Derisking deep-water Namibia

Neil Hodgson[1*] and Anongporn Intawong[1] show how the drilling of four wells in deep-water offshore Namibia have reduced the risk for forthcoming drilling campaigns in what were thought to very unpromising plays.

Until very recently most explorationists looking at the hydrocarbon potential of the Namibian offshore would have quickly pointed out the three play-risking elephants in the room: no proven oil source, no proven reservoirs and no proven traps. However, over the past 18 months four key wells have been drilled in deep-water offshore Namibia, to directly investigate these assertions. The astonishing results of this drilling campaign has significantly derisked the main play elements of the margin preparing the way for clear, focused exploitation to unleash the potential of this exciting margin.

Setting the scene

Previous exploration in the three Namibian offshore basins covering 500,000 km^2 of passive margin, comprised only 16 wells, of which seven were appraisal wells in the Kudu Gas field, and all were drilled on the shelf in less than 500 m of water. The geology and hydrocarbon systems in deep-water were completely unexplored by the drill-bit, and indeed only when Spectrum acquired >20,000 km of new 2D data along the margin in 2012 could the structure and character of the margin be fully imaged. The available dataset for this study is shown on Figure 1.

The three Namibian offshore basins are the Orange River Basin in the South, straddling the border with South Africa, and the Luderitz and South Walvis Basins to the north (Figure 2). These basins were formed during the Late Jurassic to Early Cretaceous as a result of lithospheric extension followed by the breakup of Gondwana creating a north-south rift system along the present day southwest African margin. With a common mechanism of formation, unsurprisingly all of these basins have similar structures and sequences visible on seismic. However, sediment input has varied significantly into each basin such that the sequence isopach and morphology varies greatly both within and between basins.

The sequences developed prior to Gondwanan break-up, and drift i.e., below the Break-Up Unconformity (BUU) comprises syn-rift graben and half-graben in pre-rift basement on the shelf, whilst out-board, comprises thick, fanning sets of sub-aerially deposited flood basalts (Sea-ward Dipping Reflectors – SDR's). The transition between these two is commonly expressed by a broken north-south ridge of large domed structures, formed from SDR's on pre-rift basement blocks, which is known as the Outer High (Figure 3). Even farther out-board, the SDR's are replaced by angular irregular reflectors interpreted as oceanic crust formed from marine Mid Ocean Ridge Basalt (MORB).

Overlying the BUU is a sequence of Aptian marine mudstone which, in-board of the Outer High, is overlain by a prograding and aggrading Albian carbonate platform sequence and Cenomanian-Turonian organic-rich mudstones. This in-turn is overlain by a prograding Late Cretaceous and Tertiary clastic sequences.

Prior to the recent drilling campaign, exploration wells had been drilled on the shelf of all three basins, targeting

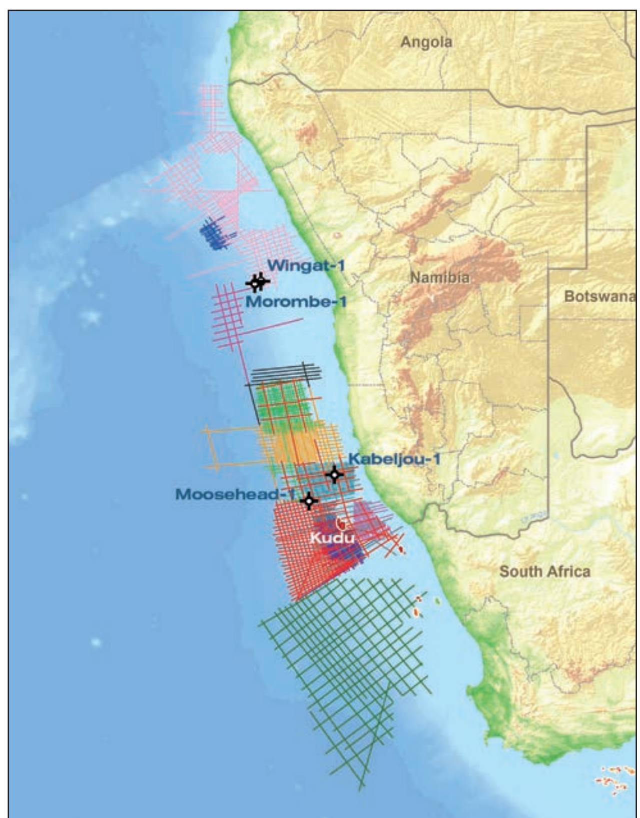

Figure 1 Spectrum's evaluation dataset of 2012/2013 2D acquisition and 2012 reprocessing of legacy datasets. In total over 40,000 km of 2D data was available for this evaluation.

