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Source rock, maturity data indicate potential off Namibia

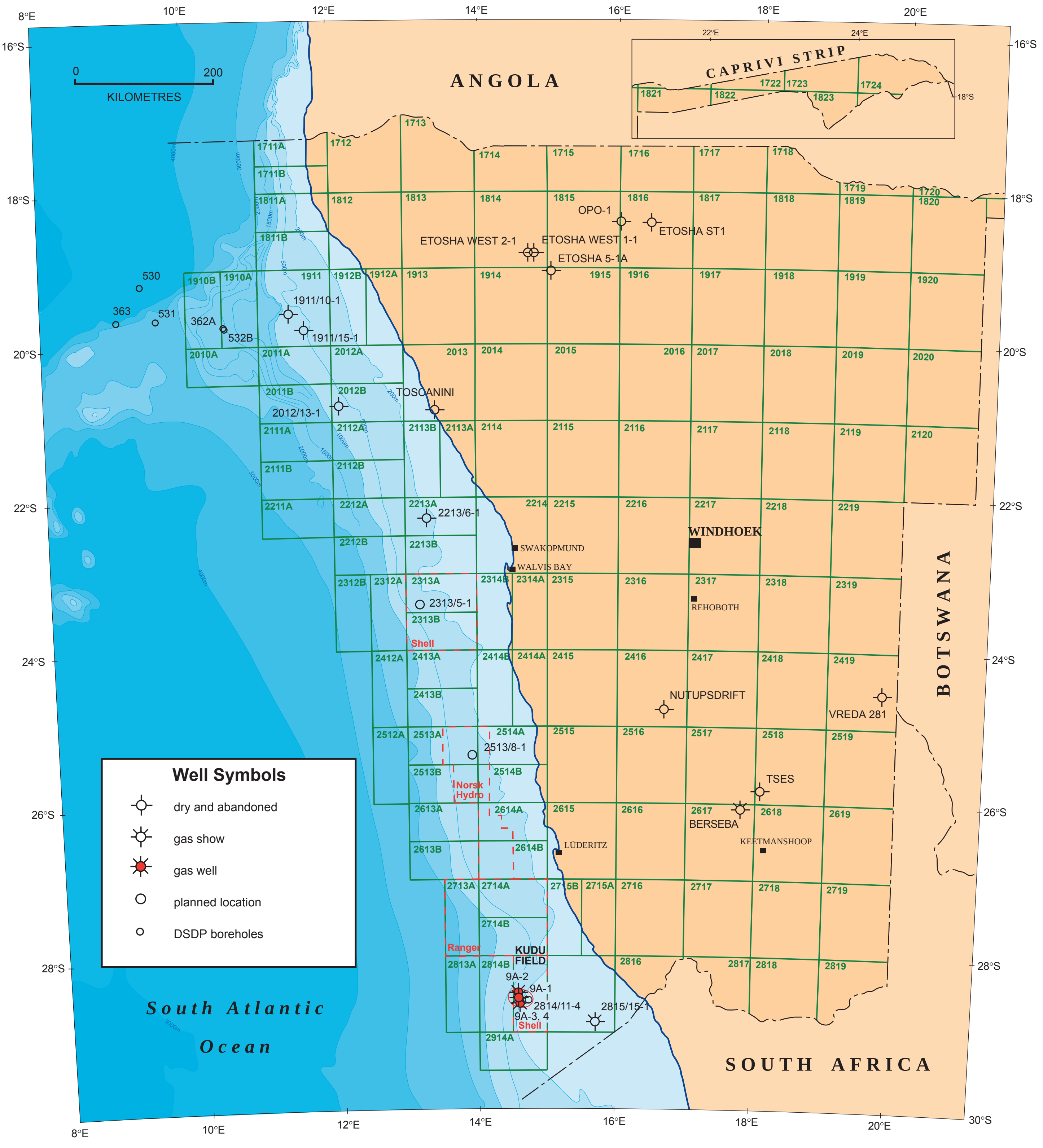
Richard Bray, Exploration Consultants Ltd, Henley-on-Thames, UK
Steve Lawrence, Exploration Consultants Ltd, Henley-on-Thames, UK
Roger Swart, National Petroleum Corp. of Namibia (Pty.) Ltd., Windhoek, Namibia

Introduction

Namibia's territorial waters occupy a large proportion of West Africa's continental shelf. The area to the 1000m isobath is comparable in size to the combined offshore areas of Gabon, Congo, Zaire and Angola. Around half as much again lies in water depths between 1000m and 2500m. The whole unlicenced part of this area will be open for bidding when the 3rd Licencing Round opens on 1st October (**Figure 1**). The Round is expected to attract keen interest, especially in the wake of recent successes in the West Africa deep water play.

Offshore Namibia is underexplored with only seven exploration wells drilled. Shell's Kudu field represents a considerable gas resource with reserves of around 1.4 TCF, but is presently the only commercial discovery. The entire shelf area is covered by seismic and a deep water survey has recently been completed to extend coverage to 2500 m water depth. Data from three wells are now in the public domain and four regional non-exclusive surveys have been shot since the last licence round in 1994. New information on source rocks is provided by the wells and a study of thermal history, maturity development and hydrocarbon generation has just been completed, based on Apatite Fission Track Analysis (AFTA®) and new vitrinite reflectance data, as discussed below.

