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Log-Based Gas Content and Resource Estimates for the Antrim Shale, Michigan Basin

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ABSTRACT

Antrim Shale multicomponent gas storage mechanisms of adsorption, porosity and solution in bitumen preclude the use of conventional gas-in-place volumetric calculations. Total *in-situ* gas content has been measured using canister degassing techniques adapted from coalbed methane technologies. Gas measurements ranged from approximately 5 scf/t to 166 scf/t. Gas contents exceed apparent gas-filled porosity by 6 to 8 times where organic content is high. Cross plots of gas content to companion TOC and density measurement resulted in a direct correlation between increasing gas content corresponding to progressive increases in organic matter and an inverse relationship between increasing gas content and decreasing density. The linear function relating density and gas content can be used in conjunction with open-hole log bulk density measurements to calculate gas-in-place.

A side-by-side comparison of gas content measurements from rotary sidewall core and whole core demonstrated that the measurements from both core sampling types are of equal accuracy. From the standpoint of cost, sample homogeniety and sampling selection, rotary sidewall cores are preferred over whole core. The total gas contained in the shale can be completely released as a single measurement by crushing the core upon retrieval. Utilizing the on-site gas content measurements, density/gas content relationship and density log it is possible for the first time to locate and quantify gas bearing Antrim shale intervals from well logs.

References and illustrations at end of paper.

INTRODUCTION

Despite over 3,000 wells drilled during the last four years to produce gas exclusively from the Antrim shale in the Michigan basin, there has been little effort to measure reservoir properties which control production. Previous GRI-funded research has demonstrated that adsorption is an important gas-storage mechanism in the Antrim shale of the Michigan Basin. This gas was generated in-situ and is thought to be pervasively distributed throughout the black shales, which cover an area of approximately 30,000 mi^2. Measurement of in-situ gas content of all members of the Antrim formation has been performed on core samples from Otsego, Oscoda, Ogemaw and Livingston counties. Uniform gas content relationships have been established over large areas, despite the large geographic distribution of data sets. Based on measured gas contents, the in-place gas resoures of the Antrim shale have been estimated to range from 16 bcf/mi^2 to over 35 bcf/mi^2.

Advanced Resources International (ARI), working under contract to the Gas Research Institute (GRI), has developed a cost-effective method to determine gas content in the Antrim Shale from logs. The new procedures shorten the time required to obtain data needed for gas-in-place calculations and, ultimately, field reserves. Conventional reservoir-engineering-based resource estimates cannot be used for the Antrim because of its unusual reservoir storage and production mechanisms.

Natural gas in the Antrim shale is stored by three primary processes: adsorbed on both organic matter and clays, dissolved in bitumen, and as free gas in the pore volume. The reservoir and production characteristics of the Antrim Shale are similar to those of coalbed methane reservoirs. Consequently, the techniques currently used to measure gas content in coal have been applied to the Antrim shale.

Gas content is measured by direct desorption of the Antrim shale. Core samples are placed in a sealed canister and the volume of gas desorbed over time is measured. After the sample has degassed for one to several months, the sample is crushed to measure the residual gas. The third component of gas content is the "lost" gas estimate, which is the volume of gas released between cutting the core and placing the sample in a sealed container. Total gas content is the sum of lost, desorbed, and residual gas.

ANTRIM SHALE STRATIGRAPHY

There are two Devonian stratigraphic classification schemes developed for the Antrim Shale currently in use, the most recent classification (1) has officially replaced Ells classifications (2) although it is not in widespread use in the oil and gas community. This has lead to some confusion when describing the stratigraphic succession of the gas bearing intervals of the Antrim Shale in the Michigan Basin. It is important therefore to distinguish the two classifications since this paper will use the nomenclature of the new classification.

A composite stratigraphic column (Figure 1) including the two classification schemes as well as a gamma ray log displays the position of the black and gray shales of the Antrim. The distinctive gamma ray character of the Norwood, Paxton, and Lachine Members throughout the basin permits regional correlation of these units. The high gamma ray response in the black shales is associated with high uranium concentration which itself has become chelated onto organics. Organic richness then is reflected by gamma ray response. Core samples have been selected over a wide spectrum of organic content in order to examine the relationship between gas content and organic content.

Current production is from the Norwood and Lachine Members, previously referred to as the 1C and 1A Units respectively by Ells. These producing zones correspond to the two lower black shales of the Antrim Shale Formation as it is now called. An intervening gray shale, often referred to as the Middle Gray by operators, is called the Paxton Member in the new classification. Above the Lachine Member is the Upper Member of the Antrim Shale Formation and includes the Ellsworth Shale. (Units 4, 5 & 6 of Ells).

Geologic studies have established basin-wide correlation of the Norwood, Paxton and Lachine members (3). The regional correlation have been useful in relating basin-wide significance of results achieved from gas content measurement sites which have a large geographic distribution.

MEASUREMENT OF GAS CONTENT

A program to measure in-situ Antrim shale gas content was initiated by GRI in 1991 to evaluate the sorption characteristics of this important gas reservoir. The principal objective of this research is to improve understanding of the geologic and reservoir processes which control gas production. Whole core and sidewall core samples were provided by Nomeco, Mercury Exploration, Terra Energy, and Taurus Exploration from wells located in Otsego, Oscoda, Ogemaw and Livingston counties (Figure 2). Samples were primarily black shales from the Upper Antrim, Lachine, and Norwood intervals.

Initially, the methodology which had been developed to measure coal seam gas content was adapted to measure the gas content of the Antrim shale. The U.S. Bureau of Mines established the most widely used procedure for coal gas content measurement (4), and later updated and modified this method (5). Coal gas content units of standard cubic feet per ton (scf/t) likewise were adopted for shale. Shale gas contents formerly were reported in standard cubic feet per cubic foot (scf/cf), but can be converted to scf/t by multiplying by approximately 12 to 14, depending on shale density.

Standard gas content measurements are performed by sealing a freshly cored sample in an airtight canister and releasing desorbed gas for measurement (measured gas). Once gas desorption slows significantly, the sample is crushed and the released gas measured (crushed gas). Using conventional coring equipment, gas will also desorb from the core during retrieval (lost gas). This third gas component can be estimated by extrapolating early-time desorption based on the square root of time or using the Williams and Smith unipore model (6). Lost gas volumes are high if gas diffusion from the matrix is rapid. However, shale gas diffusion rates are relatively slow, consequently the lost-gas component for shale is much less than for coal. Based on the five-well data set, lost gas volumes were determined to be insignificant, averaging 1 scf/t (Figure 3). Total gas content is the sum of lost gas, measured gas and crushed gas.

