Future exploration potential for oil on a partly exhumed continental margin, coastal East Africa

Presented by

Mike Rego

Rego Exploration Limited

With contributions from

Chris Matchette-Downes - MDOil Limited
Dr. David Boote - DavidBoote Consulting Limited
Nicholas Cameron - GeoInsight Limited
Andrew Long - Terranes
Dr. Andrew Carr - Geochemical Systems Limited

EAST AFRICA OIL GROUP

Finding Petroleum, The Geological Society, Burlington House, London, 23rd February, 2017

Introduction

- Despite the recent major discoveries of gas offshore deepwater East Africa since 2010, the exploration history of coastal East Africa has been one of failure in the quest for oil.
- Comparatively easy deepwater exploration logistics and application of state-of-art technology to identify and de-risk exploration leads, coupled with intense marketing by offshore seismic contractors has perhaps skewed our perception of prospectivity.
- Improvements in seismic imaging combined with increased knowledge of source rock geochemistry indicates significant potential for both conventional and unconventional hydrocarbons, including oil and condensates.
- Deepwater exploration success, and that of some of the interior rift basins, has raised expectations amongst the local populations of cheap and readily available power but until the deepwater gas is monetized, and expectations of the people are met, there are genuine opportunities for smaller scale (and lower cost) onshore and nearshore exploration and development projects with shorter lead times to first production.

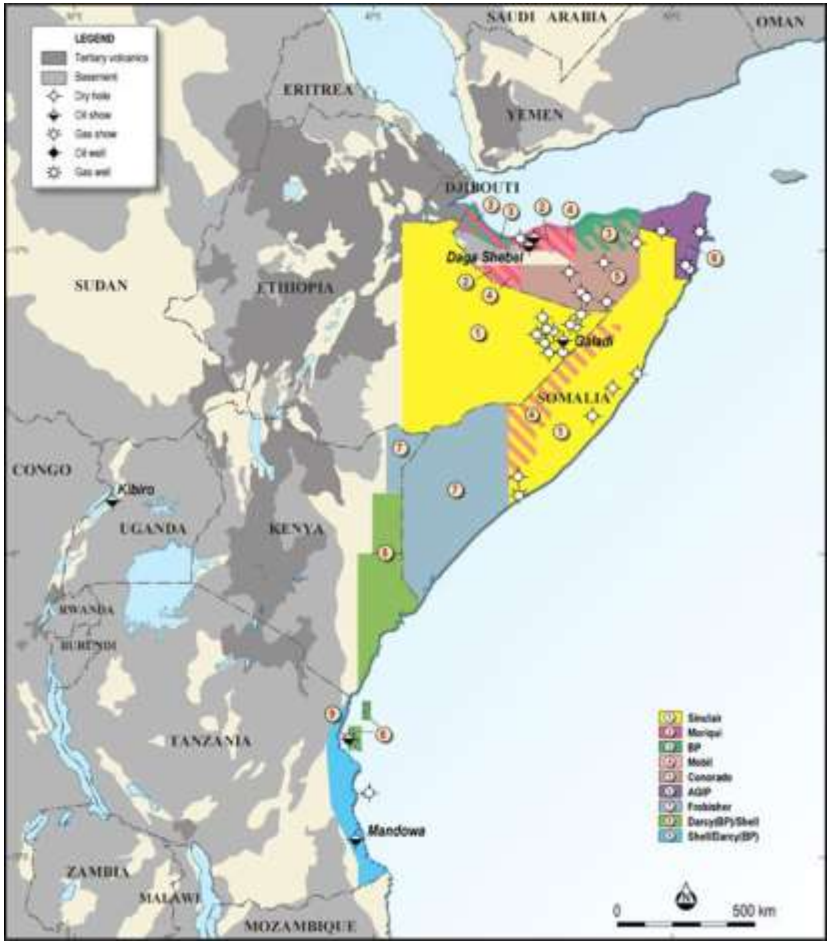
Why has the industry been so transfixed by the deepwater?

Why has past onshore and nearshore coastal margin exploration been so disappointing, and how can we improve our chances of success (and find oil instead of gas)?

Exploration History

Exploration History

- Exploration started along the East African margin in the late 1940's - early 1950's, dominated by several of the majors and a few large North American independents, chasing the oil plays of the Middle East southwards into Africa.
- In Tanzania, Shell and BP drilled 3 wells in onshore coastal settings, all encountering shows of oil and/or gas.
- In Kenya, BP and Shell drilled 10 wells in Lamu, many with oil and/or gas shows.
- In Madagascar, SPM (a subsidiary of Elf Aquitaine) drilled Sikhily-1 in the Morondava Basin, a small gas discovery with a likely Permo-Triassic charge, still not in production.
- In Somalia, exploration began in the 1950's, with the Agfoy-1 well testing gas in 1966, but despite two further wells located with modern seismic in 1984 and 1985, and numerous DST's, the wells were P&A'd dry.
- In Mozambique Sasol discovered the Pande gas field in 1956, yet despite 2.6 Tcf of reserves, due to politics it was not in production until 2009…



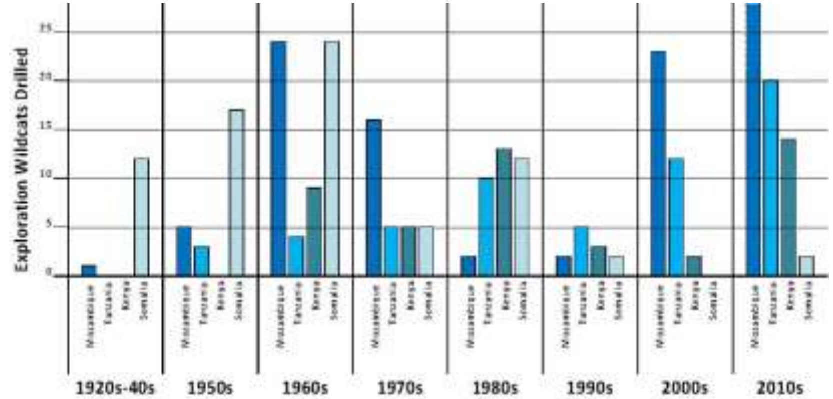
Horn of Africa – 1950's Exploration Status

From award of the first exploration licence to BP/Shell in 1952, until 1982 when Agip/Amoco withdrew following discoveries of gas at Songo Songo and Mnazi Bay, Tanzania was explored by only 2 operators.

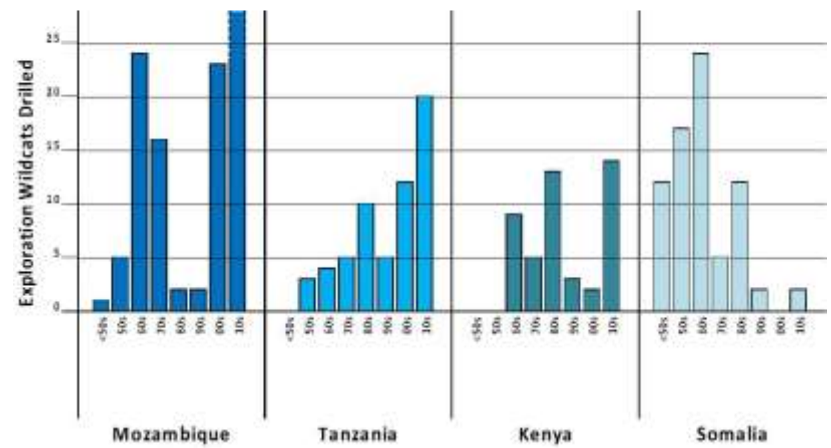
Oil and Gas Exploration in East Africa: A Brief History; Peter Purcell, Search and Discovery Article #30388 (2014) adapted from oral presentation from the History of Petroleum Geology session given at AAPG International Conference & Exhibition, Istanbul, Turkey, September 14-17, 2014

Exploration History

- The 1960s saw some diversification, with heightened activity in Mozambique resulting in the Buzi (1962) and Temane (1967) gas discoveries in Mozambique.
- In Madagascar, exploration opened up to non-French companies, notably Chevron, Agip, Conoco and Texaco, but with no commercial success.
- Somalia enjoyed a burst of activity but despite promising wells no actual success.
- Post-independence politics and uncertainty in Tanzania and Kenya was not a great incentive, and there was no further regional success until the discovery of Songo Songo in 1974 by Agip-Amoco.
- Civil war and political unrest also affected activity in Somalia and Mozambique.
- Commercial discoveries prior to 2000 consist of just Pande, Buzi and Temane onshore gas fields in Mozambique, and Songo Songo and Mnazi Bay in Tanzania, with no production until the 1990's onwards (Songo Songo did not actually commence production until 2004 – 30 years after discovery).



East Africa: exploration wildcats drilled by decade*



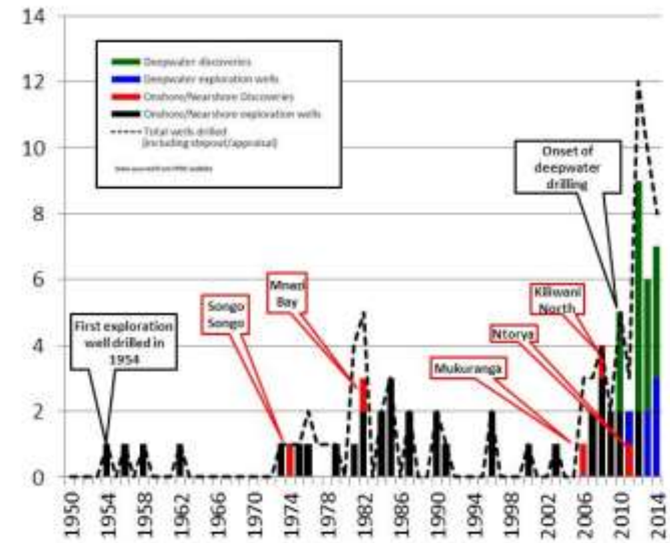
East Africa: exploration wildcats drilled by country

Source: Modified after Purcell, "Oil and Gas Exploration in East Africa: A Brief History"; Peter Purcell, Search and Discovery Article #30388 (2014) adapted from oral presentation from the History of Petroleum Geology session given at AAPG International Conference & Exhibition, Istanbul, Turkey, September 14-17, 2014.

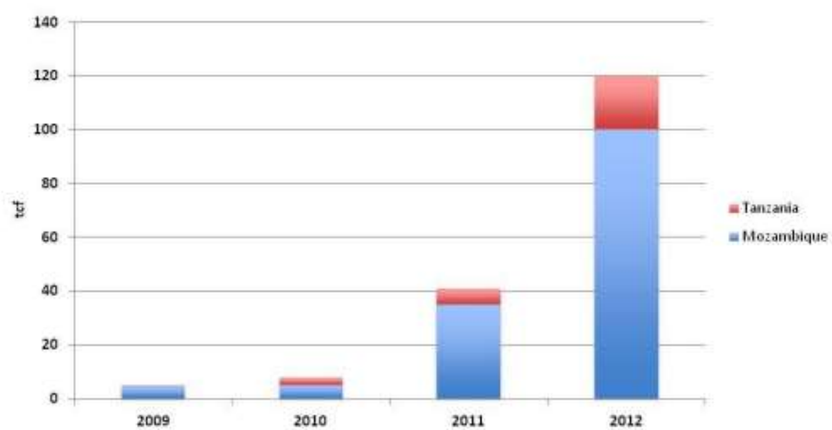
Additional data courtesy of DrillingInfo

Exploration History

- **The drilling history of Tanzania illustrates well the recent upsurge in deepwater drilling activity at the expense of the onshore and nearshore marine.**
- **Statistically, because of the large size of their early licences, the majors/larger companies have been the most prolific explorers in terms of wells drilled with time. Although their interest waned in the 1980's and 1990's, recent deepwater exploration and success has seen many return since the 2000's.**



Tanzania Drilling History 1950 - 2014



Tanzania	Pweza-1 (4) Chewa-1 (4)		Chaza-1 (1) Jodari-1 (1) Zafarani 1 (2) Mzia-1 (1) Lavani-1 (2) Lavani-2 (2) Papa-1 (3)
Mozambique	Windjammer (1) Lagosta-1 (1) Barquentine-1 (1) Ironclad-1 (1)	Coral 1 (4) Mamba S-1 (4) Camarao-1 (1) Barquentine-3 (1) Lagosta-1 (1)	Mamba N (4) Lagosta-3 (1) Barquentine-2 Barquentine-4 Mamba NE-2 (4) Mamba S-2 (4) Coral 2 (4)

East Africa Gas – Increase in estimates of recoverable gas reserves, 2009 to 2012

Source: David Ledesma, "East Africa Gas – Potential for Export", The Oxford Institute for Energy Studies, March 2013.

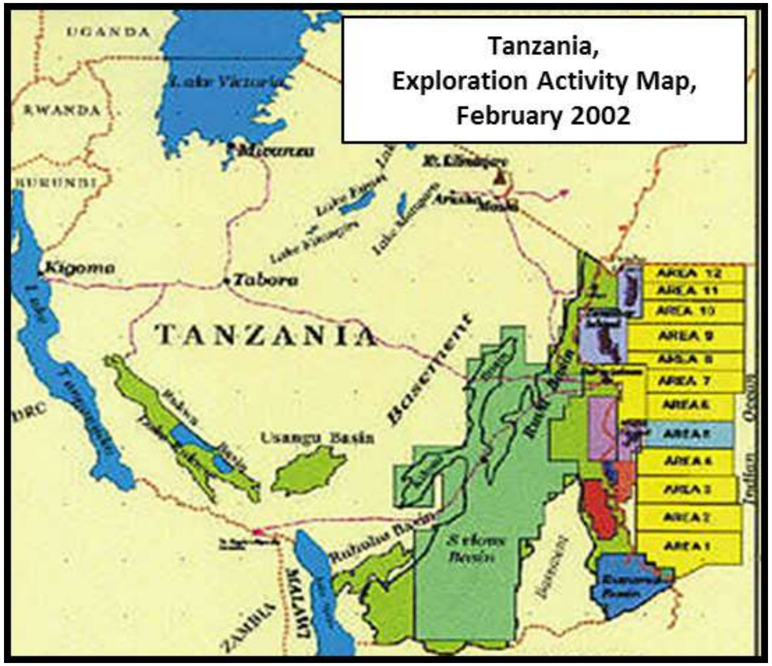
Exploration History

- The type of companies that carried out most of the exploration since the early work of the majors is reflected partially in the disparity between exploration wells drilled onshore versus offshore (prior to exploration in the deepwater).
- Most exploration activity prior to 2000 has been onshore:
  - In Tanzania, only 7 out of 25 wells were drilled offshore (1 in 4)
  - In Mozambique, only 13 out of 66 wells were drilled offshore (1 in 5)
  - In Kenya, only 4 out of 30 wells were drilled offshore (1 in 7)
  - In Somalia, only 3 out of approximately 38 wells were drilled offshore (1 in 13)
  - In Madagascar, only 10 out of more than 50 wells were drilled offshore (1 in 5)
- Non-deepwater offshore exploration wells drilled since 2000 is... 2, both on the Mozambique shelf, in 2008 and 2012. Both were dry holes.

