Meeting the Challenge of Distinguishing ‘Fizz’ from Commercial Gas

By REINALDO J. MICHELENA

The volumetric estimation of reserves of natural gas in exploratory environments is a challenging problem. Geological complexities, sparseness of well data and ambiguities in the seismic response due to the presence of gas can result in large uncertainties that must be evaluated before decisions are made about the development of the resource.

Three different scenarios might result in the presence of natural gas molecules in the porous space. In the first, the molecules are related to gas that is trapped in rock after migrating from the source rock. This is a case that could have commercial value if the volume of trapped gas is large enough within the context of the economic variables of the project. But two other scenarios are also possible. Another possibility is that the presence of natural gas molecules is associated with gas that was trapped during migration, but subsequently released, leaving gas traces behind. Alternatively, in the third scenario, gas molecules are associated with gas that passed through the rock during migration from the source rock but did not become trapped.

The last two scenarios are called “residual” or “fizz” gas, in contrast with the first scenario of trapped gas which is commonly called “commercial.”

In exploratory environments where the available data consists only of 3-D seismic and a few wells with limited log data, the distinction between commercial and residual gas poses a significant challenge. This is because commonly employed amplitude attributes respond to gas in a manner like a severe allergic reaction of the immune system, in which a small amount of gas (or the allergen) produces a disproportionately large response. This behavior was explained by S. Norman Domenico in his classic 1974 Geophysics paper that shows that the velocity of a water saturated rock decreases significantly by adding just a little gas. Figure 1 clearly exhibits this effect and shows that it is not possible to separate, for instance, scenarios of 20-percent and 90-percent water saturation by examining velocities alone. This ambiguity has resulted in a mixed bag of successes and failures over decades of practical applications, and for this reason it is still an important topic of research and discussion among explorationists. Figure 1 shows a realistic gas reservoir model depicting the complexities of the problem. Similar seismic response between commercial and residual gas accumulations may result in erroneous reserve estimates.

Our interest here is in the different aspects of the problem of distinguishing between residual and commercial gas. I begin by addressing the broader issue of dealing with the non-uniqueness of seismic interpretations. Then, I review the main recommendation from experts in the past, which is to try to estimate the rock density attribute. In the next section, I explain how seismic acquisition advances in the last 20 years can help better estimate the density attribute because long-offset data has become more prevalent. The following section discusses the importance of understanding the geologic context in terms of the origin of the gas, possible migration paths, and where it can be trapped. Then, I expand on the idea that if seismic data on its own is not sufficient, we should consider other concepts and methods that include geomechanics evaluations for potentially conductive and sealing faults, and control source electromagnetic (CSEM) for the estimation of a low-resolution resistivity related gas saturation. Finally, I present a simple recipe or checklist that can be changed to suit different data and geological scenarios in which the separation between commercial and residual gas is the central issue.

The Issue of Non-Unique Seismic Interpretations

Before digging into the question of differentiation between commercial and residual gas using seismic data, let’s first discuss the fact that the interpretation of seismic anomalies can often be non-unique. In these cases, a significant effort might be required to minimize the non-uniqueness and manage the associated risks. Ideally, interpreters would like to use attributes that yield unequivocal interpretation results, like a seismic horizon or a fault in a simple structure, but this is not always the case. When two rock types A and B show a similar response in one attribute (e.g., acoustic impedance),

