Hydrocarbon play concepts in the Orange Basin in light of the Venus and Graff oil discoveries

Richard Hedley[1], Anongporn Intawong[1], Felicia Winter[1*] and Victoria Sibeya[2]. highlight two proven plays that help to calibrate the deepwater source rock story and identify analogues along the margin.

Recently reported large oil discoveries (Venus-1 and Graff-1) have renewed interest in the prospectivity of the Orange Basin (Figure 1) of Namibia and South Africa. This paper summarises some of the main play concepts and will be showcasing how the two new proven plays help to calibrate the deepwater source rock story and help to guide the identification of analogues with equivalent reservoir, traps and charge along the margin.

Introduction

The Orange Basin is part of a volcanic-rifted passive margin south of the Walvis Volcanic Ridge, along the southern South Atlantic coast of Namibia and South Africa. The basin formed in the Late Jurassic to Early Cretaceous period, as South America and Africa started to rift apart, creating continental syn-rift half-graben for example, offshore South Africa, where light oil was discovered within the Hauterivian lacustrine and fluvial sandstone reservoirs. Large rift-related half-graben contain thick subaerial flood basalts that were subsequently developed during the transitional phase from the continental rifting to oceanic seafloor spreading. These form a large area of Seaward Dipping Reflectors (SDRs), now measuring more than 5 km thick, regionally visible on seismic data. Similarly thick SDRs were developed on the conjugate margin offshore southern Brazil, Uruguay, and northern Argentina (McDermott et al, 2018). The thickest part of the subaerial igneous rocks forms a NW-SE trending ridge, known as the Outer High basement ridge (Figure 2).

Structurally, the Orange Basin can be divided into two major sub-basins separated by the Outer High basement ridge (Figure 2). The inner sub-basin formed first in a NW-SE direction, possibly in the Neocomian. The outer sub-basin formed later, during the Aptian with the submersion of the SDRs. Although this provided an opening to the sea, the overall environment was still restricted marine as the southern South Atlantic Ocean only began to open in the Early Cretaceous period, creating a narrow ocean. During the break-up phase of the South Atlantic, the young South Atlantic Ocean's circulation was restricted by the Agulhas-Falkland Fracture Zone, forming the southern limitation, which created anoxic marine conditions in the southern basins. Such a restricted marine environment existed throughout the Barremian to Aptian eras, allowing good quality source rock facies to develop and deposit under anaerobic conditions. In the inner sub-basin, they are referred to as the Kudu Shale Formation.

Hydrocarbon play concepts offshore Namibia and South Africa

The Outer High ridge developed as a regional trend during the deposition of flood basalts and can be mapped from the Walvis Basin to the Orange Basin on 2D seismic data. The Outer High

