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SPECIAL CORE ANALYSIS FOR WESTERN TIGHT SANDS

Annual Report for the Period August 1, 1980—July 31, 1981

By
Krishnaswamy Sampath
Walter Rose
Clarence J. Raible

May 1982
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U. S. DEPARTMENT OF ENERGY

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SPECIAL CORE ANALYSIS FOR WESTERN TIGHT SANDS
Annual Report, Aug. 1, 1980-July 31, 1981

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SUMMARY

This report presents the results of laboratory investigations of low-permeability sandstones at the Institute of Gas Technology (IGT), Chicago. The core samples used in these studies were from the following wells:

a) Mapco RBU 11-17F well (Section 17, T10S, R20E) from the Uinta Basin, Utah, and b) PTS 24-19 Federal (Section 19, T33N, R114W) from Sublette County, Wyoming. Core samples from the Greater Green River Basin in Wyoming were also used in some of the experiments.

Permeability to gas was measured as a function of pore pressure, confining pressure, and partial water saturation. Porosity characteristics of the samples were also measured, and a new method was developed to measure pore volume compressibility of sandstone samples. A comprehensive theoretical analysis of anisotropy in porous media was completed, and a novel experimental technique was developed to characterize anisotropy in sandstone sediments. Correlations have been developed to describe the dependence of permeability of tight sandstones on confining pressure and partial water saturation. In addition, a cooperative program was developed with USGS Denver, whereby the results of petrographic analyses conducted at the USGS were used in conjunction with reservoir parameters measured at IGT to better understand the properties of tight sandstones.

Topical reports on the measurement of directional permeability trends and another one on the dependence of porosity on confining pressure have been prepared and are presented as separate Special Reports.^{1,2}

INTRODUCTION

The strong dependence of tight sandstone permeability on confining pressure has been documented extensively in recent years.³⁻⁶ Geologic observations indicate that the pores in these low-permeability sandstones are typically small and the flow paths are tortuous. Proper understanding of the pore characteristics is essential to the evaluation of these reservoirs. In addition, such an understanding is also necessary to extend conventional core analysis results to in-situ conditions.

Conventional permeability measurements, which are conducted on dry samples under a nominal confining pressure at near-atmospheric pore pressures, have to be corrected for the following: a) the phenomenon of gas slippage, which occurs because the dimensions of the flow paths are comparable to the mean free path of the flowing gas; b) the confining pressure; and c) partial water saturation. In addition, it may be desirable to account for directional permeability trends that are exhibited by Western tight sands sediments.

Petrographic observations help characterize sandstone material. Low-permeability sandstones are generally fine- to very fine-grained; pores are found to be lined with authigenic clays, and the mineralogical characteristics of these sandstones tend to vary drastically within a few inches because of differences in the amount of carbonate cement and in grain size, and because of the presence of silt and clays.⁷⁻⁸ The samples investigated are similar to other low-permeability sandstones of the Late Cretaceous age from the area.⁹

The porosity of tight sandstones is another petrophysical parameter that is of interest in formation evaluation and reserve calculations. Since porosity measurements are generally conducted at ambient conditions, the effect of confining pressure on this parameter also has to be understood so that conventional measurements can be used in reservoir evaluation. Especially in the case of partially water-saturated reservoirs, the combined effects of fluid expansion and pore volume reduction (due to pressure reduction during production) can result in an increase in partial water saturation and hence can decrease effective permeability to gas. In addition, since partial water saturation levels are generally calculated from the weight of the samples at ambient pressure, porosity reduction can also affect the interpretation of relative permeability measurements.

Visual examination of tight sandstone samples indicated that there is considerable cross-bedding. This cross-bedding can result in varying values of permeability depending on the orientation of the core sample with respect to the bedding direction. The extent to which the ratio of maximum to minimum permeability can vary due to directional permeability trends has a bearing on the interpretation of laboratory-derived permeability data.

APPARATUS AND EXPERIMENTAL METHODS

The experimental apparatus used for permeability measurements has been described in detail elsewhere.¹⁰ For the sake of completeness, a simplified schematic diagram is shown in Figure 1. Core samples approximately 2 inches long and 1 or 1-1/2 inches in diameter were used in the experiments. The core holder was capable of exerting up to 10,000 psi confining pressure in a hydrostatic mode. All experiments described in this report were conducted at low pore pressures. Dry nitrogen was used as the flowing fluid in all the gas flow experiments. For liquid flow experiments, different liquids were tried. Differential pressure was monitored using a transducer, and the output was recorded using a strip-chart recorder. Downstream pressure was maintained at atmospheric level in all experiments.

