This presentation will demonstrate the importance of understanding petroleum composition (Gas-Oil ratio and viscosity) and reservoir pressure in order to find sweet spots in shale liquids plays and other tight oil plays. This study will also demonstrate the importance of understanding post-burial uplift in shale plays and its effect on reservoir pressure.

Although many companies focus on finding the right rock in a shale play (using TOC, thickness, brittleness, etc.) the properties of reservoir fluids and pressure are at least as important as properties of the rock for defining the most valuable parts of a shale fairway. This study will show that the sweet spot (i.e. the most profitable part) of the Eagle Ford Shale is found where the least viscous liquid phase and the most oil-rich vapor phase occur at highest reservoir pressure. Thus, sweet spots in shale and other tight liquids plays are best understood by focusing on concepts of fluid mobility rather than strictly on rock properties.

For this study, in-house source rock kinetic models were coupled with regional basin modeling in the Eagle Ford Shale fairway to delineate the sweet spot. This work involved the prediction of petroleum compositions and evaluation of the effect of petroleum generation on pore pressure. Maps of thermal stress were converted to maps of gas-oil ratio, viscosity, and BTU content to predict mobility of shale liquids and flow of revenue from wells across the fairway. The results of this study indicate that petroleum compositions in the Eagle Ford Shale are closer to an instantaneous product over a narrow thermal stress range rather than a cumulative product from expulsion and migration over a broad range of thermal stress. The petroleum is in near equilibrium with the thermal stress state of the rock and most petroleum was generated in situ and retained as the last generated product with limited lateral migration. Fluid viscosities are closely linked to composition (GOR), and thus are predictable. Thus, although the Eagle Ford expelled large volumes of petroleum and this petroleum migrated out of the formation, the petroleum that we produce from the Eagle Ford was generated in situ and is not the result of lateral migration.

Mobility of shale liquids and, thus, revenue flow are also strongly a function of reservoir pressure. The reservoir pressure we see in the Eagle Ford today is the result of how the pressure was created and how it was preserved after burial. Several authors have proposed that most of the over-pressure in shale source rocks was created by petroleum generation. Basin modeling performed in this study suggests that petroleum generation can account for some of the over-pressure within the Eagle Ford Shale gas and liquids fairway (as measured in psi above hydrostatic). However, much of the regional over-pressure was generated from disequilibrium compaction during rapid Late Cretaceous through Paleogene burial. Late exhumation altered shale reservoir pore pressure in the western half of the Eagle Ford fairway. The central part of the Eagle Ford fairway had comparatively less uplift. As a result, the amount of over-pressure in the western part of the fairway is not directly linked to thermal maturity and GOR. Fluids with higher Gas-Oil ratio occur at relatively lower reservoir pressure in the west compared to the central part of the fairway. Therefore, whereas retained petroleum properties can be linked closely to thermal stress, creation and retention of over-pressure is not strictly due to petroleum generation and a broader, basin-scale interpretation is required in order to define regions where revenue generation will be highest. Because it is often the foreland phase of rapid subsidence and burial that catalyzes both disequilibrium compaction and source rock maturation, the generation of petroleum and over-pressure are often coeval and their effects on reservoir pressure, effective stress, permeability, and reservoir deliverability can be difficult to differentiate. Lastly, it can be shown that there is a strong inverse link between uplift and preservation of over-pressure. North American onshore basins that have experienced large amounts of uplift and erosion are often normally pressured. Basins that have experienced minor amounts of uplift and erosion have retained high over-pressure.