ROUGH DRAFT

CONF-810518--6

NMR Determination of Porosity and Permeability
of Western Tight Gas Sands*

MASTER

by

Donald F. Cowgill
Sandia National Laboratories
Albuquerque, New Mexico
Janet K. Pitman
U.S. Geological Survey
Denver, Colorado
Del. O. Seevers
Chevron Oil Field Research Company
LaHabra, California

ABSTRACT

Samples of fine-grained sandstone from the Colorado Interstate Gas Exploration (CIGE), Natural Buttes No. 21 core, Uinta Basin, Utah were studied using pulsed nuclear magnetic resonance (NMR) and standard mineralogical techniques. Brine-saturated rock porosities varied from 1 to 13 percent and were found deducible from the magnitude of the proton NMR. The complex pore geometry and presence of authigenic carbonate and clay minerals in these samples precluded the use of standard flow models for predicting brine permeabilities from T_1 decays. A network model of the pore system is proposed and shown capable of accurately reproducing measured rock permeabilities, which varied from 10^{-4} to 1 millidarcy.

*This study was supported by the U. S. Department of Energy.

DISCLAIMER

This book was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

MGW

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency Thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

DISCLAIMER

Portions of this document may be illegible in electronic image products. Images are produced from the best available original document.

INTRODUCTION

The Rocky Mountain region contains large accumulations of gas in nonmarine unconventional (low-permeability) reservoir rocks of Tertiary and Cretaceous age. Most of the gas occurs in the pores of fine-grained sandstone and siltstone. These sequences represent individual and composite channel-form beds that were deposited in alluvial (stream) and lacustrine (lake) environments. Although the volume of gas estimated to be contained in these rocks is very large, individual sandstone reservoirs that contain the gas are lenticular; i.e., of limited lateral and vertical extent. Variation in the geometry of these reservoir rocks is due to relatively impermeable claystone and carbonate beds complexly inter-bedded with the sandstones, abundant cross-cutting channel-formed sandstones, and a complex diagenetic history. Potential reservoir sandstones in these geologic settings are commonly referred to as being unconventional or tight because measured porosities are highly variable and measured permeabilities are characteristically very low. As a result, gas production rates from these lenses tend to be low. An understanding of the reservoir properties of tight sandstones is necessary in order to accurately employ stimulation techniques for enhanced gas recovery.

The proton nuclear magnetic resonance (NMR) signal detected from wet sandstone is produced by fluids contained within the pores of the rock. This signal is sensitive to the presence of fluid-pore interfaces and thus has potential for probing the pore structure. The utility of the NMR technique for deducing information about the pore geometry and the volume and kind of fluid contained in the pore structure is not new. Nuclear magnetism logging of residual oil in uncased pore holes was developed in the 1960's and early 1970's. The logging tools developed are capable of detecting hydrocarbons and water in rocks with large pores. Laboratory measurements on unconventional, marine, sandstone samples have yielded some successes in relating the NMR to porosity, pore size, wettability, water saturation, and rock permeability. However, the tools have not been found useful for detecting water in the micropores, the spaces between clay particles, present in clay-filled tight sandstone.

The purpose of this study was to gain a better understanding of the mineralogy and pore structure of the nonmarine western tight gas sands and to evaluate NMR as a means of deducing the sandstone porosity and permeability to brine. Since the NMR response of fluids contained in pores depends only on pore geometry and not on pore interconnectivity, predictions of permeability can be used to test hypothesized fluid flow models. Thus, an additional aim of this work was to examine existing flow models and a newly-proposed hybrid network model in terms of their

applicability to clay-filled tight sandstone. This paper reports preliminary porosity, permeability, and mineralogy data obtained on a suite of samples selected from the Colorado Interstate Gas Exploration (CIGE), Natural Buttes No. 21 core, Uinta Basin, Utah and presents comparisons of these data with porosities and permeabilities determined by NMR analysis of the same samples.

