Thomas and Clouse (1995) have presented results of a detailed laboratory model of secondary oil migration using a sand pack, and then used scaling group theory to extrapolate their observations to field-scale source rock/carrier-bed/reservoir systems. They conclude that for water-wet homogeneous systems, the charging of traps is not controlled by secondary migration rates or losses but by the rate of primary migration from the source rock. Although this conclusion is compatible with the observation that estimates of field charging times are broadly similar to estimates of the time interval for a source rock to mature and expel oil (Saigal et al., 1992), we feel that several of their arguments about real secondary migration processes are misleading and require further discussion.

To scale the sand-pack experiment to the field scale, Thomas and Clouse (1995) apply Rapoport’s (1955) scaling relations, including the following dimensionless group:

$$\left( \frac{kP_c}{\phi \gamma^2} \right)_{\text{model}} \left( \frac{kP_c}{\phi \gamma^2} \right)_{\text{field}}$$

where $k$ is permeability, $\phi$ is porosity, $\gamma$ is the interfacial tension, and $P_c$ is the capillary pressure with respect to fluid saturation function. The $P_c$ function can be substituted by the capillary entry pressure if the function shape is assumed to be identical between model and field (as they assume).

First, to translate a 710-d lab permeability model to a field permeability of 100 md, the authors assume a field capillary entry pressure of 18 kPa (2.61 psi) vs. the model value of 0.34 kPa (0.049 psi). Published evidence would suggest that this capillary entry pressure is too high for a 100-md rock (unless the oil–water interfacial tension were extremely high); for example, Honarpour et al. (1994) report a value of about 0.5 psi for 100-md Berea sandstone. Second, Rapoport’s scaling laws were derived for an isotropic medium. Introducing realistic permeability anisotropy (the $k_v/k_h$ ratio) into the scaling group (as shown by Sorbie and Clifford, 1988) would introduce a very substantial change in the efficiency of vertical migration and saturation distribution in their model, and consequently their inferences about secondary migration efficiency. Finally, and most importantly, the assumption of a homogeneous medium is critical, particularly in the gravity- and capillary-force-dominated systems they are modeling. When the Leverett-$j$ scaling parameter

$$\sqrt{k/\phi}$$

embodied in the above scaling relation is applied to capillary-dominated flow in heterogeneous systems, very significant capillary trapping and retention can occur, which is not captured by a homogeneous model with the same average properties. We have demonstrated this for multiphase flow models with typical clastic sedimentary heterogeneity (Ringrose et al., 1993; Ringrose and Corbett, 1994). The implication is that for realistic sedimentary media much higher levels of oil retention during secondary migration are to be expected (i.e., around 20–40% residual oil saturation as compared with 5–10% for homogeneous media). This is borne out by recent experiments in sandstone rock samples (as opposed to artificial sand packs). Huang et al. (1994) observed residual oil saturations of 30–40% following a water/oil/water, drainage/imbibition flood cycle in a laminated eolian sandstone (average permeability of around 1 d), and Selle et al. (1993) observed residual oil saturations of 10–30% after secondary migration in a Berea sandstone core (average permeability of 660 md). Both systems were considered to be water wet. In fact, the latter group compared experiments of secondary oil migration in sand packs (similar to those of Thomas and Clouse, 1995) with Berea rock core...