NAMIBIA LICENSE BLOCKS, WELLS



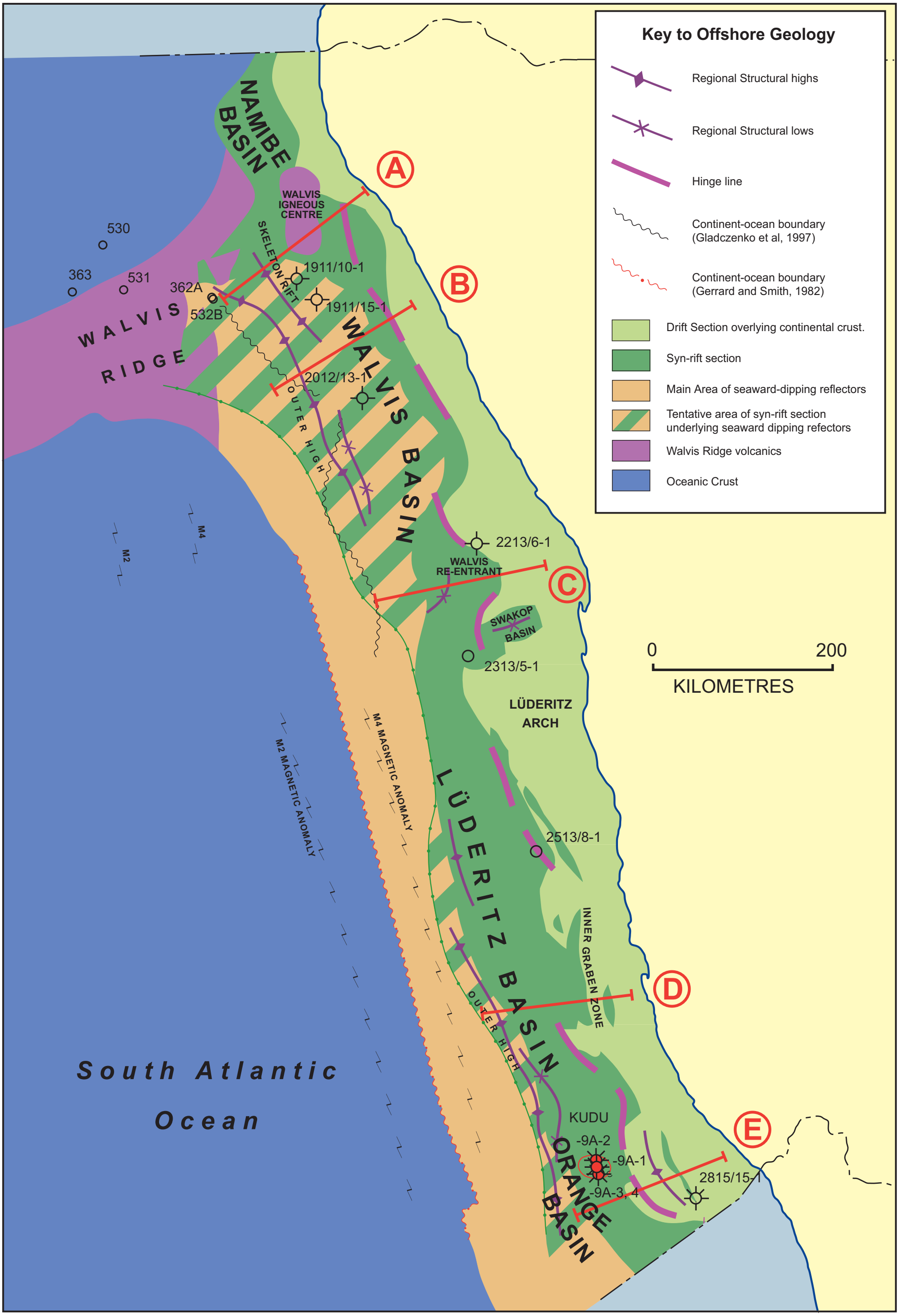
Namibia's offshore area holds enormous exploration potential. Good quality sandstone reservoirs are likely to be distributed widely and a number of prospective structural and stratigraphic traps have been identified. The recognition of Cretaceous marine oil-prone source rocks combined with the results of new thermal history reconstruction and maturity modelling studies are particularly significant in assessment of the oil potential.