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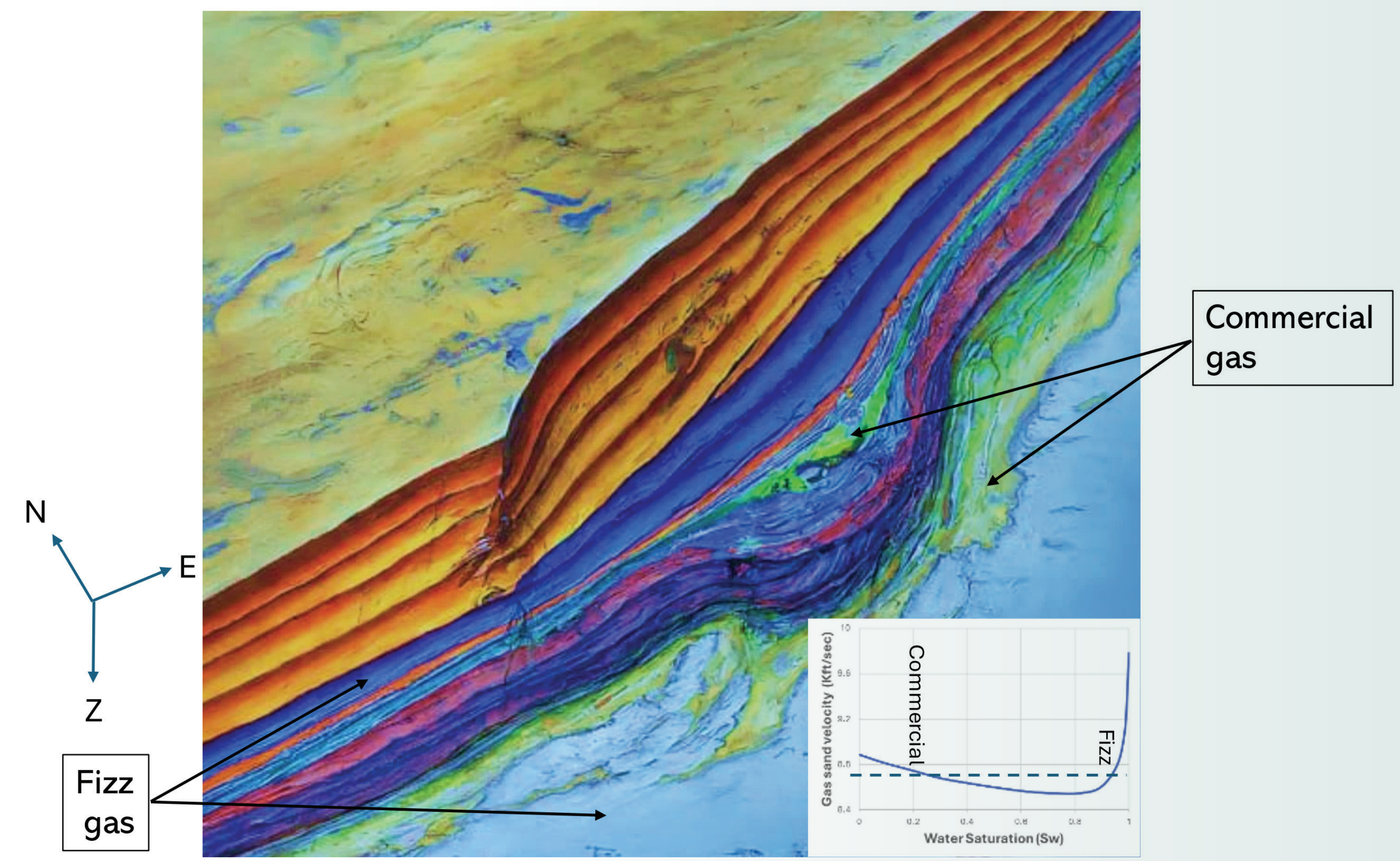

Figure 1: A slant view of a gas reservoir depicted with residual and commercial accumulations. The blue/bluish colors indicate the more abundant intervals that are more prone to be residual gas, whereas the greenish color indicates intervals prone to be commercial gas. However, similar seismic response (not shown here) between the two types of accumulations may result in erroneous reserve estimates. The inset shows a graph of variation of gas sand velocity as a function of water saturation. The largest changes in velocity occur by replacing just a small fraction of the water with gas. The non-monotonic behavior of the curve also creates ambiguities in the seismic response. Modified after Domenico (1974).