Songo Songo gas field Rig 5

Exploration History

- For most of the coastal margin success has been elusive, despite numerous oil and gas shows.
- For the majors with more diverse portfolios, there was lower hanging fruit elsewhere such as West Africa and the Middle East, with oil more likely than gas.
- With political unrest, minimal infrastructure, little existing (legacy) data, large geographic areas and high contractor costs, plus high risk of exploration failure (and impact on career development!), East Africa rapidly fell out of favour particularly with the larger companies.
- Gas discoveries, as at Songo Songo and Mnazi Bay, were not great incentives to further exploration due to the lack of infrastructure and local markets, and lack of favourable gas terms – (PSAs were often based on oil terms only).
- With decreasing interest, by the 1990's in order to attract exploration investment host governments were offering less onerous exploration licence terms, and were often favourable to smaller less established companies.

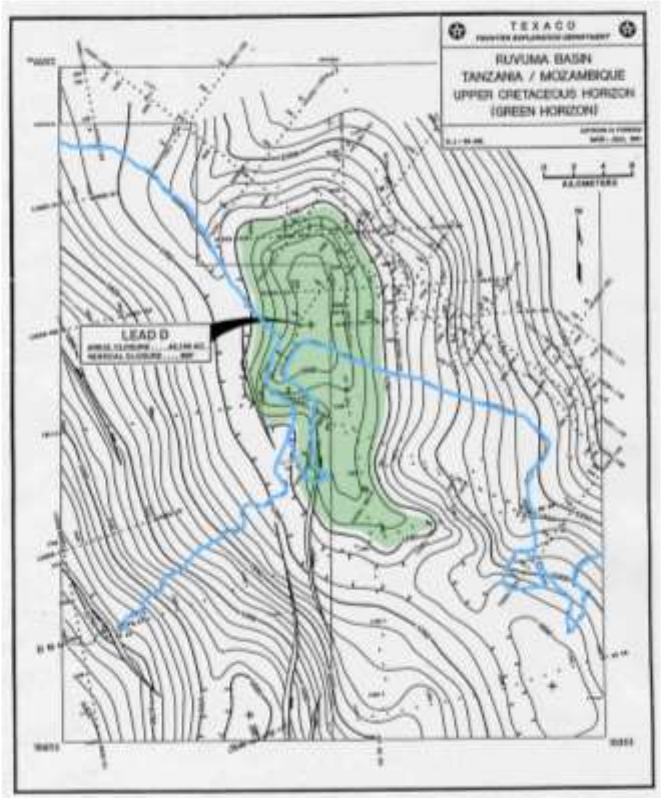


The licence activity map for Tanzania, February 2002, is representative of the licence situation for most of the East Africa coastal Margin at the time – few active exploration licences, several areas under Technical Evaluation Agreements (TEA's), and the only large company involvement being a single deepwater licence.

Note also the lack of licences over the interior rifts.

Exploration History

- The downside of issuing licences to so many less-established companies was that often their exploration programmes were funded from stock market investors rather than a portfolio of production assets – as such their exploration programmes would often be the minimum required in order to meet their drilling commitments.
- Often reprocessing of legacy seismic data was seen as a key part of the work programme, convenient as low cost, but with hindsight often of doubtful benefit.
- Corners were trimmed and eventual well locations were often not as adequately de-risked as they might have been… a poor drilling result was invariably taken as further proof of the region's lack of prospectivity.
- The few larger companies that ventured East were often equally as guilty – they were only interested in structures large enough to justify the massive investment in infrastructure required in the event of success.
- Onshore seismic was generally shot on large scale reconnaissance grids of 5km – 10km, often with minimal static control; offshore 2D seismic was constrained to the easier parts of the shelf. If structures were not big enough to show up on such regional grids they were probably not worth drilling…

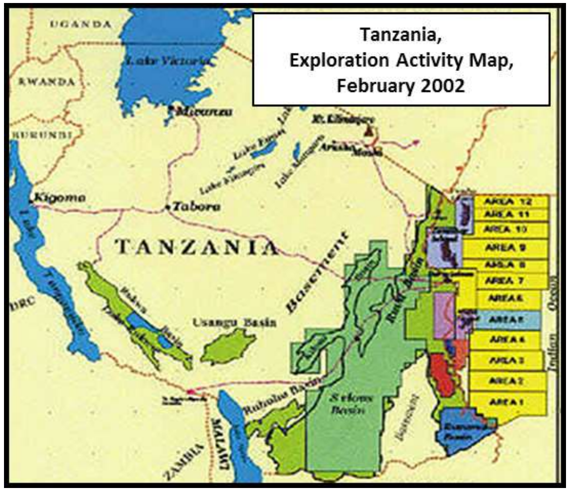


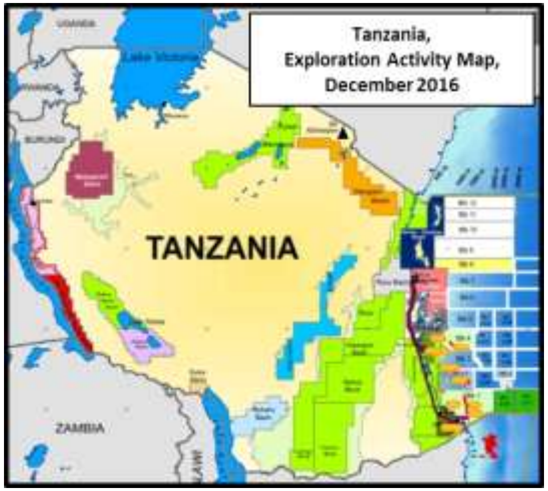
Upper Cretaceous Lead D, Ruvuma Basin, as mapped by Texaco, 1992.

Lead D was mapped on a seismic grid of up to approx. 8x8km, over a coastal estuary and mangroves; areal closure at Top Cretaceous was estimated at approx. 170.4km^2, with 800ft of vertical closure (Texaco 1992). Seismic reprocessing in 2010 and the subsequent revised interpretation did not support the originally mapped structure.

Source: "The Ntorya-1 Gas Discovery, and Implications for the Forward Exploration Programme within the Ruvuma PSA, Southern Tanzania", by M.C.P.Rego, 6th East African Petroleum Conference and Exhibition, Arusha, Tanzania 6th – 8th February, 2013

Exploration History



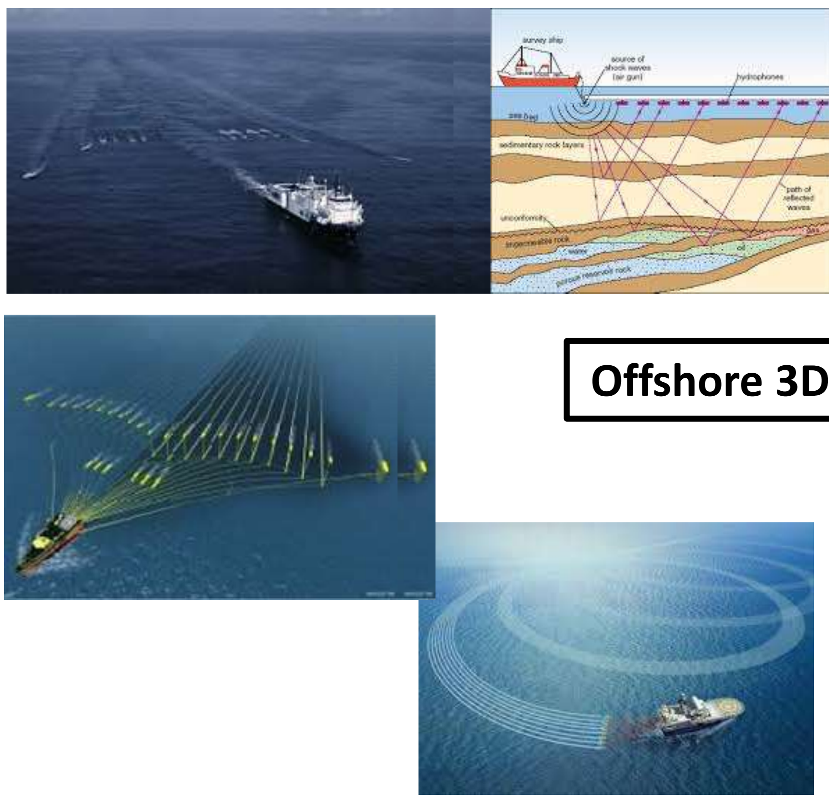


- The drilling and seismic contractors were not keen to support East Africa – lack of local follow-on work meant high mob/demob charges and day rates, putting further pressure on already tight exploration budgets.
- The State oil companies were in no position to complain – they were bringing in investment against the general industry trend, and new exploration companies could be attracted on the promise of favourable terms and a potential big find.
- The losers were the host governments, whose acreage remained in the high risk category as far as the industry was concerned, and the investors who lost money on dry holes.
- By the early 2000's, the landscape had begun to change. There was more data available in the public domain, initial deepwater 2D seismic had been acquired, and the first EAC Petroleum Conference was held in Nairobi in 2003 to disseminate knowledge and promote exploration investment.

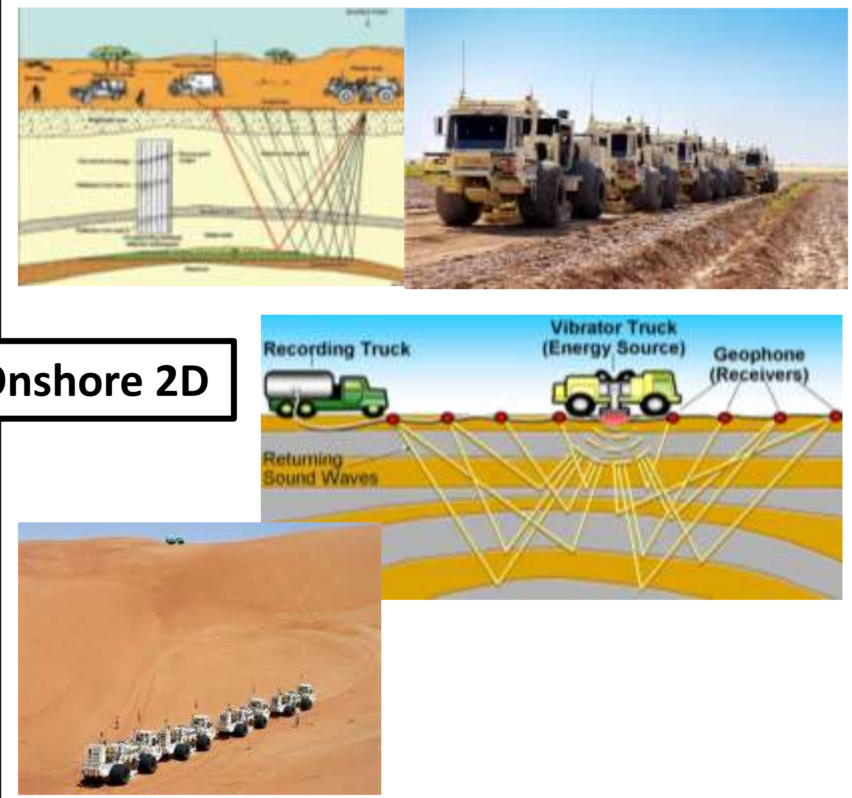
Improving the Onshore and Nearshore Prospectivity

Improving the Onshore and Nearshore Prospectivity

- The deepwater environment promised a lot of riches for the contractors as well as for the exploration companies, especially for 3D seismic, compared to the logistically more difficult onshore and shallow marine environments with their perceived low chances for success.
- 3D marine seismic can offer greater financial rewards to contractors for acquisition and processing contracts, and offers significant advantages over 2D in de-risking leads and prospects.



