Assessment of the Undiscovered Oil and Gas of the Senegal Province, Mauritania, Senegal, The Gambia, and Guinea-Bissau, Northwest Africa

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Foreword

This report was prepared as part of the World Petroleum Assessment 2000 of the U.S. Geological Survey's Energy Resources Program. The purpose of the World Petroleum Assessment 2000 is to assess the quantities of oil, gas, and natural gas liquids that have the potential to be added to reserves within the next 30 years. These volumes either reside in undiscovered fields whose sizes exceed the minimum-field-size cutoff value of at least 1 million barrels of oil equivalent, or occur as reserve growth of fields already discovered.

In order to organize, evaluate, and delineate areas to assess, a hierarchical scheme of geographic and geologic units was developed. This scheme consists of regions, geologic provinces, petroleum systems, and assessment units. In the World Petroleum Assessment 2000, regions serve as organizational units and geologic provinces are used as prioritization tools.

The project divided the world into 8 regions and 937 geologic provinces. Provinces were ranked according to the discovered oil and gas volumes within each (Klett and others, 1997; Klett and others, 2000a). Seventy-six "priority" provinces (exclusive of the United States and chosen for their high ranking) and 26 "boutique" provinces (exclusive of the United States and chosen for their anticipated petroleum richness or special regional economic or strategic importance) were selected for appraisal of oil and gas resources.

A geologic province is an area that characteristically has dimensions of hundreds of kilometers and that encompasses a natural geologic entity (for example, sedimentary basin, thrust belt, accreted terrain) or some combination of contiguous geologic entities. Province boundaries were drawn as logically as possible along natural geologic boundaries, although in some places their location is based on other factors such as a specific bathymetric depth in open oceans.

Total petroleum systems and assessment units are delineated within each of the geologic provinces assessed for undiscovered oil and gas. Although the boundaries of total petroleum systems and assessment units are usually contained within a geologic province, it is not required. The petroleum system concept emphasizes the similarities in oil composition (Magoon and Dow, 1994), unlike geologic provinces and plays that emphasize similarities in the rocks. The mapped area of the total petroleum system, as defined for this study, includes all genetically related petroleum that occurs in seeps, shows, and accumulations (discovered and undiscovered) generated by a pod or by closely related pods of mature source rock (Klett and others, 2000b). The area also includes the essential geologic elements (that is, reservoirs, seals, traps, and overburden rocks) that control the fundamental processes of petroleum generation, expulsion, migration, entrapment, and preservation. The "minimum" petroleum system is that part of a total petroleum system encompassing discovered shows, seeps, and accumulations together with the geologic space in which the various essential elements have been proved by these discoveries.

An assessment unit is a mappable portion of a total petroleum system in which discovered and undiscovered fields constitute a single, relatively homogeneous population. The methodology of our resource assessment is based on the probability of number and size of undiscovered fields and, therefore, is sensitive to the homogeneity of each population being assessed.

A total petroleum system might equate to a single assessment unit or, if necessary, may be subdivided into two or more assessment units such that each assessment unit is sufficiently homogeneous in terms of geology, exploration considerations, and risk to assess individually. Heterogeneity cannot be alleviated in all assessment units. In such cases, accumulation density and exploration concepts are not extrapolated across the entire assessment unit.

A numeric code identifies each region, province, total petroleum system, and assessment unit; these codes are uniform throughout the project and throughout all publications of the project. The code used in this study is as follows:

Unit	Name	Code
Region	Sub-Saharan Africa	**7**
Province	Senegal Basin	7**013**
Total petroleum system	Cretaceous-Tertiary Composite	7013**01**
Assessment unit	Coastal Plain and Offshore	701301**01**

The codes for the regions and provinces are listed in Klett and others (1997, 2000a).

Known oil and gas volumes quoted in this report are derived from Petroconsultants, Inc., 1996 Petroleum Exploration and Production database (Petroconsultants, 1996) and other area reports from Petroconsultants, Inc., unless otherwise noted. Increases in reported estimated total recoverable volumes are commonly observed from year to year. To address this phenomenon, the U.S. Geological Survey created a "reserve-growth" model. When applicable, this model is applied to the reported data, and the resulting "grown" data rather than the "known" data are used in the assessment process.

Figures in this report that show boundaries of the total petroleum system and assessment unit were compiled using geographic information system (GIS) software. Political boundaries and cartographic representations were taken, with permission, from the Environmental Systems Research Institute ArcWorld 1:3 million digital coverage (Environmental Systems Research Institute, 1992). These boundaries are not politically definitive and are displayed for general reference only. Oil and gas field center points, shown in these figures, are reproduced, with permission, from Petroconsultants (1996).

Abstract

Undiscovered, conventional oil and gas resources were assessed in the Senegal Province as part of the U.S. Geological Survey World Petroleum Assessment 2000 (U.S. Geological Survey World Energy Assessment Team, 2000). Although several total petroleum systems may exist in the province, only one composite total petroleum system, the Cretaceous-Tertiary Composite Total Petroleum System, was defined with one assessment unit, the Coastal Plain and Offshore Assessment Unit, having sufficient data to allow quantitative assessment.

The primary source rocks for the Cretaceous-Tertiary Composite Total Petroleum System are the Cenomanian-Turonian marine shales. The Turonian shales can be as much as 150 meters thick and contain Type II organic carbon ranging from 3 to 10 weight percent. In the Senegal Province, source rocks are mature even when situated at depths relatively shallow for continental passive margin basins. Reservoir rocks consist of Upper Cretaceous sandstones and lower Tertiary clastic and carbonate rocks. The Lower Cretaceous platform carbonate rocks (sealed by Cenomanian shales) have porosities ranging from 10 to 23 percent. Oligocene carbonate rock reservoirs exist, such as the Dome Flore field, which contains as much as 1 billion barrels of heavy oil (10° API, 1.6 percent sulfur) in place. The traps are a combination of structural closures and stratigraphic pinch-outs.

Hydrocarbon production in the Senegal Province to date has been limited to several small oil and gas fields around Cape Verde (also known as the Dakar Peninsula) from Upper Cretaceous sandstone reservoirs bounded by normal faults, of which three fields (two gas and one oil) exceed the minimum size assessed in this study (1 MMBO; 6 BCFG). Discovered known oil resources in the Senegal Province are 10 MMBO, with known gas resources of 49 BCFG (Petroconsultants, 1996).

This study estimates that 10 percent of the total number of potential oil and gas fields (both discovered and undiscovered) of at least the minimum size have been discovered. The estimated mean size and number of assessed, undiscovered oil fields are 13 MMBO and 13 fields, respectively, whereas the mean size and number of undiscovered gas fields are estimated to be 50 BCFG and 11 fields.

The mean estimates for undiscovered conventional petroleum resources are 157 MMBO, 856 BCFG, and 43 MMBNGL (table 2). The mean sizes of the largest anticipated undiscovered oil and gas fields are 66 MMBO and 208 BCFG, respectively.

The Senegal Province is underexplored considering its large size. The province has hydrocarbon potential in both the offshore and onshore, and undiscovered gas resources may be significant and accessible in areas where the zone of oil generation is relatively shallow.

Introduction

The Senegal Province (fig. 1), which includes the onshore and offshore (to a water depth of 2,000 m) parts of the Senegal Basin, is situated along the northwestern African coast and includes parts of Western Sahara, Mauritania, Senegal, The Gambia, Guinea-Bissau, and Guinea. The Senegal Basin is classified as an Atlantic-type passive margin or marginal sag basin of Middle Jurassic to Holocene age overlying a Paleozoic basin (Wissmann, 1982). Figure 2 is a generalized geologic map of northwest Africa showing the location of Senegal and adjoining provinces. The northern limit of the Senegal Basin is the Precambrian Reguibate Shield in Morocco, and the southern limit is the Bove Basin of Guinea (fig. 3). The eastern edge of the basin is separated from the Taoudeni Basin by Precambrian rocks of the Mauritanide Mountains that were uplifted during the Late Paleozoic Hercynian Orogeny (figs. 2 and 3).

The Senegal Basin is the largest of the northwest African Atlantic margin basins (De Klasz, 1978), with a total land area of about 340,000 km^2 and an offshore portion in excess of 100,000 km^2. The offshore portion of the basin was limited for this study to water depths of 2,000 m or less. Three major subbasins (fig. 3) have been recognized in the Senegal Basin: (1) the Mauritania offshore subbasin, which extends north from the Senegal River to the southern part of Western Sahara; (2) the Northern subbasin, which is located north of the Gambia River to the Senegal River; and (3) the Casamance subbasin, which extends south from the Gambia River through the Casamance region into Guinea-Bissau.

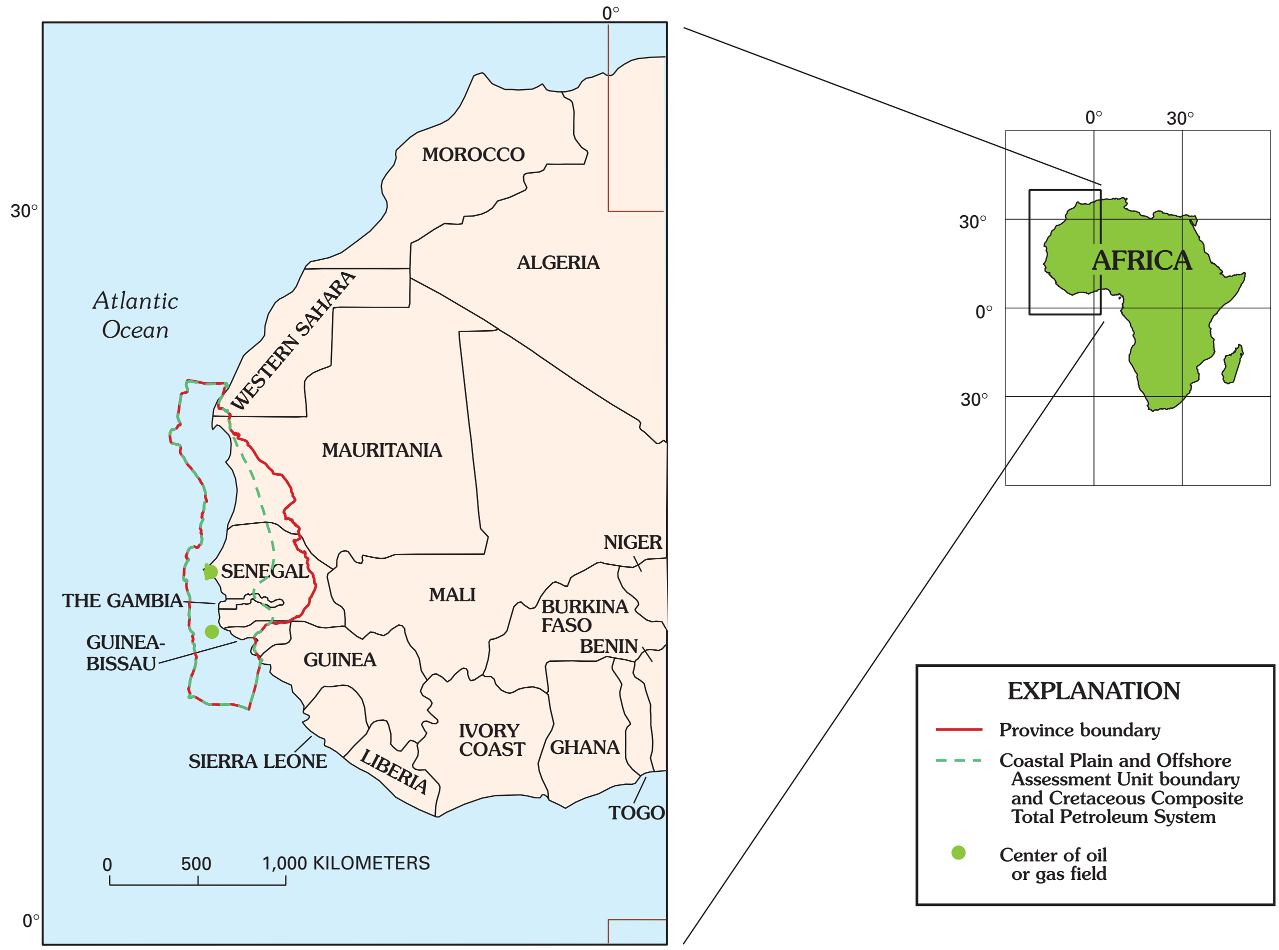


Figure 1. Location map showing the Senegal Province (7013) boundary, the Cretaceous-Tertiary Composite Total Petroleum System (701301), the Coastal Plain and Offshore Assessment Unit (70130101), and the center points for oil and gas fields.