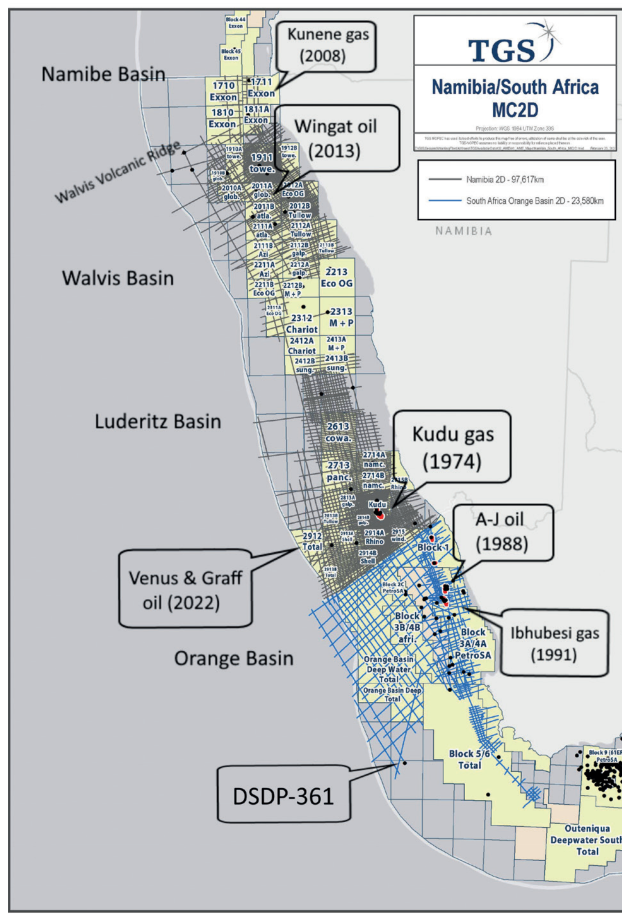

Figure 1 Location map showing the southern South Atlantic basins in offshore Namibia and South Africa

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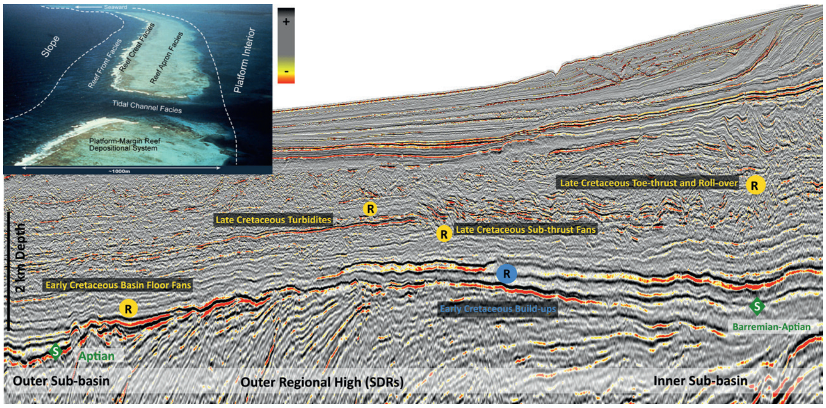

Figure 2 Hydrocarbon play concepts inboard and outboard of the Outer High in the Orange Basin. Yellow R = Clastic Reservoir; Blue R = Carbonate Reservoir; Green S = Source Rock. Inset showing carbonate banks with clastic influx route (Loucks et al., 2003)

plays an important part in controlling reservoir and source rock distribution and deposition, and is partially responsible for generating many trapping configurations. Hydrocarbon play concepts in the Orange Basin within the vicinity of the Outer High are presented in Figure 2, and in more detail in Figure 3 and 4, as discussed in the following paragraphs.

The Early Cretaceous post-rift sequence in the Orange Basin is comprised of a 2.5 km thick section of interbedded carbonates and clastics of likely Barremian age. A thin (20-30 m) Barremian limestone interval recorded at the Kudu wells 1 to 4 has been identified above the Kudu aeolian sand reservoirs, which is part of the SDRs sequence, interbedded with basalts, and below the Late Barremian-Early Aptian Kudu shale source rock (Intawong et al., 2019). The carbonates eventually drown out and onlap on to the Outer High where they form a carbonate platform, which could be reservoirs in the form of shallow marine bioclastic limestones, build-ups, and shoals. Well-defined Albian-aged prograding seismic reflectors have been identified onlapping on the aggrading carbonate platform. These represent an influx of fluvial-deltaic siliclastics, that accumulated inboard of the Outer High basement ridge. The TotalEnergies-operated Venus discovery is located in the outer sub-basin, west of the Outer High. A seismic dip line through the Venus discovery trend is shown in Figure 3. The Aptian reservoir sands were probably sourced from the east and transported across the carbonate platform that sat on top of the Outer High. The Venus reservoir is an Aptian sandstone deposited in the outer sub-basin that ponded in the accommodation space west of the Outer High (Figure 3). The light oil that was recently discovered in the Venus prospect was trapped due to the basin floor fan fairway onlapping onto the Outer High.