Offshore 3D vs Onshore 2D



Improving the Onshore and Nearshore Prospectivity

- **Management of deepwater marine seismic crews is logistically simple for seismic contractors, compared to more complex onshore and shallow marine environments – e.g., manpower requirements, mobilisation, crew sustenance, hire of unskilled local labour, environment, etc.**

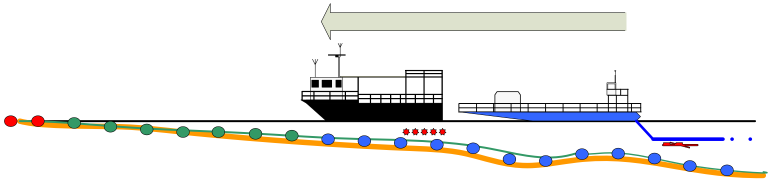
- **3D seismic volumes offer greater financial rewards for acquisition and processing contracts, and significant advantages over marine and onshore 2D in de-risking leads and prospects.**

Offshore 3D
vs
Onshore 2D

Improving the Onshore and Nearshore Prospectivity

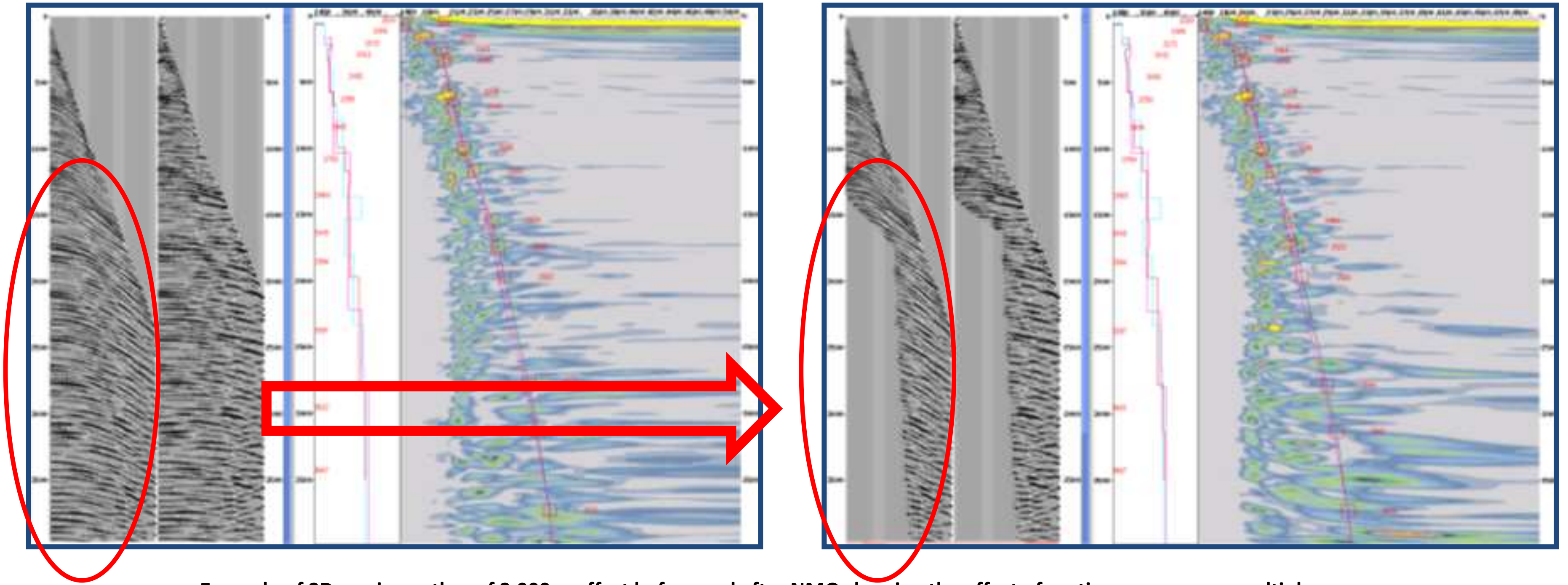
- Because of shallow reefs, islands, and coast proximity, much of the legacy marine 2D seismic has been shot with a short far offset, particular from southern Kenya to northern Mozambique, due to difficult survey logistics – EOL turning circles, vessel draft, small uncharted submerged reefs, native fishermen, etc.
- Far offsets of most legacy data are typically 1,200m to 1,500m, only occasionally to 3,000m - too short for meaningful AVO analysis and multiple suppression. Benefits of reprocessing can be limited.
- Many marine seismic contractors have geared up for the more lucrative 3D market in recent years, with fewer regularly offering 2D, or having suitable vessels for nearshore operations.
- Transition zone seismic is prohibitively expensive to many smaller companies – choice of contractors is limited, crew availability and rates are significantly greater than for conventional towed streamer operations, and contingency for weather downtime and standby costs can be a major liability.
- But the rewards are there for those who persist…

MV Geomariner – a shallow draft 2D/3D seismic vessel with a max draft of only 2.9m, able to operate in depths as shallow as 4m, used along coastal East Africa 2005 – 2007.



Transition Zone: Example of simultaneous land/marine recording (marine source), combining source boat with towed streamer and geophones and hydrophones on land, inter-tidal zone, and marine zone.

Improving the Onshore and Nearshore Prospectivity

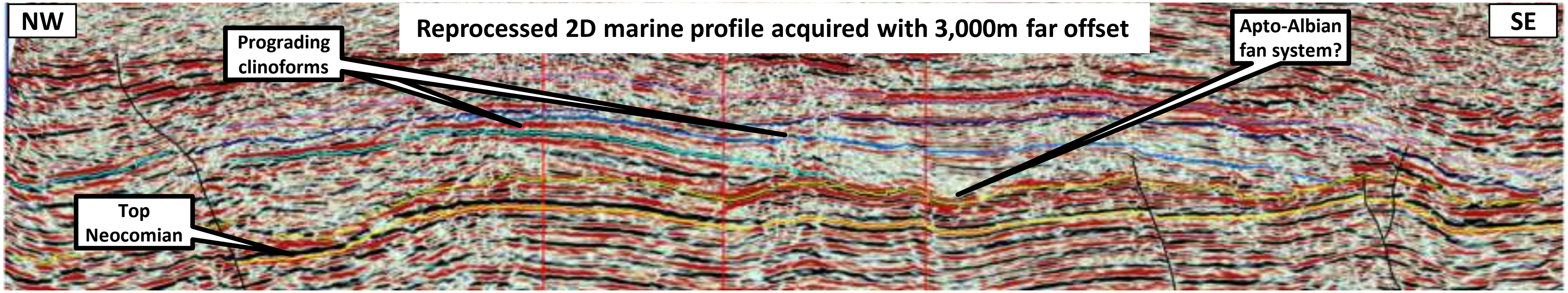


Example of 2D marine gather of 3,000m offset before and after NMO showing the effect of muting near-source multiple energy.

Source: "East African Exploration Success", M.C.P.Rego, 8th African Independents Forum, 18th Africa Oil Week, Cape Town, 31st October – 4th November, 2011.

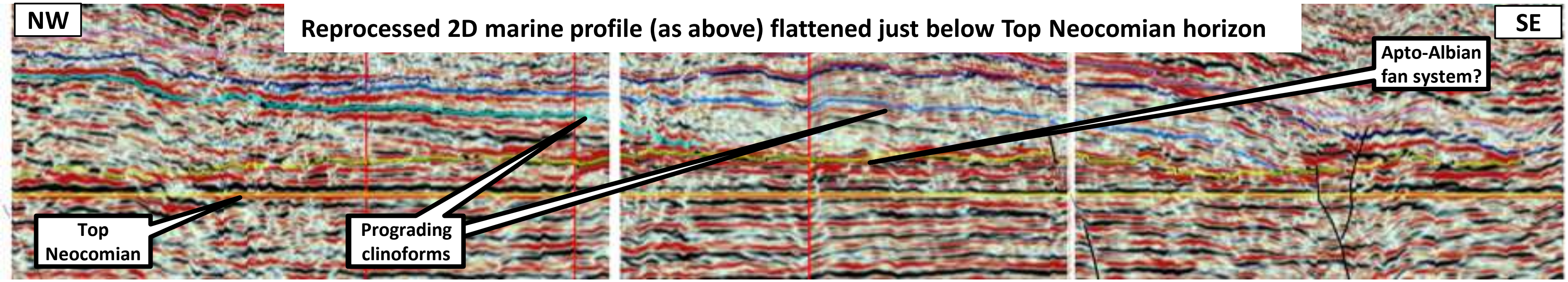
- **In 2010, Aminex had the opportunity to reprocess a recent 2005 shallow marine 2D dataset acquired with a 3,000m far offset.**
- **Examination of the data revealed severe near-offset multiple energy extending out to as much as 2,000m offset, that could not be sufficiently removed with the processing algorithms available from the processing contractor.**
- **Good results were achieved by surgically muting the nearest 2,000m offset data, but due to maximum offsets of much of the older local legacy data being less than 2,000m, this is not a viable option for much of the older local data in the nearshore environment.**

Improving the Onshore and Nearshore Prospectivity



NW-SE marine 2D profile acquired with 3,000m far offset in less than 35m water depth, offshore Rufiji Delta, Tanzania, showing improved stratigraphic details as a result of applying surgical mute to near offset gathers during reprocessing. The Upper Cretaceous clinoforms appear to be prograding from the Rufiji Delta to the northwest, with apparent bright amplitudes on their upper surfaces.

Source: "East African Exploration Success", M.C.P.Rego, 8th African Independents Forum, 18th Africa Oil Week, Cape Town, 31st October – 4th November, 2011.



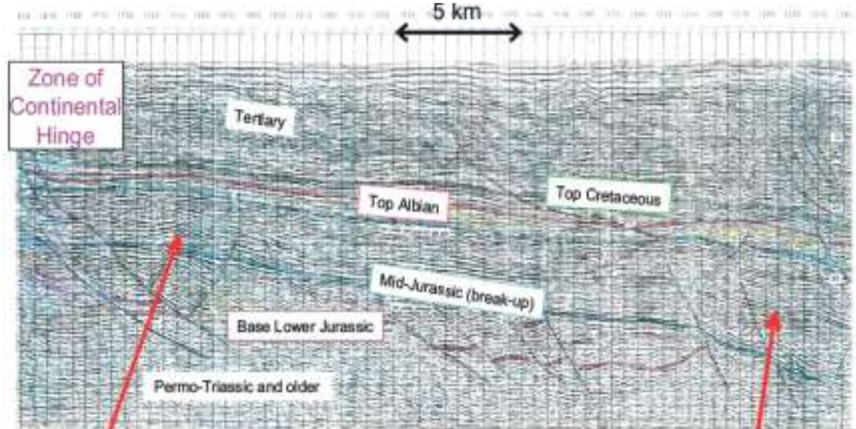
Flattening at Top Neocomian shows the Apto-Albian to have the appearance of a basinal fan, with distinct Upper Cretaceous prograding clinoforms.

Source: "East African Exploration Success", M.C.P.Rego, 8th African Independents Forum, 18th Africa Oil Week, Cape Town, 31st October – 4th November, 2011.

- **Efficient removal of multiple energy from longer offset data – the offset restricted by the limitations of acquisition on the marine shelf – enables the imaging on the shelf of feeder channels to deepwater fan plays.**
- **Potential stratigraphic traps rather than structural traps may be identified on poorer quality 2D legacy data and targeted for improved success.**

Improving the Onshore and Nearshore Prospectivity

- Until recently, most onshore exploration has been focused on identifying large structural closures.
- 2D seismic grids have been coarse, typically at >4km line spacing and up to 10km or greater, mainly for reconnaissance, but also partly due to lack of perceived prospectivity, contractor availability, and high survey acquisition costs.
- Reprocessing of legacy data is frequently hampered by lack of static data, such as LVL's, uphole surveys, even topographic elevation data that has been lost.
- Often legacy data appears to have been acquired with minimal statics partly to save costs, and partly because the data was acquired as a regional reconnaissance grid to identify major structures.
- Little stratigraphic potential was recognisable on such data, sufficiently de-risked to justify drilling.
- New onshore 2D seismic data acquired in 2014 to appraise the Ntorya gas discovery was acquired with regular LVL's and upholes, and detailed field tests for optimum source parameters.

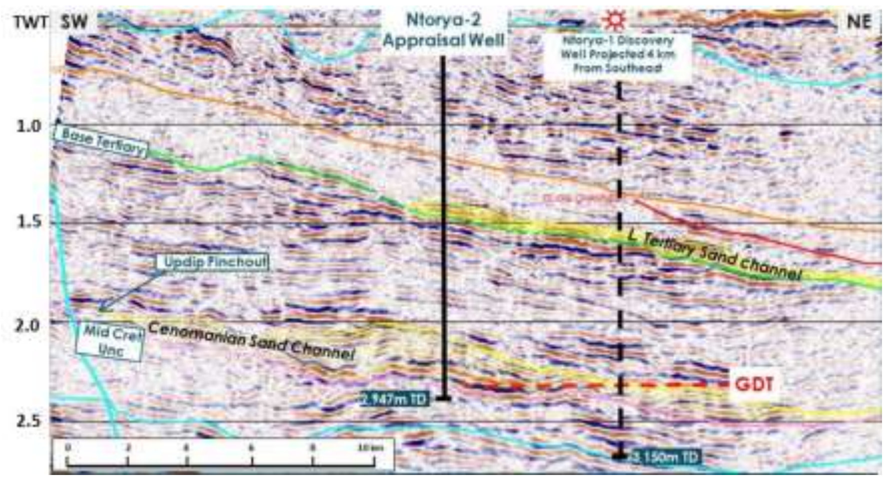


Indications suggestive of erosive channel scours at palaeo shelf break, particularly at time of Aptian-Cenomanian lowstands.

Less pronounced channel scours to East of palaeo shelf break in Lower Cretaceous reflecting relatively lower energy environments.

Onshore 2D seismic profile, northern Ruvuma Basin.

Source: "East African Exploration Success", M.C.P.Rego, 8th African Independents Forum, 18th Africa Oil Week, Cape Town, 31st October – 4th November, 2011.



Onshore 2D seismic profile, northern Ruvuma Basin, acquired Spring 2014 along axis of Ntorya Albian channel.

Source: Aminex PLC AGM, May 2015.

Improving the Onshore and Nearshore Prospectivity

Summary – simple measures to improve nearshore 2D seismic Imaging

- Employ shallow draft seismic vessels – when available.
- Where possible, acquire data with far offsets of 3,000m or greater.
- Acquire data with separate source boat and streamer boat, in multiple passes, to obtain longer offsets.
- Consider acquiring data with transition zone seismic crew rather than conventional towed streamer.
- Negotiate to acquire data in co-operation with other local operators, to share and reduce costs.

Summary – simple measures to improve onshore 2D seismic Imaging

- Employ tight QC to oversee detailed field acquisition parameter tests – this is key to better quality.
- Acquire frequent LVL surveys and regular upholes to better constrain near-surface velocities.
- Reshoot LVL surveys and upholes on legacy lines to enhance reprocessing, to improve resolution.
- Negotiate to acquire data in co-operation with other local operators, to share and reduce costs; for example local labour once trained are an asset; co-ordinate purchase, import and bunkering of explosives.