ANALYTICAL TECHNIQUES

The mineralogical composition of the sandstone samples was determined by X-ray diffraction and petrographic analysis. Modal analyses of thin sections were made by counting three hundred mineral grains per slide. Each section was stained to identify carbonate cement and was impregnated with blue epoxy to aid in the characterization of porosity. Scanning electron microscopy (SEM) and energy dispersive X-ray spectrometry were used to identify the presence and distribution of authigenic clay minerals within pores.

NMR samples were cut into 2.54 cm diameter, 2.54 cm long right circular cylinders. They were cleaned with condensed toluene and vacuum dried overnight at 50°C. After dry weights were measured, they were saturated with a deoxygenated brine solution, introduced from vacuum. The brine was pressurized to 900 psi for 2 hours to assure saturation. Samples were stored in the brine under ambient conditions prior to the measurements. The brine solution consisted of 161,000 ppm NaCl to prevent swelling of clay minerals. Sample weight gain due to the saturation was used to deduce brine porosities. The brine was also used for brine permeability measurements¹⁰ on the samples at near ambient temperature and pressure, prior to the NMR analyses.

NMR measurements consisted of nuclear free induction decays (FID) and spin-lattice relaxations (T_1) of the proton resonance. The measurements were performed at 10 MHz in a 12 inch Varian super-stabilized magnet using Magnion rf electronics. Signals were digitized and processed with a PDP 11/05 computer. The magnet T_2^* was about 8 milliseconds and the electronics dead time was 20 microseconds. FID's were measured by sampling the signal at various times following a 90-degree pulse. These signals were found to decay exponentially with time t and were extrapolated to $t = 0$ to give FID magnitudes. Signal background, obtained with the sample removed from the apparatus, was stripped from these signals. These magnitudes were compared with that of a 10% porosity standard in order to determine sample porosities. This procedure was followed in order to minimize systematic errors arising from the FID extrapolation process. The standard sample consisted of a teflon can of the sample geometry, filled with a 10% mixture of H_2O in D_2O , and doped with Mn^{++} to produce about the same signal decay rate as was observed for the sample FID's.

The T_1 relaxation for each sample was measured using a 180°- τ -90° pulse sequence, where τ was varied from 0.1 to 50 milliseconds. Magnetization recovery signals were averaged for five sequences at each τ and the pulse sequences were spaced by at least 5T.

MINERALOGICAL PROPERTIES

Sandstone samples for this study were selected from the CIGE, Natural Buttes No. 21 core (Sec. 15, T.10S., R.22E.) Uinta Basin, Utah. The samples range in depth from approximately 4400 feet to 8500 feet and represent the Mesaverde Group and the Wasatch and Greenriver Formations. Samples were selected to provide a large range in pore structure and fluid flow characteristics, a necessity for evaluating NMR interpretation and modelling efforts. X-ray diffraction and petrographic analyses performed on the sandstones indicate the rocks are fine grained and composed of varying amounts of quartz and feldspar framework grains, carbonate, and clay. The formation of authigenic carbonate and clay minerals very early during the rocks burial history has significantly modified grain morphology and pore geometry. The recognition of these minerals and their mode of occurrence is necessary in order to understand patterns of porosity and permeability in unconventional reservoir rocks.

POROSITY

Laboratory measurements of sandstone porosity, permeability to brine and the relative amounts of carbonate in each sample are tabulated in Table 1. Porosity values vary over a wide range (1.4 and 13.2%). In general, the variation in porosity in these unconventional reservoir rocks reflects the amount of cement which fills inter-and-intra-granular pore-space. Although secondary silica occurs in many of the rocks, the dominant cementing agent in these samples is a complex assemblage of carbonate minerals, calcite (CaCO_3), dolomite ($\text{CaMg}(\text{CO}_3)_2$), and ankerite ($\text{Ca}(\text{Mg},\text{Fe})(\text{CO}_3)_2$). The most important of these is calcite. Petrographic analyses indicate that the carbonate minerals occur as an inter-granular cement and as a replacement product for feldspar grains and rock fragments. In most samples, carbonate, usually calcite, either completely cements the rock or it has been dissolved by pore fluids that migrated through the system. In samples where carbonate dissolution has occurred, the size and shape of pore space has been significantly modified. Figure 1 shows some examples of dissolution pores. The presence of pores that are commonly oversized, isolated relicts of calcite cement, and corroded feldspar grains in almost all of the sandstones is evidence that carbonate previously occupied much of the rock. Therefore, measured porosity values that are high may correlate with carbonate values that tend to be low. Likewise, low porosity measurements frequently correspond with an increase in carbonate content.

