Appendix iii.

ROCK TYPE

- SANDY CONGLOMERATE
- CONGLOMERATIC SANDSTONE
- SANDSTONE
- CALCAREOUS SANDSTONE
- MUDDY SANDSTONE
- VERY MUDDY SANDSTONE
- SILTSTONE
- CALCAREOUS SILTSTONE
- MUDSTONE
- SILTY CLAYSTONE
- CLAYSTONE
- SANDY CLAYSTONE
- INTERLAMINATED SANDSTONE & MUDROCK
- SANDY LIMESTONE
- MUDDY LIMESTONE
- LOST CORE

STRATIFICATION

- HORIZONTAL LAMINATION
- TROUGH CROSS BEDDING
- TABULAR CROSS BEDDING
- INDISTINCT BEDDING
- LENTICULAR BEDDING
- RIPPLE LAMINATION
- CONTORTED BEDDING

HCS = HUMMOCKY X-STRATIFICATION

MISC. FEATURES

- BURROWS
- CARBONACEOUS DEBRIS
- SHELL FRAGMENTS
- SIDERITE NODULES
- CONCRETIONS
- PYRITE
- FRACTURES (SUBVERTICAL)
- ROOT TRACES

COLOR

- WHITE TO V. LIGHT GRAY
- LIGHT GRAY TO TAN
- MED. GRAY TO BROWN
- DARK GRAY TO DARK BROWN
- V. DARK GRAY - BLACK

TRACE FOSSILS

AST = ASTEROSOMA
CHN = CHONDRITES
OPH = OPHIOMORPHA
PLN = PLANOLITES
TEI = TEICHICHNUS
THL = THALASSINOIDES
SK = SKOLITHOS
TRI = TRICHICHNUS

Appendix iv.

SPE

Society of Petroleum Engineers of AIME

SPE 7551

A LABORATORY STUDY OF LOW PERMEABILITY GAS SANDS

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ABSTRACT

Multiple tests on more than 100 tight gas sand core samples from five formations indicate that in situ gas permeability is ten to more than a thousand times less than indicated by routine tests owing to the combined effects of overburden pressure, reduced gas slippage, and presence of connate water. The separate influence of each is discussed. Correlations, in equation form, are presented which, utilizing routine core data, may be used for estimating gas permeability under reservoir conditions. The results also indicate that invasion of aqueous drilling or fracturing fluid filtrate has little permanent influence on rock permeability but clean-up times may be extensive because of the low level of formation permeability. The salinity of the invading fluid appears to be of secondary importance.

INTRODUCTION

Yearly compilations of U.S. oil and gas reserves by the American Gas Association[1] show that U.S. gas reserves reached a maximum in 1967 of nearly 290 trillion cubic feet ($8x10^{12}$ m^3). With the exception of the year 1970 when Prudhoe Bay reserves were added, gas reserves have declined at a near constant rate of 10 trillion cubic feet ($2.8x10^{11}$ m^3) per year since then. To help moderate or reverse this trend, the industry is extending its exploration and development efforts to include horizons with permeabilities in about the same range as common cement; i.e., microdarcies. The design of stimulation treatments to achieve commercial rates of production and reliable assessment of potential reserves in such low permeability rocks demands accurate knowledge of their permeability, porosity, and flow properties. Though meager, there is sufficient information already available in the literature to suggest that some of the flow properties of these rocks differ markedly from those of more permeable rocks and thus require closer study.

Results of several different studies of the properties of low permeability gas producing horizons have previously been published. Studies by Thomas and Ward[2] showed that the permeability of cores from the Pictured Cliffs and Fort Union formations were significantly affected by confining pressure. Porosities, however, were not greatly altered. They also reported that the presence of a simulated connate water saturation (about 50%) reduced gas permeabilities to only 10% to 20% of the specific gas permeability. Vairogs et al[3] concluded that very low permeability rocks are affected by stress to a greater degree than those having higher levels of permeability. This agreed with results reported earlier by McLatchie[4].

Tannich[5] mathematically studied liquid removal from fractured gas wells in low permeability horizons and concluded that in very low permeability rocks, clean-up times could be extensive, but that permanent formation damage was not likely. This study, however, provided no measured experimental data of the flow properties of low permeability rocks.

Early wells drilled and cored by Amoco in the Wattenberg Field of Colorado in the Union Pacific Railroad Lease Area indicated the need for further laboratory studies of tight gas sands. Large differences in formation permeabilities, as derived from core analyses and from pressure buildup analysis, were not entirely explainable from data available in the literature. In addition, developments in stimulation design showed the need for reliable reservoir permeability values to prevent overdesign (and cost) of massive hydraulic fracturing treatments. In addition, concern existed over the proper choice of drilling and stimulation fluids to minimize formation damage. The study reported herein is part of an ongoing study by Amoco to provide answers to these and other problems that arise in the development of tight gas sand reserves.

Reported herein are the results of selected laboratory tests that were designed (1) to study the factors that cause routine core analysis permeability values to be different than exist in the reservoir, (2) to study the range of the influence of these factors in low permeability producing horizons in areas of interest to Amoco, (3) to develop, if possible, correlations for predicting reservoir values of permeability from core analysis results, and (4) to evaluate the effects of invasion of fluids of different salinities on the rate of regainment of permeability to gas.

References and Illustrations at end of paper.

