Exploration well failures and reservoir distribution along the Scotian Slope (eastern Canada)

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With 13 deepwater wells over 260 000 km^2, the Scotian Margin remains a frontier basin. From 2011 to 2015, exploration activities from major petroleum companies have resumed but success is slow in coming. The last two - Shell's Cheshire (2016) and Monterey Jack (2017) remain confidential. Currently, only the Marathon Annapolis G-24 (2002) and Chevron Newburn H-23 (2002) discovered gas in deepwater. Post-mortem analyses have concluded that the issue in finding viable prospects is not the petroleum system *per se*, but the difficulty to properly predict reservoir location due to complex salt tectonics.

The current study aims to show that coupling 3D seismic character attributes analysis with seismic stratigraphy and stratigraphic modelling will increase the probability of success. We present different cases of study across the Scotian Basin with a focus on the Central Scotian sub-basin.

In the case of the Central Scotian Basin, we hypothesized that two main factors lead to the latest well failures: (1) seismic processing that, for instance, didn't take into account seabed related interferences; and (2) misunderstanding of the depositional model which rely too much on the Gulf of Mexico analogues. We have revisited the Cretaceous depositional model and made assumptions on reservoirs distribution through space and time. We then tested the robustness of the sandstone distribution model against stratigraphic modelling using DionisoFlow™. Our geological model combined with stratigraphic modelling results suggest that significant trapping systems formed at the shelf edge during the Upper Missisauga–Logan Canyon formations (Barremian–Albian), which coincides with the timing of the salt canopy formation. Sand proportions between 10 to 25% are expected in some salt-induced minibasins downslope. There is a particular area southeast of the Tantallon M-41 well highlighting a sediment pathway showing sand proportion ranging between 20 and 25% for the studied interval.

In the case of Georges Bank and Shelburne sub-basins, the use of stratigraphic modelling was extended through the Jurassic. Results have highlighted a significant amount of Middle Jurassic and Early Cretaceous sandstones from Georges Bank to the southern part of Shelburne sub-basin. It's interesting to note that results from the 2011 PFA stratigraphic modelling in northern Shelburne Sub-basin suggest the Cheshire and Monterey Jack wells were drilled outside the main carbonate play and within an area dominated by shale until the Albian.

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