The plot of cumulative measured gas versus time (Figure 4) reveals that the first few days of measurement are the most important, after which the desorption rate slowly declines. Shales typically release small volumes of gas, much less than from coal, thus accurate measurements are essential. Large potential errors can be caused by excessive free volume (headspace) inside the canister. Changes in ambient temperature and pressure cause expansion or contraction of headspace gas. The magnitude of error is proportional to the ratio between the volume of desorbed gas and headspace (7): for a ratio of 2:1, errors of less than 10% occur, while ratios of less than 1:1 may produce errors greater than 30%. Headspace error can be minimized by using an appropriate canister size, or by filling the headspace volume with a nonreactive material such as pure quartz sand.

Oxidation of organic material is another significant source of error in gas content measurement, particularly if desorbed volume is less than twice as large as headspace volume. The oxidation rate of atmospheric oxygen onto shale can be similar to the desorption rate of methane, causing methane desorption volumes to be underestimated. Recent work by

Gustafson (8) indicated oxidation can cause total gas content to be underestimated by up to 20% of headspace volume. The negative effects of atmospheric oxygen on volumetric measurements can be avoided by 1) recalculating desorbed gas by routinely analyzing its composition (7); or, preferably, 2) flushing the sealed canister with an inert gas such as helium.

The extremely slow desorption rate of shale makes complete desorption of a sample impractical. A representative sample can be taken from the core and crushed to determine the remaining gas. Crushed gas volumes for the five-well data set averaged more than 50% of total gas content for samples that were crushed following 30 days of desorption (Figure 5). The crushed gas volume of samples from the Dey A1-15 well, which were desorbed over a three-month period, was still more than 40% of total gas content. The dominance of the crushed gas component and the difficulty of obtaining accurate individual desorbed gas measurements supports the approach of crushing samples immediately upon retrieval at the wellsite. The low and uniform lost gas volumes make it unnecessary to record early time desorption data for lost gas extrapolation, if crushing is performed immediately upon retrieval.

CORRELATION OF GAS CONTENT, SHALE DENSITY AND ORGANIC MATTER

Estimating Antrim shale gas content from open-hole log response is potentially more accurate and cost-effective than the core analysis method. Log data can be collected over the entire extent of a reservoir, whereas direct core analysis provides only a finite and not necessarily characteristic number of data points. This study proposed and tested the hypothesis that relationships exist between gas content and total organic carbon (TOC), and between TOC and bulk density. Such a linkage would readily permit log determination of gas content, because bulk density can be accurately measured using conventional downhole logging tools.

A cross plot of TOC versus gas content for the entire five-well data set demonstrated a close relationship between these two parameters, with a correlation coefficient of 94% (Figure 6). This data set supports the theory that gas contained in the Antrim shale is adsorbed onto organic matter and that gas production will be influenced by diffusion mechanisms. Based on this new correlation, gas content can be estimated if shale TOC is known. It is important to note that correlations presented in this section are restricted to depths of 1,300' - 2,100' and shale maturities ranging from .45 - .55 V_{ro}. In addition, the method assumes that the Antrim is equally gas saturated in all study wells, though not necessarily fully gas saturated, and that gas content only varies as a function of organic matter.

The TOC/gas content relationship is also useful for comparing alternative methods of gas content measurement. The gas content and TOC of whole core and rotary sidewall core are plotted on Figure 7. Based on this one-well data set, the gas content/TOC relationship for sidewall cores is just as accurate or even superior to that for conventional cores. In addition, rotary sidewall coring is significantly cheaper than obtaining whole core.

Gas content also correlates closely with TOC for rotary sidewall cores that were crushed shortly (less than 1 hour) after retrieval (Figure 8), just as closely as for the five-well data set (correlation coefficient = 94%). The crushed gas component was assumed to represent the entire gas content of these samples. Based on this one-well comparison, it appears that rotary sidewall coring and on-site crushing is a reasonably accurate method for directly measuring gas content. Furthermore, this technique is more rapid and less costly than the conventional desorption approach.

Mineralogic analysis of the Antrim shale shows that pyrite and kerogen are the primary components which potentially affect overall rock density (Figure 9). Low shale densities appear to be controlled by increasing amounts of low-density organic components (Figure 10). Data points which stray from this best-fit line are probably caused by anomalously high pyrite concentrations, which has a much higher density than rock-forming minerals.

Because gas content increases with TOC and TOC increases with decreasing shale density, it follows that gas content should increase with decreasing shale density. This inference is supported by a cross-plot of gas content and shale bulk density (Figure 10; correlation coefficient = 91%). This linkage deomonstrates that gas content in this portion of the basin can be estimated from log-derived bulk density measurements as shown on Figure 11.

The accuracy of gas content estimates can be improved by increasing the count rate function of the conventional density tool. Typically, two counts per foot are recorded on a conventional density logging run, but this can be increased to ten counts per foot to increase the resolution of shale density. The high-count-rate density log records the thin, interbedded nature of the Antrim shale much more accurately than the conventional density log (Figure 12). Furthermore, the bulk density gain is higher in the high-resolution log. However, the high- count-rate log must be run at a slightly slower logging speed and may require more repeat runs compared with the low-count-rate log. Nevertheless, the thin-bed resolution and more accurate bulk density measurement of the high-resolution density tool makes it the preferred log for accurate determination of log-derived gas content.

LOG DERIVED GAS-IN-PLACE CALCULATIONS

A forecast of recoverable gas requires an accurate estimate of gas-in-place. Gas-in-place can be calculated using the following equation:

$$GIP\ (bcf/mi^2) = \left(1359\ \frac{T/AF}{g/cc}\right)(640\ ac)\ (\rho)\ (gc)\ (h)$$

Using digital log-derived bulk density data and simple spread sheet calculations, interval gas-in-place calculations can be performed. A plot of gas-in-place by Antrim shale interval for the Mercury Exploration Dey A1-15 well is shown in Figure 13. This analysis shows that the currently producing Norwood and Lachine members are the most important gas reservoirs, with combined resources of 7.3 Bcf/mi^2. The Upper Black member is an attractive secondary target, estimated to contain 8.6 Bcf/mi^2 of gas-in-place.

CONCLUSIONS

Geologic analysis of core and log data from five wells in the Antrim shale leads to the following conclusions:

1) Conventional methods developed for measuring gas content in coal beds do not adapt well to the Antrim shale. Antrim gas desorption volumes are small and diffusion rates are very slow. Consequently, significant errors in gas content are often introduced by atmospheric temperature and pressure fluctuations and by reaction between the shale and headspace gas.

2) On-site crushing and measurement of gas content from Antrim shale sidewall cores provides a cost-effective alternative which is as accurate as conventional gas desorption methods for this low-diffusion reservoir. This method also avoids the errors caused by headspace gas.

