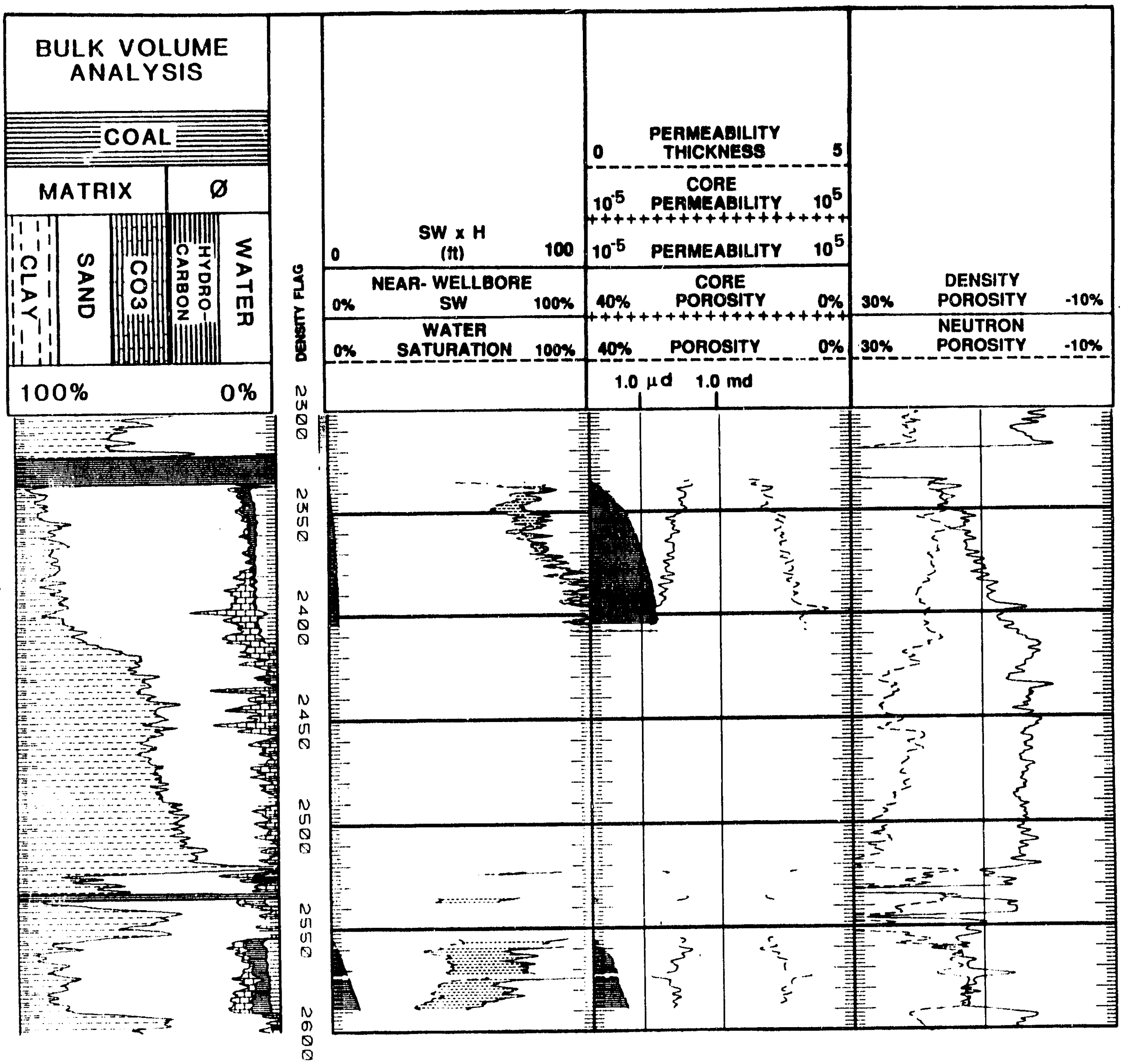


Figure 53 TITEGAS Computed Log, Dekalb Wagon Trail Fed. No. 44-11

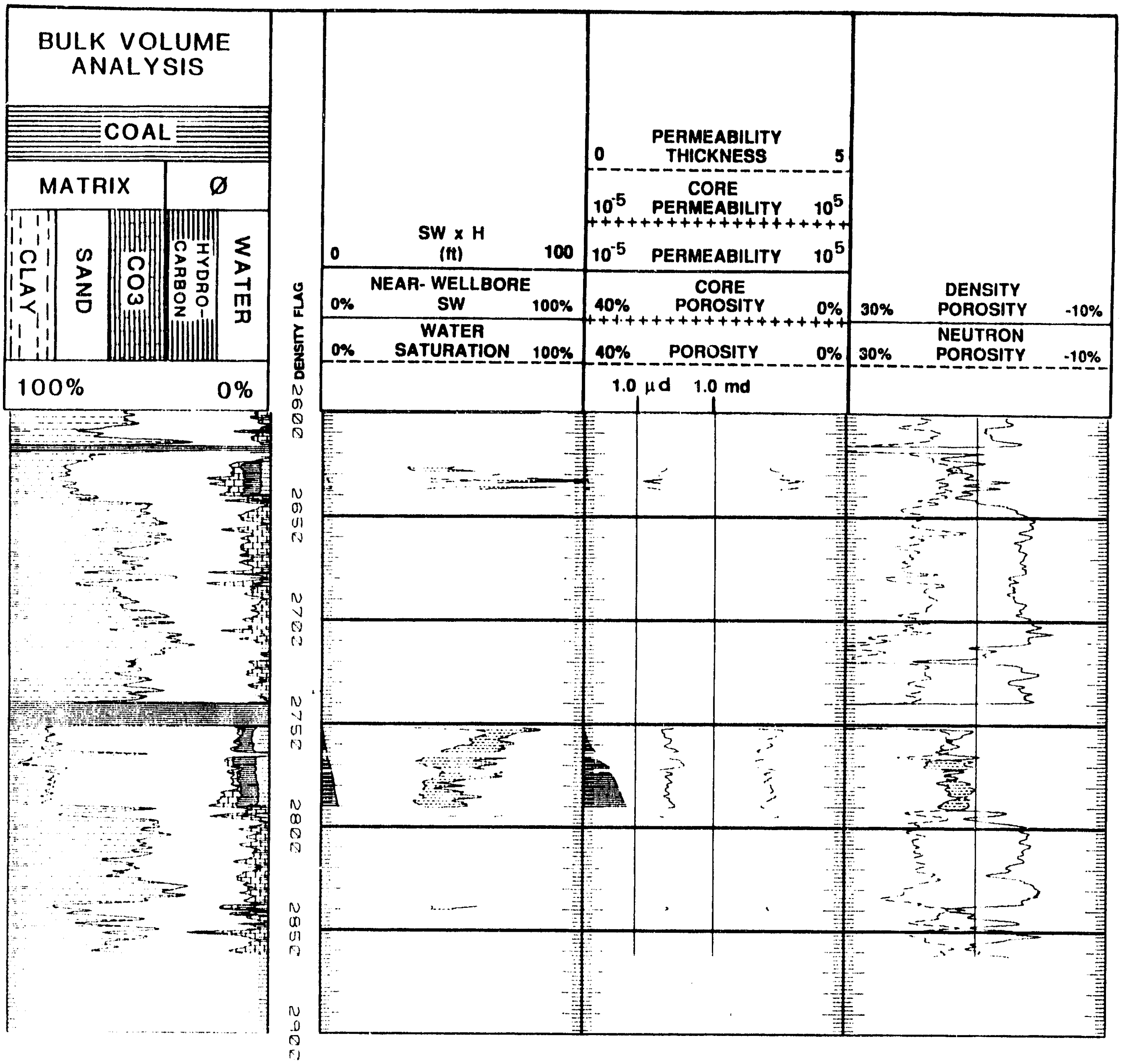


Figure 53, Continued

The Cozzette sandstone is subdivided into four zones. The net thickness is 44.5 ft. The maximum porosity is 14.5 percent and averages 10.8 percent. The log calculated kh is 0.806 md-ft. Maximum log calculated permeability is 0.070 md. The minimum clay volume is 8.3 percent and averages 17.9 percent. The minimum water saturation is 31.4 percent and averages 42.9 percent.

The net thickness of the Rollins sandstone is 71.5 ft. The maximum porosity is 15.5 percent and averages 10.2 percent. The log calculated kh is 1.288 md-ft. Maximum log calculated permeability is 0.092 md. The minimum clay volume is 4.6 percent and averages 16.1 percent. The minimum water saturation is 48.4 percent and averages 82.0 percent.

Porosities and permeabilities of the marine sandstones in this updip area of the Piceance Basin are higher as compared to MWX marine sandstones. This difference is attributed to a shallower depth of burial for the Wagon Trail marine section. Both the Corcoran and Cozzette are interpreted as being at irreducible water saturation. The Rollins sandstone has a high water saturation and would be expected to produce significant water.

The Wagon Trail logs were visually examined through the logged interval. Both the paludal and fluvial Mesaverde sandstones are wet in this well. This is consistent with the Phase I TETWGS west-east Piceance Basin cross section. The development of the Corcoran and Cozzette as gas reservoirs in the Wagon Trail well are similar to their development in the Horseshoe Canyon Federal No. 2 well in Sec 29, T9S, R97W and the Federal 30-3 well in Sec 30, T8S, R97W. These wells are in the Shire Gulch and Debeque Fields, respectively. The Wagon Trail well adds additional confidence that the Shire Gulch/Debeque Fields will eventually merge into a continuous gas productive area.

3.0 SYNOPSIS OF NATURAL FRACTURE AND STRESS ORIENTATIONS IN THE SOUTHERN PICEANCE BASIN

The regional perspective of natural fracture orientations examined in this study are shown in Figure 54. It is interpreted here that the dominant extension fractures encountered in the wells belong to the basin-wide Mesaverde reservoir fracture set recognized at MWX and as described by Lorenz et al., 1991, and Lorenz and Finley, 1991. These fractures generally trend west-northwest in the central part of the basin but east-northeast in the southern part of the basin. Many of these fractures are partially open at depth and provide significant, highly anisotropic permeability in the sandstones.

Principal in-situ stress orientations determined in this study by interpretation of borehole breakouts and induced fractures are shown in Figure 55. At MWX the induced fractures tend to strike parallel with the natural fractures. Stress orientations are west-northwest in the eastern part of the basin, similar to the strikes of fractures. However, in the Grand Valley and Southeast Plateau areas, stress orientations are oblique to the fractures in a counter clockwise direction. This suggests that hydraulic fracture stimulation in these areas could have greater success in accessing natural fractures than in the MWX area and to the east.