Improving the Onshore and Nearshore Prospectivity

- The major advantages of shooting 3D seismic in deepwater over 2D or 3D in an onshore or nearshore environment is the lack of obstacles to simple acquisition logistics, that allows wide arrays, long streamers, and minimal navigation issues. These are all features that help to acquire high quality data for interpretation and rigorous analysis, thereby justifying increased acquisition costs and removing much of the ambiguity and subjectivity that can arise with 2D in shallower or onshore environments, and most importantly the potential for finding large hydrocarbon volumes in younger slope/basin floor fan settings.

- For smaller companies, the greater costs of 3D seismic can be an increased burden, but deepwater drilling costs and their potential for significant cost over-runs in such hostile environments can be a major liability.

- With lower drilling costs, 3D seismic does not have to be a pre-requisite to drilling in onshore or shallow marine environments – high quality 2D seismic can remove many of the associated risks, if acquired in a timely manner – less onerous licence schedules would help, rather than standard "boiler plate" time schedules.

- Onshore exploration especially can be so much cheaper than the deepwater – so why are so few companies looking there?

Comparative Exploration Costs for Seismic and Drilling

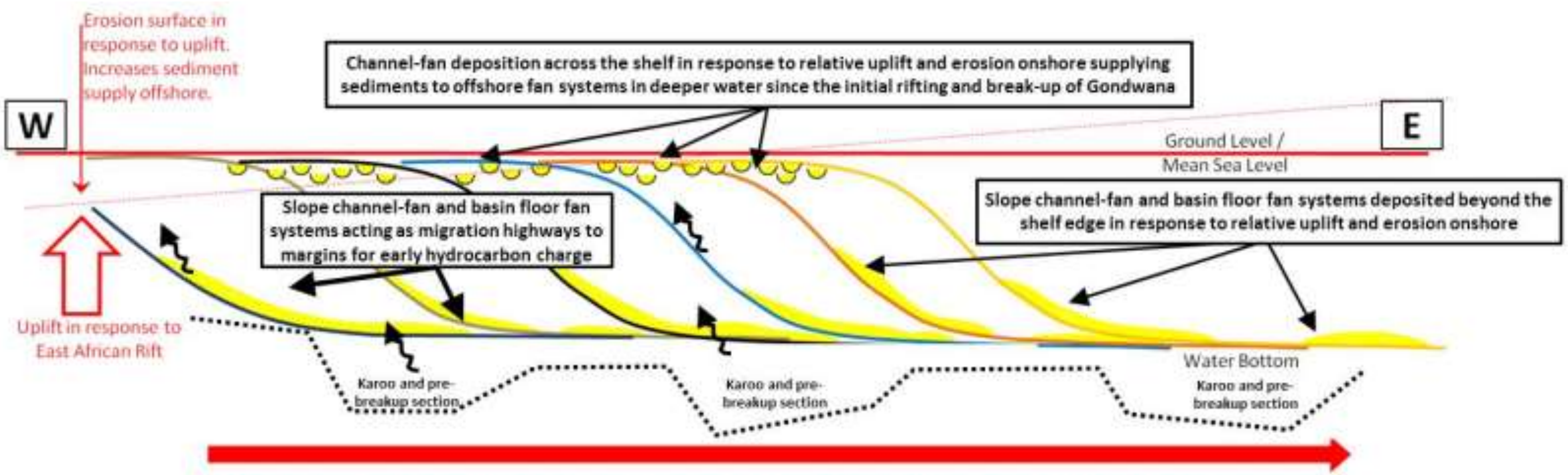
Activity	Onshore ($)	Transition Zone ($)	Offshore ($)
2D Seismic per km	2,000-3,000[1]	25,000	5,000
3D seismic per km[2]	20,000[2] 15,000[3]-25,000[4]	45,000[5]	15,000[6]
3D processing			1,500[7]
Daily rate - drilling[8]	150,000 - 200,000		1200000
Well cost[8]	15,000,000 - 40,000,000		100,000,000 - 170,000,000

The above costs for seismic are general minimum estimates dating from 2009, whilst the drilling costs are for Tanzania as published by TPDC in 2013. Whilst costs for seismic and drillig have fallen since the date of these estimates, the point to note is the relative difference in costs between 2D and 3D and for onshore versus offshore, and likewise for drilling, onshore versus deepwater offshore.

[1] Central region Russia and West Siberia, 2009. [3] Yamal region Russia, 2009. [3,4] Saudi Arabia, Vibroseis and dynamite, 2009. [5] Ocean Bottom Cable, SW Africa 2009. [6] SW Africa, 2009. [7] Seismic processing per km[2], SW Africa dataset, 2009. [8] From Tanzania, "Oil and gas exploration, general overview", a presentation to the delegation from Tanzania Private Sector Foundation (TPSF), by Dr.Emma Msaky, 2013

Improving the Onshore and Nearshore Prospectivity

- **Recent deepwater drilling along the margin has begun to verify the stratigraphic systems identified from modern high quality seismic, that have previously not been clearly imaged from existing onshore and nearshore seismic to sufficiently de-risk drillable prospects.**
- **Successive progradation of the East African shoreline means that the deepwater gas discoveries in basin floor fan systems have older potentially analogous traps extending back to the onshore or shallow marine shelf.**
- **Drilling results to date would suggest that the source section(s) are increasingly overmature as the Continent-Ocean Boundary (COB) is approached, however, the same source rocks are believed present in the nearshore and onshore, potentially at lower maturities, and in at least one instance still within the oil window.**
- **Many wells along the margin have recorded traces of oil, and many of the condensates recovered in wells and seeps show evidence of having been derived by evaporative fractionation of oils. But where are the oils now?**
- **In September 2016 a group of five explorers with over 140 years combined industry experience, with at least 60 from East Africa, came together under the umbrella of the EAOG to address the issue of *where are the oils?***

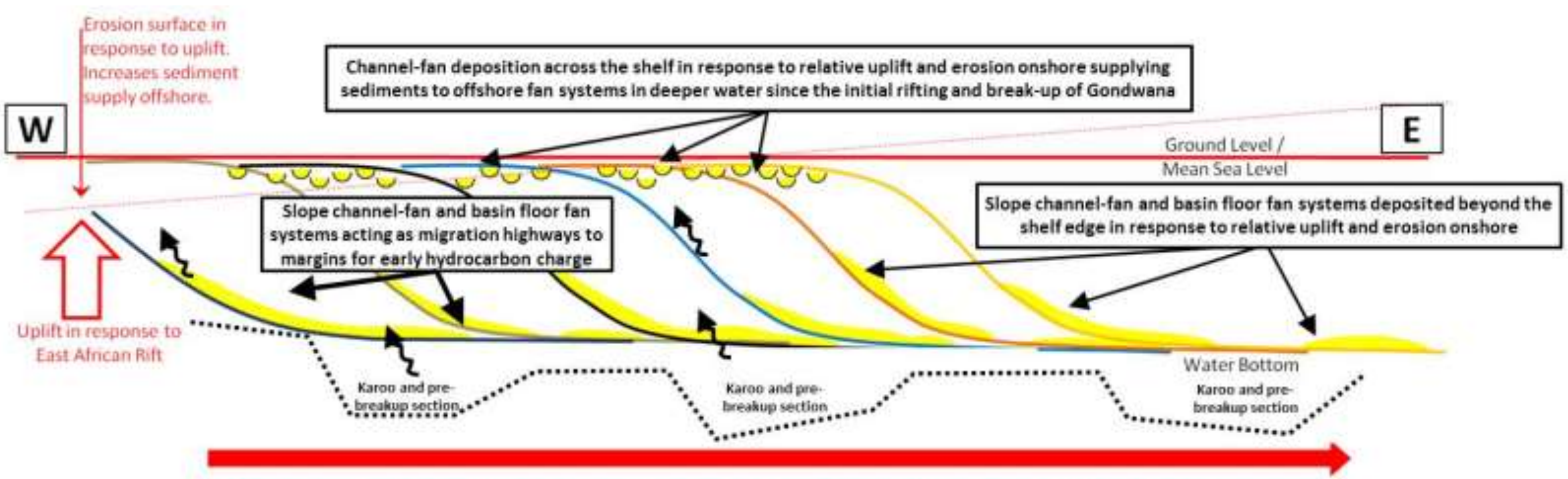


Progressive migration of shoreline and delta systems prograding oceanwards with time

Oil Potential –
Understanding the Source Rock Story

Oil Potential – Understanding the Source Rock Story

- **Few wells have been drilled onshore or nearshore to confirm the presence of the systems as encountered in the deepwater, other than Ntoya-1 (2012) and possibly Mambakofi (2015), both of which were declared as significant gas discoveries, with several Tcf in place. Appraisal for these discoveries is ongoing.**
- **Whilst there is seemingly much effort by host governments and seismic contractors to promote the deepwater and even the ultra-deep water with licence rounds and off-the-shelf seismic spec' data for sale, the same efforts are not being applied to the onshore or nearshore environments along much of the margin.**
- **Whether or not many of the deeper offshore licences will be taken up remains to be seen; whilst there may be evidence from seismic for eastward continuation of the sedimentary systems favourable to reservoir development to be present, the big uncertainty would seem to be the precise nature of the crust eastwards of the Davie Fracture Zone (DFZ), and whether transitional or oceanic crust can support the presence of Lower-Middle Jurassic (oil-prone) source rocks, or pockets of earlier Karoo source rocks in large enough quantity to generate the significant volumes required for commercial viability.**



Progressive migration of shoreline and delta systems prograding oceanwards with time

Oil Potential – Understanding the Source Rock Story

- **Oil was and is clearly present along the margin, given the abundance of slicks, seeps, shows, etc., and by analysis the intimated quality of the source rocks. Be *very wary* of the definition of a "dry hole".**
- **Anadarko have said that they entered deepwater Mozambique arguing the case for oil, but ENI have not stated their case.**
- **Few wells have actually penetrated the known source rock intervals; Lukuledi-1 and Mbate-1 in Tanzania are key wells.**

Oil soaked sand, Wingayongo oil seep, Rufiji Trough, Tanzania.

Oil soaked sand, Tundaua oil seep, western Pemba Island, Tanzania.

Tarballs from foreshore of Nyuni, and Okuza Islands, offshore Tanzania.

Condensate seep, western margin of onshore Ruvuma Basin, Tanzania.

Tanzania

Makarawe: Tarry bitumens – Karoo age / Jurassic
Tundaua: Oil seep - Jurassic
Pemba # 5: Oil shows - Jurassic
Kiwangwa: Tarry bitumens – Jurassic?
Zanzibar: Gas shows -
Tancan: Gas shows
Mafia Island: Oil & gas shows
Okuza island: Oil shows - Jurassic
Nyuni Island & well: Oil & gas shows - Jurassic
Lipwapwatawre: Oil seep
Mikandani: Oil seep
Kisangire: Oil shows - Jurassic
Wingayongo: Oil seep – Jurassic
Wingayingo #1 & #2 - 30m & 40m of tar sand
Ruhoi River (5km from Wingayongo) - Oil seep
Lukuliro: Gas shows - tars, sands in wells
Songo Songo: Gas reservoir & condensate. 845 Bcf (3P) & Jurassic oil?
Nyuni well & island – Oil seep and shows - Jurassic
Mita Gamma: Oil shows
Mandawa: Oil shows
Mbuo: Oil shows
Mnazi Bay: Gas reservoir. 1 Tcf (GIIP)
Msimbati: Oil seep

Kenya

Pandangua #1: Oil shows
Ria Kalui: Tarry bitumens – Permo Triassic / fish beds
Cities wells offshore Kenya: Oil shows
Oil & gas seeps

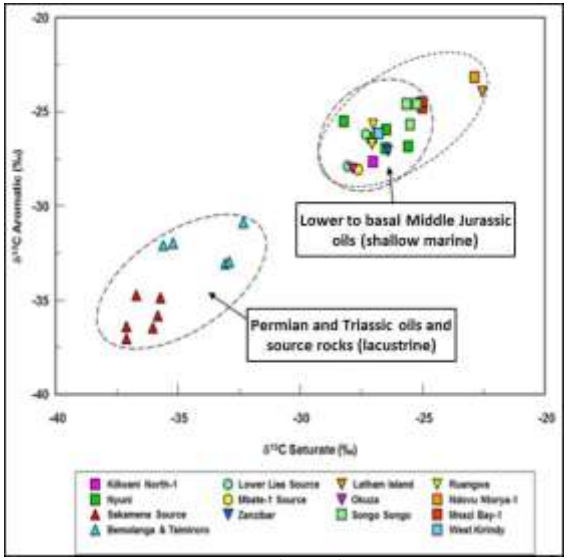
Mozambique

Rovuma basin: Oil seeps

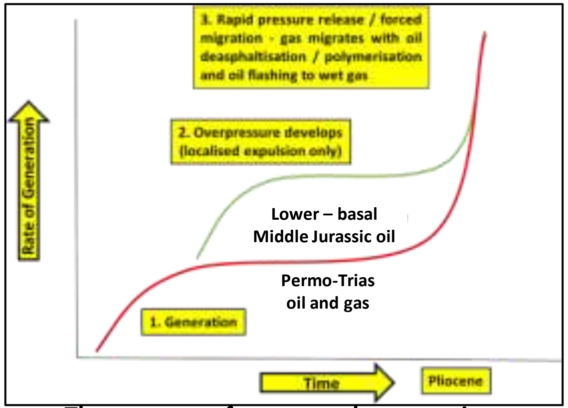
Source: Modified from "Finding Big Oil Fields in East African: Understanding the Source Rock Story" M.C.P.Rego, A.Carr, N.Cameron, Finding Petroleum, London, April 2013. After C.Matchette-Downes.C., Rego, M., Carr, A., "The Greater East African Oil-Prone System", PESGB & HGS Third Annual International Symposium "Africa: The Continent of Challenge and Opportunity", London, September 2004

Oil Potential – Understanding the Source Rock Story

- **There is good evidence from biomarkers and isotope ratios for two distinct oil families:**
  - **Lower to basal Middle Jurassic source rocks deposited in a restricted marine environment with a carbonate influence, as might be expected from the early rifting of Gondwana and the formation of the Indian Ocean.**
  - **Permo-Trias source rocks, with evidence for both restricted marine and lacustrine sources, with peripheral coals, reflecting an initial failed rifting phase.**
- **To date there has been no definitive evidence for a Cretaceous source presence; there has been some evidence for localised Tertiary oil-prone source rocks, most notably with BG's recent Sunbird-1 well offshore Kenya, but these are not believed to be widespread, and generally immature where present locally. (Whilst Oleanane, often cited as a Tertiary biomarker associated with Angiosperms (flowering plants), has in fact been around since the Permian albeit in miniscule quantities, some workers believe it may be present as a contaminant picked up during migration.)**
- **Regional correlation of Permo-Trias stratigraphy as catalogued from well data is imprecise, particularly the ages of coals penetrated – Sakhamena or earlier Sakhoa? – however the Sakhamena is considered to be a major potential Permo-Trias oil source, with additional potential from Sakhoa coals where HI's of over 400 have been reported.**



Two distinct tribes of oils from around the East African Margin.