APPARATUS AND EXPERIMENTAL PROCEDURE

Plug samples 3/4-inch in diameter by 1-inch (1.9 cm D x 2.5 cm L) long drilled parallel to formation bedding planes were tested in Hassler sleeve holders capable of exerting up to 10,000 psi (70 MPa) confining pressure uniformly in all directions (so-called "hydrostatic" test conditions). Permeability to either gas or water could be measured at injection pressures up to 1000 psi (7 MPa) and were measured at flow rates sufficiently low to avoid turbulence. Vacuum de-aerated liquids, passing through line filters, were supplied to the cores at constant pressure by nitrogen-driven transfer cylinders designed to prevent diffusion of nitrogen into the driven liquid. Flowing pressures were measured with Bourdon gauges for gas, and variable reluctance diaphragm transducers and indicators for liquid. Confining pressures were exerted by oil and were adjusted to compensate for average pore pressure to obtain a given net confining pressure.

Flow rates of liquids were measured by timing their travel in pipets. Flow rates lower than 10^{-6} cm^3/sec could be measured to allow measuring permeabilities down to 10^{-6} md. Low gas flow rates were measured by timing the passage of the meniscus when displacing oil from a horizontal pipet whose tip was bent downward to discharge under oil. This arrangement, with its constant, slightly negative oil head, insured instant displacement of oil by the gas and avoided complications from the action of interfacial forces either at the meniscus or pipet tip. It is important that the meniscus travel horizontally; if the oil head changes during flow measurement, gas between the core and meniscus will change volume sufficiently to introduce significant error when using small bore pipets. Ten cm^3 pipets however can be operated vertically with less than 1% error if volume between the core and pipet is less than 5 cm^3. Samples were liquid saturated by evacuating them in pressure chambers for 4 hours at pressures less than 1 mm Hg (130 Pa) after which deareated liquid was admitted and then pressured at 1000 psi (7 MPa) for 16 hours to dissolve remaining traces of gas. Pore volume compressibilities were determined using the Hassler cells and measuring the liquid displaced into calibrated pipets (0.001 cm^3 subdivisions) with time allowed to obtain equilibrium at each step.

Effects of confining pressure on permeability were ordinarily measured in gas flow tests using dry cores. Permeabilities were measured at increasing confining pressure levels up usually to the reservoir net overburden pressure. (Net overburden pressure is taken to be the difference between gross overburden pressure, assumed to increase at 1.0 psi/ft (22.6 kPa/M), and reservoir fluid pressure.) Klinkenberg (no gas slippage) permeabilities were determined at the highest confining pressures by the conventional method of measuring permeabilities at more than one average flowing pressure; preliminary investigations indicate that measurements at two injection pressures provided sufficient data. Gas drive tests were performed using cores which had been saturated with formation water and whose permeability to water had been determined. For reasons discussed in a later section, nitrogen was injected, usually at 1000 psi (7 MPa) (sometimes lower, if needed, to avoid turbulence) until 3500 cm^3 (at ambient pressure) had emitted downstream. Permeability was monitored throughout the test. Hold-up volumes were too great to permit measuring the rate of water production so that saturation data for determining relative permeabilities could not be collected except for end points.

RESULTS

Effect of Confining Pressure on Permeability

The large effect of confining pressure on the permeability of tight gas sands documented earlier[2,3,4] were also found in this study. Hydrostatically applied confining pressures equaling reservoir net overburden pressure (5000 to 6000 psi) reduced permeability nearly 10-fold below the routine values measured under surface conditions in which confining pressure is 150 to 250 psi. Reductions ranged from less than 3-fold to more than 20-fold. Typical results are displayed in Figure 1. The reason that confining pressure has greater effects on tighter sands than on more permeable ones is not well established. A popular conjecture holds that rock compression is distributed as greater fractional changes of the smaller apertures of the tight sands, the effect of which is further increased by the fact that flow depends upon a higher power of the aperture dimension (round capillaries vary as the fourth power and slits by the cube of the dimension).

The experimental data were plotted in a number of ways in search of linear relationships to facilitate data handling, correlation, and ultimately, to simplify testing. For representing behavior between 1000 psi and reservoir net overburden conditions, a plot of the cube root of permeability versus the logarithm of confining pressure was found well suited. Figure 2 shows plots of the cube root of permeability against the logarithm of confining pressure using the data presented in Figure 1 to illustrate the linear character of the above relation. Permeability values are normalized on the basis of permeability measured at 1000 psi net confining pressure to allow direct comparison of the influence of confining pressure independent of permeability level; the slopes of the lines are measures of this influence. A convenient form of the equation for the relation is:

$$k = k_{1000} \left(1 - S \log \frac{P_k}{1000}\right)^3 \quad \ldots\ldots\ldots \quad (1)$$

where S, the magnitude of the negative slope, is given by

$$S = \frac{1 - \left(\frac{k}{k_{1000}}\right)^{1/3}}{\log \frac{P_k}{1000}} \quad \ldots\ldots\ldots\ldots \quad (2)$$

Use of the straight line relation simplifies both testing and handling of data. Permeabilities need be measured at only two confining pressures to fix the slope parameter of the equation well enough for most engineering purposes. Measurements usually are made at 1000 psi (6.90 MPa) and at the reservoir net overburden pressure. The "S" factor, the absolute value of the slope, embodies the effect of confining pressure in a single number convenient for conceptual and correlation purposes. Increasing values of "S" imply increasing effects of confining pressure. Moderate effects of stress, such as seen in testing higher permeability rocks, produce S factors in the vicinity of 0.1 to 0.2. Significant effects, as obtained in most tight gas sand tests, yielded "S" factors in the range of 0.3 to 0.6 with factors over 0.7 indicating large reductions. A rock decreased 10-fold in permeability below routine permeability by reservoir overburden pressure would have an "S" factor of approximately 0.4.