From an examination of published and original fracture and stress orientation information in the Piceance Basin, Lorenz and Finley, 1991, hypothesized that fractures seen at the surface are the product of the westward directed indentation of the White River plateau into the basin. Present stress orientations determined in this study (Figure 55) are consistent with Lorenz and Finley's indentation stress trajectory model (their Figure 14B). This suggests that either the Late Laramide stress regime is still active or that the stress orientations measured today are "locked-in memory of earlier horizontal compression".

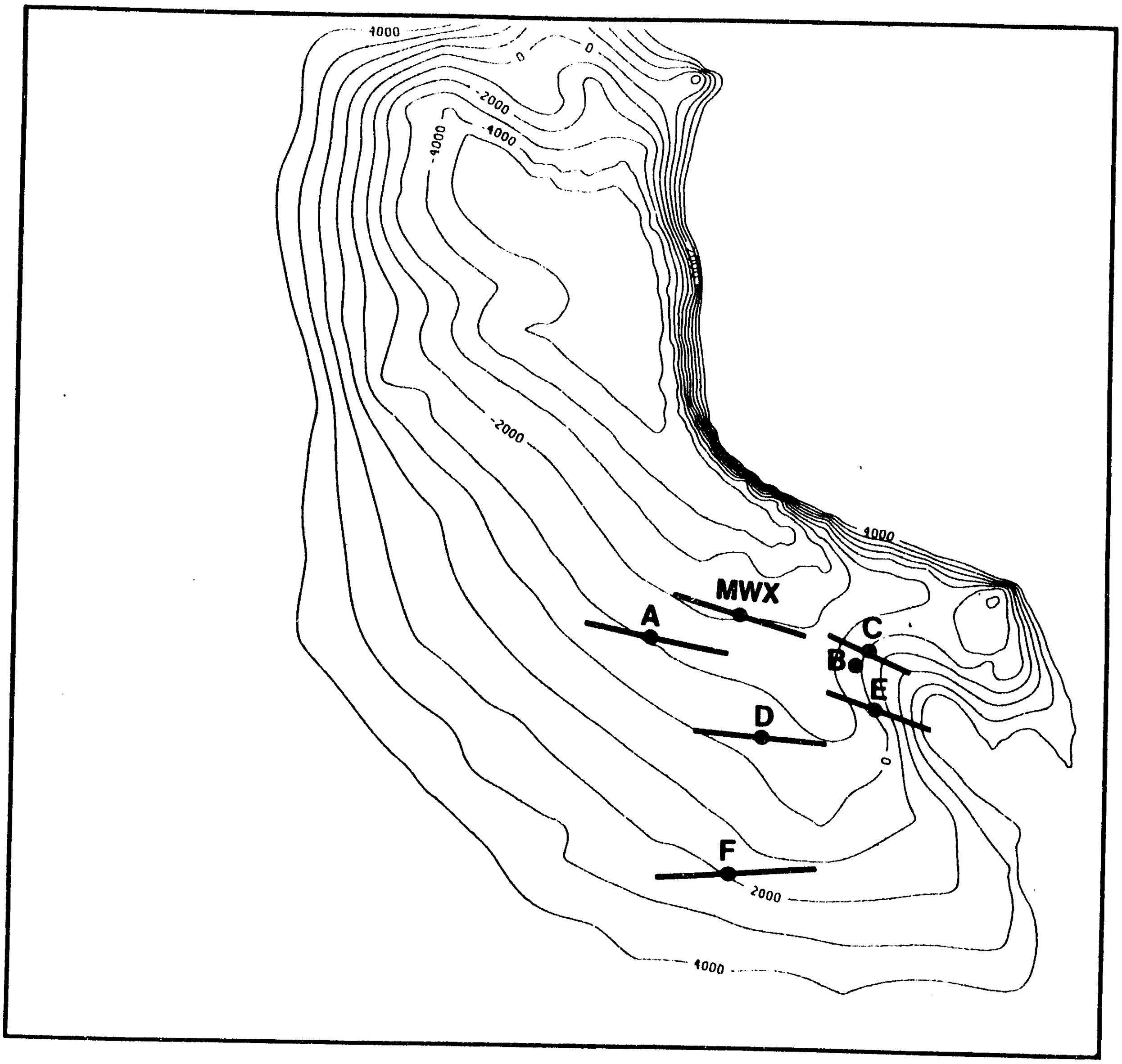


Figure 54 *Generalized Orientations of Natural Fracture Strikes Determined in Mesaverde Cores or Interpreted from Borehole Image Logs, Southern Piceance Basin where A = Barrett MV 8-4, B = Mobil T 45-20P, C = Meridian 12-14 Lyons, D = Oryx Collier Creek, E = Oryx Acapulco Federal, F = Fuelco E-22-10- 94-S (Structure Base Map is Top of Rollins Sandstone)*

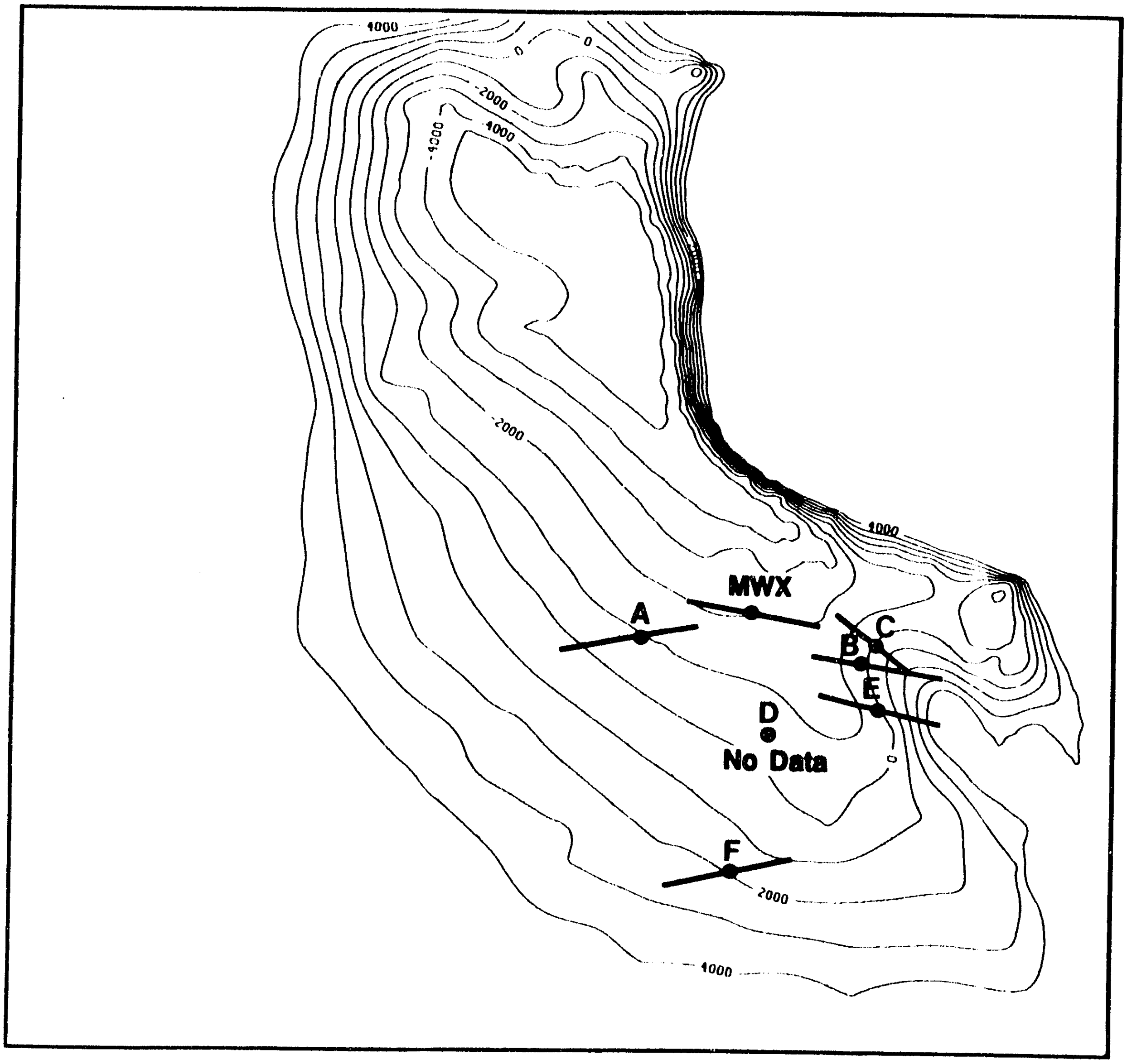


Figure 55 *Generalized In-Situ Maximum Horizontal Stress Orientations Determined from Induced Fractures in Core and Borehole Image Logs, Southern Piceance Basin where A = Barrett MV 8-4, B = Mobil T 45-20P, C = Meridian 12-14 Lyons, D = Oryx Collier Creek, E = Oryx Acapulco Federal, F = Fuelco E-22-10-94-S (Structure Base Map is Top of Rollins Sandstone)*

4.0 MODIFICATIONS TO PARTITIONED AREA DEFINITIONS

The well information gained in these field verification tests suggests modifications to the original partitioning map of the Phase I report (Figure 3). Based on the discussions in previous sections of this report the following modifications are made to each area as shown in Figure 56.

4.1 CENTRAL BASIN

The map of the Central Basin area does not change. The Barrett MV 8-4 well findings verified the characteristics of the Central Basin area. Production potential exists in the fluvial and paludal, with probable contribution of natural fractures to production. The Meridian and Mobil wells, though not productive in the coals, do have some paludal and fluvial potential. They are located at the eastern edge of the area. The Oryx Acapulco Federal well, while wet in the Cozzette sandstone, could still have potential production uphole, characteristic of other Central Basin areas. While the Meridian, Mobil, and the Oryx Acapulco wells are near the eastern edge of gas saturated sandstones within the basin-centered gas accumulation, the present drilling distribution does not allow mapping of the gas/water contact in each reservoir unit. The Oryx Collier Creek well tested water in the Cozzette, the only formation tested. If the Cozzette has a water saturation that is locally above irreducible, the partitioning would not change.

