Mauritania - How Prospective is the Deepwater for Oil?

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International interest in the Mauritanian deepwater was reinvigorated in 2014, following the disappointments in the Chinguetti region, by Cairn's major oil discovery at SNE-1 in Senegal and again the following year by Kosmos Energy's giant gas find at Tortue-1 on the Mauritanian - Senegal border. The Tortue play was largely constructed for Senegal from 2012 onwards by the Timis Corporation and for Mauritania by Kosmos with both companies recognizing, in part from existing seismic and wells, and in part by the ongoing global surge in deepwater exploration, the potential for basin floor fans (BFF) located west of the Jurassic to early Cretaceous carbonate bank (see the earlier occasional short releases by FEC for more detail on this feature). Kosmos acquired in 2012 three ultra-deepwater Mauritanian blocks, C-8, C-12 and C-13 (Figure 1), located immediately to the north of the border (in 2016 Block C-6 was also awarded to them) and in 2014 they acquired by farm-in Timis's on-trend, Senegalese blocks to create a broad, on-trend portfolio of deepwater acreage. After Tortue-1, Kosmos made further giant gas finds north and south of the border, but their predicted oil was not encountered, and their final three wells were dry. Two of these wells, Hippocampe-1 (Block C-8) and Lamantin-1 (C-12), were in Mauritania.

Total acquired three blocks in mid-2017 (C-7, C-9 and with Kosmos C-18) and two more in December 2018 (C-15 and C-31). Their first three blocks lie directly on trend to the north of the Kosmos acreage in areas formerly held by Tullow and Dana. The two new blocks lie to the west of the Kosmos blocks in previously unexplored, distal basin settings with water depths in excess of 3,000 meters. In late 2017, Exxon acquired three deepwater blocks, C-22, C-17 and C-14, followed by Shell in July 2018 who secured Chariot's former Block C-19 and Tullow's Block C-10. Exxon's blocks lie on trend with Total's distal C-15 Block, while Shell's blocks lie on the previously productive trend positioned between the carbonate bank and Kosmos's acreage. Their southern block, C-10, includes the now abandoned Chinguetti Field, plus various adjacent oil and gas discovery wells. Tullow retain their north-south elongated block, C-3. which lies between the coast and the carbonate bank. This region hosts multiple early wells, many with shows.

