EXPLORATION MODEL FOR THE COAL - BEARING SAGINAW FORMATION - MICHIGAN BASIN

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ABSTRACT

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By

Jaime Alberto Rodriguez

Coal as an energy source is becomming increasingly important.

Michigan coal deposits have proved marginal at least over the years with some 46,239,607 tons recovered by 1949, and practically none since that date.

As energy requirements have prompted the reappraisal of all coal reserves, the objective herein is to survey the various exploration techniques that are compatible with existing data collecting procedures, mostly oil and gas, wells that penetrate the coal-bearing Sagniaw Formation. By means of such geophysical logs and samples or descriptions that exist on the Saginaw Formation, it is hoped that a model can be constructed that will show the most feasible means of testing the principle parameters of potentially commercial coal.

Though there are few oil and gas bore holes for which both samples and multiple geophysical logs exist, those logs available were plotted against lithologic types, both singularly and in combination (crossplots). The optimum combination of log types for in-situ exploration of the coal-bearing formation would appear to be compensated sonic, side wall neutron porosity and gamma ray logs.

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INTRODUCTION

The importance of coal in the nation's energy sphere is gaining on a daily basis. It behooves the energy producing companies and the federal and state agencies to investigate all potential coal-bearing areas for both short and long range resources.

Michigan has never been a major coal producer. However, 46,239,607 tons were recovered by 1949 (Cohee, 1950). Since that time little mining has been carried out. Thus an assessment of Michigan coal is in order. More information is needed on the quality, quantity, and availability under practical and feasible mining techniques.

In order to undergo this assessment, two approaches are foreseen. The first is based on data available from existing information such as oil and gas well records, past records of mining operations, coal analyses, and stratigraphic reports in the Michigan Basin area. The second approach is to develop, if possible, an exploration tool or technique that might be applied to existing well data to make more complete logging procedures of existing abandoned wells, and to projected drilling operations (again most likely oil and gas bore holes) that can produce more meaningful data regarding the various parameters of coal such as quality, mineral content and other physical characteristics. The present study will be focused on the later approach.

It should be mentioned that existing data on Michigan coal is sketchy to say the least for several reasons:

1. Coal samples rarely survive the drilling operations of oil and gas bore holes.

2. Drillers logs of oil and gas wells may or may not mention coal in descriptions and if so are not pin-pointed as to depth, thickness or composition.

3. Geophysical logs are rarely made in the higher part of the stratigraphic section, above important oil and gas targets.

4. Among these few logs available, sonic, density and neutron-neutron logs are essentially non-existant.

5. Most old mines are not now accessible for sampling, and existing records are scarce.

For the above and other likely constrictions affecting the present state of knowledge of our coal it would appear important to design a program that, should Michigan coal warrant a concerted effort in the future, would be most applicable to that exploration.

The present study would presume that future drilling, whether for oil and gas or drilling programs directed specifically for coal testing (for example, small diameter diamond drilling methods) should be directed along the lines of sample collecting in the Saginaw Formation and the running of several different types of geophysical logs. It is possible that abandoned bore holes might also be re-entered for purposes of obtaining log data. The study herein is proposed to test what geophysical log data, or combinations of log data might best be utilized in arriving at, hopefully, a better knowledge of our coal resources.

PROCEDURE AND SCOPE

The primary sources of subsurface information consist of data gathering available from existing driller-geologist logs printed by the Geological Survey of Michigan Department of Natural Resources.

An attempt was made to find the most complete samples of the Saginaw Formation for which geophysical logs are available. For this purpose many of the sample logs, mounted well cuttings, available at the University of Michigan, were examined as well as the samples of the Sample Library at Michigan State University.

The most efficient type of logs, Gamma Ray-Neutron, Caliper, Sidewall Neutron Porosity, Compensated Sonic, and Compensated Density were investigated in order to determine whether or not accurate lithologic interpretations, including coal, may be obtained from individual types of these logs or from different combinations of logs (Crossplots) and to test the most reliable technique for lithologic interpretation. It was assumed that if logs were available at definitely recognizable coal horizons, certain conclusions might be made concerning the determination from the logs of composition, thickness and lateral persistence of coal, and other reinforcing information such as density and porosity. Also the contiguous nature of the coal or the presence and character of the shale partings and other characteristics which could affect "mineability" of the coal might be determined.

To approach the problem an area was selected for study where coal is known to have been mined and therefore would be most likely to show in the drill records and logs. The technique of crossplot interpretation will be described and discussed.

PREVIOUS STUDIES OF THE COAL SECTION

The earliest investigations of the Pennsylvanian System in Michigan date back to approximately 1835 and were originally initiated by the discovery of coal-bearing strata in the vicinity of Jackson, Michigan. The first systematic appraisal of the areal extent of the Pennsylvanian coal measures was conducted between 1838 and 1841 by the State Geologist, Douglass Houghton, and his associates, Bela Hubbard and C. C. Douglass.

The results of these initial investigations were subsequently modified and augmented by more detailed studies conducted by Alexander Winchell, Carl Rominger and C. D. Lawton between 1861 and 1882. It was during this period that Winchell subdivided the coal measures of Michigan into three stratigraphic units, which subsequently became the basis of the present system of Michigan nomenclature. Rominger and Lawton contributed substantial information in their descriptions of numerous stratigraphic sections throughout the state.

In response to the growing interest in native coal resources, State Geologist Alfred C. Lane prepared a comprehensive report on the coal of Michigan (1902). In his report, Lane compiled and synthesized the results of the work of several men over a period of approximately 15 years. The report placed primary emphasis on the origin, occurrence, and development of coal, but also contained significant information regarding the stratigraphy and lithology of the Michigan coal measures.

Also included in the report were identifications of Michigan flora and fauna made by David White and G. H. Girty of the U. S. Geological Survey. On the basis of plant identifications, the Michigan coal measures were tentatively correlated as Pottsville.

Classifications regarding the quality of the coal were included in his report. He classified the coal as bituminous, rather high in moisture and inclined to be gas coals and to pass into low grade cannel coal. He divided the coal section into three units.

The Upper Verne, or Monitor Seam, is the only one which appears to be at all gassy. It is a coking coal, duller than the next lower seam and containing more charcoal, and a medium amount of sulphur. The roof is a Lingula shale. The ratio of fixed carbon to combustibles runs up to .57.

The next seam below, the Lower Verne, is generally not far below; it is also coking coal but is high in sulphur and ash. The ratio of fixed carbon is less than .50.

The third seam and lowest coal, the Saginaw Seam, is higher in moisture and fixed carbon than the previous seams, but contains much less ash and sulphur (not classified as a coking coal). It is a good heating coal.

For the Saginaw Seam the best analyses give a ratio of fixed carbon to total combustibles of .61, while in the Verne coals this ratio is usually near .50, but is more variable.

After Lane's report of 1902, the next 25 years witnessed the appearance of additional publications, which included those of W. M. Gregory (1902, 1912), W. F. Cooper (1906, 1909), and R. A. Smith (1912) as well as subsequent annual reports by Lane.

In 1928, Dr. W. A. Kelly of Michigan State University began an extensive study of the Pennsylvanian System, which culminated in 1936 with his publication on the Pennsylvanian System in Michigan a publication which essentially represents the present state of knowledge of Pennsylvanian strata in the Michigan Basin.

During the course of his investigations, Dr. Kelly contributed valuable information regarding Michigan faunas and floras, lithologic and stratigraphic descriptions, including coal, as well as a detailed review of work previously done on Pennsylvanian strata in Michigan in 1930, 1931, and 1933.

Other contributions to the present state of knowledge were made by R. B. Newcombe, whose work resulted in a modification of the areal distribution patterns of Pennsylvanian strata in Michigan. From the standpoint of paleobotanical investigations, Dr. C. A. Arnold (1934, 1949, 1950) of the University of Michigan conducted detailed studies of the Pennsylvanian flora of Michigan, which helped to establish a basis for correlating Michigan strata with neighboring Pennsylvanian coal basins.

Additional work on the Pennsylvanian System was conducted by G. V. Cohee of the U. S. Geological Survey. Cohee and his colleagues (1950) made an extensive compilation of subsurface data and prepared the latest summary of Michigan coal resources.

In his report he provides important information regarding the lithology and thickness of the Saginaw Formation as well as the Michigan coal basin and Michigan coal reserves. The method he used for estimating reserves is summarized briefly below based on the following assumptions: (1) measured coal is coal for which tonnages are computed from measurements taken in mine workings and drill holes; (2) indicated coal is coal for which tonnage estimates are based primarily on thickness measurements in isolated drill holes; (3) inferred coal is coal for which tonnage estimates are based on the isolated drill holes that were also used in computing indicated reserves. The general rule was to limit inferred coal to the area lying outside the circle of 1/8-mile radius containing indicated reserves and inside a circle of 1/4-mile radius with the drill hole being the center. In some areas, however, where drill holes are more than 1/2-mile, but less than 1 mile apart, the evidence indicates that the coal is fairly persistent. Some reserves have been inferred to be present between the holes.

The measured reserves were divided for purposes of summary study and tabulation into three thickness categories of 14 to 28, 28 to 42 inches and more than 42 inches.

Because of the relatively small area covered by the estimates and the completeness and density of the data, it was possible to eliminate mined-out areas before calculations were made, and to present estimates of coal remaining in the ground as of January 1, 1950.

Finally, Shideler, in a regional study of the Pennsylvanian of Michigan (M.S. Thesis, Department of Geology, Univ. of Illinois, 1965) indicated the general character of the lower, middle, and upper sequences of the Saginaw Group. He also noted those areas within each of these where some coal was believed to occur, apparently based on available samples and drillers logs, but not identified as individual seams. This is an important contribution to Saginaw stratigraphy and implications on coal distribution.

STRATIGRAPHY

The following paragraphs presented by W. A. Kelly (1936) review the present concepts of the Pennsylvanian stratigraphy in Michigan as well as the evolution of Michigan nomenclature.

The Pennsylvanian System of Michigan was originally divided into three stratigraphic units of formational rank by Winchell (1861) a division which has been maintained up to the present. The formational units, in ascending order, were designated as the Parma Sandstone, the "Coal Measures", and the Woodville Sandstone.

The Parma Sandstone (type locality near the town of Parma in Jackson County) is characterized as a sporadically distributed unit of variable thickness. It exhibits a thickness range of from 0 to 220 feet (Newcombe 1928), with the thickest sections occurring in Shiawasee County. Where present, the Parma unconformably overlies Mississippian strata. The Pennsylvanian age of the Parma was determined by Winchell on the basis of its sparse flora which included specimens of Calamites. Because of the meager paleontological criteria, inter-regional and intrastate correlations of the sporadically distributed Parma are of a dubious nature.

Lithologically, the Parma is characterized as a clean, white quartzose sandstone with local conglomeritic phases and occasional dark shale members. The feldspar percentage is notably low, as contrasted with sandstones in the overlying "Coal Measures".

The "Coal Measures", presently known as the Saginaw Group, was a term originally proposed by Winchell to designate the coal-bearing strata of the Pennsylvanian System between the Parma and the overlying Woodville Sandstone. This sequence of strata was subsequently designated as the "Jackson" series, and eventually became known as the "Saginaw" formation (Lane 1901-03).

The Saginaw Formation can be characterized as a heterogeneous association of terrestrial and marine strata, consisting of interbedded sandstone, shale, coal, and carbonate units. The formational thickness is highly variable, attains a maximum of approximately 650 feet (Cohee 1950), and averages approximately 400 feet (Newcombe 1928). Individual lithologic units of the Saginaw generally display a high degree of lateral discontinuity over relatively short distances, resulting from both lithologic variability and numerous local unconformities.

The sandstone members are normally argillaceous, slightly feldspathic, and contain a higher percentage of micaceous minerals than the underlying Parma. Tourmaline, zircon, and various varieties of garnet are the principal heavy mineral constituents. The texture is generally fine grained with occasional conglomeratic phases in the basal portions of individual units. Many of the sandstone bodies are notably lenticular in form, and exhibit irregular bedding. The only reported fossil remains consist of fragmented plant material.

Argillaceous members of the Saginaw Formation demonstrate a considerable degree of variability, depending on their mode of origin. Individual descriptions may range anywhere from that of a dark, fissile, marine shale to that of a light colored, structureless underclay. Textural variabilities are great, and are a function of the percentage of arenaceous or calcareous material in a particular member.

An important aspect of the shale members is their fossil content which has proved useful in determining the age of the Saginaw Formation. Some shales contain marine or brackish water assemblages. There are a few marine black shale members highly fossiliferous and appear to be of a greater areal extent than their non-marine counterparts.

The coal horizons, as described by Cohee (1950), are of small areal extent, commonly undulatory and frequently containing shale partings; their thicknesses vary from a few inches to a few feet. However, only three of these coal horizons, the Saginaw, the Lower Verne and the Upper Verne coal beds, are persistent, and they are thin as compared with coal beds in the Appalachian field. The Saginaw coal is the lowest bed of commercial importance. The Lower and Upper Verne coals occur above the Saginaw coal and in some areas the two beds are so close together that they could be worked as one coal bed, whereas in other areas they are as much as 40 feet apart. The Lower Verne coal is generally about 2 feet thick. The Upper Verne coal, which yielded most of the coal mined in Bay County, is generally 2 1/2 feet thick. The Upper Verne coal is commonly underlain by fireclay, and overlain by black shale.

The coal seams were used by Lane (1901) and Cooper (1905, 1908) for subdividing the Saginaw "Formation". Cooper (1908) recognized 14 individual horizons as a basis for subdivisions but the validity of his correlations was questioned (Smith 1912) and the classification was eventually abandoned.

The limestone members of the Saginaw Formation are generally thin, highly argillaceous, and normally contain quantities of authigenetic pyrite. They are commonly fossiliferous and contain assemblages of invertebrates, as well as occasional fragments of plant material. Of particular significance is a marine limestone member, the Verne limestone, which has been used as a key bed in subdividing the Saginaw Formation. It is characterized as an argillaceous limestone, containing a prolific invertebrate assemblage and having a relatively widespread distribution.

The foregoing has been a brief lithologic description of the Saginaw Formation, which constitutes the major portion of Pennsylvanian strata in Michigan. The type locality of the Saginaw Formation, the Saginaw Valley, contains no natural expodures; and type descriptions were made from geologic sections derived from several mine shafts within that locality.

The most extensive natural exposures of the Saginaw Formation are located near the town of Grand Ledge in Northern Eaton County. The stratigraphy of the Grand Ledge area was studied and described in detail by Kelly (1933). During his investigations, Kelly noted the cyclothemic nature of the stratigraphic succession of beds comprising the Saginaw Formation. He divided the Grand Ledge section into eight distinct cyclothems, which were generally thin (less than 15 feet thick) and highly truncated by local unconformities. He explained the stratigraphic succession as basal sandstone overlain by sandy shale, gray shale, underclay, coal, black shale, and limestone. As a result of this findings, Kelly gave formational rank to the individual cyclothemic units and elevated the status of the

Saginaw Formation to that of a group. The Saginaw Group was divided into the "Post-Verne" and "Pre-Verne" cyclical formations on the basis of their stratigraphic position in reference to the Verne Limestone Member. The faunal assemblage of the Verne Limestone Member was tentatively correlated with that of the Seville Limestone of Illinois, thus inferring a possible late Tradewater or early Desmoinesian Age for the Verne cyclical formations.

Shideler (1965) divided the Saginaw Group into three sections: The lower or interval "A", the middle or interval "B", and the upper or interval "C".

Interval "A" represents the oldest sediments of Morrowan age and includes all strata from the Mississippian-Pennsylvanian unconformity up to and including the roof shale of the Saginaw coal. In areas of the basins where the Saginaw coal is absent, which is generally the situation, the top of interval A is near the base of a dark shale sequence (Paramillerella).

Interval "B" represents the Lampasan or Atokan sediments of the Michigan section, includes all strata above the roof shale of the Saginaw coal or the dark shale sequence, and below the Verne Limestone member (Fusulinella iowensis). In the absence of the Verne Limestone member, the upper boundary of interval "B" would be the base of the "A" sandstone assemblage unconformably overlying the dark shale sequence.

Interval "C" represents the youngest Pennsylvanian sediments and it includes all strata from the base of the Verne member (or the base of the sandstone assemblage) up to the base of the "Red Beds", or Pleistocene drift when the "Red Beds" are missing.

The Saginaw Group, in turn, is frequently capped by a distinct and unconformable sandstone assemblage which has been traditionally referred to as the "Woodville" sandstone, which with the Ionia and Eaton sandstones form the "Grand River Group" (Kelly 1936).

The Pennsylvanian system of Michigan is normally overlain by thick deposits of Pleistocene drift. However, throughout much of the central basinal area the material directly overlying Pennsylvanian strata consists of a series of red shales and sandstones, with interbedded gypsum layers. This pre-Pleistocene series identified by A. T. Cross as Upper Jurassic in age represents a contrasting lithologic and faunal assemblage, which is distinctively different from underlying strata of Pennsylvanian age.

EXPERIMENTAL PROCEDURES

The Gamma-Ray Log has been used in an attempt to determine the shale content as an aid in Log Interpretation, but this has not been generally successful. It therefore remains primarily a correlative device. Also the shale content that Gamma-Ray depicts is roughly the amount of clay present as a fraction of bulk volume. There are, however, a number of exceptions to this rule:

1. Potash Salts (plyhalite, sylvite) have, because of their potassium content, a high Gamma-Ray intensity even when completely free of clays. They occur frequently in evaporite sequences and can be distinguished by their relatively high resistivities.

2. Formations (often Ss) containing carnotite or other uranium or thorium salts in quantity show anomalously high levels of radioactivity.

3. Igneous rocks usually have higher radioactivity than sedimentary rocks. Among these are conglomerates and breccias derived directly from igneous plugs.

4. On erosional surfaces, clay minerals of exposed shales may undergo a secondary enrichment of potassium, thus providing a marker for erosional unconformities.

5. In old fields, circulating or produced ground waters may deposit radioactive scale at the perforations in the liners or casing. This gives rise to extremely high intensities on the Gamma-Ray logs. This could represent a problem in the case of the Saginaw Formation.

The relative clay content or shaliness is judged by comparison with shale deflections and the deflections for the cleanest parts of the formations.