There are both offshore and onshore hydrocarbon occurrences in several formations in the Senegal Basin. The best understood hydrocarbon occurrences in the Senegal Basin are in Cretaceous and Tertiary reservoirs. The lower Paleozoic rocks contain oil-prone organic matter, and recent seismic data have delineated a Permian-Triassic pre-salt clastic section that may contain hydrocarbon source rocks. The Jurassic and Lower Cretaceous rocks have been explored only nearshore where they contain Type III organic matter (terrestrial plant material) and might be potential sources of gas.

At least three total petroleum systems may exist in the Senegal Province: (1) the hypothetical Lower Paleozoic Total Petroleum System, (2) the hypothetical Sub-salt total petroleum system, and (3) the Cretaceous-Tertiary Composite Total Petroleum System. Drilling and production data available for this study are mostly limited to the Cretaceous and Tertiary rocks in the basin. Therefore, only the Cretaceous-Tertiary Composite Total Petroleum System with its contained Coastal Plain and Offshore Assessment Unit was assessed in this study. Due to limited drilling and production data, total petroleum system and assessment unit boundaries can only be approximately delineated and are subject to future revisions.

Senegal Basin Geology

The Senegal Basin formed at the culmination of a Permian to Triassic rift system that developed over an extensive Paleozoic basin during the breakup of North America, Africa, and South America. The Senegal Basin has undergone a complex history that can be divided into pre-rift (Upper Proterozoic to Paleozoic), syn-rift (Permian to Triassic), and post-rift (Middle Jurassic to Holocene) stages of basin development. The basin can be divided into a number of subbasins aligned in a north-south direction and delimited by an east-west fault system and other structural dislocations related to syn-rift tectonics.

The initial phase of the post-Hercynian opening of the North Atlantic and the splitting of North America from Eurasia and Africa began during Late Permian-Early Triassic time (Lehner and De Ruitter, 1977; Ziegler, 1988; Lambiase, 1989; Uchupi and others, 1976; Uchupi, 1989) and is represented by syn-rift rocks in the Senegal Basin. The final breakup of Africa and South America began in the Late Jurassic in the southernmost part of the South Atlantic and prograded northward during Neocomian time (Binks and Fairhead, 1992; Guiraud and

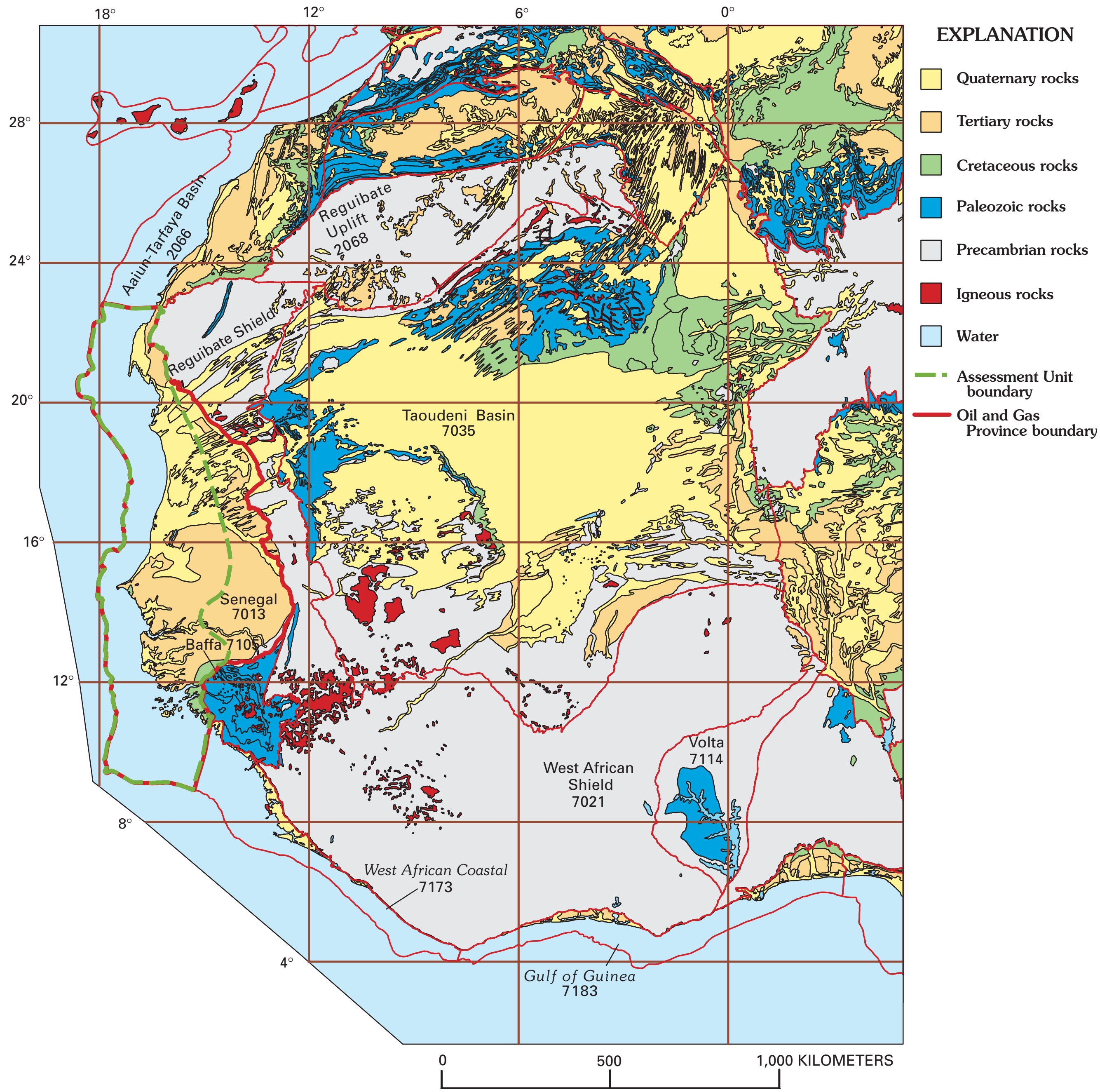


Figure 2. Generalized geologic map of northwest Africa (Persits and others, 1997) showing the Reguibate Shield, province boundaries, selected province names and codes as defined in Klett and others (1997, 2000a) and the boundary of the Coastal Plain and Offshore Assessment Unit for the Senegal Province. The Baffa Province includes the Paleozoic Bove Basin.

Maurin, 1992). The opening of the Atlantic was not completed until Albian time. The presence of Triassic evaporites and clastics in the Senegal Basin provides evidence that rift-basin sedimentation occurred during this time, associated with the breakup of northwest Africa and North America. The basal Jurassic and lowermost Cretaceous limestones of the Mesozoic-Tertiary platform (figs. 3 and 4) are most likely related to the Tethys Sea rather than the South Atlantic because the final opening of the Atlantic did not take place before Albian time.

Pre-rift Section

The pre-rift section consists of Precambrian- to Devonian-age rocks that outcrop in the Bove Basin of southern Senegal and Guinea, which is an extension of the Taoudeni Basin (figs. 2 and 3). The most complete pre-rift section was recognized in the Diana-Malari (DM–1) and Kolda (KO–1) wells (fig. 3), which penetrated Ordovician, Silurian, and Devonian rocks in southernmost Senegal, also known as the Casamance

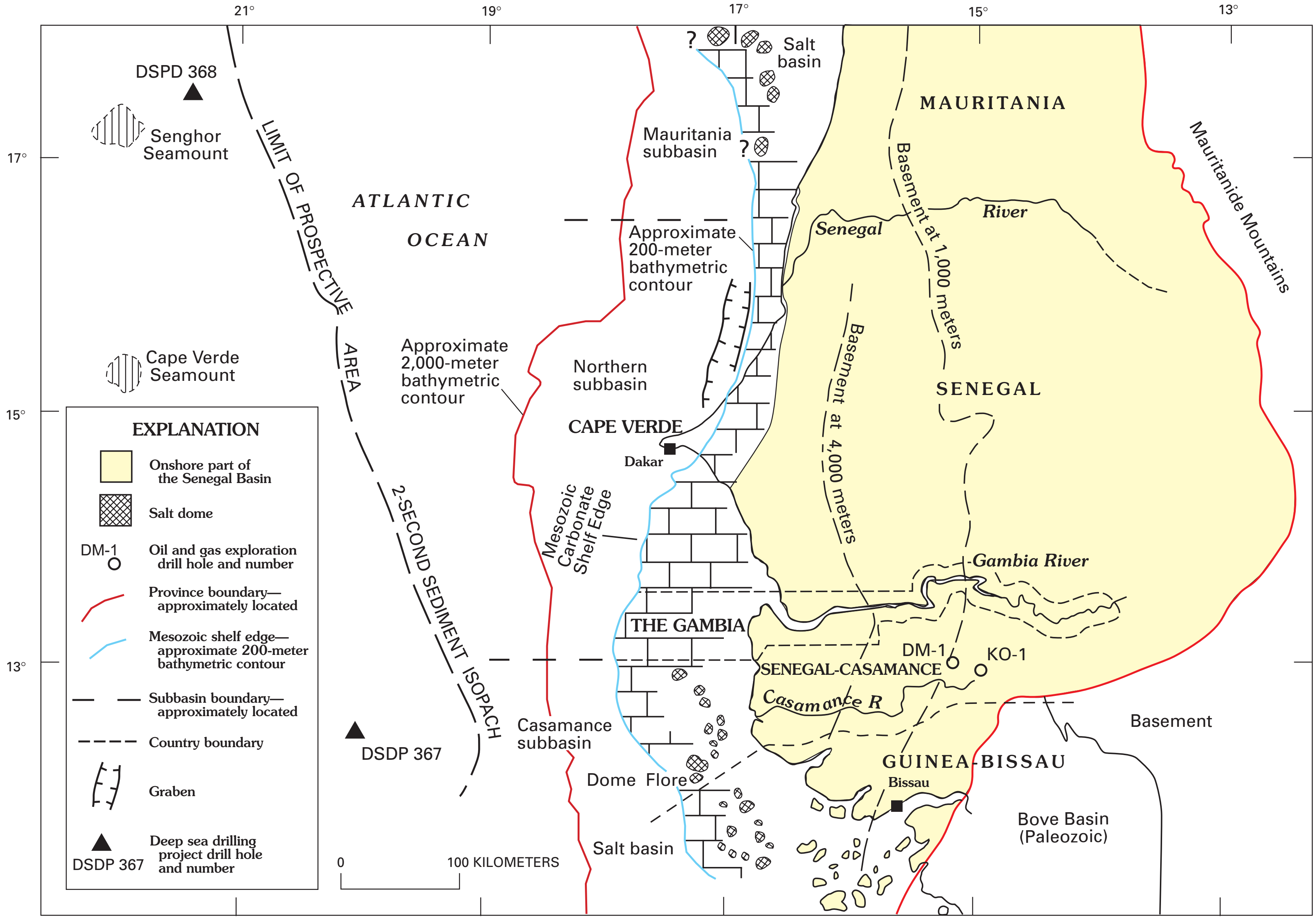


Figure 3. A generalized map of the central and southern parts of the Senegal Basin showing part of the Senegal Province, the Mauritania, Northern, and Casamance subbasins, the Mesozoic shelf edge, the northern and southern salt basins, the Mauritanide Mountains, the Bove Basin, the Deep Sea Drilling Project sites 367 and 368, the 2-second sediment isopach, and the onshore depth to basement isopachs. Also shown are the appropriate locations of the Diana-Malari (DM–1) and Kolda (KO–1) wells that penetrated the Silurian source rocks (Buba Shale). Brick pattern delineates the Mesozoic carbonate rock platform. Modified from Bungener and Hinz (1995).