A comparison of the porosity values determined by the NMR analysis with the laboratory measurements is shown in Figure 2. The NMR data ϕ_{nmr} show a good correlation with the laboratory porosity ϕ_{L} values; however, the NMR values are consistently about one percent higher than the laboratory values. The source of this discrepancy has not yet been determined.

PERMEABILITY

The interaction of diffusing protons (e.g., within water molecules) with the pore walls can induce nuclear transitions causing relaxation of the proton NMR. Torrey, et. al.¹¹ considered this idea and formulated an expression relating the observed T_1 relaxation time to the relative volume of the fluid in the surface layer influenced by the pore wall. Seevers⁶ experimentally verified this expression for compacted glass bead samples and (clay-free) sandstone. In addition, Seevers showed that, for his glass bead and sandstone samples, the Kozeny equation can be used to accurately predict the permeability k from a knowledge of the pore surface-to-volume ratio, S/V . According to this model, _____

$$k = \alpha \phi [T_1 T_B / (T_B - T_1)]^2 \dots \dots \dots (1)$$

where ϕ is the fractional porosity and T_B is the relaxation time of protons in the bulk fluid. The constant α is a function the relaxation rate and residence time of a proton in the proximity of a pore surface and the Kozeny pore tortuosity factor. Seevers found that for most clay-free sandstones, $\alpha=1$ darcy/sec².

For the present sandstone samples, the observed relaxation of the proton magnetization was not a simple exponential decay function with at time constant T_1 . An example of the relaxation we observed is shown in Figure 3. The signal $M(t)$ can be fit, however, by the sum of three exponentials with different decay constants and amplitudes.

The solid line through the data points in Figure 3 is the result of a weighted least-squares fit to Eq. (2) using the procedure developed by Timur. The three components (A, B, and C) producing the fit are also shown. A listing of the relaxation parameters (amplitudes and time constants) computed for each of the samples is given in Table 2. For three samples, the observed T_1 decay was accurately fit by two exponential components. The relaxation for the bulk brine solution was found to be a simple exponential with time constant T_B varying from 2.20 to 2.55 seconds, depending on the sample.

$$M(t) = M(0)[A \exp(-t/T_{1A}) + B \exp(-t/T_{1B}) + C \exp(-t/T_{1C})] \dots (2)$$

The observed three-component T_1 relaxation may be interpreted as a three-component distribution of pore S/V. Component permeabilities k_A , k_B , and k_C can be computed for each relaxation component, using Eq. (1). Each component permeability may be viewed as a sample permeability for a sample composed entirely of pores with the corresponding S/V. The procedure for combining these component permeabilities to produce an effective permeability for the actual sample depends on the flow model or pore interconnection model selected for the sample. It will be shown that a knowledge of the sample mineralogy can contribute to this selection process.

Parallel Flow Model

Two simple flow models for combining the component permeabilities are a parallel model and a serial model, similar to the electrical analog of combining conductors in parallel and series electrical paths. Timur⁷ used the parallel model and arrived at the permeability

$$k_p = \alpha \phi \left\{ A \left(\frac{T_B T_{1A}}{T_B - T_{1A}} \right)^2 + B \left(\frac{T_B T_{1B}}{T_B - T_{1B}} \right)^2 + C \left(\frac{T_B T_{1C}}{T_B - T_{1C}} \right)^2 \right\} \dots (3)$$

He found that permeabilities calculated according to Eq. (3) correlated with measured laboratory permeabilities for conventional marine sandstone samples from a variety of wells.

