Tight gas sand reservoirs are formally defined by the Federal Energy Regulatory Commission (FERC) as reservoirs with less than 0.1 md permeability. Although this is a permeability-based definition, these reservoirs frequently also have very low porosities (< 10%). Reservoirs that currently classify as “tight gas sands” account for approximately 19% of the total U.S. gas production and may contain upwards of 35% of the U.S. recoverable gas resources. In the U.S. Rockies alone, tight gas-sand reservoirs may contain upwards of 41.7 trillion cubic feet of gas; considerably more gas may exist in tight gas sand reservoirs at depths > 15,000 ft (Oil and Gas Investor, 2005).

Because of the unique and difficult technical challenges often posed by tight gas-sand reservoirs, considerable effort has been made during the past few years on developing new drilling and completion techniques. In addition, advances in logging and core evaluation techniques have improved our ability to understand the petrophysical characteristics of these complex reservoirs. Only recently, however, have new geophysical techniques been deployed in an effort to better image and understand unconventional reservoirs. Somewhat surprisingly, less effort has been made towards developing a more rigorous understanding of the controls on the elasticity of these complex rocks.

In this paper we show well-log and core data from a typical low-porosity sandstone reservoir. Examination of these data shows that velocity-porosity relationships in tight gas sands are complex and cannot be explained without inferring the presence of very low-aspect ratio pores, and/or microcracks in the rock matrix. An important outcome of this work is the following: for the case of porosity less than approximately 8–10%, variations in elastic moduli may be more influenced by pore geometry than porosity. In addition to this, inversion of log data done as part of this study shows that, in some instances, there may be preferential alignment of the microcracks in the rocks, giving rise to velocity anisotropy. It is important to note that this preferential alignment may also give rise to anisotropic permeability (see Rojas, 2005) and resistivity.

Results of this study, and analysis of other tight gas-sand reservoirs, indicate that microcracks provide a primary control on velocities in many, if not most, low-porosity sandstones (φ < 10%). This must be considered when attempting to use sonic velocities or seismic amplitudes to determine reservoir porosity.

**Velocities in tight gas sandstones**

Velocity data from several wells were analyzed in an effort to better understand the rock physics of tight gas sand reservoirs. Although many studies have examined velocity measurements in tight sandstones, little work has been done to quantify the complex relationships between composition, grain arrangement, porosity, and pore microstructure in these rocks. In this paper we focus on the microstructure of the pore space in low-porosity sandstones and its impact on the velocity behavior of these rocks.

All log and core examples shown in this study are from quartz-rich sandstones (V_quartz > 80%, with minor amounts of chert and other accessory minerals). Porosities are computed from bulk density, using a model that has been calibrated to core measurements (Figure 1). Uncertainties in computed porosity certainly exist due to unexpected changes in matrix density and fluid properties. As much as possible, we have attempted to minimize these uncertainties.
Pore aspect ratios, $\alpha$, are defined to be the ratio of the short axis to the long axis of a pore; a perfect sphere would have an aspect ratio ($\alpha$) of 1.

**Observations**

Log data from this study often show anomalously high variations in P-wave velocity (approximately 1 km/s; Figure 1), with a mean P-wave velocity of 4.9 km/s (Figure 1b). Note that the average log-computed porosity for this zone is less than 6%. During a conventional petrophysical analysis, it is often assumed that these velocity variations are due to variations in porosity. However, Figure 2 shows that there is only a poor correlation, at best, between velocity and porosity for this well ($R^2 = 0.37$). The absence of a correlation is also supported by core measurements for the zone of interest (Figure 3). Note that the large range in P-wave velocities from the core measurements (Figure 3) is consistent with the range in velocity observed from the well log (approximately 1 km/s; Figures 1a and 1b). It is important to note that no correlation was found between composition and velocity. If velocity does not vary as a function of composition, other factors must be considered when attempting to understand this velocity behavior.

Figure 4 shows log data from other nearby wells in the study area; all data points shown in this figure are from the clean sandstone that constitutes the zone of interest. When all the wells are evaluated simultaneously, the range in P-wave velocity for the zone of interest increases to approximately 2
km/s. It is also important to note that the velocity-porosity relationship for the combined wells is poorly defined ($R^2 = 0.44$). For this data set, velocities are nearly independent of porosity.