Generally, the lower the core permeability the more it is affected by confining pressure. This is illustrated in Figure 3-a, a plot of "S" factors of Frontier formation samples against the logarithms of permeabilities measured at 1000 psi (6.895 MPa) net confining pressure. Note also that the data, although scattered, have a linear trend. A best fit straight line through the data afford a compact description of the average effect of confining pressure on permeability of cores from this formation. Figure 3-b shows a similar type of plot of Mesaverde Formation and Cotton Valley formation data in which the data group below that of the Frontier Formation data to indicate lesser effects of confining pressure.

No correlation between permeability and reduction due to confining stress was found which extended down to the 150 to 250 psi net confining pressure condition commonly used in routine core testing; such correlations evidently must be made on an individual formation basis. Permeability measured at 1000 psi net confining pressure usually is between 0.4 to 0.75 times the routine permeability.

Above 2000 psi (14 MPa) net confining pressure the logarithm of permeability versus the logarithm of confining pressure produce fairly linear plots which possibly may be the best correlative relation for use in predicting effects by confining pressure on permeability as reservoirs are depleted.

Gas Slippage

Gas slippage, or Klinkenberg[6] effects, are large in tight gas sands. As an example, a sample with 0.001 md true, or "Klinkenberg", permeability typically would exhibit about 0.003 md with gas injected at 100 (0.6895 MPa) psig and exiting at atmospheric pressure, and more than 0.007 md if upstream pressure were 15 psig (103 kPa). Effective pore radii of sands with less than 0.1 md are indicated by mercury injection data and by gas slippage theory to range downward from 1 μm into the size realm of the mean free paths of the gas molecules. Because of this, there was concern that the conventional extrapolative procedure (in which permeability plotted versus reciprocal arithmetic mean pressure is extrapolated to zero reciprocal pressure) for determining Klinkenberg permeability might not yield a straight line for the very low permeability, tight gas sands. The reason for this concern was that Warburg's model[7], on whose theory Klinkenberg based his development, assumed mean free path length was small compared to capillary radius. Klinkenberg ascribed depressions in "b" factors (the slope of the line connecting a data point to the Klinkenberg permeability in the above plot) determined at reduced pressure to this departure from Warburg's model. In the present study, however, very good straight line Klinkenberg plots were obtained for rocks with Klinkenberg permeabilities even less than 0.0001 md. An example is given in Figure 4, showing the results of a test on an 0.000088 md sample in which upstream pressures ranged from 50 to 1000 psig (0.34 to 6.9 MPa). Both dry Klinkenberg permeabilities and specific permeabilities to a 1.3 cp (MPa·s) refined oil (Soltrol 130) were measured in tests on a series of cores in the 0.001 to 0.01 md range; the results are given in Table 1. Oil permeabilities were equal to or lower than Klinkenberg permeability in every case, averaging 25% less. The agreement is sufficiently close, however, to assume that Klinkenberg permeabilities obtained by the extrapolation procedure are satisfactory for practical application. It is not known which, if either, of the permeabilities is "correct". Oil permeabilities might be low because of interactions between the oil and rock, or Klinkenberg values may trend higher because of departure from the Warburg model.

For this study, Klinkenberg permeabilities and "b" factors were calculated from permeabilities measured usually at 100 psig (0.7 MPa) and 1000 psig (7 MPa) upstream pressure and atmospheric pressure downstream. Lower pressures were used when necessary during tests of the more permeable samples to avoid turbulence. The measurements were made at net confining pressures equalling reservoir net overburden pressures. Confining pressure was increased sufficiently to offset average increase in pore pressure to keep confining pressure essentially constant during determination of the Klinkenberg permeability. Klinkenberg's "b" factor was calculated from the data using the Klinkenberg equation

$$k_a = k_\infty \left(1 + \frac{b}{\bar{p}}\right) \quad . \; . \; . \; . \; . \; . \; . \; . \; . \; . \; . \; . \; . \; . \quad (3)$$

As indicated by the equation, the "b" factor is an index of the magnitude of the gas slippage effect. It is often regarded as the fractional increase in apparent permeability which would be observed when measuring permeability with gas at atmospheric pressure.

The results of measurements made on more than 100 tight gas sand samples are given in Figure 5 as a plot of the logarithm of "b" factor against the logarithm of Klinkenberg permeability, a method used by Heid et al[8] for presenting results of the 1950 study by Penn State for the API. The tight gas sand data are scattered closely about a straight line not greatly different from an extrapolation of the best fit straight line through the higher permeability 1950 Penn State data, the equation for which is

$$b = 0.777\, k_\infty^{-0.39} \quad . \; . \; . \; . \; . \; . \; . \; . \; . \; . \; . \; . \; . \; . \quad (4)$$

The best line through the tight gas sand data given in this study is:

$$b = 0.86\, k_\infty^{-0.33} \quad . \; . \; . \; . \; . \; . \; . \; . \; . \; . \; . \; . \; . \; . \quad (5)$$

As discussed in the 1950 Penn State study, for ideal cases consisting of a parallel capillary bundle, "b" should vary inversely as the square root of permeability, which would yield a slope of -0.5 cycles/cycle. The -0.39 slope was regarded as nearly corresponding to this idealized view. The -0.33 slope obtained in this tight gas sand study is reminiscent of the cube root relation arising from Lamb's[9,10] expression for flow through ducts and suggests that apertures controlling flow in the tight sands may be slit-like rather than round.

