MODELLING HYDROCARBON MIGRATION AS A TOOL FOR RESERVE ESTIMATION

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Hydrocarbon migration modelling aims at reconstructing the generation of hydrocarbons, then its movements in the sediments of a basin through geological times. This technique has now been widely used to quantify various parameters of utmost importance for hydrocarbon exploration, such as maturity of source rocks, migration speed and direction, overpressure development or leakage through faults or top seals. However, a new application of this technique emerges in recent years, with the use of basin modelling techniques for original oil or gas in place estimation. This presentation will focus on this topic and present the principles of the application, as well as its related uncertainties.

Migration modelling, also called basin modelling, integrates the geological history of a sedimentary basin and reconstructs the major physical events that give birth to hydrocarbon accumulations:

- burial or erosion of sediments;
- compaction and pressure development;
- temperature changes due to conduction or convection;
- source rock maturity and hydrocarbon expulsion;
- hydrocarbon migration, accumulation and dismigration (Figure 1)

Each of these features can be described by physical or chemical equations. Sophisticated software tools that solve the equations have been developed and marketed by various companies, among which Temis3D is the tool issued from R&D performed in IFP.

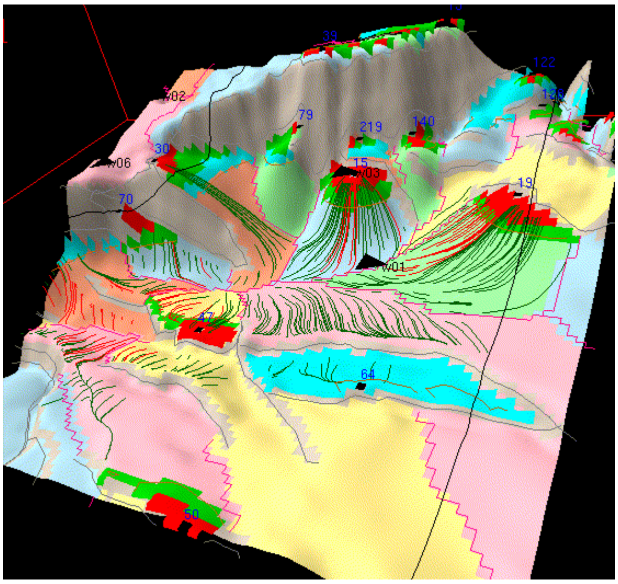

Figure 1 : Synthetic view of a HC migration modelling on a reservoir layer

Because the basic assumption of all physical laws in nature is mass conservation, the hydrocarbon reserves, here defined as original oil or gas in place, can be quantitatively estimated. This estimation goes through several steps, which will be illustrated in the paper:

1. definition and estimation of the porosity of the main reservoir units;
2. computation of the surface and pore volume of closed structures;
3. estimation of the mass of generated hydrocarbons in the various source rocks;
4. estimation of the nature of the expelled hydrocarbons, either oil, condensate or gas;
5. computation of accumulated HC volumes in the previously defined closures;
6. computation of lost hydrocarbons through capillary leakage or fracturation
7. estimation of volumes of hydrocarbons in surface conditions.

Among the important points, the structural closures are defined for each potential reservoir, with the computation of the local structural tops, the closure heights and the maximum trapped volumes (Figure 2). Faults can be taken into account as being laterally permeable or impermeable. Moreover, fault transmissivity can vary with geological time or orientation. These structural tops are computed through geological times, as their size and their spill points may change with basin subsidence and tilting.

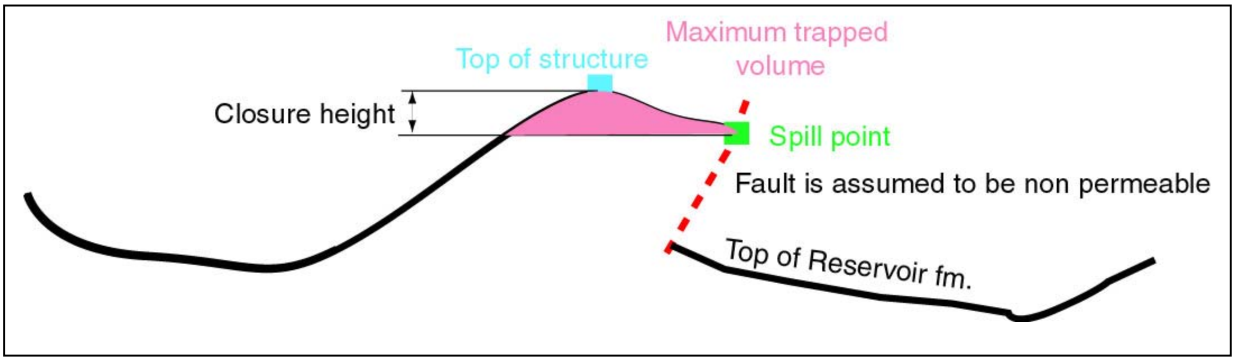

Figure 2 : Computation of maximum trapped volume of a structurally defined closure

Simultaneously, the quantity of generated and expelled hydrocarbons from the source rocks of the basin can be computed, based upon compositional kinetics and volume and mass balances within the pore space of the source rock. Because of constant progress in the knowledge of primary and secondary cracking, the detailed composition of fluids generated and expelled can be predicted. Thanks to the chemical description of the generated fluids, the uncertainty on this composition is reduced.

Then, the hydrocarbon charge of accumulations is computed through fast migration. With fast migration, opposed to full Darcy migration, only the most important components of the hydrocarbon system are taken into consideration. Migration of hydrocarbons is therefore computed along the source rock layers, the faults and the reservoir layers, as illustrated in Figure 3. It can be seen that at given moments in the basin history, some faults might be located within the drainage areas of structural traps. Therefore, only structures located near vertically leaking faults might be filled in a first step of migration.