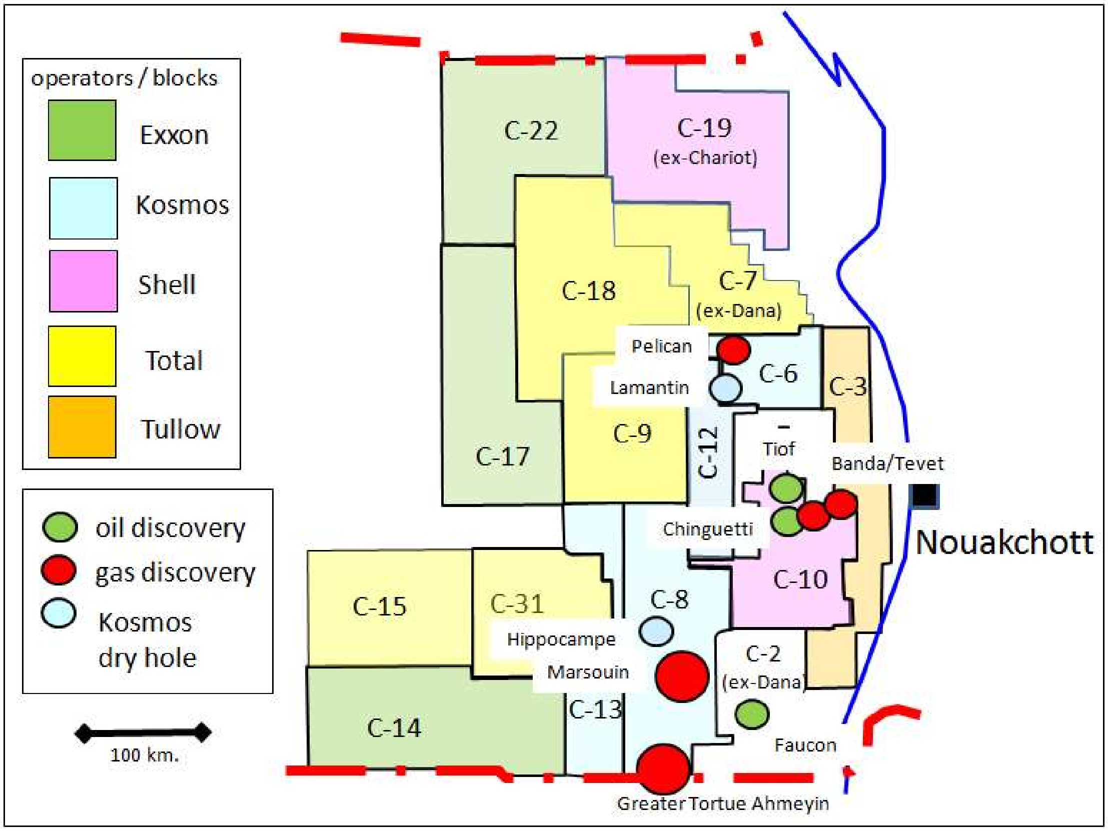

Figure 1. Block operators in Mauritania (draft).
(open acreage is excluded; the new shape of the C-10 Block remains to be determined)

The petroleum geology of the deepwater

The following observations draw primarily on FEC's 2016 Senegal country report since this study provides a post-SNE-1 / Tortue-1 review of the geology west of the carbonate bank up to and just across the Mauritanian border. Two other important resources were the insightful play maps periodically released by Kosmos for the southern two thirds of Mauritania and the depth converted, deepwater seismic line that that was included in a public domain file released by Spectrum in May 2015. Collectively, these three items are sufficient to construct an initial review on the possibilities for continued commercial discoveries in the Mauritanian deepwater and to examine where the sought for deepwater oil could be found (updates to this note will prepared as more information emerges).

In Northern Senegal the drift succession from the mid-Albian upwards is dominated by long term progradation associated with the Diender Lobe of the Casamance Delta (Figure 2). This Lobe, as well as providing the reservoir sands for the Kosmos discoveries, also supplied copious gas-prone source rocks. The considerable thickness of the overall progradational cover was sufficient to depress the source section, regardless of whether oil-prone kerogens were present, into the Gas Window. Insufficient public domain information is available to assess how far significant Lobe progradation extended into Mauritania. The Kosmos base map used for Figure 2, assuming that the green shaded, hydrocarbon yield colors relate to an uniform quality source, suggests that the progradation could extend north of the Kosmos blocks (the second assumption is that the lighter green colored, lower yield tongue, depicts regions of thicker section). However, the broadly east to west orientation of the channel defined prospect trends shown on the same base, for example west of the Chinguetti region, indicate there was also sediment supply from the east: this channel orientation direction was first defined by the Chinguetti area discoveries. The Miocene depocenter created by the Nouakchott River and windblown, Saharan sands is indicated on Figure 2. Deep sea drift was predominantly to the north.

