Further de-risking source rock maturity in the Luderitz Basin using basin modelling to support the BSR-derived near-surface geotherm

Anongporn Intawong[1*], Mads Huuse[2], Karyna Rodriguez[1], Neil Hodgson[1] and Martin Negonga[3] **present results to support the interpretation that the underexplored Luderitz Basin contains thermally mature source rocks of both Aptian and Turonian age.**

The discovery of Kudu gas-condensate accumulation and recent wells drilled offshore in the Namibian margin have successfully de-risked source rock presence and maturity (Hodgson and Intawong, 2013). Both the acquisition of an extensive 2D seismic dataset in 2012 and a recently acquired cross-border survey 2015 offshore Namibia and South Africa have facilitated the evaluation of source rock maturity distribution for the Early Aptian and Cenomanian-Turonian source rocks along this margin (Figure 1).

Conventionally, we have no tools to interrogate heat flow and geothermal gradient in an undrilled basin and have to rely on extrapolation from offset wells, imposing models on a structural interpretation of the basin margin. Near-surface geotherm estimation derived from seismic measurement of the thickness of a gas hydrate accumulation with respect to the water depth found in the Luderitz Basin has been employed as a preliminary approach for the initial evaluation of source rock maturity in this margin (Hodgson et al., 2014). The approach remains an under-utilised seismic method for initial evaluation of source rock maturity in undrilled basins. Public domain heatflow data (Davies, 2013), knowledge of subsurface thermal conductivity and crustal heat production can be used to predict geotherms and thus temperature spatially away from control points.

Petroleum system modelling is the most efficient way of systematically investigating the thermal maturity of sedimentary basins. This can be tailored to available constraints, which in the case of the deepwater Luderitz Basin include shallow temperature data derived from BSR (60°C/km in the upper 500 mbsf) and heatflow measurements (40-60 mW/m2; Davies 2013). The uppermost sediments have a thermal conductivity of < 1 W/m/K, which is 2-3 times lower than deeper (compacted) clastic sediments. That would provide an average geothermal gradient of 30°C/km as previously proposed by Hodgson et al. (2014).

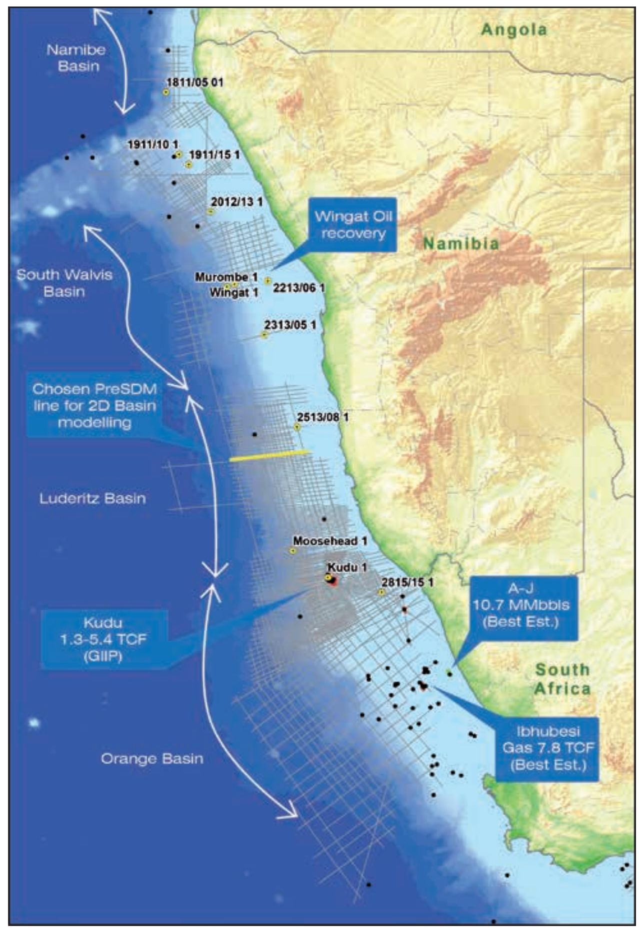

Figure 1 *Basin distribution and location of the exploration wells drilled in Namibian margin in relation to the Spectrum 2D seismic database. Chosen profile for 2D basin modelling displays in yellow line.*

2D petroleum systems modelling of the Luderitz Basin has been undertaken using a geological cross section derived from a Spectrum 2D PSDM seismic section. This confirms the near-surface Bottom Simulating Reflector (BSR)-derived

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geotherm for the Luderitz Basin. These results support the interpretation that the underexplored Luderitz Basin contains thermally mature source rocks of both Aptian and Turonian age that are presently in the oil generative window.