Three stages of source rock maturation.

Source: "Why have there been no oil discoveries so far in Tanzania?" M.C.P.Rego, A.Carr, N.Cameron, Finding Petroleum, London, April 2013. After C.Matchette-Downes.C., Rego, M., Carr, A., "The Greater East African Oil-Prone System", 12th PESGB/HGS Conference on African E&P, "Africa: Success in Rift, Sagand Passive Margin Settings", London, September 2013.

Oil Potential – Understanding the Source Rock Story

- **Outside of the Mandawa Basin of Tanzania, there is scant meaningful published data on Karoo source rock potential, yet the limited data hints at the potential for regional shales of considerable thickness with encouraging source potential – up to 15,000ft of shales are estimated to be present in the Mandawa basin.**
- **With such shale thicknesses present regionally, aside from conventional hydrocarbons, there must surely be significant potential for shale oil and shale gas, at least on the western flanks of basins such as the Ruvuma, Rovuma, Lamu and Ruvu where the stratigraphic section shallows prior to potentially outcropping at surface.**

Maturity/other Shale Gas Data

Well	Basin	Shale Thickness (m)	Well Status	Remarks
Mbuo-1 (1990)	Mandawa	100 Marine black shales	P & A	Oil/gas shows; TOC's to 9.35%, VR=0.57%
Mbate-1 (2001)	Mandawa	1,321	P & A	Dry
Mandawa-7 (1958)	Mandawa	> 499 Marine black shales	P & A	TOC's = 1.7-5.54%, VR=0.6-1%
Liwale-1 (1985)	Selous		P & A	TOC's = 3.5-9.0%, VR=0.4% at 150m, gas shows at 1,008-1,090m
Lukuledi-1 (1990)	Ruvuma	96	P & A (Stratigraphic test)	TOC's to 70%, HI's to 317% - oil-mature source

Source: Modified from "New Data, Volumetrics and Studies on Shale Oil and Gas in Tanzania", Emma Msaky & Henk Duyverman, 15th PESGB & HGS Conference on African E&P, "Africa: What's Next?" Houston, September 2016.

Oil Potential – Understanding the Source Rock Story

- The multiple source rocks make for a complex charge story – the oil and gas both migrated independently into the same traps or 'hotels' traps, the oil prior to any inversion and the condensate and gas during inversion, and as the pressure continued to be reduced by continued uplift, the condensate and gas evaporated away from the oil (although a minor oil component is often entrained in the gas and condensate as they evaporated away the oil).

- Thus any Permo-Trias derived gas will flush earlier generated Permo-Trias sourced oil as well as any Lower/basal Middle Jurassic derived oil, potentially simultaneous to the oils being flashed to a gas-condensate by evaporative fractionation as a result of contemporaneous structural inversion.

- Given the presence of oil seeps along the margin, there is the implication for oil to be reservoired in the subsurface, possibly on the flanks of major structures such as Songo Songo… having been displaced to the flanks by later charges of lighter gas and gas condensates.

- According to a recent RNS put out by Bounty Oil & Gas NL on the Australia Stock Exchange, (22 September 2016), a minority partner in the Kiliwani North well, the well was reported to be producing at rates "… mainly between 15 and 25 MMcfd with up to 150 barrels of condensate", a condensate:gas ratio up to ten times higher than reported when the well was first tested in 2008. Given that the estimated gas:water contact is some 40m deeper than at the adjacent Songo Songo gas field, where condensate:gas ratios are believed to be lower at approx. 1 barrel condensate per MMcf gas, could this be indicative of a liquid rim?

- The fact is that there have been few discoveries of gas to date in the nearshore and offshore, and the few discovery wells for which reliable data are published have been in crestal locations. One exception is the Ntorya-1 discovery well in the Ruvuma Basin, which is believed to have been located close to the downdip limit. Ntorya-1 tested at 20MMcfd and 139 barrels of condensate – it will be interesting to learn the results of testing the recently drilled Ntorya-2 appraisal well, as well as the recent Mambakofi discovery.

Oil Potential – Understanding the Source Rock Story

- The potential volumes of oil and gas that may be generated from Lower/basal Middle Jurassic source rocks within the onshore and offshore Ruvuma/Rovuma Basin at approximately 50,000km^2, put the oil and gas potential into perspective.
  - Let us take a Lower/basal Middle Jurassic oil prone source rock of 50m thickness, with HI=350, TOC=5%, which will expel a volume of 9.8 MMbbls oil and 32.6 Bcf gas per km^2
  - For a basin of 50,000km^2, assuming source rock presence over 80%, i.e., 40,000km^2, this is equates to expulsion of 393,800,000,000 bbls oil and 1,303,000,000,000,000 cf gas
    - (393.8 Billion bbls oil and 1,303 Tcf gas)
  - If we assume that only 10% of the expelled hydrocarbons become effectively trapped for exploration, this still equates to 39,380,000,000 bbls oil and 130,300,000,000,000 cf gas
    - (39.38 Billion bbls oil and 130.3 Tcf gas)
- If we have a similar source interval in the Permo-Trias, there is potential for a further similar volume; if there is any evaporative fractionation or "cracking" of the oils to gas, for every 10 Billion barrels of oil there is the potential for a further 6Tcf of gas.
  - Thus for a basin of 50,000km^2, with a total 100m source rock interval from the Permo-Trias and the Lower/basal Middle Jurassic, this is equates to 78,760,000,000 bbls oil and 260,600,000,000,000 cf gas
    - (78.76 Billion bbls oil and 260.6 Tcf gas)
- With 150-200Tcf of gas discovered primarily offshore to date, there are some phenomenal source rocks present, but most importantly, what has happened to 78 Billion barrels of oil, and where is it?

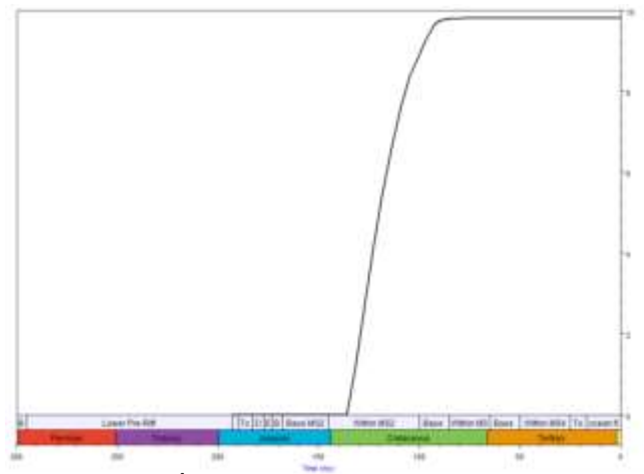
Oil Potential – Understanding the Source Rock Story

- Timing of expulsion and the migration pathway for any liquids is key to oil prospectivity: simple maturation modelling for a Lower/basal Middle Jurassic source rock suggests that they would probably be depleted by around late Cretaceous… thus any Jurassic-sourced oil, gas, or condensate would have to be either trapped in place by then, or be re-migrated from an earlier trap, unless parts of the basin had a suppressed maturity due to lack of burial or severe over-pressure retarding rate of maturity.

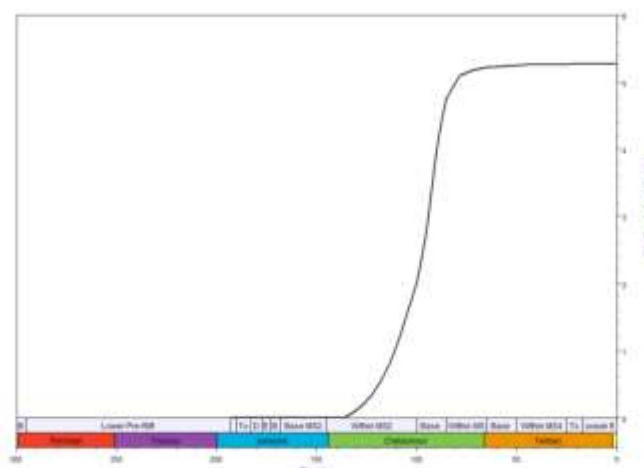
- This implies that most of the hydrocarbons found to date have likely re-migrated from trap to trap over time.

- Key to migration will be a network of carrier beds – the main contenders must surely be the channel-fan systems along the rift margins dating from Lower/basal Middle Jurassic break-up times through to present, allowing for migration generally updip and westwards towards the shelf.

- Thus it can be surmised that the best opportunities for oil will be associated with early migration along the exhumed coastal strip, i.e., nearshore and onshore to the West, away from the influence of any plume activity.



Simplified Lower/basal Middle Jurassic oil expulsion curve

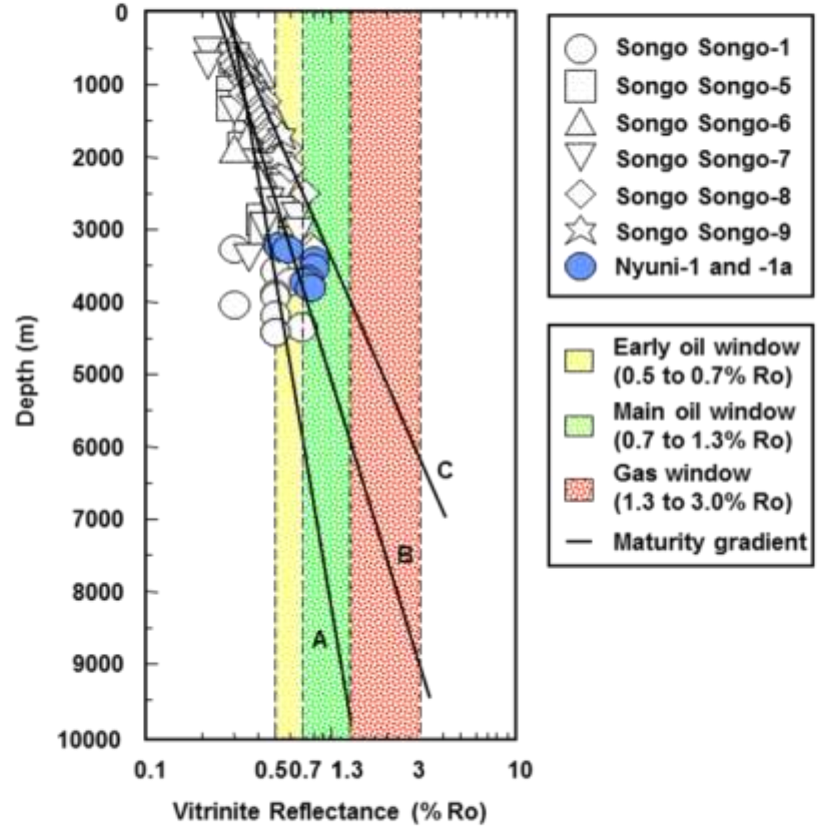


Simplified Lower/basal Middle Jurassic gas expulsion curve

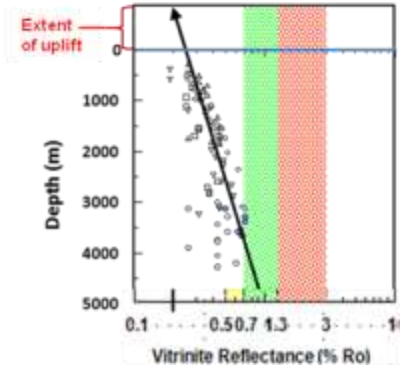
Source: A.Carr, July 2016.

Oil Potential – Understanding the Source Rock Story

- Offshore, the greater the extension, the higher the heat flow and the greater the final water depth.
- From published offshore well data (pre-2010), the maturity gradient in the offshore is slightly steeper than onshore, which implies a greater maturity than at equivalent depths onshore due to greater uplift offshore.
- However, at depths >10,000 ft offshore, the trend is reversed with the offshore section being less mature than the equivalent depth onshore, due to the effects of pressure, which is good for preserving oil potential offshore, but not when overlying oceanic crust.
- Understanding the nature of the crust is therefore considered to be crucial before embarking upon any deepwater exploration programme, especially eastwards of the Davie Fracture Zone.



Vitrinite reflectance values from various Songo Songo wells and Nyuni-1, Tanzania, (also indicating average uplift of approx. 800m.