4.2 SOUTHEAST UPLIFT

The Southeast Uplift has undergone considerable reinterpretation, even though none of the study wells were actually located in the area. The Divide Creek anticline produces gas from the fractured Cozzette at the anticline crest. Based on their information, Oryx reports that the Divide Creek anticline is a structural or updip trap with water downdip to the west. This hypothesis is supported by the wet Cozzette section in the Acapulco well. The Divide Creek anticline and the pe ıpneral, structurally controlled fields, Baldy Creek and East Divide, are not part of the basin-centered gas accumulation but are separate traps. They remain part of the Southeast Uplift partitioned area.

The Ragged Mountain field lies along the southeastern basin axis and is not believed to be one of the peripheral structural traps. Gas accumulation in the marine and paludal are thought to be within the basin-centered trap. Because the trapping mechanisms are different between Ragged Mountain and Divide Creek, the Ragged Mountain area is no longer included in the Southeast Uplift partitioned area and is in an undefined area.

Further development in the Southeast Uplift area will probably be limited to delineation of the reservoirs within the structural traps and infill drilling.

4.3 SOUTHWEST FLANK

The Southwest Flank boundaries have also been modified by the new well data. Because of similarities of marine production in the Dekalb well with that in the Shire Gulch and DeBeque

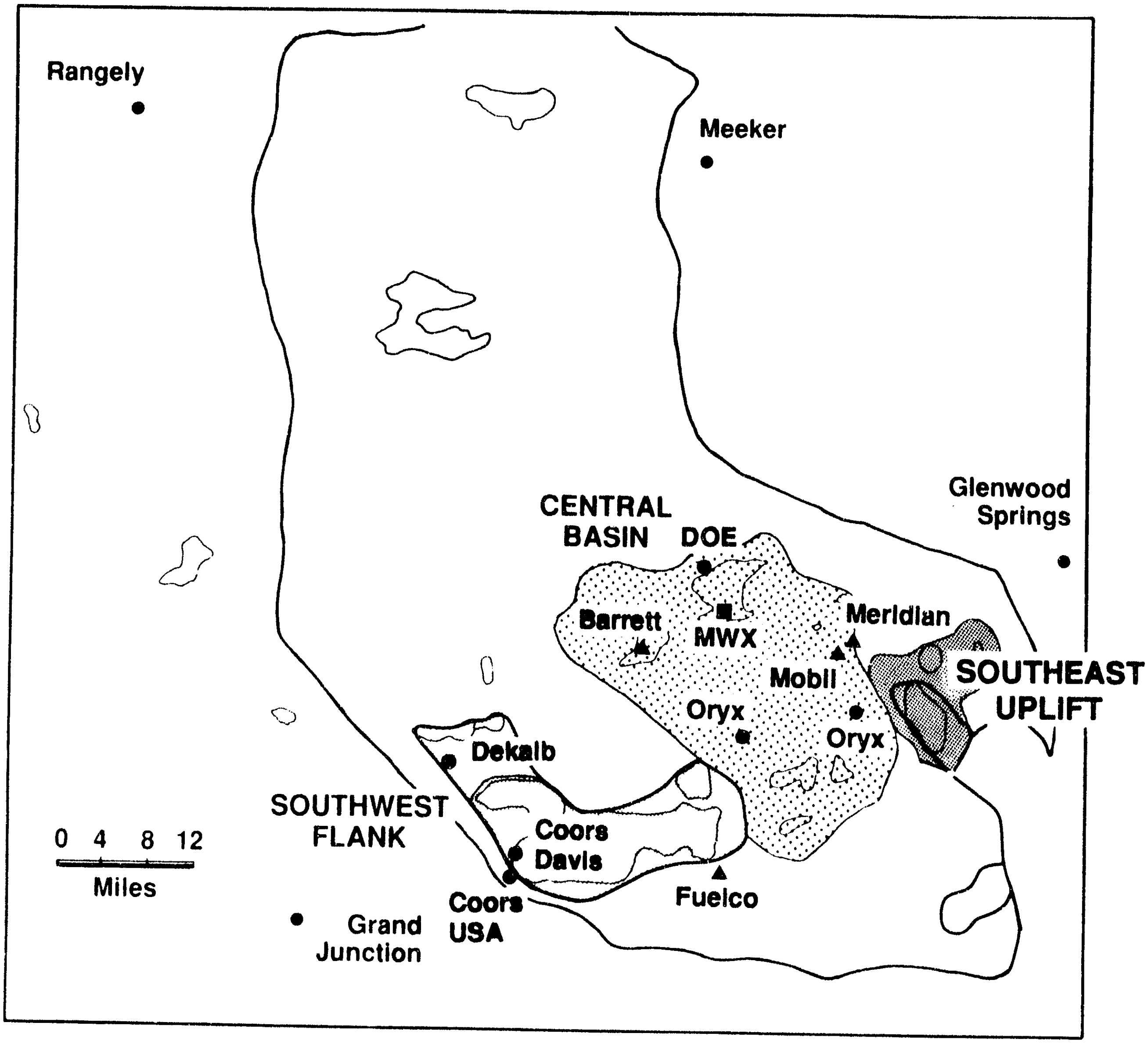


Figure 56 Map Showing the Revised Phase II Partitioned Areas: Central Basin, Southeast Uplift and Southwest Flank (Triangles are Cooperative Wells. Dots are Supplemental Information Wells)

fields, the Southwest Flank partitioned area has been extended northwestward to include Debeque and Coon Hollow fields.

The previous discussion details how the two Coors wells, the Davis and the USA wells, limit the producing area of the southwestern end of Plateau field. The area boundary in that part of the field is thus substantiated and remains unchanged.

The Plateau field produces primarily from both Corcoran and Cozzette sandstones. In the Fuelco well, both of these sands were wet, so the Fuelco location remains outside the partitioned area.

The partitioning of the southern Piceance Basin is evolving into a pattern controlled by structural position and depth. The central area is deeper, has more section in the gas saturated zone, and is naturally fractured. This area will eventually be enlarged as other basin axis areas are drilled. A limiting factor in near term development is high or steep topography in much of the central axis region.

The low dip western syncline limb of the Southwest Flank is characterized by production from the lower part of the Mesaverde section and is limited by updip water to the southwest. Natural fractures are not required for production in some wells but fractures are present in the downdip areas. The Southwest Flank partitioned area will probably continue to expand along strike both to the northwest and to the southeast. To the northwest production will be limited by the depositional limits of the marine sandstones north of DeBeque. Further to the northwest, other marine sandstones, such as the Sego, might come into play. It is possible that other Southwest Flank-type production might be scattered across the southern limb of the basin between Plateau and Ragged Mountain fields. Presently that area is undrilled because of the high topography of Grand Mesa. Production from the marine section in the extreme southern part of the basin is likewise limited by the depositional limits of the marine sandstones.

5.0 CONCLUSIONS

The field verification tests and supplemental well information have contributed to a successful program to further characterize the geologic and production aspects of the three partitioned areas. The following conclusions are important contributions of this study:

The natural fracture system identified as important to Mesaverde gas production at MWX/SHCT was found throughout the Central Basin area with consistent orientation. The same fracture system could also contribute to production in the eastern part of the Southwest Flank.

Production potential of the paludal and fluvial intervals in the Central Basin area was further verified. The Central Basin area has the potential to expand in other deeper basin axis areas.

The Southeast Uplift partitioned area is distinctly different from the other southern Piceance Basin producing areas. The Southeast Uplift produces from geographically limited structural traps. The other two partitioned areas produce from the large basin-centered gas trap. The Ragged Mountain Field was removed from the Southeast Uplift partitioned area.

Three tests encountered unexpected water production from the marine sandstones in the Central Basin and near the Southwest Flank partitioned areas. The gas/water distribution in the marine section is not fully understood.

The Southwest Flank area was expanded to the northwest. It has the potential to expand further to the north and east along the western and southern basin limbs.

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APPENDIX 1

DESCRIPTION OF THE LOG ANALYSIS MODEL

A significant portion of the Phase II TETWGS study included the log analysis of cooperative wells and various other key wells in the Piceance Basin. This analysis used the TITEGAS log analysis system which is a computer program developed by CER Corporation. The TITEGAS system is used specifically for tight gas sand applications. Porosity analysis accounts for both variable lithology and variable flushing using the techniques that CER has described in SPWLA and SPE technical papers (SPWLA Trans, Kukal, 1984; Kukal and Hill, 1986; SPE 12851, Kukal, 1984). Water saturation is calculated using the modified Simandoux Equation and CER's Density-Neutron saturation equation (SPWLA Trans, Kukal, 1983). The dual treatment of saturations provides a technique to solve for formation water resistivity which is highly variable in the Mesaverde Group. This treatment also normalizes local variations in "m" and "n" which improves the reliability of the calculated water saturations.

Matrix permeability is quantified from empirical relations presented in SPE Formation Evaluation (Kukal and Simons, Dec. 1986). The core and log database used to develop the empirical permeability equations are from the marine, paludal, coastal and fluvial Mesaverde cored intervals in the three MWX wells. The calculated absolute permeability is corrected for net stress and is therefore much less than the permeability that is routinely measured from core samples. The interpretation of permeability is supported by two additional quantitative techniques. One technique is based upon the formation flushing characteristics and the other is based upon the formation SP development. SP analysis is performed only on select wells.

The log analysis uses both a porosity cutoff and a clay volume cutoff. If the calculated porosity is less than 3 percent or if the clay volume in matrix is greater than 25 percent, the other reservoir parameters are not computed. A computed interval has a "net" thickness that is the thickness that passes these two cutoffs. Cutoffs delimit vertical reservoir compartments and provide more meaningful averages of reservoir parameters. In general, when an individual Mesaverde sandstone is separated by non-reservoir barriers, the unit is broken into sub-units and accumulations and reservoir parameter averages are performed for each sub-unit.

Each zone in each sub-interval is numbered sequentially from bottom to top. The zone numbering system uses the letter prefixes Cor, Coz, R, P, FG, FT and FW which correspond to the Corcoran, Cozzette, and Rollins sandstones, paludal, fluvial-gas, fluvial-transition, and fluvial-wet sub-intervals, respectively. The discussion for the John Brown E&C DOE No. 1-M-17 well further divides the FG sub-interval into the C and F which corresponds to the coastal and fluvial depositional environments.

A computer program was run to accumulate and average the reservoir parameters and a table was made to summarize the reservoir characteristics of each zone.