Permeabilities for the present samples computed according to the parallel flow model k_p are plotted against the laboratory permeabilities k_l in Figure 4. Here, Eq. (3) was used with the relaxation parameters reported in Table 2. Also, it was assumed that $\alpha=1$ darcy/sec². Nearly all of the computed k_p values are significantly greater than k_l . Selection of $\alpha=1/30$ darcy/sec² produces the correlation shown by the dashed line. The k_p values are found scattered about this line with deviations in many instances by an order-of-magnitude or more. The deviations about this line suggest that the permeability components have not been combined correctly. For most of the samples, the component relaxation times T_{1A} , T_{1B} , T_{1C} each differ by roughly an order-of-magnitude. As a result, the relaxation component due to the large pores, the A-component, dominates the contributions to k_p in Eq. (3). The small pore or C-component has negligible effect. Thus, this model does not consider the restrictive effect on fluid flow that is produced by the presence of small interconnecting capillaries between the large pores. In contrast, the serial flow model over-emphasizes such restrictive effects and produces computed permeabilities with no relationship to the laboratory values.

X-ray diffraction and scanning electron microscopy analyses indicate these sandstone samples contain a large fraction of authigenic clay, principally illite, kaolinite, and minor amounts of chlorite. These clays are most abundant in samples where carbonate cement and grains replaced by carbonate underwent extensive leaching. Complex inter-and-intra-granular pore space in almost all of the samples is either partly or completely filled with varying amounts of fibrous illite and booklets of kaolinite (Figures 5 and 6). In addition to pore modification by dissolution of large amounts of carbonate, the extensive development of authigenic clay in these sandstones has further modified pore geometry such that pore networks are tortuous and some pore throats are completely blocked. The pore system that exists is, therefore, one in which there is little connectivity between individual pores. As a result, fluid flow is severely retarded.

Hybrid Network Model

Because fluid flow properties in these tight sandstones are affected by a micropore network, we propose that the permeability that characterizes these rocks can be more appropriately modeled using a random network of interconnecting pores. Dullien¹² has summarized various treatments of permeability using network approaches. These models ideally can incorporate pores of different size and a distribution in the node coordination number z , the number of pores joining at a node. We extend the network idea to a hybrid approach which combines the network structure with localized flow permeability components given by k_A , k_B , and k_C . A brief description of this hybrid network model is given below. A complete mathematical analysis of the model and its application to the permeability problem will be given elsewhere.

The problem of flow in networks has been treated by Kirkpatrick¹³ in an electrical conduction analog by a self-consistent, effective medium theory of conduction in mixtures. He has considered this electrical network and shown that the average effect of the randomly distributed conductivities σ can be expressed by giving each a single value σ_m and choosing σ_m such that the effects of changing any one back to its true value will, on the average, cancel out. For a single node coordination z , he deduces an expression relating the conductivities, their distribution, and σ_m in accordance with the self-consistency condition. In terms of permeability, this expression is written

$$\int dk p(k) (k_m - k) / [k + (\frac{1}{2}z - 1)k_m] = 0 \dots \dots (4)$$

where $p(k)$ is the distribution function of the permeabilities and k_m is the equivalent effective medium permeability. Inserting a ternary distribution into Eq. (4) produces an equation, cubic in k_m , which has a solution

$$k_m = (2/3) \sqrt{s^2 - 3q} \cos(\theta/3) - s/3 \quad \dots \dots \dots (5)$$

$$\cos \theta = \{(2s^3 - 9sq + 27r)^2 / [4(s^2 - 3q)^3]\}^{1/2}$$

where

$$s = (\frac{1}{2}z - 1)^{-1} \sum_{i \neq j} p_i k_j - \sum_i p_i k_i,$$

$$q = \frac{1}{2}(\frac{1}{2}z - 1)^{-2} \sum_{h \neq i \neq j} p_h k_i k_j - (\frac{1}{2}z - 1)^{-1} \sum_{i \neq j} p_i k_i k_j$$

$$r = -(\frac{1}{2}z - 1)^{-2} k_A k_B k_C.$$

The indexes (h, i, j) run over the components A, B, C. According to this hybrid approach, the probabilities for each component p_i are the amplitudes A, B, and C in Table 2, and the permeability components are the k_A , k_B , and k_C determined by the Kozeny equation, using the observed S/V distribution.