A more detailed analysis of Figure 4 suggests that the data can be divided into two groups, “A” and “B”. Data points in group “A” show a very weak correlation with porosity, and extrapolate to velocity values of nearly 6 km/s at 0% porosity. Data points in group “B” show a similar weak dependence on porosity, but extrapolate to velocity values of approximately 5.2 km/s at 0% porosity.

The wide range in P-wave velocity observed in Figure 4, along with the very poor correlation to porosity, is interpreted to be the result of highly variable pore geometries within the rocks. A small volume of microcracks within the rock matrix may also contribute to the large variation in velocities. The effects of microcracks on velocity will be evaluated further in the modeling section of this paper.

Velocity measurements as a function of stress are often used as an indicator of the presence of microcracks in sedimentary rocks (Figure 5; e.g., Xu et al., 2006). Figure 5 shows velocity versus effective stress measurements for the eight core samples shown in Figure 3; it is important to remember that all of these samples have less than 5% porosity. Note the rapid and large increase in P-wave velocity as effective stress increases. Also note the large range in P-wave velocity at the approximate reservoir net effective stress (approximately 0.6 km/s). The large observed sensitivity of the velocities to effective stress is anomalous for a rock with less than 5% porosity and is best interpreted as being due to the closure of abundant and compliant microcracks in the rock matrix.

Figure 5. Laboratory measurements of P-wave velocity as a function of net effective stress (NES; dry measurements). All samples shown in this figure have less than 5% porosity (Figure 3). Note the large and rapid increase in velocity from low- to high-effective stress. This behavior is most likely due to the closure of compliant microcracks during the increase in net effective stress. Also note the large range in $V_p$ at 4000 psi (~28 MPa; approximate reservoir NES). This range in velocity is consistent with the velocity range observed in the log data (Figure 4) and is most likely the result of highly variable crack concentration in these low-porosity rocks.

Figure 6. Core and thin section observations. (a) Core sample with a cemented crack. Evaluation of core from this study shows that these features are common in the subsurface, and possibly may contribute to the large range in P-wave velocities observed from log measurements. (b) Thin section from the zone of interest. Notice the combination of high aspect-ratio pores and low aspect-ratio pores within this single sample. Also note the presence of diagenetic cements, which partially occlude the porosity in the low aspect-ratio pores. This indicates that the low aspect-ratio pores occur in the subsurface and are not a result of sample damage during the coring or thin section preparation process. It is the combination of the larger-scale fractures observed in hand samples (a) and the microcracks observed in thin sections (b) that give rise to the wide range in velocities in these rocks.
Many studies infer the presence of microcracks in rocks based solely on the velocity behavior during increases in effective stress (Figure 5). In Figure 6, we show core and petrographic evidence for the presence of multiple scales of fractures and cracks in this particular reservoir. Figure 6a is a photograph of a core sample, showing the presence of a small fracture that is subparallel to bedding; this particular sample is cemented together via diagenetic cements along the fracture surface. Fractures/cracks of this scale are common in this particular reservoir, but not all of these fractures are cemented (some are most likely induced during the coring process).

Figure 6b is a thin section photomicrograph that illustrates the presence of both high aspect-ratio pores ($\alpha \approx 1$) and very low aspect-ratio pores (i.e., “cracks”) within the rock matrix. Note that the low aspect-ratio pores (i.e., “cracks”) occur within grains and between grains. Careful inspection of this and other thin sections shows the presence of diagenetic cements in some of the microcracks. The presence of these cements is evidence that some of these microcracks exist in the subsurface, and are not a result of the thin section preparation process or stress release during core retrieval.

**Modeling**

Numerous theoretical models exist in the rock physics literature which allow us to model the effects of pore geometry on the elastic properties of a rock (e.g., Kuster and Toksöz, 1974; O’Connell and Budiansky, 1974; Budiansky and O’Connell, 1976; also see Mavko et al., 1998). Although each model makes different assumptions about how pores are added to the rock matrix, they all show that the addition of small volumes of cracks to the rock matrix can significantly weaken the rock and lower velocities. Although microcracks reduce both P-wave and S-wave velocities, they have a relatively small impact on $V_P/V_S$ ratios in sandstones (Katahara, 1999).

