Simulation of Petroleum Migration in Fine-Grained Rock by Upscaling Relative Permeability Curves: The Malvinas Basin, Offshore Argentina

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ABSTRACT

Early exploration of the Malvinas Basin (1979–1991) targeted Lower Cretaceous sandstones assuming that hydrocarbons would migrate laterally from the basin depocenter in the south to structures located in shallow water. Hydrocarbons were found, but not in large enough quantities to be commercially viable. Recently, exploration has moved closer to the depocenter and focuses on Eocene to Miocene sandstones a few thousand meters vertically above the mature Lower Cretaceous source rock. As no faults crosscut the entire section between the source rock and reservoirs, they cannot be evoked as conduits for hydrocarbon migration. Therefore, kilometer-scale vertical migration across fine-grained sediments was considered as the main process to transport hydrocarbons from source rock to reservoir.

This migration mechanism is commonly mentioned, but poorly constrained. Darcy flow and invasion percolation calculators were used to simulate hydrocarbon migration. If we consider that hydrocarbons migrate along thin stringers, the relative permeability parameters have to be upscaled to consider that not all of the rock is being saturated by petroleum. Furthermore, fine-grained sediments present a very high specific area, which gives a higher sorption capacity for water, and therefore, less petroleum is needed to reach the saturation threshold for flow. Secondary migration across fine-grained sediments takes time to initiate, but as soon as hydrocarbons invade the pore space, the migration is effective; it occurs with minimal hydrocarbon losses and is essentially controlled by the expulsion rate of petroleum from the source rock and the stratigraphic architecture. From a physics standpoint, the Darcy method looks more appropriate because it incorporates the full physics of the problem. However, under these conditions, viscous forces can be ignored and the invasion percolation method seems appropriate to simulate secondary migration of hydrocarbons across fine-grained sediments.
GEOLOGIC FRAMEWORK

The Malvinas Basin (Figure 1) is the southernmost offshore sedimentary basin in Argentina with water depths ranging from 50 to 1000 m (164–3281 ft). It has a triangular shape (Figure 2) and is limited by the Rio Chico High in the west, onlaps onto the Malvinas platform to the east, and is constrained to the south by the Burwood Bank, which is a topographic expression of the fold and thrust belt associated with the South America and Scotia plates. The Malvinas Basin formed in response to early rifting and volcanism related to the first breakup of Gondwana (Vayssaire et al., 2008), which caused the separation of eastern Gondwana (India, Australia, and Antarctica) from western Gondwana (South America and Africa) in the Late Jurassic (168 Ma). In the Malvinas Basin, the termination of this synrift period correlates with oceanic crust formation in the Weddell Sea (150 Ma). It was followed by a phase of postrift thermal subsidence throughout the Cretaceous that led to a marine transgression and developed the backstepping sands of the Springhill Formation (Figure 3). The transpressional deformation acting along the South America–Scotia plate boundary deepened the southern part of the basin. This led to the development of a fold and thrust belt during the Oligocene and the lower Miocene, forming the southernmost limit of the Malvinas foreland basin.

The Springhill Formation was targeted during the early exploration of the basin (1979–1991). This exploration has proven the existence of a working petroleum system, albeit without the discovery of commercially viable petroleum accumulations. This economic failure is most likely caused by poor efficiency of lateral migration of the hydrocarbons from the depocenter toward the structures.

Today, exploration focuses in the southern part of the basin. Targeted reservoirs are of Eocene to Miocene age, a few thousand meters above the Lower Cretaceous source rock. Only kilometer-scale vertical migration of hydrocarbons can explain reservoir infilling.

HYDROCARBON MIGRATION ACROSS FINE-GRAINED SEDIMENTS

Aplin and Larter (2005) believe that most of the world’s petroleum migrated vertically through large thicknesses of fine-grained sediments. Estimating the flow rates is extremely difficult because it is such a slow process that laboratory experiments are very challenging and, in most cases, impossible.