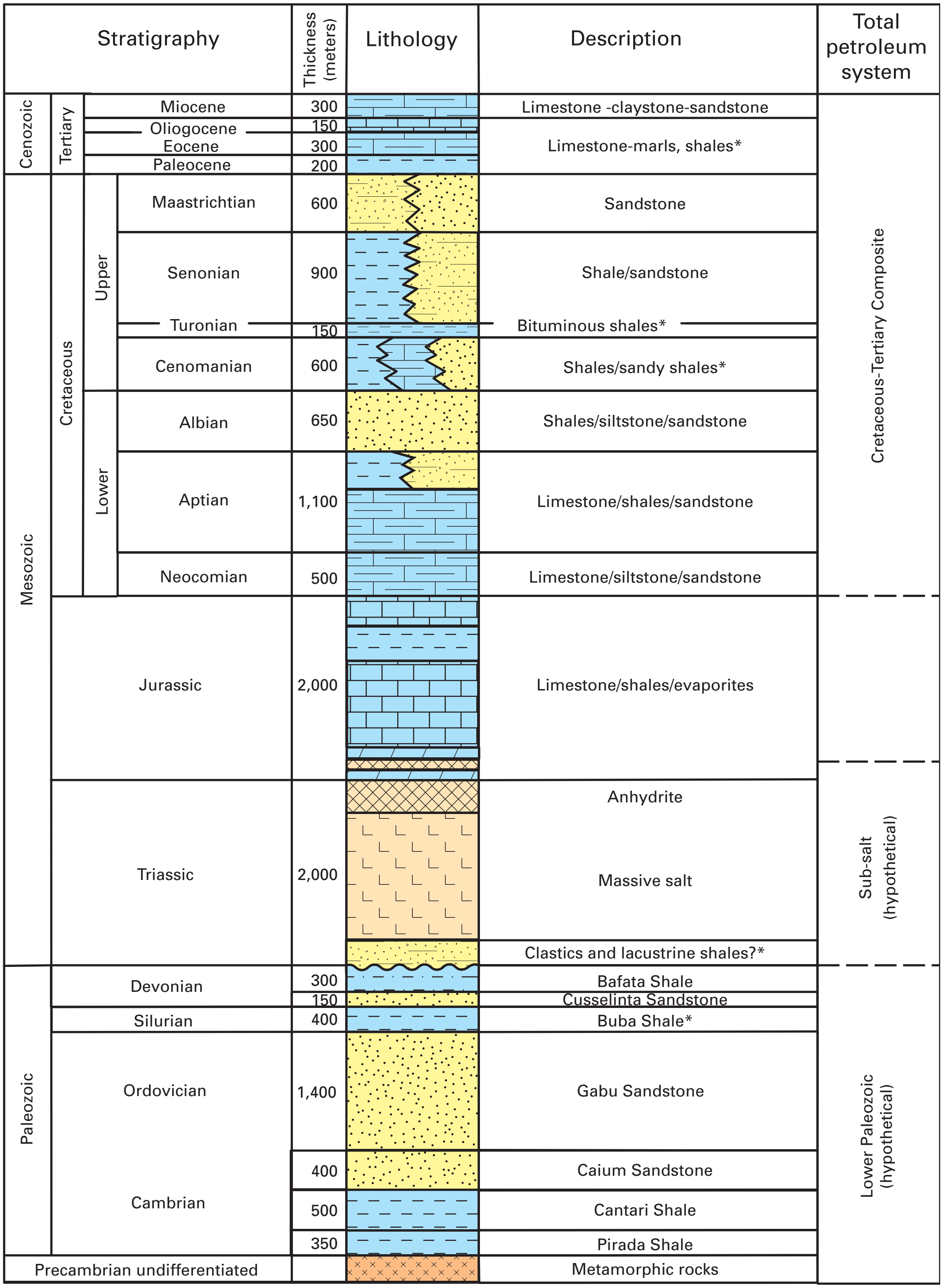


Figure 4. Generalized stratigraphic column showing the three total petroleum systems in the Senegal Basin and the rocks found in the Casamance region of southern Senegal and Guinea-Bissau, includes the Bove Paleozoic Basin, which is an extension of the Taoudeni Basin of Mauritania and Mali. * denotes potential source rocks. Modified from Dumestre and Carvalho (1985).

subbasin. The Cambrian rocks are known only from outcrops in the Bove Basin. The pre-rift section might be as much as 3,500 m thick in the Bove Basin, whereas over 5,000 m of pre-Mesozoic rocks are interpreted from seismic data in the deeper offshore part of the Senegal Basin (Hinz and Martin, 1995). The Precambrian basement consists of metamorphic rocks of unknown thickness (fig. 4). The Cambrian sedimentary section is as much as 1,250 m thick and contains three units: the Pirada Shale, the Cantari Shale, and the Caium Sandstone. The Ordovician Gabu Sandstone attains a maximum thickness of 1,400 m. The Silurian section contains the graptolitic Buba Shale source rocks, which are as much as 400 m thick. The Devonian rocks are widespread and are the youngest Paleozoic rocks known in the basin. The Lower Devonian consists of the Cusselinta Sandstone, a 150-m-thick unit, and the Middle and Upper Devonian are represented by the 300-m-thick Bafata Shale. The section is known to occur under much of the southern one-half part of the basin (south of the Mauritanian border).

Two main tectonic regimes have been recognized in the Paleozoic pre-rift part of the Senegal Basin. An extensional system is defined south and east of the Casamance subbasin and south of Cape Verde (fig. 3) in which a pre-Hercynian structural style of horsts and grabens and tilted blocks was preserved, and a compressional regime has been defined in the central and northern parts of the basin resulting from the combined effect of Caledonian and Hercynian orogenies (figs. 5 and 6).

Syn-rift Section

The syn-rift section of the southern Senegal Basin consists principally of thick Triassic to Early Jurassic evaporites (Uchupi and others, 1976) overlying inferred Triassic clastic rocks, which may include organic-rich lacustrine rocks (fig. 4). The syn-rift evaporite section in the Casamance subbasin may be as much as 2,000 m thick and consists mostly of salt with an anhydrite cap, whereas the underlying clastic section may be as thick as 1,500 m (fig. 7). In the Northern and Mauritania subbasins, the evaporite section might be as thick as 2,000 m (fig. 8), whereas the thickness of the underlying Triassic clastic section is unknown but may have a thickness similar to the Casamance subbasin (fig. 7). Except for a few salt structures (Ayme, 1965; Wissmann, 1982) in the Casamance and Mauritania subbasins, the Northern subbasin,

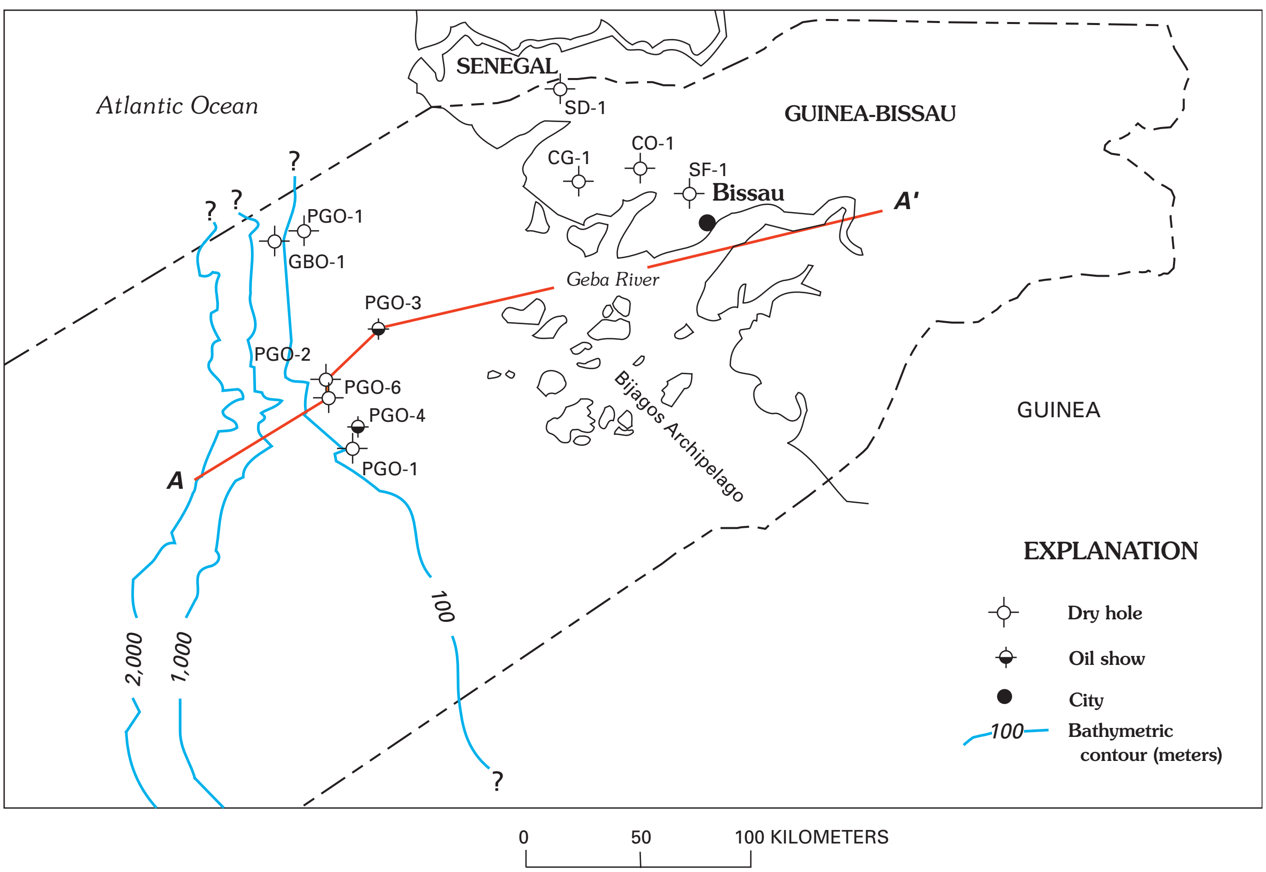


Figure 5. Location map for Guinea-Bissau showing line of section and oil and gas exploration holes, southern Senegal Basin, northwest Africa. Cross section *A* to *A'* is shown in figure 6. Modified from Dumestre and Carvalho (1985).