APPENDIX 2

FORMAT FOR LOG ANALYSIS RESULTS

Tabular log analysis results include the log depths of each zone, gross thickness (GROSS H), in ft, net thickness (NET H), in ft, average porosity (AVG Ø), in percent, maximum porosity (MAX Ø), in percent, average water saturation (AVG SW), in percent, minimum water saturation (MIN SW), in percent, a summation of hydrocarbon-ft (HCFT) = [H x Ø x (1 - Sw)], in ft, average clay volume in matrix (AVG CLAY), in percent, minimum clay volume in matrix (MIN CLAY), in percent, and SP index.

The next few paragraphs are a guide to the TITEGAS computed log and offer suggestions for the interpretation of this log. Track 1 presents a bulk volume analysis of matrix and fluid components. From left to right the bulk volume includes clay, sand, carbonate, gas-filled porosity and water-filled porosity. When coals are discriminated, lines are hatched across Track 1. Results for carbonate volume are only presented when photoelectric effect measurements are available. Invalid density data may be flagged in the depth track.

Computed water saturations are presented in Track 2. The dashed curve is the water saturation of the formation, i.e., is a conventional shaly sand treatment using the deep resistivity log. The solid curve is the water saturation of the "near wellbore zone" and is modeled from the response of the density and neutron logs. The dual calculation of deep and shallow water saturations provides a permeability indicator, i.e., the departure of the deep and shallow water saturation curves are an indication of flushing. The difference between the two saturations is called the "flushing index". This index is accumulated throughout each zone in Track 2. Experience has shown that sandstones must have greater than 0.01 millidarcy matrix permeability to show significant flushing (not to be confused with invasion into natural fractures which shows little expression on density and neutron logs). However, flushing is influenced by both time and pressure differential and these factors must therefore be taken into consideration when correlating flushing index with permeability.

Track 3 presents total porosity and absolute matrix permeability. The permeability trace is scaled logarithmically. Two reference lines are drawn for 1.0 microdarcy and 1.0 millidarcy. A summation of permeability (kh) through each vertically continuous zone is presented on the left side of Track 3. Core porosity and stressed core permeability (∞) are presented as a "+" symbol when core data is available.

Track 4 presents basic density porosity (using the matrix that is indicated on the computed log heading) as a solid curve and corrected neutron porosity as a dashed curve. SP Index is a solid curve. This index is the ratio: Rw true formation/Rw that is calculated from the SP. The SP Index normally varies between 0.0 and 1.0. Zones having a higher SP Index often have higher permeability, although there are exceptions to this generalization. When a zone is significantly under-pressured with respect to the mud weight gradient, a streaming potential may develop. Streaming potential is caused by a dynamic water loss into the formation. A zone having an SP Index that is greater than 1.0 usually indicates a streaming potential.

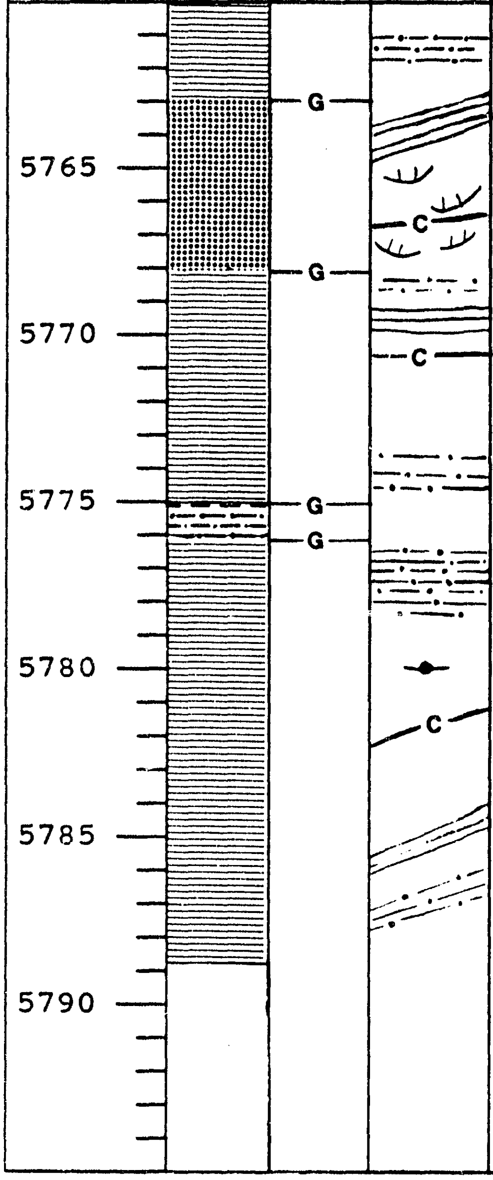
APPENDIX 3

CORE AND FRACTURE DESCRIPTIONS FROM THE BARRETT MV 8-4

DOE-MWX TECHNOLOGY EXTRAPOLATION DATE 18 December 1989
FIELD CORE DESCRIPTION PAGE 1 of 1

OPERATOR Barrett Resources Corp. **WELL** MV-8-4
COUNTY/STATE Garfield County, Co. **LOCATION** Sec 4, T7S,R96W
CORE NUMBER/CORED INTERVAL Core No. 1; 5760.0-5788.8 ft
DATUM 6063.0 **FT (KB, DF, GL) Geol.** C. Riecken/E. Price
REMARKS

CORE DEPTH	ROCK TYPE	CON-TACT	MODI-FIERS	FRACS	SHOWS	CORE DESCRIPTION AND COMMENTS



5760-63 ft Mudstone; dk gry-blk, slty; non calc.
5763-68 ft Sandstone; vf g, gry, calc, f lams, inclined & rippled, 1-2 mm ms and coaly partings
5768-84 ft Mudstone; drk gry to blk, calc w/ coaly films and partings on horz lams and surfaces, interbedded w/ drk gry slty-ms and slst; 5775-76 ft gry calc slst

5784-88.8 ft Mudstone; blk, interbedded w/ inclined lams of drk gry, calc slst

VERTICAL SCALE: 5 FT

OPERATOR Barrett Resources Corp. **WELL** MV-8-4
COUNTY/STATE Garfield County, Co. **LOCATION** Sec 4, T7S,R96W
CORE NUMBER/CORED INTERVAL Core No. 1; 5760.0-5788.8 ft
DATUM 6063.0 **FT (KB, DF, GL) ANALYST** E. Monson
REMARKS Core scribed and downhole survey tool run.

FRAC. NO.	FRAC. DEPTH	MEASURED STRIKE	DIP	TRUE AZIM.	CLASS	DESCRIPTIVE FEATURES
1	5760.6-5762.3	46	89	57	CI	Subvertical; unbroken, width 0.2 mm to <0.05 mm; begins at break in core; enclosed; centerline
2	5763.0-5765.0	58	83	69	CI	Subvertical; unbroken (5763.0-63.2 ft) width <0.05 mm; broken (5763.2-65.0 ft) no mineralization or slickensides; hooks out at bottom; penetrating; petal-centerline
3	5765.5-5767.5	53	87	64	CI	Subvertical; broken (5765.5-67.0 ft), no mineralization or slickensides; unbroken (5767.0-67.5 ft), width 0.05 mm; hooks out at top; penetrating; petal-centerline
4	5767.9-5770.8	71	89	82	CI	Subvertical; unbroken, width 0.1 mm; broken (5770.0-70.1 ft), no mineralization or slickensides; begins & ends in core; enclosed; centerline
5	5770.5-5780.2	59	89	70	CI	Subvertical; unbroken (5770.5-70.9 ft), width <0.05 mm; broken (5770.9-71.2 ft), no mineralization or slickensides; unbroken (5771.2-80.2 ft), width <0.05 mm; enechelon; hooks out at top; ends at break in core; penetrating; petal-centerline

NOTE:TRUE AZIMUTH NOT CORRECTED FOR HOLE DEVIATION, IF ANY CER85-6

DATE 18 December 1989
PAGE 2 of 2

OPERATOR Barrett Resources Corp. **WELL** MV-8-4
COUNTY/STATE Garfield County, Co. **LOCATION** Sec 4, T7S,R96W
CORE NUMBER/CORED INTERVAL Core No. 1; 5760.0-5788.8 ft
DATUM 6063.0 **FT (KB, DF, GL) ANALYST** E. Monson
REMARKS Core scribed and downhole survey tool run.

FRAC. NO.	FRAC. DEPTH	MEASURED STRIKE	MEASURED DIP	TRUE AZIM.	CLASS	DESCRIPTIVE FEATURES
6	5770.9-5771.0	62	32	73	CI	Inclined; broken, no mineralization or slickensides; intersects fracture No. 5 at 5771.0 ft; hooks out at top penetrating; petal
7	5780.2-5782.8	280	90	111	CI	Vertical; unbroken, width 0.05 mm; trace right of MOL ends at 5781.1 ft; begins and ends at break in core; enclosed; centerline
8	5785.1-5787.1	45	89		CI	Subvertical; broken, no mineralization or slickensides; begins and ends at break in core; enclosed; centerline
						5788.8 ft bottom of core
						Continuous Interval, ft 5760.6-5782.8

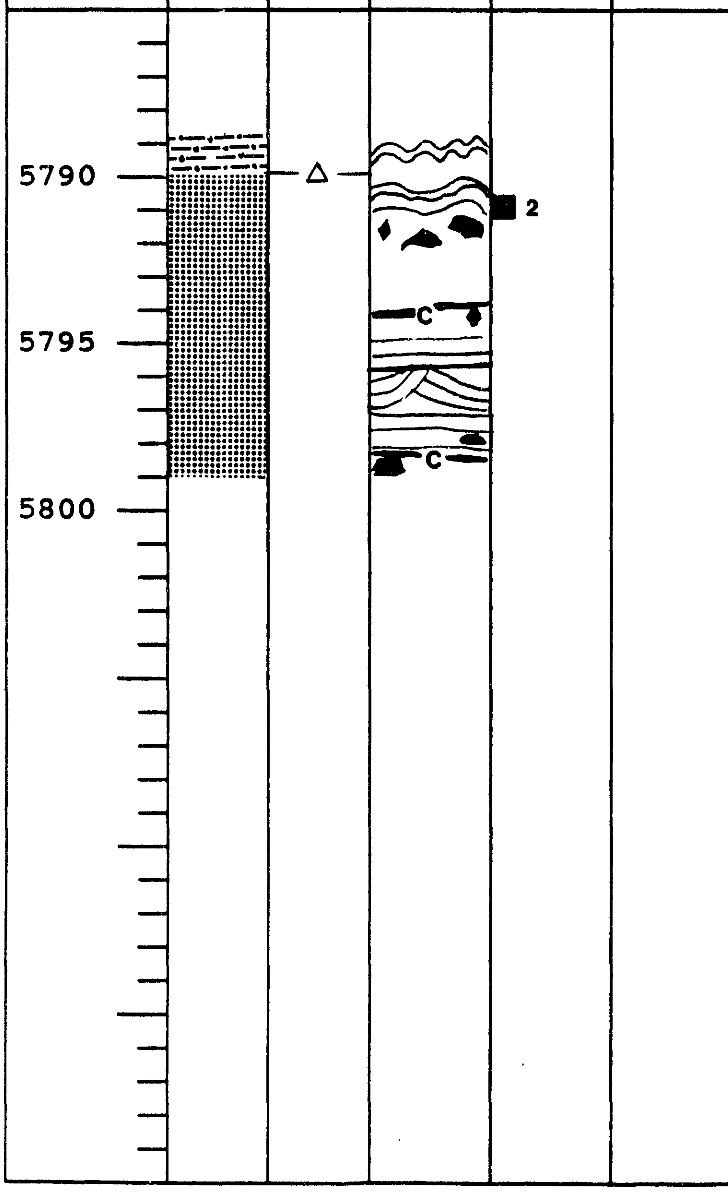
NOTE: TRUE AZIMUTH NOT CORRECTED FOR HOLE DEVIATION, IF ANY