Neutron logs measure the radioactivity induced in formations by bombardment with high-energy neutrons. Either the Neutron Density or the Intensity of Gamma Rays induced by Neutron capture is detected at some distance (1-2 ft.) from the neutron source.

The Neutron log reflects primarily the presence of liquid-filled pore space and of bound water associated with rock minerals. The most common rock constituents with appreciable chemically-bound water content are the clay minerals, the presence of which can usually be detected on the Gamma Ray curve. Gypsum has very low natural radioactivity and appears on the Gamma Ray Log as "Clean". Its bound water causes the neutron curve to indicate a very high apparent porosity equivalent to limestone with 49%, whereas its actual porosity is virtually zero, as indicated by extremely high resistivity values.

In most clean formations, however, the neutron curve is essentially a porosity log. The effect of lithological composition (other than clay content) on the porosity determination is smaller for the neutron-neutron devices than for the neutron-gamma logs, and smaller for the fast and epithermal detection systems than for the thermal neutron logs. Modern interpretation techniques tend to combine the neutron log with either a sonic log or a formation density log, and this combination allows construction of a so-called lithology plot and makes possible quantitative porosity determination in formations of diverse compositions.

The hole diameter and mud composition effects have been largely eliminated by the side-wall type of neutron-porosity logs. For older neutron surveys, the uncertainties due to hole effects can frequently be reduced by using resistivity logs to "calibrate" the neutron porosity curve.

There are several approaches for determination of porosity from the neutron curve. They are basically dependent on the premise that the neutron deflection is some function of total porosity.

To calibrate for porosity it is important to correlate the neutron curve deflection with the porosity obtained by other means, usually directly from cores. This usually approximates a straight line on semilog paper with porosity percent on the log scale, and the neutron deflections on the linear scale. The importance of this method is to determine the calibration of the wells. This is determined by the fact that in "clean" rocks the neutron deflection is roughly proportional to the logarithm of porosity.

The amount of the porosity for these points plotted in the graph porosity versus neutron deflection correlates roughly with the magnitude of the gamma ray deflection. Similar empirical correlations can be used to correct the neutron derived porosities for clay effects. The neutron-porosity correlation applies only to the formation, hole and casing size, and type of neutron survey for which it is established. Such plots are therefore rather limited in their application.

Ideally, porosity determinations based on core analyses would be best for making corrections but such was not available.

A useful parameter that can be obtained from these local studies is the apparent porosity of certain marker shale horizons; and the apparent shale porosities are frequently quite constant over a large area for a given horizon and can be used as pivot points for neutron porosity calibrations for other wells in the area with different hole conditions.

Where insufficient core data are available (as is the case in this study) to firmly establish a definite line on the neutron curve there are several possible alternate procedures that might be followed:

1. Combination of shale line and a dense limestone.

2. Shale line alone.

3. Dense limestone or anhydrite line alone.

4. Surface radiation.

5. Instrument zero.

Method 1 is the most common and is the one used herein for the interpretations.

The following steps may be considered as a set of general rules for reading porous zones. Each step is shown on the log (Figure 1.A).

1. Establish a shale reference on the neutron curve by using the average minimum shale value. This will be called the minimum neutron shale line.

2. Establish a maximum reference by drawing a line through the average of the maximum curve values, as shown on the neutron curve. This line will be used as the 100% neutron line. Care should be exercised in determining this maximum neutron line, and thorough knowledge of the territory will help in determining its position.

3. On the neutron curve, draw a line which is of the distance from the minimum neutron shale line toward the 100% neutron line. This will be known as the 60% neutron line. Draw another line midway

between the minimum neutron shale line and the 100% neutron line. This will be known as the 50% neutron line.

4. Establish a shale reference on the gamma ray curve by drawing a line through the average shale value. This will be known as the average or 100% gamma ray shale reference line.

5. Draw a line through the average minimum gamma ray curve value in a clean limestone or sandstone. This will be known as the average minimum gamma ray line.

6. Draw a line on the gamma ray curve 1/5 of the distance between the minimum line and the 100% shale line; this will be known as the 20% gamma ray line; do the same with another line 2/5 of the distance, calling this a 40% gamma ray line.

7. For all values on the gamma ray curve between the zero (or minimum line) and the 20% line, pick all porous zones on the neutron curve that extend to the left of the 60% line.

8. For all values on the gamma ray curve between the 20% line and 40% line, pick all porous zones on the neutron curve that extend to the left of the 50% neutron value.

9. Any zone that lies on the gamma ray curve beyond or to the right of the 40% value should not be picked as a porosity zone, even through the neutron curve indicates a very low neutron value.

For open-hole neutron logging, Schlumberger has introduced a series of interpretation charts which make allowance for bore hole effects, based on hole diameter, mud weight, mud cake thickness and temperature. The charts furnish a porosity index value as a function of the neutron deflection in API units. This porosity index is the percentage porosity that would prevail if the formation were limestone.

For other known lithologies a set of neutron porosity equivalence curves then permits conversion of the limestone porosity index to the true porosity. If the lithology is not known, one can use the resistivity-type calibration of the neutron-porosity relationship or combine the neutron deflection with the response of either a sonic or a density log as will be made for a particular well with the density log.

Density logs are based on the fact that the absorption of gamma rays traversing a medium by Compton scattering is roughly proportional to the density of the medium. Density logging was introduced by Stanolind Oil and Gas Company (Panamerican Petroleum Corporation) some eighteen years ago as a porosity determination tool.

The porosity is related to the measured bulk density, PB, of the rocks by:

$$\phi = \frac{P_G - P_B}{P_G - P_F}$$

where P_G = matrix or grain density

P_F = density of interstitial fluids

Early density logs were fairly sensitive to factors such as hole diameter, mud density, mud cake thickness and density, and bore face rugosity (bore hole effects). Modern logs use two detectors, one of which is very close to the source and quite sensitive to the hole effects. From the combination of the signals a correction to the log-spacing detector recording is computed. The corrected signal is registered directly in terms of bulk density in grams per cubic centimeter on a linear scale. In addition, a second trace records the amount of correction (or compensation) made, and some times either the uncompensated bulk density or the short-spacing curve is also recorded frequently, when both compensated and uncompensated curves are given it is difficult to distinguish between the two. One can identify the correct compensated curve by the relation:

$$\rho B \text{ (compensated)} = \rho B \text{ (uncompensated)} + \Delta\rho \text{ (correction)}$$

where $\Delta\rho$ is added algebraically with whatever sign is shown on the log. In many cases one or more porosity scales are also shown on the log. The sandstone porosity scale is based on an average grain density of 2.65 for sandstone. The limestone porosity scale is based on $\rho g (\equiv \rho ma)$ 2.71. In the absence of such scales, porosity is found from bulk density, using the graph shown in Figure 1.B.

The grain density for dolomites is 2.87 G/CC. The value for anhydrites is still higher ($\approx$ 3.0 gr/CC). In areas where rapid compositional changes occur, accurate porosity determination from density alone becomes difficult, and the density log should be combined with an SNP (side wall neutron porosity) or gamma ray-neutron log as described in the following interpretation.

The sonic log measures the travel time of acoustic waves through formations. The signal is created by an acoustic transducer, and the travel time Δt is recorded as the difference in times of first arrival at two receivers. The two-receiver system largely eliminates the effects of the travel or linkage of the signal trhough the mud column to the bore fact. Typical spacings for the sonic log are 3 ft. from transducer, T, to first receiver, R_1, and 1-3 ft. for the receiver span R_1-R_2. The logging trace records the travel time through the formations in microseconds per foot (μ sec/ft).

Acoustic velocities are higher, and hence travel times are shorter in dense rocks than in porous formations and shales. In order to facilitate correlation with resistivity logs, the travel time scales are inverted, with the low travel times to the right and the high ΔT values to the left. The curves go off scale to the left and reappear on the next higher scale at the right hand edge.

Porosity determinations from the sonic log are usually based on an empirical relation between travel times and porosities established by Wyllie et al. (1956).

This relationship, referred to as the time-averaging formula, is:

$$\Delta t = \frac{\phi}{V\ \text{Fluid}} + \frac{1 - \phi}{V\ \text{Matrix}}$$

For common lithologies in the formations the velocity varies from 18,000 to 26,000 ft/sec.

Interstitial clays or thin shale laminations reduce the sonic velocity and increase the apparent porosity. Schlumberger suggested a correction of the form:

$$\phi = \frac{\phi a}{2^{\alpha}}$$

where ϕa is the apparent porosity obtained from equation (1) and is the ratio of the S.P. deflection of the shaly bed to that of a clean formation at the same Rmf (Resistivity of the formation), Rw (Resistivity of the formation water), and formation temperature. The ratio or so-called SP reduction factor can be obtained by comparison with adjacent horizons or from an SP plot.

Individual Logs

It is likely that future exploration for coal would depend on oil and gas well information, as coal is mostly lost in sampling and most samples and drillers records do not give satisfactory information on thickness or character of coals. For this reason a fairly complete spectrum of geophysical logs will be needed to test the quality and thickness of coal.

The developments of the Sonic, Formation Density and Side Wall Neutron Porosity logs have greatly improved determinations of formation porosity; however, the interpretation of each requires knowledge of the matrix and fluid characteristics of the formations. When the characteristics of the matrix in the formations are known, accurate results can often be obtained by using only one of the porosity-sensitive devices.

The following interpretation will be taken from the porosity logs:

1. Porosity from the Side Wall Neutron Porosity log.
2. Porosity from the Conpensated Density log.
3. Transit time from the Compensated Sonic log.
4. Lithologic criteria from the Gamma Ray log.

The following values ideally could identify the presence of coal:

1. Porosity on the Side Wall Neutron of more than 40%. Porosity on the Compensated Density log will be in the range between 50% and 80%.

2. The bulk density value (P_B) taken from the Compensated Density log of between 1.18 gr/cc and 1.8 gr/cc.

3. The transit time taken from the Conpensated Sonic log of between 110 microseconds and 140 microseconds.

4. The Gamma Ray values will be low in the order of 10 IPA (International Petroleum Association Units), and the resistivity will be high.

5. The porosity registered on the density log will be greater than the porosity registered on the Side Wall Neutron porosity log.

The typical profiles for the density, sonic, and gamma ray logs for coal identification and other lithologies are shown in Figures 1.D, 1-1A, 1-1B, and 1-1C.

Crossplots

Proper combination (crossplots) of the logs mentioned above may be able to provide reliable information for: (1) porosity determination; (2) lithologic identification; (3) mineral identification; and (4) correlation for subsurface mapping.

In addition to the sonic, density and side wall logs the gamma ray-neutron log will give information about: (1) lithologic changes (through steel pipe); (2) accurate depth control and thickness; (3) locating radioactive tracers; (4) indicating shale content in sands; and (5) obtaining an index of porosity.

Schlumberger plots representing the best experimental data based on years of experience in log response to porosities and lithologies appear to be useful. These plots are convenient to display both porosity and lithologic information when two porosity logs are available. Points on the figures that concern the crossplots on this study, where density and side wall neutron porosities are crossplotted, correspond to particular water-saturated, pure lithologically defined lines (sandstone, limestone, dolomite, etc.) which can be graduated into porosity units; or a single zero porosity point (e.g., salt point) may be defined. These figures are entered with porosities computed as if the matrix had the same properties as water-saturated limestone; as a result the limestone line is the straight line of equal neutron and density porosities.

When the matrix lithology is a binary mixture (e.g., quartz-lime or lime-dolomite) the point plotted from the log readings will fall between the corresponding lithology lines.

All the crossplots included in this study were constructed for a clean, fully liquid-saturated formation with only primary porosity and holes filled with water or water-base mud. These figures can be used with negligible error for salt mud as well as fresh.

The following example (Figures 1.C, 2.CI, 2.CII, 2.CIII, 3.C and 4.F) taken from Schulumberger (1969) illustrates how the interpretation can be made. This example will appear in all the figures (crossplots) represented by dashed lines. The porosities ϕ = 15% (2.48 GR/CC bulk density) and ϕSNP (limestone = 19%), respectively, define the point P, lying between the limestone and dolomite curves, and falling near a line connecting the 18% porosity graduations on the two curves. Assuming a matrix of limestone and dolomite, by proportioning the distance between the two curves the point is found to correspond to about 40% dolomite, 60% limestone.

Crossplots of sonic Δt V_s neutron porosity logs as with density neutron plots for resolution between quartz, limestone, and dolomite lithologies, are good, and errors in choice of lithologic pairs among these minerals will have negligible effect on the porosity value found.

Shaliness produces a shift of the crossplot point in the direction of so-called "shale point" and is found by crossplotting the apparent porosities $(c\phi_d)$ sh, (o_n)sh, Δtsh) observed in the neighboring shale beds. However these shale values may only approximate the parameters of the shaly material within the permeable beds.

Analysis of Well No. 1

The first well studied was the Michigan Consolidated Gas Company well, Permit No. 27,734 located in Isabella Co. 16N-6W-sec 29, NW, NW, SW. The following logs were run for this well: Gamma Ray-Neutron, Compensated Formation Density, bore-hole Compensated Sonic Log (not available) and the description of the formations (Table 1.A). The Gamma Ray-Neutron and the Compensated Density Logs are used in this analysis. The Compensated Sonic Log with the Compensated Density Crossplot would give us additional lithologic interpretation, as well as the Gamma Ray with the compensated Sonic Log.

The density log bulk densities of the numbered points of the logs (Figure 1-B) for different Saginaw Formation intervals were plotted against the equivalent limestone porosities, obtained from the uncorrelated Neutron Porosity log (Figure 1-C). Superimposed on the joint plot are the characteristic empirical lines for different matrix composition.

Points 1, 3, 4, 5, 6, 7, 8, 9, and 10 (Figure 1-C) represent dolomite beds.

Points 11, and 12 represent dolomitic limestone. These interpretations differ greatly from the driller-geologist log (Table 1) and sample examination. Some of the reasons for this could be given as follows:

1. The presence of hydrogen in the argillaceous material or hydrates may make the porosity calculation too high.

2. Furthermore, hydrogen may be present in the fluid filling the pore space.

3. Hydrogen may also be present in chemically bound water (gypsum) or physically bound water (shales).

It is well recognized that the Saginaw Formation contains water and this water may cause the neutron porosity log to register anomalously high porosities. Thus, it may be necessary to correlate these values with the porosity obtained from core or sample analyses.

Another correlation could be made with the resistivity log which is a function of Ri, Di and Rt, and some slight hole effects. The combination of Rt and Ro, in turn, yields the water saturation (Sw).

The term resistivity denotes an electrical property of matter, which is the inverse of conductivity and is defined as the resistence of a cube of the material to current flow. The most common unit used for expressing resistivity in well logging is the OHM-meter, which is the resistance of a cube the sides of which are 1 mt long. Rt denotes the true or undisturbed formation resistivity, Rm is the resistivity of the drilling mud (or fluid) and Ri is the average resistivity of the portion of the stratum surrounding the bore hole, which has been invaded by the filtrate of the drilling mud and is referred to as the invaded zone resistivity (Figure 1-E).

Analysis of Well No. 2

The second well studied was the Michigan Consolidated Gas Company well, Permit No. 27, 394 located in Clare Co. 20N-4W, sec. 35, C SE1/4 NE1/4. The following logs were run for this well: Gamma Ray-Neutron, Compensated Formation Density Log, Induction Log, and the description of the formations (Table 2). The Gamma Ray-Neutron and the compensated formation density logs will be used in this analysis.

Calculations of porosity were made for this well using Schlumberger interpretation charts which make allowance for bore hole effects, based on hole diameter, mud weight, mud cake thickness and temperature.

Two methods were worked out for this well. In the first one using the reference lines method the points 2, 3, 6, 7, 8, 9, and 10 on the crossplot (I) (Figure 2-C) represent shales. This interpretation according to the Gamma Ray log is correct for the points 6 and 7. For the points 2 and 3 the Gamma Ray interpretation besides shale in very small quantity, would be some sand grains. According to the geologist-driller's log for point 3 this interpretation is correct but for point 2 the sand grains are not present. For points 8, 9, and 10 the Gamma Ray shows shales with low radioactivity typical of carbonaceous shale with intermitent sandy shales and thin sand stringers (Figure 2-A).

Points 11, 13, 15 and 16 are close to the dolomite line on the crossplot, as well as the points described before, interpretation that can not be given to these intervals in the Saginaw Formation because dolomite is not present. Thus, point 10 could be the line limit (lower contact) for the Saginaw Formation. However, the lithologic description mentions dolomite for points 15 and 16 which is acceptable more or less to the Gamma Ray reading and could represent the underlying formation. Point 12 on the Gamma Ray is correct according to the lithologic description as well as points 14 and 1 which in the crossplot would be sandstone and shale, respectively.

When Schlumberger correction by porosity was applied to this well (Figure 2-C II) some of the points went apart to porosities up to 40% as shown in Table 2, as indicative of the high shale content in some, and in others the presence of argillaceous materials or hydrates.

Points 12 and 13 with the corrected porosity from 18 and 30%, respectively, becomes 3.5% and 1.5% and with these new values the lithologic interpretation is sandstone for both intervals. Interpretation that according to the driller's log is correct for point 12 but not for point 15 which in the driller's log besides sandstone shows limestone and dolomite.

Points 7, 10, 11, 13, 14 and 16 (where limestones or dolomites are present) appear well defined on the crossplot and are compatible with the Gamma Ray log and the driller's log.

Another crossplot (Figure 2-C, III) with the expected porosities (constant density for each interval) was made. In this crossplot two problems arose:

1. When lithologies such as sandstone cemented with dolomite are encountered there is no way to plot satisfactorily the point on this crossplot as they may be interpreted as either sandstone or dolomite. The same situation arises with shale and sandstone. In this instance the Gamma Ray log helps in clarifying the interpretation.

2. The density for sandstone is 2.65 usually. However, if the density should occur as high as, say, 2.66, the crossplot reading could be interpreted as limestone.