Whereas oil can flow at a few centimeters per hour in reservoir rocks, Appold and Nunn (2002) predicted oil migration in fine-grained sediments is in the order of 100 m/Ma. This still allows 1 km (0.6 mi) of vertical migration in 10 Ma, but represents only 0.1 mm/yr. Neuzil (1994) and Dewhurst et al. (1999) calculated a hydraulic conductivity between 0.01 mm/m.y. and 1 km/m.y.

The mechanism of hydrocarbon secondary migration across fine-grained sediments is also not well understood. For primary migration, Appold and Nunn (2002) ventured the hypothesis of the porosity wave that would favor the displacement of hydrocarbons within the source rock. Osborne and Swarbrick (1997) showed that the release of hydrocarbons from kerogen during cracking would lead to an increase of fluid volume and pore pressure, generating microfractures and primary migration of hydrocarbons in low-permeability source rocks. This hypothesis is supported by observations that the top of the overpressure section commonly coincides with the petroleum generation window (Spencer, 1987; Isaksen 2004).

Regarding the formation of hydrocarbon pathways during secondary migration, Aplin and Larter (2005) demonstrated that polar compounds in petroleum, such as phenols, penetrate the mineral water films such that hydrocarbons can wet the mineral surface. In this case, cap rocks do not act as permanent seals, but simply retard the inexorable flow of petroleum. Other migration mechanisms have been proposed, including migration because of fracturing of the cap rock when the buoyancy forces exceed the tensile strength of the rock or the propagation of methane-filled fractures that develop the potential to entrain and transport oil (Nunn and Meulbroek, 2002).

It appears that the processes previously mentioned take time to initiate, but as soon as hydrocarbons invade low-permeability rock, more petroleum can migrate through this pathway very easily and rapidly even in the absence of a pressure gradient to drive Darcy flow. Existing pathways can be reused in a very efficient way with a quasi-instantaneous velocity and minimal hydrocarbon losses.

MIGRATION SIMULATIONS IN THE MALVINAS BASIN

In the Malvinas Basin, the Temis Darcy simulator from IFP (Institut Francais du Pétrole, Rueil Malmaison, France) and the MPath invasion percolation (IP) simulator from The Permedia Research Group (Ottawa, Canada) were used to model hydrocarbon migration in three dimensions. The IFP model assumes that the hydrocarbons migrate as a separate phase and follow a generalized Darcy’s law (Bear, 1972), which gives a complete description of the forces controlling the fluid flow considering the intrinsic permeability tensor, the relative permeabilities in the porous medium, as well as the viscosity,
density, and capillary pressure of the hydrocarbon phase and the pore pressure of the water phase (Ungerer et al., 1984). The IP technique considers that the balance between the buoyancy and the capillary forces overwhelmingly controls the trajectories of the hydrocarbon flow and that the migration distance and velocity is predominantly controlled by the rate and volume of petroleum expelled from the source rock (Carruthers, 2003), and hence, the viscous forces are ignored.

Both simulations show great similarities in the present-day saturation distribution in the Miocene and Eocene reservoirs (Figure 4). Both models have the same lithologic description and contain realistic stratigraphic variability. The calculated temperatures and pressures are identical at all ages. The rock parameters such as porosity, capillary pressure, and relative permeability curves are also identical. The grid resolution is vertically the same, but the Darcy model was laterally upscaled to decrease the number of grid cells to reduce the calculation time. This upscaling has no effect on the migration mechanism and the distribution of the hydrocarbon accumulations.

Nevertheless, the charging process of the two models is very different. With Darcy flow, the oil that fills the reservoir comes from the top of the migration front, whereas with the IP technique, the early expelled oil has already migrated through the entire column up to the surface, and the oil filling the reservoir has been recently expelled. This result seems to be more in accordance with sea bottom piston-coring results and other direct hydrocarbon indicators, suggesting that the hydrocarbons reached the sea floor in great quantities.
In other words, with IP, most of the expelled hydrocarbons reach the sea floor, whereas with Darcy flow, most of the petroleum remains in low-permeability layers between the source rock and the reservoirs. Figure 5 displays hydrocarbon saturation during the Miocene along a cross section extracted from two three-dimensional blocks resulting from Darcy and IP simulations. The saturations in the Darcy simulation are high between the source rock and “Sand-1.” The IP simulation shows much lower saturations and migration pathways up to the surface. Abundant hydrocarbons leave the model boundary through the sea floor, which is not the case with the Darcy simulation.