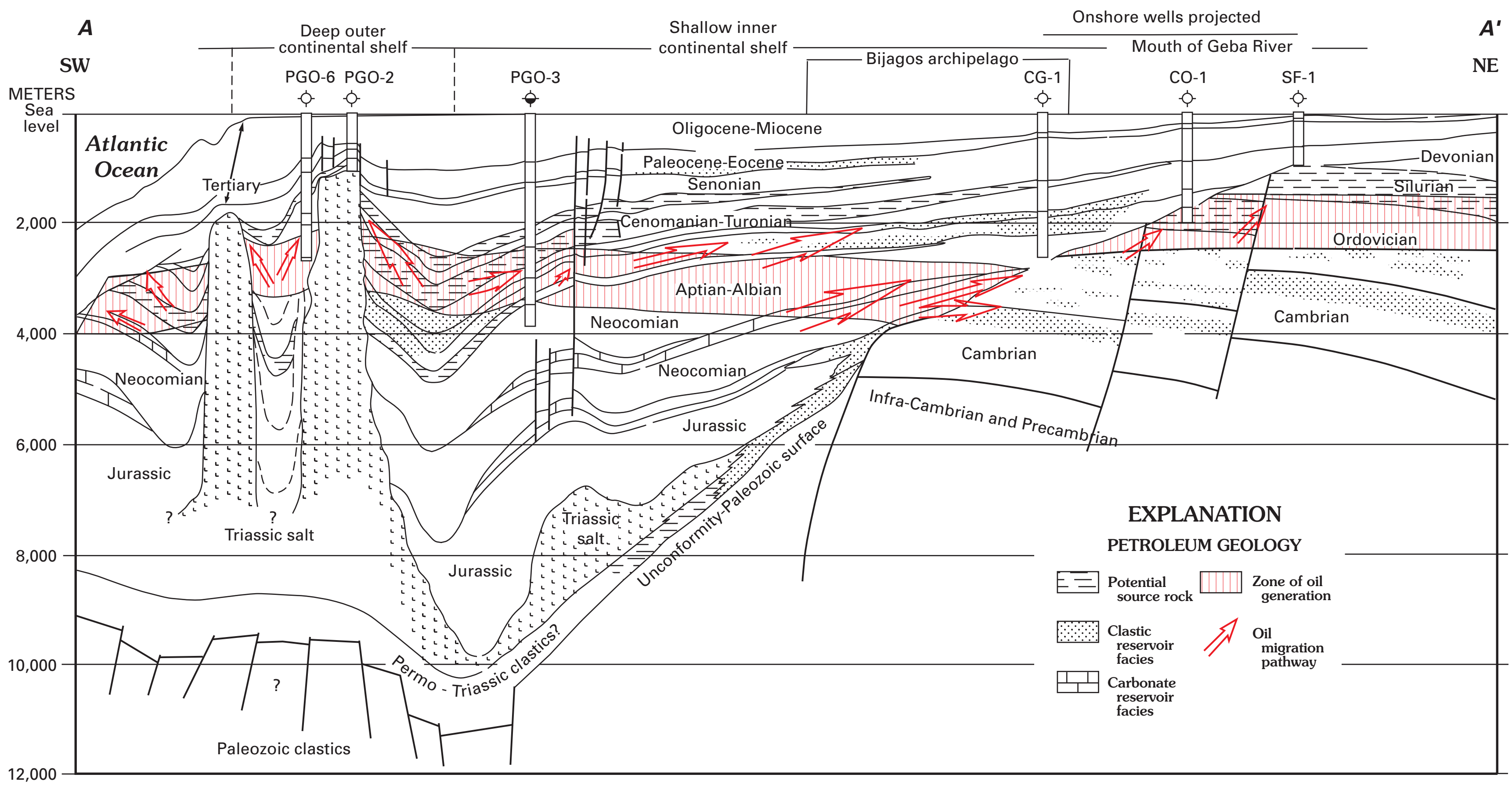


Figure 6. Schematic stratigraphic northeast to southwest cross section, Guinea-Bissau, southern Senegal Province, showing potential reservoirs and source rocks with the zone of oil generation and possible oil migration pathways. Modified from Dumestre and Carvalho (1985).

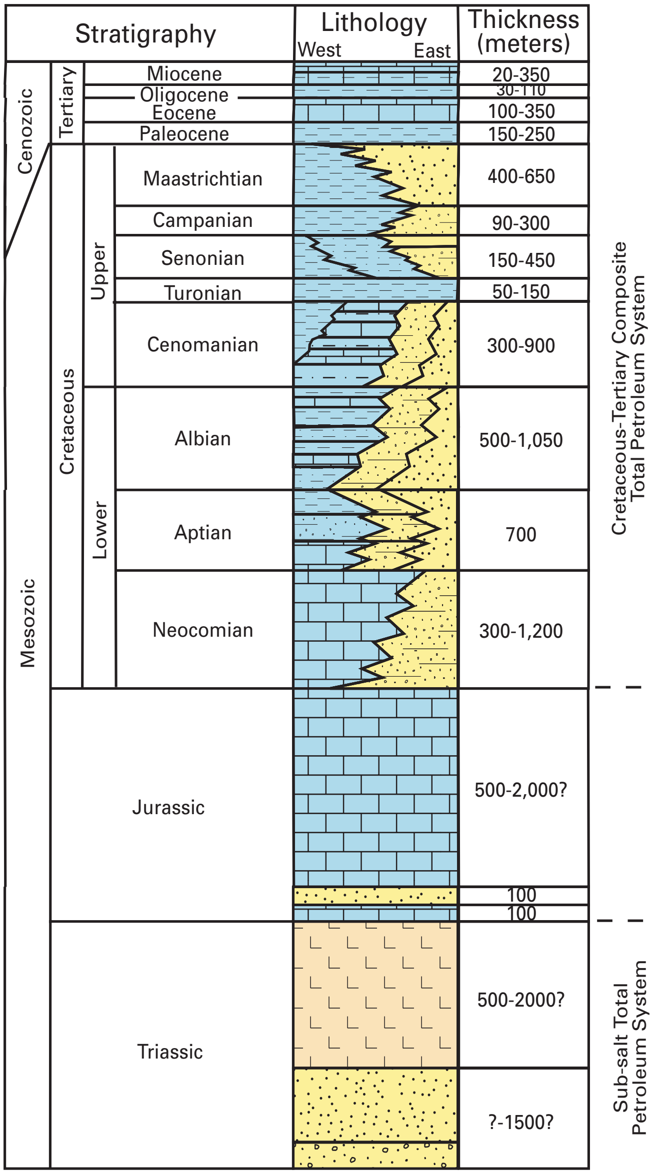


Figure 7. Generalized stratigraphic column of the Casamance offshore subbasin, south of Cape Verde, Senegal Basin, northwest Africa. In the Casamance subbasin, the best source rocks are in the Cenomanian and Turonian units. Possible source rocks may exist in the clastic section below the evaporites. Modified from Dumestre (1985).

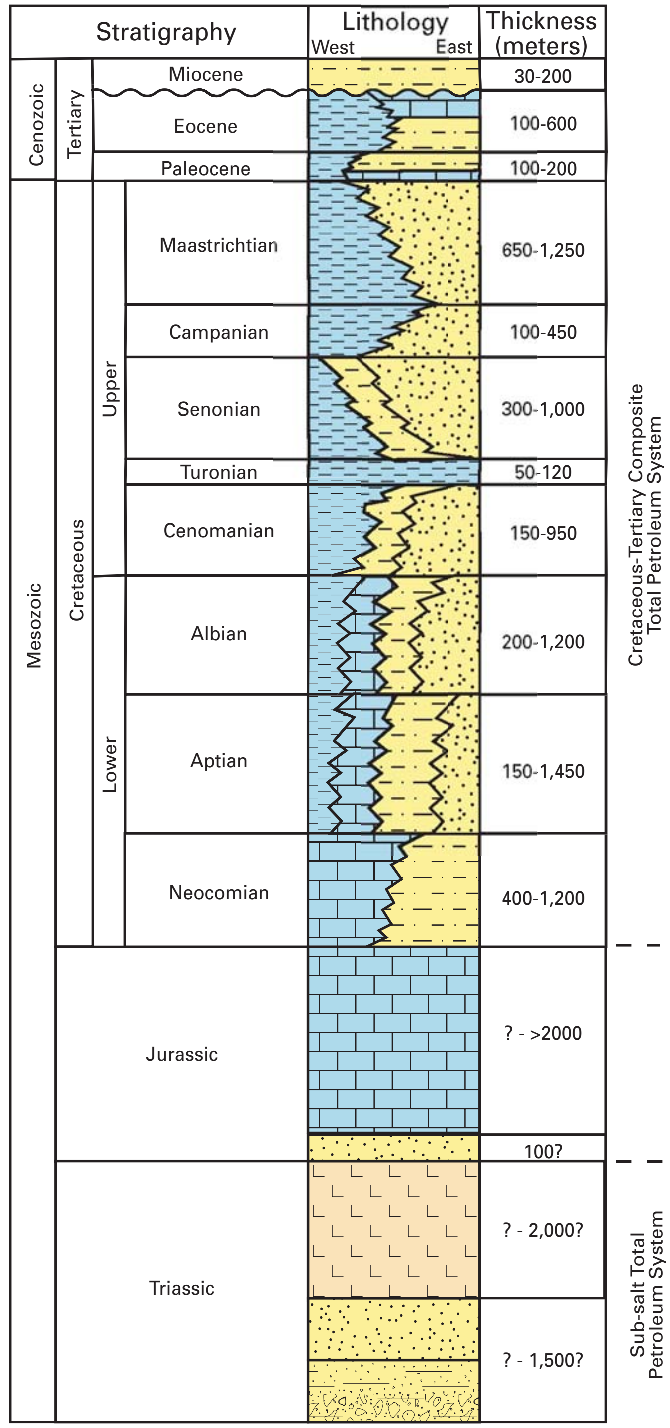
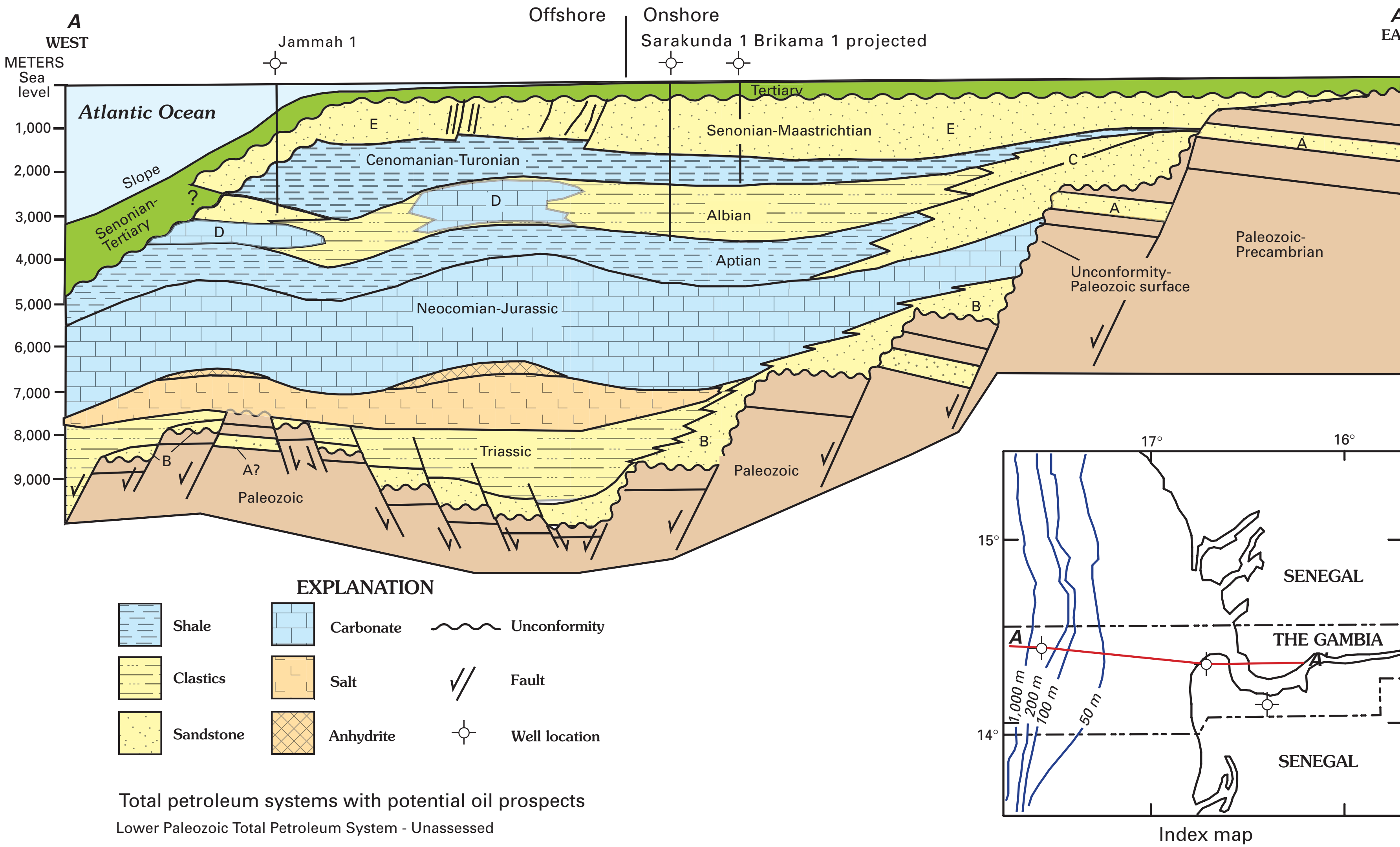