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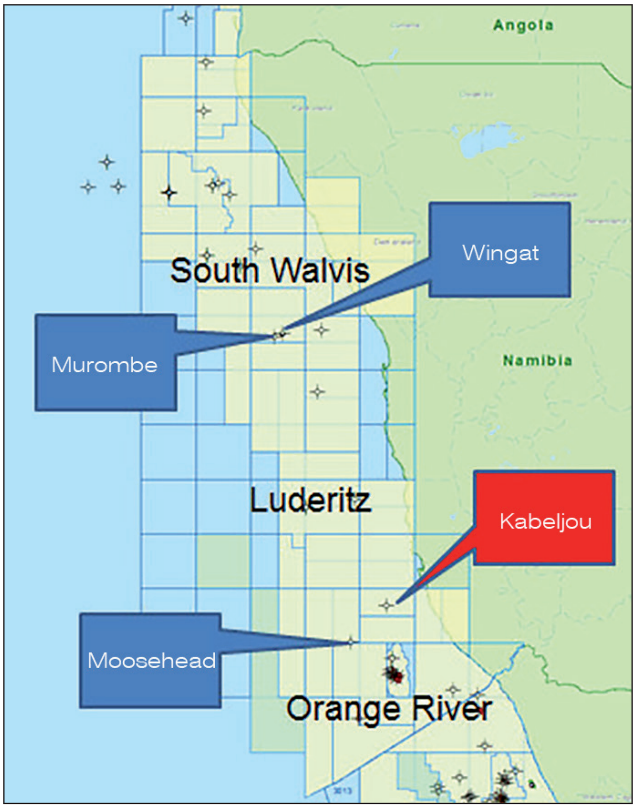

Figure 2 Four wells drilled in the last 18 months in Namibia have transformed the prospectivity of the basin.

Early Cretaceous syn-rift clastic reservoirs charged by syn-rift lacustrine source rocks. This source rock play was later to yield success in the South African Orange River Basin (the Ibhubesi gas field in 1981 and the AJ-1 oil discovery in 1988), but in Namibia had yielded little more than shows until the discovery of the Kudu field in 1974. The 1.3 TCF Kudu gas field hints at the potential from offshore Namibia, yet the resource is a particularly curious accumulation, comprising reportedly modest porosity aeolian sands of Hauterivian age, sandwiched between thick flood-basalt layers, a combination that is resistant to seismic derisking. Despite, or perhaps due to this success, source continued to be a concern in this margin as repeating the charge system of Kudu is unpredictable, coupled with Kudu's complex reservoir diagenesis, and frankly an oil source is principally what was being sought.

2012-13 Campaign

Four wells have been drilled in the last 18 months looking at other, non-Kudu plays on the Margin. These wells include the Kabeljou (Petrobras Operated) and Moosehead (HRT Operated) wells drilled in the Orange River Basin and the Murombe and Wingat wells (HRT Operated) drilled in the South Walvis Basin (Figure 2)

Discussing the released results from these wells in time sequence with reference to the available seismic dataset is illustrative as they showed a great diversity of exploration target, and point tantalizingly to a key untested play.

Kabeljou-1

Kabeljou-1 (2714/06-1) was drilled in 377 m water from July to September 2012, reaching TD of 3150 mSS. The well targeted an outer high play in the Orange Basin (Figure 4). High amplitude targets can be observed between the green (top Albian) and purple (BBU) horizons. These high amplitudes were interpreted to be sandstone turbidites draped over the outer high structure.