The tight gas sand correlation, Equation 5, yields values of "b" factor sufficiently accurate for many practical purposes. The correlative power function may be substituted for "b" in Klinkenberg's equation as follows:

$$k_a = k_\infty \left(1 + \frac{0.86\, k_\infty^{-0.33}}{\bar{p}}\right). \; . \; . \; . \; . \; . \; . \; . \; . \; . \quad (6)$$

This expression can be used as a starting point for generating graphs or numerical solutions for calculating Klinkenberg permeabilities and "b" factors from ordinary permeability data, provided the pressures used in the measurements are known. An expression originating from the above equation from which k_∞ may be estimated from permeabilities (k_a) measured at 100 psig (0.7 MPa) upstream pressure is

$$k_{\infty} = 10^{(-.0398 \log^2 k_a + 1.067 \log k_a - 0.0825)} \quad \ldots (7)$$
$$0.0001 \text{ md} < k_a < 1 \text{ md}$$

which agrees with equation (6) within a few percent over the k_a range of 0.0001 md to 1 md.

Pore Volume Compressibility

The chief reason for measuring pore volume compressibility was to determine if porosity values measured in routine tests were significantly greater than under reservoir conditions. It was found that the behavior of tight gas sands was similar to higher permeability, consolidated rocks and that the porosity measured at the surface was not appreciably greater than at depth. Pore volume diminished usually between 5 and 10 percent; a rock exhibiting 10 percent porosity under surface conditions would, in the reservoir, have 9.0 to 9.5 percent porosity. For many purposes, the effect of overburden pressure on porosity can be ignored. Multiplying porosity by a factor of 0.95 will correct most data sufficiently close to reservoir condition porosity for all but the most exacting purposes. Pore volume compressibility averages about 6×10^{-6} vol/vol/psi (vol/vol/6895 Pa).

Results of a typical test are shown in Figure 6. The percent decrease in pore volume is given as a function of increasing confining pressure. The pore volume compressibility at reservoir stress level is calculated from the slope of the curve at the reservoir net overburden pressure, taking also into account the pore volume decrease up to that point. Table 2 presents the data from a number of such tests, showing both pore volume compressibility and total effect on pore volume.

Effect of Water on Core Permeability

Water greatly reduces permeability of tight gas sands and in a manner different from its effect on higher permeability sands. Brine causes almost as great a reduction in permeability as fresh water. For example, a 60,000 ppm NaCl solution will reduce permeability typically 85% below Klinkenberg permeability of the dry core; introduction of distilled water will cause further reduction, but only in the order of another 10% for a total reduction of about 95%. Examples of such test results are given in Table 3. A more permeable water-sensitive sand, such as Berea, would lose about 50% permeability upon introducing the above brine but would lose more than 49% additional permeability upon exposure to distilled water for a total reduction of more than 99%. Fresh water has a lesser proportionate effect on tight gas sands possibly because otherwise dispersible clays or mineral fines may tend to be mechanically locked or wedged in place in the smaller pores of the fine-textured rocks and are thereby inhibited from moving to form obstructions. The reason that even highly saline solutions can severely reduce permeability is, however, not easily explained. There are several existing theories which alone or in combination may offer explanation. The most popular theory, although subject to much controversy concerning the magnitude of the effects, holds that water adjacent to high energy surfaces becomes ordered to result in viscosity increase or even solidification sufficient to significantly reduce effective pore diameter. Calculations based upon Poiseuille's and Lamb's laws applied to pore radii calculated from Klinkenberg "b" factors[6,8] indicate that fixed layers of water would need to be in the order of 0.01 μM (100 Å) or more to account for the minimum reduction observed in 0.001 to 0.1 md samples of this study.

Smectites exfoliate and most clays and many other mineral fines associate with water in going from the dry to the moistened state (even in brine) to increase the volumes of aggregates. Apertures could be reduc by this mechanism sufficient to impede flow.

The specific permeabilities to formation water of more than 100 tight gas sand samples were measured. Klinkenberg permeabilities were measured with the samples dry prior to the water flow tests. All tests were made at net confining pressure equaling reservoir net overburden pressures. The results are given in Figure 7 as a plot of the logarithm of water permeability versus the logarithm of Klinkenberg permeability. Two features are evident: The trend is linear and, the lower the permeability the more water reduces permeability. A line centered in this data is the power function.

$$k_w = k_{\infty}^{1.32} \quad \ldots\ldots\ldots\ldots\ldots (8)$$
$$k < 1 \text{ md}$$

This correlative function may be used to calculate the average effect of water on permeability. Plots such as these of data from single formations or rock types may be less scattered meaning that in particular cases, laboratory data from samples selected from a range of permeabilities can be used to determine the exponent applicable for use in the water-effect power equation for that formation. Examination of Figure 7 shows that the boundary of minimum effect appears well defined, a line along this boundary has a slope of about 1.13 cycles/cycle. A line bounding most of the data below 0.1 md dry Klinkenberg permeability on the side of maximum effect has a slope of about 1.5 cycles/cycle. This function can be used in conjunction with the correlations describing effects of stress and slippa-- to obtain estimates of in situ gas permeability fro routine permeability values. This is discussed in a later section.

Clay content was not found to correlate with effect of water on permeability. Large clay content usually forecasts large effects of water but low clay content does not forecast low effects. Cores with large amounts of clay were probably affected most because of the low permeability resulting from the presence of clay rather than by effects of the clay per se.