The calculated permeability k_m for several of the present samples with laboratory permeabilities varying over a wide range are plotted as a function of z in Figure 7. Here, the k_m are normalized to the laboratory values k_ℓ to allow ease of comparison over the range of permeabilities and the curves are labeled with their laboratory values. The value of k_m can be varied about k_ℓ by selection of the parameter z . The coordination number producing $k_m = k_\ell$ for each sample is given by the intercept of each k_m curve with the line $k_m/k_\ell = 1$. For four of these samples, $z \approx 3$. However, for one sample $z = 7.5$. These curves are typical of all the samples studied.

The effective-medium permeability for each sample was calculated according to Eq. (5) using $z = 3$. These results are plotted against k_ℓ in Figure 8. For most of the samples, k_m lies within a factor of three of k_ℓ , a significant improvement relative to the results of the parallel flow model. Points lying below the correlation line, $k_m = k_\ell$, can be raised by using a larger z value; those above the line, lowered by using a somewhat smaller z , as indicated by the curves in Figure 7. The pore

coordination described by $z = 3$, on the average, characterizes a structure of Y-type elements. As z approaches 2, the pore network resembles that of a chain-like structure consisting of pores of varying size connected end-to-end. Larger z values represent a more complex interconnecting pore network. Use of the random interconnection assumption may not be valid for a complex pore assembly with large z . The assumption also breaks down for samples of high porosity with a large distribution in pore size. In either case, the pore interconnection probability becomes dependent upon pore size and the accuracy of derived pore coordination numbers must be questioned. Fluid flow through such permeation networks has been studied by Chatzis and Dullien.¹⁴ They have shown that the flow in sandstone can be modeled by such networks with z on the order of 3. The relationship between the pore coordination number and the mineralogical composition of the sandstones is uncertain; however, it is interesting to note that large amounts of clay were detected in samples requiring a large value of z to produce $k_m = k_g$. (See Figure 8). Similarly, for samples for which z is less than 3, only small amounts of clay were found.

CONCLUSIONS

This study indicates the NMR technique is useful for determining porosity of saturated western tight gas sands. However, we propose that a network model be adopted in place of the common parallel flow model for predicting permeability. The parallel flow model, whose success is based on clay-free rocks, does not accurately reflect the fluid-flow properties in these low permeability reservoir rocks. The pore geometry of tight sandstones is very complex due to the presence of authigenic carbonate and clay minerals. When combined with the network model, an understanding of the relationship between these mineral constituents and the pore assembly will extend NMR as an accurate means of predicting fluid flow through relatively impermeable sandstones.

ACKNOWLEDGEMENTS

We wish to acknowledge Bob Brown and Ken Gardner at the USGS for X-ray diffraction measurements and thin section preparation and John Borely at Chevron for the NMR measurements and sample preparation.

This study was supported by the Department of Energy's western gas sands project, administered by the Bartlesville Energy Technology Center.

