The petroleum systems of Orange and Luderitz basins, Namibia: The new and future super–giant petroliferous province for hydrocarbon accumulations in the South Atlantic realm

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Summary

In 1974, the first offshore well was drilled in the Namibian Offshore basins. The Kudu-1 well, Orange Basin, discovered a strand gas field in Aptian aeolian sandstones. Since then, for the following almost 40 years, another 19 wells were drilled and failed to discover any liquid hydrocarbon, stablishing the gas-prone paradigm for all the Namibian offshore basins and halting further exploration activities in the region.

In 2013, the Brazilian company HRT Petroleum performed an integration of advanced oil geochemistry with 3D-PSDM seismic data interpretation and mapped several prospects that had a combined prospective resource of almost thirty billion barrels of oil in the Walvis-Bay and Orange basins.

Following all the data analyses, HRT drilled two deep-water wells and tested two different play concepts, a Cretaceous carbonate platform, and a sand-rich turbidity system, in the deepwater of Walvis Basin (e.g., Wingat-1 and Murombe-1 wells). Both wells discovered good-quality, light oils (41º to 43º API, with GOR around 1,900 m3/m3), in good-quality, although very thin, upper Barremian/Aptian turbidity sandstone reservoirs.

Since February 2022, up to March 2024, seven wells have been drilled in a row, resulting in the consecutive discovery of six giant light-oil accumulations. The combined reserves found in Venus's discovery, made by Total Energies, Graff, La Rona, Jonker, and Lesedi, made by Shell, and Mopane, made by Galp, can surpass fifteen billion barrels of light oil/condensate in basin floor-fans, Lower and Upper Cretaceous in age, with good to excellent perm-porosity characteristics. All the deep-water discoveries were drilled in water depths that range from 2,000m–3,200m. In conclusion, offshore Namibia is already, with only the recently giant to supergiant light oil discoveries, one of the largest hydrocarbon provinces of the South Atlantic Realm.

Introduction

The first Namibian light-oil discovery was made by HRT's drilling campaign in 2012 with its deepwater Wingat-1 and Murombe-1 wells (e.g., Figure 1; Mello et al., 2015). The discoveries, although sub-commercial, recovered 41º API, good-quality marine oils, breaking the gas-prone paradigm that had been set for the entire Namibian margin after the discovery of Kudu Gas Field (Figure 1).

The HRT's discoveries in Walvis Basin were followed by the Orange Basin's deepwater giant light oil discoveries that were made by Total Energies' Venus-1X and Shell's Graff-1 wells in 2022, in Cretaceous sand-rich turbiditic reservoirs with good to excellent perm-porosity characteristics. In 2023, Shell added three other giant discoveries (e.g., Rona-1, Jonker-1, and Lesedi-1) also in Orange Basin. In the first quarter of 2024, GALP's well, Mopane-1 was also successful and made a giant light-oil discovery, demonstrating that the oil-rich Namibian deepwater province extends towards the north of the "sweet-spot" of the Orange Basin, drilled by Total Energy and Shell, and indicates that the southern Lüderitz Basin has an outstanding potential for containing significant size of hydrocarbon accumulations (Figure-1).

This paper will discuss in detail the elements and processes of the supergiant Lower and Upper-Barremian lacustrine and Cretaceous-marine restricted petroleum systems identified in Orange Basin, and how they also can support outstanding exploration potential for the southern deep-water areas of Lüderitz Basin.