Geology of the Luderitz Basin

The four main Namibian offshore basins are the Orange Basin to the south, straddling the border with South Africa, and the Luderitz Basin, Walvis Basin and Namibe Basin to the north (Figure 1). These basins were formed during the Late Jurassic to Early Cretaceous during the break-up of Gondwana (Blaich et al., 2011). The break-up was initiated from south to north as a north-south rift system along the present-day southwest African margin (e.g. Karner and Driscoll, 1999) that developed to become the Atlantic. With a common mechanism of formation, unsurprisingly all of these basins have similar basement morphologies (Hodgson and Intawong, 2013). However, sediment input from the South African Plateau has varied significantly into each basin through time (e.g. Guillocheau et al., 2012; Rouby et al., 2009) such that the sequence isopach and morphology varies greatly both within and between basins. Despite this, sequence architecture dominated by sea level variation and common structural response is such that a general tectono-stratigraphic breakdown of the offshore Namibian basins south of the Walvis Ridge is presented in Figure 2.

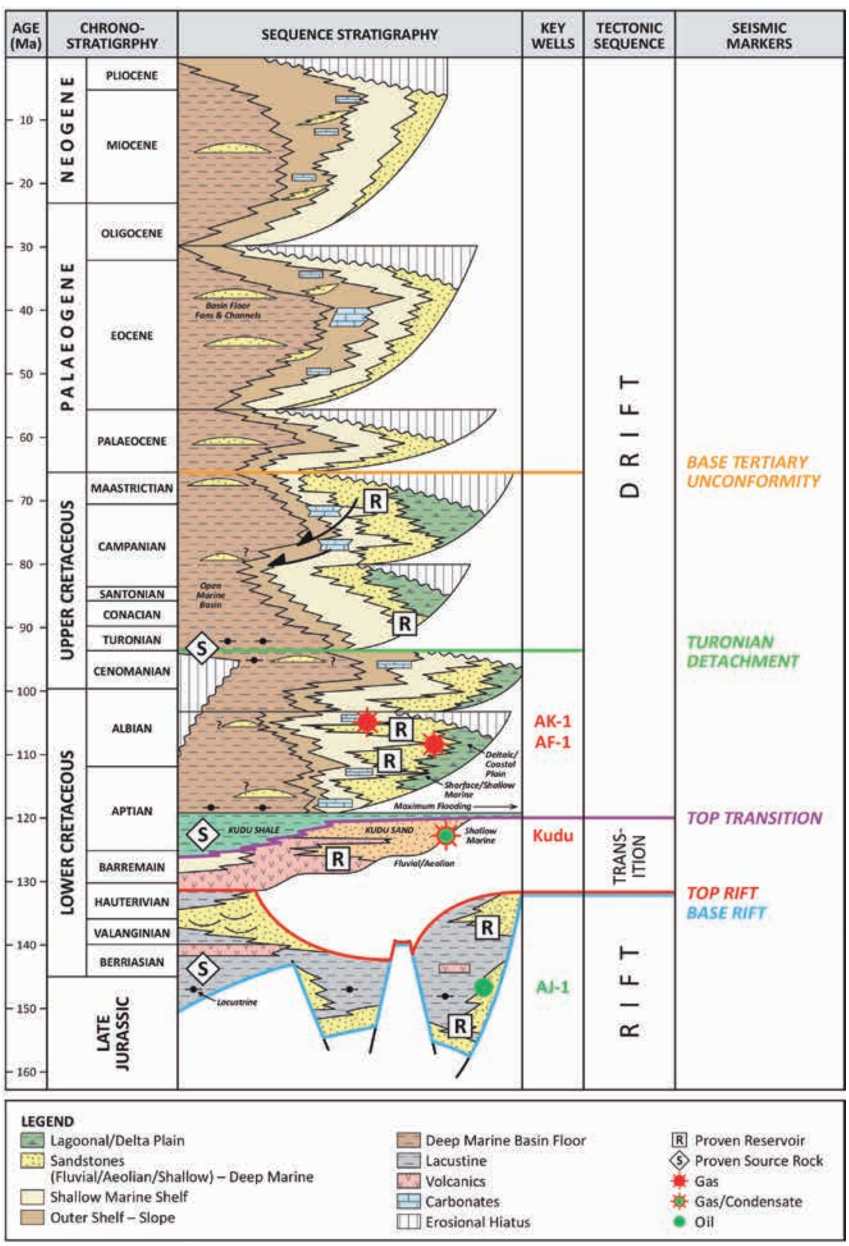