The fact that water of even high salinity can seriously affect tight gas sand permeability but, that in contrast, fresh water has relatively less additional effect has obvious practical significance. Limiting entry of water during drilling or stimulation should help preserve reservoir permeability and hasten clean-up time. Filtrate invasion from muds can be reduced by maintaining mud weights close to balance, or even underbalanced, with respect to reservoir pressure. Minimizing post-fracture shut-in times might also reduce fracturing fluid invasion and prove beneficial. Another point implied since fresh water is not a great deal more harmful than brines, is that less concern is needed regarding the chemical composition of fracturing fluids or mud filtrates.

Effect of Partial Water Saturation on Gas Permeability

Those tight gas sands whose specific water permeabilities are a great deal less than the Klinkenberg permeabilities of the dry samples also have correspondingly low gas permeabilities in the presence o: simulated connate water saturations. As a first approximation, effective gas permeability under reservoir conditions can be taken as equal to specific permeability to water measured under reservoir stress conditions. Experiments demonstrating this observation are discussed below.

Relative permeability apparatus suitable for testing tight gas sands was not available at the initiation of the study. Exploratory gas drive experiments showed, however, that gas injected usually at 1000 psi (6.9 MPa) into the plug samples (2.5 cm L x 1.9 cm D) for a time sufficient to produce 3500 cm^3 downstream at atmospheric pressure reduced water saturations to an average of 40% pore space. Under these conditions most of the water is removed by displacement not more than 10% pore space of the water was evaporated. No attempt was made to measure or account for saturation gradients which may have existed. An example of the development of permeability with time in a gas drive test of this type is shown in Figure 8. Results of 22 gas drive tests are given in Table 4 in which are compared Klinkenberg permeabilities of the dry cores, specific permeability to water, and effective gas permeability at the indicated water saturations. There is a degree of bias in that testing of higher permeability samples was favored because of the inordinate lengths of time required for tests of samples with less than 0.001 md permeability. Examination of the data shows that effective gas permeability in every case is nearer the specific water permeability, most often by a large margin, than to the Klinkenberg permeability of the dry samples. In more than three-quarters of the cases, effective gas permeability is within a factor of two of the specific permeability to formation water. Effective gas permeability averaged about 35% higher than specific water permeability. This suggests, as mentioned earlier, that the more easily obtained water permeability values could be used for estimating formation gas permeability. Gas drive tests are lengthy and must be closely attended while, on the other hand, several specific water permeability tests may be conducted simultaneously by one person, usually faster than a sample per cell per day.

The Combined Effects of Confining Pressure, Gas Slippage, and Water on Permeability

The individual effects of stress, gas slippage, and water on tight gas sand permeability have been described in the preceding sections. Also, the measurement of specific formation water permeability under reservoir stress conditions was suggested as a core test for estimating effective gas permeabilities under reservoir conditions. This section deals with methods of estimating reservoir-condition gas permeability using routine core analysis data.

Routine permeabilities are inexpensive and consequently plentiful, but because they are measured on dry cores at low stress levels, and at low flowing gas pressures, they poorly represent in situ tight gas permeabilities. Routine values range from ten to more than a thousand times too high. Also, because of variability in response, routine values cannot be depended upon for comparison purposes. Frontier sand samples, compared to Mesaverde sand samples for example, commonly exhibit higher routine values but lower effective gas permeabilities under reservoir conditions of stress, presence of water saturation, and elimination of slippage. Methods for correcting routine permeability values to reservoir-condition permeability must therefore not only compensate for the large changes but also for the wide range of rock variability.

Two methods for estimating reservoir-condition gas permeability are suggested. The first involves correcting sequentially for stress, slippage, and finally for the presence of connate water and is the more flexible of the two because adjustments can be made for the individual effects. The second method is derived from the first in which all effects are compounded into a single "stadium" equation (providing "ballpark" values) with two parameters which are varied simultaneously over the range from minimum to very large effects of stress, water, and slippage. Neither method, at least at present, appears capable of high precision but do provide more reasonable values for reservoir gas permeability than the routine permeability values.

The first method requires five steps: correction of routine permeability to that at 1000 psi confining pressure; calculation of "S" factor (influence of pressure), calculation of effect of overburden pressure using the "S" factor, correction for gas slippage; and last, calculation of the effect of water. Core tests over a range of permeability values for each rock type can be used to evaluate necessary parameters which may then be applied to existing routine results. For scoping studies, values of the necessary parameters may be assumed; only three estimates are necessary; the correction of routine permeability to 1000 psi confining pressure (a factor usually of 0.4 to 0.75), selection of an S factor equation between defined upper and lower limits, $S = (0.1 \text{ to } 0.3) - (0.1 \text{ to } 0.23) \log k_{1000}$, and selection of a water-effect exponent for Equation 8 which also lies within the reasonably well defined limits of 1.13 to 1.5; k_w is then assumed equal to k_g.

The above method was used to generate a series of curves ranging from minimum effect of stress and water to maximum, assuming that rocks most affected by stress were also most affected by water. These calculations all generated gently curving, almost linear curves in plots of the logarithms of routine permeablity against the logarithms of the calculated reservoir-condition gas permeability. Straight lines were fitted by eye to these curves which lay within a few percent of the calculated value over the range of 0.02 to 0.55 md routine permeability. The intercepts and the slopes of these lines are the coefficients and exponents used in the stadium equation:

$$k_g = a\,k^b \qquad (9)$$

$$0.02 \text{ md} < k < 0.55 \text{ md}$$

in which k_g is effective gas permeability under reservoir conditions and k is routine permeability. The coefficient "a" varies from 1/5 to 1/20 and the exponent "b" varies from 1.5 to 2.7 as the effect of stress and water increases.