Core samples were placed in rubber sleeves and mounted in the core holder and confining pressure was imposed on them, following which dry nitrogen was flowed through them. Differential pressures were monitored, and the flow rates were measured using a bubble flowmeter or a calibrated pipette.

Two different methods were used to measure pore volume reduction. In the first method, the amount of water expelled from a liquid-saturated core sample was monitored. The experimental setup is shown schematically in Figure 2 and is very similar to that described by Hall.¹¹ Core plugs were evacuated and saturated with deaerated water. The saturated plugs were placed in a core holder, and all the flow lines were filled with deaerated water also. Initially, a nominal confining pressure of 200 psi was imposed on the samples, and subsequently confining pressure was raised in steps to 5000 psi. At each confining pressure level, the volume of water expelled due to pore volume reduction was measured using a calibrated micropipette. The time required for equilibrium at each stage in the experiment varied from sample to sample and was generally of the order of 1 to 2 hours.

In the second method, dry samples were used to measure pore volume reduction. Figure 3 is a schematic diagram of the experimental apparatus. A dry sample was mounted in the core holder and a nominal confining pressure of 200 psi was imposed on the sample. Dry nitrogen at 80 psi was expanded into the sample, and the calibrated positive displacement pump was used to increase the pore pressure back to 80 psi. The change in volume to achieve this was noted, and initial pore volume was calculated using the ideal-gas law. Confining pressure was then increased in steps up to 5000 psi. At each confining pressure, the position of the piston in the positive displacement pump was adjusted to maintain constant pressure and the volume was noted. Thus a direct measurement of pore volume reduction was obtained using gas as the pore fluid. The time required for equilibrium was reduced significantly. Further, the use of a strip-chart recorder in conjunction with a transducer enabled equilibrium to be ascertained visually.

The apparatus for anisotropy measurements is similar to the apparatus described for permeability measurements. The upstream and downstream ends in the core holder, however, were modified so that divided portions of the effluent stream can be collected and measured. In addition, provision was made for the core chamber to accommodate sandstone samples with slanted ends. Figure 4 shows a schematic diagram of the modified core chamber. The space between the end plates and the core end face was filled with loose sand or

glass beads to prevent the rubber sleeve from collapsing. A rubber septum was used to partition the effluent end into upper and lower half-cells. For detailed experimental procedures, the reader is referred to a Special Report.¹

Figure 1. SCHEMATIC DIAGRAM OF PERMEABILITY APPARATUS

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Figure 2. SCHEMATIC DIAGRAM OF SATURATED PORE VOLUME APPARATUS

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Figure 3. SCHEMATIC DIAGRAM OF DRY PORE VOLUME APPARATUS

- ① CORE SAMPLE
- ② HASSLER SLEEVE SEAL
- ③ SAND-FILLED SPACE TO ACCOMMODATE SPECIAL CORE SHAPES
- ④ RUBBER SEPTUM PARTITIONING UPPER AND LOWER EFFLUX CHAMBERS
- ⑤ INFLOW AND OUTFLOW TUBES
- ⑥ END PLATES
- ⑦ HOUSING

A81071587

Figure 4. SCHEMATIC DIAGRAM OF PERMEABILITY CORE HOLDER

EXPERIMENTAL RESULTS AND DISCUSSION

Single Phase Permeability

The concept of "slip" during gas flow through capillaries with diameters small enough to be comparable to the mean free path of the gas was used by Klinkenberg¹² to explain the discrepancies between gas and liquid permeabilities of porous media. He presented the following equation, which relates the apparent gas permeability, K_g , of a gas flowing at a mean pore pressure, $\bar{P}$, to the true permeability of the porous medium, K_∞ :

$$K_g = K_\infty (1 + b/\bar{P}) \quad (1)$$

In this equation, b is a constant and is a function of the capillary radius, r_b , and the mean free path of the gas, λ , at pressure $\bar{P}$:

$$b = 4c\lambda\bar{P}/r_b \quad (2)$$

In Equation 2, c is a constant approximately equal to 1. Loeb¹³ showed that Poiseuille's law for viscous flow can be modified to account for slip and defined a coefficient of slip that can be shown to be equal to the term $c\lambda$ in Equation 2.

