Basin Modeling - the Key for Unconventional Play Assessment*

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Abstract

The objective of this paper is to demonstrate how a basin modeling study can help in the evaluation of unconventional shale gas/oil resources. We present an improved expulsion model that accounts for the evolution of retention capacity as a function of maturity. Basin modeling is indeed a key tool to help in (1) the evaluation of the initial organic matter distribution, type and quality inside a formation, and (2) the assessment of the present-day total organic content (TOC) and maturity level of the formation. These two parameters have a first order control on the volume of hydrocarbons generated and still retained in the formation.

Introduction

Hydrocarbons are generated from kerogen during the source rock burial due to an elevation of temperature. As for the gas, it can be either of biogenic origin (generated at low maturity), or of thermogenic origin (generated from the cracking of kerogen and oil at higher maturity levels).

Part of the gas/oil generated is expelled from the source rock and then migrates to conventional reservoirs through carrier beds. The other part is retained by the source rock. Hydrocarbons composition and volumes generated and retained depend on the initial organic matter properties and maturity. Expulsion models in the past have been designed in order to quantify the expelled amounts. These models have to be revisited and improved in order to better quantify the retained gas/oil.

The source rock retention capacity is tightly linked to the TOC content, the organic matter type and the maturity. Hydrocarbons can be stored in source rocks by adsorption (this process concerns mainly the gas) and as free hydrocarbons inside the porosity (Figure 1).

The porosity in mature source rock can be of two types: (1) An effective porosity inside the non-organic fraction of the rock; the evolution of this porosity vs. depth is controlled by burial and possible diagenetic phenomena, and (2) porosity inside the organic matter itself. This second porosity is created consequently to the loss of kerogen mass resulting from the transformation of organic matter into hydrocarbons. It is assumed that the organic porosity is poorly connected to the non-organic effective porosity as the pore threshold size in this organic porosity is believed to be of the nanometer order of magnitude. These two different porosities represent a storage space for hydrocarbons in the source rock.

Retention Model

The adsorption also represents a very efficient way to retain important volumes of hydrocarbons inside the source rocks, especially gas, as the density of the adsorbed layer is much higher than the density of the free hydrocarbons phase in bottom conditions. The adsorption capacity of the rock is modeled as a function of TOC, pressure and temperature through Langmuir isotherms that are calibrated from lab experiments.

Workflow

To assess the potential for shale gas/oil in a formation, and as the volume and quality of hydrocarbons generated depends on the initial geochemical parameters of the formation and the maturity evolution through time, it is necessary to evaluate:

- The initial TOC, the organic matter distribution, type and quality;
- The source rock present-day maturity;
- The storage capacity in the non-organic porosity, the organic porosity and the adsorption;
- The generated HC quantity and quality, in order to quantify how much is retained in the source rock intervals, in the porosity or by adsorption.

In order to achieve these tasks (Figure 2), a numerical basin model of the area of interest is built. This model, carefully calibrated in temperature, maturity and pressure against the available data, is used as a framework to compute an evaluation of the shale gas potential of the considered formation.

The initial TOC and kerogen initial HI are inverted from present-day values. The present-day TOC is deduced from logs using an improved Carbolog® methodology, which combines sonic and resistivity logs (Carpentier et al., 1991; Schneider et al., 2010). For thick formations, or if the source rock is not well known, a forward stratigraphic model, such as Dionisos®, can help in assessing the source rock extent and its internal sedimentary architecture.

The geochemical study, and especially the analysis of the Rock Eval® data, enables defining the kerogen type and quality and helps in selecting a relevant kinetic scheme. The basin model, calibrated in maturity, allows estimating the transformation ratio of the kerogen, which is used to calculate the initial TOC from the present day TOC.

Accurate compositional kinetic parameters for kerogen thermal decomposition are key elements in this kind of study to predict the hydrocarbons fluids quality and type as a function of maturity. IFP kinetics schemes have proven to be effective for accurately representing kerogen transformation into oil and gas (Behar et al., 1997, 2008). They provide an accurate and proven reactions scheme, able to predict early or late gas. They have been successfully applied to Barnett and Posedonia shales (Behar and Jarvie, 2011). A solution for modeling biogenic gas has also been proposed (Schneider et al., 2010).

The modeling of hydrocarbons generation allows estimating the mass loss in the kerogen and the organic porosity consequently created as a function of maturity. Gas adsorption potential on organic material is calculated using a modified-Langmuir model implemented within the basin simulator which takes into account spatial distribution of pressure, temperature, and remaining TOC. The effective porosity in the shale matrix is estimated from log analysis, using a methodology that allows correcting the log response from the effect of organic matter.

The integration of these tasks allows estimating the retention capacity of the formation, accounting for shale effective porosity, organic porosity and adsorption capacity. This retention capacity depends primarily of the TOC distribution and the TOC decreases with maturity.