Analysis of Well No. 3

The third well studied was the Michigan Consolidated Gas Company well, Permit No. 27, 666, located in Osceola Co. 17N-9W, sec. 10 SE NW NW. Gamma Ray-Neutron and Density logs were run for this well. The following data were interpreted from these logs:

Gamma Ray Reading	Inter- val	API Units	Porosity	Density
7	1	960	22.5%	2.34
4	2	1,040	18.0%	2.35
5.5	3	800	30.0%	2.34
		700	35.0%	2.40
5.5	4	640	38.0%	2.43
				2.38
5.5	5	660	37.0%	2.39
5.5	6	680	37.5%	2.36
0.5	7	840	29.0%	2.44
0.5	8	1,000	21.5%	2.35
5.0	9	700	35.0%	2.31
4.0	10	1,040	19.5%	2.38
1.0	11	860	26.0%	2.39
1.0	12	1,060	19.0%	2.35
4.5	13	1,060	19.0%	2.33
0.5	14	840	29.0%	2.34
5.0	15	840	29.0%	2.37

Hole Diameter	7 7/8 In.
Mud Weight	10.5#/gal.
Temperature	78°F

The API reading obtained from the Neutron Log was corrected using the chart for salty mud, uncased holes and limestone porosity base units of Schlumberger interpretation charts. The porosity (Figure 3-A) and the density (Figure 3-B) were plotted and the following interpretation is given (Figure 3-C).

Points 1, 2, 8, 10, 12, 13 and 14 (Table 3) represent on the crossplot dolomitic lime and limestone beds. The lithologic description is correct for some of the points. The porosities on the neutron are in the range from 18% up to 26%. The Gamma Ray can be interpreted as normal limestone or sandstone.

Points 3, 4, 5, 6, and 7 represent shales on the crossplot and in the lithologic description. The gamma ray tells the same but the radioactivity varies among them. The porosity is rather high varying from 29% to 38%. This might be explained by the presence of hydrogen in argillaceous materials, or hydrates.

Points 9, 11, and 15 on the crossplot represent lithologies very close to those given by the Gamma Ray and the lithologic description.

So far this has been the best method for lithologic interpretation indicating that the bore hole effects as well as the other factors mentioned before have some influence on the results.

Analysis of Well No. 4

The fourth well studied was the Michigan Consolidated Gas Company well, Permit No. 29,916 located in Isabella Co. 13N-4W, sec. 22, NE NE NE. The following logs were run for this well: Dual Laterolog, Borehole Compensated Sonic Log (Figure 4-B), Side Wall Neutron Porosity Log (Figure 4-A).

The readings of porosity were taken directly from the Side Wall Neutron Porosity Log (Figure 4-A) and with the readings of transit time (Figure 4-B) the crossplot was obtained (Figure 4-C).

Points 1, 2a, 2b, 3, 5, and 6a represent shaly formations on the crossplot; according to the Gamma Ray Log this interpretation is correct for points 1, 3 and 5. For interval 2 the point 2c on the crossplot and the Gamma Ray Log represents a sandstone. Combining these interpretations one can say that the interval 2 is a compound of shale with intermittent sandy shales and twin sand stringers cemented with limestone. The same thing applies to interval 4 where point 4a indicates sand grains.

Interval 6 indicates according to the gamma ray and the crossplot that three lithologies are present: sandstone (6b), limestone (6c), and small amount of shale (6a) (Gamma Ray Log).

Point 7 represents a sandstone interval interpretation that is correct according to the Gamma Ray Log and the lithologic description.

Point 8 represents a sandstone on the crossplot, an interpretation that according to the Gamma Ray Log is correct. However, limestone is not represented as it appears on the driller's log. However, the driller's log in this well shows lithologies grouped into large units. After the above experiment, the writer was able to locate sample cuttings of the well described in Table 4-A. The experiment was repeated using the sample descriptions divided into smaller and more definitive units. Although some major deflections on the Sonic and Side Wall Neutron Porosity logs occurred in "lost sample" intervals, a reasonable interpretation of the lithologies was obtained in Figures 4-D, 4-E and 4-F.

Although some lithologies were not altogether definitive on the crossplots, it would appear that a combination of Sonic and Side Wall Neutron Porosity and Gamma Ray logs was the best of the crossplot experiments. It is further concluded that the addition of a Density Log would create perhaps the optimum combination for lithologic interpretations.

SUMMARY AND CONCLUSIONS

In the introduction a technique was discussed that might be applied to existing well data to make more complete logging procedures of existing abandoned wells, and to projected drilling operations that can produce more meaningful data regarding the various parameters of coal production. The present study would presume that future drilling would be directed along the lines of sample collecting in the Saginaw Formation and collecting several different types of geophysical logs.

An attempt was made to find the most complete samples of the Saginaw Formation for which geophysical logs were available.

The most efficient type of logs: Gamma Ray-Neutron, Side Wall Neutron Porosity, Compensated Sonic and Compensated Density Logs were investigated in order to find accurate lithologic interpretations including coal.

Even the interpretation of each porosity log requires knowledge of the matrix and fluid characteristics. An empirical log sequence was composed including Gamma Ray, Density and Sonic Logs (Figure 1-D). It is considered that these three logs give much of the basic information needed for the purpose of this investigation. The Neutron and Side Wall Porosity logs are used for determining the real porosity. The porosity obtained by different corrections and procedures from these two logs was used in the crossplots.

Crossplots are used only when there are at least two geophysical logs available. A comprehensive search through log and sample files of the Michigan Geological Survey, the University of Michigan, Michigan State University, the Michigan Well Log Service and Oil Well Sample Service in Mt. Pleasant and the Michigan Consolidated Gas Company was made in an attempt to bring about the coincidence of the proper geophysical logs and samples (or reasonably adequate lithologic description on the driller's log, especially where the logs had been checked by a geologist). The few logs and samples (or descriptions) used herein are the result of that search.

Schlumberger logs of various types were plotted against lithology to illustrate individual log response to typical Saginaw Formation units (Figures 1-1A, 1-1B, 1-1C and 1-1D). Schlumberger techniques appear to be the best obtainable for crossplot displays.

For the first analysis (Figure 1A, 1B, 1C) the results were not very satisfactory. It was necessary to calculate the porosity from the Neutron log. Modifying factors could have been hydrogen present in argillaceous material, fluid filling the pore space, chemically bound water (gypsum) or physically bound water in shales.

In the second analysis (Figures 2A, 2B, 2CI, 2CII, 2CIII) Density and Gamma Ray-Neutron logs were used. Three kinds of crossplots were generated: (1) In the first crossplot, the bulk density for each lithologic unit of the Saginaw Formation was read from the Compensated Density log with the other parameter being the lithologic description (Figure 2CIII); (2) The porosity was corrected for bore hole effects using Schlumberger methods (Figure 2CII); and (3) The reference Line Method (Figure 2CI), used in the analysis for well No. 1. The second type apparently proved the most satisfactory. This would indicate that bore hole effects are important factors in determining interpretations of the lithology from Gamma Ray-Neutron and Density log crossplots.

It is unfortunate that in this experiment definite, demonstrable coal beds did not occur in sections for which adequate geophysical log coverage was available. Thus, it was necessary to resort to theoretical results expected on individual log types (Figure 1D) and crossplot response as shown in standard Schlumberger crossplots. Crossplot interpretation of various lithologic types was only partly satisfactory. The best results were obtained where the combination of Gamma Ray, Side Wall Neutron Porosity, and Compensated Sonic logs were available. Ideally it is expected that the addition of a Density log (unavailable in this instance) to this combination would give better results and would likely prove to be the optimum combination for crossplots.

The use of individual logs as Sonic, or Density, or Gamma Ray-Neutron could prove helpful in interpreting the Saginaw coal section. However, the use of combinations of these logs in crossplots should yield more meaningful data. The small amount of detailed samples, descriptions and logs of the coal section failed to develop the full potential of these techniques which could well delimit such parameters as the quality (semiquantitative) as well as the thickness and "mineability" of coal.

RECOMMENDATIONS FOR FURTHER STUDY

Without a change on the part of oil and gas exploration policy of sampling and logging only when deeper than the rocks of Pennsylvanian age, it is questionable that the state of our knowledge is far beyond the work of Cohee (1950), despite the many additional wells drilled since that time. However, the need for coal in the future may change exploration policies.

In such an event the importance of the use of geophysical logs for coal exploration will likely become very important in the ground appraisal of the coal. Though logs may be obtained, the collecting, and more important, the storage of such samples become problems.

Though little is published on log analysis of coal sections, some companies operating in coal areas today have likely developed special techniques of in-the-ground appraisal of coal, and it is recommended that such companies and geological surveys be identified and approached. Thus, a better model for exploration likely could be developed from the highly similar Pennsylvanian units of sections as in Illinois, Indiana, and Ohio where much more coal activity has been in process.

There is no exploration, of course, better than directed core drilling specifically for coal. Short of this expensive procedure, the logging of reentered abandoned oil wells might be considered, though this could well entail difficulty and expense beyond the logging depending on the nature of the plugging and abandonment history of a given well. Thus, much emphasis can be placed on the importance of multiple log collecting in present and future oil and gas well exploration.

Upon the availability of such logs, it is anticipated that a better model for in situ coal exploration could be arrived at for Michigan. It is anticipated that further studies with additional logs will better define such parameters as ash content, porosity, bulk density, possibly sulphur content; studies of such coal chips as are available could add additional data on the B.T.U. value, fixed carbon, moisture content and petrographic properties.

Techniques of log analysis by the computer directed at the various parameters of the coal section could cut short time and effort involved in the manual crossplot procedures used herein.

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APPENDICES

APPENDIX A

Well Descriptions Used in Crossplots

Table 1-A. Description of the Saginaw Formation units in Michigan Consolidated Gas Company, Permit No. 27,734, NW NW SW, section 29, 16N 6W.

THICKNESS	UNIT NO. (LOG)	DESCRIPTION SAGINAW FORMATION
815 - 825	1	Shale, dark red, green-gray; dolomite, light tan, micritic.
825 - 830	2	Sandstone, fine grained, subrounded, cemented; with shale, dark red.
830 - 835	3	Sandstone, white, clean, fine grained, subrounded, free grains.
835 - 840	4	Sandstone, gray white to greenish, clear, cemented, fine grained, some free grains; trace anhydrite, white.
840 - 845	5	Shale, dark red and medium green.
845 - 850	6	Shale, medium gray, with red and green; trace pelletal sandstone grains, fine grained, subrounded.
850 - 860	7	Shale, dark, red, trace medium green gray shale; with trace free sandstone grains, subrounded.
860 - 878	8	Shale, medium gray, with black carbonaceous specks; trace dark red shales.
878 - 885	9	Shale, medium gray.
885 - 890	-	No samples.
890 - 895	10	Sandstone, dirty white to light gray, fine grained, subangular; trace anhydrite, white, trace shale, medium green; trace dolomite, light tan, micritic.
895 - 897	-	No samples.
897 - 913	11	Dolomite, light tan-buff, finely crystalline with cemented sandstone grains, gray white, fine grained, subrounded.
913 - 920	12	Anhydrite, white; with dolomite, buff, micritic.

Table 3-A. Description of the Saginaw Formation units in Michigan Consolidated Gas Company, Permit No. 27,666, SE NW NW, section 10, 17 N 9W.

THICKNESS	UNIT NO. (LOG)	DESCRIPTION SAGINAW FORMATION
700 - 710	1	Pieces of cement 40%; shale 50%, dark gray; free sand grains 10% frosted, 0.1 to 0.2 MM grain size, subangular.
710 - 720	2	Free sand grains as above; shale 50% dark gray; pieces of cement 50%; siltstone, light gray, almost a very fine grained sandstone.
720 - 760	3	Shale, dary gray.
760 - 780	4	Shale, light gray.
780 - 790	5	Shale, dary gray.
790 - 810	6	Shale, dary gray; shale, trace, light gray.
810 - 820	7	Shale, medium gray.
820 - 830	8	Free sand grains, clear and frosted, 0.2 to 0.4 MM grain size, subangular and subrounded.
830 - 840	9	Free sand grains as above, cleaner looking sample than above.
840 - 850	10	Limestone, light brown to buff, micro-crystalline.
850 - 860	11	Limestone as above; free sand grains, 0.1 to 0.2 MM grain size, frosted, subangular and subrounded
860 - 870	12	Free sand grains as above.
870 - 880	13	As above, clean looking sand.
880 - 890	14	Free sand grains as above, sample has a gray look; traces of pyrite; shale, trace, gray.
890 - 900	15	Free sand grains as above.

Table 4-A. Sample description of the Saginaw Formation units in Michigan Consolidated Gas Company, Permit No. 29, 916, NE NE NE, section 22, 13N 4W.

THICKNESS	UNIT NO. (LOG)	DESCRIPTION SAGINAW FORMATION
510		Sandstone, light gray, brown; (sample mostly till contamination)
520		Shale, black to brown, silty; sand grains, fine to medium size.
530		Sandstone, gray-brown, medium (.5 MM); trace black shale;)mostly till).
540		Shale 90%, black gray, well laminated; 10% light gray shale, probably No. 2 shale.
550		Siltstone 95%, black gray; sandstone 5%, white, medium size, trace light gray shale.
560		Same as above.
570	1	Shale, silty, black gray, fragmented carbonaceous material, trace white sandstone.
580	2	Shale, silty, dark gray, traces of brownish shale (less than 1%).
590	3	A little higher percentage of brownish shale (approx. 2%).
600	4	Brown silty shale, higher percentage of brownish shale.
610	5	Same as above plus broken pieces of plant fragment.
620	6	Same as above.
630	7	Same as above, plus brownish shale (approx. 4%).
640	8	Mostly shale, medium to dark gray; sand-stone white to light gray, medium grain size (approx. 15%-20%).
650	9	Same as above.
660	10	Same as above.

Table 4-A - Continued:

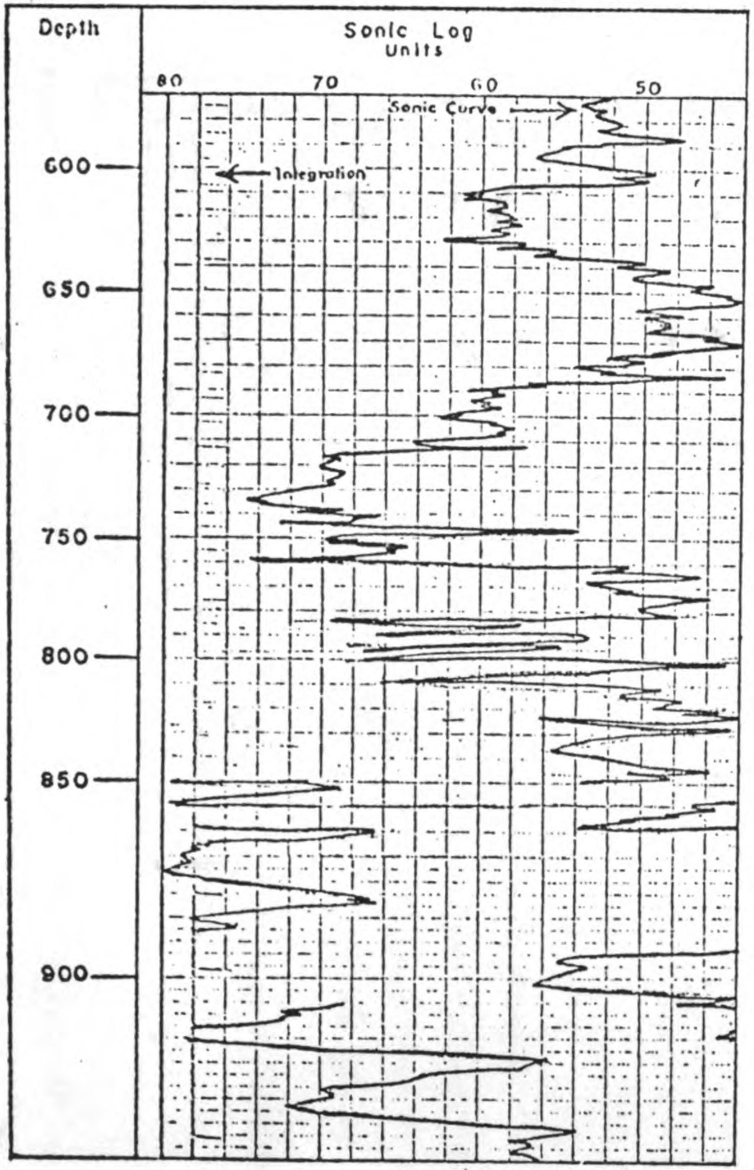
THICKNESS	UNIT NO. (LOG)	DESCRIPTION SAGINAW FORMATION
670	11	Sandstone 55% to 60%, white gray, less than .5MM; shale 40% to 45%, light gray.
680	12	Sandstone finely laminated and interbeded with shale, white and gray colors, respectively.
690	13	Sandstone, same as above, sand grains, medium size, gray.
700	14	Same as above.
710	15	Sand grains, rounded to subrounded, some perfectly clear to milky, 1.2 MM.
720		Missing.
790	22	Limestone 85%, light gray to light brown No. 3 freshwater limestone; shale medium gray, 15%, typical No. 2 shale, very compact concurve brake.
800	23	Same as above with maybe some of it kind of brownish, shale 4%-5% or less.
810	24	Limestone 70%, white to brownish, shale 30%, black gray trace carbonaceous shale.
820	25	Shale (claystone) No. 2 85%, light to medium gray; sandstone 15%, medium size grain, white.
830	26	Same as above with 60% shale and 39% sand-stone plus 1% silty shale.
840	27	Shale 60%, light gray and chocolate brown; sandstone, 40% medium grain size, white.
850	28	Same as above with 85% shale and 15% sandstone.
860	29	Mostly shale, light gray to medium gray; sandstone, 20% to 25%, white, medium size grain.
870	30	Sandstone 90%, white to light gray, very fine grain, lime 3% almost white to light gray dense, some calcareous; may be 1% chocolate shale and medium gray.

Table 4-A - Continued:

THICKNESS	UNIT NO. (LOG)	DESCRIPTION SAGINAW FORMATION
880	31	Sandstone, No. 1, 92%; limestone 5%, light gray to light brown; shale 3%, dark medium gray.
900	32	Same combination. Sandstone 85%, limestone 13% and shale 2%.