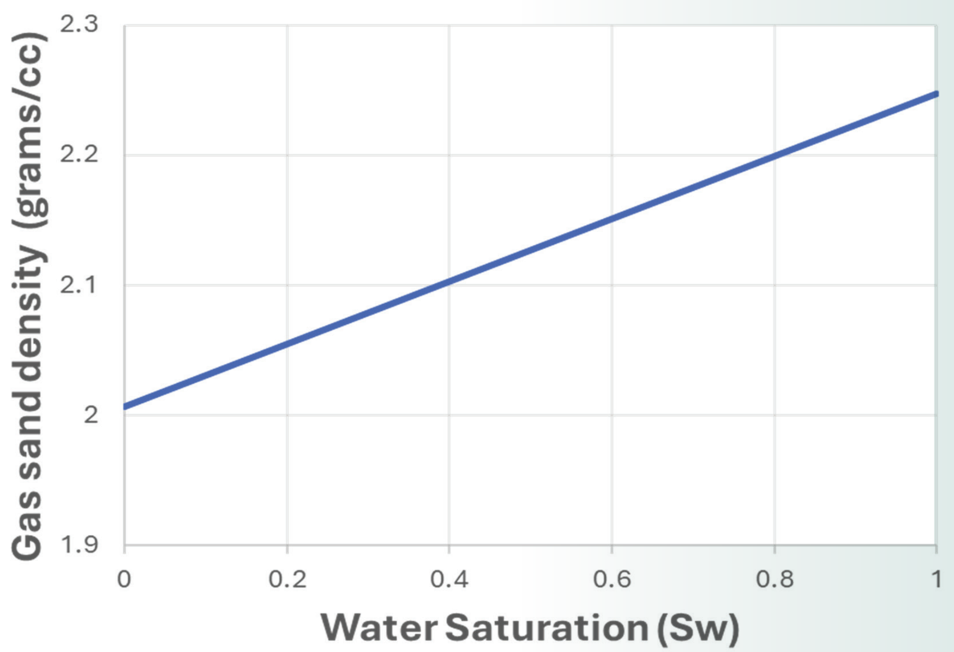

Figure 2. Unlike velocities, the relation between rock density and water saturation is linear, facilitating the use of density to map changes in water saturation. Modified after Domenico (1974).

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we typically need to use another attribute (e.g., V_p/V_s ratio) that responds to other properties of A and B. Then, with the help of well log data, we check whether A and B can be differentiated. The extraction of certain seismic attributes may require more effort than others or may require data not commonly acquired. In addition, since interpreters should be working in integrated asset teams with common goals, they should also search for other means to solve critical asset problems that might go beyond seismic data and may require a more comprehensive understanding of the geology of the problem (geology matters!) or even an understanding of other disciplines and data.

Now, going back to our initial question, the general workflow to differentiate residual ("fizz") gas from commercial gas is no different from other workflows we apply if we want to separate a target rock from the background when both have a similar seismic response.

The first recommendation in the differentiation recipe is that if using one attribute alone doesn't differentiate rock A from rock B, we should investigate the rock physics relations to find another independent attribute that can contribute to the differentiation. Occasionally, some interpreters don't follow this advice, and this is where problems start.

Expert Recommendations

Many bright amplitude anomalies have been successfully drilled over the years, but the consensus is that the drilling results are a mixed bag of good and disappointing, costly findings. Even though the pitfalls of chasing bright amplitudes as the only criterion to select drilling locations for gas have been well documented (they only serve to detect the presence of gas but have no relation with the actual gas saturation, or they could indicate simply tuning effects, or it might be related to brine saturated porous rocks, etc.), the convenience of using a single attribute seems to have overweighted in some cases the risks associated with that practice.

In 2004, Satinder Chopra invited a group of rock physics experts to write for the Recorder publication of the Canadian Society of Exploration Geophysicists their comments about the same issue we are addressing here in 2024 – that is, distinguishing residual gas and commercial gas saturations. These experts gave their opinions and provided recommendations that remain current today, but some of these recommendations are now easier to implement because of advances in seismic data acquisition and processing.

The selection of the independent attribute should be guided by petrophysics and rock physics analyses. In this context, the four experts who contributed to the 2004 Recorder's article emphasized rock density as a critical parameter. The rationale behind this emphasis lies in the linear relationship between density and gas saturation (figure 2), unlike compressional velocities which are significantly influenced by even small amounts of gas. It's worth noting that back in 2004, the practice of inverting for density was uncommon due to the limited offset ranges in most data sets, which hindered the capture of curvature variations (referred to as the "third term") in the AVO response."

Enhanced Technologies Allow Better Implementation of Known Solutions

Seismic recording technology, however, has advanced significantly in the last 20 years to the point that the old rule of thumb in survey design of a ratio offset/depth equal to one has improved to O/D of about 1.3 or 1.4 for imaging purposes, and much larger for velocity estimation. Unfortunately, the acquisition of longer offsets hasn't resulted in more use of density inversions that rely on those offsets. Many interpreters got used to the idea that density inversions were not of good quality because of the lack of offsets, so they didn't even try to perform such inversions under any circumstance. Furthermore, even if the right offsets are now available, some interpreters don't even look at the density inversions coming from recently acquired data because they think densities are intrinsically unreliable. In my personal experience, after years of working with seismic data, I have found that independent density inversions can yield useful results, even without the ideal offset range, so I always try before discarding the inversion based on hypothetical grounds. This means that, besides offsets, the nature of density contrasts also plays a role. Hopefully, seeing more and more case studies with good quality density inversions will help to change this perception. Another issue to keep in mind when using density is that the porosity variability must be well understood too, since both porosity and gas saturation contribute to bringing the density down.