The interpretation for the migration risk is very different. In the Darcy case, the risk is that the expulsion occurs too late and the hydrocarbons have no time to reach the target. In the IP case, the source may mature too early and the expelled hydrocarbon migrates to the sea floor, leaving an insufficient charge to fill the reservoirs once the trap is formed and sealed.

With the IP method, in fine-grained sediments where no contrast of capillary pressure exists, the hydrocarbon flows from one grid cell to another as soon as the critical saturation is reached. With Darcy, the calculated velocity is generally too slow to permit flow and the saturation continues to increase until petroleum occupies the maximum possible volume. At this stage, all mobile water has flooded out of the pore space. An additional increase of saturation will force the petroleum to move out of the grid cell so the saturation does not exceed the maximum value permitted. This displacement is therefore essentially controlled by the saturation limits of the relative permeability curves, and viscous forces play a nominal role.

Beyond the Malvinas case, these two different results confirm that the quantity of petroleum found in the reservoirs represents a small fraction of what was generated. McDowell (1975) and Moshier and Waples (1985) concluded that the recoverable quantity of petroleum in most basins is only a few percent of the generated petroleum, and in very few cases does this number reach 10%. This demonstrates the inefficiency of one or all of the following poorly understood processes: expulsion, migration, and trapping of hydrocarbons. Pepper and Corvi (1995) consider that hydrocarbons are sorbed within the kerogen (adsorbed in the microporosity and absorbed onto the internal surface area) and that the cracking of 200 mgHC/gC of initial hydrogen index (HI) is a prerequisite for oil expulsion. It is also generally accepted that cap rocks do not act as permanent seals.
but retard the flow of petroleum and that reservoir column heights are essentially controlled by the balance between buoyancy and capillary forces. During migration, hydrocarbons are lost along the migration pathways because of the heterogeneity of the stratigraphic architecture but also because the rock must reach a minimum petroleum saturation before oil can flow. These losses are a challenge to quantify.

MIGRATION LOSSES

Sylta (2002) and other authors mention that simulators using modified Darcy equations may overestimate hydrocarbon losses, and therefore, the calculated migration velocities are too low. The simulation of hydrocarbon migration in low-permeability rock using Darcy's law (Figure 6) clearly shows that the calculated Darcy true velocities never exceed 3.6 m/m.y., and the average velocity is around 0.5 m/m.y. These numbers cannot explain the present-day migration front 2.5 km (1.5 mi) above the top of the source rock, with the expulsion starting at 120 Ma. The migration rate must exceed 20 m/m.y. to account for the migration front location at present day.

In fact, it looks as if the losses have a significant impact on migration velocity. Under certain conditions, decreasing migration losses by increasing the residual water saturation does not significantly affect the velocity calculated by the Darcy equation but forces the migration to move faster and further because the petroleum saturation rapidly approaches the maximum saturation threshold value. The extra mass is then forced to move where the hydraulic head is the lowest (commonly upward) whatever the velocity calculated by the Darcy solver. Two synthetic cross sections are shown at the top of Figure 7. The only difference between the two sections is the maximum hydrocarbon saturation allowed in each grid cell. On the left, the relative permeability curve allows maximum hydrocarbon saturation to reach 100%. The mean true Darcy flow calculated is 4 m/m.y., and the migration front at present day is around 1 km (0.6 mi) above the top of the source rock (bottom layer). At the right, the maximum hydrocarbon saturation was
reduced to 30%. The migration velocity did not change much (5 m/m.y. instead of 4 m/m.y.), but the migration front moved much farther (4000 m [13,123 ft] instead of 1000 m [3281 ft]).