3) Gas content determined from sidewall cores correlates closely with bulk density log response in the Antrim shale. Using this correlation, a new log-based method for gas determination in the Antrim is proposed. This method is faster and less costly than conventional gas desorption for determination of gas content and in-place gas resources for the Antrim.

4) High-resolution density logs enhance the accuracy of gas content and gas resource estimates in the Antrim and are the preferred tool for this method.

NOMENCLATURE

GIP =	Gas-in-place	ac =	acre
T/AF =	Tons/acre-foot	ρ =	bulk density
g/cc =	grams/cubic centimeter	h =	thickness
		gc =	gas content

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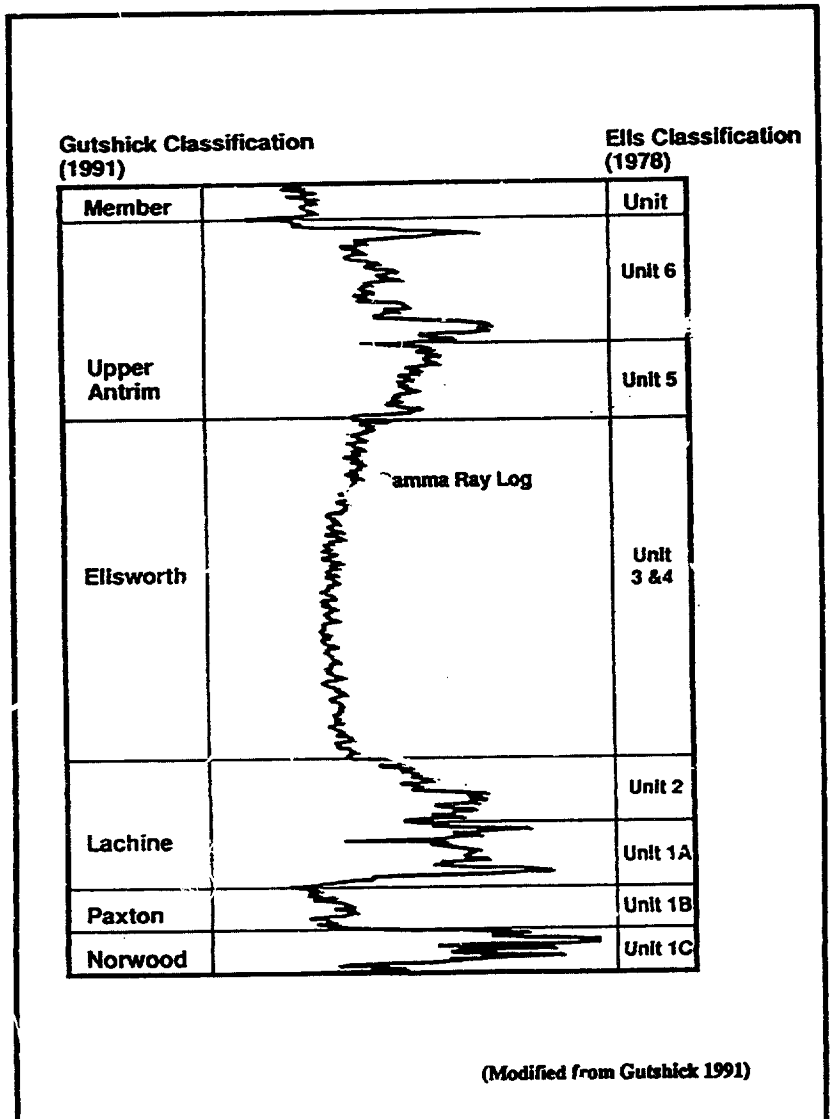

Figure 1.
Stratigraphic Classifications of the Antrim Formation

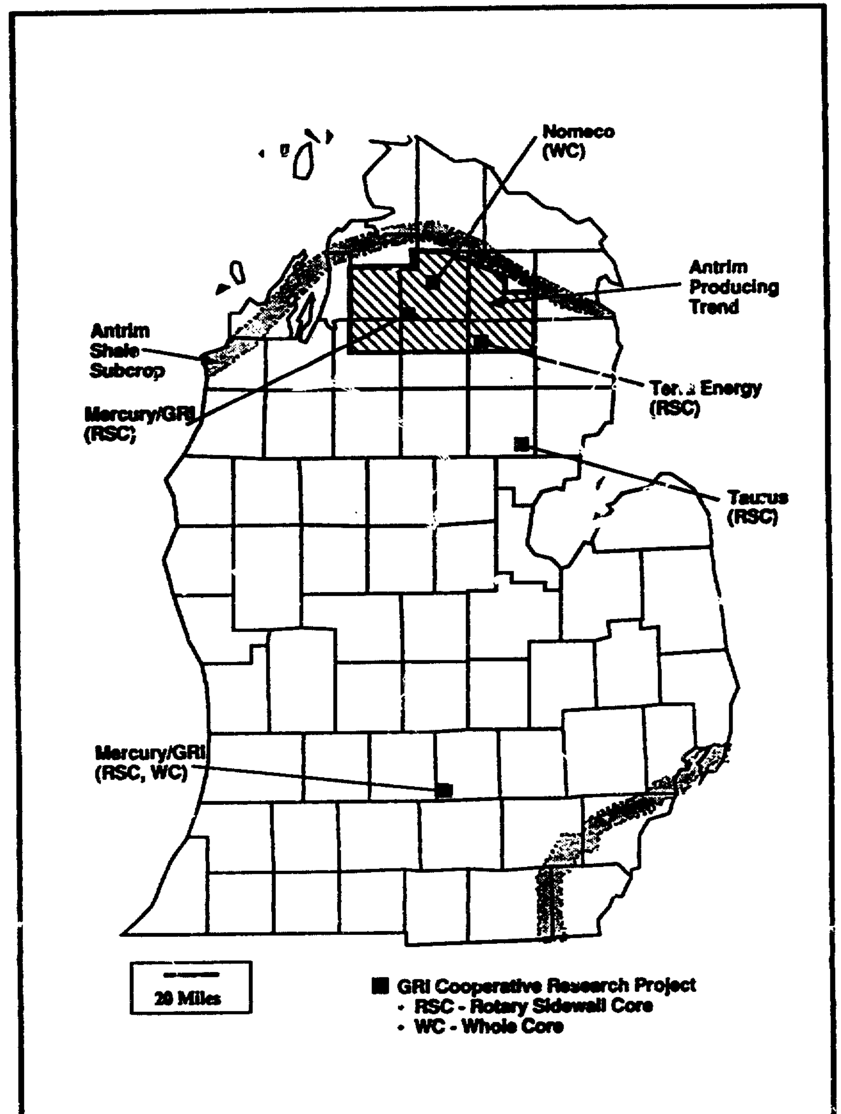

Figure 2.
Location Map of GRI Cooperative Research Projects for Gas ContentMeasurement in the Antrim Shale