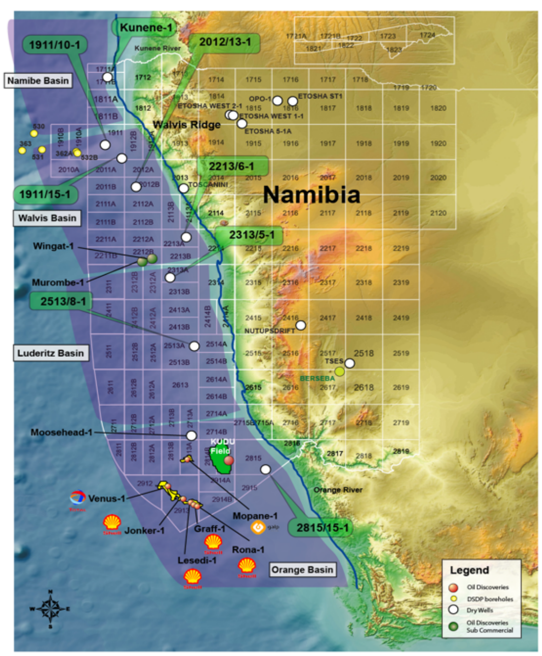

Figure 1. Map of the Namibian offshore sedimentary basins, showing the locations of the wells that have discovered light oils since 2012 in the Walvis and Orange basins. Note the location of the Kudu 9A-1 well that discovered gas and condensate in 1974 (Mello et al., 2O15 and 2023).

Results and Discussion

The evolution of the Southern South Atlantic sedimentary basins, in Brazil, Angola, and Namibia provided the general tectonic-stratigraphic conditions for the establishment of various effective petroleum systems. The formation of source rocks, reservoirs, and traps are directly related and connected to the phases of the evolution of the passive continental margins where syn-rift, transitional, and thermal sag (drift) sequences are present (Figure 2; Mello et al., 1991; Katz and Mello, 2000; Mello et al., 2015).

Source rock/oil Systems.

Samples of only one active source-rock system have been evaluated so far, in offshore deep-water Namibia: The Upper Barremian, Sag-marine restrict Kudu Formation (Figure 3; Mello et al., 2015, 2022). However, biological marker and diamondoid analyses, performed in oils from almost all wells from Walvis, Lüderitz, and Orange basins, indicate the presence of two oil systems: a Lower Barremian, syn-rift, lacustrine, and an Upper Barremian/Aptian, Sag-marine restricted (Figure 4; Mello et al., 2015 and 2022; Figure 3). Therefore, although not sampled yet in Namibia, such data also suggest the presence of an active Lower Barremian, syn-rift, lacustrine source-rock system, deeply buried below the Sag-marine sequence in the Namibian offshore basins (Katz and Mello, 2000; Mello et al., 1991, 2015, 2022 and 2023). The Upper Barremian–Aptian, Sag-marine restricted, source-rock system sampled in the Walvis and Orange basins present TOC content that can reach 6%, potential yield up to 30 mgHC/g of Rock, and HI over 600 mgHC/g TOC composed of type II algal kerogen (Figure 3; Mello et al., 2015 and 2022). The thickness variation of these marine-restricted Kudu source rocks varies between 150 and 200 meters. The presence of such an euxinic organic facies, which are widespread for hundreds of kilometers in the entire deep- to the ultra-deep waters of Walvis and Orange basins, suggests the presence of an overcharged Aptian to Barremian, supergiant source-rock system in the area. Furthermore, molecular geochemistry and nanotechnology oil data show that the Walvis, Lüderitz, and Orange basins share similar Lower Barremian, syn-rift oil types, and consequently share also an overcharged lacustrine source-rock system.

Figure 5 shows a residual Bouguer gravimetric map that suggests the presence of major depopods of potential oil generation, widespread in the deep- and ultra-deep-waters from the southern portion of the Orange up to the northern portion of the Lüderitz Basin. Such tectonic features suggest the possibility of the occurrence of syn-rift and Sag source-rock systems in the deep- and ultra-deep-waters of Lüderitz and Orange basins. As can be observed, a distinct hinge-line separates an area of a relatively thin late drift-sedimentary unit, which onlaps on a shallow basement rock, from the zone of rapid sediment thickening towards the west and it coincides with the wedge-out of the syn-rift sedimentary wedge. The area west of the hinge line presents the best potential to hold not only active lower Cretaceous lacustrine and marine source-rock systems but also sizeable reservoir sequences that are able to bear giant oil accumulations.