CER85-6

DOE-MWX TECHNOLOGY EXTRAPOLATION DATE 18 December 1989
FIELD CORE DESCRIPTION PAGE 1 of 1

OPERATOR Barrett Resources Corp. **WELL** MV-8-4
COUNTY/STATE Garfield County, Co. **LOCATION** Sec 4, T7S,R96W
CORE NUMBER/CORED INTERVAL Core No. 2; 5788.8-5799.0 ft
DATUM 6063.0 **FT (KB, DF, GL) Geol.** C. Riecken/E. Price
REMARKS

CORE DEPTH	ROCK TYPE	CON-TACT	MODI-FIERS	FRACS	SHOWS	CORE DESCRIPTION AND COMMENTS



5788.8-90 ft Siltstone; drk gry, calc

5790-96 ft Sandstone; gry, f-m g, calc, chiefly horz lams, w/ thin 1-2 mm coal partings, occ pyr, and brn sid mud lumps

5796-99.0 ft Sandstone; drk gry, m g, calc, cross bedded lams grading to horz, 1-2 mm coaly partings, 5mm sid mud lumps

VERTICAL SCALE: 5 FT

DOE-MWX TECHNOLOGY EXTRAPOLATION DATE 18 December 1989
CORE FRACTURE DESCRIPTION PAGE 1 of 1

OPERATOR Barrett Resources Corp. **WELL** MV-8-4
COUNTY/STATE Garfield County, Co. **LOCATION** Sec 4, T7S,R96W
CORE NUMBER/CORED INTERVAL Core No. 2; 5788.8-5799.0 ft
DATUM 6063.0 **FT (KB, DF, GL) ANALYST** E. Monson
REMARKS Core scribed and downhole survey tool run.

FRAC. NO.	FRAC. DEPTH	MEASURED STRIKE	MEASURED DIP	TRUE AZIM.	CLASS	DESCRIPTIVE FEATURES
1	5790.1-5790.4	294	71	25	CI	Inclined; unbroken, width <0.05 mm; hooks out at top; penetrating; petal
2	5791.5-5792.0	301	88	112	Nat	Subvertical; unbroken, width 0.2 mm; mineralized, completely infilled; reacts with HCl; enechelon; enclosed
						5799.0 bottom of core
						Continuous Interval, ft 5789.2-5798.0

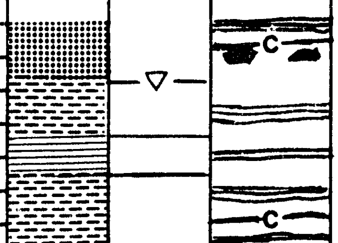
NOTE: TRUE AZIMUTH NOT CORRECTED FOR HOLE DEVIATION, IF ANY CER85-6

DOE-MWX TECHNOLOGY EXTRAPOLATION
FIELD CORE DESCRIPTION

DATE 19 December 1989
PAGE 1 **of** 1

OPERATOR Barrett Resources Corp. **WELL** MV-8-4
COUNTY/STATE Garfield County, Co. **LOCATION** Sec 4, T7S,R96W
CORE NUMBER/CORED INTERVAL Core No. 3; 5799.0-5805.6 ft
DATUM 6063.0 **FT (KB, DF, GL) Geol.** C. Riecken/E. Price
REMARKS

CORE DEPTH	ROCK TYPE	CON-TACT	MODI-FIERS	FRACS	SHOWS	CORE DESCRIPTION AND COMMENTS
						5799.0-5800.7 ft Sandstone; gry, m g, calc, thin 1-2 mm carb partings
5800						5800.7-02.4 ft Shale; blk, carb, non calc
						5802.5-03.5 ft Mudstone; gry
5805						5803.5-05.6 ft Shale; blk, carb, non calc



VERTICAL SCALE: 5 FT

DOE-MWX TECHNOLOGY EXTRAPOLATION
CORE FRACTURE DESCRIPTION

DATE 18 December 1989
PAGE 1 of 1

OPERATOR Barrett Resources Corp. **WELL** MV-8-4
COUNTY/STATE Garfield County, Co. **LOCATION** Sec 4, T7S,R96W
CORE NUMBER/CORED INTERVAL Core No. 3; 5799.0-5805.6 ft
DATUM 6063.0 **FT (KB, DF, GL) ANALYST** E. Monson
REMARKS Core scribed and downhole survey tool run. Fracture strike and dip measured with respect to Principal Scribe Line.

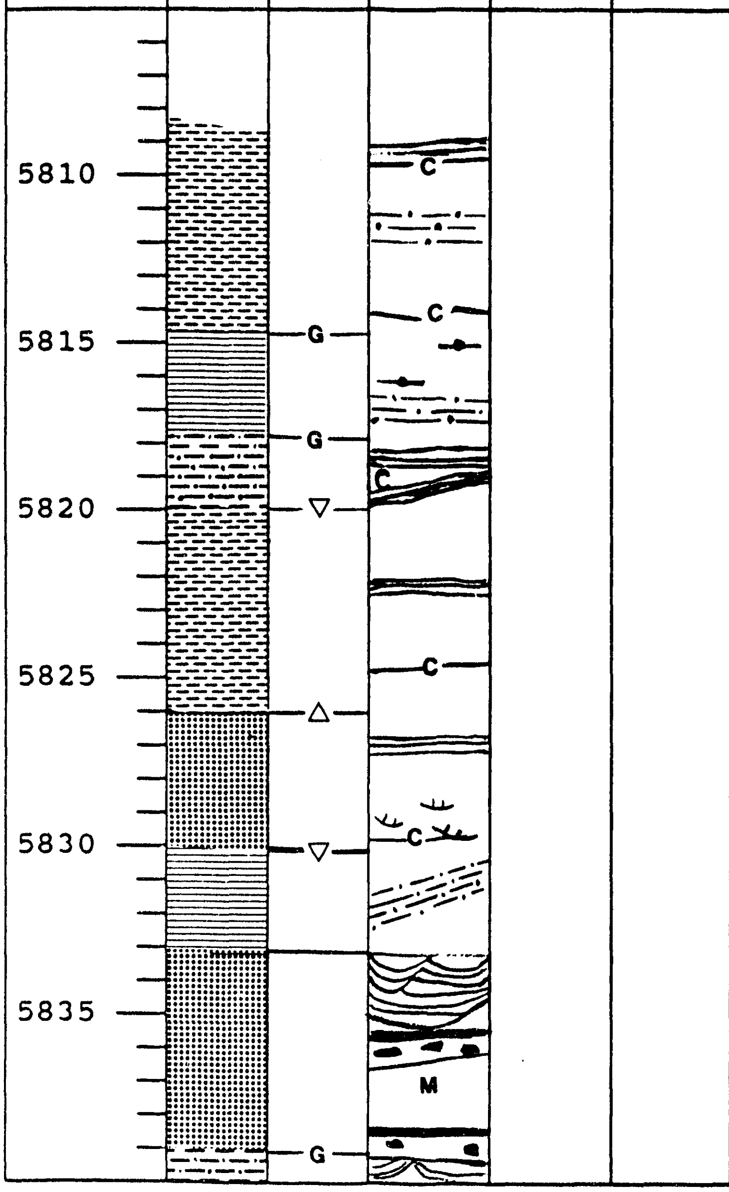
FRAC. NO.	FRAC. DEPTH	MEASURED STRIKE	MEASURED DIP	TRUE AZIM.	CLASS	DESCRIPTIVE FEATURES
1	5803.7-5803.8	295	53	70	CI	Inclined; unbroken, width 0.05 mm; hooks out at top; penetrating; petal
2	5804.5-5804.6	306	64	81	CI	Inclined; broken, no mineralization or slickensides; hooks out at top; penetrating; petal
3	5804.7-5805.0	303	78	78	CI	Inclined; broken, no mineralization or slickensides; hooks out at top; penetrating; petal
						5805.6 ft bottom of core
						Continuous Interval, ft 5799.0-5805.5

NOTE: TRUE AZIMUTH NOT CORRECTED FOR HOLE DEVIATION, IF ANY

CE885-6

OPERATOR Barrett Resources Corp. **WELL** MV-8-4
COUNTY/STATE Garfield County, Co. **LOCATION** Sec 4, T7S,R96W
CORE NUMBER/CORED INTERVAL Core No. 4; 5808.6-5869.0 ft
DATUM 6063.0 **FT (KB, DF, GL) Geol.** C. Riecken/E. Price
REMARKS

CORE DEPTH	ROCK TYPE	CON-TACT	MODI-FIERS	FRACS	SHOWS	CORE DESCRIPTION AND COMMENTS



5808.6-10 ft Shale;
blk, carb, non calc w/ thin coaly partings

5810-14 ft Shale;
drk gry-blk, slty, chiefly horz 5-10 mm slst lams

5814-14.5 ft Shale
blk, carb, w/ thin 5-10 mm coaly streaks

5814.5-17.8 ft Mudstone;
gry, slty, fos

5817.8-20 ft Siltstone;
gry, w/ coaly partings

5820-26 ft Shale;
blk, carb w/ thin shiny blk coal partings

5826-28 ft Sandstone;
gry, slty-vf g, w/ thin horz lams

5828-30 ft Sandstone;
gry, f-m g, thin 2-10 mm lams, w/ v thin < 1 mm coaly partings