Figure 2 General tectono-stratigraphic chart of the offshore Namibian basins south of the Walvis Ridge (Modified after HRT (2011)).

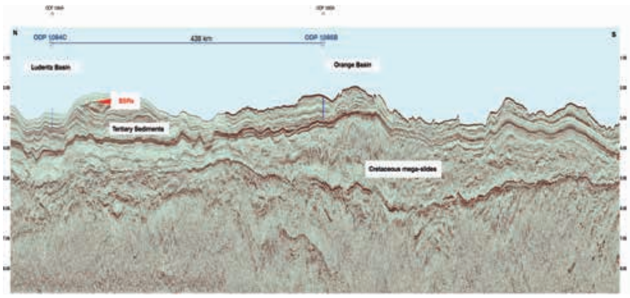

Figure 3 A composite north-south strike line through Luderitz and Orange basins demonstrates the variation in sedimentary depocentre with time on the Namibian passive margin (Hodgson et al., 2014).

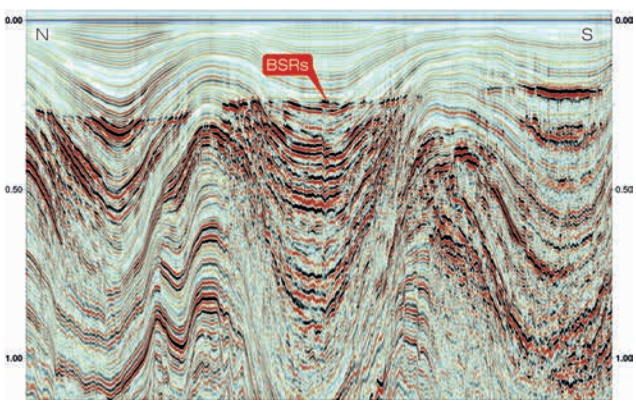

Figure 4 Example flattened seabed seismic reflection profile from Spectrum 2D survey showing the BSR in the Luderitz Basin (Hodgson et al., 2014).

Variation in sedimentary depocentre location on passive margins is an important feature of the Namibian passive margin and its conjugate, the Pelotas Basin in Brazil and Uruguay (Saunders et al., 2013). The Luderitz Basin is divided from the Orange Basin by a NW basement high displaying a thinner Late Cretaceous section compared to the Orange Basin and yet containing a thicker Tertiary section (Figure 2). The Tertiary section in Luderitz developed very rapidly, accumulating a thick clastic section laterally offset from the present-day mouth of the sediment source (Hodgson et al., 2014). Within the Tertiary sequence of the Luderitz Basin, a near-surface solid