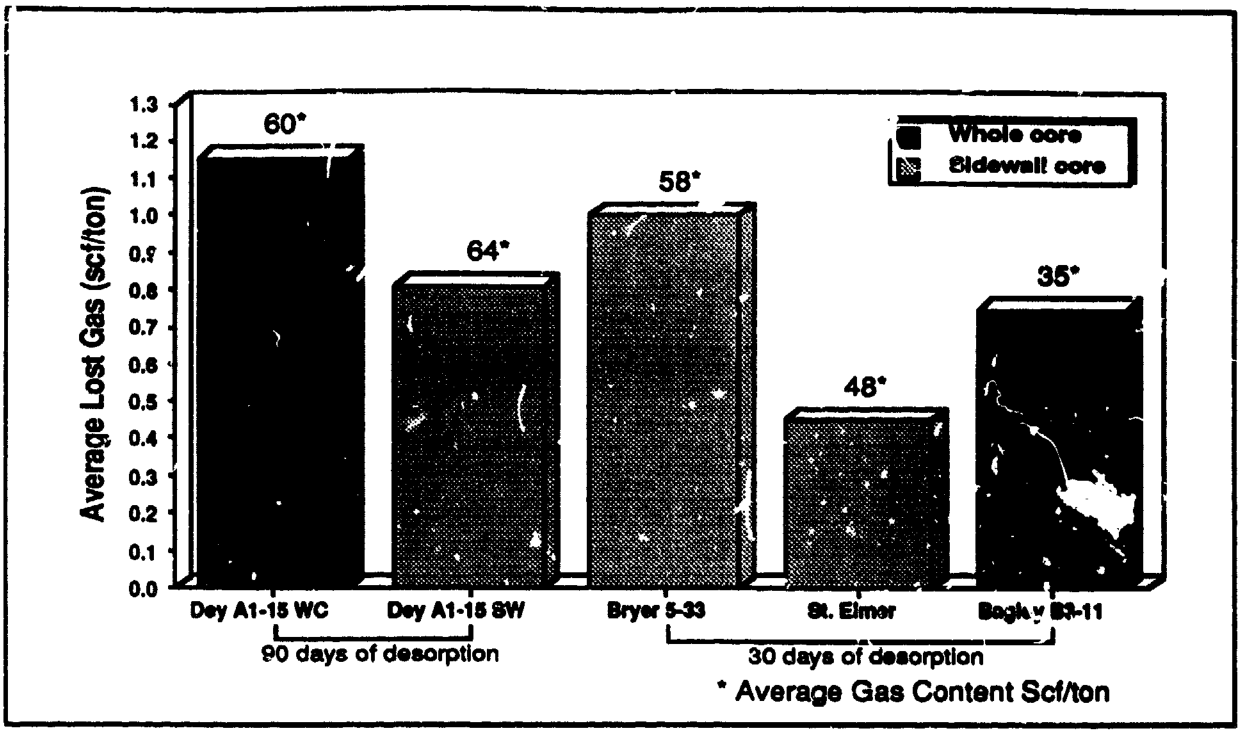

Figure 3.
Calculated Lost Gas (scf/ton)