If density cannot be extracted by itself, examining any density-related attribute might provide useful insights. This is the case for the PS reflectivity, which is mostly sensitive to changes in density and S wave velocity. Although the estimation of PS

reflectivity (or PS impedance, if inversion is performed) requires the recording of multicomponent data, it turns out that the density information is contained in the near offset PS conversions, which might prove useful when recording long offsets is not possible or when near offset 3C VSP data is available. By analyzing PS reflections, it should be possible to explain the reasons for the strong amplitude anomalies observed in conventional PP data: weak PS reflections could indicate residual gas in the interval of interest, whereas strong PS reflections might indicate commercial gas.

In the absence of long-offset PP or near-offset PS data that facilitates the estimation of density, using conventional inverted attributes such as Lambda*Rho, Mu*Rho or even spectral decomposition to look for areas of decreased wavelength due to the presence of gas are better alternatives than using raw poststack amplitude or AVO attributes alone, in particular when calibration data from different wells is available and more reliable correlations can be established. Modeling the seismic response for different "what-if" scenarios can help understand the sensitivity of different attributes to changes in saturation.

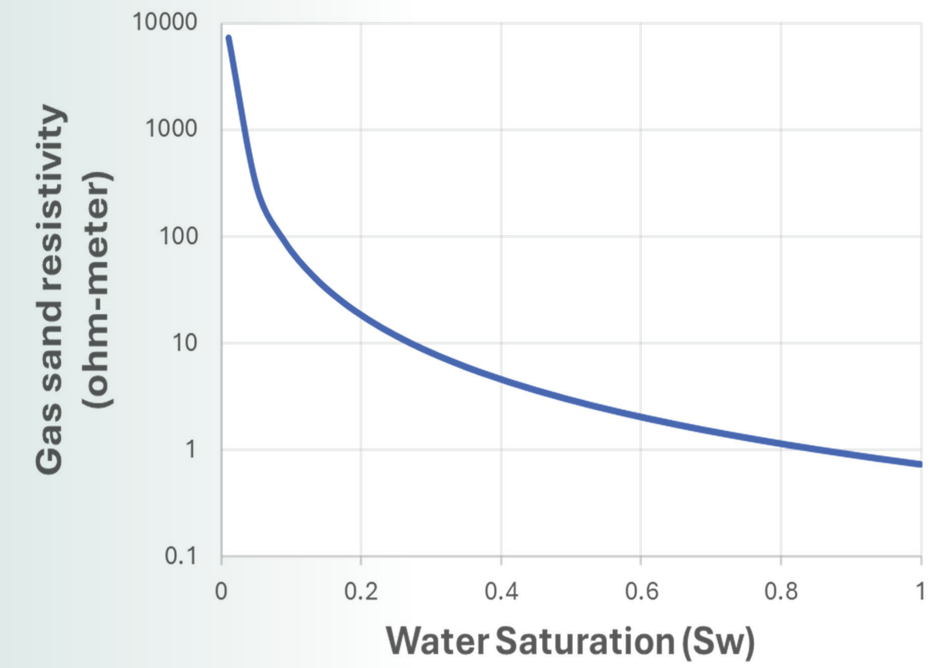

Figure 3. Resistivity of a gas sand decreases with water saturation. In log-log scale this decrease is linear. Resistivities estimated from CSEM can be a useful complement to seismic information for the estimation of water saturation.

Understand the Geologic Context: Origin, Migration and Trap

Since the isolated analysis of seismic attributes provides only a partial picture of the problem, a broader geologic understanding is crucial to improve the models and reduce risk. We should also understand where the gas comes from and how it is trapped. As discussed in the introduction, residual gas is often found in areas where gas has either migrated through the subsurface but was not trapped or migrated from gas traps that leaked away, leaving some "residual saturation" behind. These residual gas molecules change the P-wave velocities and create bright amplitude anomalies.