APPENDIX B

The Geophysical Log Plots

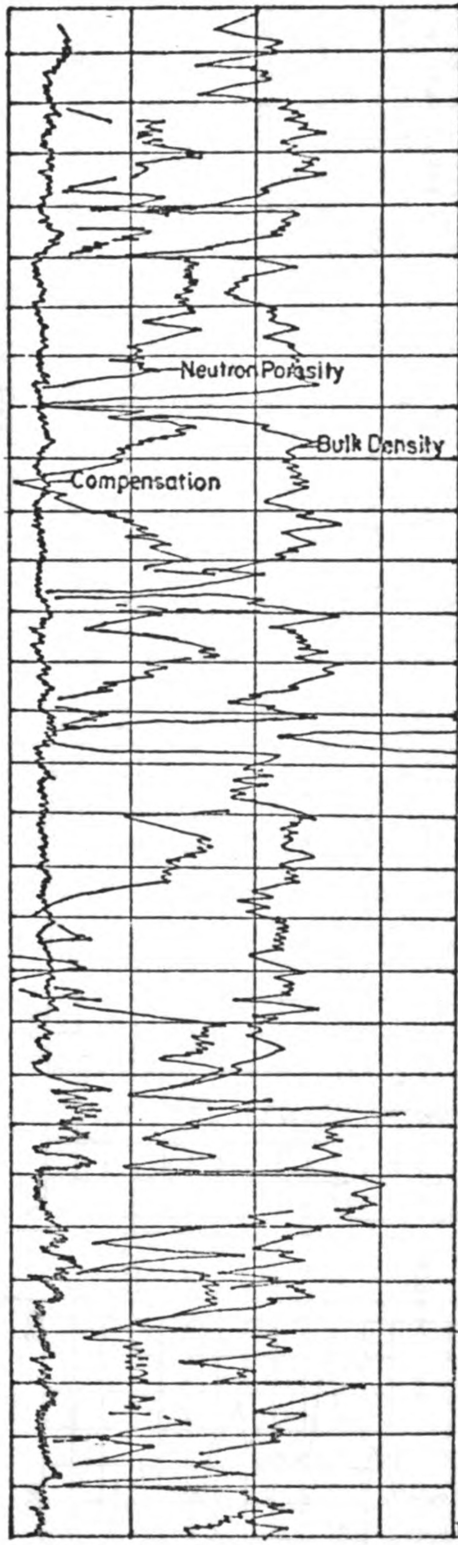


SAMPLE DESCRIPTION

570	Shale, silty, black gray, fragmented carbonaceous material, trace white sandstone.
580	Shale, silty, dark gray, traces of brownish shale (less than 1%)
590	A little higher percentage of brownish shale (aprox. 2%).
600	Brown silty shale, higher percentage of brownish shale.
610	Same as above plus broken peaces of plant fragment.
620	Same as above.
630	Same as above, plus brownish shale (aprox. 4%).
640	Mostly shale, medium to dark gray; sandstone white to light gray,medium grain size, (aprox. 15%-20%).
650	Same as above.
660	Same as above.
670	Sandstone 55% to 60%, white gray, less than .5 MM; shale 40% to 45%, light gray.
680	Sandstone finely laminated and interbeded with shale, white & and gray colors respectively.
690	Sandstone, same as above, sand grains, medium size, gray.
700	Same as above.
710	Sand grains, rounded to subrounded, some perfectly clear to milky, 1:2 MM
720	Missing
790	Limestone 85%, light gray to light brown No 3 fresh water limestone; shale medium gray, 15% , tipical No 2 shale, very compact concuve brake.
800	Same as above with may be some of it kind of brownish,shale 4%-5% or.less.
810	Limestone 70%, white to brownish, shale 30%, black gray trace carbonaceous shale.
820	Shale (claystone) No2 85%, light to medium gray; sandstone 15%, medium size grain, white.
830	Same as above with 60% shale and 39% sandstone plus 1% silty shale.
840	Shale 60%, light gray and chocolate brown; sandstone,40% medium grein size, white.
850	Same as above with 85% shale and 15% sandstone.
860	Mostly shale, light gray to medium gray; sandstone, 20% to 25% , white, medium size grain.
870	Sandstone 90%, white to light gray, very fine grain, lime 3% almost white to light gray dense ,some calcareous; may be 1% chocolate shale and medium gray.
880	Sandstone Nol 92%; limestone 5%, light gray to light brown; shale 3%, dark medium gray.
900	Same conbination. Sandstone 85%, limestone 13% and shale 2%.

FIGURE 1-1A DIAGRAM SHOWING DEFLECTIONS OF THE SONIC LOG VERSUS LITHOLOGY

SAMPLE DESCRIPTIONS



720 Shale, brownish, gray; sandstone, trace of white .1 MM grain size, subangular, medium cemented
730 with limestone.
Shale, dark gray
740 Shale, dark gray; shale, trace grayish-brown.

750 Sandstone, grayish, white .1-.15 MM grain size, subangular, medium well cemented with dolomite.
760 Sandstone, off white .1-.15 MM grain size, suban-
770 gular, medium cemented with dolomite; a porous looking sandstone.
780

790 Shale, medium gray, silty.

800

810

820 Shale, dark gray, blackish.

830

840 Shale, dark gray.

850 Free sand grains, clear .15-.35 MM grain size, subangular.
860

870

880 Shale, dark gray.

890

900

910 Shale, black.

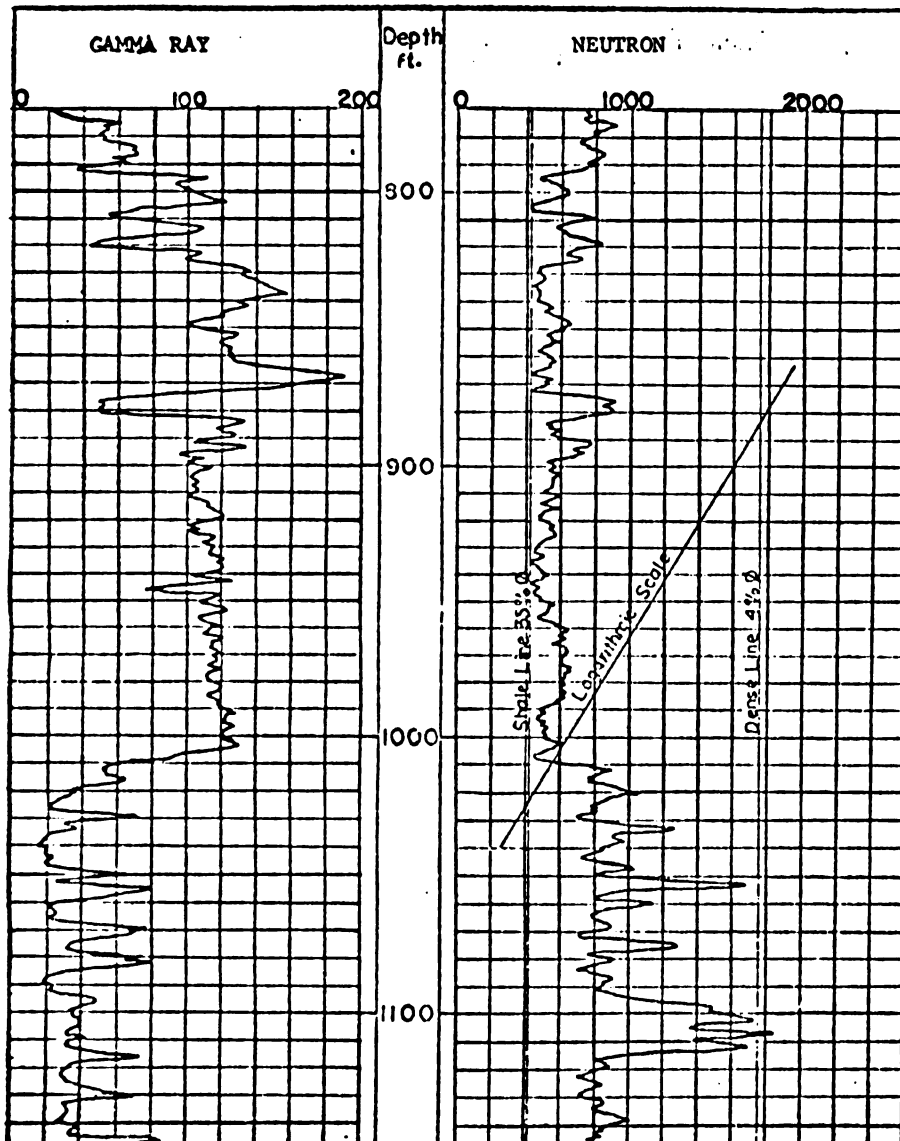
920 Shale, light gray, slightly greenish cast.
930 Limestone 60%, cream, microcrystalline; shale 40% as above.
940 Limestone 60%, cream, microcrystalline to cryptocrystalline.
950 Shale 70%, medium gray; limestone 30%, as
960 above

970 Shale, pale green and light gray; limestone 30% as above.
980 Shale, as above, sandy.

990 Shale, medium gray.

1000

FIGURE 1-1B DIAGRAM SHOWING DEFLECTIONS OF THE SIDEWALL NEUTRON POROSITY LOG AND THE COMPENSATED DENSITY LOG DEFLECTIONS VERSUS LITHOLOGY



SAMPLE DESCRIPTIONS

773 Free sand grain, clear .15-.25 MM grain size, subangular.
800 Shale, dark brown-blackish.
810 Shale 50% as above; free sand grains 50% slightly frosted,.15 MM grain size, subangular.
820 Free sand grains as above.
830 Free sand grains as above; shale,dark gray-blackish.
840 Shale 60% as above; free sand grains 40% as above.
850 Shale 90% dark gray-blackish; sandstone 10% gray; .1 MM grain size, subangular,poorly cemented with dolomite.
900 Shale, medium gray, trace of carbonaceous black fossil week stems & leaves; siltstone, trace, gray.
1020 Shale 70% medium gray; shale 30% light gray & greenish,plastic;sandstone,trace,off white,.15 MM grain size,subangular,medium cemented.
1030 As above, plus limestone,trace,cream,microcrystalline.
1035 Limestone,60% cream as above;shale 40% medium gray; sandstone, trace,as above.
1045 Limestone 50% brown,microcrystalline;sandstone 30% off white,.15-.25 MM grain size,subangular,fair cemented with lime;shale 20% gray.
1055 Limestone,brown;sandstone,trace as above.
1100 Sandstone 70% off white,.15-.25 MM grain size,subangular,medium well cemented with dolomite;dolomite 30% brown,microcrystalline.
1105 Dolomite,brown as above;limestone,trace,cream,microcrystalline;sandstone,trace as above.
1115 Free sand grains,frosted and clear,.15-9.45 MM grain size,subrounded;limestone & dolomite,trace as above.
1140 Dolomite,tan-cream,microcrystalline;dolomite,trace, brown,microcrystalline;free sand grains,trace as above.

FIGURE 1-1C. DIAGRAM SHOWING DEFLECTIONS OF THE GAMMA RAY-NEUTRON LOG VERSUS LITHOLOGY.

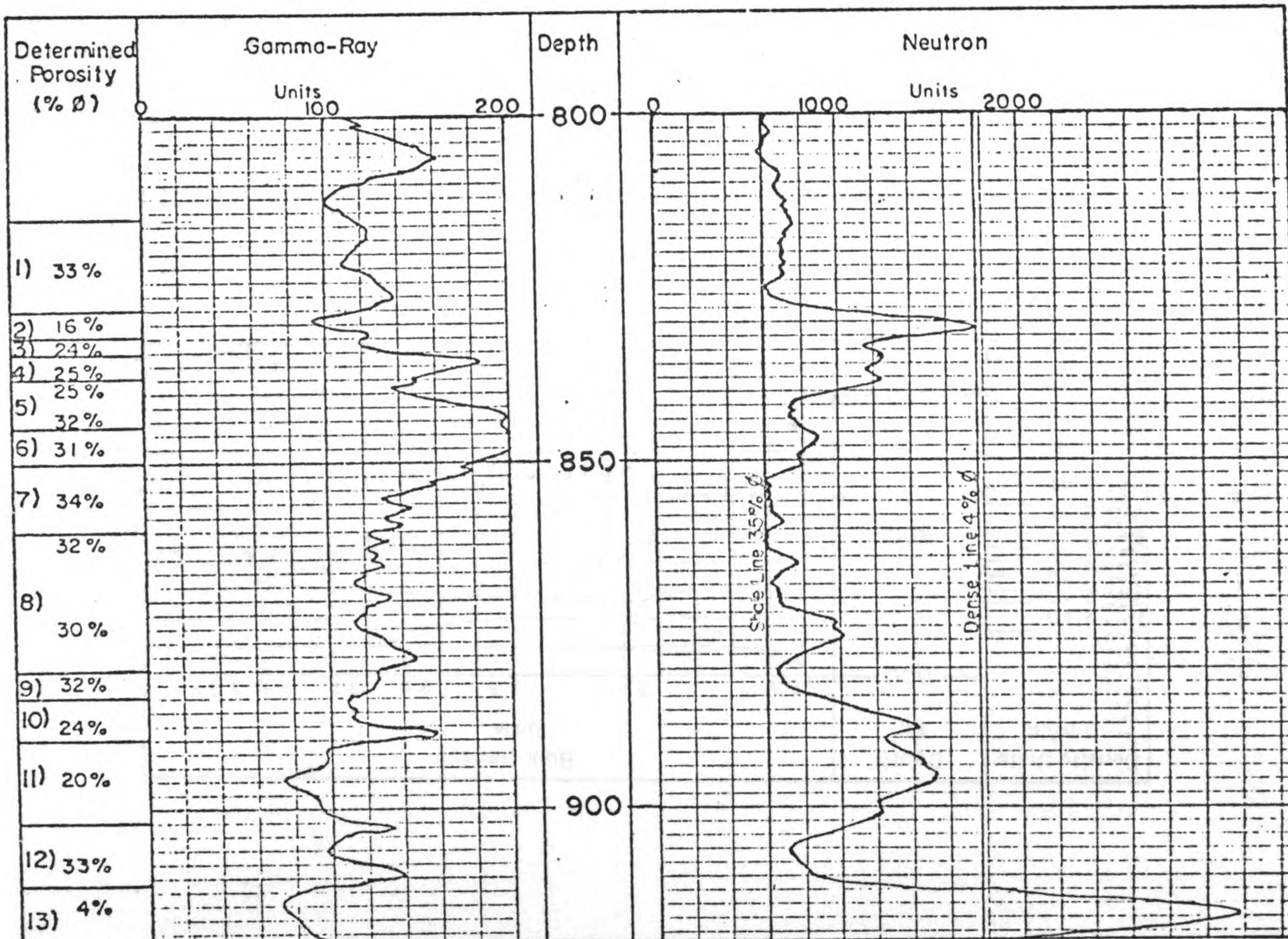


Figure 1A– Gamma Ray-Neutron Log. Michigan Consolidated Gas Co. Well N° 1, Permit N° 27,734

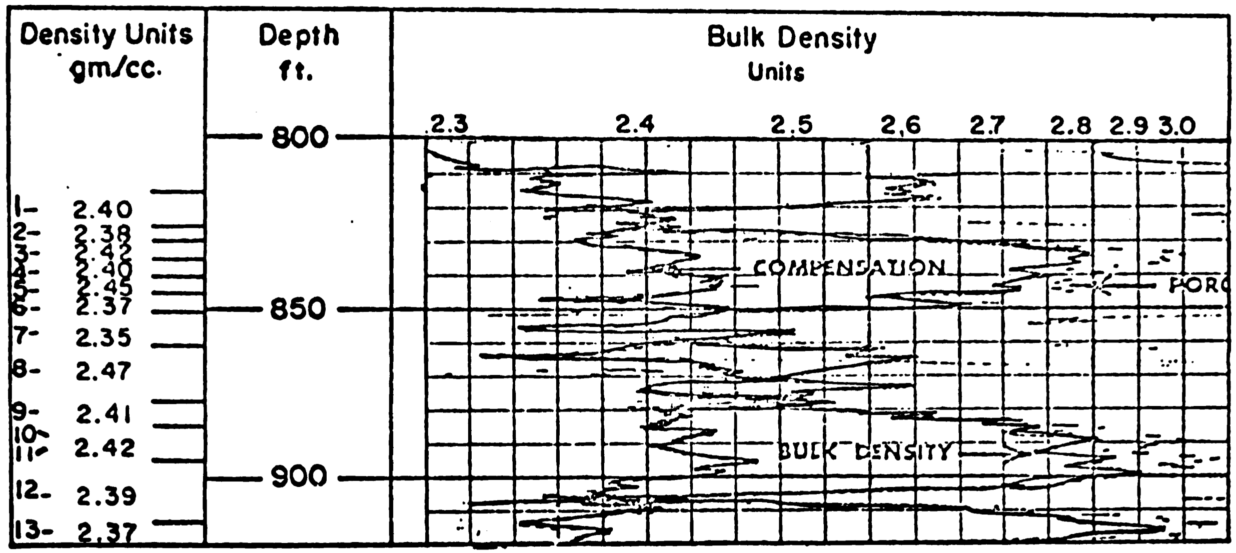


Figure 1B- Bulk Density. Michigan Consolidated Gas Co. Well N° 1, Permit N° 27,734

POROSITY AND LITHOLOGY DETERMINATION
FROM
Formation Density Log and Sidewall Neutron Porosity Log
May also be used with G.N.T. or H. Neutron logs
SALT WATER