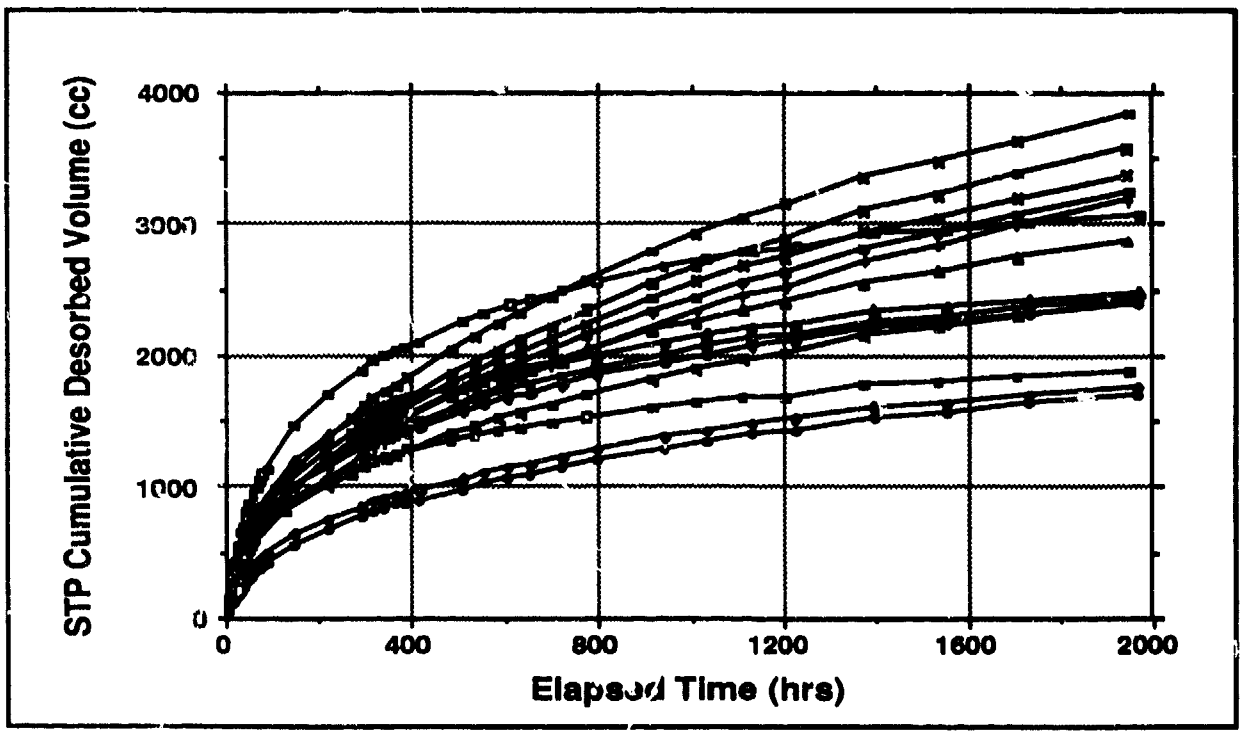

Figure 4.
Cumulative Desorbed Gas versus Time, Mercury Dey A1-15

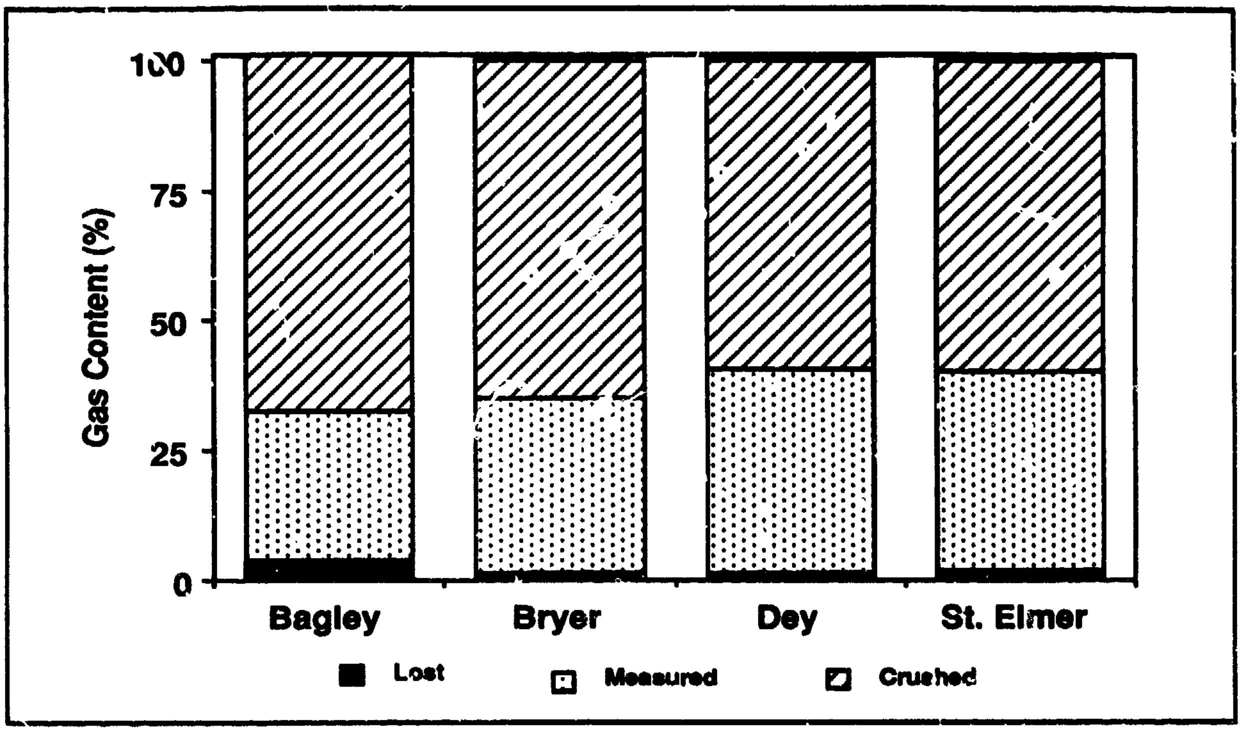

Figure 5.
Average Percent Lost , Measured and Crushed Gas

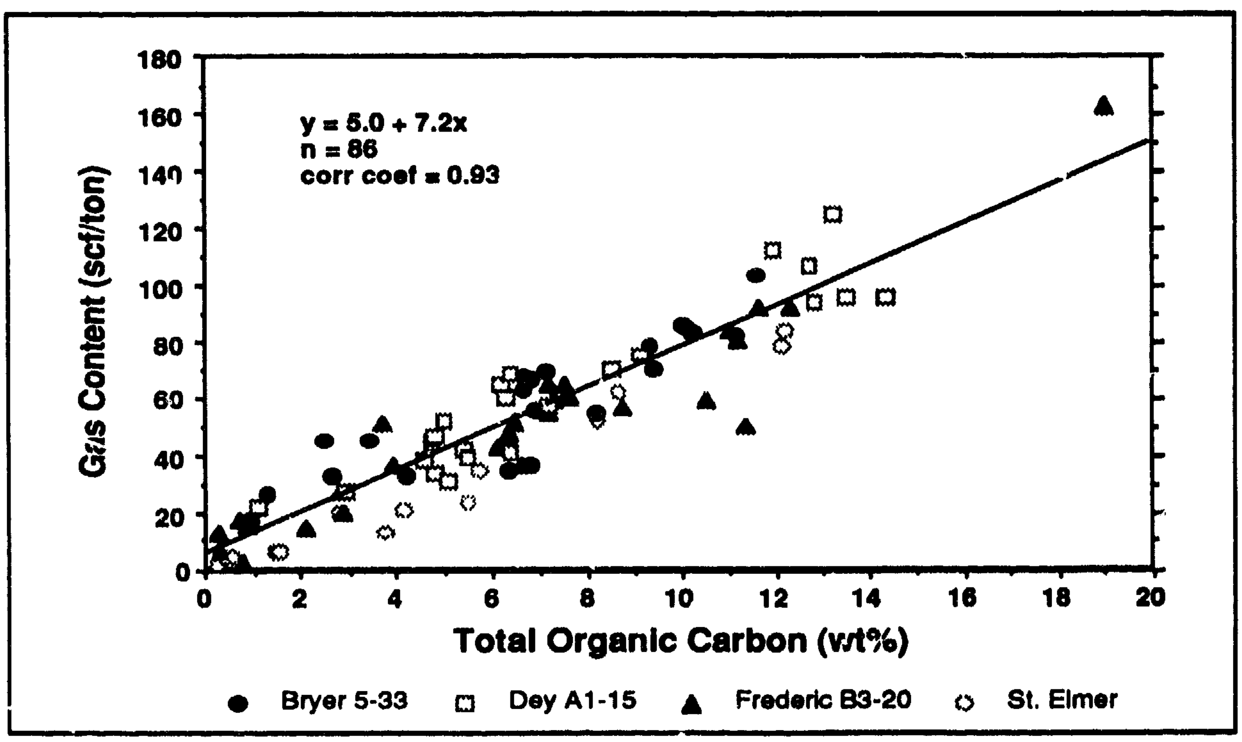

Figure 6.