REFERENCES

1. Keighin, C. W., and Fouch, T. D.: "Depositional Environments and Diagenesis of Some Nonmarine Upper Cretaceous Reservoir Rocks, Uinta Basin, Utah," Recent and Ancient Nonmarine Depositional Environments as Modeled for Exploration, Ethridge, F. G., and Flores, R. M., eds.; Society of Economic Paleontologists and Mineralogists Special Publication No. 31 (1981), in press.
2. Pitman, J. K., and Fouch, T. D.: "Mineralogical Characteristics of Some Lower Tertiary Low-Matrix Permeability Reservoir Rocks, South-Central Uinta Basin, Utah," A.A.P.G. Bull. (1978), 62 (5), 891.
3. Brown, R. J. S., and Gamson, B. W.: "Nuclear Magnetism Logging," Trans. AIME (1960) 219, 199.
4. Loren, J. D.: "Permeability Estimates from NML Measurements," J. Pet. Tech. (1972), 923.
5. Robinson, J. D., Loren, J. D., Vajnar, E. A., and Hartman, D. E.: "Determining Residual Oil with the Nuclear Magnetism Log," J. Pet. Tech. (1974), 226.
6. Seevers, D. O.: "A Nuclear Magnetic Method for Determining the Permeability of Sandstone," Trans. SPWLA (1966) 6 (Sec L), 1-14.
7. Timur, A.: "Pulsed Nuclear Magnetic Resonance Studies of Porosity, Moveable Fluid, and Permeability of Sandstone," J. Pet. Tech., (1969) 775-786.
8. Loren, J. D., and Robinson, J. D.: "Relations Between Pore Size, Fluid, and Matrix Properties and NML Measurements," Soc. Pet. Eng. J. (1970), 249, 268.
9. Cowgill, D. F., "A Hybrid Network Model of Fluid Flow in Porous Media," to be published.
10. Brine permeabilities were measured by the Petroleum Testing Service, Inc., Santa Fe Springs, California.
11. Torrey, H. C., Korringa, J., Seevers, D. O., and Uebbersfeld, J.: "Magnetic Spin Pumping in Fluids. Contained in Porous Media," Phys. Rev. Lett. (1959), 3 (9), 418-419.
12. Dullien, F. A. L.: Porous Media, Fluid Transport and Pore Structure, Academic Press, Inc., New York (1979), 44-66 and 181-190.
13. Kirkpatrick, S.: "Classical Transport in Disordered Media: Scaling and Effective-Medium Theories," Phys. Rev. Lett. (1971), 27 (25), 1722-1725.
14. Chatzis, I., and Dullien, F. A. L.: "Modelling Pore

Structure by 2D and 3D Networks with Application to Sandstones," J. Can. Pet. Technol. (1977), 16, 97-112.

NOMENCLATURE

α	= constant
A	= relative amplitude of the longest T_1 decay component
B	= relative amplitude of the intermediate T_1 decay component
C	= relative amplitude of the shortest T_1 decay component
θ	= dummy variable
h,k,j	= dummy indexes referring to permeability components
k	= permeability, component permeability
k_l	= flow laboratory measured permeability
k_m	= effective-medium permeability
k_p	= parallel model permeability
$M(t)$	= NMR magnetization at time t
ϕ	= fractional porosity
ϕ_l	= laboratory measured porosity
ϕ_{nmr}	= NMR deduced porosity
p	= component probability
$p(k)$	= distribution function of permeabilities k
q,r,s	= dummy variable
S/V	= pore surface-to-volume ratio
σ	= electrical conductivity component
σ_m	= effective-medium conductivity
τ	= rf pulse separation in time
t	= time
T_1	= spin-lattice relaxation time constant
T_2^*	= spin-spin relaxation time due to magnet inhomogeneity
T_{1A}	= relaxation time constant for the longest T_1 decay component
T_{1B}	= relaxation time constant for the intermediate T_1 decay component
T_{1C}	= relaxation time constant for the shortest T_1 decay component
z	= node coordination number

FIGURE CAPTIONS

- Fig. 1** Photomicrograph showing secondary porosity, represented by dark areas between grains.
- Fig. 2** Porosity plot relating NMR-deduced values (ϕ_{nmr}) to laboratory measurements (ϕ_l).
- Fig. 3** Typical T_1 relaxation data, the computed fit, and its exponential components.
- Fig. 4** Permeability plot relating NMR-deduced values computed using the parallel flow model (k_p) to laboratory measurements (k_l).
- Fig. 5** Photomicrograph of authigenic illite filling a pore.
- Fig. 6** Photomicrograph showing authigenic kaolinite (arrows) filling secondary pore-space.
- Fig. 7** Node coordination number dependence of the effective-medium permeability (k_m) computed for several samples with different laboratory permeabilities (k_l).
- Fig. 8** Permeability plot relating effective-medium values (k_m) computed with $z = 3$ to laboratory measurements (k_l).
- Fig. 9**

TABLE HEADINGS

- Table 1** Measured porosity, permeability, and relative carbonate content for tight sandstone samples (X-ray data in counts/sec; leaders (--) not present; asterisk (*) fractured core).
- Table 2** T_1 relaxation components (A,B,C relative amplitudes; T_{1A} , T_{1B} , T_{1C} decay time constants; leaders (--) not present).