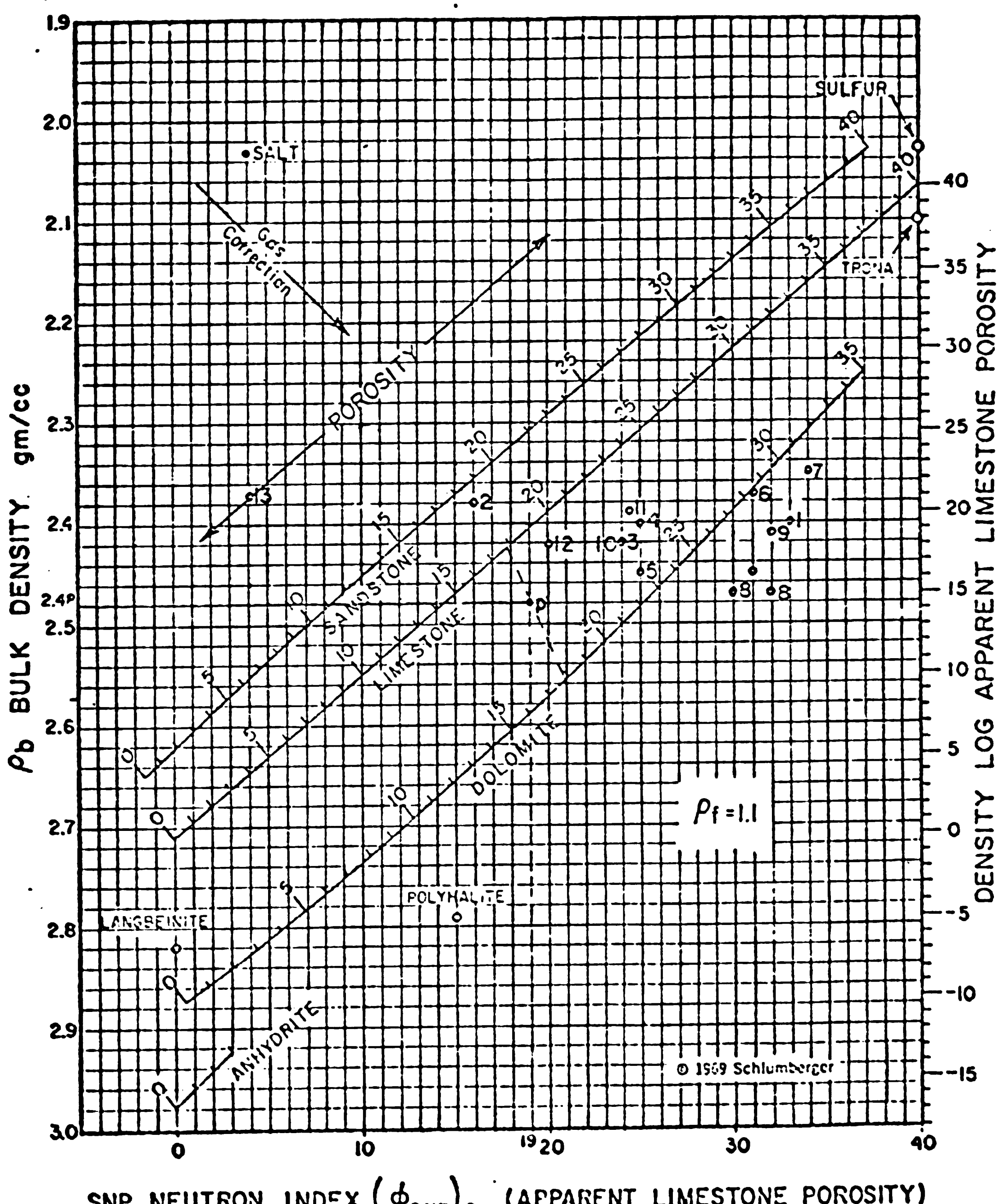


Figure 1C- Crossplot. Michigan Consolidated Gas Co. Well N° 1, Permit N° 27,734

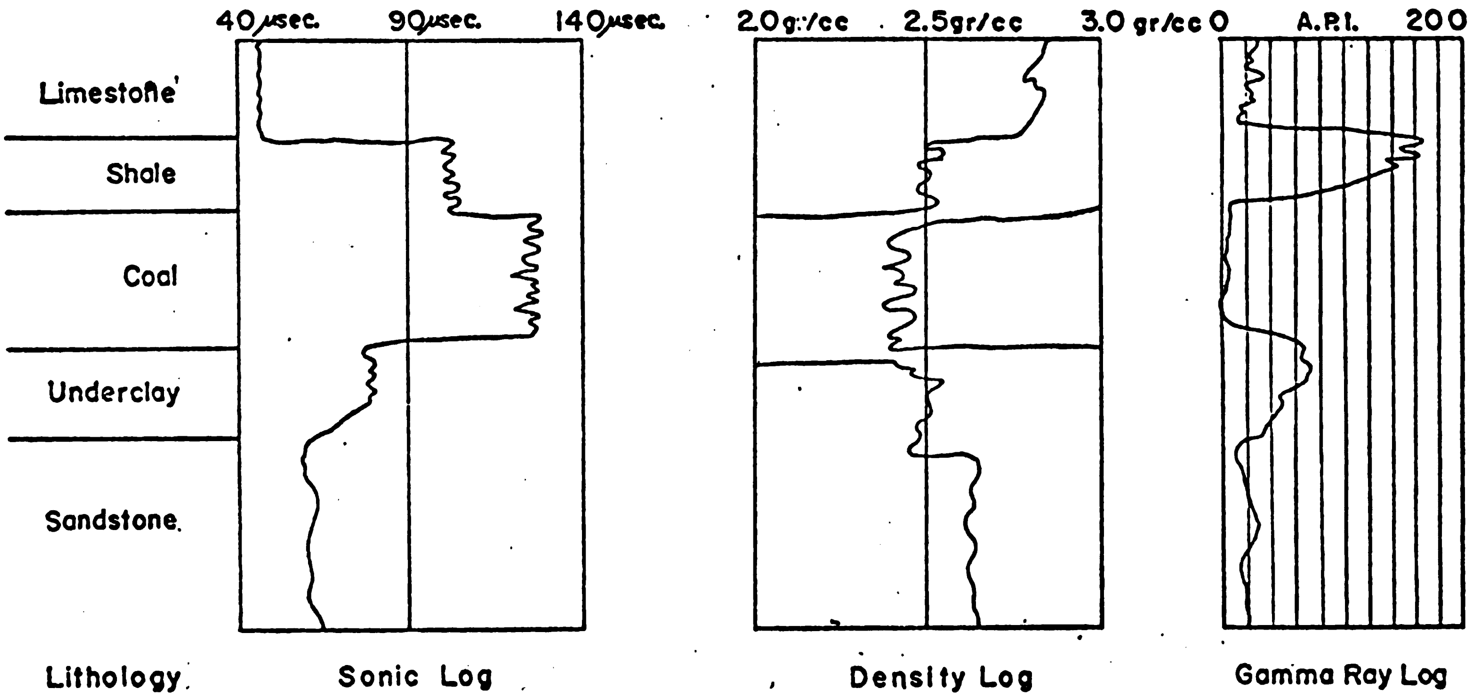
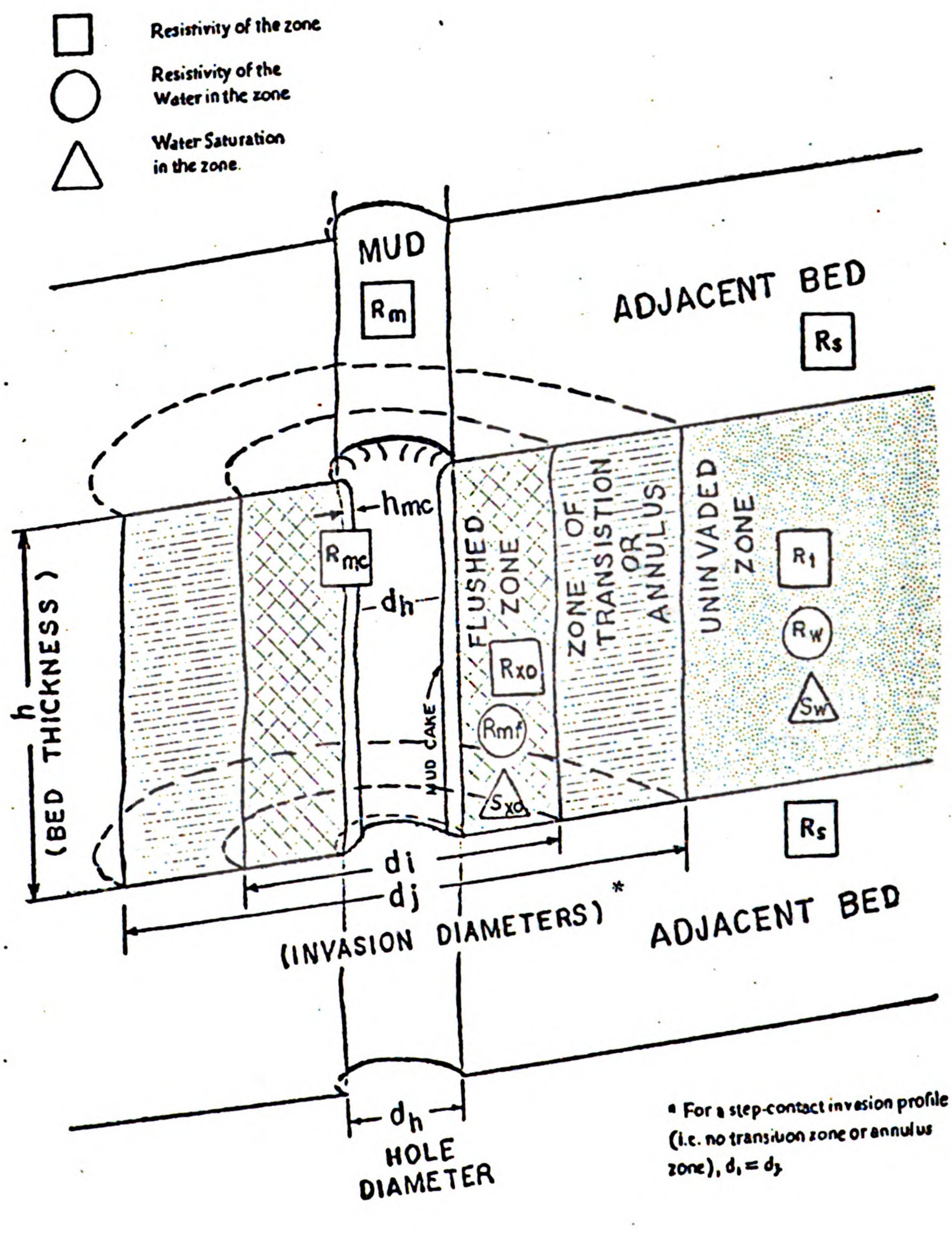


Figure ID- Diagram showing the comparison of typical log deflection on lithologic types.

Figure IE

SYMBOLS USED IN LOG INTERPRETATION

(Schematic)



* For a step-contact invasion profile (i.e. no transition zone or annulus zone), $d_i = d_j$

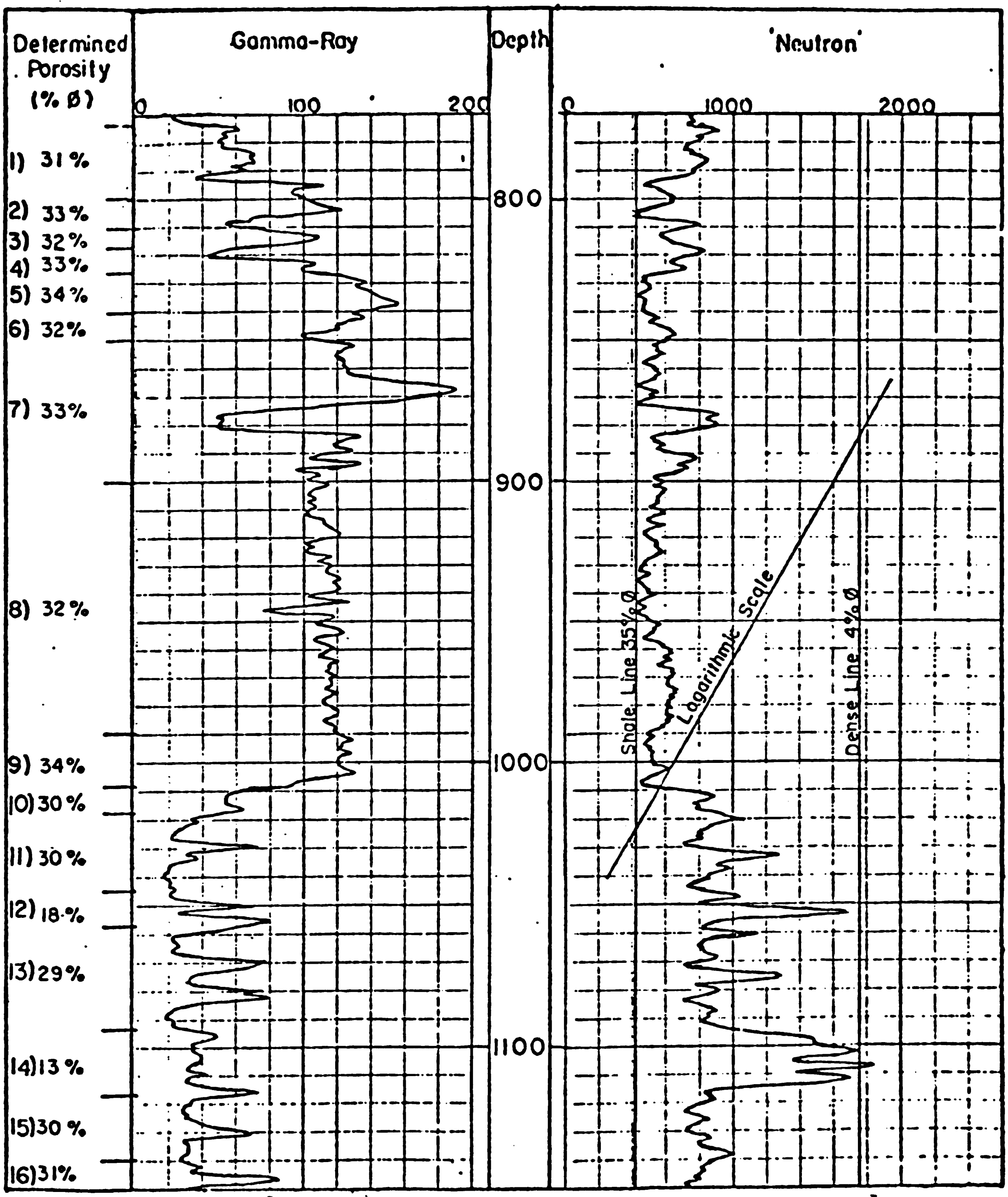


Figure 2A - Gamma Ray-Neutron Log. Michigan Consolidated Gas Co. Well N° , Permit N° 27,394