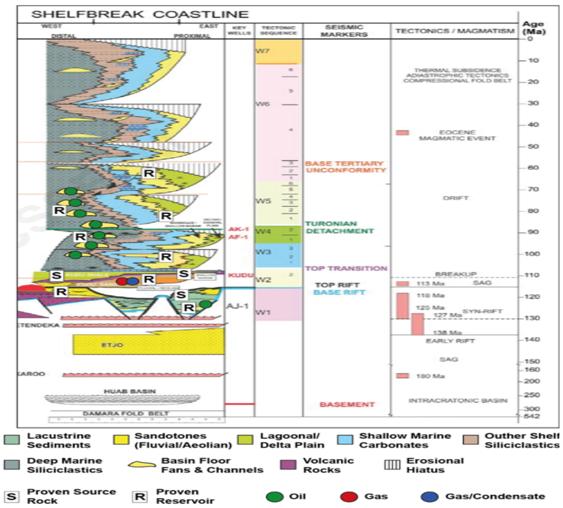

Figure 2. Tectonic-stratigraphic schematic chart of the Namibian Namibe/Walvis/Lüderitz/Orange basins (modified from Mello et al., 2015). Note that the Aptian to Valanginian syn-rift strata is covered by volcanic wedges of seaward-dipping reflectors. Active source-rock systems are characterized in the Namibian margin within the Lower Barremian synrift lacustrine sequence and in the transitional section in the Sag-marine sequence (Upper Barremian–Aptian).

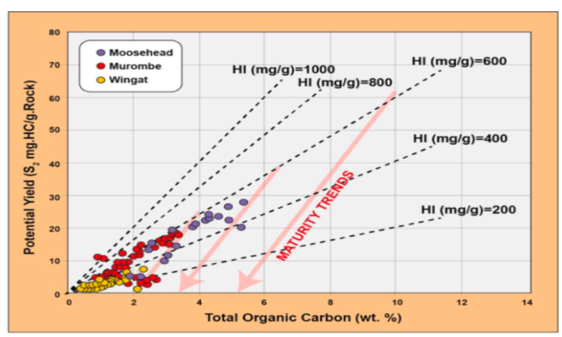

Figure 3. Correlation of the total organic carbon (TOC), versus the potential yield (S2) and hydrogen index data among the upper Barremian–Aptian source-rock layers sampled by the Wingat-1, Murombe-1, and Moosehead-1 wells (Mello et al., 2015, 2022).

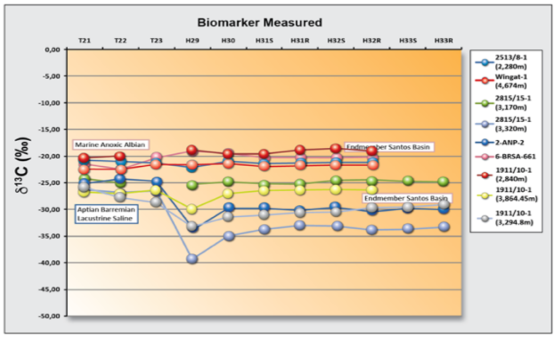

Figure 4. Plot of the compound-specific isotope of Biomarkers (CSIA-B), showing data for oil samples from most wells drilled in Walvis, Lüderitz, and Orange basins, offshore Namibia, together with reference data from de Santos and Campos basins, Brazil.

As can be observed in Figure 4, the oil data indicates the presence of two active source-rock systems: the Lower Barremian, syn-rift, lacustrine source rocks, deeply buried below the Upper Barremian–Aptian, Sag-marine restricted source rock. Note a perfect correlation, grouping all the marine and lacustrine oils with the Campos and Santos endmember oils from Brazil (Katz and Mello, 2000, 2015; 2022).

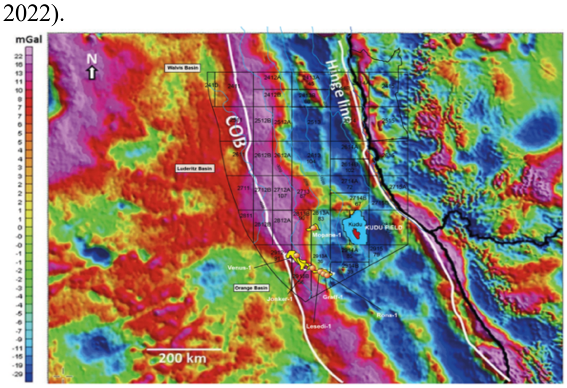

Figure 5. Residual Bouguer gravity map that suggests the presence of several source-rock potential depopods of generation, widespread in the deep- and ultra-deep-waters from the southern portion of the Orange up to the northern portion of the Lüderitz Basin.

