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Systematic Variations in Eagle Ford Shale Porosity and Pore Size Distribution Revealed by High Resolution Scanning Electron Microscopy – Implications for Basin Modeling

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ABSTRACT

Productive shale reservoirs are low permeability source rocks, petroleum was generated within the source rock, and while much petroleum has been expelled a significant volume has still been retained within the source, either stored within the porosity or sorbed onto the organic matter. This retained petroleum is the resource we seek to extract from shale gas/oil reservoirs. These retained petroleum plays require the placement of long laterals and hydraulic fracturing before the petroleum will flow, because matrix permeabilities are very low. To evaluate potential shale plays reliably we require robust geological models which can simulate the generation and retention of petroleum, porosity and permeability in source rocks from first principles, and which can be implemented in basin modelling software. To be predictive, such basin models need to be calibrated against observations from real shale plays; a key control on the amount of retained petroleum is the porosity in the shale and the abundance of organic matter. Scanning electron microscopy (SEM) of Ar–ion milled shale samples can potentially reveal systematic variations in the amount of porosity, pore types and distributions across a range of thermal maturities. These observed variations in porosity can be used to calibrate or 'sense check' basin modelling output and refine predictive models. For this reason BP has conducted scanning electron microscopy studies of shale plays including the Eagle Ford shale. Our studies involve pore image analysis of Ar-ion milled 2d sections. The results show that the larger mineral-associated pores disappear with increasing thermal maturity, due to compaction and cementation. By contrast the organic matter (OM) hosted pores are absent in low thermal maturity samples (where %Ro < 0.7) and become increasingly more abundant as thermal maturity increases. In moderate maturity samples there are OM–hosted pores that range in pore size from 5-500nm. In the high maturity samples only small (<50nm) OM-Hosted pores predominate. Our studies reveal that porosity evolution in organic rich shales is a complex process involving mechanical compaction, diagenesis, bitumen generation and development of secondary porosity within organic matter. However, the variations are systematically related to thermal maturity and lithology and can hence be simulated in basin models.