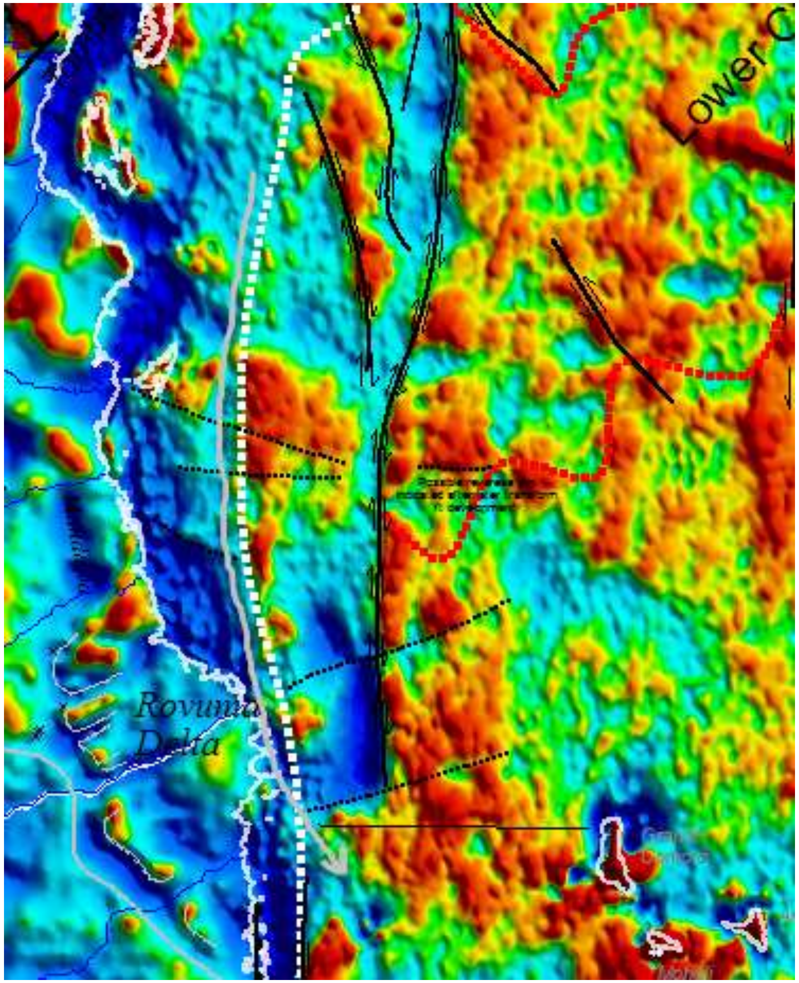


Source: "Finding Big Oil Fields in East African: Understanding the Source Rock Story" M.C.P.Rego, A.Carr, N.Cameron, Finding Petroleum, London, April 2013.

Oil Potential –
Understanding the Onshore/Nearshore

Oil Potential – Understanding the Onshore/Nearshore

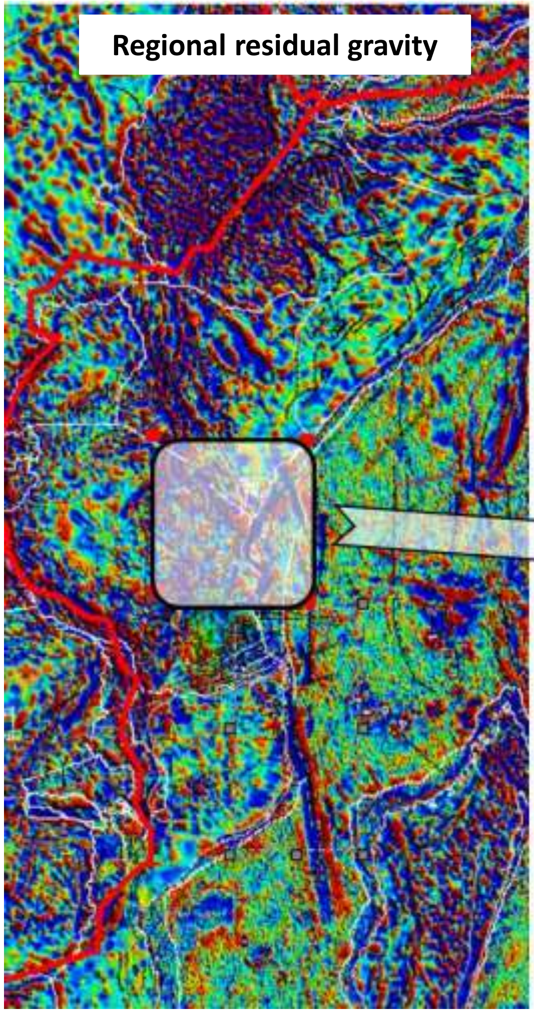
- A better understanding of basin architecture is vital if the source rock geochemistry is to be refined in the context of migration and entrapment by features identified on seismic.
- Much of the available seismic can be ambiguous below 2,000-3,000m with poor syn-rift and pre-rift imaging; recognition of basement is often tenuous.
- Onshore and nearshore well density is low: for the nearshore and onshore basins of Tanzania it is approx. 1 well per 3,750km^2. Few wells penetrate known source rock intervals, or tag basement.
- On a regional scale, there is considerable debate as to the location of the Continent-Ocean Boundary (COB), and extent and nature of the COB transition zone – highly relevant to extent and presence of source rocks offshore in the deepwater, especially with current efforts to promote exploration in the ultra-deepwater.
- At the EAOG we are currently attempting to better define the regional tectonic picture, using gravity and magnetic data and plate models to locate the basins and the COB's, in turn to build a detailed regional stratigraphy, typing the oils and condensates, and assessing the thermal histories.



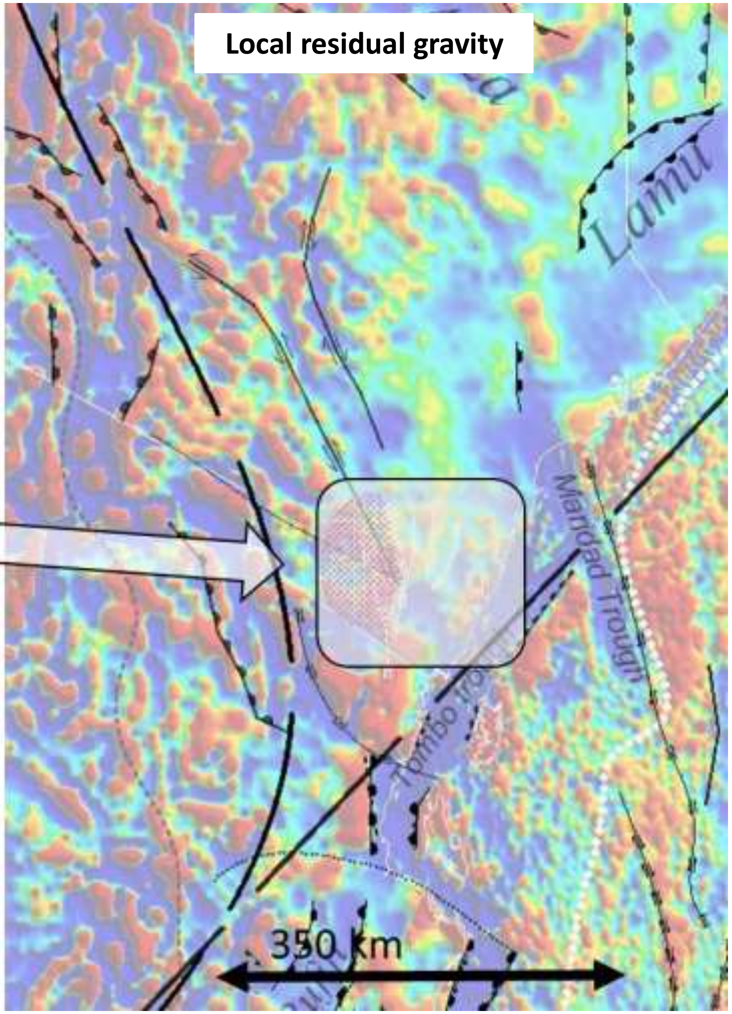
Upward continued (20km) isostatic gravity map of coastal margin of northern Mozambique and Tanzania showing key tectonic elements.
(Gravity data sourced from Sandwell Free Air Gravity V23.1; offshore resolution ~2km, onshore ~10km.)

Oil Potential – Understanding the Onshore/Nearshore

- **A clear example is from Kenya, focusing on the area of the Ria Kalui well, drilled in 1962 to a TD of 1,538m.**
- **The well reached TD in Permo-Trias, and was P&A'd with bituminous oil staining in the basal Permian grits.**
- **The well is believed to have been drilled "off structure", hence there is potential for better oil deposits with a revised location.**



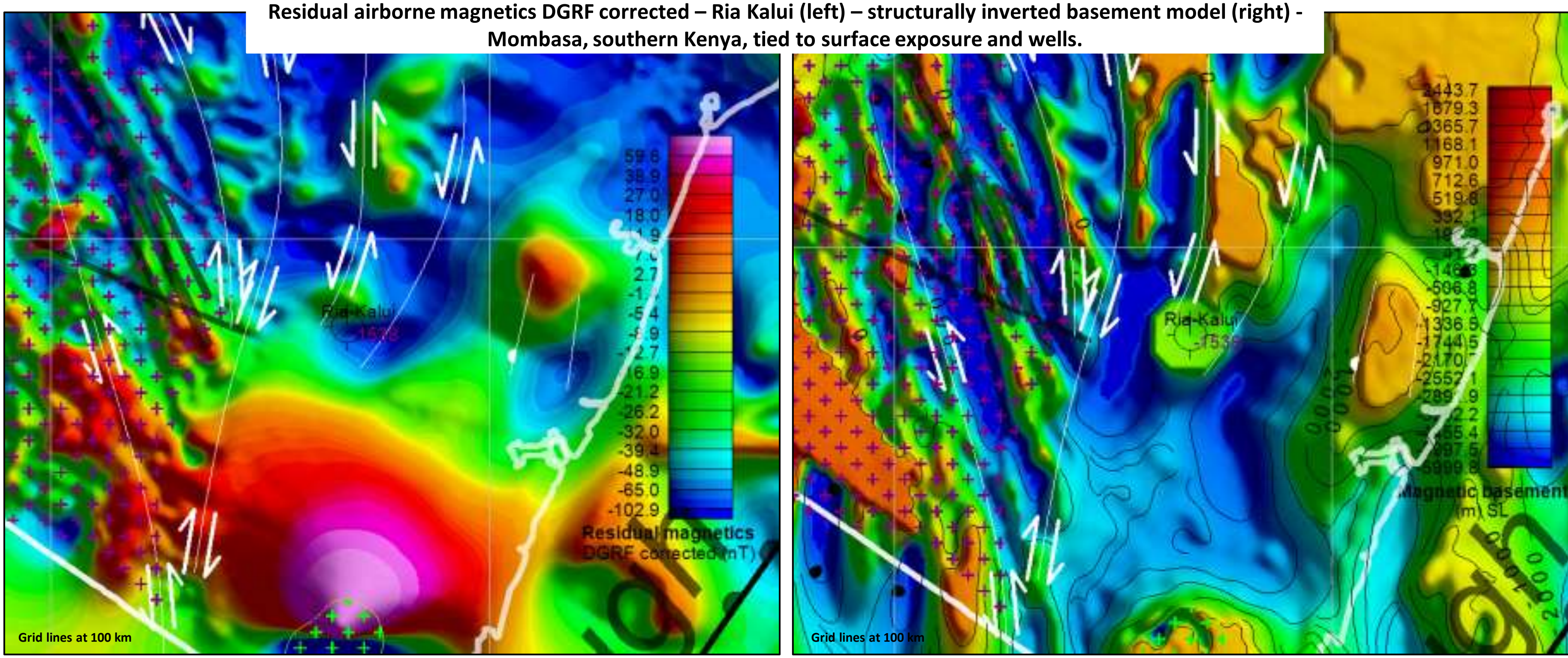
Upward continued (2km) isostatic residual gravity, first vertical derivative residual.
(Gravity data sourced from Sandwell as before.)



Upward continued (20km) isostatic gravity map zoomed in.
(Gravity data sourced from Sandwell as before.)

Oil Potential – Understanding the Onshore/Nearshore

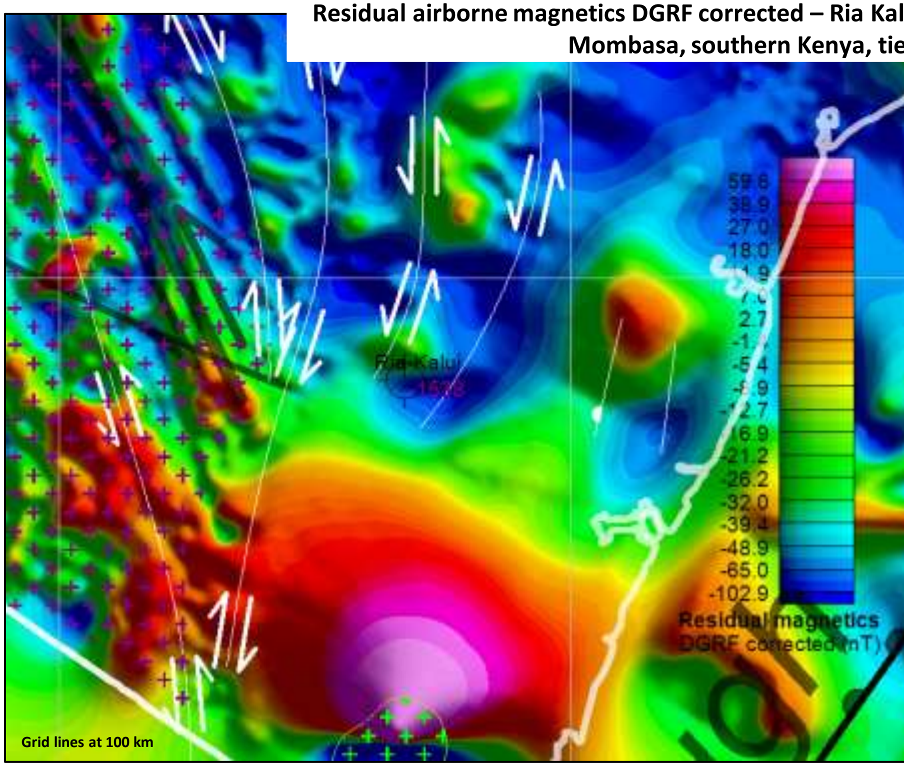
Residual airborne magnetics DGRF corrected – Ria Kalui (left) – structurally inverted basement model (right) - Mombasa, southern Kenya, tied to surface exposure and wells.

