USING GAS GEOCHEMISTRY TO ASSESS GAS RESERVOIR COMPARTMENTALIZATION

Information concerning reservoir connectivity between wells may come from wireline logs, seismic data, fluid contact depths, production testing, production histories, or reservoir descriptions (from core, cuttings and log data). Such information is used to optimize field production by helping reservoir engineers and development geologists to determine if additional completions are warranted, and to locate the optimum placement for injectors.

However, sometimes these geological, geophysical, and engineering data are not available, or interpretations of these data are ambiguous due to poor data quality. In such cases, gas geochemistry data provide two additional very powerful tools for evaluating reservoir continuity: these tools are the chemical and isotopic compositions of gases.

In addition to helping resolve ambiguous geology-based conclusions or engineering-based conclusions concerning reservoir continuity, gas geochemistry data are particularly valuable for another reason: Gas geochemistry data often provide the ability to evaluate reservoir continuity from gas samples in "real time" (while drilling) as described in our discussion of mud gas isotope analyses.

At OilTracers, we assess gas reservoir compartmentalization by integrating gas geochemistry and engineering data to determine the sealing capacity of potential no-flow barriers.

Oil geochemistry and gas geochemistry typically provide very inexpensive keys to interpreting ambiguous geological and/or engineering information. The geochemical approach for assessing gas reservoir compartmentalization is similar to that applied to oil accumulations (see Assessing Reservoir Continuity in Oil Accumulations), and is based on the proposition that gases from separate reservoirs tend to differ from one another in composition (e.g., Beeunas et al., 1996, 1999).

While geochemical assessment of oil reservoir continuity typically relies on gas chromatography data, assessment of gas reservoir continuity is based on a greater range of geochemical analyses, including:

- Gas chromatography analyses of gas condensates (with the data being processed using the inter-paraffin peak ratio method described in Assessing Reservoir Continuity in oil accumulations)
- Gas composition (e.g., relative abundance of each gas present, including trace gases, such as helium)
- Isotopic composition of carbon and/or hydrogen in specific gas species (methane, ethane, CO2, etc).
• Isotopic composition of carbon and/or hydrogen of the paraffins in the gas condensate

Depending on the field, compositional differences between gas compartments exist for one or more of the following 5 reasons:

1. Differences in the ratio of bacterial to thermogenic gas in different compartments.
2. Differences in the abundance of non-hydrocarbon gas components in different compartments.
3. Processes that affect petroleum composition after hydrocarbons enter a reservoir (e.g., processes such as biodegradation, water washing, and evaporative fractionation) do not operate to exactly the same extent in separate compartments.
4. Petroleum that a source rock generates at a given time differs slightly both from subsequently generated petroleum and previously generated petroleum due to continuous, subtle changes in the maturity of the source rock and changes in precisely which part of the source rock is in the oil window. Since no two compartments are of identical geometry, and since no two compartments have exactly the same filling history, it is difficult to achieve precisely the same homogenized composition in two separate compartments—even with petroleum from the same source.
5. More than one source rock may contribute petroleum to an accumulation, and the gases from different sources may differ in composition. Since gases from different source rocks may have different times of generation or different migration paths, the presence of more than one source may cause different compartments to fill with different mixes of gas from the respective sources.

For assessing continuity, the stable carbon isotopic data is often more useful than the chemical composition, because isotopes are less affected by variations in sampling conditions, production methods, GOR, and phase changes.

**Gulf of Mexico case study**

Three examples from the South Marsh Island 61 field (US Gulf Coast; Beeunas et al, 1996) illustrate how gas geochemistry (stable isotopic compositions of the hydrocarbon gases) is used to assess reservoir continuity between wells.

In Figure 1, replicate analyses of gas samples collected two months apart from two wells demonstrate the high analytical precision of this analysis. As expected, differences between repeat samples from the same well are on the order of ±0.1 ‰.
Figure 1: Replicate analyses of gas samples indicate that the isotopic compositions of the light hydrocarbon gases (methane, ethane, propane, n- and i-butane) are nearly identical for each pair of analyses. However, note the clear compositional differences of the gases from the two reservoir sands; these differences indicate that the two reservoirs are not in communication.

In the next figure, nearly identical carbon isotopic compositions of light hydrocarbon gases are obtained from two wells producing from the same interval within a single fault block. Differences between samples are on the order of ±0.1 ‰.
Figure 2: Stable carbon isotopic compositions of light hydrocarbon gases from two wells producing from the same interval (B-1 Sand) within a single fault block. These samples illustrate the compositional homogeneity of gas that may be found in a laterally continuous reservoir.

The last figure shows gas isotopic data for two wells producing from the same correlative interval, but in separate fault block reservoirs.
Figure 3: Gas isotopic data for two wells producing from the same correlative interval (C-2 Sand), but in separate fault block reservoirs. As expected, there are significant differences in stable carbon isotopic compositions of the light hydrocarbon gases, indicating discontinuity and reservoir separation.

**Necessity for integration of geochemical, geological and engineering data**

At OilTracers, to interpret reservoir continuity rigorously, we believe it is critical to integrate geochemical information with engineering data and what is known about the geology/geologic history. Other key types of data we utilize include:

- RFT/ DST pressure data
- Pressure decline curves
- Wire-line log data
- Dew-point calculations
- Reservoir descriptions (from core, cuttings, and log data)
- Fluid contact depths
- Fault sand/shale gouge ratios
- Fault juxtaposition (Allen) diagrams
- Seismic data

**Project specifics**

For gas geochemistry projects, gas samples are usually collected from production tests or from shows while drilling (e.g., see [Sampling Techniques](#)).
As discussed above, gas geochemistry data are particularly valuable because gas geochemistry data often provide the ability to evaluate reservoir continuity from gas samples in "real time" (while drilling) as described in our discussion of mud gas isotope analyses.

For more information on the techniques described here, or to discuss a specific project, e-mail us at oiltracers@weatherfordlabs.com or call us at U.S. (214) 584-9169.

References