Figure 8. Generalized stratigraphic column for the Northern subbasin and the southern part of the Mauritania subbasins (see fig. 3). Type II and III source rocks are found in the Cenomanian and Turonian units. Modified from Dumestre (1985).

and offshore Guinea-Bissau, drilling has not yet penetrated these rocks, but new and reprocessed seismic data have delineated this section in some parts of the Senegal Basin. In the southern Senegal Basin, the evaporite section has undergone extensive halokinesis evidenced by salt diapirs intruding the overlying Cretaceous and Tertiary rocks (fig. 6). Seismic studies have shown salt diapirs in offshore Mauritania, confirming that this section also is present in the northernmost part of the basin (fig. 3). Salt diapirs have not been recognized in the Northern subbasin (fig. 3). Figure 9 is a schematic east-to-west cross section through The Gambia where the syn-rift section is present but the evaporites exhibit little halokinesis. The onshore part of central Senegal Basin has a thinner syn-rift section consisting of probable Triassic age continental clastics and organic-rich lacustrine shales (fig. 10). The northwest Africa basins have been virtually undisturbed by extension since the Jurassic (Lambiase, 1989).



Total petroleum systems with potential oil prospects

Lower Paleozoic Total Petroleum System - Unassessed

Prospect A - Ordovician-Devonian reservoirs, Silurian source?

Sub-salt Total Petroleum System - Unassessed

Prospect B - Lower Paleozoic? and Triassic reservoirs, Triassic and (or) Silurian source?

Cretaceous-Tertiary Composite Total Petroleum System - Assessed

Prospect C - Albian/Aptian reservoirs, Turonian/Cenomanian source

Prospect D - Albian carbonate and sandstone reservoirs, Turonian/Cenomanian source

Prospect E - Tertiary/Upper Cretaceous reservoirs, Turonian/Cenomanian source

Figure 9. Schematic east-to-west cross section through The Gambia showing locations of potential oil prospects with their associated total petroleum systems, reservoirs, and source rocks. Modified from Bungener (1995).

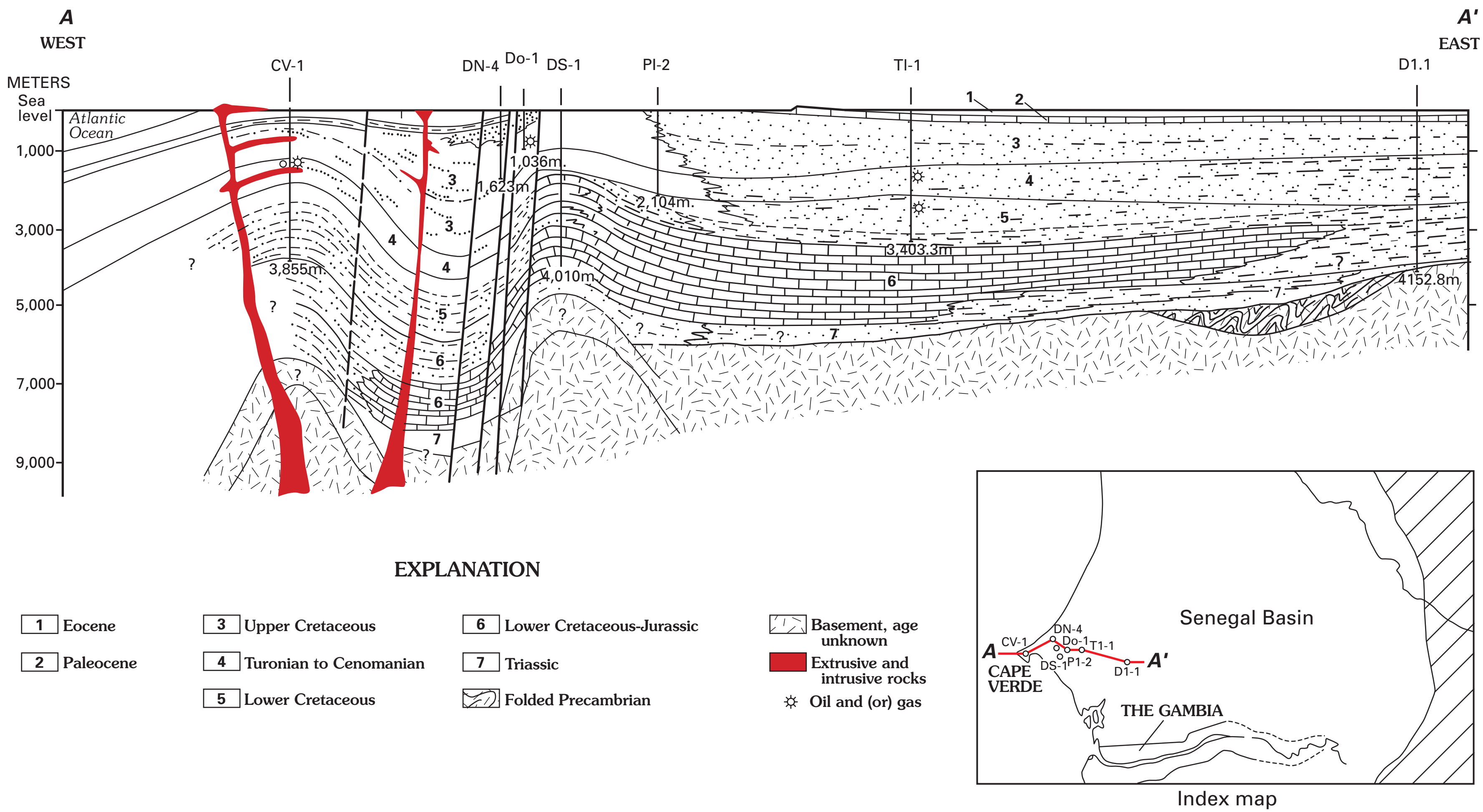


Figure 10. Schematic stratigraphic east-to-west cross section through Cape Verde showing producing zones, Senegal Basin, northwest Africa. Modified from Petroconsultants (1979).

Post-rift Section

Marine deposition began during the Early Jurassic in Morocco with transgressing seas reaching the southern end of the Senegal Basin by the Late Jurassic (Uchupi and others, 1976). The post-rift section in the Senegal Basin consists of Middle Jurassic to Holocene rocks. The section increases in thickness from east to west across the Senegal Basin. The basal unit of the post-rift sequence is a thick, carbonate-rock shelf of Middle to Late Jurassic to Neocomian age that is genetically related to the Tethys Sea. The carbonate-rock unit ranges in thickness from 2,300 m to 3,200 m in the Mauritania, Northern, and Casamance subbasins (figs. 7 and 8). During the Aptian and Albian this carbonate-rock unit continued to be deposited in the central offshore part of the basin, whereas in the northern part of the Mauritania subbasin and southernmost part of the Casamance subbasin it was replaced by deeper water sediments. The Cenomanian rocks of the post-rift section are represented by thick marine shales interbedded with marginal marine sandstones, deposited after the opening of the Atlantic Ocean. Minor carbonate-rock banks and reefs are present. The Turonian marks the time of maximum Cretaceous transgression and is represented by widespread black, and commonly bituminous, shale that is an important hydrocarbon source rock in the basin. The Turonian shales range in thickness from 50 to 150 m. The Senonian stage was a time of major marine regression that culminated with the deposition of widespread and thick sandstone units in the Maastrichtian. Tertiary sediments are unconformable with the Upper Cretaceous and consist primarily of marine shales and carbonates. The thickness of the post-rift section is about 12,000 m in the depocenter near the GBO–1 well (fig. 5) in the Guinea-Bissau part of the basin (Dumestre and Carvalho, 1985).

Two major stratigraphic domains delimited by the present shelf edge are recognized within the Senegal Basin. The shelf of northwest Africa is characterized by a 35- to 100-km-wide plain cut by sparse, shallow channels, especially north of Cape Verde (Egloff, 1972), while south of Cape Verde the shelf is more incised by canyons and affected by recent deltaic deposits. The shelf and western edge of the Jurassic to Lower Cretaceous carbonate-rock platform (fig. 3) roughly parallels the 200-m bathymetric contour.

East of the present shelf edge is a gently westward dipping Mesozoic and Cenozoic platform characterized by prograding deposits separated by regressive episodes and regional unconformities. The section thins eastward so that the Paleozoic sequence is accessible to drilling over a large area. The Mesozoic section has not undergone any orogenic or compressional stress. Normal faults generally strike north-south and are typically downthrown to the west, reflecting the predominant tensional structural style during the Mesozoic and Cenozoic. Salt diapirs in the offshore Casamance and Mauritania subbasins have pierced the Mesozoic section and are prominent structural targets for exploration.

West of the shelf edge (greater than 200-m water depth) where the sedimentary thickness can exceed 12,000 m, the regional structural style is dominated by gravitational features such as listric faulting and slumping, reflecting a slope environment and the influence of the opening of the Atlantic. The current sedimentary depocenter is located west of the shelf edge in water depths of 1,000–2,000 m.

Petroleum Occurrence in the Senegal Basin

There are both offshore and onshore hydrocarbon occurrences in several formations in the Senegal Basin. The best understood hydrocarbon occurrences in the Senegal Basin are in Cretaceous and Tertiary reservoirs in the Casamance, Northern, and Mauritania subbasins. The lower Paleozoic rocks contain oil-prone organic matter, and recent seismic data have delineated a pre-salt clastic section in the Lower Triassic. The Jurassic and Lower Cretaceous rocks have only been explored nearshore and contain continental-derived organic matter, which may be gas-prone.