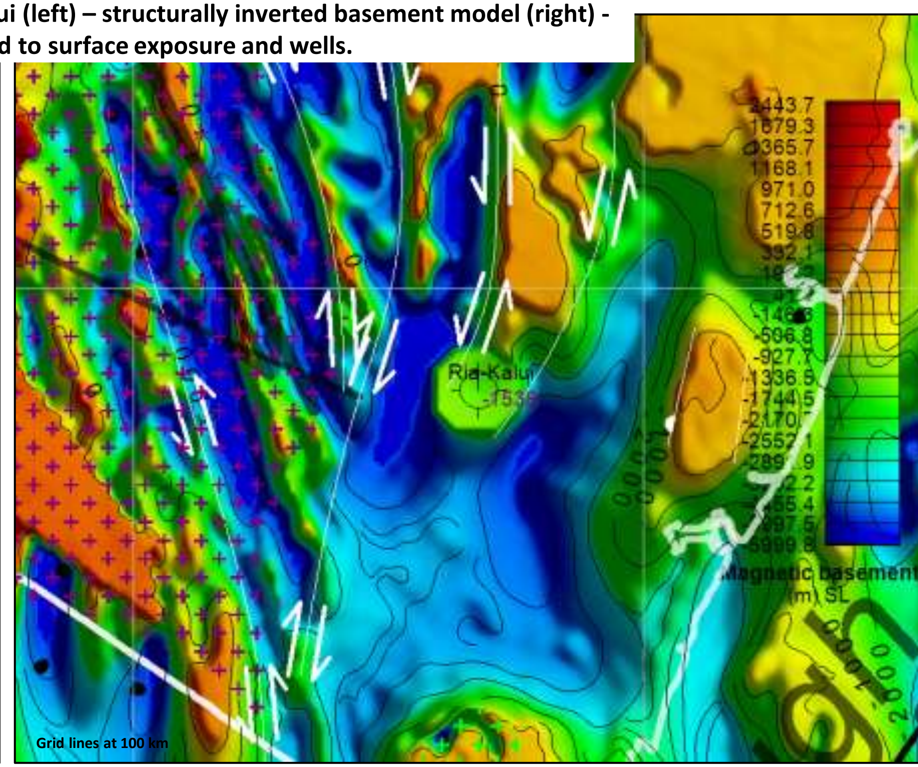


- **The basement is shown relative to sea level, modelled by higher resolution vintage data constrained by surface Pre-Cambrian exposure in the West (shallow structural features) and the Ria Kalui well, to a deeper Karoo-bearing basin system to the East which outcrops at surface.**
- **The model is constructed assuming all magnetization arises from basement, so no Karoo magnetic shales, or dolomited Fe-Mg replacement in possible shallow water facies. The Cretaceous extrusives in the extreme south (green +'s) give rise to the large dipolar anomaly seen in the magnetics.**
- **Ria Kalui sits at the southern end of a horst nose, surrounded by deep channels running through the area beneath 'Karoo' exposure at outcrop.**

Oil Potential – Understanding the Onshore/Nearshore

Residual airborne magnetics DGRF corrected – Ria Kalui (left) – structurally inverted basement model (right) - Mombasa, southern Kenya, tied to surface exposure and wells.



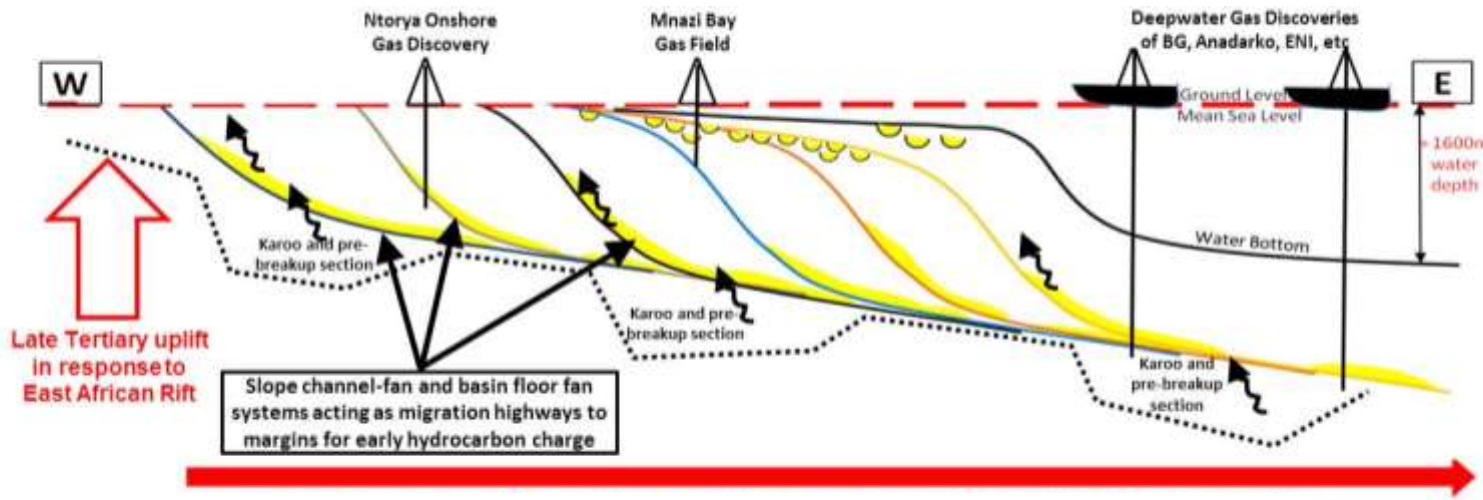


- **Fill in the surrounding area is from 4km to in excess of 6km depth on the flanks, with the pre-Jurassic (Carb-Triassic) Karoo exposed at surface.**
- **The thick early pre-Jurassic Karoo sequence could be locally matured by average depth of burial maturation, with potential for localised shale oil/gas potential in the surrounding basins.**
- **By examining regional oil data in the context of the tectonic picture, the EAOG is generating a deeper approach to exploration for the oil that has been generated along the margin.**

Bringing It All Together – A Way Forward

Bringing It All Together – A Way Forward

- **The source rocks that have given rise to 150-200 Tcf of gas offshore are present over much of the onshore; the nearshore and onshore coastal margin is on a direct migration pathway for hydrocarbon migration from the source rocks downdip to the East, via channel-fan systems initiated at breakup.**
- **The nearshore shallow marine environment has been desperately under-explored, but has good stratigraphic potential similar to the deepwater subject to improved seismic imaging.**
- **Early generation, expulsion and migration of liquids and subsequent charge is likely to be best preserved on the basin margins, away from significant plume activity, etc. There is potential for shallow oil-sands and shale oil/gas as a result of early migration or re-migration of hydrocarbons, and key source rock intervals preserved at shallower depths.**
- **There is only limited up-to-date and reliable geological mapping from the coastal margin available in the public domain – there is much still to be learnt from basic fieldwork and surface outcrop geology along the margins that can high-grade key areas for oil prospectivity.**



Source: Modified from "Finding Big Oil Fields in East African: Understanding the Source Rock Story" M.C.P.Rego, A.Carr, N.Cameron, Finding Petroleum, London, April 2013.

Bringing It All Together – A Way Forward

- **Obstacles to successful exploration in the shallow marine and onshore environment are not insurmountable but can include limited choice of seismic contractors at competitive prices (partly due to disproportionately high mob/demob costs); lack of available crews to conduct the required surveys; limited availability of appropriate offshore drilling rigs.**

- **Greater pooling of resources by operators as consortia to reduce costs of surveying and drilling, and greater sharing of technical knowledge to help de-risk exploration programmes would be beneficial. This does not mean giving up a strategic advantage, but increased sharing of data to reduce shared risk. The biennial petroleum conferences initiated by the East African Community in 2003 have been a major success in promoting the region.**

- **Pooling of resources by contractors could also be beneficial – shared regional storage yards in-country, alliances to share basic equipment and personnel, import/export expertise, explosives procurement and local taxation expertise.**

- **Exploration costs and risk can be reduced in the onshore environment, by improving legacy seismic data with acquisition of new static data to reprocess old seismic, and potential alliances between contractors to share or manage bulk procurement, for example explosives.**

Onshore drilling rig, Tanzania, January 2012.

Bringing It All Together – A Way Forward

- From the perspective of the host governments, there needs to be a clearer recognition that onshore and nearshore is a difficult area to explore, and in areas without established production or widespread exploration success as along the East African Coastal Margin (EACM), there needs to be encouragement and incentives to invest in exploration rather than obstacles:
  - Readily available access to legacy data at minimal cost
  - Longer licence periods, to reflect limited contractor availability at reasonable cost, procurement issues (e,g., explosives) and weather windows, especially for shallow/transition zone marine environments
  - Less onerous work commitments reflecting high cost operating environments (e.g., shallow/transition zone marine)
  - Greater flexibility in issuing of licences outside of competitive bidding rounds

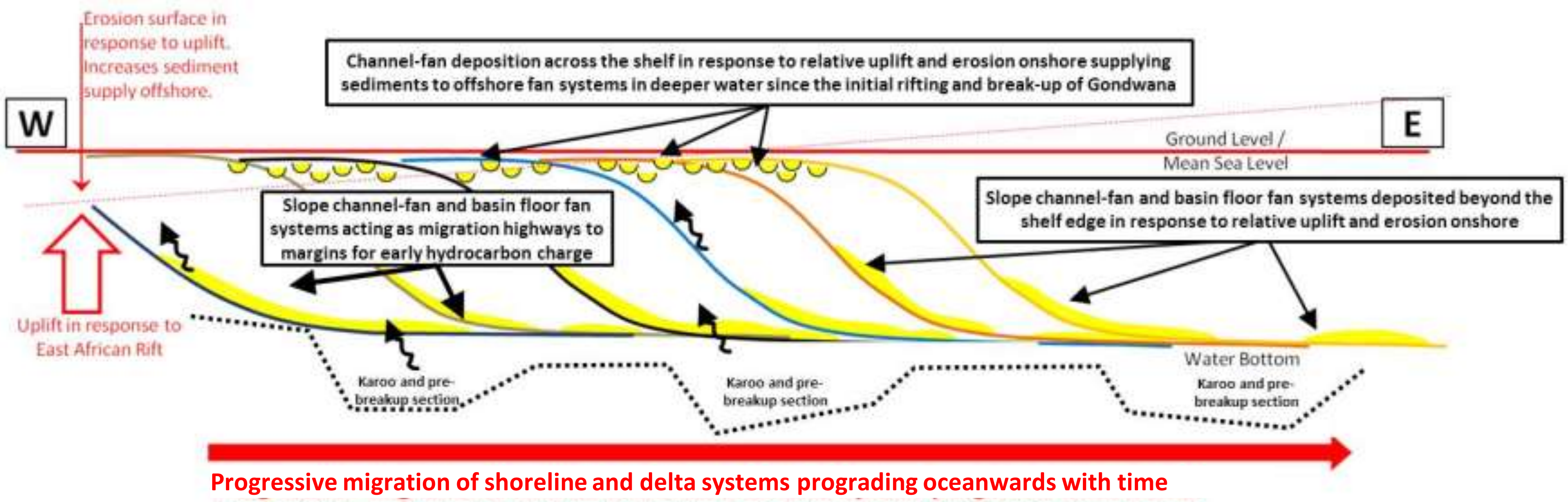
- At the end of the day, it is in the interests of the host governments to support companies to achieve exploration success. The immature onshore and nearshore areas of the EACM failed to attract the majors at times of high oil prices, it will not be any easier with cheap oil, nor with the threat of an over-supply of gas/LNG - the smaller more entrepreneurial companies need support and encouragement.

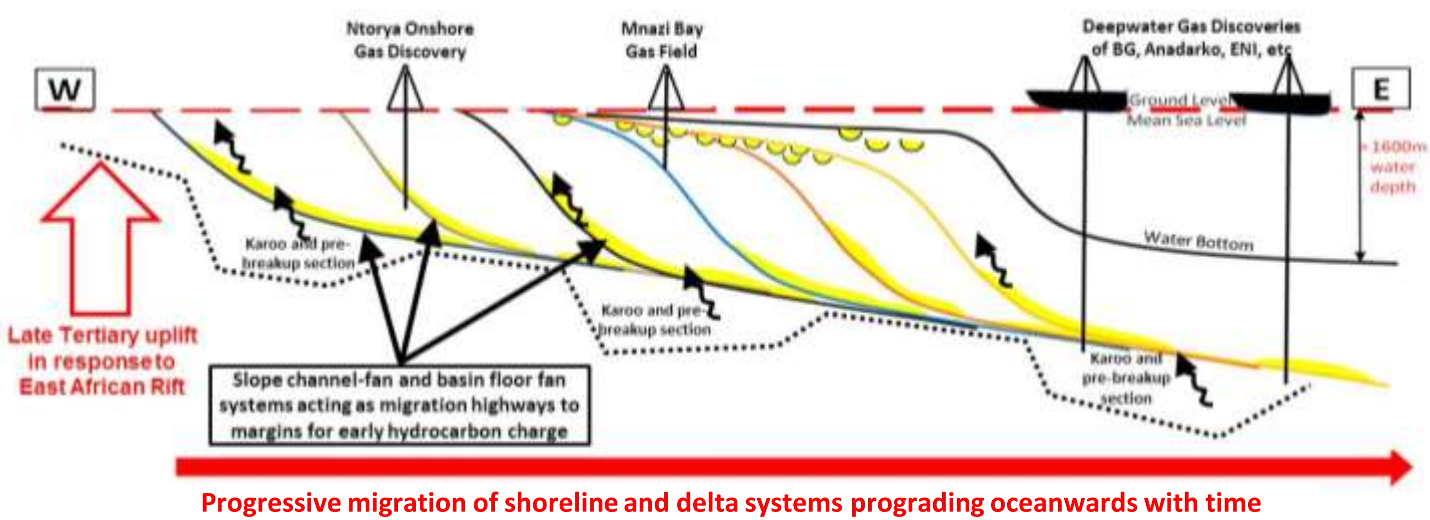
"The age of cheap oil has gone and it is not going to come back.“

Paul Stevens, senior research fellow at the Royal Institute of International Affairs at Chatham House, London, February 2010.

- Despite such predictions, cheap oil *has* arrived, and looks set to stay for at least the forseeable future. The industry has little choice but to adapt in order to survive all along the chain – not just the explorers, but the contractors and the host governments also – we all need each other, but must establish new ways to survive and thrive. The EACM offers excellent opportunities for smaller independent explorers.