5830-33 ft Mudstone-SLST;
gry-blk, inclined lams

5833-37 ft Sandstone;
gry, f-m g, calc, cross bedded lams, w/ blk 1-2 mm inclined (13 degree) partings, drk gry mdst interclasts

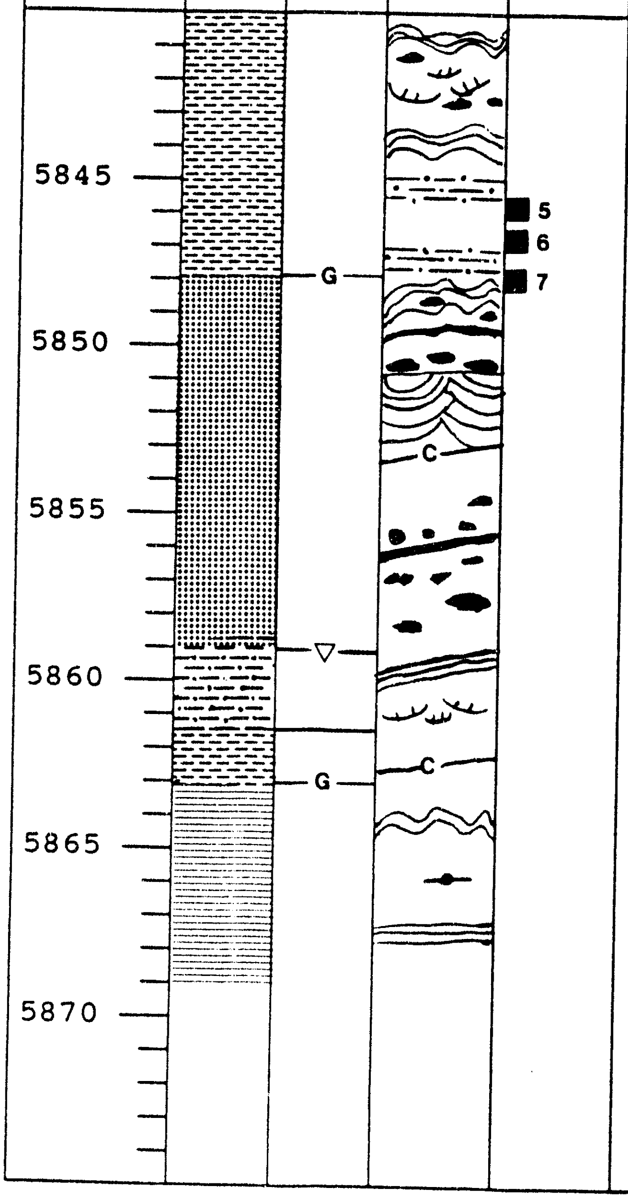
VERTICAL SCALE: 5 FT

DOE-MWX TECHNOLOGY EXTRAPOLATION
FIELD CORE DESCRIPTION

DATE 19 December 1989
PAGE 2 of 3

OPERATOR Barrett Resources Corp. **WELL** MV-8-4
COUNTY/STATE Garfield County, Co. **LOCATION** Sec 4, T7S,R96W
CORE NUMBER/CORED INTERVAL Core No. 4; 5808.6-5869.0 ft
DATUM 6063.0 **FT (KB, DF, GL) Geol.** C. Riecken/E. Price
REMARKS

CORE DEPTH	ROCK TYPE	CON-TACT	MODI-FIERS	FRACS	SHOWS	CORE DESCRIPTION AND COMMENTS



5837-39 ft Sandstone; gry, m g, w/ blk sh parting, 7.5 cm thick at 5835.5 ft

5839-40 ft Siltstone/Shale; gry-blk

5840-42 ft Shale; blk

5842-48 ft Shale; blk, interbedded w/ sltst, gry, calc, highly contorted & inclined lams, ripup clasts & mdst partings, vertical and inclined ccf

5848-50 ft Sandstone; gry, f-m g, calc, w/ blk mdst interclasts, contorted bedding. 5849.75 ft 5 cm blk mdst parting

5850-59 ft Sandstone; gry, m g, w/ blk irr shaped (up to 15 cm) mdst interclasts, 5851 ft cross-bedding, 5853 ft thin (1-2 mm) coal partings, 5855 ft small (up to 1 cm) mdst interclasts & mud balls 5858.8 ft gry-blk mdst interclasts

5859-61.4 ft Siltstone; gry, interlam w/ 1-5mm blk carb mdst partings

5861.4-63 ft Shale; blk w/ thin 1-2mm coaly lam

VERTICAL SCALE: 5 FT

OPERATOR Barrett Resources Corp. **WELL** MV-8-4
COUNTY/STATE Garfield County, Co. **LOCATION** Sec 4, T7S,R96W
CORE NUMBER/CORED INTERVAL Core No. 4; 5808.6-5869.0 ft
DATUM 6063.0 **FT (KB, DF, GL) Geol.** C. Riecken/E. Price
REMARKS

CORE DEPTH	ROCK TYPE	CON-TACT	MODI-FIERS	FRACS	SHOWS	CORE DESCRIPTION AND COMMENTS
						5863-65.5 ft Mudstone; blk interlam w/ gry slst showing contorted lam 5865.3-69.0 ft Mudstone; gry-blk

VERTICAL SCALE: 5 FT

OPERATOR Barrett Resources Corp. **WELL** MV-8-4
COUNTY/STATE Garfield County, Co. **LOCATION** Sec 4, T7S,R96W
CORE NUMBER/CORED INTERVAL Core No. 4; 5808.6-5869.0 ft
DATUM 6063.0 **FT (KB, DF, GL) ANALYST** E. Mcnson
REMARKS Core not scribed and no downhole survey tool run.

FRAC. NO.	FRAC. DEPTH	MEASURED STRIKE	DIP	TRUE AZIM.	CLASS	DESCRIPTIVE FEATURES
1	5826.3-5826.5	61	61		CI	Inclined; unbroken, width <0.05 mm; hooks out at top; penetrating; petal
2	5826.6-5826.8				CI	Inclined; unbroken, width <0.05 mm; hooks out at top; not developed enough to measure strike and dip; penetrating; petal
3	5826.9-5827.0	67	57		CI	Inclined; unbroken, width <0.05 mm; hooks out at top; ends at break in core; penetrating; petal
	5830.0	174	7			Bedding plane; blk mdst; crossing
4	5830.1-5830.5	291	68		CI	Inclined; unbroken, width <0.05 mm; hooks out at top; ends at break in core; penetrating; petal
	5835.15 5835.25	169	13			Bedding plane; crossing
	5838.4	129	2			Bedding plane; drk blk mdst; dip and strike measured at top of contact; crossing
	5844.2-5844.5	15	40			Bedding plane; crossing

NOTE:TRUE AZIMUTH NOT CORRECTED FOR HOLE DEVIATION, IF ANY CER85-6

DOE-MWX TECHNOLOGY EXTRAPOLATION   DATE 19 December 1989
CORE FRACTURE DESCRIPTION   PAGE 2 of 2

OPERATOR Barrett Resources Corp. **WELL** MV-8-4
COUNTY/STATE Garfield County, Co. **LOCATION** Sec 4, T7S,R96W
CORE NUMBER/CORED INTERVAL Core No. 4; 5808.6-5869.0 ft
DATUM 6063.0 **FT (KB, DF, GL) ANALYST** E. Monson
REMARKS Core not scribed and no downhole survey tool run.

FRAC. NO.	FRAC. DEPTH	MEASURED STRIKE	DIP	TRUE AZIM.	CLASS	DESCRIPTIVE FEATURES
5	5845.2-5845.7	162	89		Nat	Subvertical; unbroken, width 0.5 mm; mineralized, completely infilled, reacts with HCl; trace left of MOL enechelon; ends at blk mdst bed; enclosed
6	5846.1-5846.4				Nat	Subvertical; unbroken, width 0.5 mm; mineralized, completely infilled, reacts with HCL; 6 traces left of MOL; enclosed
7	5847.8-5848.1				Nat	Subvertical; unbroken, width 0.1 mm; mineralized, completely infilled, reacts with HCL; single trace 168 right of MOL; enclosed
8	5853.1-5854.2	294	89		CI	Subvertical; broken, no mineralization or slickensides; begins and ends in core; enclosed; centerline
	5863.0	266	23			Bedding plane; crossing
						5869.0 bottom of core
						Continuous Intervals, ft 5809.5-5814.3 5819.2-5822.5 5822.5-5827.5 5827.9-5835.8 5835.8-5839.2 5840.0-5867.2

NOTE:TRUE AZIMUTH NOT CORRECTED FOR HOLE DEVIATION, IF ANY   CER85-6

APPENDIX 4

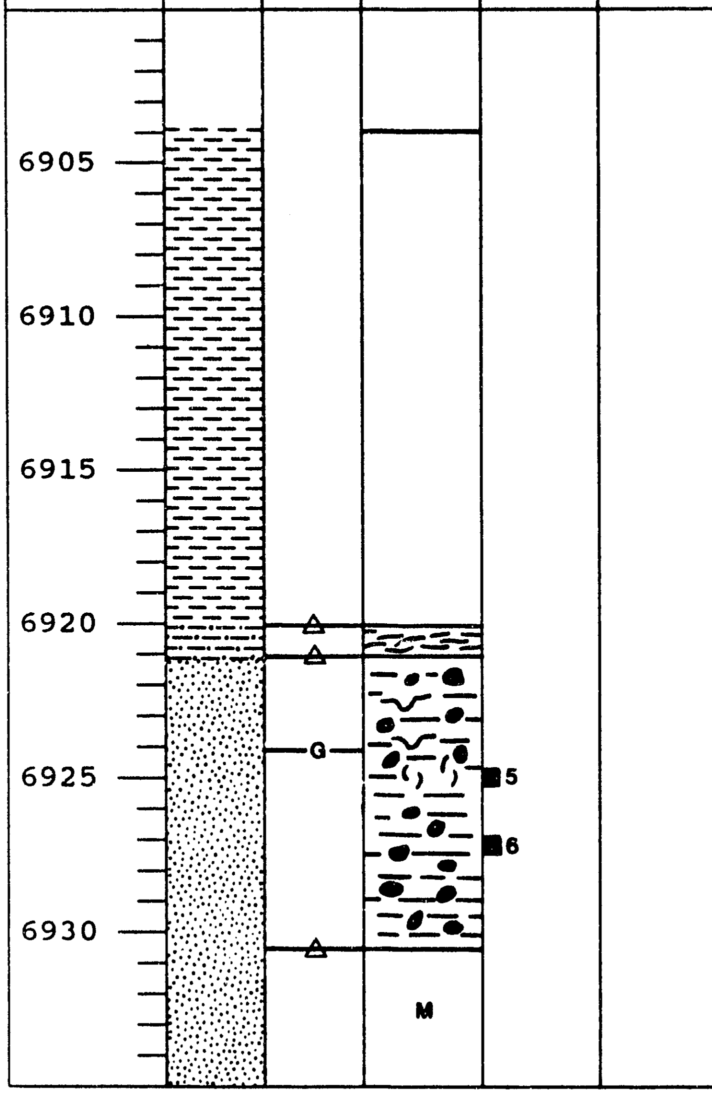
CORE AND FRACTURE DESCRIPTIONS FROM THE FUELCO E-22-10-94-S