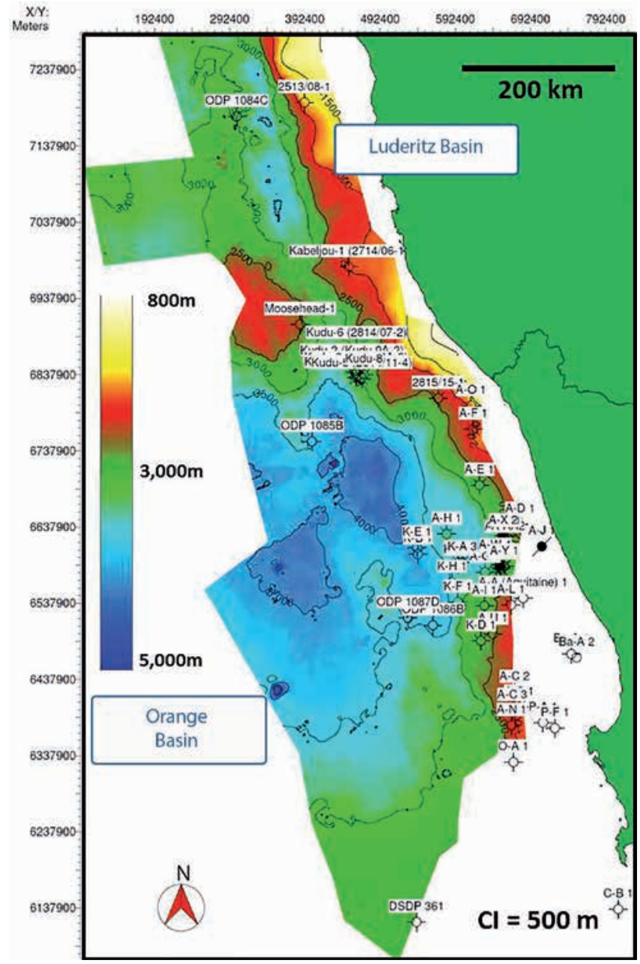

Figure 5 Top Aptian source rock depth below seabed in the Orange and Luderitz Basins.

gas hydrate layer has accumulated (Hodgson et al., 2014). The lower boundary of the gas hydrate is marked by a Bottom Simulating Reflection (BSR), a bright seismic reflector with a high impedance contrast of the reverse polarity to seabed cutting across near surface bedding, and representing the lowest point of stability of the gas-hydrate ((Figure 3 and 4).

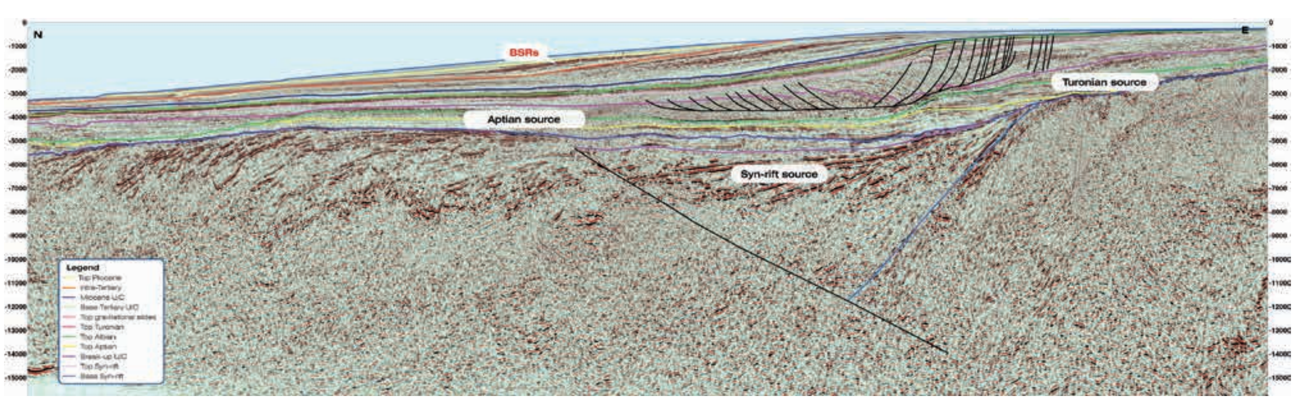

Figure 6 The PSDM 2012 profile for 2D basin modelling, located in the Luderitz Basin where BSR is identified in the shallow section.