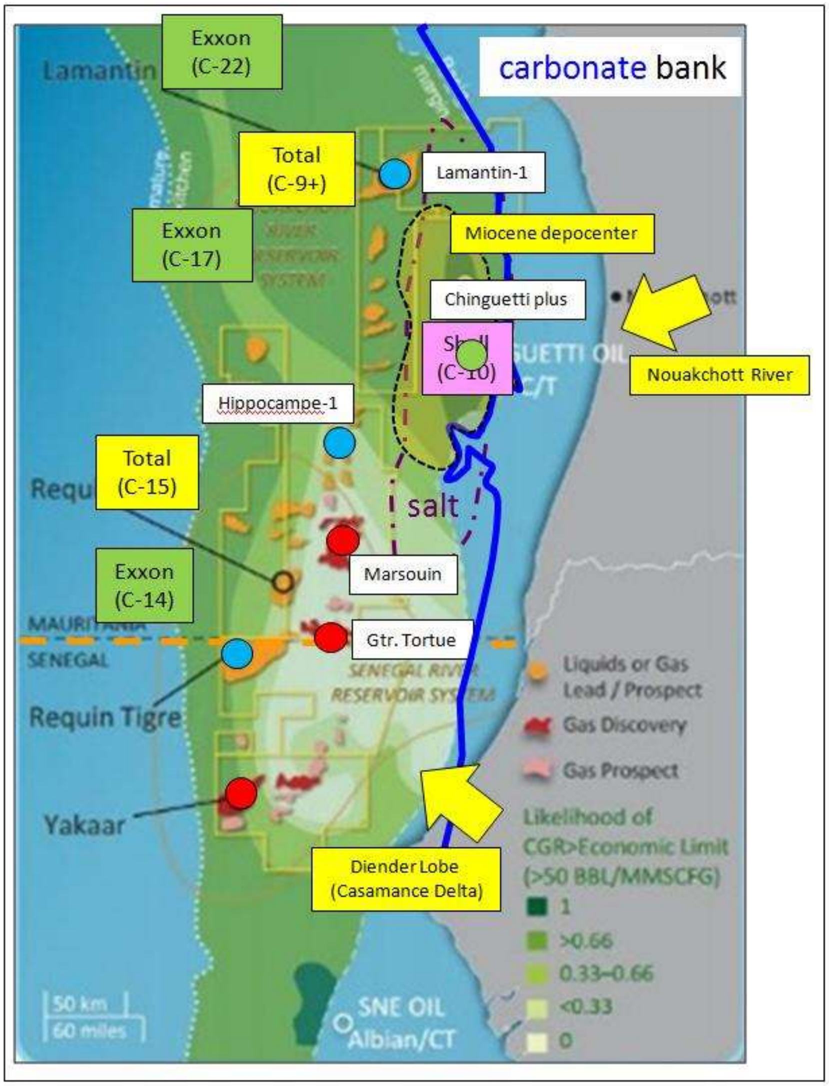

Figure 2. Deepwater play controls (base taken from Kosmos press releases). The track of the carbonate bank and the outlines of the salt basin and Miocene sand depocenter are copied from industry press releases. Kosmos' prospects are combined structural-stratigraphic opportunities which means pure stratigraphic opportunities exist. Kosmos consider the structural control for their prospects was provided by the reactivation of deep faults following a change in plate movement direction in the younger Cretaceous (the Santonian event). This observation may explain why so many features on this figure track the COB.

Spectrum's depth converted line (Figure 3) provides a deepwater dip section that runs westwards from the edge of the salt basin in the Chinguetti region. At depth, the eastwards thickening succession that disappears into the salt basin is, based on basin configuration comparisons with Senegal, is considered to be of older Jurassic age.