Gas Content Increases with Increasing Organic Content

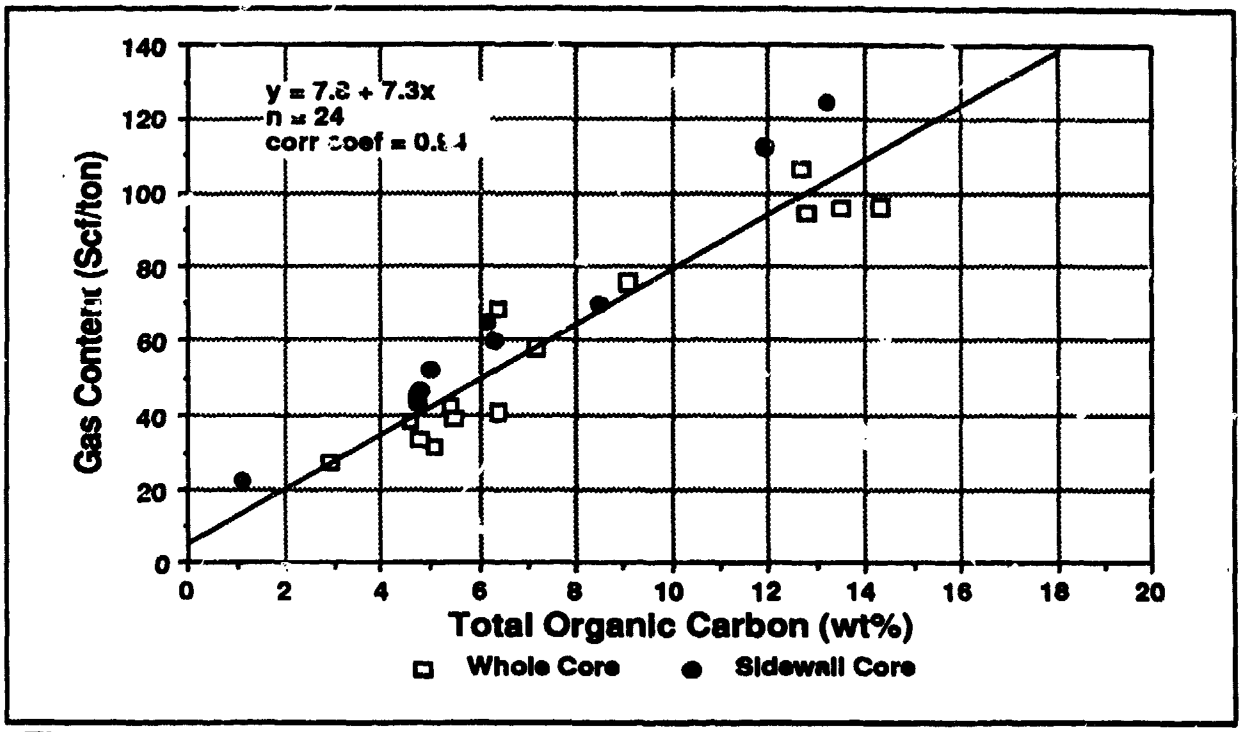

Figure 7.
Rotary and Whole Core Gas Content Comparison, Mercury [illegible] A1-15

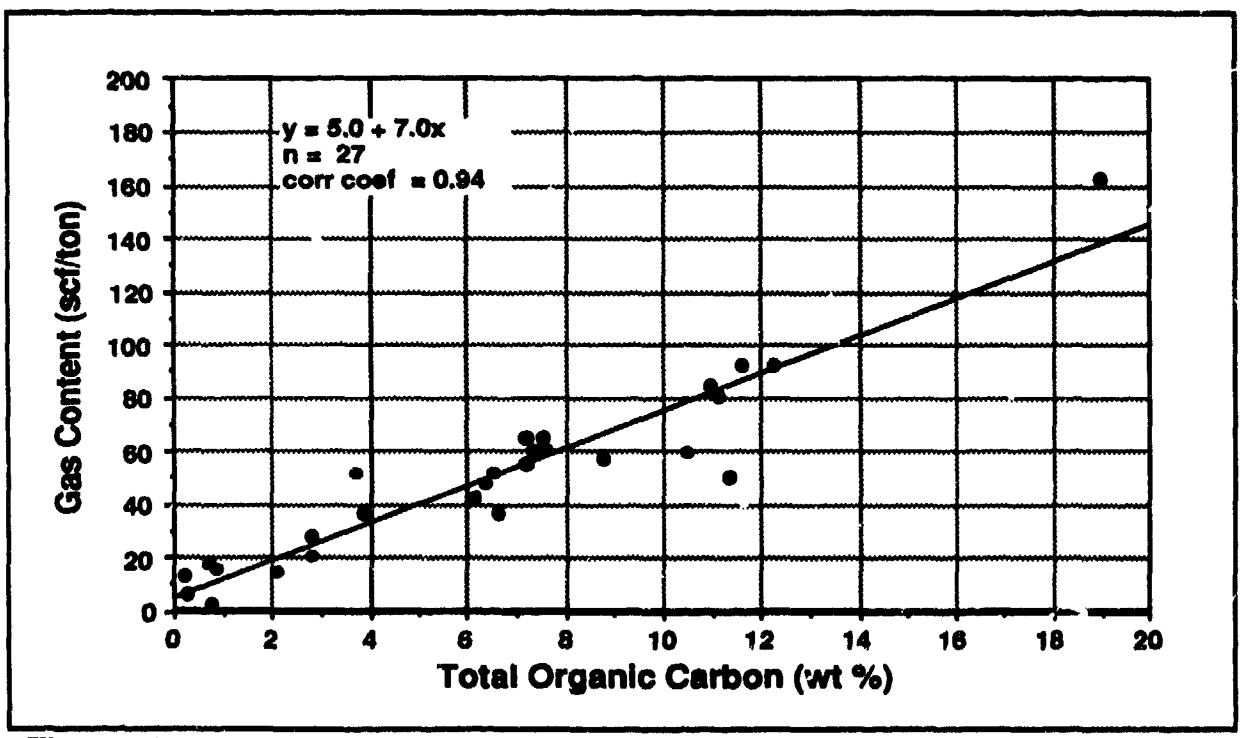

Figure 8.
Gas Content versus TOC from Crushed Sidewall Cores, Mercury Frederic B3-20