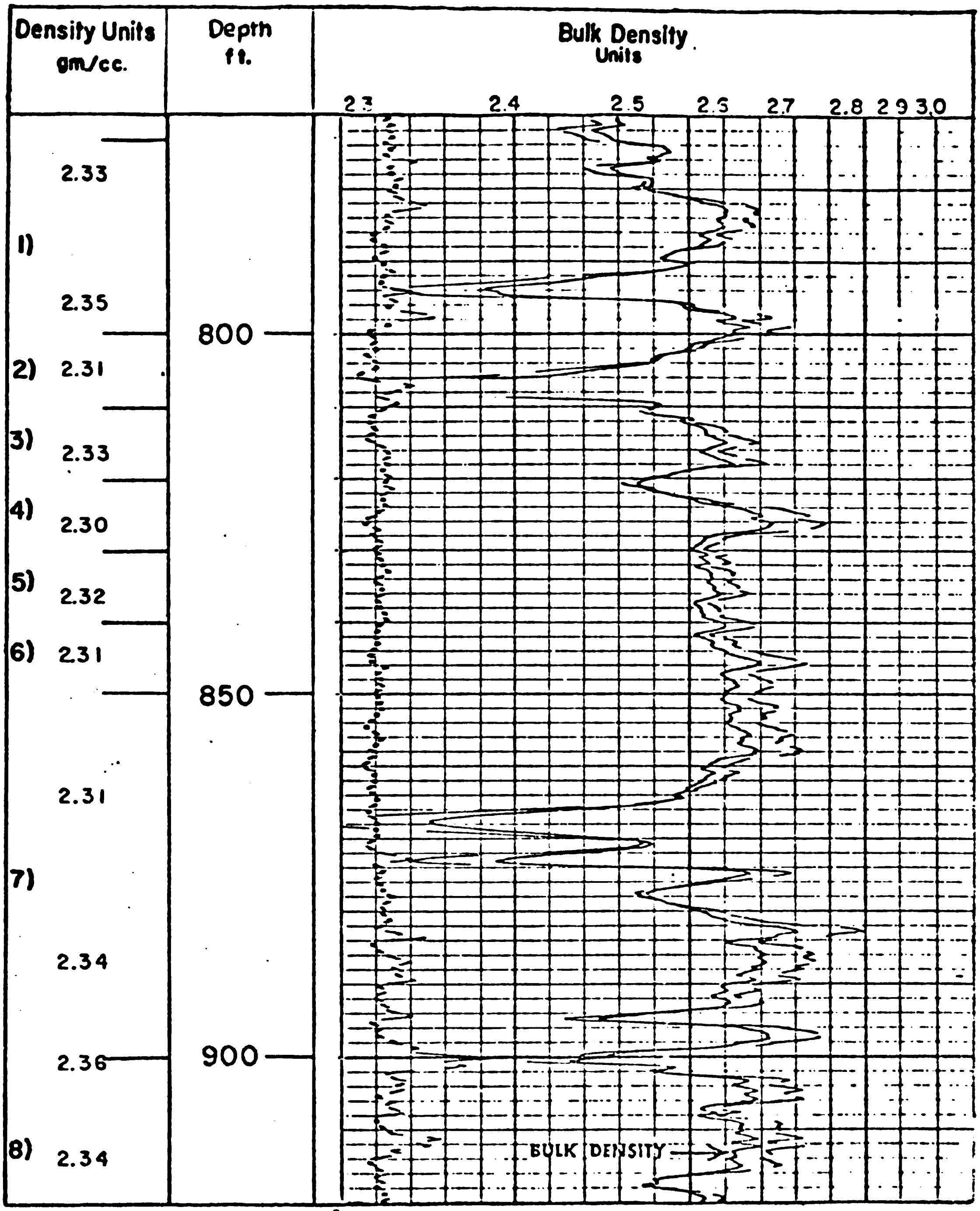


Figure 2B- Bulk Density. Michigan Consolidated Gas Co. Well N°2, Permit N°27,394

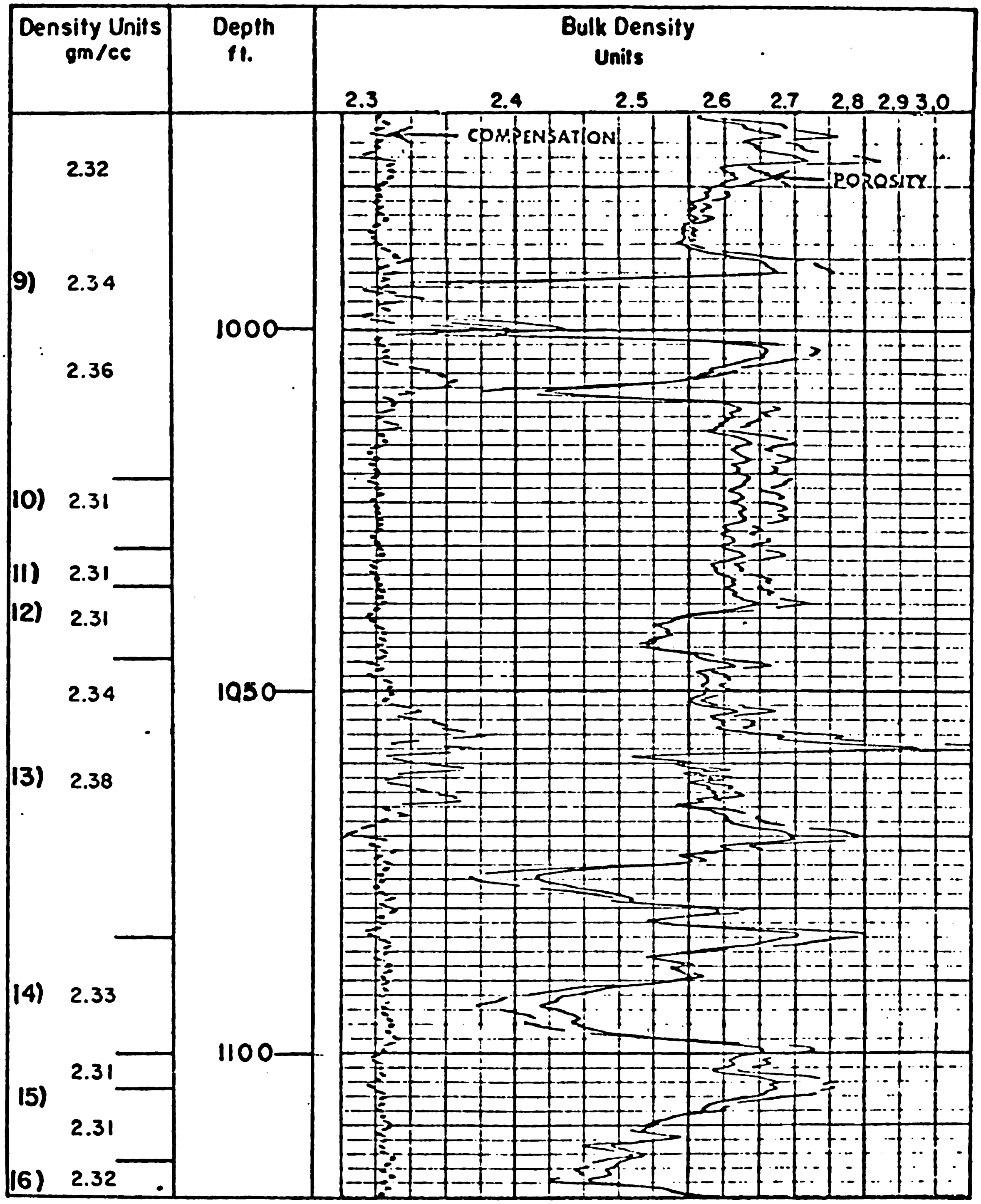


Figure 2B- Bulk Density. Michigan Consolidated Gas Co. Well N°2, Permit N°27,394

POROSITY AND LITHOLOGY DETERMINATION
FROM
Formation Density Log and Sidewall Neutron Porosity Log

May also be used with G.N.T. or H. Neutron logs.

SALT WATER

(I)

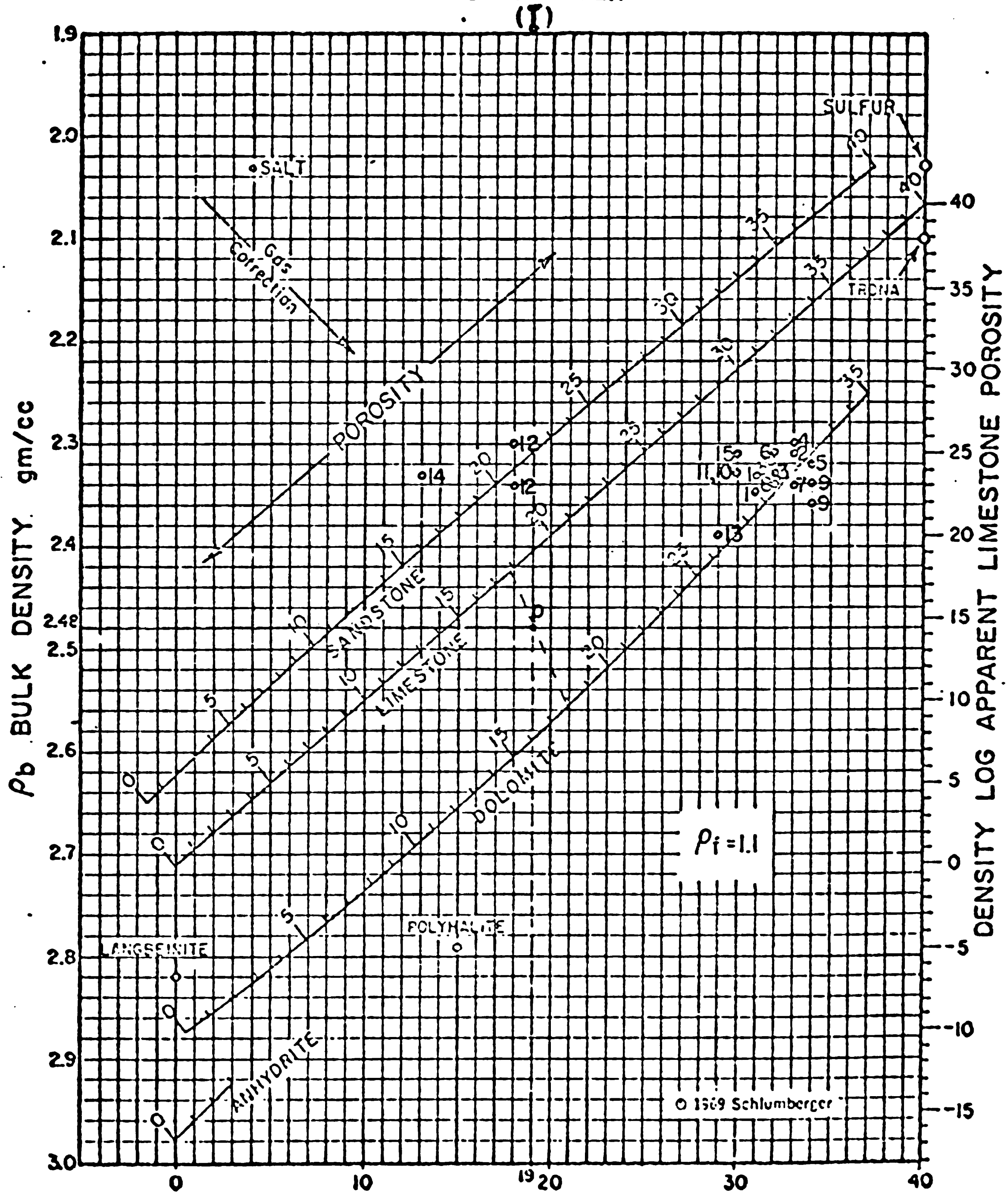


Figure 2C- Crossplot. Michigan Consolidated Gas Co. Well N°2, Permit N° 27,394

POROSITY AND LITHOLOGY DETERMINATION
FROM
Formation Density Log and Sidewall Neutron Porosity Log
May also be used with G.N.T. or H. Neutron logs.
SALT WATER
(II)

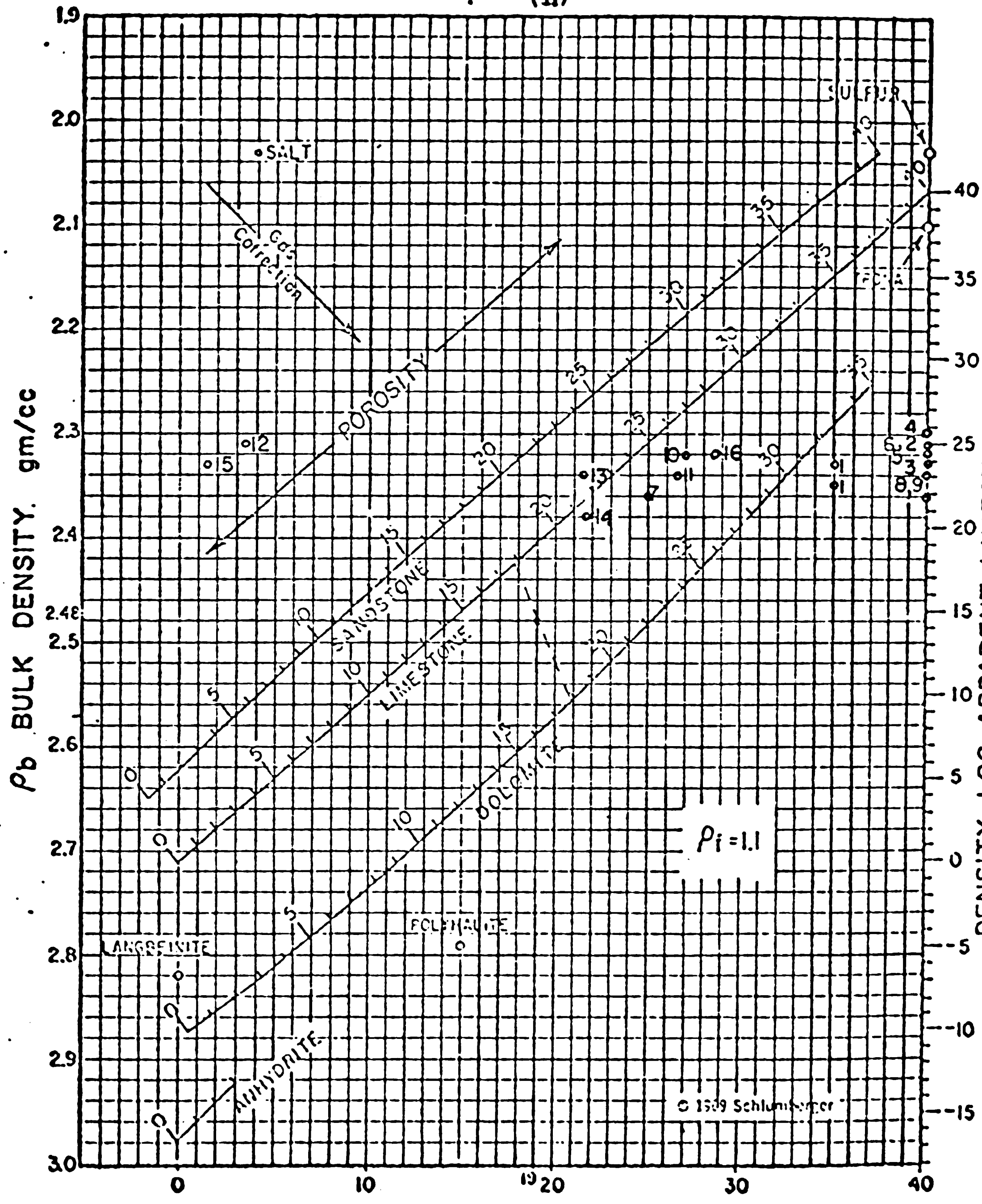


Figure 2C- Crossplot. Michigan Consolidated Gas Co. Well N°2, Permit N° 27,394

POROSITY AND LITHOLOGY DETERMINATION
FROM
Formation Density Log and Sidewall Neutron Porosity Log

May also be used with G.N.T. or H. Neutron logs.

SALT WATER

(III)

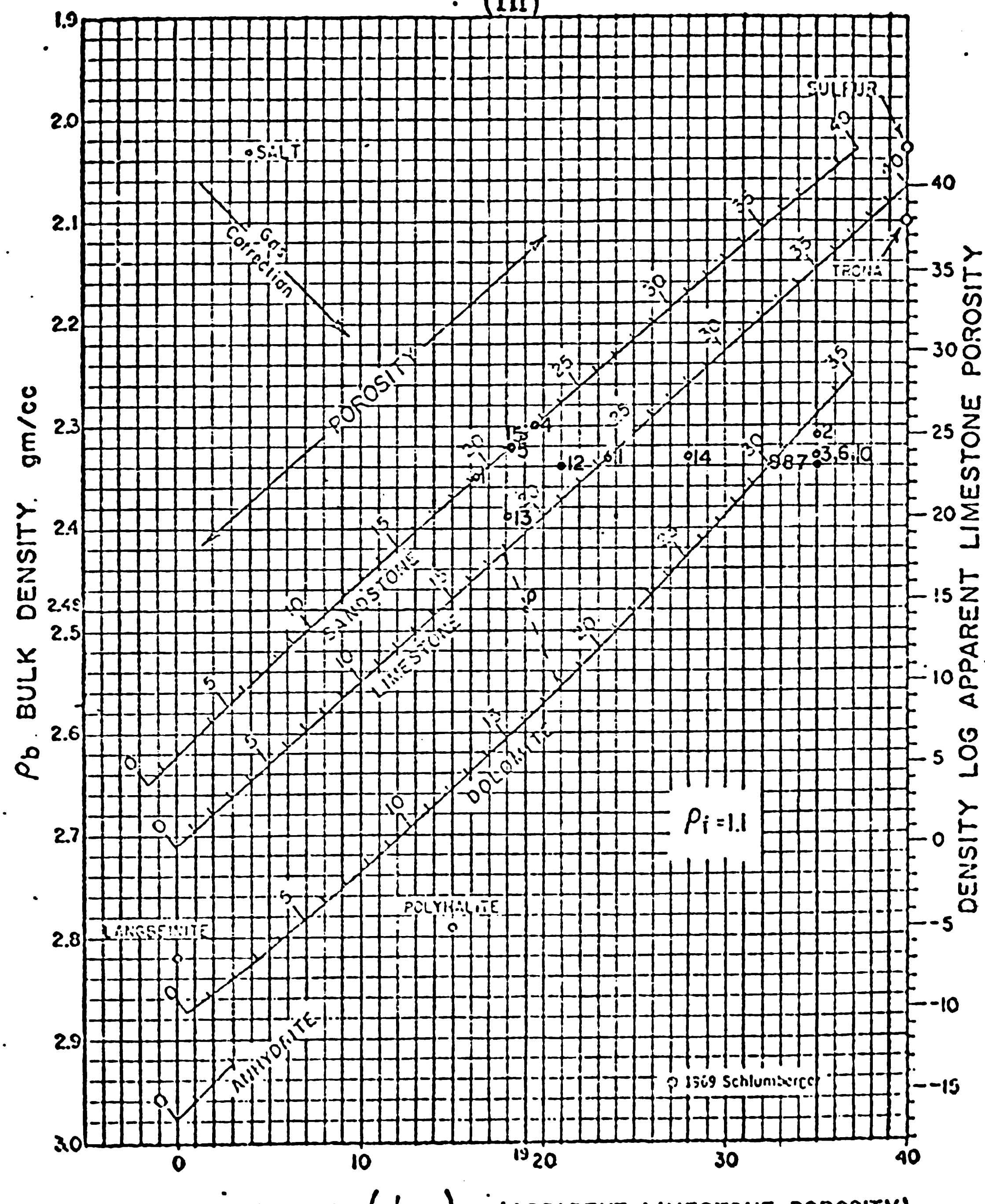


Figure 2C- Crossplot. Michigan Consolidated Gas Co. Well N°2, Permit N° 27,394

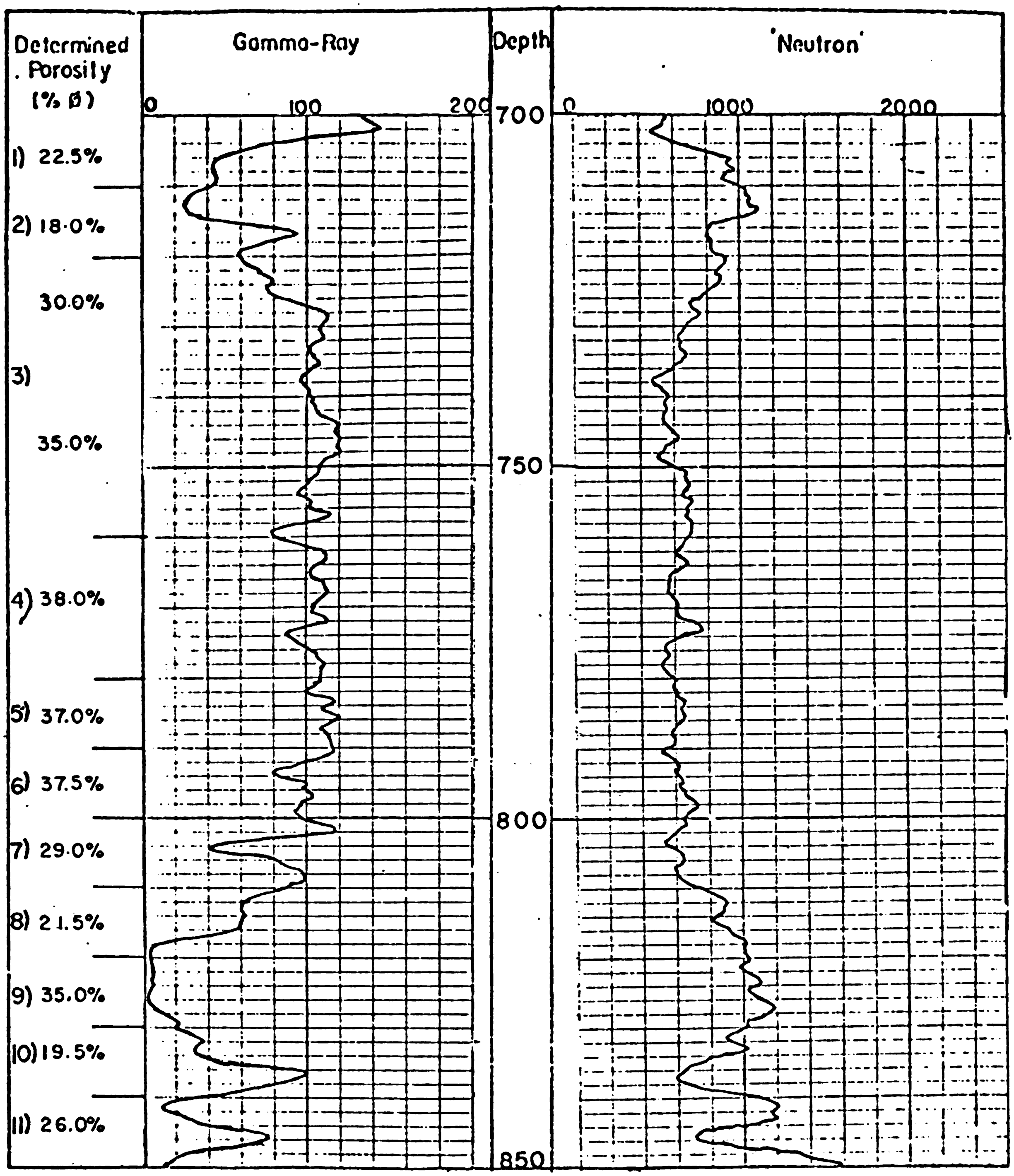


Figure 3A- Gamma Ray-Neutron Log. Michigan Consolidated Gas Co. Well N°3, Permit N° 27,666