The effect of pore geometry is modeled in this paper using the effective medium model of Kuster and Toksöz (1974). This model is employed for the following reasons: (1) it applies to low concentrations of inclusions (pores), and (2) it assumes a random orientation and isotropic distribution of inclusions. Analysis of log and core data from the well in Figure 1a suggests that these conditions may be met for this particular reservoir.

Kuster-Toksöz allows the velocity data to be modeled using one of two different approaches: (1) a single value for $\alpha$ is employed to model each velocity-porosity pair, or (2) multiple pore geometries are used simultaneously to model the range in velocities exhibited by the log and core data (Figures 1 and 3). In Figure 7a, each data point is uniquely modeled using a single value for $\alpha$. In order to describe all of the data points in this plot, a very large range in aspect ratios ($0.005 < \alpha < 1$) would be required, and each velocity-porosity pair would require a unique value of $\alpha$. Importantly, note that very low values of $\alpha$ are necessary in order to model the data points with the lowest velocities ($V_P <$ approximately 5 km/s).
Figure 8. Velocity modeling for a low-porosity sandstone ($\phi = 8\%$). In order to model $V_p$ and $V_s$, a combination of low and high aspect-ratio pores was required (6% porosity from spheres, and 2% porosity from cracks); a single value of $\alpha$, regardless of the modeling parameters, cannot be used to simultaneously model both $V_p$ and $V_s$. If only spheres are modeled, the P-wave velocity would be approximately 5.8 km/s, which is nearly 1 km/s faster than the measured P-wave velocity. This large difference in velocity is inferred to be largely due to some combination of microcracks and higher aspect-ratio pores in the rock.
Figure 9. Cross-dipole measurements for the zone of interest shown in Figure 8. Note that the upper sand displays variable degrees of anisotropy, whereas the lower sand is isotropic. These measurements are the basis for the models discussed in this paper.

This model has two problems. First, petrographic observations show the presence of both large and small aspect ratio pores in these rocks. Thus, the assumption of a single value of \( \alpha \) to describe each data point is not appropriate. Second, and perhaps more importantly, \( V_p \) and \( V_s \) cannot simultaneously be modeled using a single value of \( \alpha \). In order to better describe these rocks, at least two pore types must be added to the model.

Figure 7b shows a scenario where both spheres and cracks are added to the rocks (\( \alpha = 1 \) and 0.001, respectively). In this figure, the X-axis now represents the abundance of spheres (\( \alpha = 1 \)) and becomes the log-calculated porosity. Variable concentrations of low aspect-ratio pore (\( \alpha = 0.001 \)) are then added to the model in small increments. The maximum crack concentration in this model is 0.5%. By adding small volumes of low aspect-ratio pores (i.e., “cracks”) to the rock, the entire range in P-wave velocity (approximately 2 km/s) can be readily explained. An additional outcome of this model is that the addition of spheres and cracks to the rock matrix results in velocity-porosity trends that are relatively “flat.” For this data set, these models would imply that group “A” wells have relatively low concentrations of cracks, whereas group “B” wells have higher concentrations of cracks. In both instances, however, the volume of crack porosity in the rock matrix is very low (< 0.5%). It is also important to note that a complex mix of pore types also makes it possible to simultaneously model both \( V_p \) and \( V_s \) (Figure 8).

Cracks and anisotropy

Evaluation of cross-dipole sonic data shows that tight gas sands are often anisotropic (Figure 9). Figure 9 and Figure 10 show that the upper sand has upwards of 3–9% shear-wave anisotropy, whereas the lower sand behaves as if it is essentially isotropic.

Figure 11 compares the dry bulk and shear moduli for the clean sand fraction (\( V_{clay} \leq 20\% \)) with those predicted using the Kuster and Toksöz model for a random orientation and isotropic distribution of pores (oblate ellipsoids in this model). Multiple pore aspect ratios are modeled and are indicated on the curves in Figure 11. It is important to note from Figure 11 that the dry bulk and shear moduli lie along curves corresponding to different aspect ratios. This may indicate the
presence of partially oriented cracks, since a vertically propagating compressional wave is most sensitive to the horizontal cracks, while the vertically propagating shear waves have sensitivity to vertical cracks due to their horizontal polarization.