The Late Cretaceous evolution of the Orange Basin is strongly characterised by episodic gravitational collapse of the margin. The main gravitational collapse structure is found inboard of the Outer High and characterised by a down-dip contractional domain along a basal detachment of possibly over-pressured Cenomanian-Turonian source rock. This by default creates an up-dip extensional component featuring dipping sediment blocks over listric and normal faults. Late Cretaceous fluvial-deltaic and turbidite sands are attractive potential reservoir targets, such as roll-over anticlines within the extensional domain and toe-thrusts within the contractional domain. The Orange Basin Cretaceous section above the Cenomanian detachment has suffered a structural collapse towards the west, creating multiple toe-thrust imbricate structures. The majority of these appear to sole out on the common detachment surface – quite possibly the organic-rich shales of the Cenomanian-Turonian global anoxic event, see Figure 2. The Shell-operated Graff-1 discovery is Late Cretaceous in age (possibly Campanian to Santonian) and buried approximately 2.5 km below mudline. The trap appears to be a sub-thrust trap developed at the end of the main Late Cretaceous toe-thrust structure. The Outer High has probably played an important role in the deposition of the Graff-1 Late Cretaceous reservoir by acting as a backstop, causing turbidite sands to pond east of the High. Equally, the Outer High seems to control the westerly extent of the Late Cretaceous toe-thrust imbricates. A seismic line through the Graff discovery trend is shown in Figure 4.

An untested play is the trend of toe-thrust structures introduced by the Orange Basin's gravitationally driven system. Further untested trap trends are the large roll-over structures confined within the extensional domain of the same gravity-driven system (Figure 2). The carbonates on the Outer High are another unexplored play which may provide reservoirs in the form of shallow marine limestones, shoals and reef build-ups. The Early Cretaceous carbonate platform play is mainly restricted to the inner sub-basin and the crest of the Outer High. These carbonate plays extend into South Africa (Intawong et al., 2019), and may exist in all the Namibian basins south of the Walvis Volcanic Ridge.

Source rock presence and maturation modelling

The Barremian-Aptian restricted marine source rock has been encountered in offshore wells, with up to 14% Total Organic Carbon (TOC), including the DSDP 361, South African and Kudu wells, as well as the exploration wells Wingat-1, Morombe-1 and Moosehead-1 (Figure 5). This source rock is also believed to be a contributor to the Kudu gas and condensate discovery in Namibia, along with other gas and condensate discoveries on the shelf of South Africa. The Kudu Shale interval has a low frequency seismic character on full stack data and in places it seems to have an AVA class 4 response – i.e., gradually increasing negative amplitude with offset (definition by Eastwood et al., 2018). Interpretation of regional well and 2D seismic data in the Namibia and South Africa margin suggests that the Barremian-Aptian source rock is present over wide parts of offshore Namibia, as far north as the Walvis Ridge and in South Africa.. The source rock is ubiquitously distributed over the Orange Basin with some variation in thickness over the two main sub-basin depocentres divided by the Outer High (Intawong et al., 2015).

Cole (2021) presents a synopsis of available geochemical data from wells offshore South Africa and summarises that the inboard Orange Basin wells have Barremian-Aptian intervals in South Africa characterised by TOC values of less than 2% and generally low Hydrogen Indices (HI) of less than 100. These are indicating gas-prone kerogens, and Cole (2021) attributes this lack of source rock development to clastic dilution. The location of the wells close to the palaeo-shoreline would represent accommodation of considerable amounts of clastic sediments, enabling the dilution of kerogens. The model proposed by Cole (2021) suggests that outboard, away from the shelf margin, the source rock seem likely to be better developed, since these parts of the basin received less clastics in conjunction with good sorting. An example of this is DSDP 361, located 280 km SW of Cape Town, which encountered a relatively thin interval of Aptian/Albian shales with good potential for oil (1 to 14% TOC and has HI values up to 750, Figure 5).