Basin development and regional structure

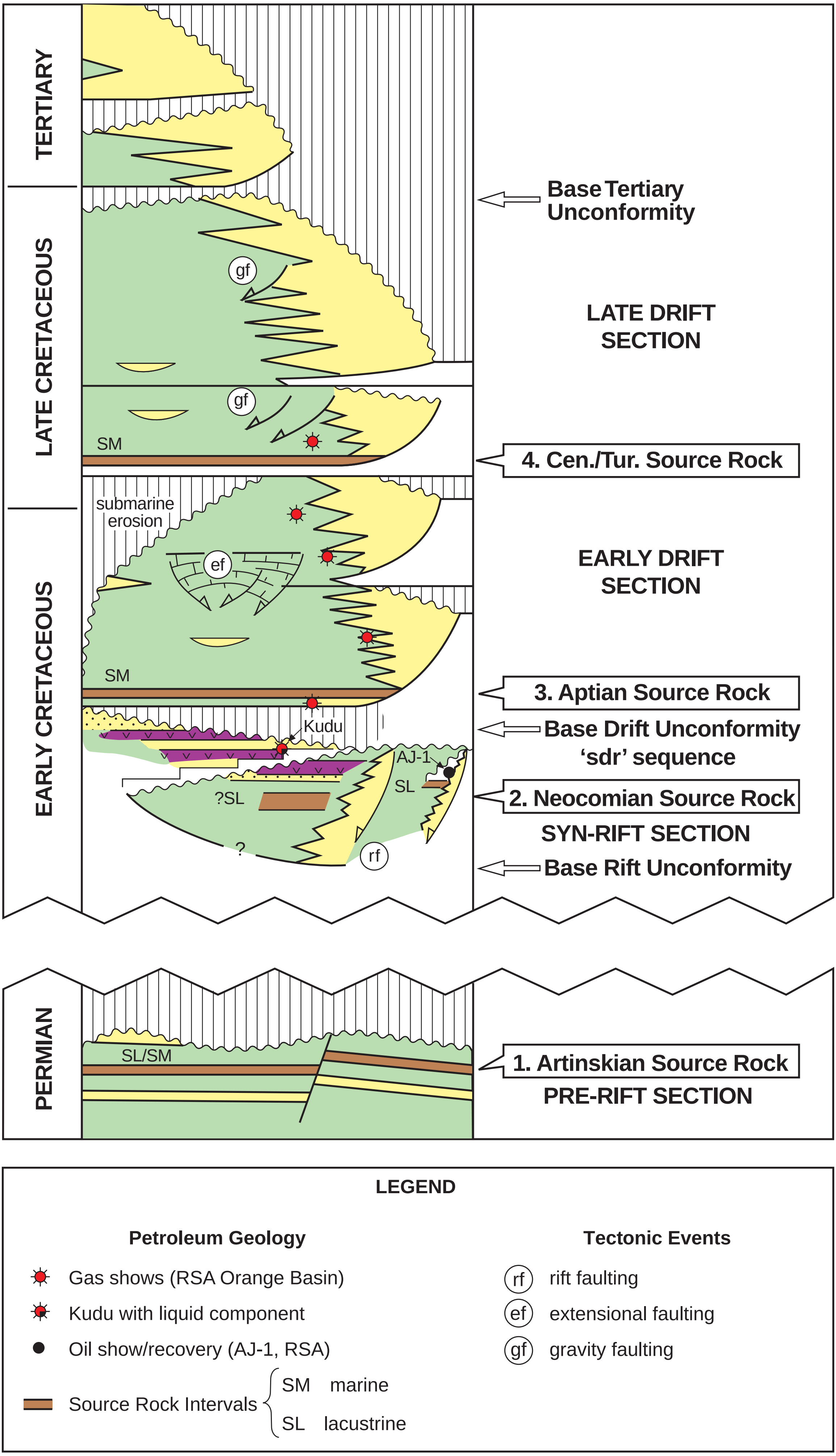
Namibia's offshore basins formed in a passive margin setting during continental break-up and the opening of the South Atlantic. A thick wedge of Cretaceous to Tertiary sediments built out over an early Cretaceous rift section, forming a major basin system extending over the entire offshore area. Four basins are defined (**Figure 2**), although the division into separate basins is somewhat artificial since the sedimentary section is continuous along strike.

Four tectono-stratigraphic units are recognised, separated by three major unconformities (**Figure 3**). A pre-rift Karoo section of presumed Permo-Carboniferous to Triassic age is separated from the early Cretaceous syn-rift section by the 'base rift unconformity'. The uppermost part of the syn-rift section is penetrated at Kudu, where it provides the reservoir interval comprising aeolian sandstones and basalts. The 'base drift unconformity' occurs at the Hauterivian/Barremian boundary at Kudu and marks the transition from non-marine to marine sedimentation. The overlying 'early drift' section is of late Barremian to Cenomanian age and comprises a marine claystone-dominated sequence including organic rich intervals. The Turonian to Recent 'late drift' section volumetrically forms the main part of the basin fill and can be divided into lower and upper units by the base Tertiary unconformity. A number of transgressive-regressive cycles are recognised but overall the drift sequence is progradational causing progressive build-out of the continental shelf and slope.