As is evident from Equation 2, the contribution resulting from slip is inversely proportional to the capillary radius. At mean pore pressures usually employed in the laboratory measurements of permeability, the slip effect is significant in the case of tight sands because of the small pore sizes.^{7,8}

The dependence of tight sandstone permeability on confining pressure and partial water saturation has been documented by numerous investigators.³⁻⁶ It appears reasonable, therefore, that the slip effect would also be affected by confining pressure and water saturation. A series of experiments was conducted in conjunction with petrographic observations in an attempt to understand the possible alterations in pore dimensions that result from confining stress and partial water saturation.

And indeed, the results of the experimental observations did confirm these presumptions. For all the samples investigated, it was noted that the slope of the line relating apparent gas permeability and reciprocal mean pore pressure did change as a function of net confining pressure and partial water saturation, as did the intercept. A typical set of data is shown in Figure 5a for core no. 5172* from the PTS 24-19 well. It is evident from the figure that the extrapolated gas permeability (the y-intercept) and the slope of the line relating apparent gas permeability and reciprocal mean pore pressure both decrease as a function of net confining pressure. Shown in Figure 5b is a set of data for core no. 8358.3 from the RBU 11-17F well. It is obvious that the trend is similar.

* Core numbers correspond to core depth in feet.

Figure 5a. EFFECT OF CONFINING PRESSURE AND PORE PRESSURE
ON GAS PERMEABILITY (Well PTS 24-19)

Figure 5b. EFFECT OF CONFINING PRESSURE AND PORE PRESSURE
ON GAS PERMEABILITY (Well RBU 11-17F)

It is evident from Equation 1 that the extrapolated gas permeability values should be identical to liquid permeability values under similar stress conditions. Brine (2% KCl + 2% NaCl) was flowed through the core samples at different confining pressures. The measured liquid permeabilities, K_L , are shown in Table 1 and compared with extrapolated gas permeability values at confining pressures of 1000 psi and 5000 psi. There are some discrepancies between the gas and liquid permeabilities. Brine permeabilities were significantly lower at all confining pressures. A typical comparison is shown in Figure 6.

Scanning electron micrographs of samples that were exposed to brine indicate that there was noticeable dissolution of kaolinite and illite, signifying changes in pore structure.⁸ This rock/fluid interaction partially accounts for the noted differences between gas and liquid permeabilities. In addition, it was seen that distilled water also affected the clays, especially the illite. Permeabilities measured using decane were also lower than the extrapolated gas permeabilities, indicating that there probably is some dislodgment of fines and clays during liquid flow.

The reduction in the extrapolated gas permeability as a function of net confining pressures is shown in Figure 7a for four samples from the PTS 24-19 well and in Figure 7b for sample no. 8358.3 from the RBU 11-17F well.

The dependence of the extrapolated permeability on confining pressure for all samples from the RBU 11-17F well was seen to be approximated by the relationship:

$$\left(\frac{K_{\infty}}{K_{1000}}\right)^{0.5} = 1 - 0.41 \ln \left(\frac{P_c}{1000}\right) \quad (3)$$

where K_{∞} = extrapolated gas permeability (md)

K_{1000} = extrapolated gas permeability at a net confining pressure of 1000 psi (md)

P_c = confining pressure (psi).

The following salient features are to be noted:

1. The logarithmic fit provided the best fit for the data.
2. A second-degree polynomial fit provided a good approximation but the polynomial had a minimum at approximately 5000 psi, and hence was not useful for extrapolations beyond 5000 psi.
3. Different exponents for the normalized permeability (the term on the left-hand side of Equation 3) between 0.1 and 1 were tried. A value of 1 for the exponent yielded a correlation coefficient of 0.90, as opposed to a correlation coefficient of 0.94 for an exponent of 0.5 and 0.86 for an exponent of 0.3333. It was hence concluded that an exponent of 0.5 is adequate. In addition, it was noted that the data for individual core samples were approximated by the same semilogarithmic relationship signified by Equation 3, with correlation coefficients greater than 0.95.