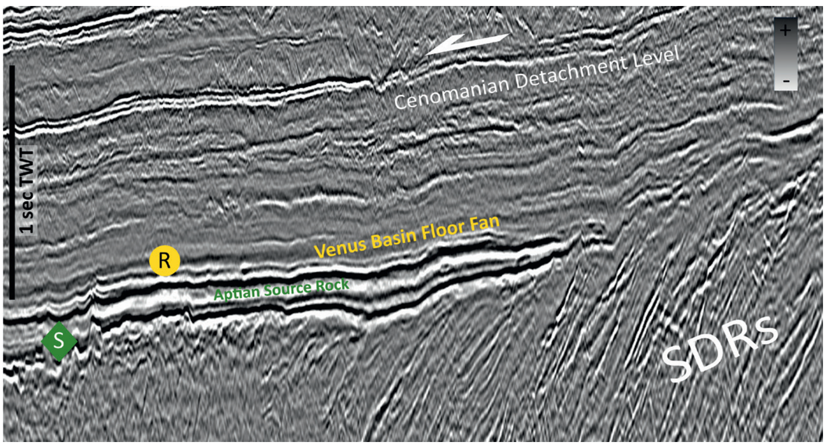

Figure 3 SW-NE dip line through the Venus-1 structure; Basin floor fan fairway sitting on Aptian source rock in the outer sub-basin west of the SDR basement high. The reservoir is onlapping onto the high, creating the Venus trap, which trapped the light oil discovered in 2022 by TotalEnergies.

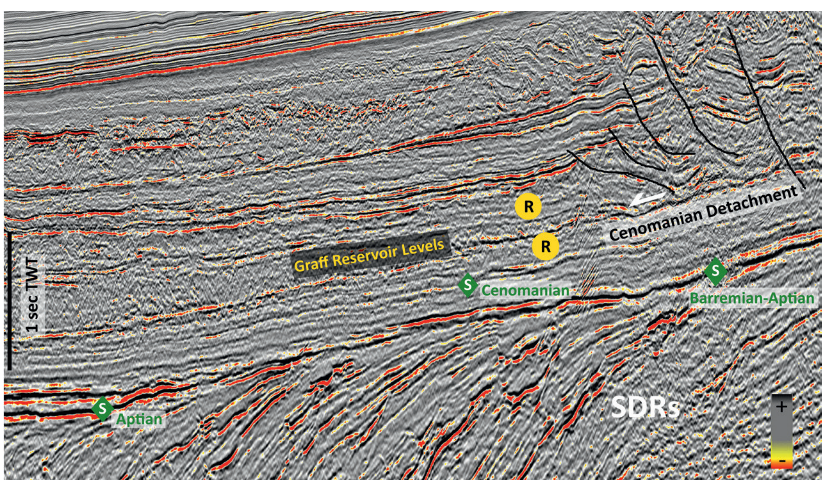

Figure 4 SW-NE dip line through the Graff light oil discovery trend at the western end of the toe-thrust system and the base of the collapse structures, The Santonian-Campanian turbidites have been trapped above the outer high, which likely acts as a backstop for the reservoir influx from the east. Light oil in two different reservoir levels has been discovered by Shell in 2022.