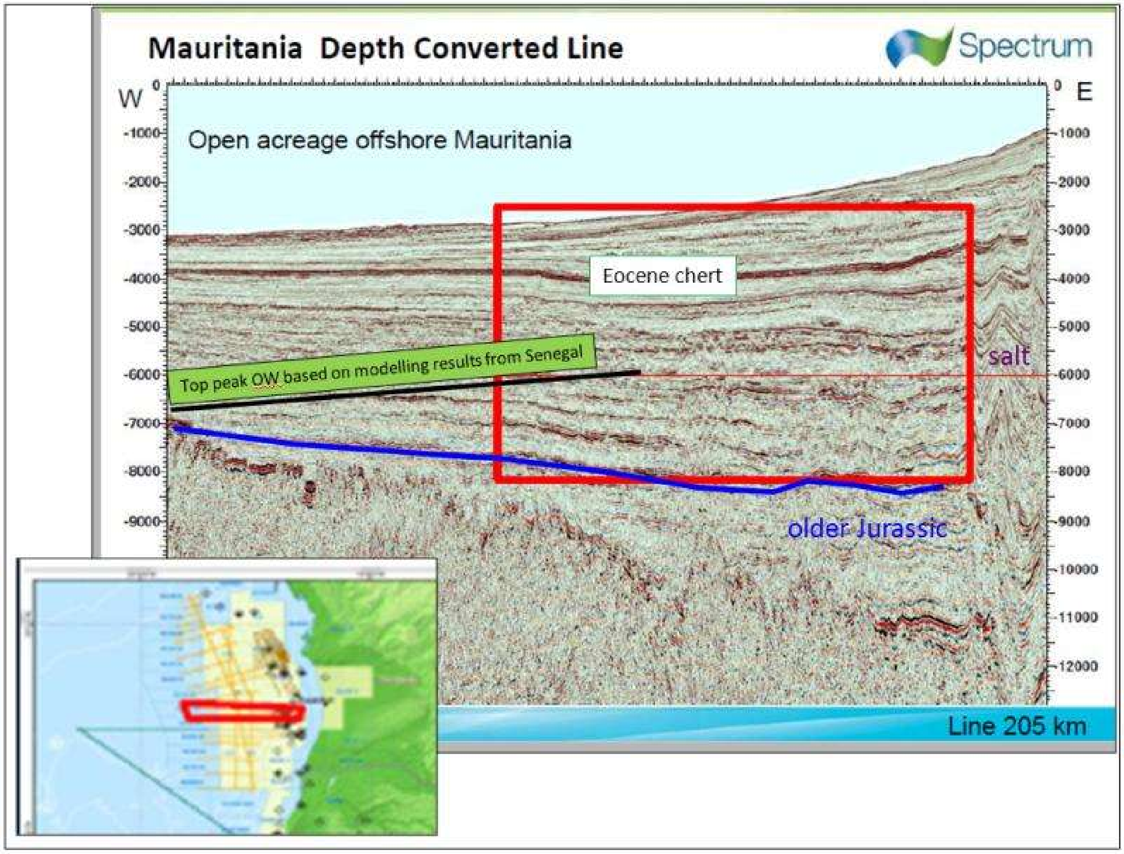

Figure 3. Spectrum depth converted line running west of the salt basin and illustrating Cretaceous hosted, amplitude anomalies in then open acreage. This area is now shared by Kosmos (east) and Total (west). The line can be found at: *http://ae1968dbb5a02367acda-2ff7336f4b8235523c252a2d7618cadf.r7.cf1.rackcdn.com/Spectrum.pdf*
The shallow strong reflector is interpreted to be the regional Eocene chert marker. The top Jurassic pick is assumed to be the boundary between even thickness units (drift) and the deeper eastwards thickening units (late rift).

Included on Figure 3 is the equivalent position of the peak Oil Window derived from FEC's Senegal report for the region south of the Cainozoic magmatism in the north of the country. Its position suggests there should be significant generation from the Cretaceous source horizons almost to the western end of the profile and thus out into the new ultra-deepwater blocks. This possibility, though, is not supported by the amplitudes on the profile which die westwards. One reason could be the decreasing amount of gas as the source section becomes progressively less mature in that direction or the gas could have come largely from the deep Jurassic section. An alternative and more insightful explanation may be available from the findings of a 2018 paper by Lodhia et al. who find that top asthenosphere temperatures are lower in the coastal region of Mauritania than they should be as a result of mantle flow westwards towards the hot Cabo Verde swell. The result is an enhanced thickness of Neogene sediments (the Nouakchott depocenter) compared to the coastal regions further north and south following a temperature decrease at the top asthenosphere (less than 100° C). How much the modern geothermal gradient within the sedimentary cover has been lowered will require modelling, but any drop will lower the active Oil Window from its earlier position. Such a developing cooling event could account for Woodside's many dry holes, plus Kosmos' recent results if previous charges emplaced in a hotter regime have been dissipated by leakage and the current charge rates are insufficient to replace those leakage losses. One quoted reason for the failure of Lamantin-1 was leakage, another was lack of charge. This possibility could mean the amplitudes on Figure 3 are related to residual charges. It is unknown ahead of modelling whether geothermal gradients are currently rising in the far western, ultra-deepwater acreage towards Cabo Ledo. Maybe, nearer the coast, an outcome should be an increased focus on the Chinguetti region with its extra Neogene loading as the fall in the geothermal gradient may be compensated by the thicker Neogene section. With the incoming of the Jurassic section there is also more section to host peak Oil Window generation. A downside, as noted below, is that moving east may raise the seal risk.