Table 1. SUMMARY OF CORE MEASUREMENTS

Sample No.	$(K_{\infty})_1$, md*	$(K_L)_1$, md*	$(K_{\infty})_2$, md**	$(K_L)_2$, md**	ϕ
8243.3	0.0081	0.0025	0.0005	0.0005	0.098
8243.9	0.0138	0.0103	0.0014	0.0005	0.111
8290.4	0.0421	0.0063	0.0048	0.0005	0.067
8290.9	0.0536	--	0.0028	--	--
8298.4	0.022	0.0112	--	--	0.066
8298.8	0.116	0.0334	0.0124	0.0034	0.063
8358.3	0.056	0.0606 [†]	0.0087	0.0041 [†]	0.077
8358.7	0.134	0.0319	0.0238	0.0045	0.079
8365.4	0.0252	0.0067	0.0004	0.0004	0.058
8365.9	0.0143	0.0121 [†]	0.0017	0.001 [†]	0.059

* $(K_{\infty})_1$, $(K_L)_1$ are the extrapolated gas permeability, liquid permeability at a confining pressure of 1000 psi.

** $(K_{\infty})_2$, $(K_L)_2$ are the extrapolated gas permeability, liquid permeability at a confining pressure of 5000 psi.

† Decane was the liquid used. Brine (2% KCl + 2% NaCl) was used in all other cases.

WELL: MAPCO RBU 11-17F

CORE DEPTH: 8290.4 FT

Figure 6. COMPARISON OF LIQUID AND GAS PERMEABILITIES

Figure 7a. EFFECT OF CONFINING PRESSURE ON
GAS PERMEABILITY (Well PTS 24-19)

WELL: MAPCO RBU 11-17F

CORE DEPTH: 8358.3 FT

Figure 7b. EFFECT OF CONFINING PRESSURE ON
GAS PERMEABILITY (Well RBU 11-17F)

The Klinkenberg-extrapolated data are shown in Figure 8 along with the line of best fit. The same trend is consistent with the data of Thomas and Ward.⁴

The liquid permeability data were found to be approximated by the line

$$\left(\frac{K_L}{K_{1000}}\right)^{0.5} = 1 - 0.44 \ln \left(\frac{P_C}{1000}\right) \quad (4)$$

A comparison of Equations 3 and 4 shows that, in spite of the discrepancies between liquid and extrapolated gas permeabilities, the response to confining pressure is approximately the same in both cases. The data are shown in Figure 8, plotted along with the extrapolated gas permeability values.

To understand possible changes in pore characteristics due to confining pressure the following experiment was conducted. Core no. 8290.8 was sawed into two halves and injected with blue dye epoxy. One half was allowed to set under ambient pressure. The other half was placed in a core holder, and the epoxy was allowed to set under a confining pressure of 5000 psi. Thin sections were prepared of both halves and examined (at USGS Denver). In the half in which the epoxy was cured under ambient pressure a number of thin-film intergranular pores were visible. In the other half, such intergranular pores were not prevalent. Similar observations were recorded on some other samples also. This lack of thin film porosity under confining pressure suggests that these intergranular spaces are sealed off at high confining pressures and hence are one of the possible causes of the observed reduction in permeability. The pore volume reduction in tight sandstones due to confining pressure is much less significant than the reduction in permeability, once again supporting the hypothesis that the absence of intergranular porosity results in permeability reduction since such thin film pores do not contribute significantly to the total pore volume of the samples.

Relative Permeability

In a similar manner, plots relating apparent effective gas permeability and reciprocal mean pore pressure were obtained as a function of partial water saturation. A typical set of data is shown in Figure 9a for core no. 5210 from the PTS 24-19 well, and in Figure 9b for core no. 8358.3 from the RBU 11-17F well. The slopes of the lines decrease with increasing partial water saturation. Rose¹⁴ has recorded similar observations for the flow of gas through higher permeability porous media.

Byrnes, Sampath, and Randolph⁵ showed that relative gas permeability can be expressed as a function of partial water saturation by a modified form of an equation proposed by Corey.¹⁵ The extrapolated relative gas permeability of the samples investigated was approximated by an equation of the type

$$K_{rg} = \left(1 - \frac{S_w}{0.7}\right)^n (1 - S_w^2) \quad (5)$$

where S_w is the fractional water saturation, K_{rg} is the relative gas permeability value extrapolated to infinite gas pressure, and n is an empirical exponent. The value of n was 1.3 for samples from the PTS 24-19 well and 1.5 for samples from the RBU 11-17F well. The data from the PTS 24-19 well are shown in Figure 10a and the data from the RBU 11-17F well in Figure 10b along with the lines calculated using Equation 5.