Severity of Effects of Stress and Water	"a"	"b"
Minimum	1/5	1.5
Moderate	1/7.5	1.9
Great	1/12	2.3
Very Great	1/20	2.7

Examples of formations having lower effect of stress and water are clean Mesaverde and Cotton Valley sands. Those moderately affected are shaly Cotton Valley Sand samples and cleaner Frontier sands. Most Frontier samples studied exhibited large effects and some experienced very large effects. Lesser effect tends to accompany increased induration, while increased clay content appears associated with larger effects. Parameters of "a" equaling 7.5 and "b" equaling 1.9 are reasonable values for use as first approximations in the absence of other information.

CONCLUSIONS

Results of compressibility and flow tests on more than 100 tight gas sand core samples from five formations indicate:

1. Confining pressure simulating net reservoir overburden pressure reduces permeability of tight gas sands two to more than 10 times, depending on permeability and rock type. The cube root of permeability was found to be a linear function of the logarithm of confining pressure; the slope of the line being indicative of the intensity of the effect of stress was found correlatable with permeability with correlations varying with rock type. Lower permeability rocks were more affected by stress than higher ones.

2. Gas slippage (Klinkenberg) effects were found to be substantial, as would be anticipated for lower permeability rocks. Slippage effects were found correlatable with an expression not greatly different from an earlier expression derived from more permeable rocks.

3. Water (including brine) severely reduced permeability with the effect more pronounced in the lower permeability rocks. This indicates that preservation of permeability in an invaded zone in a reservoir would be assisted by minimizing invasion of water during drilling and fracturing. Water permeability was found correlatable with Klinkenberg permeability.

4. Specific water permeability measured at the reservoir level of confining pressure was found useful as an approximation of effective gas permeability under conditions of reservoir stress, gas slippage, and partial water saturation.

5. Despite large permeability reductions caused by brine, reducing salinity has comparatively less additional effect to suggest that the chemical composition of mud filtrates or fracture fluids is ordinarily of secondary importance in preventing permeability impairment.

6. Pore volume compressibility of tight gas sands is of the same order as more permeable sands. Pore volume under reservoir overburden conditions was indicated to average 93% of that under no stress for the samples tested.

7. Effects of stress, gas slippage, and water were found correlatable with permeability but not directly with clay content. Lower permeability rocks experienced large effects with both low and high clay contents. Large effects observed with clay-laden rocks are attributed to the low permeabilities accompanying the high clay content, not to the fact that the fine material was clay.

8. Correlations were found to enable estimating in situ effective gas permeability from routine core analysis data by taking into account the separate effects of stress, gas slippage, and partial water saturations.

NOMENCLATURE

- b = Klinkenberg "b" factor, atmospheres
- k = permeability, md
- k_a = apparent gas permeability, md
- k_g = effective permeability to gas, partial water saturation present, md
- k_o = specific permeability to oil, md
- k_w = specific permeability to water, md
- k_∞ = Klinkenberg (no gas slippage) permeability, md
- k_{1000} = permeability measured of dry core at 1000 psi (6.895 MPa) net confining pressure, md
- $\bar{P}$ = arithmetic mean of gas pressure in core during flow of gas, atm.
- P_k = confining pressure, psi

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TABLE 1

COMPARISON OF KLINKENBERG AND OIL PERMEABILITIES

Formation	Net Confining Pressure, psi	k_{∞}, md	k_o, md
Mesaverde	5100	0.0092	0.0092
Mesaverde	5200	0.0040	0.0032
Frontier	5400	0.0018	0.0013
Frontier	5500	0.0018	0.0010
Frontier	5500	0.0039	0.0037
Frontier	5500	0.0026	0.0023
Frontier	5700	0.0066	0.0050

TABLE 2

PORE VOLUME COMPRESSIBILITY

Formation	Porosity, %	Net Confining Pressure, psi	Perm. to H_2O, md	Pore Volume Decrease, %	Pore Volume Compressibility Vol/Vol/psi X 10^6
Mesaverde	12.8	5200	--	5.7	5.4
Mesaverde	12.1	5200	0.00057	5.8	5.0
Mesaverde	10.6	5200	0.0025	6.6	6.0
Mesaverde	13.6	5200	--	3.8	5.1
Mesaverde	13.4	5200	0.0015	5.6	4.3
Frontier	13.2	5400	0.0073	7.8	5.7
Frontier	14.3	5700	0.00029	9.5	5.7
Frontier	11.6	5700	0.012	10.4	3.5
Frontier	7.0	5500	0.00091	4.3	2.7
Frontier	10.0	5500	--	8.5	6.1
Frontier	11.1	5500	--	10.4	9.0
Frontier	10.8	5500	0.000069	9.8	9.1
Frontier	12.1	5500	0.00041	4.6	3.2
Frontier	13.6	5500	--	9.6	7.7
Frontier	13.8	5500	--	7.1	5.9
Frontier	13.5	6700	--	8.1	3.3
Frontier	14.0	5700	0.00052	7.0	5.5
Muddy "J"	10.8	4000	0.0012	8.3	9.2
Spirit River	10.2	4000	0.0099	8.1	15.7