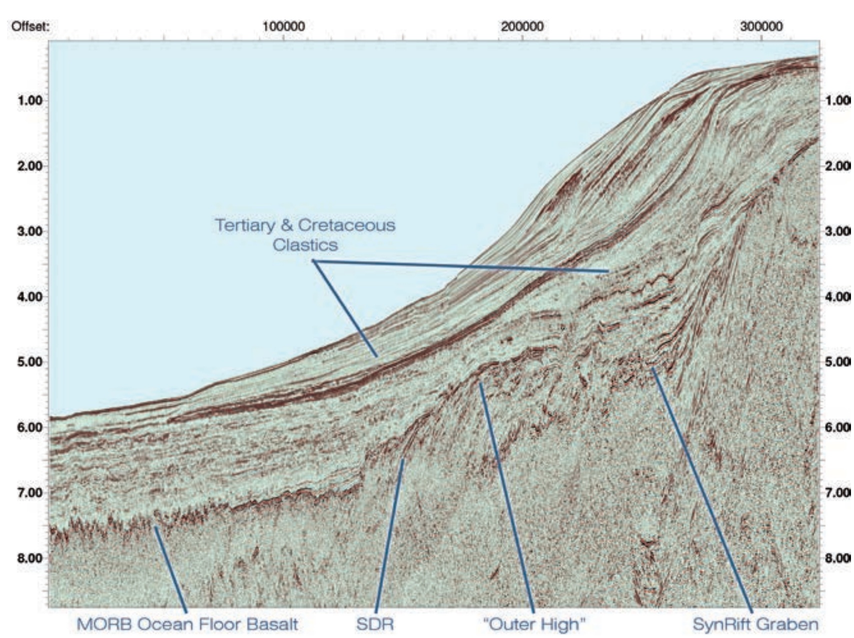

Figure 3 A typical dip seismic line showing the consistent structures on the Namibian margin. This line is oriented WSW-ENE and is 320 km long.

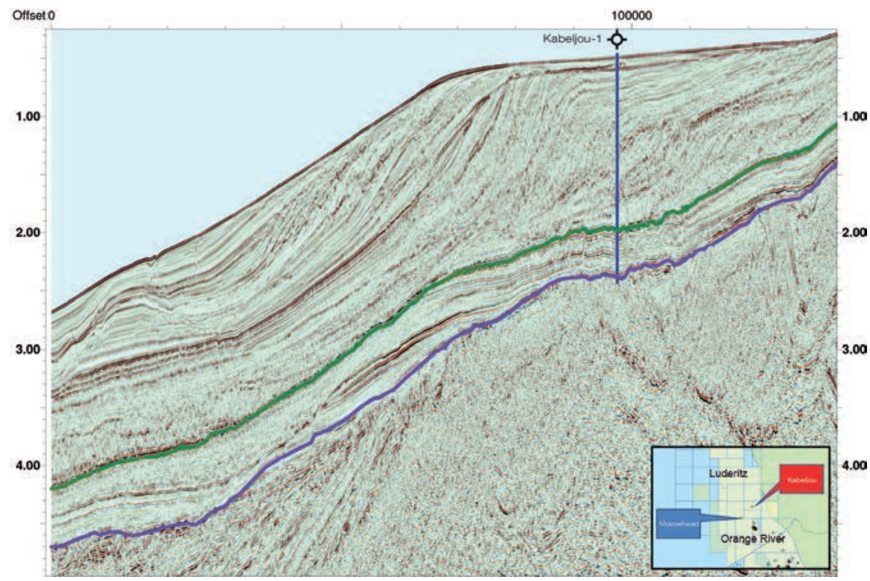

Figure 4 *Dip Line through the Kabeljou well. This 2012 reprocessed line is oriented W-E and is 151 km long.*

However the target was found to be non-reservoir, mudstone and tight siltstones. As these targets were draped over the outer high, and their contemporaneous sequences onlap on to the high, it is probable that the outer high was a positive feature during deposition, and that coarse clastic turbidites might indeed be found around the margins of the structure, leaving the crest a hard-ground. Utilization of a regional seismic grid to map sequence isopachs and isochrons will facilitate understanding of sediment deposition systems around the out-board highs.