Figure 8. PERMEABILITY-CONFINING PRESSURE CORRELATION

Figure 9a. EFFECT OF PARTIAL WATER SATURATION AND
PORE PRESSURE ON GAS PERMEABILITY
(Well PTS 24-19)

Figure 9b. EFFECT OF PARTIAL WATER SATURATION AND PORE PRESSURE ON GAS PERMEABILITY (Well RBU 11-17F)

Figure 10a. PERMEABILITY-WATER SATURATION
CORRELATION (Well PTS 24-19)

Figure 10b. PERMEABILITY-WATER SATURATION
CORRELATION (Well RBU 11-17F).

From the flow data, an effective pore radius was calculated using two different relationships. The first one is

$$r_b = \frac{4c\lambda\bar{P}}{b} \quad (2)$$

where c = constant approximately equal to 1

λ = mean free path of the gas

r_b = effective radius of the flow path.

The second relationship is a relationship between the permeability, as defined by Darcy's law, and Poiseuille's law for viscous flow:

$$r = 8.886 \times 10^{-6} (K/\phi)^{0.5} \quad (6)$$

where r = capillary radius (cm)

K = the permeability constant (md)

ϕ = porosity.

If the effective radius calculated from Equation 2 and the capillary radius calculated from Equation 6 were equal, the constant b and the ratio K/ϕ would be related to each other as follows:

$$b = 2.98 (K/\phi)^{-0.5} \quad (7)$$

An analysis of the data from the RBU 11-17F well, however, indicates the following relationship:

$$b = 0.93 (K/\phi)^{-0.53} \quad (8)$$

It hence appears that the ratio of the effective radius to the capillary radius is approximately 3.2. This can be explained by means of the following relationship:

$$K = \frac{\psi_m^2}{k_o T_1} \quad (9)$$

where m is the effective hydraulic radius, k_o is a pore shape constant, and T_1 is the tortuosity factor.¹⁶ From the data used to construct Figure 8, the product $k_o T_1$ was calculated to be 80.12. Since k_o is assumed to be equal to 2 for noncircular geometries, the tortuosity factor for the tight sandstone samples studied was calculated to be 40.06; effective radii ranged from 0.02 μ m to 1 μ m.

Pore Volume Reduction

A typical pore volume-confining pressure relationship is shown in Figure 11 for sample no. 8298.4 from the RBU 11-17F well. Results of both experimental methods are shown. Within experimental error, both methods yield similar results. At a confining pressure of 5000 psi, most of the samples investigated retained 85% or more of their initial pore volume. It was further noted that pore volume compressibility of these sandstones was

Figure 11. PORE VOLUME REDUCTION DUE TO CONFINING PRESSURE

comparable to values reported for other tight sandstones and "conventional" sandstones. Pore volume compressibilities ranged from $1.3 \times 10^{-5} \text{ psi}^{-1}$ to $2.0 \times 10^{-6} \text{ psi}^{-1}$. Table 2 summarizes the results of the measurements and shows the percentage of initial pore volume retained by each sample at 5000 psi confining pressure along with the pore volume compressibility values. It is clear from the table that two samples, core no. 8234.4 and core no. 8234.9, suffered much more severe pore volume reduction than the other samples. Mineralogical examination indicated that these two samples contained a much larger amount of calcite (20% and 42%, respectively) than the rest of the samples, which had less than 2% calcite.

Table 2. SUMMARY OF PORE VOLUME REDUCTION DATA

Sample No.	Initial Porosity, fraction	Percent of Initial Pore Volume at a Confining Pressure of 5000 psi	Pore Volume Compressibility at a Confining Pressure of 5000 psi, psi^{-1}
8234.4	0.017	65.5	1.28×10^{-5}
8234.9	0.014	57.7	1.58×10^{-5}
8243.3	0.098	89.0	4.20×10^{-6}
8243.9	0.111	90.0	2.00×10^{-6}
8290.4	0.067	86.7	3.90×10^{-6}
8298.4	0.066	87.6	3.90×10^{-6}
8290.8	0.063	86.7	4.70×10^{-6}
8358.3	0.077	85.4	4.70×10^{-6}
8358.7	0.079	86.4	2.80×10^{-6}
8365.4	0.058	90.1	4.30×10^{-6}
8365.9	0.059	85.5	5.10×10^{-6}

A plot of pore volume compressibility versus initial porosity is shown in Figure 12. The data closely follow the trend reported by Hall¹¹ for other sandstone and limestone samples.

