Estimating the volume of hydrocarbons in place, the product of porosity and saturation, is a major problem in applied geophysics, but the solution is not straightforward.

Reflection seismology depends on the contrasts of the elastic properties (impedance and velocity) that are predominantly affected by porosity and mineralogy. The elastic properties of a rock may also strongly depend on whether it is wet or hydrocarbon-saturated. However, their dependence on hydrocarbon saturation (if larger than zero and smaller than one) is weak. As a result, interpreting seismic data to quantify saturation is often difficult.

On the other hand, resistivity strongly reacts to a combination of porosity and saturation, but the latter is impossible to estimate without making an assumption about the former.

Consequently, neither seismic nor resistivity data, if analyzed separately, can provide the desired estimate of hydrocarbons in place. The question is: Can these two types of data be used together to address the problem?

In this paper, we discuss a physics-driven solution that combines two theoretical models, one that relates the elastic-wave velocity to porosity, mineralogy, and pore fluid and one that relates resistivity to porosity and saturation. This approach allows us to produce templates of the normalized resistivity versus the P-wave impedance that quantify porosity and saturation. We show examples of such templates for a sandstone reservoir with methane hydrate and with gas. This concept is based on rock physics models and is amenable to the upscaling required to interpret field measurements. We use upscaling to generate a template for the Nuggets gas field.

Our model-driven templates are flexible; they can be constructed to honor the site-specific rock properties to account for, for example, diagenetic cementation and depositional sorting as well as the presence of shale.

Figure 1. Poisson’s ratio (PR) versus the P-wave impedance for unconsolidated clean gas sand, color-coded by the total porosity (left) and water saturation (right), assuming pore pressure=30 MPa, temperature=80°C, and gas gravity=0.65.

Figure 2. Water saturation versus the P-wave impedance (left) and versus the normalized resistivity (right), color-coded by the total porosity for the same unconsolidated clean gas sand as in Figure 1.
Primer on rock physics impedance-resistivity templates.

Consider a clean, unconsolidated gas sand whose porosity ($\phi$) varies from 0.1–0.4 and whose water saturation ($S_w$) is between 0.2–1.0. The left side of Figure 2 reaffirms, using the same sand, that $S_w$ cannot be quantified from $I_p$; note the $S_w$ contour lines are essentially vertical for $S_w < 1$. The right side of Figure 2 shows the normalized resistivity ($R_t/R_w$), where $R_t$ is the measured resistivity and $R_w$ is that of water, as calculated from Archie's 1942 resistivity equation. $S_w$ strongly reacts to $R_t/R_w$, however, it cannot be quantified without knowing $\phi$. At $R_t/R_w=100$, $S_w$ can be 0.25 for $\phi=0.4$ or about 0.70 for $\phi=0.2$.

Figure 3 shows how the same relationships (between $\phi$, $S_w$, and $I_p$, and between $\phi$, $S_w$, and $R=R_t/R_w$) are used to create a resistivity-impedance mesh. We first fixed porosity (e.g., 0.4), and computed $I_p$ and $R_t/R_w$ using the soft sand model and Archie's equation for water saturations from 1–0.2, generating the first constant porosity line of the mesh on the left. Then, the same procedure was repeated six more times, changing porosity to 0.35, 0.3, 0.25, 0.2, 0.15, and 0.1. Then, we kept water saturation constant (e.g., 1.0) and computed $I_p$ and $R_t/R_w$ using the same models but changing porosity this time from 0.1–0.4, producing the first constant saturation mesh line at the bottom. Again, the rest of the constant saturation mesh lines are computed by repeating this last step eight more times. The intersection of the two measurements can be projected upon the saturation and porosity contours to yield (in this example) $\phi=0.2$ and $S_w=0.50$. Having both measurements helps constrain porosity and saturation; taking each measurement separately yields wide ranges for these variables.

The power of this approach is its flexibility; numerous models of rock physics velocity-porosity and resistivity-porosity-saturation are available, meaning site-specific templates can be generated that honor texture (e.g., cemented versus uncemented rock) as well as lithology. For example, Figure 4 displays an $I_p$ versus $R$ template in which the soft-sand model is replaced by a stiff-sand model appropriate for contact-cemented rock. As expected, the same impedance and resistivity inputs produce larger porosity and gas saturation than in Figure 3 because at the same porosity, cemented rock is faster than its uncemented counterpart. This illustrates the importance of using the right model for the right rock.

This flexibility accommodates not only the rock type but also the fluid, or, more generally, the pore-filling material. For example, in sand containing methane hydrate, both velocity...
and resistivity strongly dominate over the background. To build a relevant $I_p$ versus $R$ template (Figure 5), we select the elastic and resistivity models describing a hydrate reservoir as established for the Mallik 2L-38 hydrate well (Canada) by Cordon et al. (2006). The log data superimposed upon this rock physics mesh indicate that the porosity of the reservoir is about 0.3 with the hydrate saturation up to 0.8, which is consistent with the values directly observed in the well.

Nuggets Field example. The Nuggets gas field is offshore the U.K. in 115 m of water. The sand reservoir belongs to the Eocene Frigg Formation and has a thickness of about 25 m (Harris and MacGregor, 2006).