A positive walk-away from Kabeljou-1 is the reported encountering of thick source rocks in both the Cenomanian-Turonian and Aptian sections. The Cenomanian-Turonian system had been encountered as a potential source in several wells (e.g., 2012/13-1 and DSDP site 530) as had the Aptian in Kudu 9a-1 and DSDP site 361 which encountered Aptian source rock consisting of sapropelic black shales with up to 15% TOC. Kabeljou-1 proved these sources are thick, widespread in the deeper-water and mature for oil hydrocarbon generation.

Wingat-1

The second well of the sequence to be drilled was HRT's Wingat-1 well (2212/07-1), was located in the South Walvis Basin. This well spudded during March 2013 in a water depth of 1,005 m and reached TD in May of this year at 5,000 mMD in post-rift Aptian section.

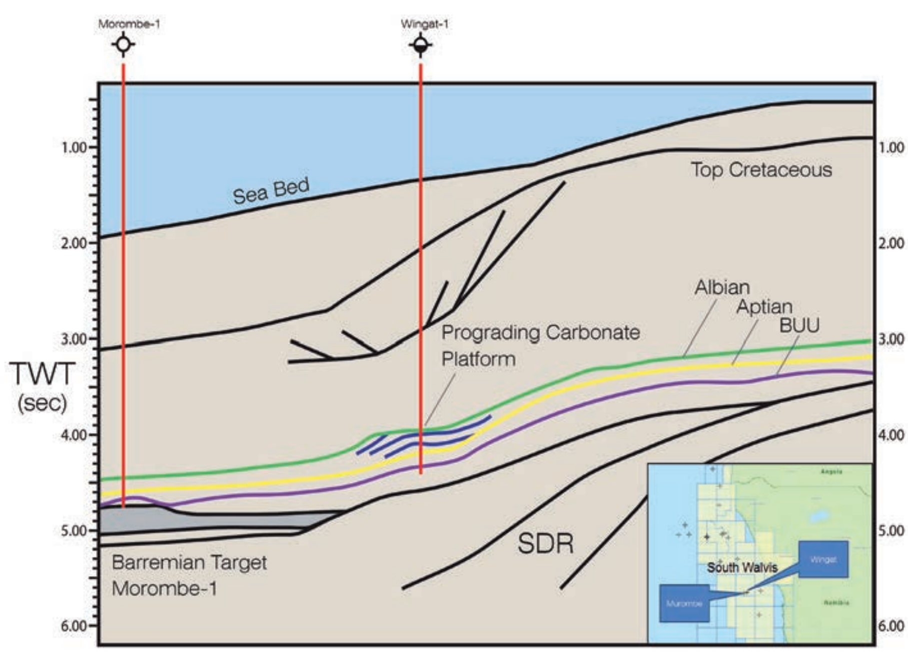

Figure 5 *Geoscience line through Wingat-1 and Morombe-1 wells. The line is orientated SE-NW and is 66 km long.*