Figure 3: Example of simplified migration route from source rock through fault leading to the accumulation in a given structure at geological time t1.

Figure 4: *Schematic view of secondary migration modelling along the reservoir bed, leading to phase separation between a liquid HC phase (green) and a vapour HC phase (red). Phase separation is linked to the composition and the pressure and temperature in the reservoir unit.*

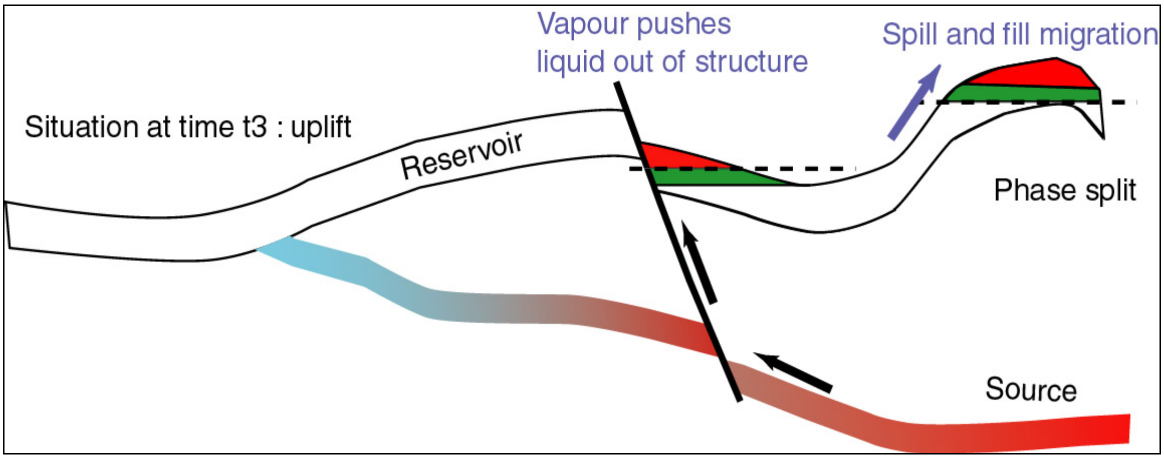

Figure 5 : Phase behaviour of the hydrocarbon charged into reservoir. With uplift, due e.g. to a global tectonic erosion, pressure is lowered in the reservoir, leading to phase split in the deepest reservoirs and to preferred secondary migration of the liquid fraction, that gets pushed out by the expansion of the gas cap.

Later, when the basin history goes on with increasing subsidence or tilting of the basin horizons, hydrocarbon secondary migration can occur through fill and spill along leakage points (Figure 4). Due to decreasing pressure and temperature with decreasing burial depth, the hydrocarbons expelled from the underlying source rock can undergo a phase split. This phase split is computed with thermodynamically based equation of state formalism. The phase split depends thus upon composition, pressure and lastly temperature. In case of a regional uplift, phase separation can occur and the global volume of trapped hydrocarbons increases. Because available pore volume in a structurally closed trap is limited, when phase separation occurs, some trapped hydrocarbons are expelled. As secondary migration occurs through the spill point, the structural trap adjacent to the spill point will be charged. In this geological configuration, the expanding vapour phase in the deepest reservoir can push out the liquid phase, that will charge a shallower structure (Figure 5).

Once completed, the migration modelling can be used to compute the total available volume of hydrocarbons in a given sedimentay basin. Because the modelling procedure takes into consideration compositional primary and secondary cracking, both in source rock and reservoirs, as well as liquid/vapour phase separation in subsurface and in surface, the total volumes of trapped oil and gas components can be computed.

The underlying (Figure 6) shows results from a real example, where 3 reservoirs named R1, R2 and R3 have been evaluated. The figure shows the trapping efficiency for all plays and prospects in the basin. It shows that on a statistical basis, one out of three available prospects might be filled for formation R1, one out of five for formation R2 and more than one out of two for formation R3. Moreover, the gas to oil filling ratio in subsurface conditions can be estimated, as shown by the colour coding. Such results can be used to better define exploration strategies in sedimentary basins.

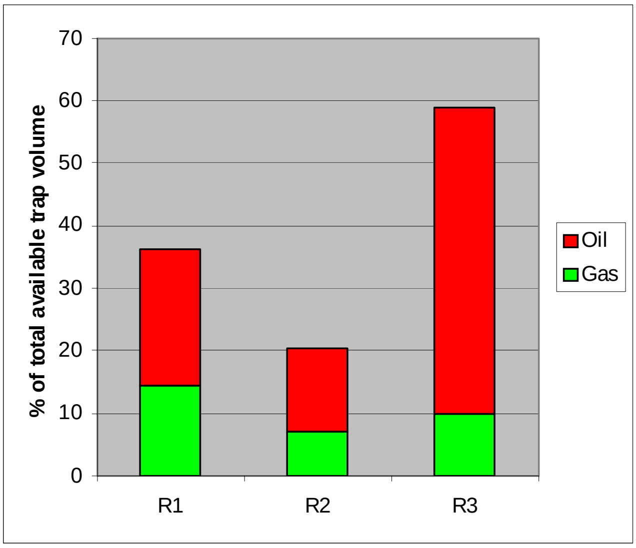

Figure 6 : Trapping efficiency for three reservoir levels in a sedimentary basin. The efficiency is defined as the ratio of the total pore volume of reservoir R1 filled by hydrocarbons to the total available pore volume at present day in the whole sedimentary basin.