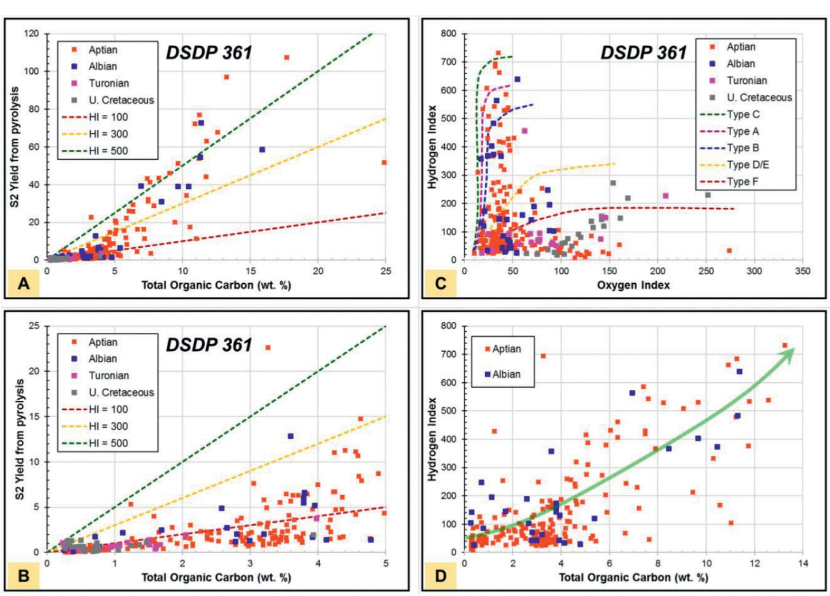

Figure 5 Geochemical data from DSDP361 offshore South Africa (taken from Cole, 2021).

In summary, after Cole (2021), Intawong et al. (2019), and Intawong and Hodgson (2017), the boreholes offshore Namibia have encountered the Kudu Shale source rock (e.g., Wingat-1, Kabeljou-1, Moosehead-1, and Murombe-1), providing initial evidence for an oil play offshore Namibia and South Africa prior to Venus-1 and Graff -1,-2. The Wingat-1 well encountered and recovered light oil, 38 to 42 o API, from the thin Aptian sandstones deposited within the 133m-thick source rock interval. The source rock interval in Moosehead-1, located just north-east of the Venus-1 discovery, has 196 m of Kudu Shale, which probably went through the oil window in the Late Mesozoic and Tertiary periods.

Overall, based on the available data, the best oil-prone source rock seems most likely to be present in the outer sub-basin or on the western edge of the inner sub-basin where it is less likely to be diluted with shelf-derived clastics.

TGS has undertaken 1D basin modelling at several well and pseudo-well locations offshore Namibia and South Africa. Depths to formation tops were calculated based on regional 2D seismic mapping tied to well data. The total sediment isopach for the Orange Basin is up to a maximum of 8 km in thickness in the basin depocentre and progressively thins to approximately 3.2 km at the Venus well location (Figure 6). The maturation temperature model is based on a continental crust rift model (rift age 160 – 130 my, beta factor = 4) which estimates a present-day geothermal gradient at 34° C per km for the basins offshore Namibia and South Africa. The resulting basal heat flow model is adjusted by incorporating a Miocene heating event for the Orange Basin only, providing an incremental 20 mw/m2 heat at 20 million years. This allows for the effects of the Orange Basin passing over the Vema mantle hot spot. Around 20 million years ago the hotspot was situated very close to the Venus-1 well location (Figure 7).

2.5D basin modelling work by Cole (2021) indicates large parts of the Orange Basin are mature or overmature for oil generation and expulsion at Aptian level (Figure 8a). On the western flanks of the Orange Basin, generation seems to have started in the Late Cretaceous period and most of the kerogen converted to oil by mid-Tertiary, corroborated by the TGS 1D burial history models of maturation through time; see the oil expulsion plot in Figure 8b. The wider basin modelling study, now tied in with the oil window from the Venus discovery, indicates favourable burial history for oil expulsion in the outboard, not only for the Orange Basin, but in the Lüderitz and Walvis basins along the equivalent fairway trend.

Discussion of source rock modelling results in light of the new discoveries and their analogues along the margin

Mapping the Outer High is key to understanding the play fairways of the recently proven outboard plays, and more importantly how each play concept works regarding the trapping mechanism of the migrated hydrocarbons. There may be many prospective