TABLE 3

EFFECT OF FRESH WATER ON PERMEABILITY

Formation	Net Confining Pressure, psi	k_∞[1], md	k_w[2], md	k_{H_2O}[3], md
Lewis	2000	0.0077	0.00094	0.00027
Lewis	2000	0.0070	0.00094	0.00034
Mesaverde	5300	0.0031	0.00032	0.00010
Mesaverde	5300	0.0063	0.0021	0.00080
Mesaverde	5300	0.014	0.0040	0.00064
Mesaverde	6000	0.0039	0.00055	0.00036
Mesaverde	6000	0.091	0.076	0.041
Mesaverde	6000	0.0040	0.0011	0.00037
Frontier	2000	--	0.0026	0.0009
Frontier	2000	0.092	0.016	0.0047
Frontier	2000	0.089	0.033	0.0090
Frontier	2000	0.0090	0.00029	0.00013
Frontier	6700	0.010	0.00084	0.00051
Frontier	5700	0.0065	0.0010	0.00026
Spirit River	4000	0.033	0.011	0.0037
Spirit River	4000	0.0068	0.0010	0.00091
Spirit River	4000	0.0011	0.000031	0.000022

[1]Klinkenberg permeability of dry core at indicated confining pressure.
[2]Specific permeability to formation water at indicated confining pressure.
[3]Specific permeability to distilled water at indicated confining pressure following flow of 60,000 ppm NaCl solution to sensitize clays.

TABLE 4

COMPARISON OF EFFECTIVE GAS PERMEABILITY TO SPECIFIC WATER PERMEABILITY

Formation	Net Confining Pressure, psi	k_∞, md	k_w, md	k_g, md @	S_w, %
Mesaverde	5100	0.0092	0.0050	0.0028	40
Mesaverde	5200	0.0032	0.00057	0.00079	29
Mesaverde	5200	0.0035	0.00041	0.00010	29
Mesaverde	5200	0.0096	0.0025	0.0033	34
Mesaverde	5200	0.0068	0.0015	0.0020	34
Frontier	5100	0.0067	0.000065	0.000054	44
Frontier	5400	0.0017	0.00010	0.000070	47
Frontier	5400	0.024	0.0073	0.0083	60
Frontier	5700	0.0039	0.00029	0.00071	33
Frontier	5700	0.047	0.012	0.029	60
Frontier	5500	0.0027	0.00091	0.00075	43
Frontier	5500	0.0012	0.000069	0.000073	49
Frontier	5500	0.0043	0.00041	0.0011	33
Frontier	6700	0.016	0.0011	0.0028	40
Frontier	5700	0.010	0.00052	0.0015	52
Muddy "J"	4000	0.0050	0.0012	0.0015	38
Cotton Valley	4900	0.0014	0.00040	0.00026	45
Cotton Valley	4900	0.044	0.022	0.018	32
Spirit River	4000	0.030	0.011	0.010	41
Spirit River	4000	0.023	0.011	0.010	38
Spirit River	4000	0.033	0.0037*	0.0063	40
Spirit River	4000	0.0068	0.00091*	0.0011	39

*Distilled water following 60,000 ppm NaCl

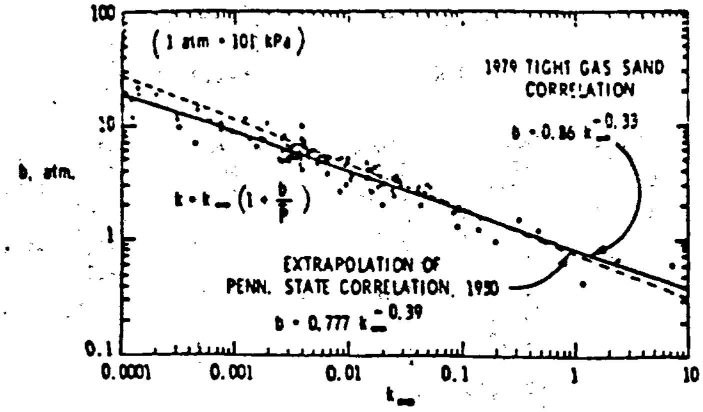

Fig. 5 - Klinkenberg "b" factor as a function of Klinkenberg permeability.

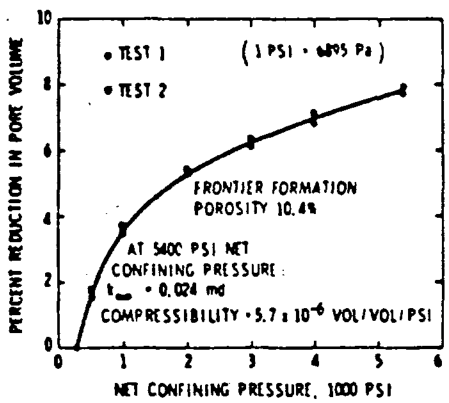

Fig. 6 - Pore volume compressibility of typical tight gas sand sample.

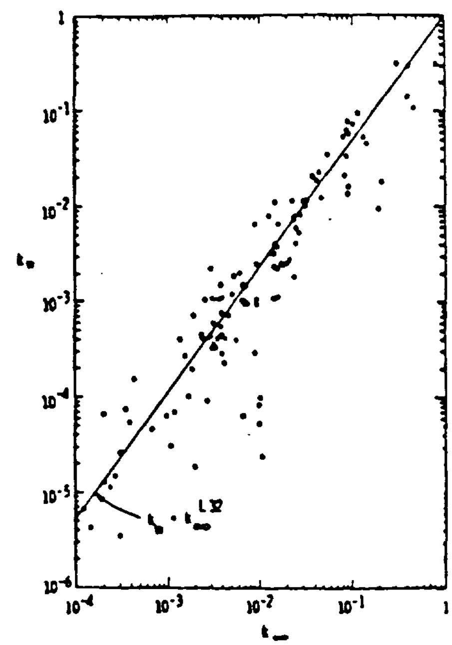

Fig. 7 - Specific water permeability as a function of Klinkenberg permeability.