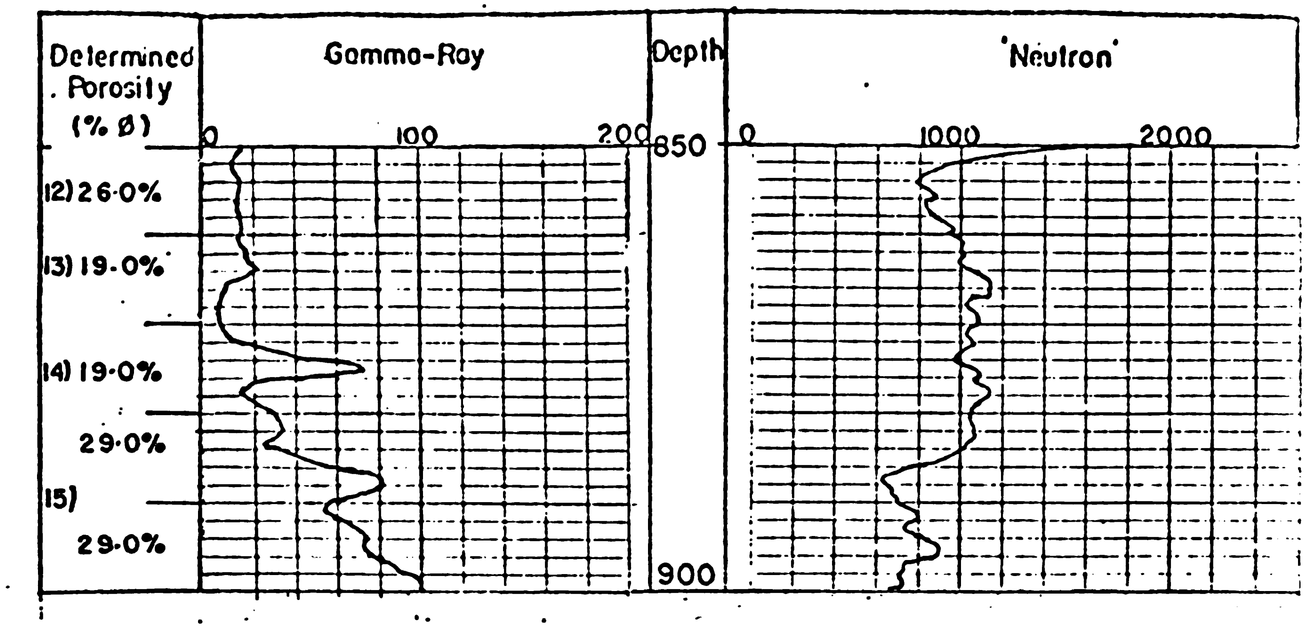


Figure 3A - Gamma Ray-Neutron Log - Michigan Consolidated Gas Co. Well N°3, Permit N° 27,666

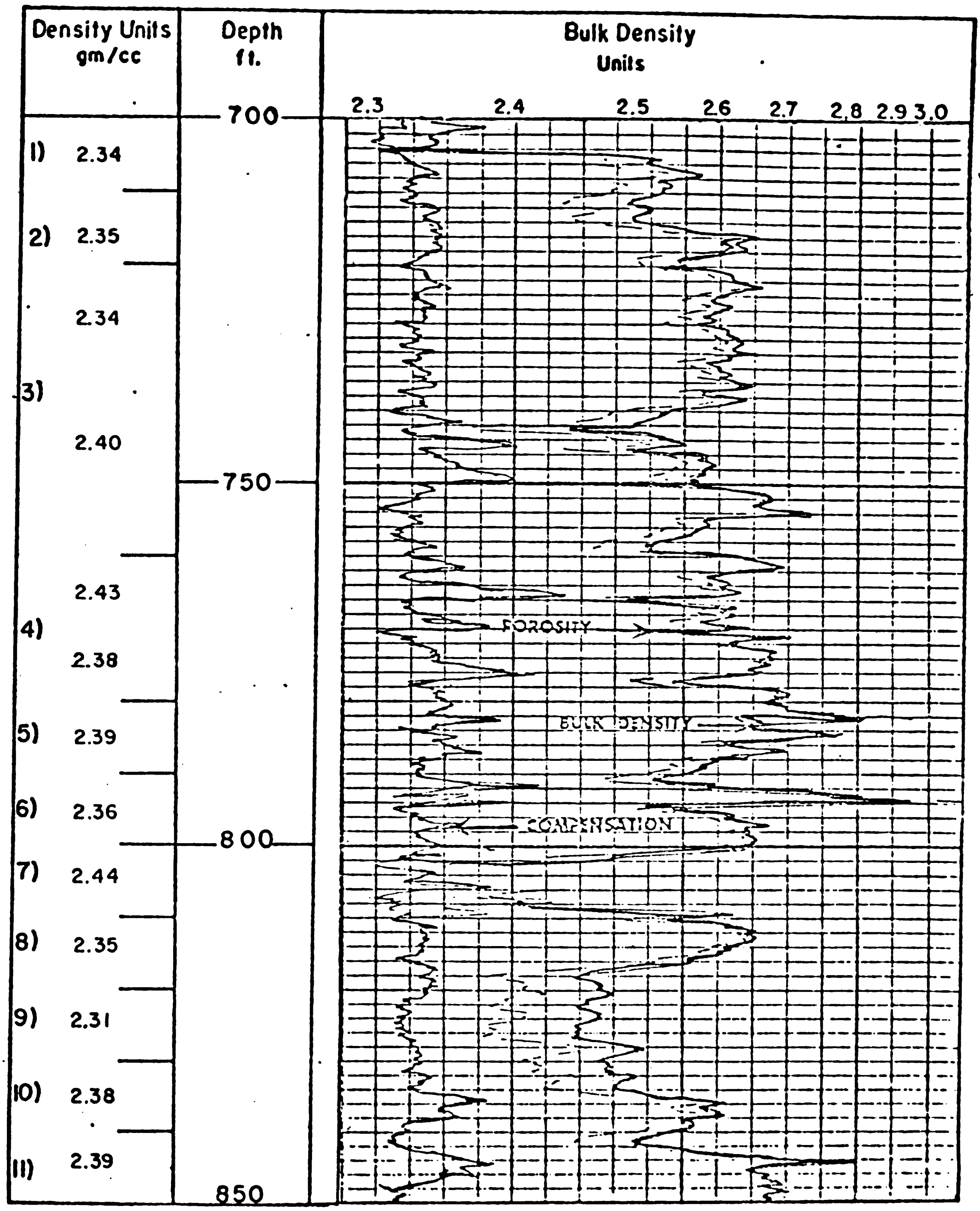


Figure 3B- Bulk Density. Michigan Consolidated Gas Co. Well N°3, Permit N°27,666

POROSITY AND LITHOLOGY DETERMINATION FROM

Formation Density Log and Sidewall Neutron Porosity Log

May also be used with G.N.T. or H. Neutron logs.

SALT WATER

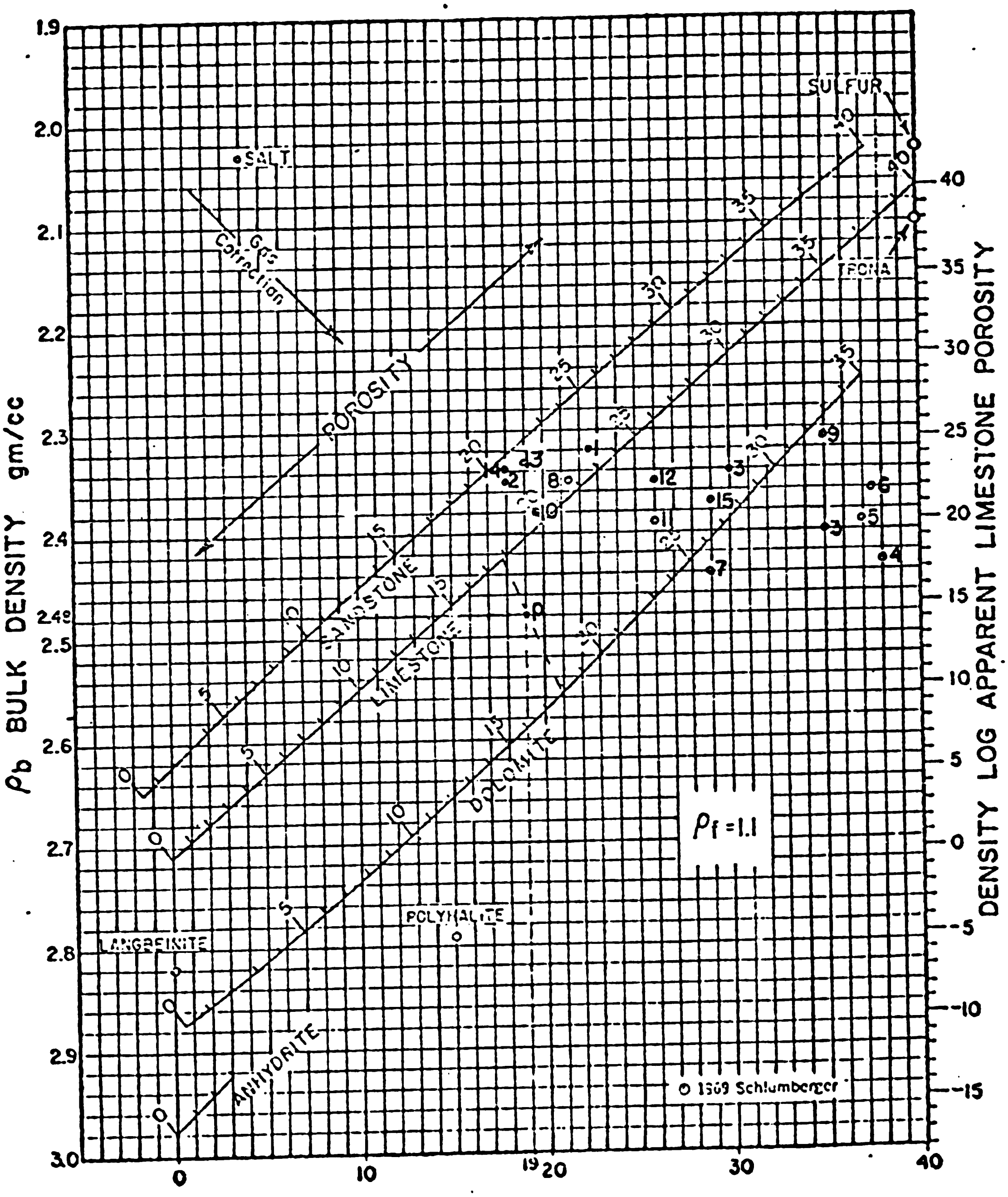


Figure 3C- Crossplot. Michigan Consolidated Gas Co. Well N°3, Permit N° 27,666

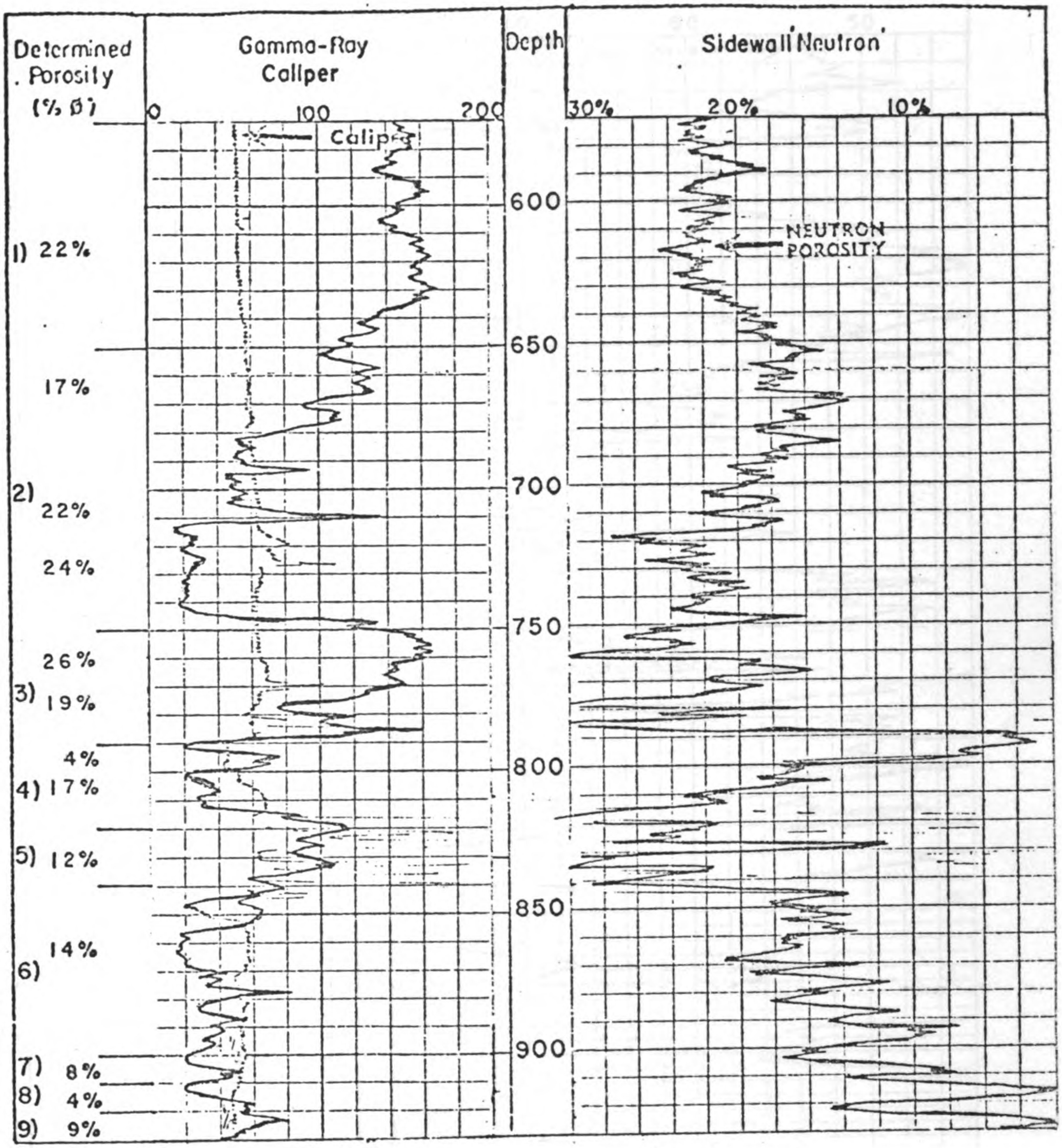


Figure 4A - Gamma Ray, Caliper, Sidewall Neutron - Michigan Consolidated Gas Co. Well N° 4. Permit N° 29,916

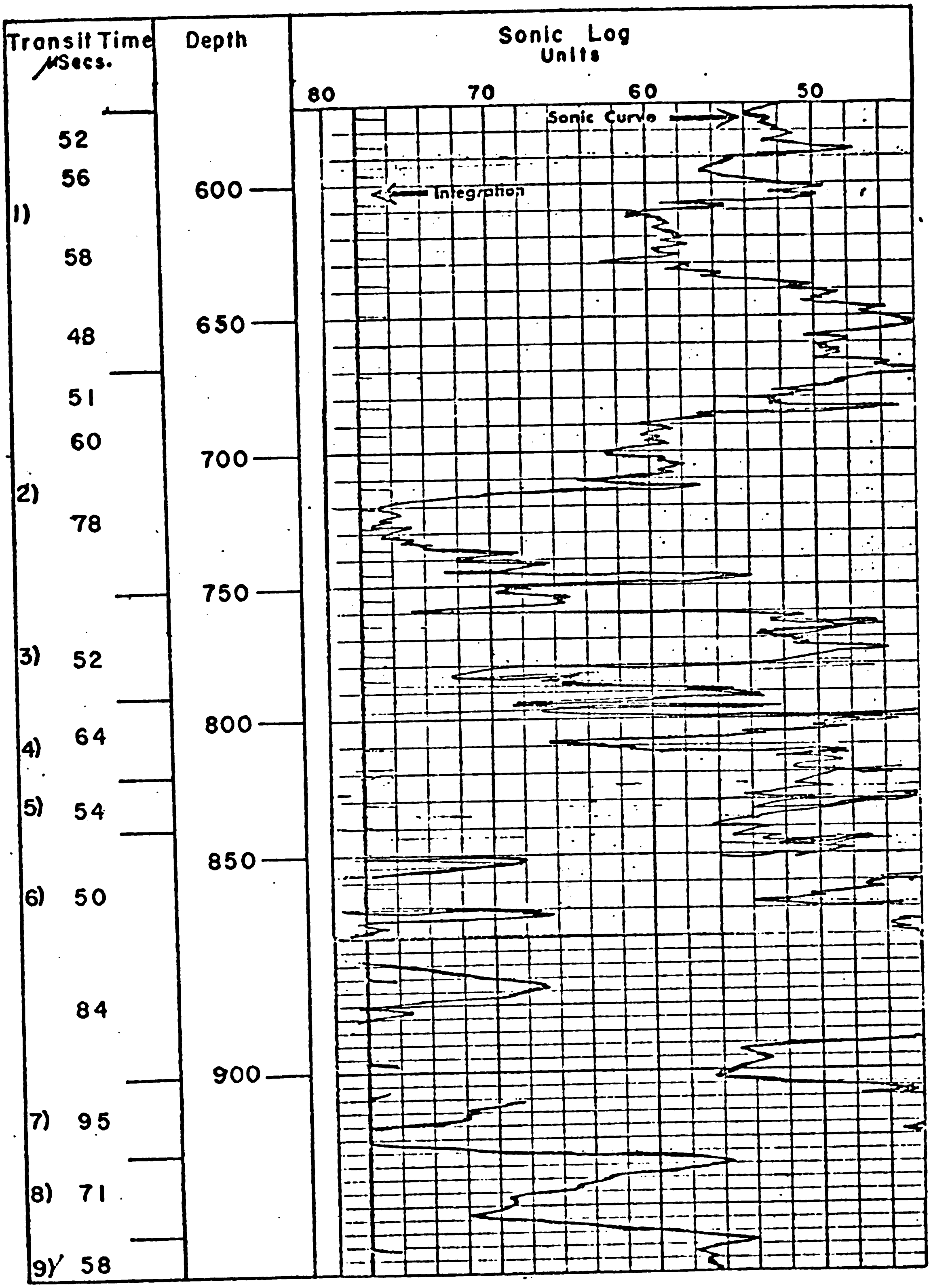


Figure 4B- Compensated Sonic Log·Michigan Consolidated Gas Co. Well N°4 Permi N°29,916

POROSITY AND LITHOLOGY DETERMINATION FROM Compensated Sonic Log and Sidewall Neutron Porosity Log

May also be used with G.N.T. or H. Neutron logs.