NAMIBIA OFFSHORE SEDIMENTARY BASINS

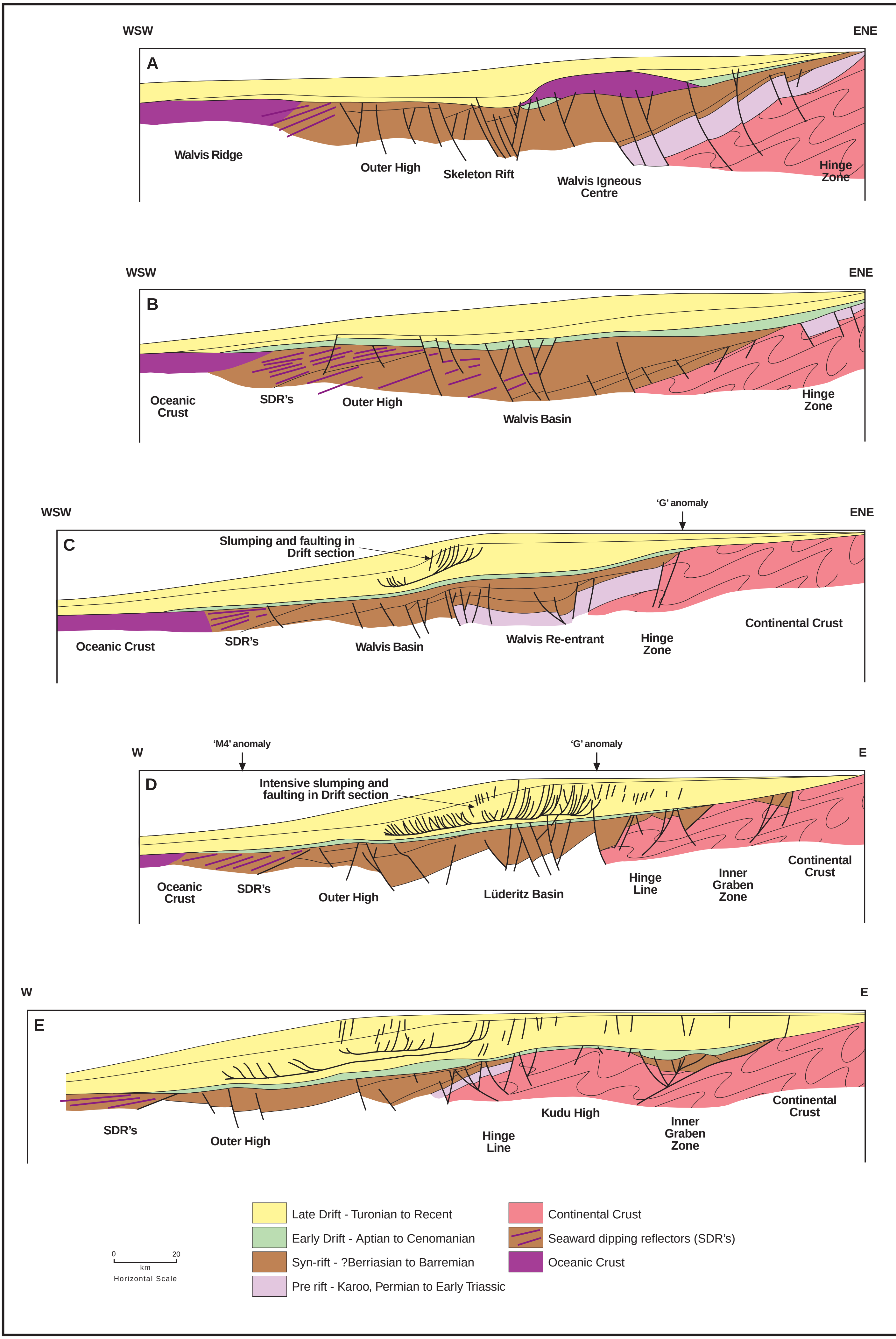


GENERALIZED STRATIGRAPHY, SOURCE ROCKS



The regional structure is illustrated in **Figure 4**. A distinct hinge-line separates an area of thin late drift sediments, onlapping shallow basement, from the zone of rapid sediment thickening to the west and also marks the 'wedge-out' of the syn-rift section. The rift zone runs the entire length of the margin, characterised by tilted blocks bounded mostly by landward-dipping normal faults. A prominent 'outer high' occurs in the rift section along parts of the margin. The rift section passes westward into the third zone comprising a thick wedge of 'seaward dipping reflectors'. These appear to overlie the western edge of the syn-rift section and pass westward into oceanic basement. They are considered to be of volcanic origin and a precursor to oceanic spreading (Austin and Uchupi[1], Gladczenko et.al.[2]). The basalts penetrated at Kudu may represent the feather edge of the seaward dipping reflector package.