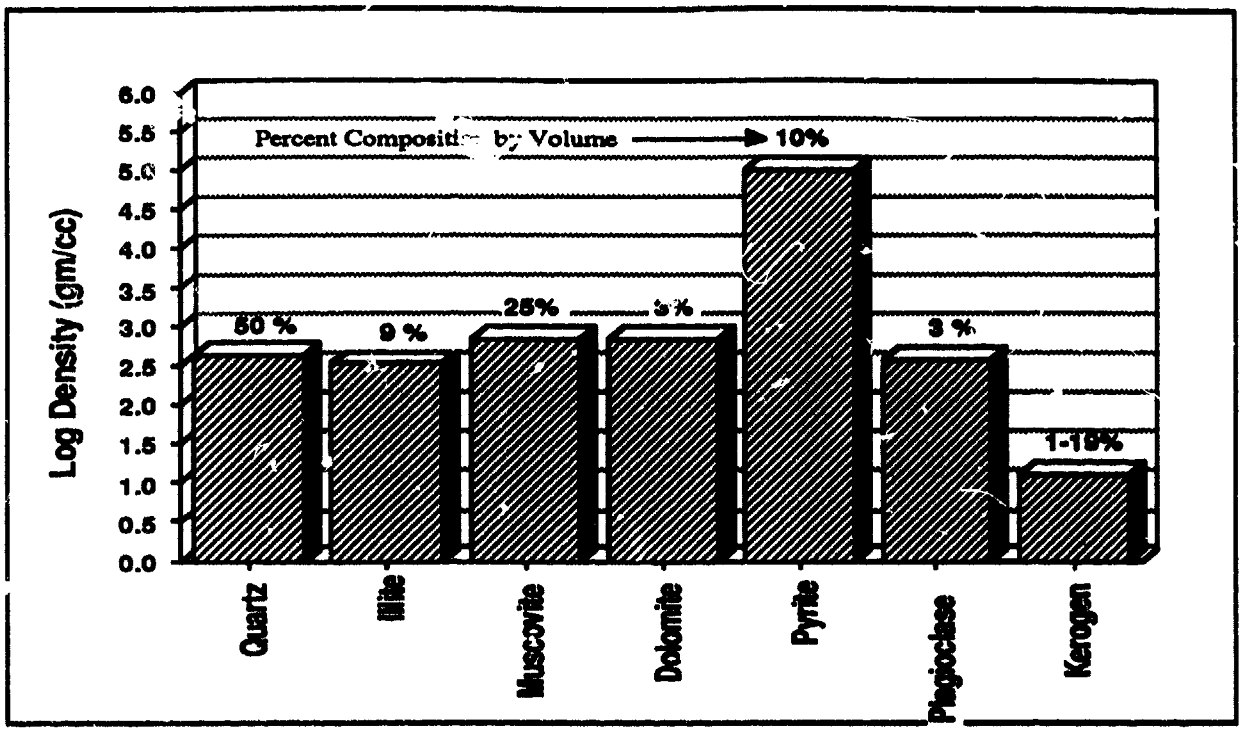

Figure 9.
Antrim Shale Mineralogic Composition, Density Comparison

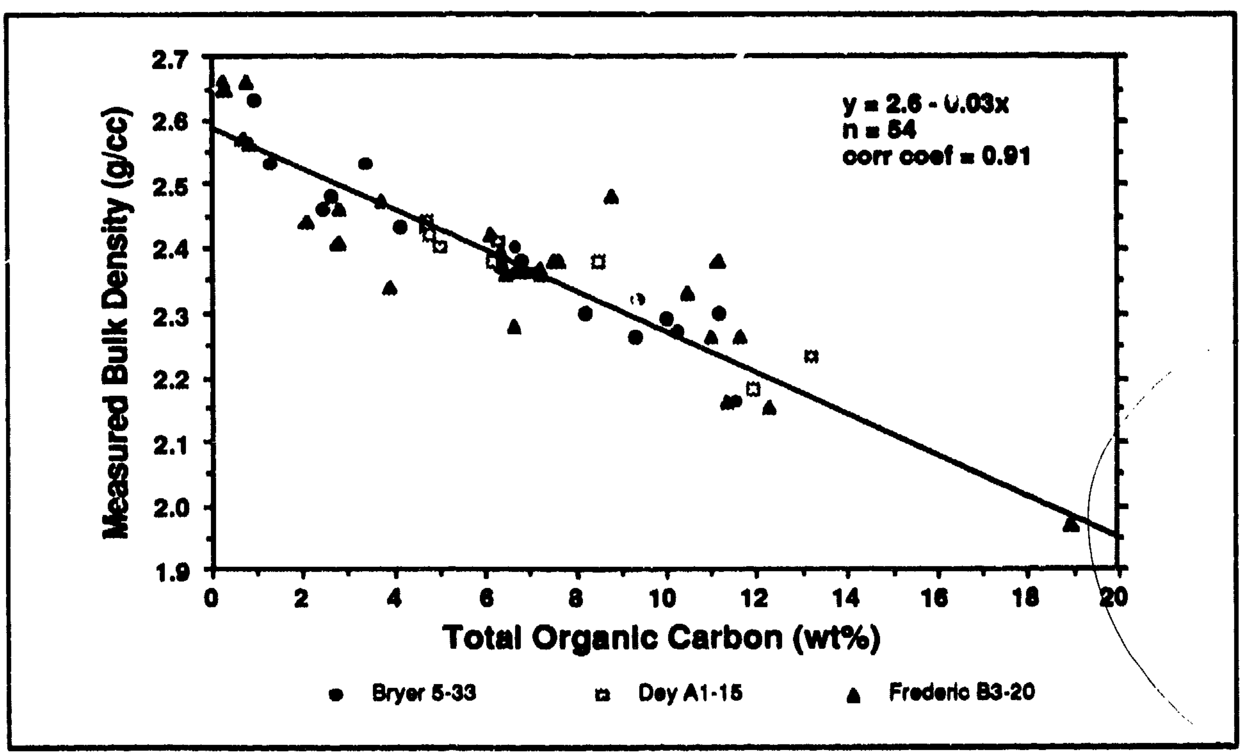

Figure 10.
TOC versus Bulk Density Measurements

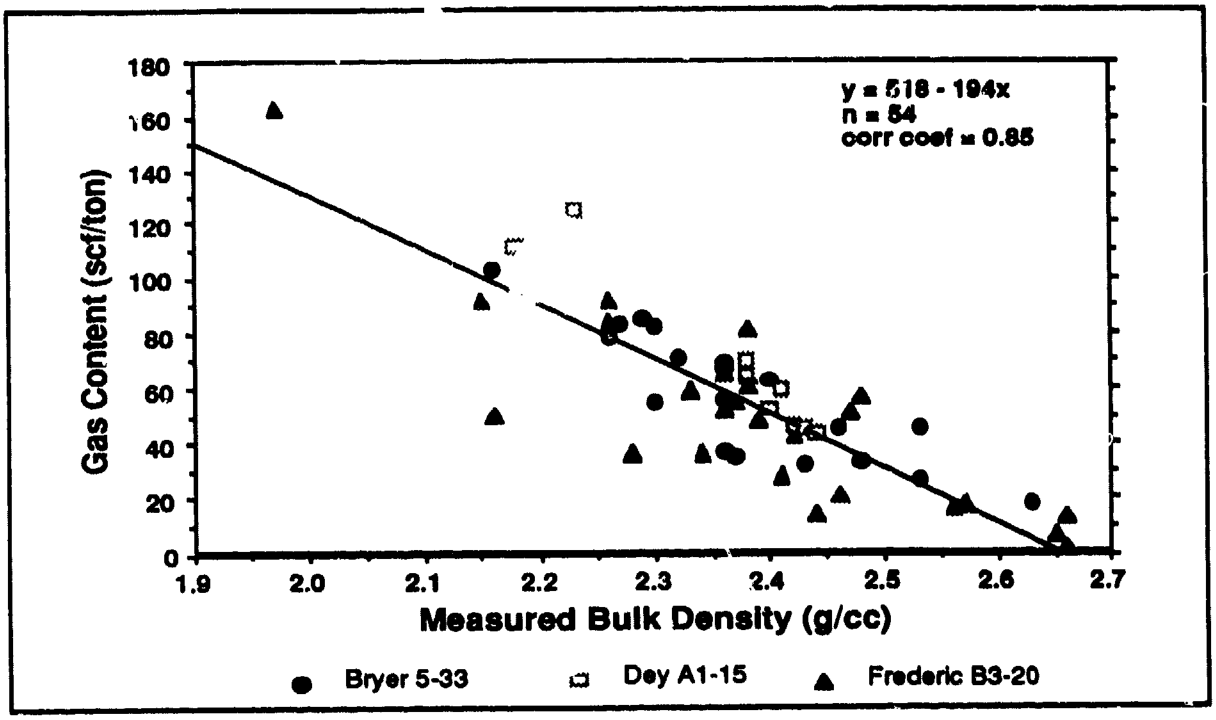

Figure 11.
Gas Content versus Bulk Density