Hydrocarbon production in the Senegal Basin has been limited to several small oil and gas fields (fig. 10) east of Cape Verde (Brown, 1981; Woodside, 1983). Discovered oil resources in the Senegal Basin are 10 MMBO, with gas resources of 49 BCFG (U.S. Geological Survey World Energy Assessment Team, 2000, disc 4, data file provvol.tab).

Hydrocarbon Source Rocks in the Senegal Basin

The most effective Cretaceous source rocks related to hydrocarbon discoveries and production in the Senegal Basin are the Cenomanian-Turonian marine shale units (figs. 7 and 8). Cenomanian to Turonian source rock units developed in two different subbasins (fig. 11). The first area is located north of Cape Verde and includes the Mauritania and Northern subbasins (fig. 3) where samples from wells located along the shelf boundary have exhibited good source rocks, up to 380 m thick, containing Type II and Type III organic matter (fig. 11) with hydrocarbon source potentials between 3 and 21 kg/ton (Reymond and Negroni, 1989). The second area is located south of Dakar in the Casamance subbasin. Reymond and Negroni (1989) state that the richest source rocks here contain Type II organic matter surrounded by a large area containing Type III organic matter (fig. 11). These source rocks display source potentials ranging between 5 and 75 kg/ton and range from 330 to 490 m thick. The Turonian interval contains bituminous shales that were probably deposited under anoxic conditions (Kuhnt and Wiedmann, 1995) with thickness up to 150 m (fig. 4). Samples analyzed from the Casamance Maritime 10 well (fig. 11) contain Type II kerogen with total organic carbon (TOC) values ranging from about 7 to more than 10 percent. Geochemical data obtained from Deep Sea Drilling Project well samples (DSDP 367 and 368, fig. 3) identified potential Neocomian to Cenomanian source rocks beyond the 2-second sediment isopach in the Senegal Basin (Tissot and others, 1980; Rullkötter and others, 1982). The source rocks contain mostly Type II kerogen with TOC values ranging from about 3 to more than 10 percent. Minor source

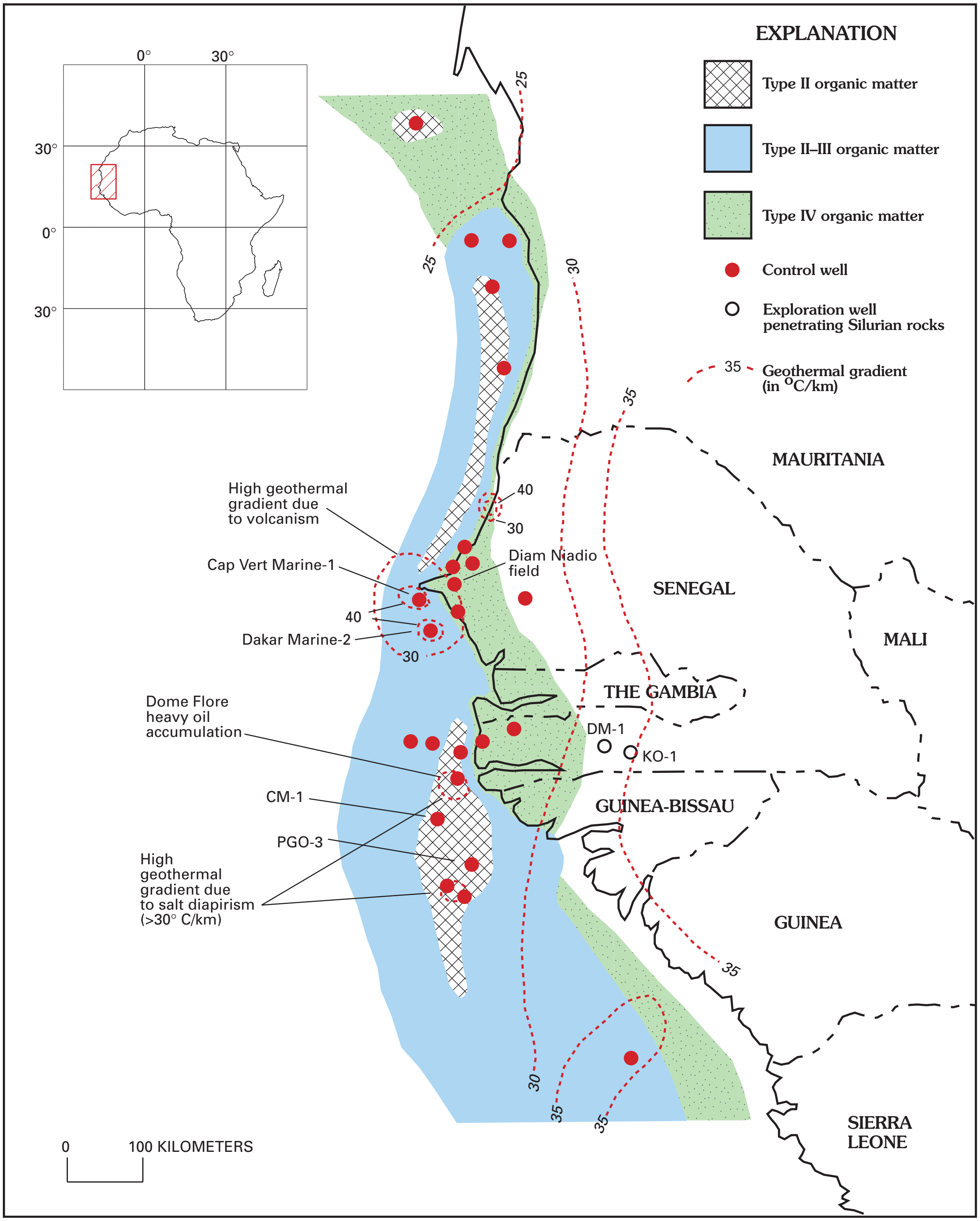


Figure 11. Distribution of organic matter in the Cenomanian to Turonian source rock. Also shown are the approximate locations of the Diana-Malari (DM–1) and Kolda (KO–1) wells that penetrated the Silurian Buba Shale source rocks (TOC as much as 5.5 percent) and the Casamance Maritime 1 (CM–1) well that penetrated the Turonian bituminous shales (TOC from 7 to more than 10 percent). Modified from Reymond and Negroni (1989).

rocks within the post-rift section have been identified (Dumestre and Carvalho, 1985; Reymond and Negroni, 1989) including the Senonian and Maastrichtian (2–5 kg/ton, Type II and III), the Paleogene (greater than 5 kg/ton, Type II with detrital Type IV), and the Miocene to Pliocene (2–5 kg/ton, Type II).

A second important source rock has been recognized recently and consists of graptolitic Silurian shale up to 400 m thick (fig. 4) in the southern one-half of the Senegal Basin. The Buba Shale may be equivalent to the oil-rich Silurian Tanezzuft Formation of North Africa (fig. 4), which is an important source rock in North Africa and the Middle East. The distribution of marine Silurian rocks, which contain oil-prone black graptolitic shales, is shown in the Silurian paleogeographic map in figure 12. Measurements conducted on samples from the Diana-Malari (DM–1) and Kolda (KO–1) wells (figs. 3 and 11) and outcrop studies in the Bove Basin and the Guinea Paleozoic Basin (Baffa Province, fig. 2) show these source rocks contain black amorphous organic matter and have TOC's ranging from 1 to 5.5 percent (Reymond and Negroni, 1989).

A third regional source rock may be related to the syn-rift section in the Senegal Basin. The source rocks are inferred Upper Permian-Lower Triassic lacustrine rocks that underlie the thick Triassic salt unit. Recent seismic studies have delineated this clastic section in the Casamance region of southern Senegal (figs. 6 and 9). The syn-rift section does not crop out in the Senegal Basin, and drilling has not penetrated it. Several analog Upper Permian? to Triassic rift basins have been recognized in Morocco, northwest Africa, and North America and contain clastic, lacustrine, and evaporite rocks (Van Houten, 1977; Evans, 1978; Manspeizer, 1981). The Newark Basin of North America is one of these rift basins that contain lacustrine beds with Type I and Type II organic matter ranging from more than 2 to 35 percent TOC (Ziegler, 1983). These beds are highly variable in organic content and thickness. A younger but similar syn-rift section related to the opening of the South Atlantic is located along the west-central African coast in the Congo-Cabinda basin off the coast of Congo. There, the section consists of Neocomian to Barremian lacustrine rocks of the Melania Formation overlain by Aptian evaporite rocks of the Loeme Formation. The lacustrine rocks contain both Type I and Type II organic matter averaging 6.1 percent and reaching as high as 20 percent (Schoellkopf and Patterson, 2000).

Burial history profiles and maturation studies have been carried out on several wells within the Senegal Basin. Maturation studies were determined from geothermal gradient data and samples analyzed from wells that penetrated the Mesozoic and Paleozoic units, and data extrapolated from outcrops in the Bove Basin for the Paleozoic part of the section. Two periods of oil generation have been determined for the Silurian source rocks (fig. 13); the first period began in the Carboniferous (300 Ma) and continued into the Hercynian orogeny (about 250 Ma). Generation paused during the Permian and Triassic, resumed during the Cretaceous, and continues to the present. The zone of oil generation ranges in depth from 1,850 to 4,000 m in the southern part of basin (fig. 6). In the eastern part of the Bove Basin, the zone of oil generation is elevated, probably in response to higher heat flow that may be due to intrusions or a local hot spot.

Hydrocarbon Generation and Migration in the Senegal Basin

The most significant hydrocarbon production within the Senegal Basin is from the Mesozoic section underlying the Cape Verde Peninsula onshore and the Casamance subbasin offshore. The Cretaceous source rocks display a highly variable maturation history. The Albian source rocks in the Mauritania subbasin started to generate oil in the late Eocene, whereas the Turonian and Senonian source rocks began to generate oil in the Miocene (fig. 14, drill hole V–1). The Upper Cretaceous source rocks began generating oil in the Miocene (fig. 14, drill hole COP–1). The Paleocene source rocks were found to be immature in the Mauritania offshore (fig. 14, drill hole COP–1). Two main areas of hydrocarbon generation have been delineated in the Senegal Province (fig. 15). The first area is located in the offshore Mauritania and northernmost Northern subbasins (figs. 3 and 15), whereas the second area is located in the Casamance subbasin and Guinea-Bissau offshore. North of Cape Verde, the amount of generated hydrocarbons increases seaward due to the combined effect of the thickening and deepening of the Cenomanian to Paleocene source rocks. The quality of source rocks onshore north of Cape Verde is not favorable for the generation of oil. In the Casamance and Mauritania subbasins, the Triassic diapiric salt (fig. 3) has induced a modification of maturation gradients because of the good thermal conductivity of the salt. Within the Casamance subbasin at least 2,500 tons of hydrocarbons per square kilometer have been generated (fig. 15) mainly from the Cenomanian and Turonian sources (Reymond and Negroni, 1989).

Present depth of the zone of oil generation ranges from less than 1,000 to more than 3,000 m depending upon the local geological and thermal parameters in the Senegal Basin (figs. 6 and 16). The zone of oil generation in parts of the Casamance and Mauritania subbasins is relatively shallow due to elevated geothermal gradients related to salt diapirism. A shallow zone of oil generation in the vicinity of Cape Verde is related to volcanism and ranges in depth from 900 m (Dakar Marine-2) to 1,200 m (Cap Vert Marine-1). Reymond and Negroni (1989) measured geothermal gradient values of nearly 45 °C/km in these wells (fig. 11). In areas where the average geothermal gradient is about 30 °C/km (fig. 11), the top of the zone of oil generation ranges from 2,285 to 2,680 m. The top of the zone of oil generation is at 2,800 m in the PGO–3 well, where Cenomanian source rocks are immature (figs. 5 and 6). Gas resources may be very significant and accessible in areas where the zone of oil generation is relatively shallow. Migration of hydrocarbons most likely began in the late Miocene and continues to the Holocene.