DOE-MWX TECHNOLOGY EXTRAPOLATION
FIELD CORE DESCRIPTION

DATE September 20, 1990
PAGE 1 of 2

OPERATOR Fuelco **WELL** E-22-10-94S
COUNTY/STATE Mesa, CO **LOCATION** Sec22 T10S R94W
CORE NUMBER/CORED INTERVAL Core #1; 6904.0-6960 ft (Rec 53.8')
DATUM 7926 KB **FT (KB, DF, GL) Geol.** C. Riecken
REMARKS

CORE DEPTH	ROCK TYPE	CONTACT	MODIFIERS	FRACS	SHOWS	CORE DESCRIPTION AND COMMENTS



6904-6920.2 ft shale; blk, carb

6920.2-6921.1 shale; blk, carb, interbedd w/siltstone drk gray to blk

6921.1-6924.2 sandstone; gry vf g, sub rounded, well sorted calc cmt, blk mica, shows extensive soft sed deformation w/blk mudstone-shale streaks, rip up clasts & brn & blk mud balls

6924.2-6930.5 sandstone; gry, vf g, sub rounded, well sorted calc cmt, blk mica, has pinpoint porosity (PP)

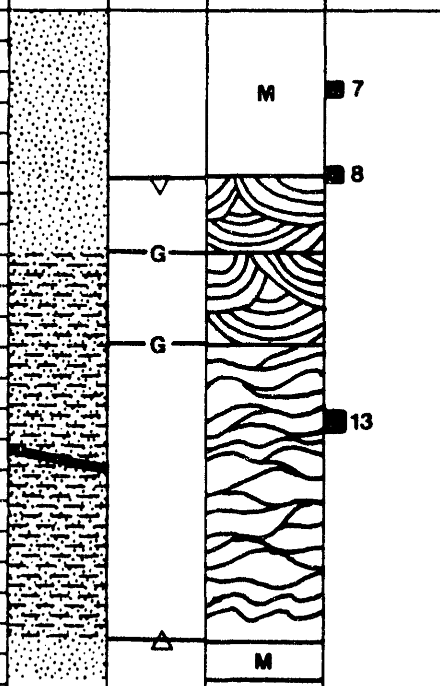
6930.5-6930.7 shale, blk, carb parting

6930.7-6940.7 sandstone; gry vf-f g, sub rounded, clean, well sorted, calc cmt, blk mica, massive bedded, PP

VERTICAL SCALE: 5 FT

OPERATOR Fuelco **WELL** E-22-10-94-S
COUNTY/STATE Mesa, CO **LOCATION** Sec22 T10S R94W
CORE NUMBER/CORED INTERVAL Core #1; 6904.0-6960 ft (Rec 53.8')
DATUM 7926 **FT (KB, DF, GL) Geol.** C. Riecken
REMARKS

CORE DEPTH	ROCK TYPE	CON-TACT	MODI-FIERS	FRACS	SHOWS	CORE DESCRIPTION AND COMMENTS
6940						6940.7-6943 sandstone, gry, vf g, calc cmt, cross bedded, fine lam
						6943-6946 sandstone, gry, vf g, calc cmt, cross bedded w/inter lam, blk shale
6945						6946-6955.8 sandstone, gry, vf g, calc cmt, chiefly 1-4mm blk shale inter lam, occasional 2 cm shale breaks, characteristically contorted bedding
6950						
6955						6955.8-6957.8 sandstone, gry f g, calc cmt w/massive bedding



VERTICAL SCALE: 5 FT

CORE FRACTURE DESCRIPTION

DATE September 20, 1990

OPERATOR Fuelco WELL EM-22-10-94-S

COUNTY /STATE Mesa, CO LOCATION sec. 22, T10S, R94W

CORE NUMBER/ CORED INTERVAL Core No. 1, cut 6904.0-6964.0 (rec. 53.8 ft)

DATUM 7926 KB FT (KB, DF, GL) ANALYST R.E. Hill and R. Zeis

REMARKS Cozzette Interval

FRAC. NO.	FRACTURE DEPTH	MEASURED		TRUE AZIMUTH	CLASSIFI-CATION	DESCRIPTIVE FEATURES
		STRIKE	DIP			
1	6904.3 6904.6	350°	90°	81°	CI	**Mudstone**, vertical, exits core at bottom, broken, no mineralization, fracture starts at top of core
2	6904.8 6905.7				CI	**Mudstone**, irregular hairline crack
3	6905.7 6920.3	0°		91°	CI	**Mudstone**, numerous hairline cracks, some cross core, most are vertical, surfaces are very irregular, one long frac extends from 6910.7 to 6919.4
4	6925.2	1°		92°	NAT	**Sandstone**, enclosed, unbroken, mineralized, non-calcareous
5	6927.2 6927.4	3°	30°	94°	NAT	**Mudstone**, inclined, crossing, broken, slicks present,
6	6930.5 6931.5	308°	79°		NAT	**Sandstone**, inclined, exits core at bottom, begins at a shale bed, width <0.5 mm, mineralized, non-calc., surface has specular appearance
7	6937.6	315°	60°		NAT	**Sandstone**, inclined, exits core at top, terminates at break in core, broken, mineralized with quartz crystals, sone crystals are euhedral-subhedral
8	6940.0 6942.2	140°	81°		NAT	**Sandstone**, inclined, crossing, broken, mineralized, blotchy calcite and <0.5 mm euhedral quartz crystals
9	6942.5	135°			NAT	**Sandstone**, sub-vertical, crossing, broken, no mineralization, crosses bedding which are thin shale laminations

CORE FRACTURE DESCRIPTION

DATE September 20, 1990

PAGE 2 OF 3

OPERATOR Fuelco WELL EM-22-10-94-S

COUNTY /STATE Mesa, CO LOCATION sec. 22, T10S, R94W

CORE NUMBER/ CORED INTERVAL Core No. 1, cut 6904.0-6964.0 (rec. 53.8 ft)

DATUM 7926 KB FT (KB, DF, GL) ANALYST R.E. Hill and R. Zeis

REMARKS Cozzette Interval

FRAC. NO.	FRACTURE DEPTH	MEASURED STRIKE	MEASURED DIP	TRUE AZIMUTH	CLASSIFI-CATION	DESCRIPTIVE FEATURES
10	6944.4				CI	**Sandstone**, inclined, exits core at top, unbroken
11	6946.2 6946.4				CI	**Sandstone**, inclined, exits core at top, unbroken
12	6946.6 6946.8				CI	**Sandstone**, inclined, exits core at top, unbroken
13	6948.3				NAT	**Mudstone**, sub-horizontal, crossing, broken, slickensides, there is also a vertical crack through mudstone with 48° strike
14	6948.8 6949.9	323°		93°	CI	**Sandstone**, sub-vertical, exits core at top, broken, no mineralization, fracs cross bedding and terminate at bedding, 6 petal fractures, with an ec-centerline fracture connecting them, one petal frac on opposite side of core
15	6951.1 6952.7	308		82	CI	**Sandstone**, sub-vertical, exits core at top, not broken, terminates at base of shale lamination with refraction at sand-shale interface
16	6953.6 6954.4	129			CI	**Sandstone**, inclined, exits core at top, broken, crosses numerous shale laminations but terminates at a shale lamination
17	6955.1 6955.4				CI	**Sandstone**, inclined, exits core at top, broken, terminates at break in core
18	6955.9				CI	**Sandstone**, inclined, exits core at top, not broken

CORE FRACTURE DESCRIPTION

DATE September 20, 1990

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OPERATOR Fuelco WELL EM-22-10-94-S

COUNTY /STATE Mesa, CO LOCATION sec. 22, T10S, R94W

CORE NUMBER/ CORED INTERVAL Core No. 1, cut 6904.0-6964.0 (rec. 53.8 ft)

DATUM 7926 KB FT (KB, DF, GL) ANALYST R.E. Hill and R. Zeis

REMARKS Cozzette Interval

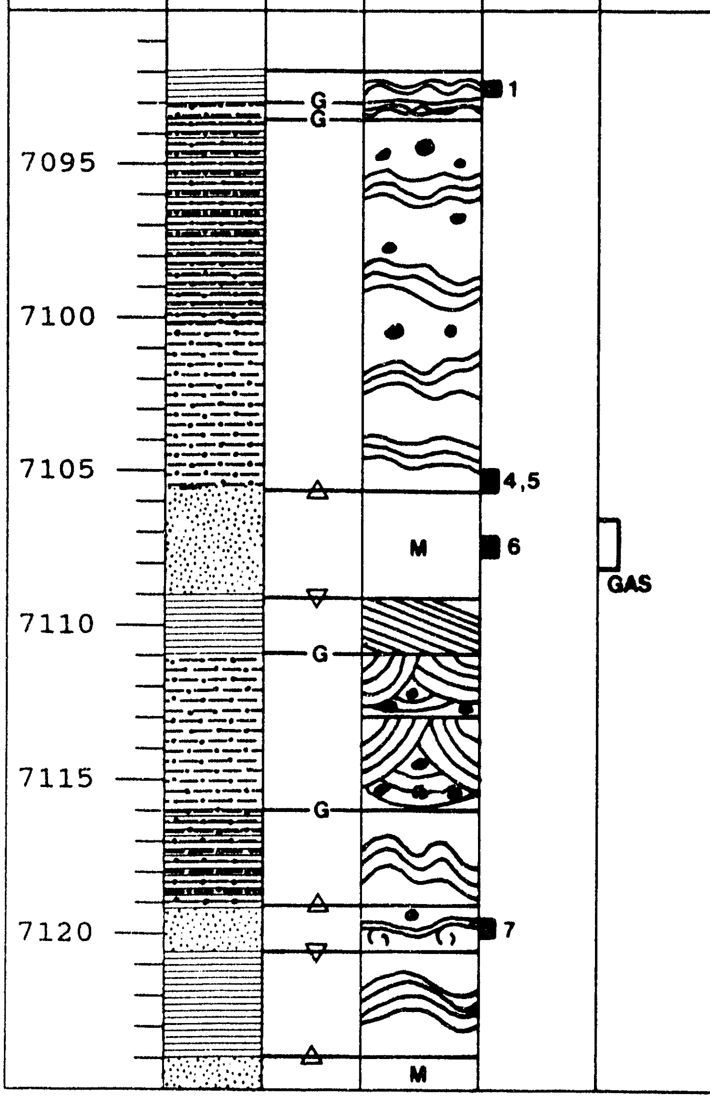
FRAC. NO.	FRACTURE DEPTH	MEASURED STRIKE	MEASURED DIP	TRUE AZIMUTH	CLASSIFI-CATION	DESCRIPTIVE FEATURES
19	6955.9 6956.0				Cl	**Sandstone**, inclined, exits core at top, not broken
20	6955.9 6957.0	310°	86°		Cl	**Sandstone**, inclined, exits core at top, not broken, opposite dip direction to Frac 19
21	6956.2 6956.3				Cl	**Sandstone**, inclined, exits core at top, not broken, en echelon with Frac 20
22	6956.9 6957.8	306°	88°		Cl	**Sandstone**, inclined, exits core at top, extends beyond bottom of core, broken, opposite half not present, parallel with Fracs 20 and 21