In the following, these measurements (Figure 9) are used to characterize the orientation distribution of the cracks in tight gas sands using the theory of Sayers and Kachanov (1995). Choosing a Cartesian coordinate system, $x_1, x_2, x_3$, the components of the elastic stiffness tensor needed to calculate the elastic wave velocities for a volume $V$ containing $N$ planar cracks can be determined using a second-rank crack tensor $\alpha_j$ defined by:

$$\alpha_j = \frac{1}{V} \sum_{r} B^{(r)} n^{(r)} A^{(r)}$$

where the summation is over the $N$ cracks within volume $V$ (Sayers and Kachanov, 1991, 1995). In this equation, $B^{(r)}$ is the compliance of the $r$th crack in volume $V$, $A^{(r)}$ is the area of the crack, and the $n^{(r)}$ are the direction cosines of the unit normal $n^{(r)}$ to the plane of the $r$th crack in the Cartesian coordinate system $x_1, x_2, x_3$.

Figure 12 shows the values of $\alpha_{11}$, $\alpha_{22}$, and $\alpha_{33}$ obtained from the inversion with $x_3$ taken as vertical for the clean sand fraction ($V_{\text{clay}} \leq 20\%$), while Figure 13 shows the difference between $\alpha_{22}$ and $\alpha_{11}$ for the same case. For the inversion, the effect of clay on the elastic moduli of the matrix was included using the Hill average. $x_1$ is chosen parallel to the direction of polarization of the vertically propagating fast shear wave, while $x_2$ is chosen parallel to the direction of polarization of the vertically propagating slow shear wave. The fact that $\alpha_{11}$ and $\alpha_{22}$ are

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{fig10.png}
\caption{Shear-wave anisotropy computed from cross-dipole sonic data. Note that the lower sand is nearly isotropic, whereas the upper sand is anisotropic. The average amount of anisotropy is approximately 3–9\%.
}
\end{figure}

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{fig11.png}
\caption{Results of the Kuster-Toksöz modeling. Model results presented here assume a pure quartz matrix ($K_m = 38$ GPa and $G_m = 44$ GPa). The numbers associated with the different curves are the pore aspect ratios modeled as part of this analysis (0.02–1). Note that different pore aspect ratios are required to simultaneously model $K_{\text{dry}}$ and $\mu$, implying that the microcracks in this reservoir may have a preferential orientation.
}
\end{figure}
The fact that $\alpha_{11}$ and $\alpha_{22}$ are greater than $\alpha_{33}$ shows that the cracks have a preferred orientation, with more cracks being aligned vertically than horizontally. It is also seen that there is a depth-varying preferred orientation of the crack planes parallel to the fast direction ($x_1$; Figure 13).

Conclusions

Velocities in sedimentary rocks are partially controlled by composition, porosity, and fluid type (all key terms in most empirical relationships and in Gassmann's equation). However, in low-porosity rocks, tight gas sands in particular, the importance of pore microstructure may be more important than other factors and may possibly dominate the velocity response. Clearly this may have an impact on our ability to use sonic velocities or seismic amplitudes as a measure of porosity in tight gas sand reservoirs.

Results of this study suggest the following should be considered when evaluating velocities from tight gas sand reservoirs:

1) P-wave and S-wave velocities from most tight gas-sand reservoirs cannot be explained without the addition of microcracks to the rock matrix.

2) The addition of compliant microcracks to the rock matrix may appreciably weaken the rock frame, which will result in lower velocities. This is predicted by effective medium theory, and is observed in the velocity data evaluated as part of this study.

3) The wide range in P-wave velocities observed in log and core data from this study (Figures 1 and 3), and the poor correlation between velocity and porosity, indicates that the volume of crack porosity within any given reservoir is highly variable.

4) A single pore geometry parameter ($\alpha$) cannot be used to
simultaneously model both $V_p$ and $V_s$. A combination of microcracks and high aspect-ratio pores was necessary in order to realistically model the log data in this study.

5) Core and petrographic observations show that the pore geometry in some tight gas sands is very complex and contains variable concentrations of high and low aspect-ratio pores. The presence of diagenetic cements in some of the microcracks indicate that these features exist in rocks in the subsurface.

6) Inversion of log data shows that these microcracks may have a preferential alignment. The resulting velocity anisotropy may also be manifest in anisotropic permeability, and perhaps resistivity.


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