The same occurs when increasing the expelled masses from the source rock: no change in the velocity calculated by the Darcy technique is observed, but the hydrocarbons move a greater distance (figure 7, bottom).

\[ V_{hc} = \frac{K.Kr_{hc}}{\mu_{hc}} \cdot \text{grad} \left( \frac{P + P_c}{\rho_{hc}.g} - Z \right) \]

\[ g(\rho_w - \rho_{hc})\text{grad}(z) > \text{grad}(P_c) \]

**Figure 4.** Simulation results showing hydrocarbon distribution (saturation) in Miocene reservoirs using the invasion percolation method (right) and Darcy’s law (left).

**Figure 5.** Simulation results from invasion percolation (IP) (right) and Darcy (left) simulators showing hydrocarbon saturation during the Miocene.
The relative permeabilities of fine-grained sediments are poorly controlled because of the difficulty of doing measurements on low-permeability rocks. Okui and Waples (1993) extrapolated relative permeabilities measured in rocks with decreasing grain size from sand to silt and showed that the residual water saturation in shales increases, significantly reducing the maximum hydrocarbon saturation to approximately 20% in low-permeability rocks. The same authors also showed that the flow of oil commences in fine-grained rocks at increasingly small oil saturations (i.e., 2%). The explanation given is that the clays in rock provide enormous specific area, giving a higher sorption capacity for water. This increases the film of immobile water surrounding the grains. This film is commonly referred to as “bound” or “connate water.” The consequence is that compared with sandstones, low-permeability rocks require less petroleum to reach the saturation threshold for migration to occur, which leads to lower migration losses.

**Figure 6.** Top: Synthetic cross section showing present-day hydrocarbon saturations. The source rock is located in the bottom layer, and the migration front is more than 2500 m (8202 ft) above it. Bottom: Hydrocarbon migration velocity in meters per m.y. for each cell versus geologic time in m.y. The red line at the left represents the history of hydrocarbon migration true velocity of the cells just above the source rock. The green line gives the velocities of the second row of cells above the source rock, and so on.

THE ROCK SAMPLES USED IN THE EXPERIMENTS ARE MUCH SMALLER THAN THE GRID BLOCKS USED IN BASIN MODELS. WITHIN THE ROCK VOLUME REPRESENTED BY THESE GRID BLOCKS, A LARGE FRACTION WOULD NEVER BE EXPOSED TO PETROLEUM. THE CRITICAL SATURATIONS USED BY THE SIMULATORS SHOULD THEREFORE BE SCALLED BY A FUNCTION OF THE GRID CELL AREA, ASSUMING THAT MIGRATION IS ESSENTIALLY VERTICAL IN LOW-PERMEABILITY ROCKS. TO ACCOUNT FOR THE LARGE NUMBER OF STRINGERS, THE SCALING MIGHT BE TURNED OFF INSIDE AND NEAR THE SOURCE ROCK. IT SHOULD THEN INCREASE AS PETROLEUM MOVES AWAY FROM THE SOURCE ROCK.

WE SHOULD THEN CONSIDER THAT MIGRATION PATHWAYS OUTSIDE THE SOURCE ROCK COVER AN AREA THAT IS MUCH SMALLER THAN THE CELL AREA USED FOR THE NUMERICAL SIMULATION. WHEN PETROLEUM SATURATES A MIGRATION PATHWAY TO ITS CRITICAL SATURATION, IT DOES NOT IMPACT THE ENTIRE SIMULATION CELL BUT INSTEAD A SMALL VOLUME CORRESPONDING TO THE STRINGERS. THE MAXIMUM HYDROCARBON SATURATION WITHIN A MIGRATION PATHWAY NEEDS TO BE UPSCALED TO REFLECT THE MEAN VALUE INSIDE THE ENTIRE NUMERICAL SIMULATION CELL. ASSUMING THAT WITHIN THE MIGRATION PATHWAY THE MAXIMUM OIL SATURATION IS 20% AT THE SCALE OF THE SIMULATION CELL, THIS NUMBER MAY DROP TO VALUES LOWER THAN 0.2%. THIS WOULD CORRESPOND TO A 1-KM² (0.39 MI²) SIMULATION CELL IN WHICH WE ASSUME THAT THE MIGRATION STRINGERS OCCUPY AN AREA OF 100 M² (1076 FT²).
DISCUSSION

Schneider (2003) (Figure 8, right) claims that successive simplifications of Darcy’s law that neglect excess pressure, assuming that fluids are not compressible and considering that migration is instantaneous with respect to geologic time, result in an equation governing the models that is controlled by percolation (Carruthers and de Lind van Wijngaarden, 2000).