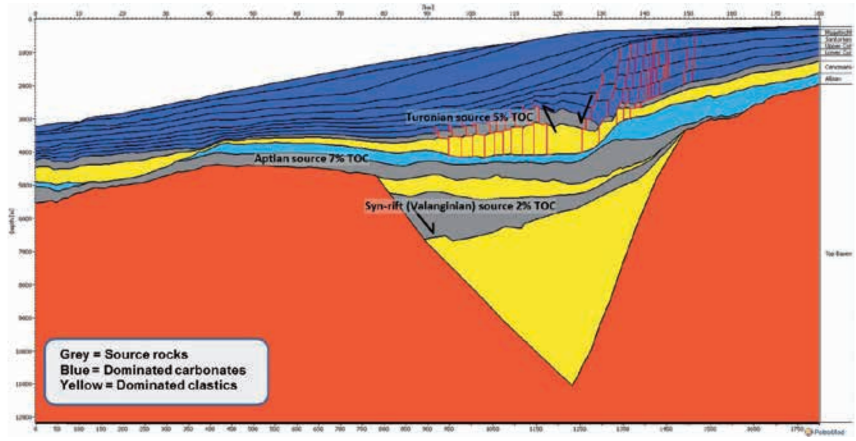

Figure 7 *Three modelled source rock derived from all available offset borehole data and seismic stratigraphic analysis.*