The migration of gas can be significantly impacted by the presence of faults, which can provide vertical communication between the source rock and the reservoir rock, lateral communication between juxtaposing formations, or serve as conduits for the gas to leak away. Although certain factors that control the conductivity of a fault, such as diagenesis, are difficult to assess with seismic data alone, other factors like the juxtaposition of porous intervals or the propensity to slip can be analyzed along fault planes derived from seismic interpretation. The main idea is that an amplitude anomaly surrounded by sealing faults will be more likely to be related to a commercial accumulation than an anomaly in contact with leaking faults. In the absence of production or geochemical data to help determine the sealing nature of a fault, juxtaposition analysis is a common first step that can be performed using commercial geological modeling tools by analyzing sand-sand or sand-shale contacts across the faults and determining the possibility of communication across different fault compartments.

When Seismic Is Not Enough, Use Other Concepts and Technologies

A less common but powerful tool that can be used to assess fault conductivity is the estimation of mechanical slip potential along the fault planes. Faults segments prone to slip (or critically stressed) will also be more prone to conduct fluids than mechanically stable fault segments which are usually closed. This kind of analysis on the fault planes requires geomechanics concepts and data such as the local stress state, fluid pressures, and rock properties in the vicinity of the faults.

The task of the geophysicist is to help the asset team solve the problem of separating commercial from residual gas, even if the method they propose is not seismic related. As a matter of fact, the measurement of choice by petrophysicists to estimate water saturation is not related to the elastic properties of the rock – it's the resistivity log. Rock resistivity has been successfully estimated at reservoir scale by performing control source electromagnetic. The result of CSEM acquisition and processing is a volume of resistivity that is related to gas saturation: high resistivity indicates higher gas saturation and vice versa. This is shown in figure 3 generated by applying Archie's equation to model the rock resistivity for fixed porosity and water resistivity. CSEM can be extremely useful in early exploration stages. This method has matured considerably in the last 20 years and is now commercially available. The main drawback of the CSEM method is its low lateral and vertical resolution, resulting in anomalies that may not be properly collocated with seismic anomalies, and making the joint interpretation tricky. Besides, different inversion algorithms might yield different results and structural changes can add another level of complexity to the analyses

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since dip changes might affect the response. Even with these weaknesses, the presence of resistivity anomalies can be a strong indication of higher gas saturations that can help rank potential gas saturated zones detected with seismic amplitudes. In any case, CSEM data must be used in conjunction with seismic data, either for qualitative joint interpretations or for constrained inversions that use the seismic derived information for better definition of the resistivity anomalies. In addition – though less common, joint inversion of seismic AVO and CSEM data can also be performed, but this requires rock physics models with related elastic and electrical properties.

A Recipe for Starters

In summary, the recipe to differentiate residual gas from commercial gas is no different from the recipe we use to differentiate rock types using seismic data. We should keep in mind that seismic interpreters should not work in isolation from other disciplines and data, and the final goal is to reduce risk for the asset.

Having said this, here is a checklist:

- Understand the geologic context: Where does the gas come from? What are the trapping mechanisms?
- Acquire the data needed to extract density-related attributes: long offsets PP data or PS converted waves data.
- Identify gas-water contacts from well data.
- Detect the gas first: make sure the seismic anomalies are gas related.
- Estimate density or density related attributes.
- Rank amplitude anomalies based on density (or gas saturation).
- Use interval attributes (from prestack inversion or spectral decomposition) instead of raw amplitudes).
- Calibrate seismic attributes with gas saturation from petrophysical evaluations in a sufficient number of wells. Local, careful analyses of inversion results with log data can go a long way in reducing risk. Probabilistic facies mapping can be helpful at this stage after commercial and residual gas facies have been identified at well locations.
- Interpret faults in the seismic data.
- Model fault juxtaposition and use geomechanics concepts and data to assess fault conductivity and compartmentalization.
- Rank possible gas traps based on potential for fluid conductivity of surrounding faults.
- Use CSEM data to assess gas saturation. Enhance the resolution of CSEM results by incorporating the structure interpreted from seismic data. Model different resistivity scenarios to help explain observations.
- Make sure all interpretations are consistent among data types and disciplines.

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__The Geophysical Corner__ is a regular column in the EXPLORER, edited by __Satinder Chopra__, founder and president of SamiGeo, Calgary, Canada, and a past AAPG-SEG Joint Distinguished Lecturer.