SALT WATER

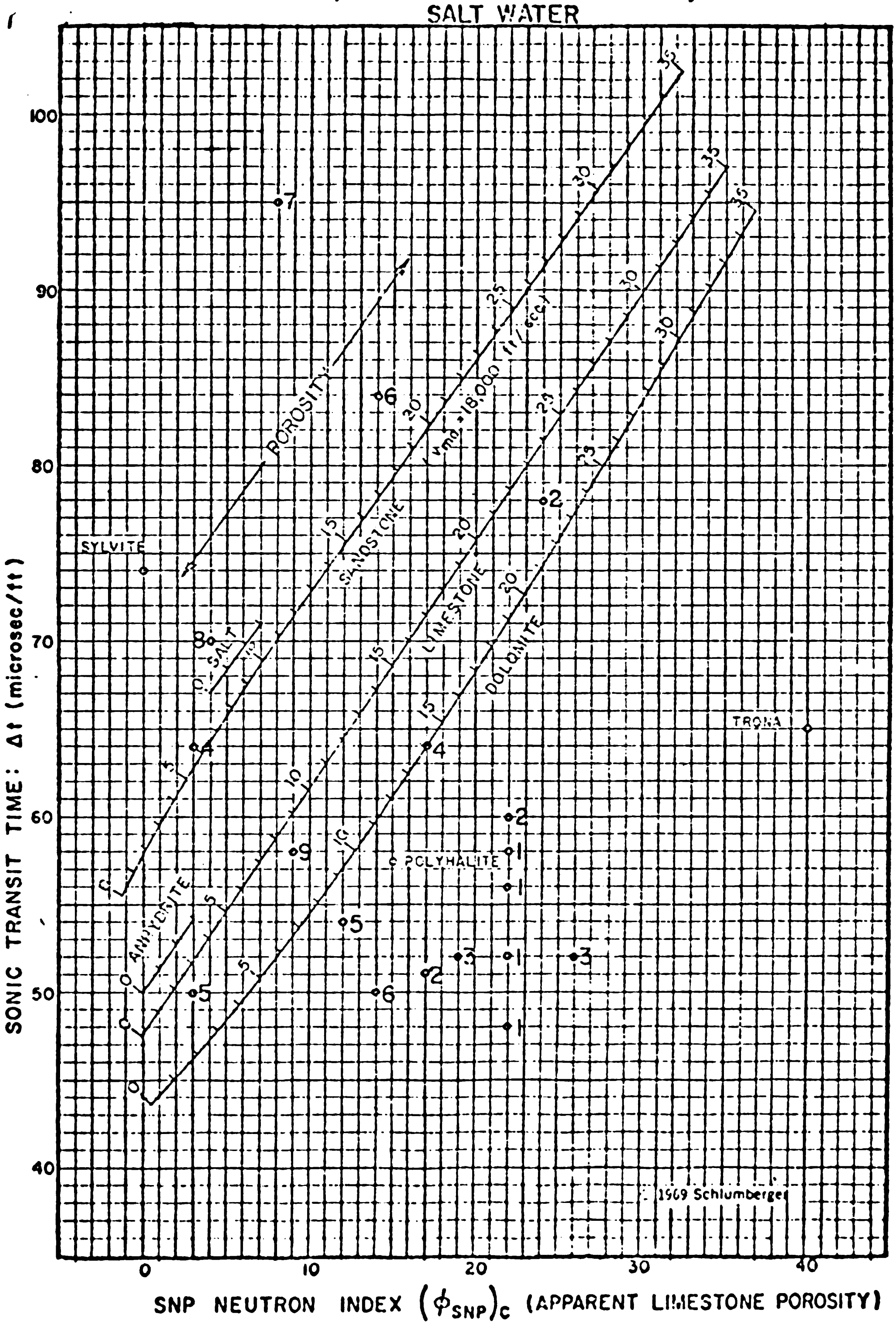


Figure 4C- Crossplot. Michigan Consolidated Gas Co. Well N°4, Permit N° 29,916

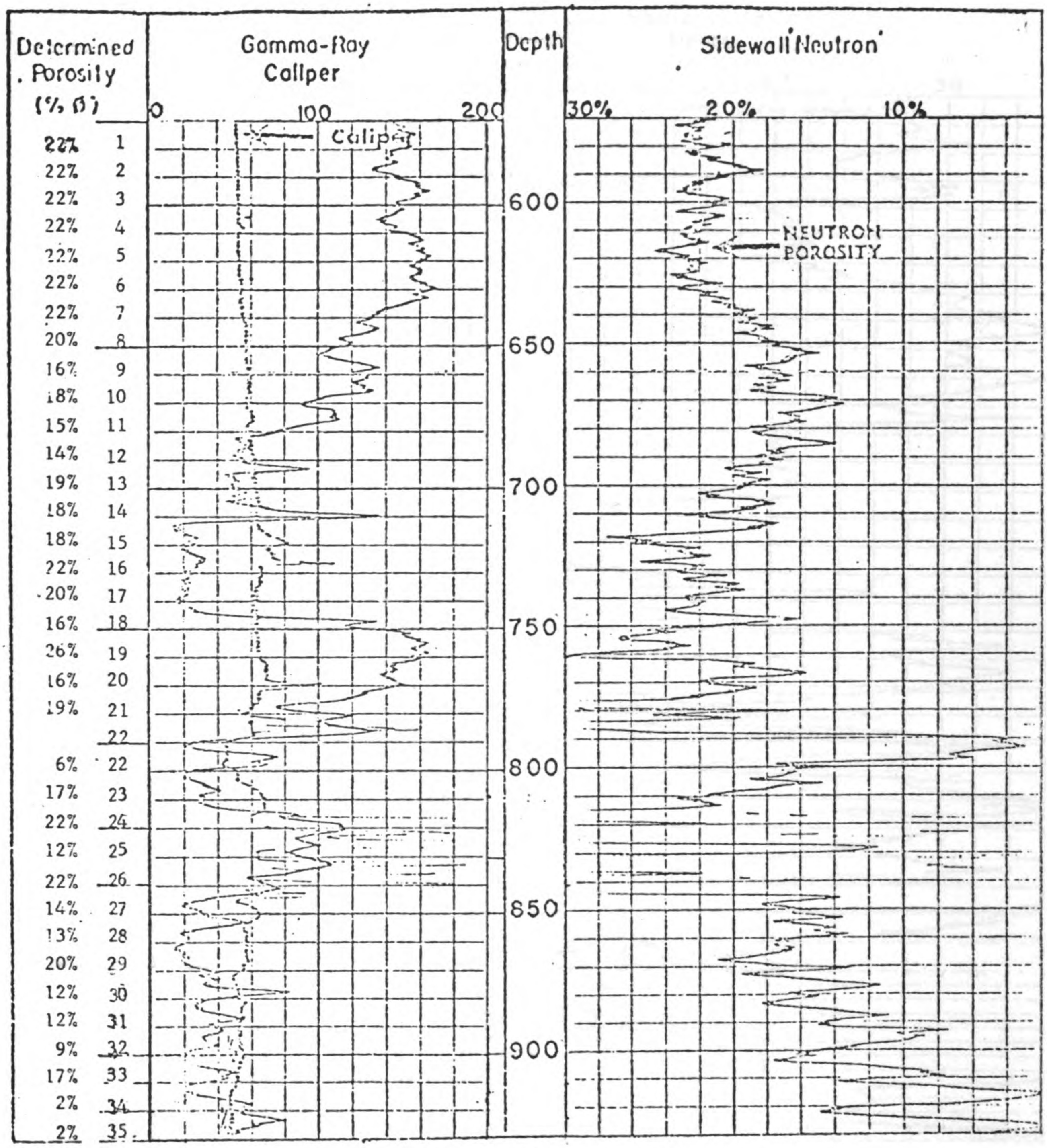


Figure 4D- Gamma Ray, Caliper, Sidewall Neutron. Michigan Consolidated Gas Co. Well N° 4. Permit N° 29,916

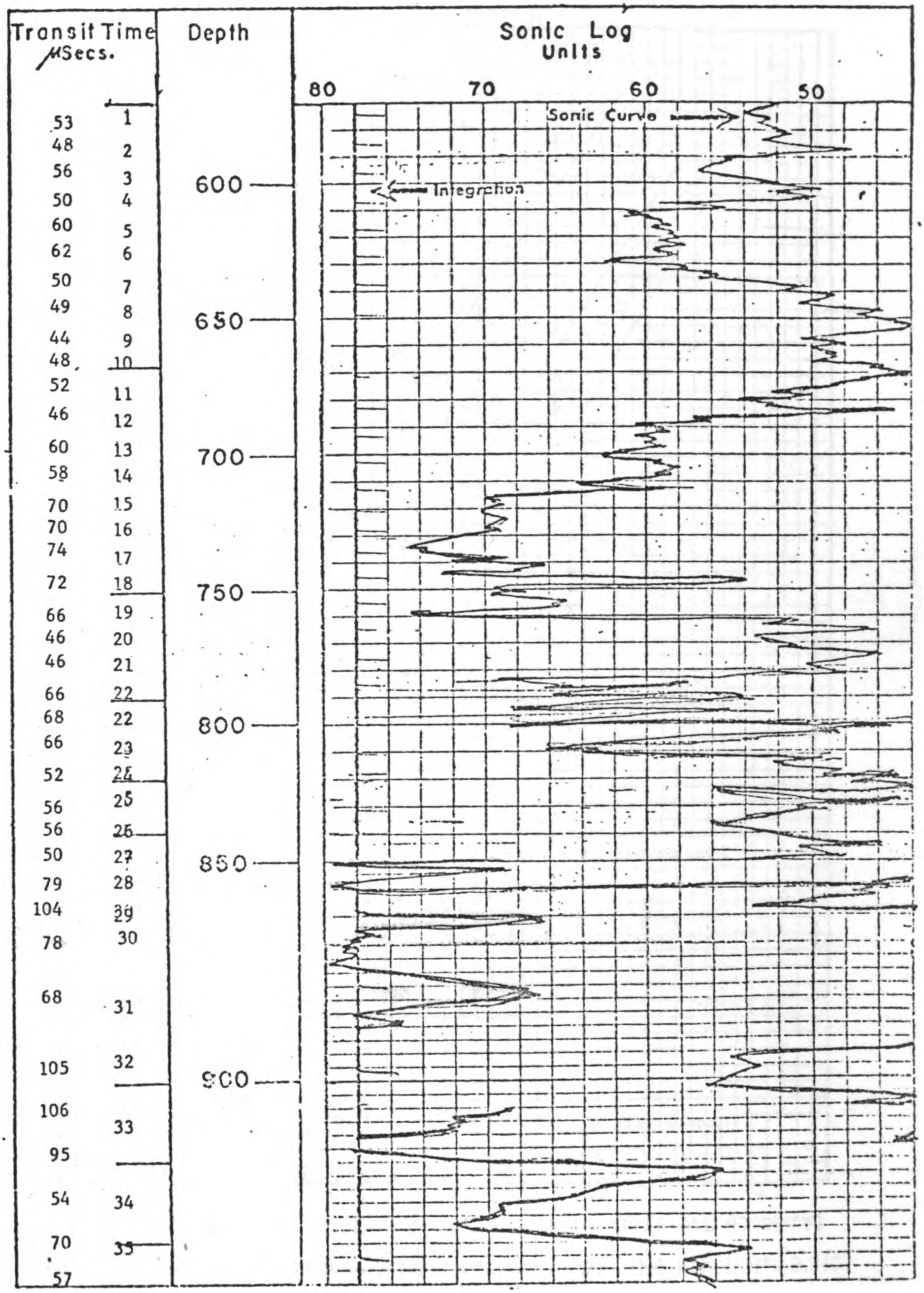


Figure 4E- Compensated Sonic Log. Michigan Consolidated Gas Co. Well N°4 Permi N°29,95

POROSITY AND LITHOLOGY DETERMINATION
FROM
Compensated Sonic Log and Sidewall Neutron Porosity Log
May also be used with G.N.T. or H. Neutron logs.

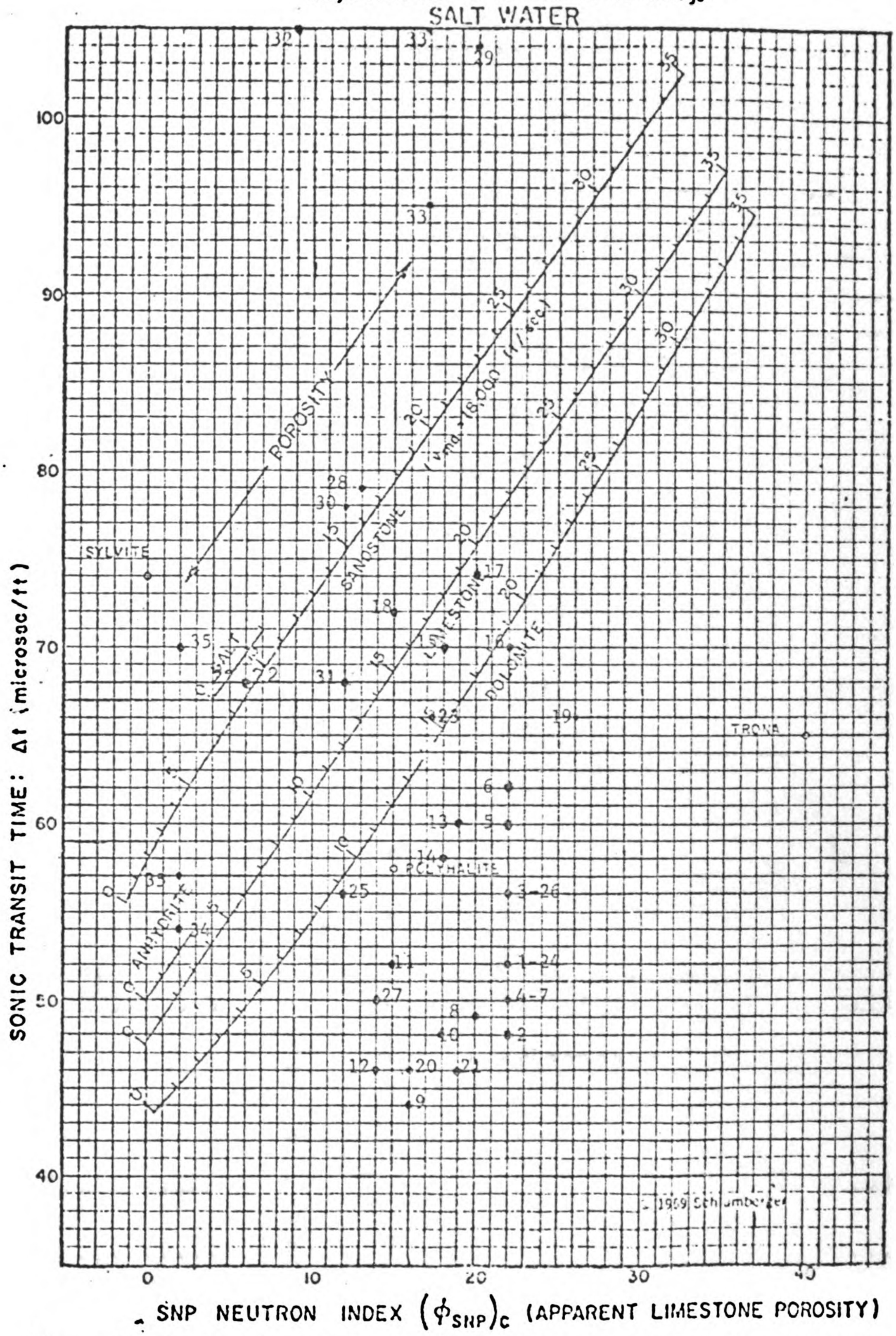


Figure 4F - Crossplot. Michigan Consolidated Gas Co. Well N°4, Permit N° 29,916