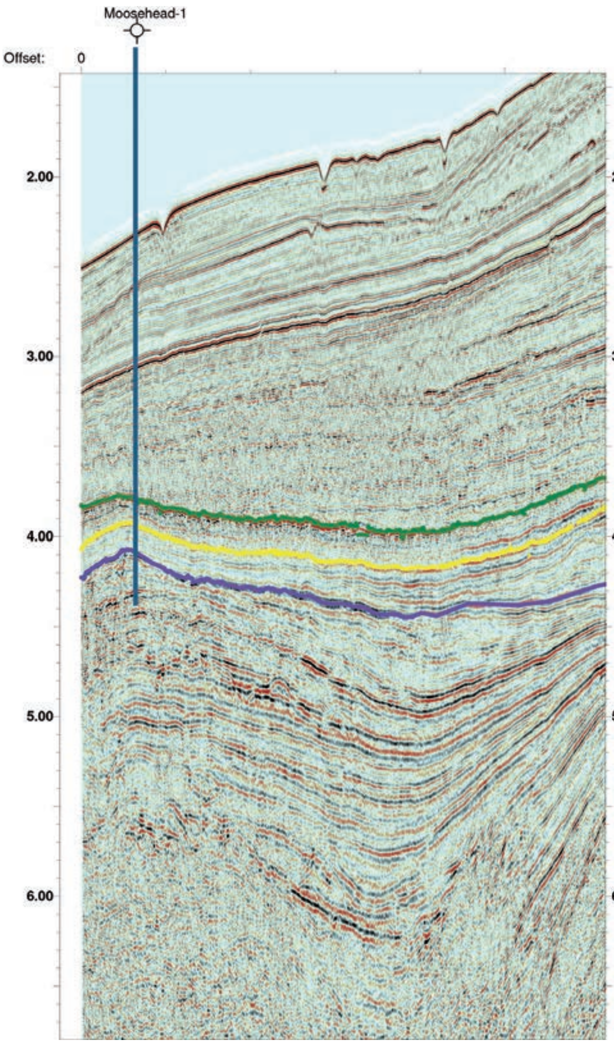

***Figure 6** Dip seismic line through the Moosehead-1 well. This line was reprocessed in 2012, oriented ESE-WNW, and is 62 km long.*

The well tested a three-way dip closure with up-dip stratigraphic trapping of the Albian carbonate platform (Green Horizon, Figure 5), sited above a proposed Aptian Source rock, that has a well-defined seismic amplitude anomaly described on HRT's published PSDM-3D data and also Spectrum's 2D data (Yellow Horizon Figure 5).

Although Albian carbonate was penetrated as prognosed, this unit was non-reservoir due to a lack of primary or secondary porosity development. However, the well was deepened into the underlying Aptian source rock which was found to be thick, and mature. Indeed from several thin, sandy lenses, light oil 38 to 42o API was recovered. This is a very significant data point, as although the Aptian had been penetrated and found to have high organic content, this is the first oil recovered from the Aptian in the deep-water and proves the efficacy of this as an oil source.

Morombe-1

Morombe-1 (2212/06-1) was the third well in the sequence to be drilled, from May to July 2013, and returned to targeting a clastic Barremian, play fairway. The Morombe-1 well is located 15 km west of Wingat-1 in 1391 m of water. Murombe-1 tested a 1000 km^2 Barremian basin floor fan on a four-way dip closure at its highest structural elevation within a turbidite complex (Figure 5), and TD'd at 5729 mMD.

A shallower, Santonian-aged secondary objective (Baobab prospect) was also targeted in this well, interpreted as a confined channel complex with turbidite reservoirs (Figure 5).

However, no reservoir was encountered at the primary target level as the Barremian reflectors in fact represent volcanics rather than ponded turbidites. However the secondary target, a channel Santonian age, encountered 242 m gross section with a 15% n/g ratio and 19% porosity, though was water-wet. This shows that Late Cretaceous coarse clastics are indeed present and, subject to having up-dip trap, will provide good exploration targets.

Yet again this well encountered a thick Aptian source rock above the BUU.

Moosehead-1

The final well in this drilling campaign was the Moosehead-1 (2713/16-1) well drilled in the Orange Basin. The Moosehead well targeted a four-way dip closed microbial carbonate developed below the proposed Aptian Source rock (Figure 6). The well was located in 1716 m of water, drilled from August to September 2013 and TD at 4170 mTVDSS.

Although the carbonate sequence was encountered as prognosed, again it was found to be non-reservoir due to a lack of primary or secondary porosity. However the well again confirmed the presence of two potential source rocks, at Aptian and Cenomanian-Turonian.

The lack of development of secondary porosity in the carbonate targets of the recently drilled wells is in itself curious, and suggests a possible causal connection relating the subsidence of the margin and limited opportunity for sub-aerial exposure.

Conclusion: significant de-risking of the hydrocarbon play system on this margin

The results of the new wells clearly show that an Aptian source rock present and effective on the Namibian margin. Regional seismic data allows the Aptian to be modelled for variation in depth of burial under the Late Cretaceous and Tertiary clastic wedges. The model of Bray et al., 1999 holds true and now, with the Wingat-1 well results is partly-proven. Inboard, the Aptian on laps the BUU yet will be oil prone as depth of burial is low. Under maximum burial of the current shelf edge, modelling suggests the Aptian may be just entering the gas condensate window and further offshore, the Aptian is again oil prone.