Fig. 14

Fig. 15

Fig. 16

Table 1.

Age	Unit	Sample Depth (feet)	X-ray diffraction (Peak height intensity)		Brine Porosity (percent)	Brine Permeability (millidarcy)
			Calcite	Dolomite		
Tertiary	Green River-Wasatch undifferentiated	4403.3	15	48	8.7	.021
		4403.8	91	30	9.2	.35
		4404.0	TR	26	13.2	1.55
		4412.0	23	23	11.2	.33
		4416.0	139	16	3.4	.002
		4461.0	36	45	3.3	.002
		4470.0	97	83	7.2	.002
		4478.3(1)	43	23	7.0	.13
		4478.3(2)	25	58	4.5	.0047
		4486.0	13	12	6.9	.006
Cretaceous	Mesaverde Group	6407.0	23	36	5.6	<.001
		6469.0	104	30	0.9	<.001
		6492.0	--	--	9.6	.20
		6493.0	TR	TR	9.6	.061
		6496.0	TR	--	10.0	.04
		6497.0	--	--	10.1	.14
		6498.0	--	33	9.1	.03
		6503.0	--	11	9.5	.12
		6507.0	145	--	1.4	.003
		7427.8	--	64	8.0	.001
		7469.0(1)	--	87	3.7	.00045
		7469.0(2)	--	97	4.7	.00090
		8483.5	--	11	4.1	<.001
		8486.0	--	14	9.8	.012
		8490.0	--	21	8.4	.009
		8492.0	--	63	9.1	.027
		8495.0	--	12	9.6	.036
		8496.5	--	--	2.6	*.77
		8525.0	--	42	6.0	.016

Table 2.

Sample Depth (feet)	A (%)	T _{1A} (ms)	B (%)	T _{1B} (ms)	C (%)	T _{1C} (ms)
4403.3	--	--	44.0	16.5	56.0	0.33
4403.8	51.8	279.7	30.9	24.2	17.3	2.3
4404.0	50.7	301	30.0	34.0	19.3	3.67
4412.0	47.2	289	30.5	50.9	22.3	5.04
4416.0	28.9	72.7	54.3	4.7	16.8	0.76
4461.0	--	--	21.8	6.58	78.2	0.89
4470.0	28.3	144	38.2	13.3	33.5	2.01
4478.3 (1)	37.2	281.2	33.8	19.8	29.1	1.3
4478.3 (2)	29.7	92.8	30.2	7.9	40.1	1.0
4486.0	34.0	230	32.7	24.7	33.3	3.00
6407.0	39.5	27.4	48.0	5.43	12.5	0.77
6469.0	--	--	37.5	16.9	62.5	1.26
6492.0	31.3	195.1	51.4	31.0	17.2	3.7
6493.0	25.3	228.4	51.6	41.0	23.1	5.3
6496.0	31.5	194	47.0	31.7	21.5	5.44
6497.0	32.7	300	47.3	46.1	20.0	6.63
6498.0	29.7	181	47.8	34.5	22.5	5.53
6503.0	36.0	249	46.0	37.9	18.0	5.53
6507.0	22.6	52.0	41.8	8.37	35.6	1.25
7427.8	44.9	58.8	46.9	9.72	8.2	1.34
7469.0 (1)	17.7	55.7	48.5	8.7	33.8	1.7
7469.0 (2)	32.9	37.5	56.6	6.3	10.5	1.1
8483.5	22.1	49.9	50.5	12.1	27.4	2.44
8486.0	33.9	226	49.4	34.0	16.7	5.87
8490.0	34.9	252	45.5	41.8	19.6	6.65
8492.0	34.4	278.3	43.8	49.5	21.8	8.5
8495.0	36.5	413	38.0	64.6	25.5	11.7
8496.5	26.2	98.5	28.0	8.7	45.8	1.1
8525.0	32.9	175.0	46.4	27.2	20.8	5.3

Figure 1.

Figure 2.

Figure 3.

Figure 4.

Figure 5.

Figure 6.

Figure 7.

Figure 8.