Directional Permeability

During last year a major program effort has been made to develop a suitable method for measuring the directional permeability properties of Western tight gas sand sediments. This work is described in further detail in a special report.

Early on, a decision was made to limit attention to cases of two-dimensional anisotropy. This is the category, for example, that is caused by the local bedding and cross-bedding that characterized the deposition of channel (as well as some of the blanket) sand formations.

The theory of transport processes in anisotropic media has been understood for a long time. In fact, what Bear¹⁷ has to say about it is sufficiently complete and comprehensive to make further elaborations unnecessary. What has been needed all along, however, is a methodology that can be used in the laboratory when unambiguous data about directional properties are wanted.

Figure 12. PORE VOLUME COMPRESSIBILITY-
POROSITY CORRELATION

The nature of the measurement problem has been recognized for a long time.¹⁶ Nye,¹⁹ for example, has understood the problem, and has described with clarity the one way to deal with it that has been favored by the earlier workers (summarized in Scheidegger²⁰ and later workers²¹) as well. Unfortunately, what Nye and others have described is an approach by which the problem is only minimized but not eliminated.

Specifically, the best idea that so far has been advanced is to choose elongate or flat sample shapes in laboratory work where end-effect disturbances will be of secondary importance. For example, if rock samples having the shape of a right cylinder are to be used, it is clear that the flow lines necessarily will be curved and the equipotential surfaces will be nonplanar. This is because locally the field of flow is that prescribed by Darcy's law, or

$$q = - (K_{ij}/\mu) \cdot (\text{grad } P) \quad (10)$$

where q is the approach (seepage) velocity, μ is the fluid viscosity, P is the fluid potential (=pressure in the case of horizontal flow of an incompressible liquid), and K is the tensorial transport coefficient by which the flux and force vectors are linearly related.

Implied by Equation 10 [where the vector $(\text{grad } P)$ makes a dot product with the tensor, K_{ij} , to be proportional to the vector q] is the idea that the vector direction of q and $(\text{grad } P)$ usually do not coincide. In fact, analysis shows that q and $(\text{grad } P)$ are colinear only when the sample is oriented so that flow occurs either parallel or perpendicular to the direction of maximum permeability. With such a sample orientation, K_{ij} takes the diagonalized form

$$K_{ij} = \begin{vmatrix} K_1 & 0 \\ 0 & K_2 \end{vmatrix} \quad (11)$$

where K_1 and K_2 are the maximum and minimum permeability, respectively. More generally, however, for arbitrary sample orientations, K_{ij} will be described in terms of four elements for the two-dimensional case, such as

$$K_{ij} = \begin{vmatrix} K_{11} & K_{12} \\ K_{21} & K_{22} \end{vmatrix} \quad (12)$$

where by reciprocity $K_{12} = K_{21}$.

The fact remains, however, that at every point in the field of flow, the angle between q and $(\text{grad } P)$ will be given by the relationship

$$A = \tan^{-1} [(K_1/K_2) \tan B] - B \quad (13)$$

where B gives the local values for the angle between the direction of $(\text{grad } P)$ and the direction of K_1 . Specifically B is the angle by which K_{ij} in Equation 12 is diagonalized to have the form of Equation 11.

In order to integrate Equation 10 for liquid flow, it is desirable to give the sample under study a shape so that A will have a fixed and constant value throughout the field of flow and on the boundaries as well. Then for the case of horizontal flow of an incompressible fluid, it follows that

$$K_{11} = (Q\mu L/\Delta P) (\cos^2 A) \quad (14)$$

where Q is the component of the volumetric flow per unit cross-section in the direction of (grad P), and L is the distance between the parallel end faces as measured along a streamline path.

As mentioned above, it has become common practice in the past to work with very flat or very elongate samples in order to minimize end-effect problems. The IGT method described in a special report,¹ however, provides an alternative measurement scheme by which end effects are entirely eliminated. This is achieved by shaping the samples under study in such a way that the entering and exiting fluid will be uniformly distributed (i.e., all streamlines are linear and all equipotential surfaces are planar and parallel to the parallel end faces). The result is that the end-effect zones are simply cut out so that they are not a part of the sample space being tested.