Focusing on the reservoir and trap parts of the hydrocarbon play system, the lack of primary or secondary porosity development in the carbonate targets drilled to-date might be common to the development of carbonate systems tracts, along the Namibian margin. This would be surprising as the Moosehead-1 and Wingat-1 wells targeted carbonates of different ages and depositional facies. However, the clastic reservoirs in the Upper Cretaceous are proven in terms of presence and effectiveness by the Morombe-1 well.

The distribution of coarse clastic in slope channel systems and basal turbidite fans can be investigated with regionally mapped sequence isopach or isochron mapping. This is a critical part of understanding the development of the Namibian basins as sediment input into the three basins has changed markedly with time and the consequent sedimentary morphologies have developed accordingly (Figure 7).

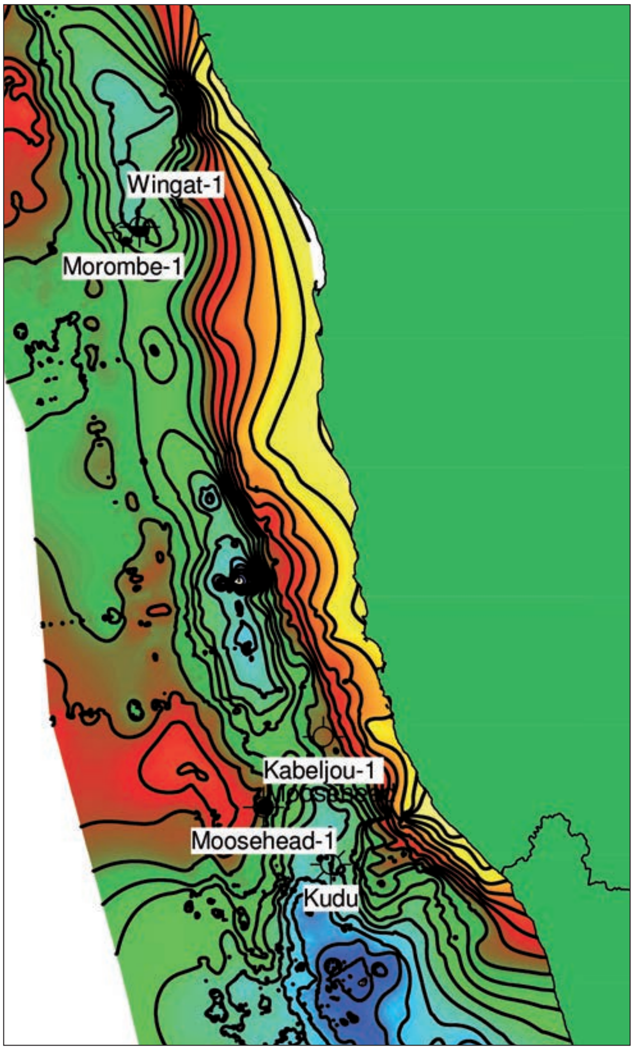

***Figure 7** Isochron Map of Post Break Up Unconformity (BUU) sequences on Namibian Margin. Contour interval 0.25 sec TWT. Kudu to Wingat 735 km.*

Additionally, the interaction of gravity controlled clastic sediments with basin floor geometry (often reflecting the BUU morphology), will guide the hunt for both coarse clastic reservoirs and the areas where bypass or non-deposition can generate up-dip trapping mechanisms. Trapping mechanisms will include the structural plays, particularly around the Late Cretacous gravity slides in the Namibian and South African part of the Orange River Basin, but also the well imaged stratigraphic channel bypass plays of the Luderitz and South Walvis Basins.

Although the recent well campaign in deep-water Namibia has not delivered a major oil success, these wells have been stunningly successful in reducing risk for forthcomming drilling campaigns, particularly those that target Late Cretaceous coarse clastic reservoirs charged by Aptian source rock. This new information, coupled with high-quality regional 2D data will fuel the science and analysis that will finally deliver the oil promise of Namibia's extraordinary deep-water geology.

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