As the Nouakchott River was far smaller than the Casamance Delta, Cretaceous source dilution may not be a concern away from Delta influences. Defining the northern limit of Casamance Delta influences will, therefore, be a further key consideration in assessing whether pure oil sources can be present.

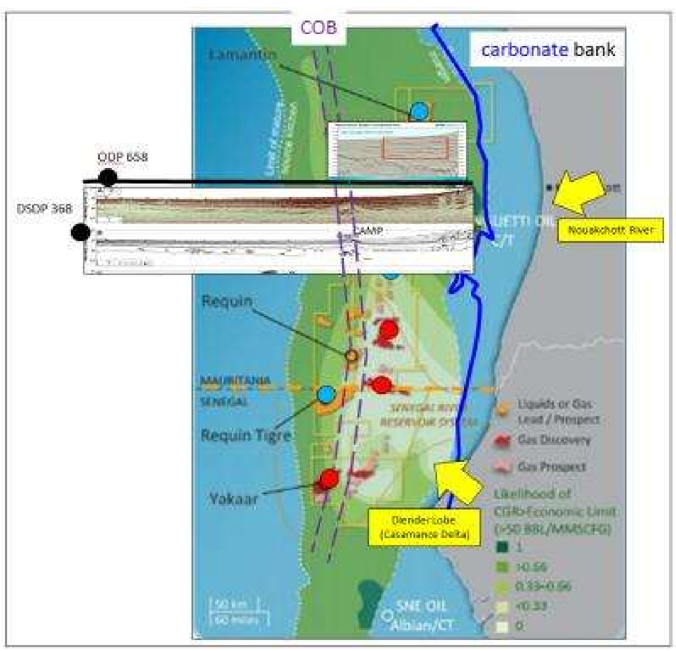

Figure 4. Dip seismic illustrations.
The shorter profile is an approximate fit of Figure 3, the longer profile is a published regional line that extends from the salt basin out to OPD site 658. This line is at:
https://www.google.co.uk/search?q=flamant-1+well+mauritania&source=lnms&tbm=isch&sa=X&ved=0ahUKEwirlbbl39bfAhUUXhUIHc_2DIcQ_AUIDigB&biw=1920&bih=911#imgrc=3XLuKU2ZJRBa0M:&spf=1546694977262

This fit is also approximate and based on figure 1B in Lodhia et al. (2018) in which the illustrated long line is their figure 9.
The COB boundary is also taken from their figure 1B and the fit is again approximate.
The COB relief on their profile is likely to be CAMP magmatics.

The Chinguetti area well results suggest that the laterally supplied sands may not be voluminous enough for ready commercialisation. It may also mean in regions where large rates are dropping that associated thin sands will become the dominant seal risk. The best potential for thick sands may lie with the distal BFFs of the Casamance Delta. The balance here will lie between the requirement for thick sands and avoiding any accompanying gas-prone sources. Just possibly the far northern waters south of the RAB Nose (not included on Figures 2 and 4) may be the optimal location as sands there may be thickened at the foot of the RAB Nose by converging deep currents and any Casamance influences may be minimal. Shell now hold this area (Block C-19).

Reference:

Lodhia B. H., C.G. Roberts, A. J. Fraser, S. Fishwick, S. Goes and J. Jarvis, 2018. Continental margin subsidence from shallow mantle convection: Example from West Africa. Earth and Planetary Science Letters, 481, 1, 350-361.
(the abstract is at:
https://www.sciencedirect.com/science/article/pii/S0012821X17305836)

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