**Introduction:** It is now well established that compositional heterogeneity in oilfield waters is the rule [1], [2]. Both inter- and intra-formational variations of water composition have been reported at the field scale. In the hydrocarbon columns, much less is known about the compositional heterogeneity of irreducible waters, which are fossils of paleo-formation water progressively displaced by hydrocarbons during reservoir filling until it becomes a discontinuous phase. At this stage the diffusive mixing of dissolved salts with the underlying aquifer is stopped, and the composition of water fossilized. The $^{87}\text{Sr}/^{86}\text{Sr}$ composition of residual salts shows that water heterogeneity down to the meter scale may be common in many fields [3], [4]. Although there is no direct causal link between the $^{87}\text{Sr}/^{86}\text{Sr}$ ratio and the overall water composition, it is likely that SrRSA gradients are accompanied by variations in the salinity of irreducible waters. Such gradients are key issues in reserves estimation, field compartmentalization assessment, scaling prediction etc. However, the scale of salinity variation suggested by the SrRSA data is much smaller than the scale of water sampling which can be commonly achieved with the conventional wireline tools.

**High resolution salinity profiles:** Core analysis allows a high degree of spatial resolution. Water salinity can be determined on plugs taken and preserved on the rig directly after core retrieval. Once extracted by ultracentrifugation in the lab, water can then be analyzed [1], [4]. Another technique consists in combining Dean Stark and RSA analyses to calculate salinity. However, the reliability of both techniques strongly depends on core contamination by the drilling mud, as well as on water loss in case of imperfect sample preservation.

The analysis of residual salts in shales allows most of these problems to be bypassed. Because of their extremely low permeability and high capillary pressures, shales have two major advantages over sands: (1) their pore space cannot be invaded by the drilling fluids, and (2) they are 100% water-saturated. Therefore, salinity can be determined by combining the analysis of residual salts with the measurement of the pore volume as an estimate of the water volume. Establishing salinity gradients in hydrocarbon-bearing reservoirs from non reservoir shaly intervals relies on two assumptions:

- in the aquifers, pore water in shales is homogenized with sands by diffusive mixing at a rate faster than the rate of oil filling.
- as with the reservoir facies, the composition of water is fossilized once the shale layer is fully isolated within the hydrocarbon pool.

The profile of Figure 1 illustrates the potential of this technique. The salinity values calculated in shales next to oil-bearing sands are well consistent with the Dean Stark-RSA method, as well as with those determined next to MDT samples when both core and water samples were available in the aquifer. In addition to connectivity assessment, Figure 1 also shows that this technique can provide useful information dealing with:

- the relative timing of hydrocarbon filling.
- the variation of filling rates in reservoirs from a single well.
- The biodegradation of hydrocarbons which is very sensitive to water salinity.

A further advantage of this method is its low cost and the possibility of using non preserved core samples.

**References:**