Porosity in carbonate reservoirs at depth- do empirical models work?

Brent Wignall
Shell International

It is a truism that the porosity found in carbonate reservoirs decreases with depth. However, quantification of the rate of porosity decrease is not a simple matter. In general, there are nine factors that control the loss of porosity in carbonate reservoirs. They are: 1) overburden pressure, 2) period of burial, 3) pore pressure, 4) rock strength, 5) rock texture, 6) temperature, 7) hydrodynamic regime, 8) pore fluid history, and 9) lithology. Note that only three of these factors can be said to co-vary with depth, and two of those factors (temperature and period of burial) have an imperfect relationship with depth. Furthermore, the temporal and spatial variations in global carbonate rock chemistries mean that rules of thumb for one particular stratigraphic unit in one basin may not work well for a different stratigraphic unit in another basin. For this reason, the development of effective global empirical porosity-depth relationships in carbonate rocks is not a simple task. At the same time, whereas in siliclastic reservoirs the chemical and mechanical processes that result in porosity closure are fairly well understood and can be modelled, the chemical variability and reactivity of carbonate rocks is not so well understood. Attempts to model these complex rock-fluid interactions are underway, but much work must be done before this science is mature and widely applicable.

Review of core plug porosity measurements for a variety of reservoirs at various depths from the PriCaspian and Western Canadian sedimentary basins support these points. There is a clear trend of porosity envelope closure (i.e. the highest porosity values decrease with depth), but there is no obvious trend of average porosity decrease with depth. Furthermore, clear differences exist for different stratigraphic units and different rock textures and lithologies. Finally, it is evident that geographically distinct reservoirs of the same stratigraphic units with similar textures and lithologies may have similar porosity histograms (proof of the analogue concept), but reservoir units that have experienced slightly different burial and fluid histories may have very different porosity distributions. All of this leads to the conclusion that using unfiltered empirical porosity-depth trends on more than a sub-regional scale does provide useful answers for explorers looking to drill deeper prospects.