The Gas Initially in Place (GIIP) can then be directly deduced from the basin modeling simulation results, as a function of this retention capacity. The numerical model computes a GIIP value at play scale and also gives access to lateral and vertical variations of gas distribution, depending on the resolution of the source rock architecture implemented in the model. Using experimental design and response surface-based methodology, the calculated GIIP may be risked as a function of the uncertainty associated to the values of some key input parameters. GIIP percentiles are then computed (P10, P50 and P90).

Examples

The methodology has been successfully applied in a number of formations over the world, including the Silurian in Algeria, Abu Gabra Formation in Sudan, Los Monos Formation in Argentina, and Lower Barnett in the Fort Worth Basin (Romero-Sarmiento et al., 2012). Most of the formations studied present significant differences from U.S. plays, in terms of thickness, organic matter type, present day TOC, adsorbed gas proportion, and volume of gas per ton of rock.

Conclusions

The methodology presented allows estimating the hydrocarbons retention capacity of the formation and the composition of hydrocarbons still retained. Our experience proves that these properties can vary significantly laterally and vertically, and that the shale gas potential of a formation can then not be simply deduced from a local evaluation that would be extrapolated throughout the basin. Shale development presents huge opportunity and faces large geological uncertainty. Innovative tools and methods are key to diminish the geological risk from resource evaluation to optimal well development.

Basin modeling can play a key role in the shale evaluation process as it allows integrating all available knowledge into a consistent and comprehensive model of the studied area, from early stages of exploration to pilot zone identification. A large research effort is still required to understand and quantify the physical processes that occur in shales and organic matter, such as retention, adsorption, and diffusion.

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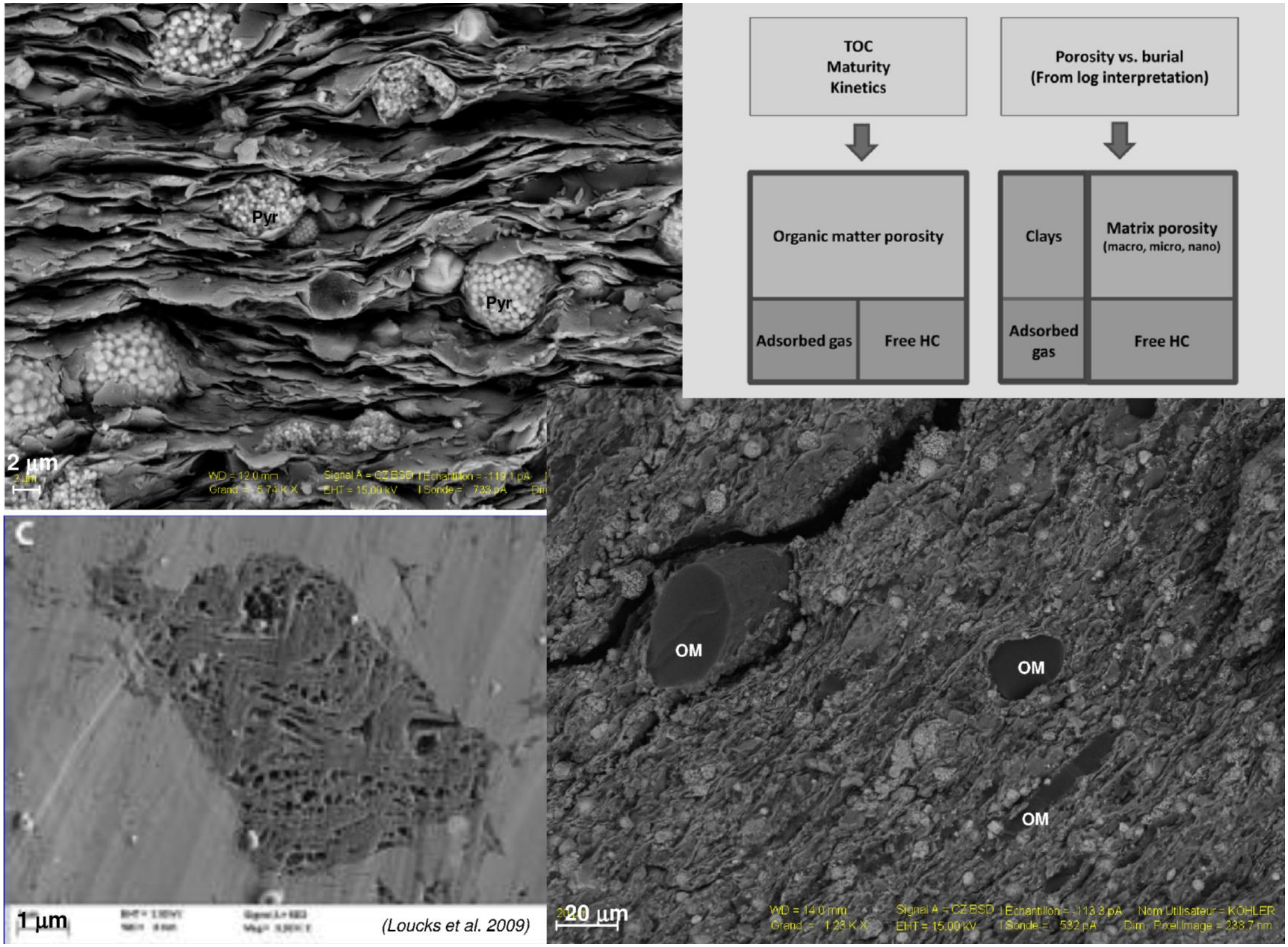