DOE-MWX TECHNOLOGY EXTRAPOLATION
FIELD CORE DESCRIPTION

DATE September 22, 1990
PAGE 1 of 2

OPERATOR Fuelco **WELL** E-22-10-94-S
COUNTY/STATE Mesa, CO **LOCATION** Sec22,T10S,R94W
CORE NUMBER/CORED INTERVAL Core #2 7092.0-7150.1 (Rec. 58.4ft)
DATUM 7926 KB **FT (KB, DF, GL) Geol.** C. Riecken
REMARKS

CORE DEPTH	ROCK TYPE	CONTACT	MODIFIERS	FRACS	SHOWS	CORE DESCRIPTION AND COMMENTS



7902.0-7903 Mudstone; blk, calcareous, vugs
7903-7903.7 Siltstone; gry
7903.7-7106.8 Mudstone; blk, inter lam gry, calcareous siltstone; extensive soft sediment deformation-contorted beds

7106.8-7109.2 Sandstone; gry vf g, sub rounded, well sorted, calcareous
7109.2-7111 Mudstone; blk, inter lam siltstone, gry, inclined beds
7111-7116 Chiefly siltstone; gry inter lam (1mm-2cm) blk mudstone, cross bed

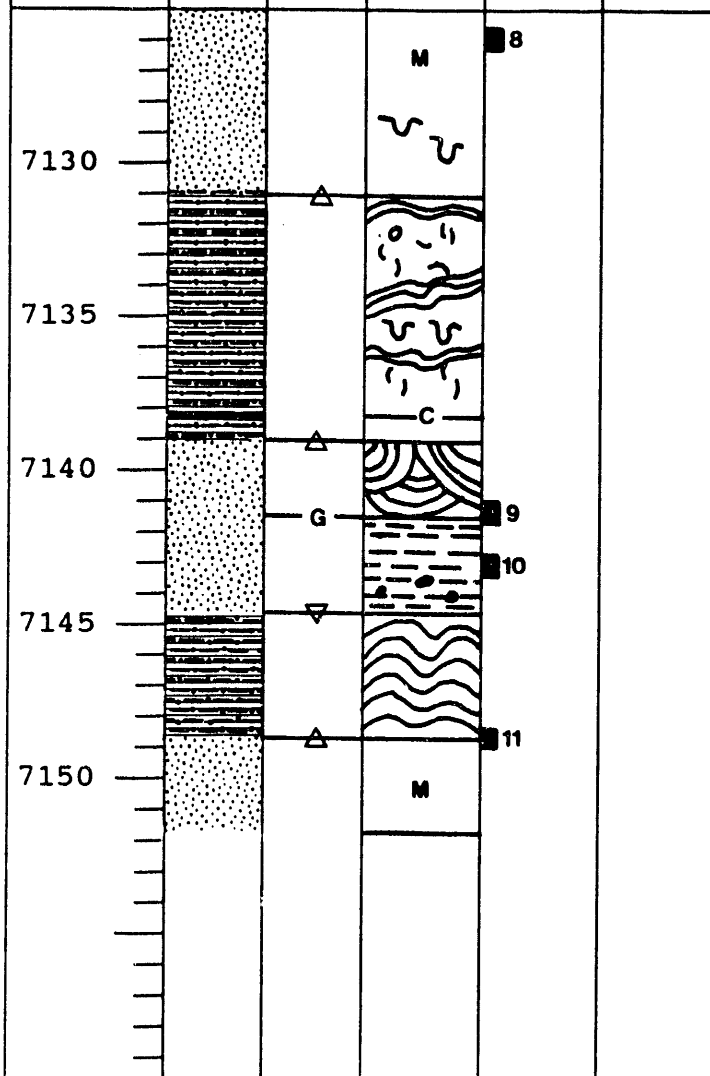
7116-7119.3 Chiefly mudstone blk w/inter lam siltstone, gry
7119.3-7120.5 Sandstone; gry, vf g, sub rounded, well sorted, calcareous, fos
7120.5-7124 Mudstone; blk

7124-7131 Sandstone; gry, vf g

VERTICAL SCALE: 5 FT

OPERATOR Fuelco **WELL** E-22-10-94-S
COUNTY/STATE Mesa, CO **LOCATION** Sec22,T10S,R94W
CORE NUMBER/CORED INTERVAL Core #2 7092.0-7150.1 (Rec.58.4 ft)
DATUM 7926 KB **FT (KB, DF, GL) Geol.** C. Riecken
REMARKS

CORE DEPTH	**ROCK TYPE**	**CON-TACT**	**MODI-FIERS**	**FRACS**	**SHOWS**	**CORE DESCRIPTION AND COMMENTS**



7124-7131 Sandstone; gry, vf g, sub rounded, well sorted, calcareous, occasional mudstone parting

7131-7139.2 Mudstone & shale blk, w/30% inter lam gry, calcareous siltstone, fos burrowed, w/ contorted lams

7139.2-7141.3 Sandstone, gry, vf g, sub rounded, well sorted, calcareous, fine lam (1-2mm)

7141.3-7139.2 Sandstone, as above w/fine lam (1-5mm) horizontal lam

7144.8-7148.7 Mudstone; blk & inter lam gry siltstone of equal proportions w/contorted beds

7148.7-7150.7 Sandstone; gry, vf g sub rounded, well sorted, calcareous, horizontal beds

VERTICAL SCALE: 5 FT

CORE FRACTURE DESCRIPTION

DATE September 22, 1990

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OPERATOR Fuelco WELL EM-22-10-94-S

COUNTY /STATE Mesa, CO LOCATION sec. 22, T10S, R94W

CORE NUMBER/ CORED INTERVAL Core No. 2, cut 7092.0-7150.1 (rec. 58.4 ft)

DATUM 7926 KB FT (KB, DF, GL) ANALYST R.E. Hill and R. Zeis

REMARKS Corcoran Interval

FRAC. NO.	FRACTURE DEPTH	MEASURED		TRUE AZIMUTH	CLASSIFI-CATION	DESCRIPTIVE FEATURES
		STRIKE	DIP			
1	7093.2 7093.4	350°		136°	NAT	**Siltstone,** sub-vertical, enclosed, broken (by hammer), mineralized with blotchy calcite, at same depth there are some low angle mineralized cracks
2	7093.1 7093.2				CI	**Siltstone**, inclined, exits core at top, unbroken, petal fracture
3	7093.3 7093.4				CI	**Siltstone**, inclined, exits core at top, unbroken, petal fracture
4	7106.5 7107.4	310°	87°	96°	NAT	**Sandstone**, sub-vertical, enclosed, broken and unbroken, mineralized with euhedral calcite crystals (~ 1mm), there is a sub-parallel frac in same interval
5	7107.4 7107.9	192°	65°		NAT	**Sandstone**, inclined, crossing, broken, mineralized with euhedral crystals (~1mm), some blotchy, intersection with Frac 4 is not clear, but the two are not parallel.
6	7107.8 7107.9	251°	16°		NAT	**Sandstone**, inclined, crossing, broken, mineralized with blotchy calcite, slickensides present and calcite has slickensides, too, this frac is not parallel with Fracs 4 or 5
7	7107.8 7108.3	350°	81°		NAT	**Sandstone,** inclined, exits core at top, broken, mineralized with blotchy calcite, terminates at mudstone bed
8	7119.6 7120.6	68°			NAT	**Sandstone**, sub-vertical, enclosed, unbroken, mineralized with calcite, width <0.5 mm, parallel frac present

CORE FRACTURE DESCRIPTION

DATE September 22, 1990

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OPERATOR Fuelco WELL EM-22-10-94-S

COUNTY /STATE Mesa, CO LOCATION sec. 22, T10S, R94W

CORE NUMBER/ CORED INTERVAL Core No. 2, cut 7092.0-7150.1 (rec. 58.4 ft)

DATUM 7926 KB FT (KB, DF, GL) ANALYST R.E. Hill and R. Zeis

REMARKS Corcoran Interval

FRAC. NO.	FRACTURE DEPTH	MEASURED		TRUE AZIMUTH	CLASSIFI-CATION	DESCRIPTIVE FEATURES
		STRIKE	DIP			
9	7126.4 7127.4	75°	87°		NAT	**Sandstone**, sub-vertical, enclosed, broken, mineralized with blotchy calcite, terminates at mudstone bed
10	7141.1 7141.4				NAT	**Sandstone**, sub-vertical, enclosed, unbroken, mineralized with blotchy calcite, en echelon with Fracs 11 and 12
11	7141.0 7141.8	63°	89°	83°	NAT	**Sandstone**, sub-vertical, enclosed, unbroken, mineralized with blotchy calcite, en echelon with Fracs 10 and 12
12	7142.4 7143.5	67°	87°	87°	NAT	**Sandstone**, sub-vertical, enclosed, unbroken, mineralized with blotchy calcite, en echelon with Fracs 10 and 11
13	7148.9 7149.0				CI	**Siltstone**, inclined, exits core at top, unbroken, no mineralization, petal frac

END

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