STRUCTURAL CROSS-SECTIONS

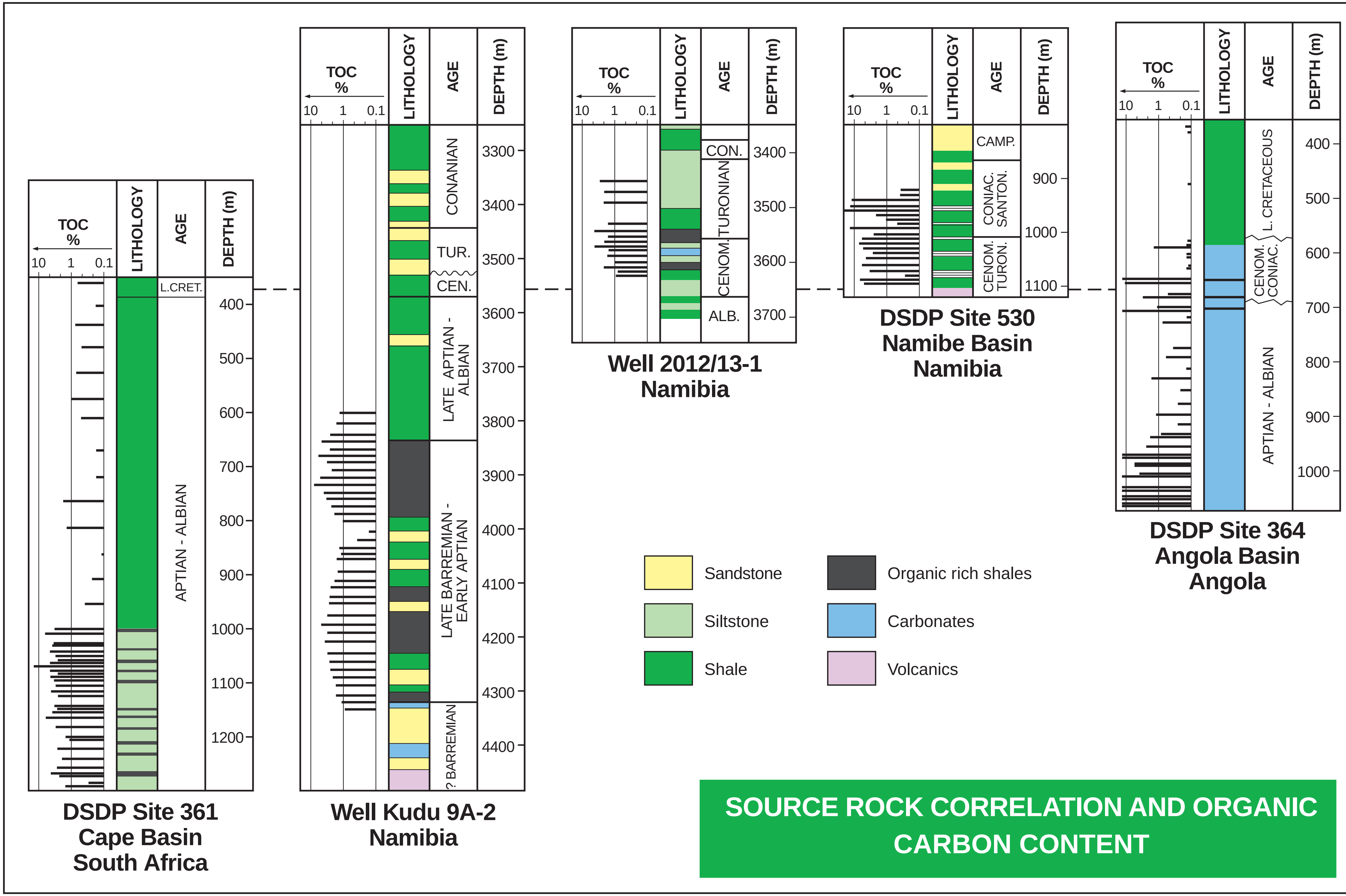


Oil Source Potential

Recently released data confirm the existence of at least two oil-prone source rock horizons in the early to mid Cretaceous drift section (**Figures 3 and 5**). The first was deposited during the early Aptian when restricted marine conditions prevailed in the South Atlantic, before the Falkland Plateau had cleared the southern tip of Africa allowing full global ocean circulation. The second source rock interval accumulated during the Cenomanian to Turonian, coinciding with the mid Cretaceous 'oceanic anoxic event'.

The Lower Aptian in the Kudu wells contains a marine oil and gas-prone source rock approximately 140m thick, overlying several thinner source intervals in the Barremian. The Aptian source has an average TOC of around 2%, although this is not representative of original levels due to the high present-day maturity. In Figure 5 TOC values in the Kudu plot have been adjusted to allow for carbon loss during maturation using the method of Cornford[3]. Pyrolysis parameters (Davies and van der Spuy[4]) indicate Type II kerogens characteristic of a source with both oil and gas potential. A good quality Aptian source is also developed in the South African Orange Basin southeast of Kudu (Muntingh[5]) and in DSDP 364 in the Cape Basin (Tissot et al[6]). DSDP 361 in Angolan waters to the north intersected an Aptian-Albian Type II organic rich section with zones of TOC's over 20%. It can be expected therefore that the Aptian oil-prone source rock will be distributed widely along the Namibian margin.

The Cenomanian-Turonian source interval appears to be absent at Kudu but an oil-prone source rock of similar age occurs in the Orange Basin (Muntingh[5]), in well 2012/13-1 where TOC's of up to 5% are recorded and in DSDP boreholes in northern Namibian and Angolan waters (**Figure 5**). Good marine, oil-prone source rocks of Cretaceous age have also been reported from well 1911/15-1. Pyrolysis results from 2012/13-1 show high S_2 and hydrogen index values, indicating that this interval would have been capable of significant oil generation over the Namibian shelf where maturity conditions allow.


TOC %
10 1 0.1
LITHOLOGY
AGE
DEPTH (m)
L.CRET.
APTIAN - ALBIAN
400
500
600
700
800
900
1000
1100
1200
DSDP Site 361
Cape Basin
South Africa
CONANIAN
TUR.
CEN.
LATE APTIAN - ALBIAN
LATE BARREMIAN - EARLY APTIAN
? BARREMIAN
3300
3400
3500
3600
3700
3800
3900
4000
4100
4200
4300
4400
Well Kudu 9A-2
Namibia
CON.
TURONIAN
CENOM.
ALB.
3400
3500
3600
3700
Well 2012/13-1
Namibia
CAMP.
CONIAC. SANTON.
CENOM. TURON.
900
1000
1100
DSDP Site 530
Namibe Basin
Namibia
L. CRETACEOUS
CENOM. CONIAC.
APTIAN - ALBIAN
400
500
600
700
800
900
1000
DSDP Site 364
Angola Basin
Angola
Sandstone
Siltstone
Shale
Organic rich shales
Carbonates
Volcanics
SOURCE ROCK CORRELATION AND ORGANIC CARBON CONTENT

The syn-rift section may also provide source rock potential. It is predicted that lacustrine environments were developed during early rifting capable of preserving organic rich, oil-prone claystones. Oil-prone lacustrine source rocks occur in the Hauterivian syn-rift section of the South African Orange Basin (Muntingh[5]). Gas plumes are observed over the wedge-out of the syn rift section on a number of seismic lines, so it is possible that syn-rift source rocks exist but in the absence of well data their quality and volumetric significance is difficult to assess.

Regional considerations also support the possibility of oil source potential in the pre-rift Karoo section. Rich oil-prone marine source rocks are developed widely in southern Africa as the Whitehill Formation and the equivalent Irati oil shales of South America (Tankard et. al.[7]). A 'live oil' seep onshore Namibia (Walter et al[8]) has now been geochemically linked to the Whitehill Formation (Walter pers comm). In addition, coals and carbonaceous shales are developed in the lower Karoo sequence of South Africa and are known at outcrop and in boreholes onshore Namibia. They reach a total thickness of 120m at Toscanini (**Figure 1**) and therefore constitute a significant gas-prone source.

Maturity development and hydrocarbon generation

Vitrinite reflectance and spore colour maturity data are presently available from the Kudu wells and 2012/13-1. A study of thermal history, maturity development and hydrocarbon generation has recently been completed, based on AFTA and new vitrinite reflectance (VR) data from offshore wells (Geotrack International[9]). Thermal history is a key parameter controlling hydrocarbon generation. AFTA provides information on the timing of paleothermal episodes responsible for hydrocarbon generation, on maturity levels attained and can give insight to the mechanisms of heating and cooling (e.g. Green et al[10], Duddy et al[11]). A brief summary of results is given below. A detailed interpretation and thermal history reconstruction will be presented in a report being prepared by Geotrack.