The final analytical result that has been obtained is that

$$K_1 = K_{11} [1 - (\tan A \times \tan B)] \quad (15)$$

and

$$K_2 = K_{11} [1 + (\tan A / \tan B)] \quad (16)$$

which is to say that the maximum and minimum permeabilities are explicit functions of K_{11} , A , and B . The angle A is established whenever the sample has been given the particular shape so that K_{11} can be obtained from Equation 11. On the other hand, the angle B will be known either from observing the bedding plane direction in the samples under study or from data obtained on measurements made on two adjacent sample pieces. The latter approach is described in detail in Appendix A.

In Table 3, the results of experiments obtained on three pieces of weathered (outcrop) Western tight sands sediments, and on three pieces of unweathered (subsurface) Western tight sands sediments, are reported. Here it is seen that the ratios of maximum to minimum permeabilities are not large (from 1.31 to 1.66). In fact the values suggest²² that directional permeability trends in Western tight sands of the type referred to in Table 3 can be ignored in practical reservoir studies.

Table 3. SUMMARY OF DIRECTIONAL PERMEABILITY MEASUREMENTS

Core	Fractional Porosity	A	B _{assumed}	K_{11}	K_1	K_2	K_1/K_2
L6(I) } L6(II) }	0.26	{ 5° 5°	{ -75° -75°	945 1009	1253 1339	922 986	1.36 1.36
II(1) } II(2) } II(3) }	0.21	{ 8° 0 0	{ -77° 0 -90°	0.421 0.576 0.402	0.677 0.576 —	0.407 — 0.402	1.66 1.43
U(17)	0.29	5°	-72°	124	156	120	1.3

On the other hand, it is quite clear that if bedded sands contain connate water (the usual case), the K_1/K_2 ratio will be very much increased. This is because the effective permeability to gas will be reduced more in the tight than in the less tight layers since the tight layers will hold most of the connate water. To end this discussion, we consider the following hypothetical case. Suppose the sediment is composed of alternating layers, M and N. If we take K_1 to be 1.5 and K_2 to be 1 md, then $K_1/K_2 = 1.5$ and $K_M = 2.366$ md, while $K_N = 0.634$ md.* Now suppose that because of the connate water, K_M is reduced by 7% to $K_M = 2.2$ md, while K_N is reduced by 68.5% to $K_N = 0.2$ md. The result is that the connate water-controlled K_1/K_2 ratio will be increased by more than 118% to $K_1/K_2 = 3.273$. This matter will be the subject of further study next year when the capillary pressure work is undertaken.

* Note that $K_1 = (K_M + K_N)/2$ and $K_2 = 2K_M K_N / (K_M + K_N)$ if the alternate layers are of equal thickness.

CONCLUSIONS

The extrapolated gas permeability of tight sandstones is significantly affected by confining pressure. The constant in the relationship describing the slip phenomenon during gas flow, b , was found to correlate with the permeability/porosity ratio in a manner much like that predicted from simple models.

Because of confining pressure, a number of small intergranular pores that were present under surface conditions were sealed off. This was also verified by petrographic studies.

The relative permeability behavior of the samples investigated can be approximately described by a simple empirical correlation.

There was some discrepancy between extrapolated gas permeability values and liquid permeability values. This is attributed to fines movement and rock-fluid interactions.

A procedure has been developed that tests core samples from sediments of Western tight sands for anisotropy. This procedure is referred to herein as the IGT method for laboratory measurement of directional permeability trends. One advantage it has over conventional procedures is that usually less core material and fewer individual measurements are required to obtain the desired information. This advantage results from the fact that the core samples are shaped in a prescribed way which eliminates end effects of the sort described by Nye.¹⁹ This means that

1. If the direction of maximum permeability is known in advance, only one sample is needed for the IGT method. Two or more are needed for conventional work.
2. If the direction of maximum permeability is not known in advance, only two samples are required to apply the IGT method. Many more are required for conventional procedures.