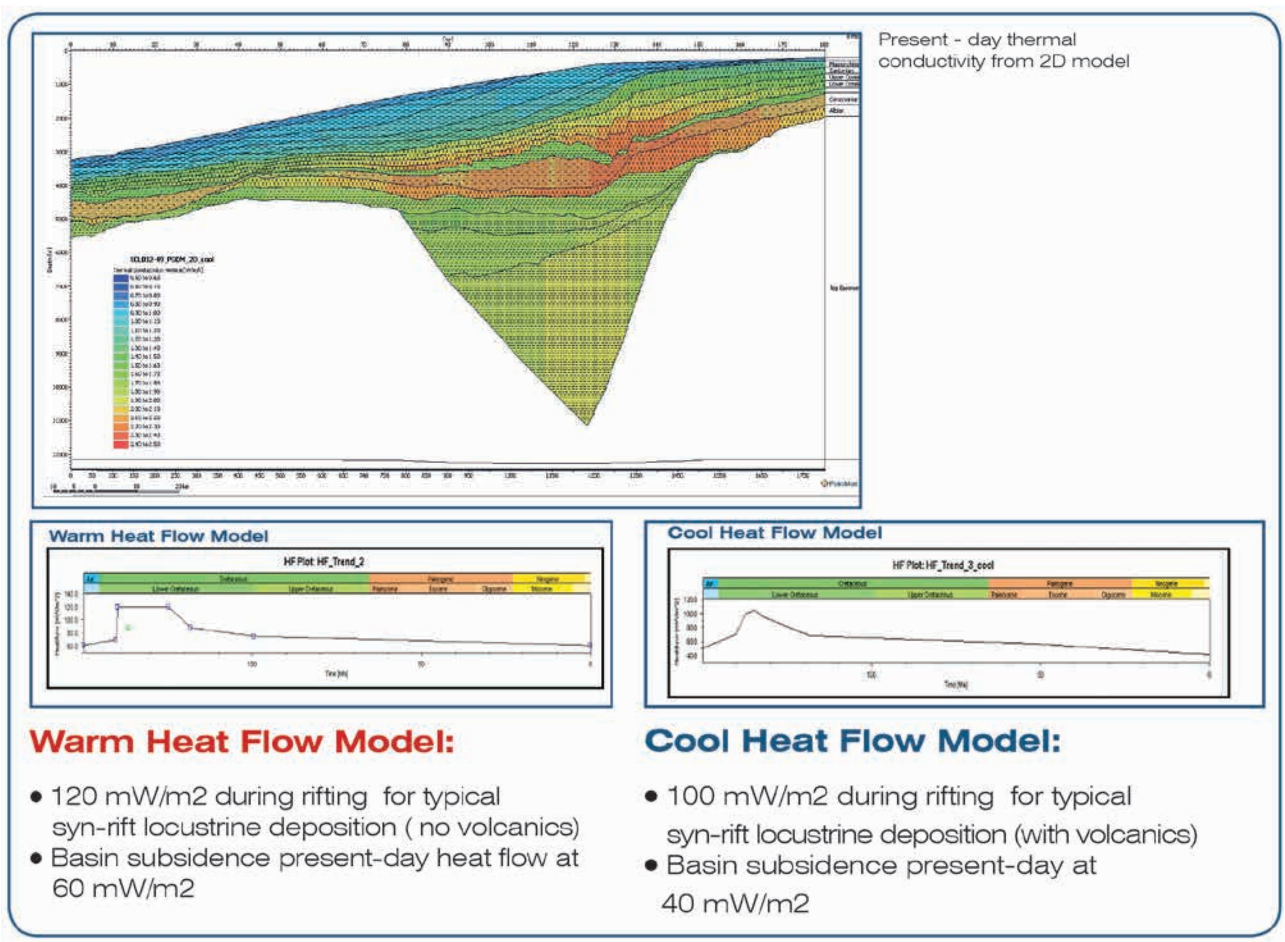

Figure 8 *Warm and Cool heatflow models and present-day thermal conductivity from the 2D models.'*

Where is the Aptian source kitchen?

Modern regional seismic data tied to recent well penetrations (Wingat-1, Murombe-1 and Moosehead-1) demonstrate the presence of source rocks in this basin, exemplified here by a depth structural map below seabed of the Aptian source rock (Figure 5) generated from a Spectrum 2D dataset (Figure 1). However, spatial maturity variations remain uncertain.

Basin modelling

As part of a Spectrum, NAMCOR and the University of Manchester collaboration, 2D petroleum systems modelling of the Luderitz Basin was performed using Schlumberger's PetroMod 2D module. The model was undertaken using a geological cross section derived from a Spectrum PSDM 2D seismic profile. The profile images

BSRs developed in slope setting in water depths from 1170 to 1950m, and it was chosen based on having a relatively thick sedimentary section, extent of depth converted seismic and presence of a well imaged syn-rift half-graben (Figure 6).

Lithology model

Lithology used in the modelling was derived from seismic stratigraphic analysis and available offset borehole evidence from ODP Site 1084 for the Tertiary section, exploration well 2513/08-1 to the east, Kudu field wells and well 2515/15-01 farther to the south defining formation tops for the Cretaceous section.

Three potential source rocks have been identified and assigned for the basin modelling in the Luderitz Basin. These are the Valanginian syn-rift lacustrine shales, the Aptian restricted marine mudstone and the Turonian organic rich marine mudstone. These display TOC values of 2%, 5% and 7% respectively (Figure 7).

The Valanginian syn-rift source rock is modelled to be deposited in a wedged shaped half-graben (Figure 6) which has similar seismic character to the half-graben developed underneath the Barremian aeolian sandstone intercalated with basalt reservoir of the Kudu field. Highly cracked condensate (oil cracking more than 95%) of lacustrine saline origin, mixed with less mature non-cracked condensate marine-derived oil types have been reported from Kudu-4 and -5 condensate samples analysis (Mello et al., 2012). The post-rift Aptian source rock has been widely reported both from the Kudu field and recent exploration wells drilled in this margin. The Turonian sequence has been penetrated by exploration wells 2513/08-1 and 2515/15-01 as well as by Kudu wells. It lies within a gravity controlled mega-slide and is associated with a down dip contractional domain zone (Figure 6).

Heatflow model

Two different heatflows were modelled representing warm and cool heatflows (Figure 8). Both models honoured meas-