The AFTA data from wells in the Walvis Basin show that a heating episode occurred during the Tertiary, causing maximum paleotemperatures significantly in excess of the present-day temperatures. Maturity indications from the new VR data are consistent with paleotemperature estimates from the AFTA. In well 2012/13-1, for example, the new data show that maturity levels are higher than those indicated by previously released data and show that the Lower Cretaceous source rocks in this well entered the early mature oil window prior to Tertiary cooling. Several regional unconformities are recognised within the Tertiary section and it is possible that the heating here was due at least in part to deeper burial prior to uplift and erosion. However, preliminary inspection of the results show that non burial-related heating may have also played an important role.

Thus, attempts to model maturity and hydrocarbon generation must take account of the potential for maturity enhancement to levels above those predicted by the present-day burial depth and thermal regime. Schematic predicted maturity maps for the Aptian and Cenomanian-Turonian source intervals are shown in Figure 5. These are based on previous basin modelling work (Intera[12], Quad Consulting[13]) modified to take account of the new thermal history results. The maps show that the Aptian source is early or mid mature for oil over the length of the Namibian offshore, increasing to late mature for oil over areas of the Walvis and Lüderitz Basins and into the main gas generation window in parts of the Namibe and Orange Basins. The Cenomanian/Turonian source reaches the mid mature window over areas of the Namibe, Walvis, Lüderitz and Orange Basins, increasing to late mature in the Lüderitz and Orange Basin depocentres and over restricted parts of the Namibe Basin.

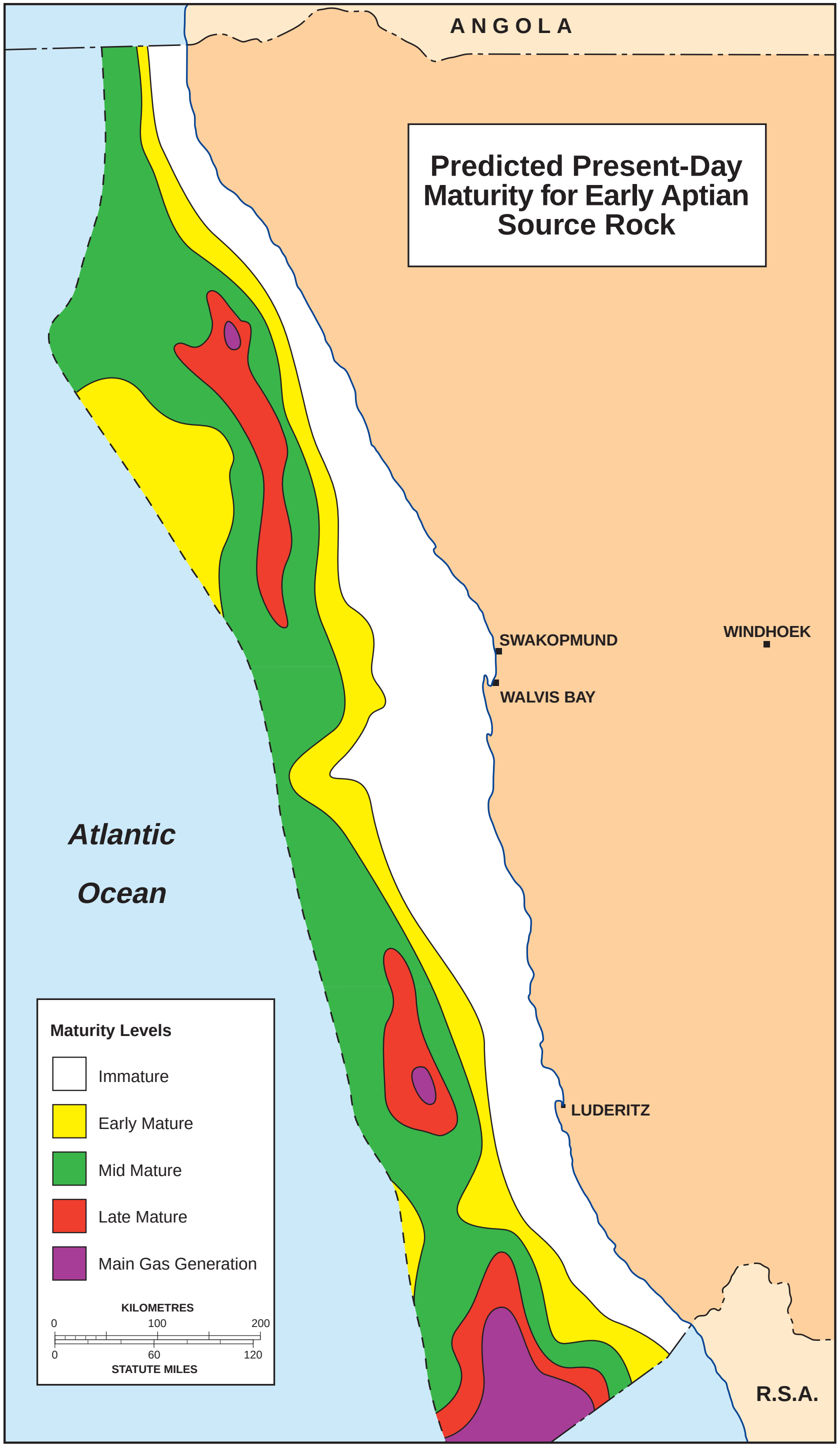
The timing of oil generation with respect to trap formation is a key factor in any setting where paleotemperatures have exceeded present-day temperatures. AFTA can help to determine this factor by identifying the timing of maximum paleotemperatures. The timing of generation at any particular location on the Namibian margin will depend critically on the relative magnitude of Tertiary paleotemperatures compared to the degree of re-heating caused by late Tertiary to Recent re-burial. The new data show that the style of thermal history at Kudu differs from that in the wells analysed in the Walvis Basin and, in some parts of the region, heating due to late Tertiary burial may have superseded the Tertiary paleothermal effects, causing maximum hydrocarbon generation at the present day. Whichever style of thermal history dominates, the timing of hydrocarbon charge is likely to be favourable along most of the margin since potential reservoirs and traps were formed and sealed by end Cretaceous time, pre-dating the hydrocarbon charge.