Figure 1. Illustration of the different porosity types that can store gas.

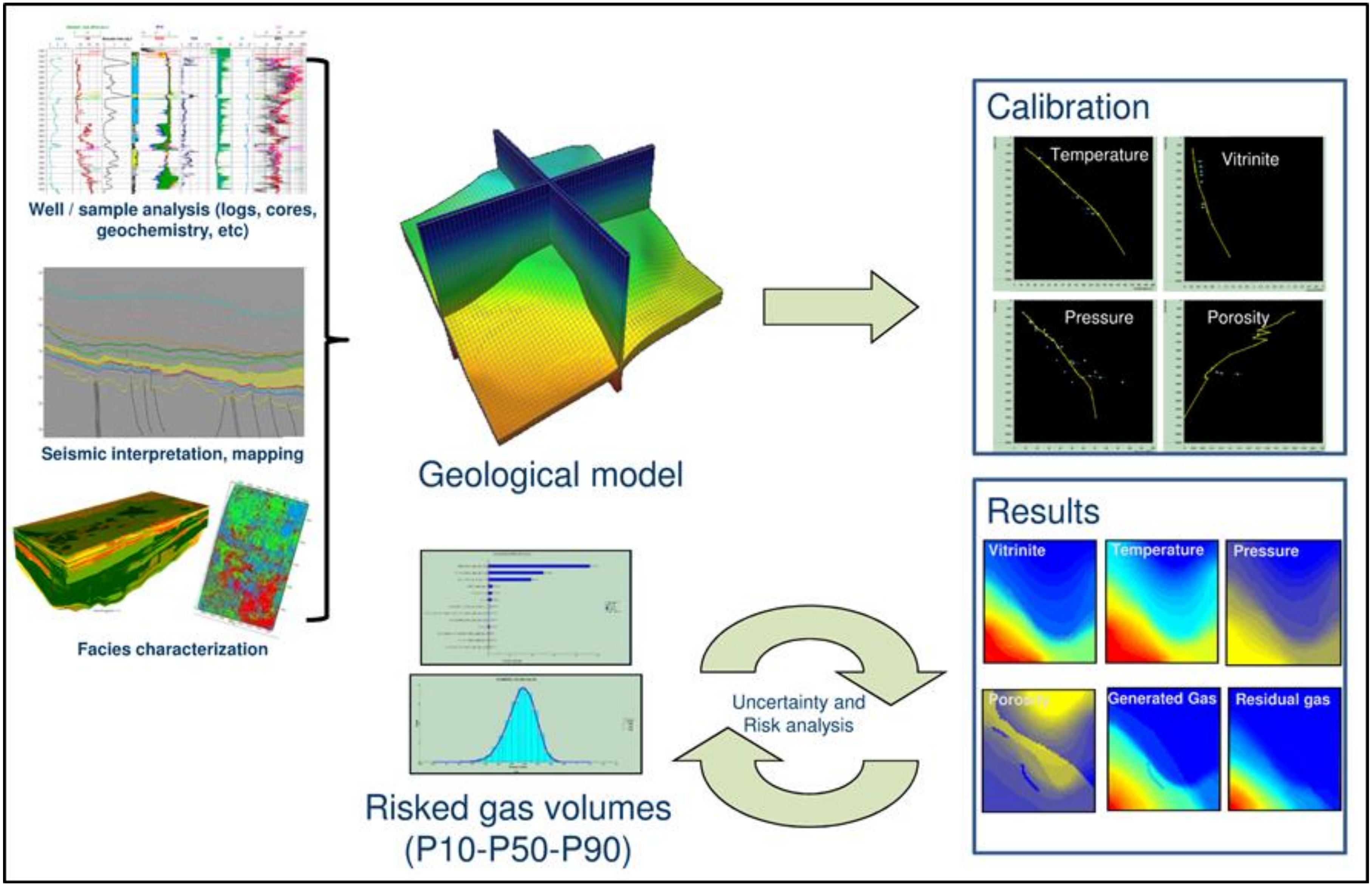

Figure 2. Workflow based on using basin modeling to assess shale gas potential.