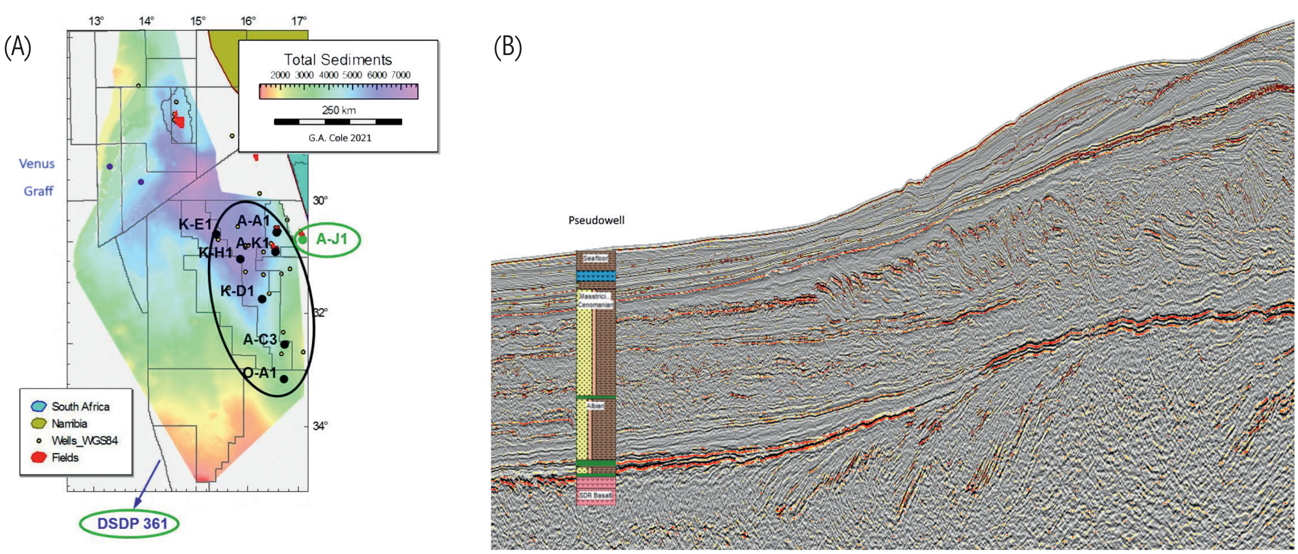

Figure 6 a) Total sediment isopach (metres) based on work of Cole (2021) with the oil discoveries in DSDP well 361 in the outboard and the A-J-1 well in a synrift halfgraben b) TGS Pseudowell location offshore Namibia with Albian and Cenomanian Source Rocks for creating a burial history and maturation model above the SDRs

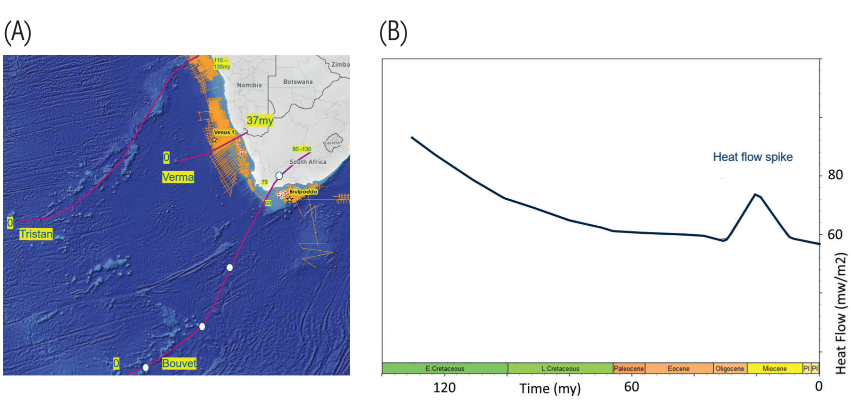

Figure 7 a) Hot spot paths for SW Africa b) consequence of hot spot presence for source rock maturation model, TGS Basal heatflow diagram, heat spike associated with area passing over Vema Hot-spot.