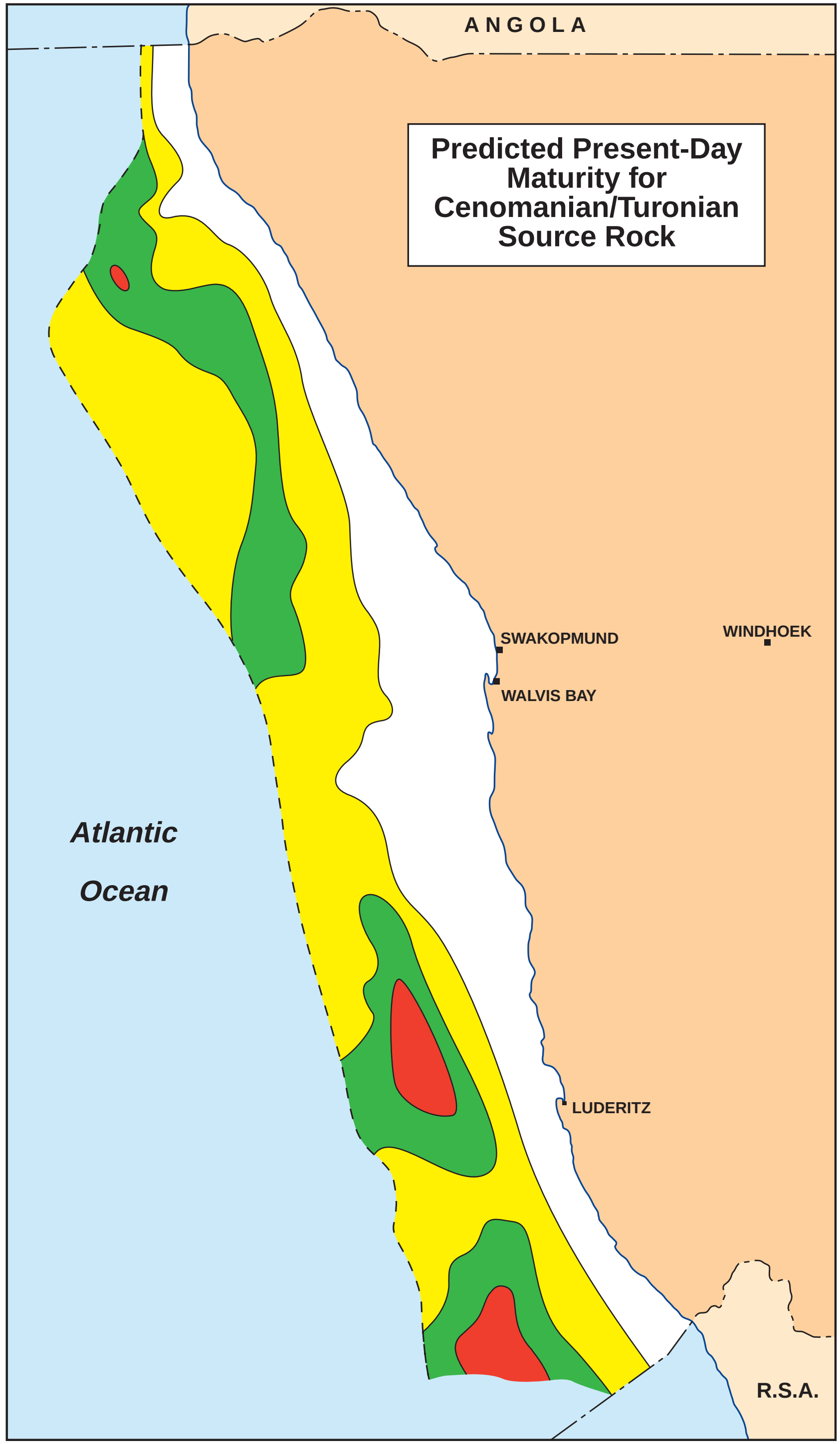
Hitherto, the literature has referred to the Kudu hydrocarbons as 'dry gas', implying a gas-prone source (e.g. Light et al[14]). However, liquid condensate was produced during well tests and small amounts of bitumen are present in the reservoirs (Davies and van der Spuy[4]). Carbon isotope data for Kudu gas (IFE[15]) indicates an origin from sapropelic kerogens, implying a marine oil and gas prone source. Maturity data from Kudu wells and the maturity maps (**Figure 6**) show the field to lie up-dip of a large kitchen area in which the Aptian source is presently in the main gas generation window. It is likely therefore that the field was sourced from the marine Aptian source interval.