Figure 6 shows a map based on 1D-, 2D-, and 3D-petroleum system modeling, covering the areas along the southern Walvis Basin in the north of the South African Orange Basin. The map depicts the present-day maturity of the Barremian, syn-rift lacustrine/Sag, and marine restrict source-rock systems. Note that all the light oil discoveries made, up to now, in the Orange Basin are in the oil-prone/condensate mapped areas, while the Kudu Gas Field is associated with the gas-prone depocenters.

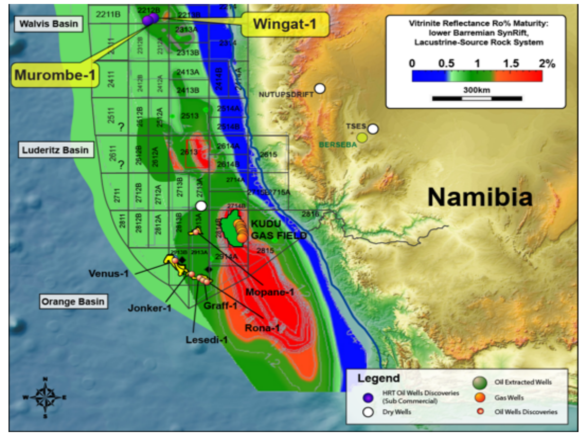

Figure 6. Map along the Namibian and northern South African margin, showing tentative predictions/assessments of present-day maturity (vitrinite reflectance, %Ro) of a lower Barremian, syn-rift, lacustrine source-rock system.

Reservoir Rock Systems

The reservoir systems identified, up to now, are composed of sand-rich basin-floor fans found at several levels between the Upper-Barremian-Aptian to Campanian sedimentary sequences. (Figures 2, 7 and 8; Mello et al., 2015).

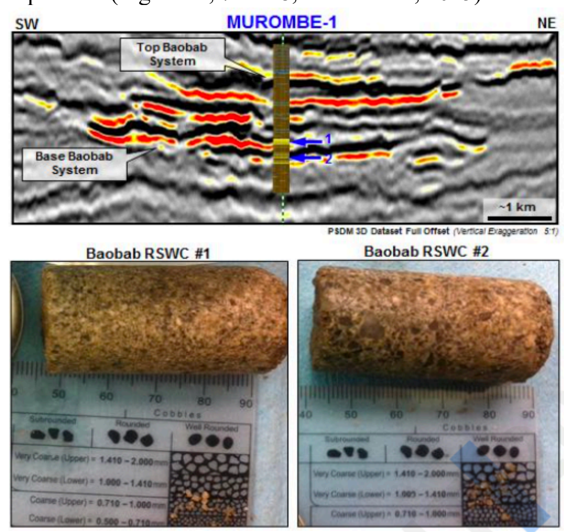

Figure 7. Interpreted 3D-PSDM seismic section showing the position of a Cenomanian confined channel complex, drilled by the Murombe-1 Well, Walvis Bay Basin. Note the core sample showing sub-angular coarse to fine-grained sand, showing around 19% average porosity and over 300 Md permeability (Taken from Mello et al., 2015).

The upper Barremian–Aptian to Turonian reservoirs observed in HRTs' Wingat and Murombe wells, Total's Venus, Shell's Graff-1/Rona, Jonker, and Lesedi and Galp's Mopane-1 wells discoveries are deep-water turbidity sandstones that display good porosities (>19%) and permeabilities (>300 mD). In the Venus discovery, the stratigraphic and, principally, the structural settings rest right over the boundary of the Continental and Oceanic Crust (Figures 2 and 6–9; Hedley et al., 2022; Mello et al., 2015).