The IGT method has been found to be fully compatible with the underlying theory of transport phenomena in anisotropic media. This connection has been shown analytically, and it is further confirmed by the data that have been obtained. Specifically, the data show that for the few samples of Western tight sands sediment obtained, the ratio of maximum-to-minimum permeability is between 1 and 2. More than that, the evidence indicates that in the samples tested, cross-bedding has been the major factor contributing to directional permeability.

A new method has been developed to measure the pore volume compressibility of sandstones. The method has been tested on some low-permeability sandstones, and the values obtained were seen to be in the range of values reported by other investigators for low-permeability sandstones. The method is easily applicable to different porous media and can be used at different pore pressures and confining pressures.

Pore volume reduction due to confining pressure in the samples studied was not significant to cause concern in the analysis of reservoir performance, but is of importance in the interpretation of laboratory data.

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Appendix. PETROGRAPHIC OBSERVATIONS ON SAMPLES FROM THE
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CONSULTING: ULTRAMICROANALYSIS • MICROSCOPY • SMALL PARTICLE PROBLEMS • SOLID-STATE CHEMISTRY

25 November 1980

Mr. K. Sampath
Institute of Gas Technology
3424 South State Street
IIT Center
Chicago, Illinois 60616

Dear Mr. Sampath:

We have examined four samples of core by optical and scanning electron microscopy per your purchase order #543619. This report serves as a followup of our meeting in early November.

Thin sections were examined and representative micrographs prepared. These micrographs are in your possession. All sections were predominantly calcareous quartz sandstones with many clays filling voids in the samples. Opaque minerals were present at about a 5% level in all samples. Some of these were iron oxide but no further identification was attempted. Occasional grains of plagioclase, potassium feldspar, muscovite and zircon were found in all samples. Chlorite was present in all samples with evidence that at least some of the chlorite is primary. The grain size varied from sample to sample. I have enclosed scales for the three magnifications used. The voids were partially or completely filled with secondary clays in all samples. Sample 5210.3, however, had a much larger unfilled void volume than the other three samples.

SEM Study

Samples were fractured to expose a fresh surface. The pieces were mounted on an aluminum stub using conductive silver paint. The samples were coated first with carbon and then with gold to render their surfaces conductive.

Sample 5172

The overall grain size and distribution of clays is shown in Figure 1. In Figure 2 kaolinite is seen partially filling voids in the sandstone. In Figure 3 a large faceted quartz grain is shown which indicates the precipitation of quartz from solution. Also visible are smaller, well faceted grains of a carbonate. Figure 4 shows a faceted carbonate grain with an embayed center. This implies a simultaneous dissolution and precipitation of carbonate.

Mr. K. Sampath
Page 2.

Sample 5205

Figure 5 is an overall view of the sample. Clays visible in Figure 6 contain K, Al, and Si (by Energy Dispersive X-Ray Analysis) and are probably illite. In Figure 7 a void is filled with fine-grained Kaolinite (bottom), freshly precipitated quartz (left) and dissolving/precipitating carbonate (right). A well formed carbonate grain is shown in Figure 8. The EDXRA spectrum is shown in Figure 9 for this crystal. The presence of iron and magnesium in addition to calcium is indicated. Fine grained submicrometer crystals containing only silicon were detected (Figures 10 and 11).

Sample 5210

Figure 12 shows the relative sparsity of clays filling pores. Kaolinite and quartz are shown partially filling a pore (Figure 13). A potassium feldspar grain (Figure 14) shows indications of dissolution.

Sample 5220

This sample is very rich in clays (Figure 15). A potassium feldspar grain (as determined by EDXRA, Figure 16) is shown in Figure 17. The incipient growth of new crystals nucleating on the feldspar is shown in Figure 18. The voids probably indicate dissolution. Kaolinite and carbonate are shown in Figure 19. Illite (by EDXRA) is shown in Figures 20 and 21.

Additional micrographs and all negatives are enclosed. Thank you for consulting McCrone Associates. If you have any questions concerning these results please contact us.

Sincerely,

Mark E. Andersen
Geochemist

MEA:gb
Ref: 9447
Encl.

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Figure 1

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Figure 2

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Figure 3

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Figure 4

Figure 5

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Figure 6

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Figure 7

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Figure 8

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Figure 9

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Figure 10

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Figure 11

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Figure 12

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Figure 13

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Figure 14

Figure 15

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Figure 16

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Figure 17

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Figure 18

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Figure 19

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Figure 20

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Figure 21

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