Summary

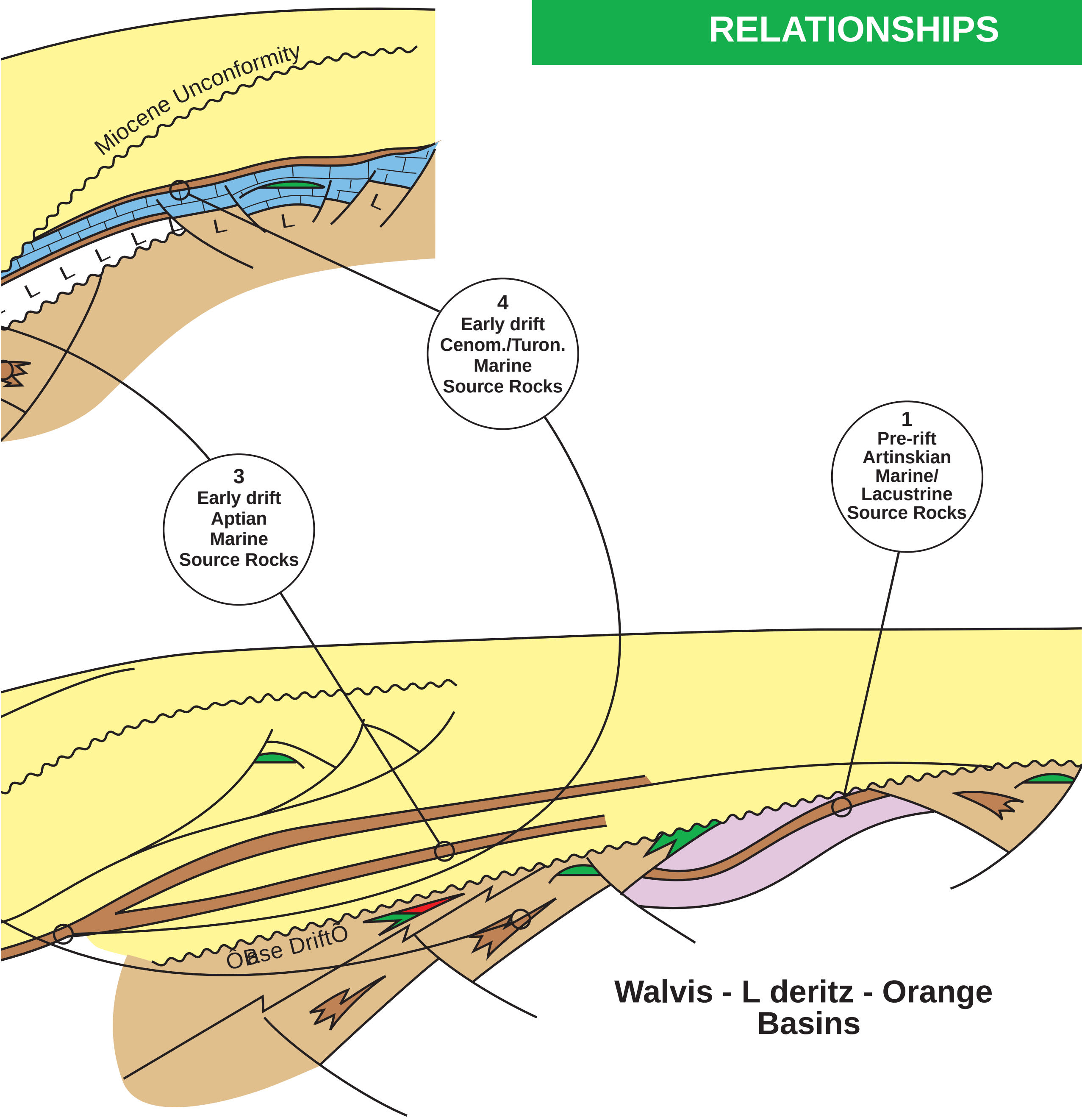
The data presently available from wells offshore Namibia show that marine oil prone source rocks occur in the early and mid Cretaceous section. Analysis of source rock quality, maturation history and structural configuration show that conditions appear to be suited to hydrocarbons generated from the drift section migrating into syn-rift reservoirs beneath the ‘base drift unconformity’, as at the Kudu field, and into potential reservoirs in the Cretaceous and Tertiary drift section (**Figure 7**). With large areas of both the Aptian and Cenomanian-Turonian marine source rocks presently in the mid to late mature windows, favourable conditions exist for the accumulation of oil in both the syn-rift and drift phase reservoirs over large parts of the Namibia offshore area.

SOURCE ROCK MATURITY DISTRIBUTION





SCHEMATIC SOURCE ROCK-TRAP RELATIONSHIPS



The Authors

Richard Bray is a petroleum geologist with 20 years experience in the oil and gas exploration industry. Since graduating from the University of Hull, England with BSc (Hons) in geology he has worked internationally with a number of service and consultancy organisations. In latter years he has worked closely with Geotrack International, specialising in the application of AFTA and thermal history reconstruction methods to source rock maturity and basin modelling problems. He is presently Associate Geoscientist with Exploration Consultants Ltd. where he is involved in the management of regional basin evaluation and hydrocarbon exploration studies.

Steve Lawrence is Principal Geological Consultant with Exploration Consultants Ltd, Henley-on-Thames, England. He is widely experienced in management of exploration projects ranging from regional appraisal of exploration potential to prospect generation and evaluation. He specialises in integrated basin analysis techniques and modelling of basin development in the context of regional structure and plate tectonics, and has pioneered 'cross-over' techniques between the hydrocarbons and minerals exploration industries. Prior to joining ECL in 1978 he worked as operations and exploration geologist for Amoco UK and Cluff Oil Ltd. He graduated from the University of London with BSc (Hons) Geology in 1971.

Dr. Roger Swart is a petroleum explorationist and Technical Manager with Namcor, responsible for overseeing the technical aspects of Namcor's role in hydrocarbon exploration and development. Before joining Namcor he worked for 12 years for the Geological Survey of Namibia, where he did extensive field work and was awarded a PhD for a study of Neoproterozoic turbidites in 1991. He is a graduate of Rhodes University, Grahamstown, South Africa.

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