The first step is to use the well-log velocity and porosity data to establish this reservoir as constant-cement sand (a model originally discussed in Avseth et al., 2000), which is consistent with this formation’s age (the earliest of the three divi-
Figure 7. Impedance-resistivity template for the Nuggets reservoir with log data superimposed. Color code is water saturation (left) and porosity (right).

Figure 8. Nuggets gas field well log (blue) and seismic/CSEM (red) data at the well. The full seismic stack was provided by TGS-NOPEC, from which we obtained the seismic impedance using the Hampson-Russell inversion package. The CSEM resistivity profile was provided by OHM. The reservoir zone is highlighted in green.
This diagnosis includes three steps: (1) bring the entire interval to the “common-fluid denominator” by theoretically making it all wet (fluid substitution from gas to formation water); (2) plot the resulting impedance-porosity data for sand and shale; and (3) superimpose theoretical impedance-porosity curves upon this plot to find which model describes the trends best.

Figure 6 shows that the constant cement-sand model is most appropriate for this specific example.

The resistivity is modeled using a version of Archie’s formula known as the Humble or Winsauer equation (Schön, 1996), which assumes the Archie constants are $a=0.62$ and $n=2.15$. The water salinity is 35,000 ppm, which translates to an $R_w$ of about 0.1 ohm-m. The resulting $I_p$ versus $R$ template (Figure 7, left) gives the sand’s porosity at about 0.3 and gas saturation up to 0.9.
This template should not be directly used with field seismic and CSEM data whose scales of measurement are vastly different from those in the well and also from each other (Figure 8). These templates have to be altered to honor the statistics of the data, which vary with the scale of measurement.

To conduct such upscaling, we need to remember that seismic and CSEM profiling simultaneously provide two values for a single location in the subsurface. What reservoir properties may generate these two responses? One approach to answering this question is forward modeling. We assume that the geometry of the reservoir everywhere is the same as at the well; i.e., we fix the thickness of the gas and wet sand layers as well as the properties of the shale surrounding this sand. Next, we create a pseudo-Earth model (or pseudo-well) as shown in Figure 9 where the impedance in the shale is about 5 km/s g/cc, similar to the original well. Then we vary the porosity in the entire sand from 0.15 to 0.40 with a 0.05 step, and, for each porosity step, vary the water saturation in the gas sand from zero to 1.0 with a 0.01 step. This produces a table of porosity and saturation at the scale of the pseudo-well.

From this table, we calculate the impedance using the constant cement-sand model and the resistivity for each realization using the Humble equation. One such realization is shown in Figure 9.

For upscaling, we use the Backus average with a 12.5-m running window (about a quarter wavelength) to transform the log-scale impedance to the seismic-scale impedance and the arithmetic average with a 150-m running window to transform the log-scale resistivity to the CSEM-scale resistivity. The latter window (150 m) was selected to honor the difference between the resistivity at the reservoir as recorded by logging and CSEM. The upscaled impedance and resistivity profiles are shown in Figure 9. We select those upscaled values in the middle of the reservoir for each realization and create an $R_t/R_w$ versus $I_p$ mesh which yields a template usable at the field scale (Figure 10).

To interpret data from Nuggets Field for porosity and saturation, we take the seismically derived impedance and CSEM resistivity selected from the depth interval around the reservoir. These values are placed upon the field-scale template in Figure 10. The contour lines in this template indicate that the gas saturation is around 0.85 and porosity is around 0.25, consistent with the actual values in Nuggets.

Conclusions. By combining two theoretical models, one that relates the elastic properties of rock to porosity, mineralogy, and pore fluid, and the other that relates resistivity to porosity and saturation, we create templates of the normalized resistivity versus P-wave impedance. We can generate these templates at the well log-scale and also upscale them to the seismic/CSEM scales of measurement. Such upscaled templates can be directly used with field data to obtain simultaneous estimates of porosity and saturation.

The answer is not unique. Many parameters can vary away from well control, including the geometry as well as the shale and reservoir properties. For an exhaustive interpretation, they all have to be varied within reasonable ranges and probability distributions. This will eventually yield not a single answer but probabilistic distributions of porosity and saturation. We envision that the approach discussed in this paper may produce useful invariants, such as porosity times saturation times thickness (or net-to-gross), which should be relied upon in reserve estimates. This is a subject of future work where the existing arsenal of stochastic modeling can be used within the framework presented here.

Finally, we have to reiterate that the rock physics models for the impedance-resistivity templates should be selected to reflect the geologic nature of rock both on the elastic and resistivity sides (the latter by, for example, using the Waxman-Smits-Juhasz equation instead of the Archie equation). Also, instead of considering just the P-wave impedance, other seismic attributes can be explored, such as the elastic impedance and attenuation, to further constrain the estimates.


Acknowledgments: Thanks to Lucy MacGregor and Peter Harris of OHM/RSI for their advice. Thanks to OHM/RSI and TGS-NOPEC for providing the data. Thanks to Hampson-Russell for providing their software to Stanford University. This work was supported by the Stanford Rock Physics and Borehole Geophysics Project, and the DOE Basic Energy Sciences Grant DE-FG02-03ER15423.

Corresponding author: gomezct@stanford.edu