Supplementary Data





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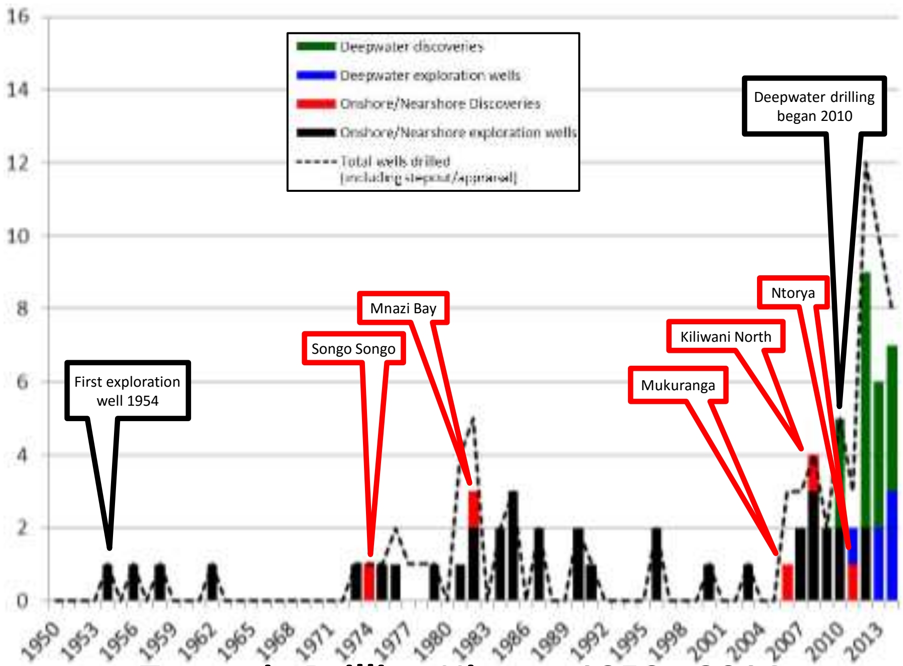
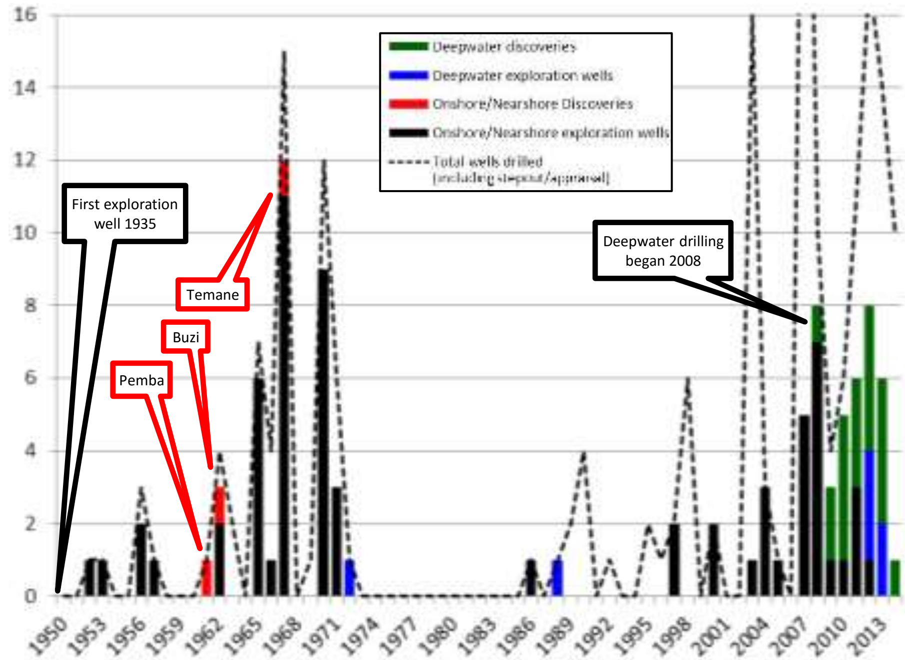


Tanzania Drilling History 1950 - 2014



Mozambique Drilling History 1950 - 2014

Data sourced from TPDC website

Data courtesy of drillinginfo better, faster decisions

- **85 wells drilled in total comprising 65 exploration wells and 20 stepout/appraisal wells**
- **Of 42 exploration wells in nearshore/onshore coastal margin, 5 were discoveries**
  COS = 12% or 1 in 8.4
- **Of 24 deepwater exploration wells (drilled since 2010) , 18 were discoveries**
  COS = 75% or 3 in 4

- **202 wells drilled in total comprising 94 exploration wells and 108 stepout/appraisal wells**
- **Of 68 exploration wells in nearshore/onshore coastal margin, 3 were discoveries**
  COS = 4% or 1 in 33
- **Of 24 deepwater exploration wells (drilled since 2010) , 19 were discoveries**
  COS = 75% or 3 in 4

Supplementary Data

MINISTRY OF ENERGY

Wells drilled in Kenya

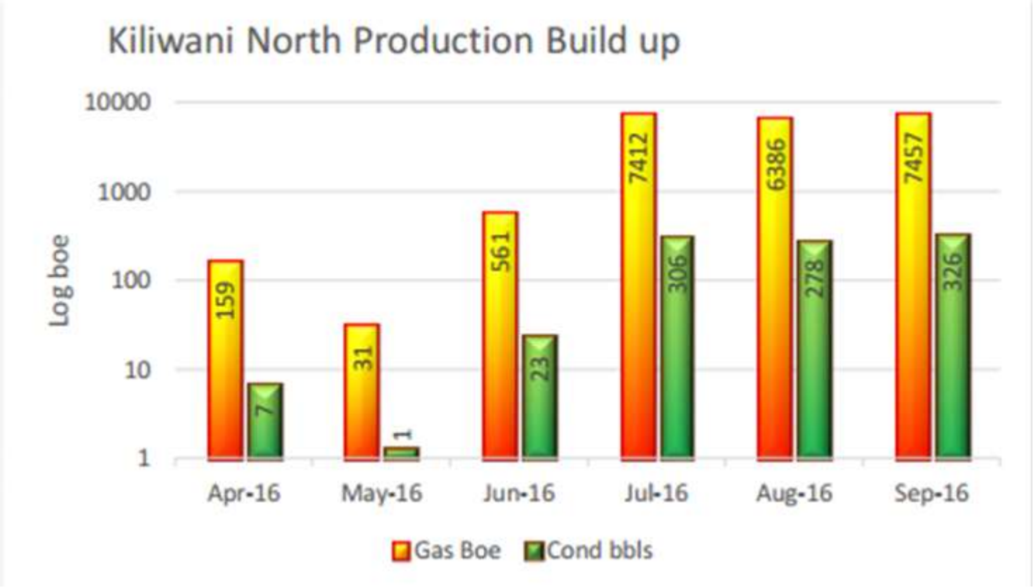
Well Name	Operator	Latitude	Longitude	TD (m)	TD Age	Year Completed	Status
Walu-1	BP/Shell	01°38'04"S	40°15'09"E	1768	Late Cret.	1960	P&A
Pandangua-1	BP/Shell	02°05'51"S	40°25'15"E	1982	Early Tertiary	1960	P&A with gas shows in Tertiary
Meri-1	BP/Shell	0°20'36"N	40°11' 00"E	1941	Early Tertiary	1961	P&A
Mararani-1	BP/Shell	01°34'57"S	41°14'10"E	1991	Early Tertiary	1962	P&A with oil shows in the Tertiary
Ria Kalui-1	Mehta & Co.			1538	Permo-Trias.	1962	P&A with oil staining in Karroo
Walu-2	BP/Shell	01° 38'02"S	40°15'10"E	3729	Early Cret.	1963	P&A with oil shows in Cretaceous
Dodori-1	BP/Shell	01°48'53.7"S	44°11'04"E	4311	Late Cret.	1964	P&A with oil and gas shows in
Walmerer-1	BP/Shell	0°05'35"S	45°35'05"E	3794	Early Cret.	1967	P&A with gas shows in Cretaceous
Garissa-1	BP/Shell	0°22'04"S	39°48'43"E	1240	Mid. Jurassic	1968	P&A
Pate-1	BP/Shell	02°03'53.98"S	41°04'52"E	4188	Early Tertiary	1971	P&A with gas shows in the Eocene
Kipini-1	BP/Shell	02°29'23.57"S	40°35'51"E	3663	Late Cret.	1971	P&A with oil and gas shows in
Hagarso-1	Texas Pacific	0°47'43.5"S	40°26'40.5"E	3092	Early Cret.	1975	P&A with gas shows in Cretaceous
Anza-1	Chevron	0°55'10.864"N	39°41'42.761"E	3662	Late Cret.	1976	P&A with oil stain in Cretaceous
Bahati-1	Chevron	0°26'32.913"N	39°47'5.077"E	3421	Late Cret.	1976	P&A with oil stain in Cretaceous
Simba-1	Total	04°00'06.60"S	40°34'03.68"E	3604	Late Cret.	1978	P&A with gas shows in Tertiary and
Maridadi-1B	Cities Services	2°53'8.795"S	40°24'7.856"E	4198	Mid. Tertiary	1982	P&A with gas shows in the Tertiary
Kofia-1	Union	02°32'31.90"S	40°56'18.30"E	3629	Late Cret.	1985	P&A with oil and gas shows in
KenCan-1	PetroCanada	0°18'57.384"S	39°46'16.572"E	3863	Permo-Trias.	1986	P&A
Elgal-1	Amoco	01°22'47"N	39°53'09"E	1280	Permian	1987	P&A
Elgal-2	Amoco	01°27'32.708N	39°58'40.063"E	1908	Triassic	1987	P&A
Ndovu-1	Total	01°59'58"N	38°52'57"E	4269	Early Cret.	1988	P&A with oil and gas shows in
Sirius-1	Amoco	2°35'00.14"N	37°32'48.98E	2638	Lower Cret.	1988	P&A with good oil shows
Bellatrix-1	Amoco	2°42'12.98"N	37°32'22.34"E	3480	Lower Cret.	1988	P&A
Duma-1	Total	1°39'35.66"N	39°30'19.77"E	3333	Early Cret.	1989	P&A with gas shows in Cretaceous
Hothori-1	Amoco	01°11'16.8"N	39°29'37.8"E	4392	Late Cret.	1989	P&A with oil and Gas shows
Chalbi-3	Amoco	3°01'50.81"N	37°24'43.09"E	3644	Lower Cret?	1989	P&A
Endela-1	Walter	0°45'20"N	39°28'52"E	2779	Early Tertiary	1989	P&A with gas shows in Paleogene
Kaisut-1	Total	1°31'03.82"N	38°16'28.89"E	1450	Early Tertiary	1989	P&A
Loperot-1	Shell	02°21'46.229"N	35°52'24.132"E	2950	Paleocene	1992	P&A with oil shows
Eliye Springs-1	Shell	03°13'50.62"N	35°54'40.19"E	2964	Upper Miocene	1992	P&A
Pomboo-1	Woodside	01°57'16.15"S	41°56'28.02E	4887	Late Cret.	2007	P&A

P&A dry hole can be misleading – many such classifications omit to mention actual shows of oil and/or gas shows recorded on mudlogs, fluorescence in cuttings, daily drilling reports, etc.

Kenyan Drilling Results 1960 - 2000

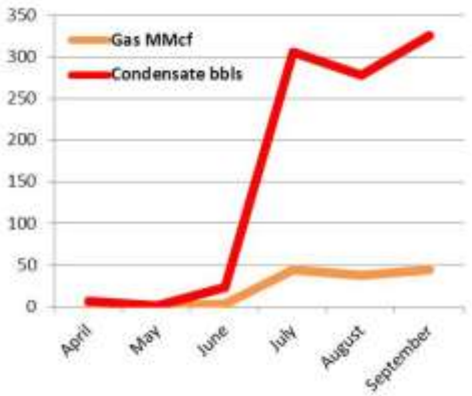
Well Name	Status
Walu-1	P&A
Pandangua-1	P&A with gas shows in Tertiary
Meri-1	P&A
Mararani-1	P&A with oil shows in the Tertiary
Ria Kalui-1	P&A with oil staining in Karroo
Walu-2	P&A with oil shows in Cretaceous
Dodori-1	P&A with oil and gas shows in
Walmerer-1	P&A with gas shows in Cretaceous
Garissa-1	P&A
Pate-1	P&A with gas shows in the Eocene
Kipini-1	P&A with oil and gas shows in
Hagarso-1	P&A with gas shows in Cretaceous
Anza-1	P&A with oil stain in Cretaceous
Bahati-1	P&A with oil stain in Cretaceous
Simba-1	P&A with gas shows in Tertiary and
Maridadi-1B	P&A with gas shows in the Tertiary
Kofia-1	P&A with oil and gas shows in
KenCan-1	P&A
Elgal-1	P&A
Elgal-2	P&A
Ndovu-1	P&A with oil and gas shows in
Sirius-1	P&A with good oil shows
Bellatrix-1	P&A
Duma-1	P&A with gas shows in Cretaceous
Hothori-1	P&A with oil and Gas shows
Chalbi-3	P&A
Endela-1	P&A with gas shows in Paleogene
Kaisut-1	P&A
Loperot-1	P&A with oil shows
Eliye Springs-1	P&A

Supplementary Data

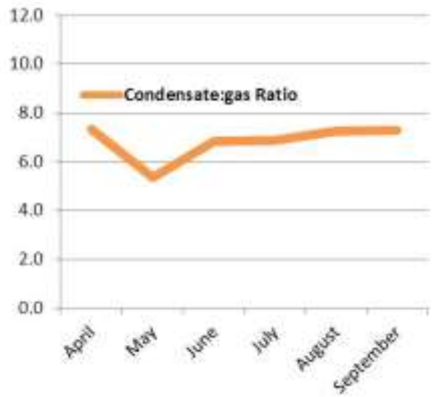


Source: Bounty Oil & Gas, 2016 AGM Presentation.
http://www.bountyoil.com/wp-content/uploads/2017/01/Bounty-Oil-ASX-Release-AGM-2016-Presentation-Exp-Mgr.pdf

Kiliwani North Production Build-up, 2016



Production gas and associated condensate production



Production condensate:gas ratio (bbls condensate per MMcf gas)