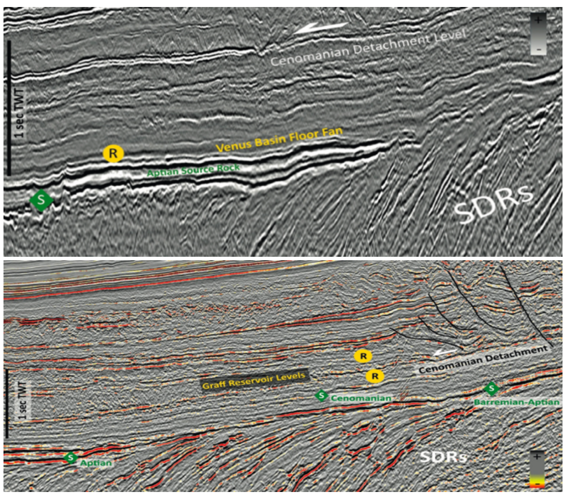

Figure 8. SW-NE dip lines through the Venus-1 and Graff-1 discovery trend show the presence of sand-rich basin-floor fans contained by stratigraphic and mixed stratigraphic-structural trap systems (taken from Hedley et al., 2022).

Trap and Seal Systems

All the discoveries made recently in the Total's Venus, Shell's Graff-1/La Rona, Jonker, and Lesedi and GALP's Mopane-1 wells, in turbidity sandstones, ranging from Lower to Upper Cretaceous, are predominantly associated with stratigraphic traps controlled by the lateral pinch-out of the sandstone reservoirs to the east and by regional dip toward the west (Mello et al., 2015; Hedley et al., 2022). It is important to mention, that some reservoirs also present a complex trap geometry, where mixed structural–stratigraphic trap systems present features such as listric faults, unconformities, and accommodation spaces, sharing similar roles in defining reservoir geometry and facies distribution.

Seals are confidently predicted to be found within the sedimentary units between the Barremian–Aptian age, as well as, in the upper Albian–Campanian, interbedded with the reservoir rocks. They are dominantly shales that were deposited in a deepwater environment.

Generation, Migration and Accumulation

3D-petroleum system modeling, calibrated with geological and geochemical data, was performed at a regional scale covering the southern Lüderitz and Orange basins, in Namibia. A regional model covering the area was built with eight structural maps that encompass the whole sedimentary section (Seafloor, Middle Miocene, Paleocene, Cenomanian, Albian, Barremian, Early Barremian - or possibly Upper Jurassic - and Basement). Two source-rocks systems were evaluated: lower Barremian – level 1; upper Barremian/Aptian–level 2.

The maturity of the source rocks is variable across the Lüderitz and Orange basins. Assuming the presence of the lower Barremian, syn-rift lacustrine source-rock system, the model suggests that this interval is the most mature in the studied area and has a great potential to generate light oil and condensate/wet gas. The kitchen zone of the Lower Barremian source rock is broader in the south of the Orange Basin than in the southern of the adjacent Lüderitz Basin. In the overlying Upper Barremian–Aptian, Sag-marine restricted source-rock system, the entire deep to ultra-deepwater areas of both basins are mostly in the peak to post peak oil window generation zone. At the south area of the Orange Basin, bordering the South Africa margin, both source-rock systems are in the gas window. This southern gas zone is restricted but corresponds to an important depocenter that certainly has charged the Kudu gas Field.
The time relation between (single or multiple) charge pulses and depositional ages of the targeted potential reservoir intervals shows that in all the studied area, reservoir deposition, and most probably also trap formation (e.g., including top seal establishment), pre-dated any significant charge volumes arriving at the traps, which is another very positive finding. The main generation time was ~90 Ma, but most of the generation and migration lasted until 70Ma, in areas with partial kerogen-petroleum conversion.

Distribution of kitchen areas, maturity at present-day, as well as the likely charge timing are predominantly controlled by burial, as determined by sedimentary input originating from the Orange River, and possibly, also other, small paleo river mouths further to the north.

Calculation of cumulative charge volumes shows that, even when making highly conservative assumptions, the charge potential is very high. If the amounts of burial, as defined by the structural maps, are not outrageously wrong, and the assumed lacustrine and marine source-rock system's (both of them) are indeed present in the area, then the petroleum systems presumably present in the entire area must be viewed as spectacularly overcharged (Figure 9).