Whereas the generalized Darcy equation contains three driving forces for hydrocarbon migration, which are buoyancy, capillary forces, and viscous forces, Carruthers (2003) considers that viscous forces can be ignored. England et al. (1987) showed that at the geologic flow rate of secondary migration, the capillary number (Figure 8, left) never exceeds 1e-10, which is far below the 1e-4 limit at which viscous forces become important.

The Darcy method has proved its efficiency for reservoir production simulation. Using Darcy-based migration solvers to represent migration at basin scale assumes that all of the physics appropriate for reservoir simulation must extend to basin time and length scales, although we know significant differences exist with the requirements of the two scenarios (grain size, saturation, grid cell, permeability, and particularly, time).

Experience shows that velocities, calculated using the Darcy equation, are too small to explain migration in low-permeability mudstones. Furthermore, numerical difficulties and high run times are encountered when running Darcy with upcaled relative permeability curves that can discourage the use of high-resolution models, and therefore reduce their use as predictive tools.

Figure 9 shows a sensitivity analysis of maximum hydrocarbon saturation in secondary migration simulation cells. It clearly demonstrates that with high values (between 10 and 15%), few hydrocarbons reach the reservoir and none flow to the surface. The risk is that the expulsion occurs too early. At 5% saturation, 23% of the expelled hydrocarbons migrated to the surface and the reservoirs received the maximum quantity of petroleum. With values lower than 4%, more hydrocarbons are lost in the sea floor and the volume in reservoir does not vary much.

Of course, great uncertainty is present with respect to the selected upcaled value, but it appears, as shown in this representative example, that as long as it has the correct order of magnitude, it does not greatly affect the simulation results.

CONCLUSIONS

The calculations of hydrocarbon migration detailed here were achieved using the Darcy simulator from IFP...
and the IP calculator from Permedia. Although they show similar present-day saturations inside the potential reservoirs, the saturation distribution outside the reservoir is drastically different because of differences in migration history. With Darcy flow, most of the petroleum remains between the source and the reservoir in low-permeability rocks. With IP, most of the hydrocarbons flowed through the topographic surface. The latter result seems to be more in accordance with sea bottom piston-coring results and other direct hydrocarbon indicators, suggesting that the hydrocarbons reached the sea floor in great quantities.

Furthermore, all simulations using Darcy’s law show relatively high saturations in low-permeability rocks behind the migration front, which has a pistonlike displacement pattern. This is something that is not confirmed by drilling, which reports very rare evidence of active secondary migration paths.

From a physics standpoint, the Darcy method looks more appropriate, as it incorporates the full physics of the problem. However, upscaling the relative permeability curves is necessary to mimic a migration process that is supposed to occur along thin stringers. Under these conditions, the Darcy velocities do not change much, whereas the migration front moves further and numerical difficulties increase. It appears that viscous and permeability terms can be ignored for calculating displacement of hydrocarbons across fine-grained sediments, and the IP technique provides satisfactory and realistic results. The petroleum migration distance and velocity are overwhelmingly controlled by the hydrocarbon expulsion rate from the source rock (timing, quantities, and products) and the stratigraphic architecture (anisotropy, buoyancy, and capillary forces).

Many unknowns remain in migration and expulsion processes. These unknowns have strong consequences in our simulations of reservoir filling. The oil and gas found in reservoirs represents a small fraction of what has been generated, which raises questions about the fate of the unaccounted mass. This emphasizes the need for more research into what happens in the source rock, not only the generation, but also the expulsion phenomena (retention, primary migration, expelled quantities, products, and the timing) and the secondary migration processes.

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