Maturity of the source rocks in the basin increases southward. This may be somewhat misleading because of the lack of data north of Cape Verde. A zone of salt diapirs off the Mauritania coast may be more widespread than previously thought and may have caused increased maturation of Cretaceous source rocks.

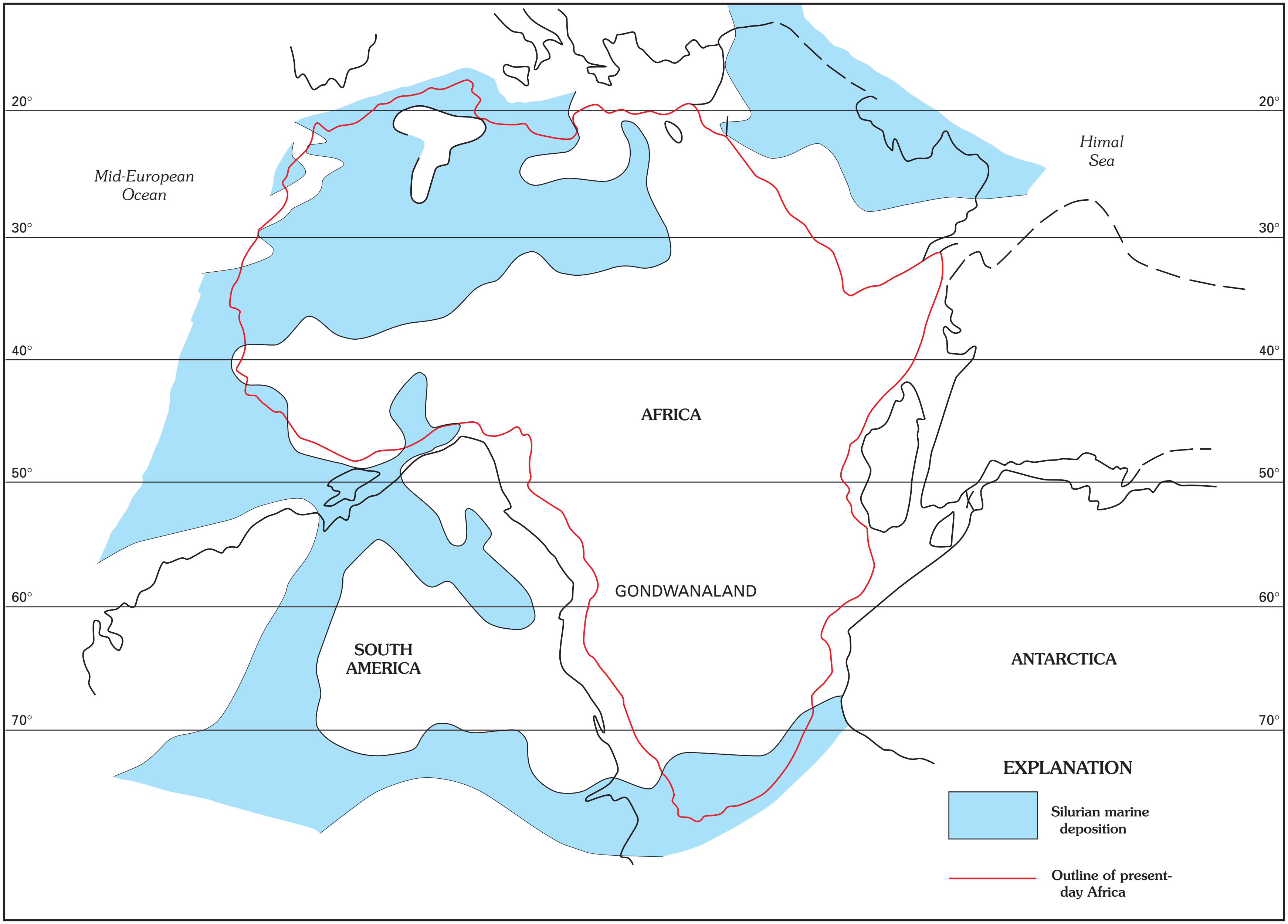


Figure 12. Paleogeographic reconstruction of the Silurian Period showing relative positions of continents and areas of deposition for graptolite-bearing Silurian rocks. Modified from Clifford (1986).

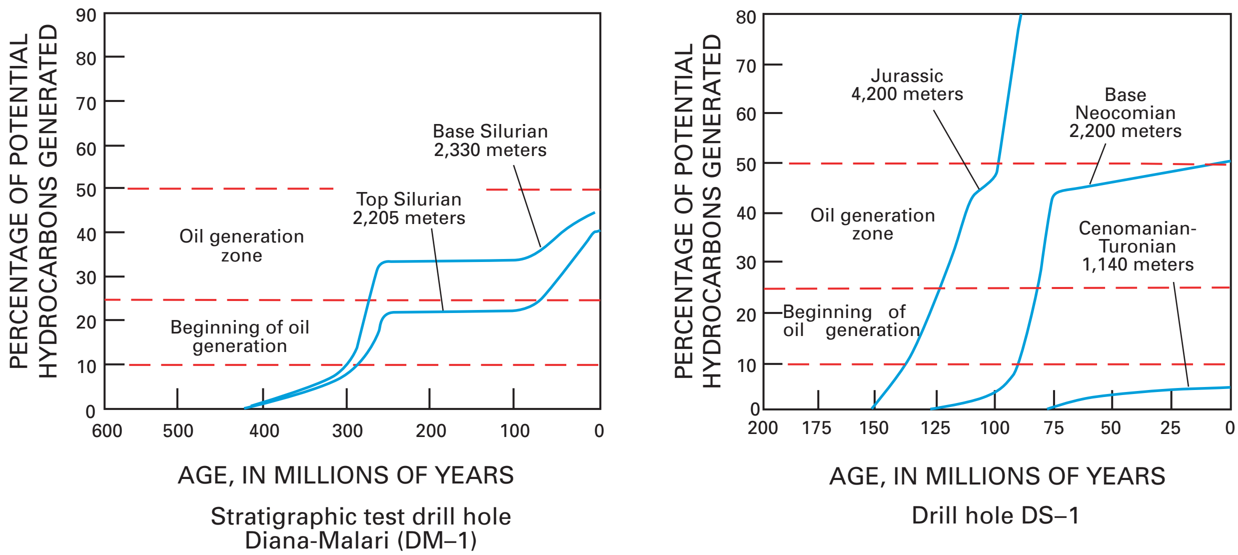


Figure 13. Examples of hydrocarbon maturation evolution in the Senegal Basin involving the Silurian, Jurassic, basal Neocomian, and the Cenomanian to Turonian source rocks. Maturity levels are expressed in percentage of potential hydrocarbons generated. Modified from Reymond and Negroni (1989).

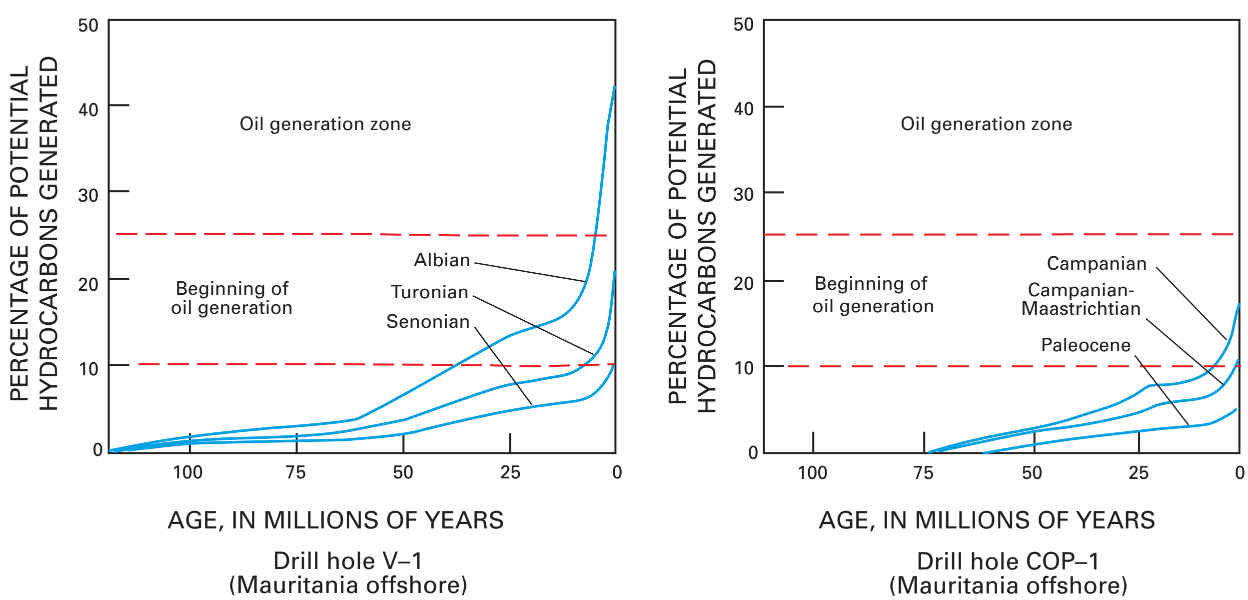


Figure 14. Examples of hydrocarbon maturation evolution on the shelf edge in the Senegal Basin involving the Albian, Turonian, Senonian, Campanian, Maastrichtian, and Paleocene source rocks. Maturity levels are expressed in percentage of potential hydrocarbons generated. Modified from Reymond and Negroni (1989).