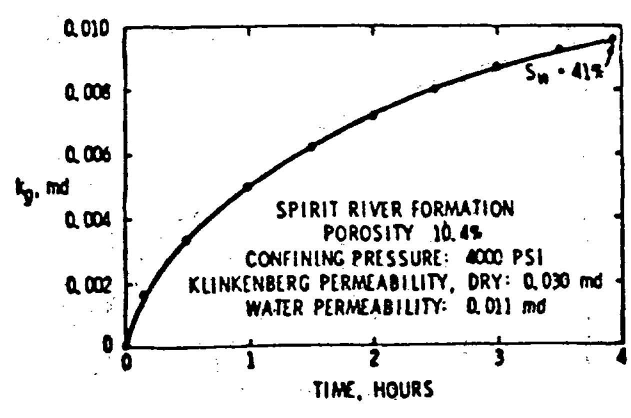

Fig. 8 - Establishment of gas permeability during displacement of water by gas.

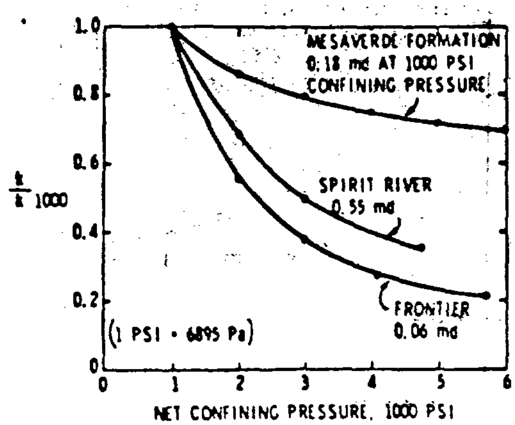

Fig. 1 – Effect of confining pressure on tight gas sand permeability.

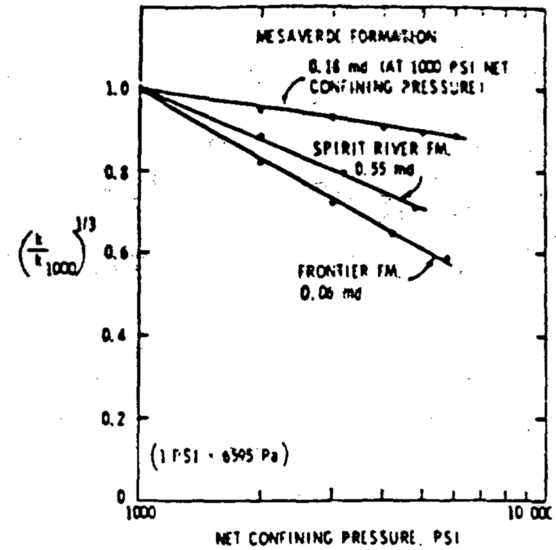

Fig. 2 – The cube root of permeability as a linear function of the logarithm of confining pressure.

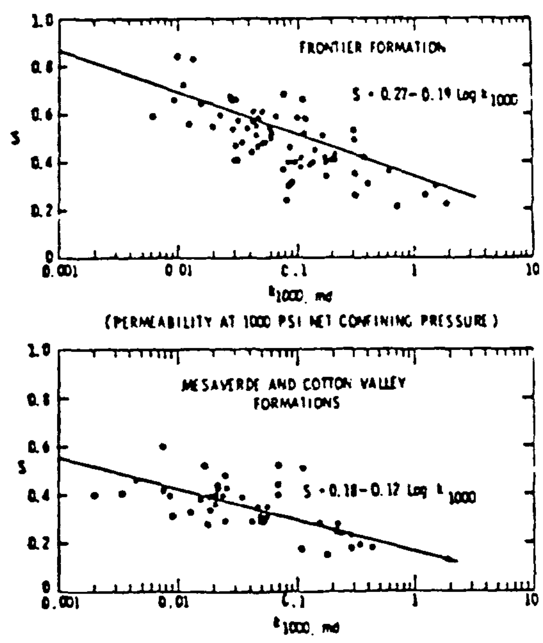

Fig. 3 – Correlation of permeability stress factor, s, with permeability.

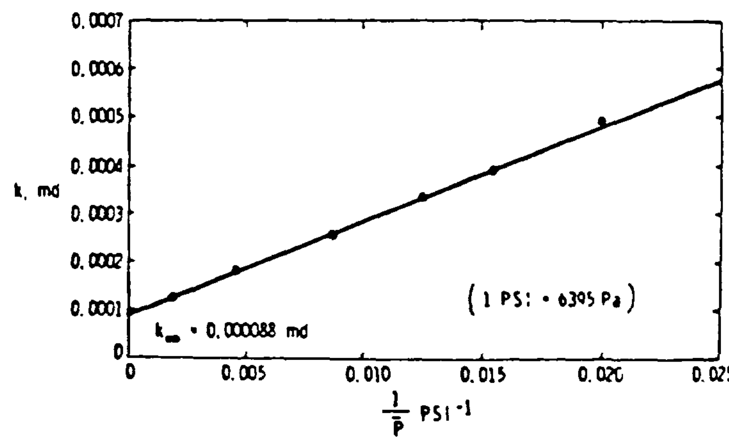

Fig. 4 – Determination of Klinkenberg permeability.