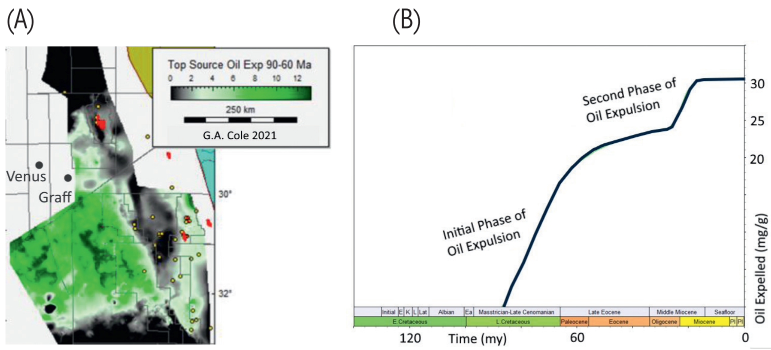

Figure 8 a) Map showing calculated oil expulsion in millions of barrels per square kilometres during the Late Cretaceous period (90-60 million years ago) (Modified after Cole, 2021). b) TGS expulsion model for Aptian Source rock from close to the Venus well. Second phase of expulsion related to the area passing over Vema hot spot.

ponded sand bodies equivalent to the Venus trap type and Graff lookalikes to hunt for along the length of the Namibian and South African outboard fairway, now that the source rock maturity and trap charge have been de-risked.

The carbonate platform play remains to be tested but holds significant potential for reservoirs capable of trapping hydrocarbons from the Barremian-Aptian source rocks on either side of the Outer High. According to TGS' basin modelling study, the carbonate reservoirs are situated in a favourable location and depth, surrounded by Aptian source rocks, which are likely in the oil window. Therefore these traps are likely charged by direct migration. More detailed basin modelling work is required along the Namibian margin to define the extent of the mature Aptian oil kitchen area adjacent to these potential carbonate reservoirs.

The Venus reservoir is buried at about 3.2 km below seabed and is located within the Aptian mature oil source kitchen area. The trap sands pinch-out back up onto the edge of the Outer High, forming a stratigraphic trap that pre-dates oil expulsion. The source rock for the Venus discovery is likely directly beneath the reservoir and generates oil, starting in the Late Cretaceous (Figure 2). Identifying channels that cut across the carbonate platform may be one method of helping to identify where Venus lookalikes may exist in other parts of Namibia, see inset on Figure 2, but key to defining the Venus anomaly trend is to map the Aptian interval west of the Outer High for fan geometries and to use AVA to help identify potential hydrocarbon trapping reservoirs. TGS' basin modelling study, now calibrated by the light oil reportedly found at the Venus discovery, indicates that the oil window may be very extensive west of the Outer High.

The Barremian-Aptian source rock at the Graff-1 location is buried approximately 3 km below mudline and is potentially in the late oil window. There is a lot of scope for finding other Graff-1 lookalike sub-thrust prospects in the Orange Basin. Based on TGS' modelling, both the Cenomanian-Turonian source rock and the Aptian-Albian source rock are mature enough to generate and expel oil. Therefore, it is unclear which source rock is responsible for the oil that has charged the Graff discovery. The toe-thrusts could be sourced with oil from the underlying Cenomanian-Turonian source rock, which locally is in the oil window along the margin, as suggested by the TGS' basin modelling study. The key to success will be mapping out and modelling the maturity of the underlying Barremian-Aptian and Cenomanian-Turonian source rocks, as well as developing a better understanding of migration paths. 3D seismic in depth would be useful to define structures and geometries more accurately, as well as define Late Cretaceous reservoir fan geometries and predict facies.

Conclusions

Petroleum system analyses indicate that there is a large Barremian-Aptian source kitchen capable of generating vast quantities of oil and gas in the Orange Basin. The deepwater areas have been under-explored and provide the best chance of finding further oil discoveries sourced from the Aptian oil-prone source rocks, as recently proven by the Venus-1 light oil discovery.

There is also a possibility of the Cenomanian-Turonian source rock being mature for oil in certain parts of the Orange Basin beneath the compressional thrust structures. Further work may demonstrate that an effective Cenomanian-Turonian source rock has good potential to charge toe-thrust, sub-thrust and roll-over structural traps in the central part of the Orange Basin; an interpretation that would include the Graff discovery.

Basin modelling in the South Walvis and Lüderitz Basins suggests a maturation history for the Aptian source rock, which is favourable for oil expulsion. Work is continuing to investigate the hydrocarbon charge and trapping potential in these basins.

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