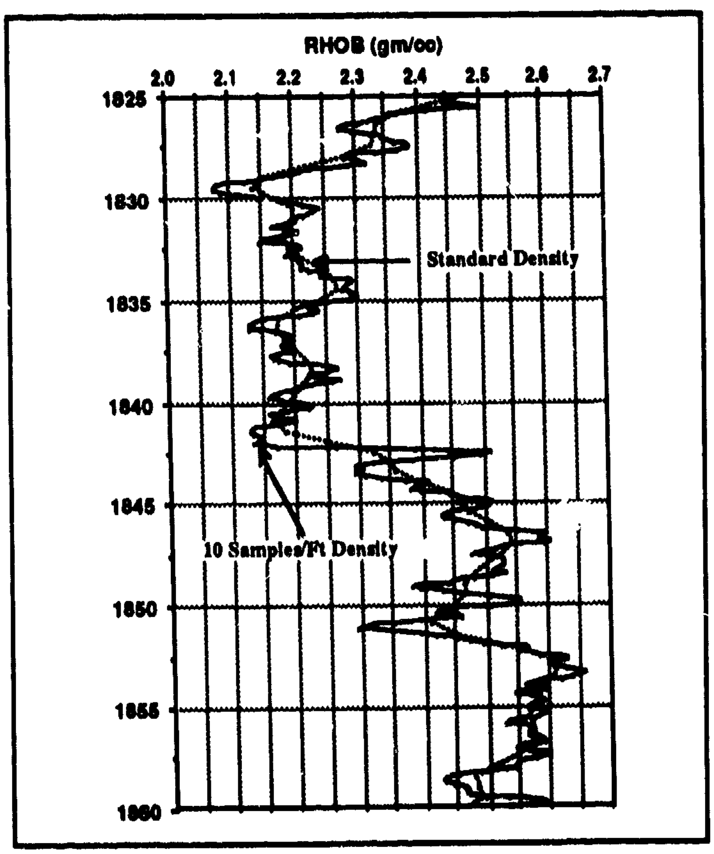

Figure 12.
A Comparison of Standard Density Log and 10 Sample rate/ft Density Log

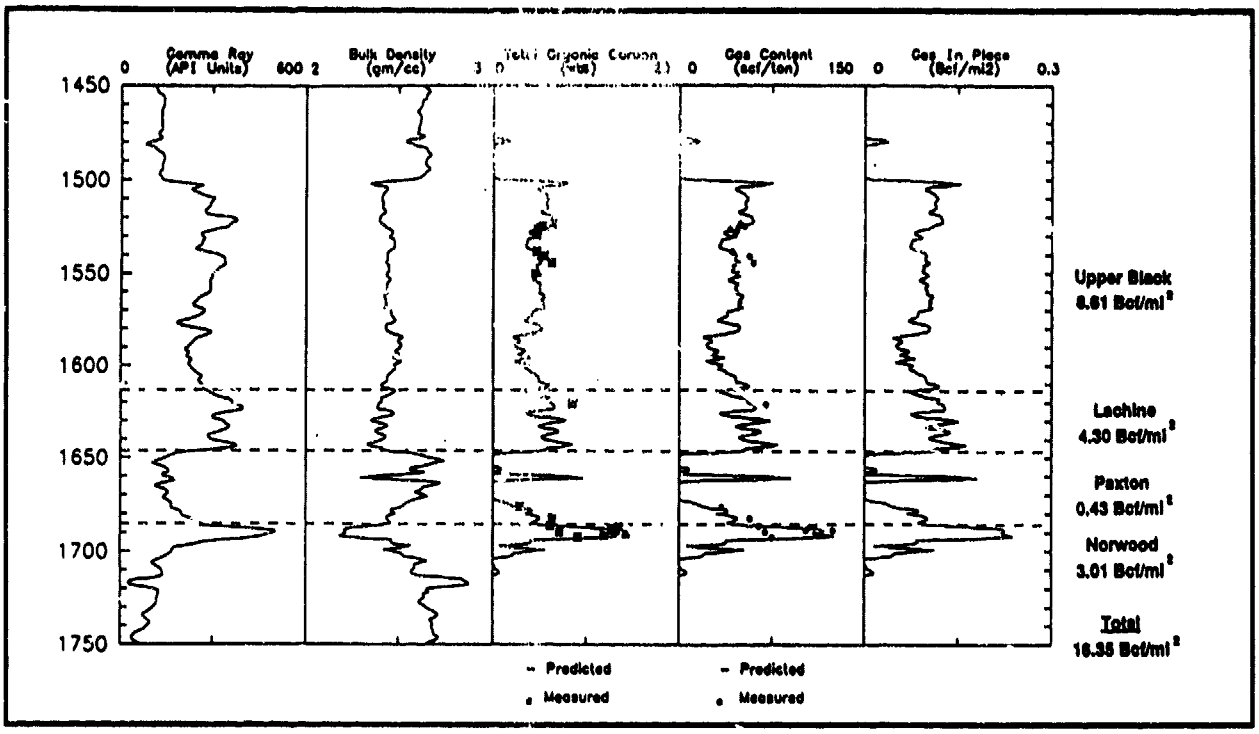

Figure 13.
Measured and Predicted TOC, Gas Content, and Gas-in-Place Estimates, Mercury Dey A1-15