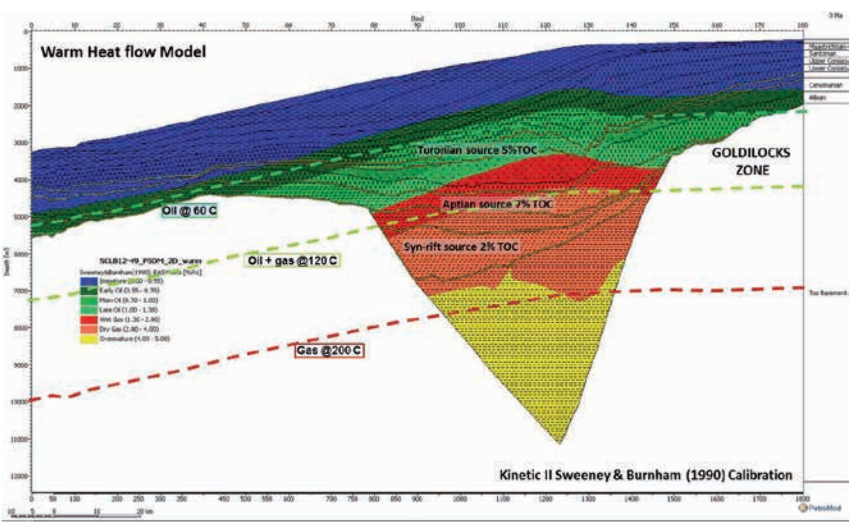

***Figure 9** Comparison of the Goldilocks Zone (Hodgson et al., 2014) to present-day hydrocarbon maturity from Warm heatflow model, 2D basin modelling.*

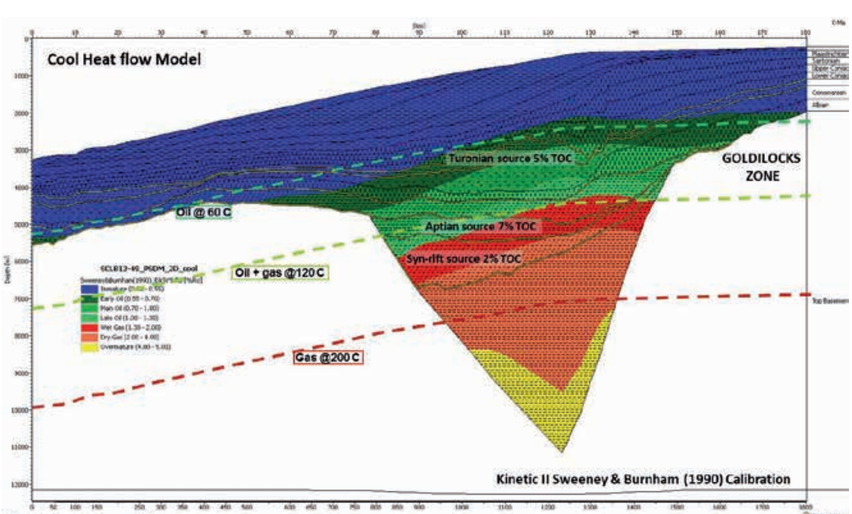

***Figure 10** Comparison of the Goldilocks Zone (Hodgson et al., 2014) to present-day hydrocarbon maturity from Cool heatflow model, 2D basin modelling.*

ured surface heat flow values from the basin and no internal heat production was assumed. Basal heatflow was modelled as equivalent to the surface heatflow. The warm heat flow model represents typical syn-rift and the cool heat flow model is an initial approach to include volcanics in the syn-rift half-graben. Present-day heatflow measurement is taken from Davies (2013).

2D Basin modelling results

Both warm and cool heatflow models indicate that the Aptian source rock is presently generating gas and condensate in the sedimentary wedge above the syn-rift half-graben, whereas inboard and outboard, where the cover is thinner, it is in the oil generative window (Figure 9 and 10).

Both models place the Turonian source rock in the oil window, early-to-late-oil for the warm heatflow model and early-to-early-mid oil for the cool heatflow model (Figure 9 and 10).

The recently predicted oil generative zone (Goldilocks Zone) derived from using the near-surface (BSR) geotherm (Hodgson et al., 2014) is found to lie within the early oil-to-wet gas window in the warm heat flow model (Figure 10) and mostly in the early-to-late oil window in the cool heat flow model (Figure 12). These results suggest that the BSR-derived and the cool heatflow geotherms correspond reasonably well, lending confidence to both approaches.

Conclusion

2D petroleum system modelling using cool and warm heat flow models in the Luderitz Basin confirm the near-surface (BSR) derived geotherm in the cited previous study. These results confirm not only that the underexplored Luderitz Basin contains thermally mature source rocks of both Aptian and Turonian age, but also that these source rocks are in the present-day oil generative window. The collaboration of near-surface geotherm estimation derived from the seismic measurement of the thickness of the gas hydrate accumulation and basin modelling workflow reduces exploration risk in the Luderitz Basin, and the technique offers a new tool for evaluating unexplored basins elsewhere.

Acknowledgement

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