The first and foremost result of migration and accumulation modeling is that the migration risk of the petroleum system appears to be very small. This is due to the lateral and vertical migration distances being short in the system, and because the mapped structures comprise an efficient network of predominantly large fetch areas feeding the trap closures, be they stratigraphic or purely structural, or mixed. Furthermore, many local migration pathways are provided by a fault network that may efficiently connect sources to the traps. But the most important point in this respect is the result that the entire system is not charge-, but rather trap-limited. Even when making highly conservative assumptions, analysis of the modeled charge volumes, GORs, and charge timing, yields very positive results. Assuming that both source rocks are present in the area, and the interpreted amounts of burial, and concepts of thermal evolution in the basin are not entirely wrong, then the system is significantly over-charged, just as suggested by the recent discoveries. Hence, in the models, the main limiting parameter controlling modeled accumulation size is trap integrity, including top (and lateral) seal capacity.

The modeling results predict several oil and gas accumulations, saturations, and migration paths throughout both the Lüderitz and Orange offshore Basins. At present day, the accumulations are in the proximities or in updip positions relative to the depocenters. The deepest accumulations are predicted to be in Early Barremian (or Upper Jurassic) reservoir rocks. They occur everywhere in the area studied, but giant accumulations appear not to occur in the northern areas of the Lüderitz, and the southern areas of the Walvis Basin. In general, the accumulation modeling was carried out for six identified turbiditic reservoir target intervals, ranging in age from upper Barremian to Campanian (Figure 9). Five of these targets occur stacked onto each other within the paleo-shelf-break exploration domain inside the areas of 3D-seismic surveys. One additional reservoir target type can be viewed as a Venus/Graff analog and is represented by leads located along the western, outboard border of both Orange and southern Lüderitz Basins (Figure 9). The outboard, Upper Barremian–Aptian potential targets that may represent analogs of the Venus/Graff discoveries, certainly comprise very large fetch areas, making these potential targets very attractive. Modeled, or likely, reservoir properties, such as porosity, temperature, or pressure, as well as likely charge volumes, are all very positive.

In a modeling-based, holistic view of the lacustrine and marine petroleum systems presumably present within the studied area, it can be said that the systems are likely significantly overcharged, and the exploration potential is only limited by trap presence and integrity, and reservoir quality. From the modeling standpoint, this is about as good as it can get!

Figure 9 shows a Petroleum Systems Chart with its elements and processes displayed on a graph with a horizontal time axis. The lacustrine and marine source-rock systems of the early Cretaceous age are present. Reservoir rocks ranging from Barremian to Campanian age have been identified, in a way that each turbidite body is supposed to be sealed by accompanying background sedimentation shales and lateral pinch-out. Trap establishment was presumably complete by the end of the Cretaceous. Generation/expulsion/charge took place in various pulses in the different areas, starting in the outboard area around 90 Ma, with the main pulse taking place just before the K-T boundary. Late charge pulses may comprise increased GOR. No biodegradation is likely. Secondary cracking may have occurred, but it is only a risk in the deepest, lower Barremian lacustrine reservoirs oils. The "Critical Moment" is defined as the point in time when the source rocks have expelled 50% of their total charge. This was the case probably around 50 Ma or so.

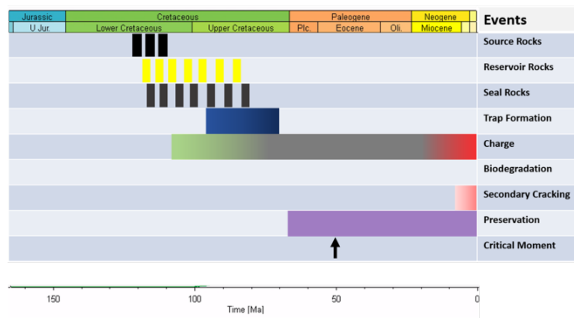

Figure 9. Petroleum system chart for both the lower Barremian, syn-rift lacustrine and upper Barremian–Aptian, Sag marine restricted systems present in the deep and ultra-deepwater real of Walvis Bay, Lüderitz and Orange basins.

Conclusions

The integration of the petroleum system elements and processes of the Lüderitz and Orange basins indicates that the recent giant and supergiant discoveries of Venus, Graff, La Rona, Jonker, Lesedi, and Mopane wells, in the deepwater realm of the Orange Basin, Namibia, is just the tip of a gigantic iceberg that will transform the Country into one of the largest oil provinces in West Africa.