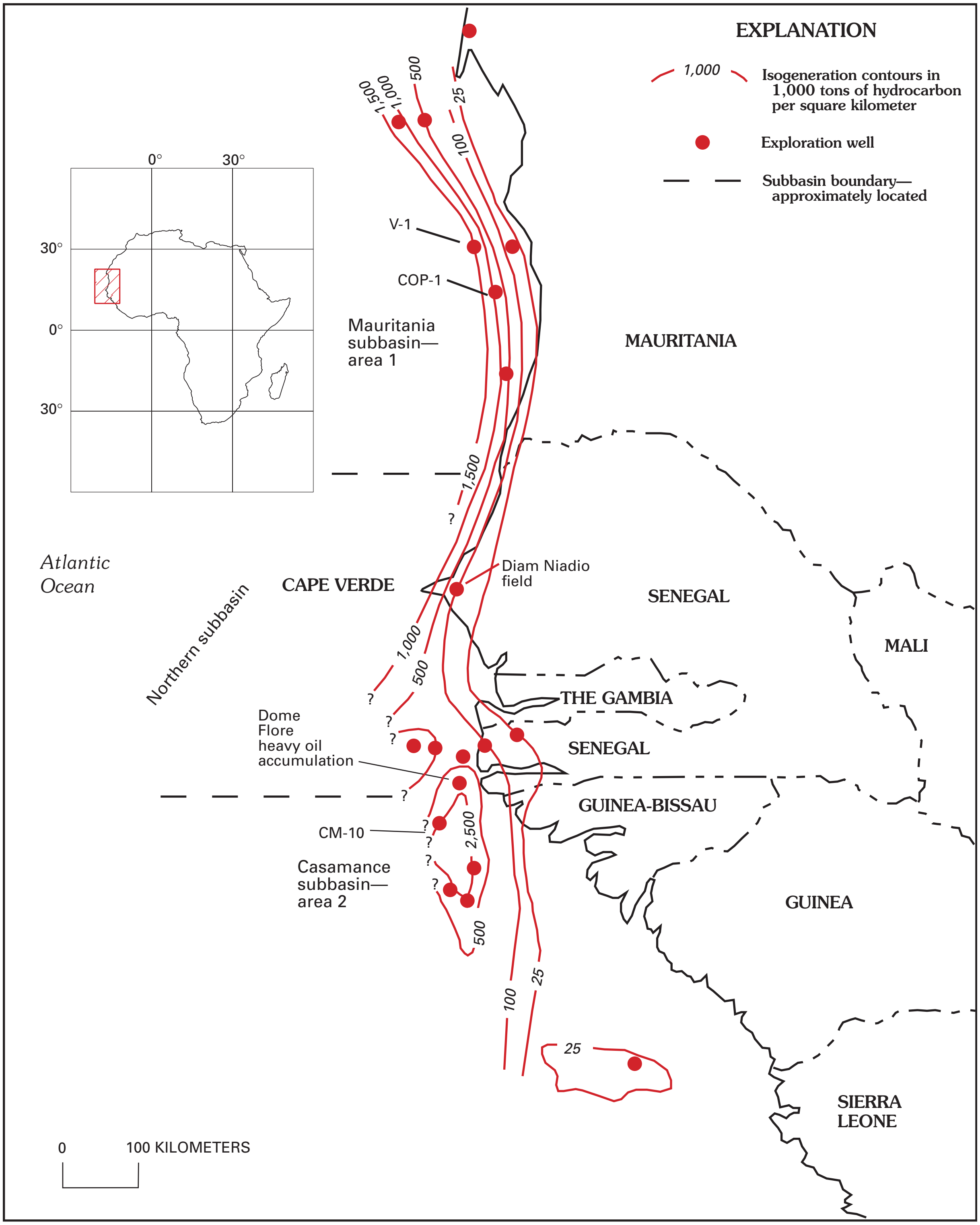


Figure 15. Isogeneration map of the Cenomanian to Paleocene source rocks in the Senegal Province. Two main source/generation areas, the Casamance subbasin and a large offshore area in the Mauritania subbasin, were delineated using Rock-Eval; maturity levels expressed in percentage of potential hydrocarbons generated (fig. 14) and net thickness of the source rocks. Modified from Reymond and Negroni (1989).

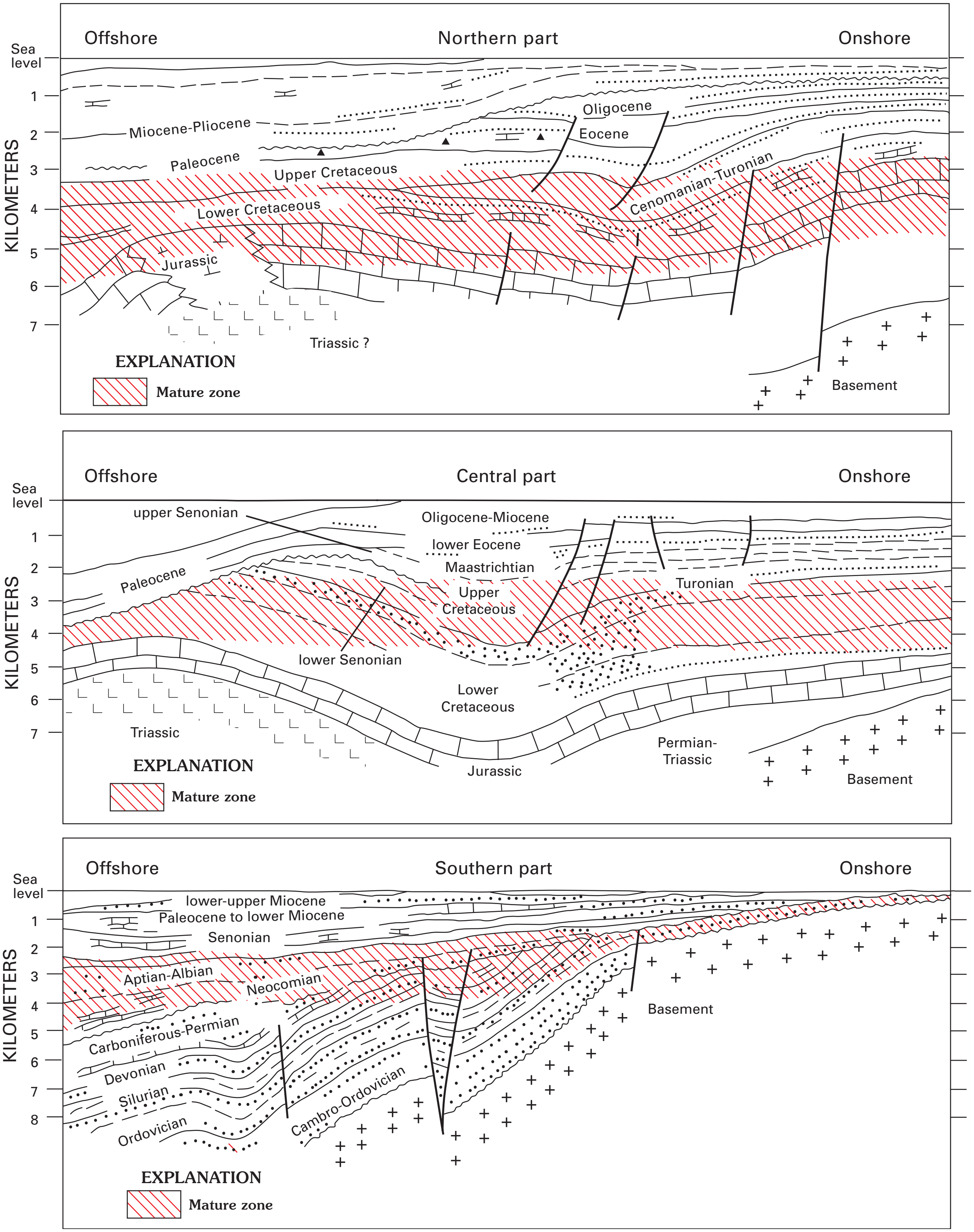


Figure 16. Schematic cross sections showing the approximate position of the zone of oil generation in the northern, central, and southern Senegal Province, northwest Africa. Zone of gas generation was not determined because gas data were not available. Modified from Reymond and Negroni (1989).

Hydrocarbon Reservoirs, Traps, and Seals in the Senegal Basin

The Mesozoic-Cenozoic section of the Senegal Basin can exceed 10,000 m in thickness and contains several primary reservoirs and seals: (1) Jurassic-Lower Cretaceous carbonate section sealed by Cenomanian or other Lower Cretaceous shales; (2) Upper Cretaceous sandstone units and overlying shale units; and (3) lower Tertiary clastic and carbonate-rock units and overlying and intercalated shale units (figs. 6, 9, and 10). Cretaceous deltaic sandstone (Clifford, 1986) with porosities ranging from 17 to 25 percent are present in the Mauritania offshore (fig. 17). The Jurassic-Lower Cretaceous carbonate-rock platform has never been fully penetrated by drilling but does show good porosities ranging from 10 to 23 percent (figs. 17 and 18). Reef prospects on the shelf edge remain to be explored. Upper Cretaceous sandstone sequences in the eastern part of the basin become interbedded with shale to the western offshore part of the basin. Maastrichtian sandstones up to 30 m thick occur at Dome Flore, with porosities ranging from 20 to 30 percent, and contain light oil (33.6° API). In the Dome Flore area, an excellent Oligocene carbonate-rock reservoir exists and contains up to 1 billion barrels of heavy oil (10° API, 1.6 percent sulfur) in place. About 40 km east of Dakar, several shallow oil and gas discoveries were made in the 1950's. Following a geologic reinterpretation of the area in 1984 (Dumestre, 1985), these wells and two new wells were found to be productive, with rates up to 300 barrels of oil per day (BO/D) and 2.4 million cubic feet of gas per day (MMCFG/D). Currently, only a small amount of gas is being produced from the Diam Niadio field (fig. 11).

The Mesozoic-Cenozoic section in the Senegal Basin contains diverse oil and gas trapping configurations. These include salt-related structures, structures related to volcanic intrusion, growth-fault-related traps, slope truncation traps along the present shelf edge, sandstone pinch-outs along the eastern margin of the Senegal Basin, Jurassic-Lower Cretaceous carbonate bank deposits, and possible turbidite-related stratigraphic traps. Seals consist of Mesozoic and Cenozoic marine shales and faults.

Sandstone reservoirs associated with syn-rift rocks might be present and interbedded with the inferred Permian-Triassic source rocks underlying the Triassic salt (fig. 9). The thick Triassic salt is the major seal in the syn-rift section in the Senegal Basin.

Potential sandstone reservoirs are abundant in lower Paleozoic rocks based on measured sections in the Bove Basin and analyzed samples from the DM–1 and KO–1 stratigraphic test wells (fig. 3). The Ordovician sandstones are intensely fractured and could constitute good secondary reservoirs, whereas the Devonian fine- to coarse-grained sandstone beds have porosities ranging from 15 to 20 percent. In the onshore portion of the Paleozoic basin, regional seismic data have shown that the Paleozoic section has been faulted and could form traps in conjunction with the Paleozoic unconformity (fig. 6). Interpretation of seismic data shows that the Paleozoic unconformity is at a depth of about 10,000 m at the PGO–3 (fig. 6) exploration hole in the Guinea-Bissau offshore. The Paleozoic reservoirs were not assessed in this study.

Total Petroleum Systems of the Senegal Province

At least three total petroleum systems (TPS) may be present in the Senegal Province: (1) the hypothetical Lower Paleozoic Total Petroleum System consisting of Silurian source rocks and Ordovician to Devonian and Triassic reservoir rocks; (2) the hypothetical Sub-salt Total Petroleum System consisting of Triassic (?) lacustrine source rocks and clastic reservoirs capped by Triassic salt; and (3) the Cretaceous-Tertiary Composite Total Petroleum System consisting of Cenomanian-Turonian source rocks and Cretaceous and Tertiary reservoirs. Only limited drilling and seismic information is available for the Lower Paleozoic TSP, whereas there is no drilling and only limited seismic information on the Sub-salt TSP. Only the Cretaceous-Tertiary Composite Total Petroleum System was considered for this assessment because current production and exploration data were almost entirely limited to the Cretaceous. We defined one assessment unit within the TSP—the Coastal Plain and Offshore Assessment Unit.

Lower Paleozoic and Sub-salt Total Petroleum Systems

Events charts (figs. 19 and 20) for the Lower Paleozoic and Sub-salt Total Petroleum Systems summarize the age of the source, seal, and reservoir rocks and the timing of trap development and generation and migration of hydrocarbons.

The likely source rocks for the Lower Paleozoic Total Petroleum System are oil-prone graptolite-bearing Silurian shale that may be as much as 400 m thick (fig. 4) in the southern one-half of the Senegal Province. Measurements carried out in the Diana-Malari (DM–1) and Kolda (KO–1) wells and outcrop studies in the Bove Basin and the Guinea Paleozoic Basin show these source rocks to contain moderate organic matter and have TOC contents ranging from 1 to 5.5 percent (Reymond and Negroni, 1989). Two periods of oil generation have been determined for the Silurian source rocks and the first period began in the Carboniferous (300 Ma) and continued into the Hercynian orogeny (fig. 13). Generation paused during the Permian and Triassic, resumed during the Cretaceous, and continues to the present. Sandstone reservoirs have been shown to be abundant in the lower Paleozoic section based on measured sections in the Bove Basin and analyzed samples from stratigraphic test wells (fig. 3). The Ordovician sandstones could be good secondary reservoirs, whereas the Devonian fine- to coarse-grained sandstone beds have porosities ranging from 15 to 20 percent and could comprise a third type of potential reservoirs.

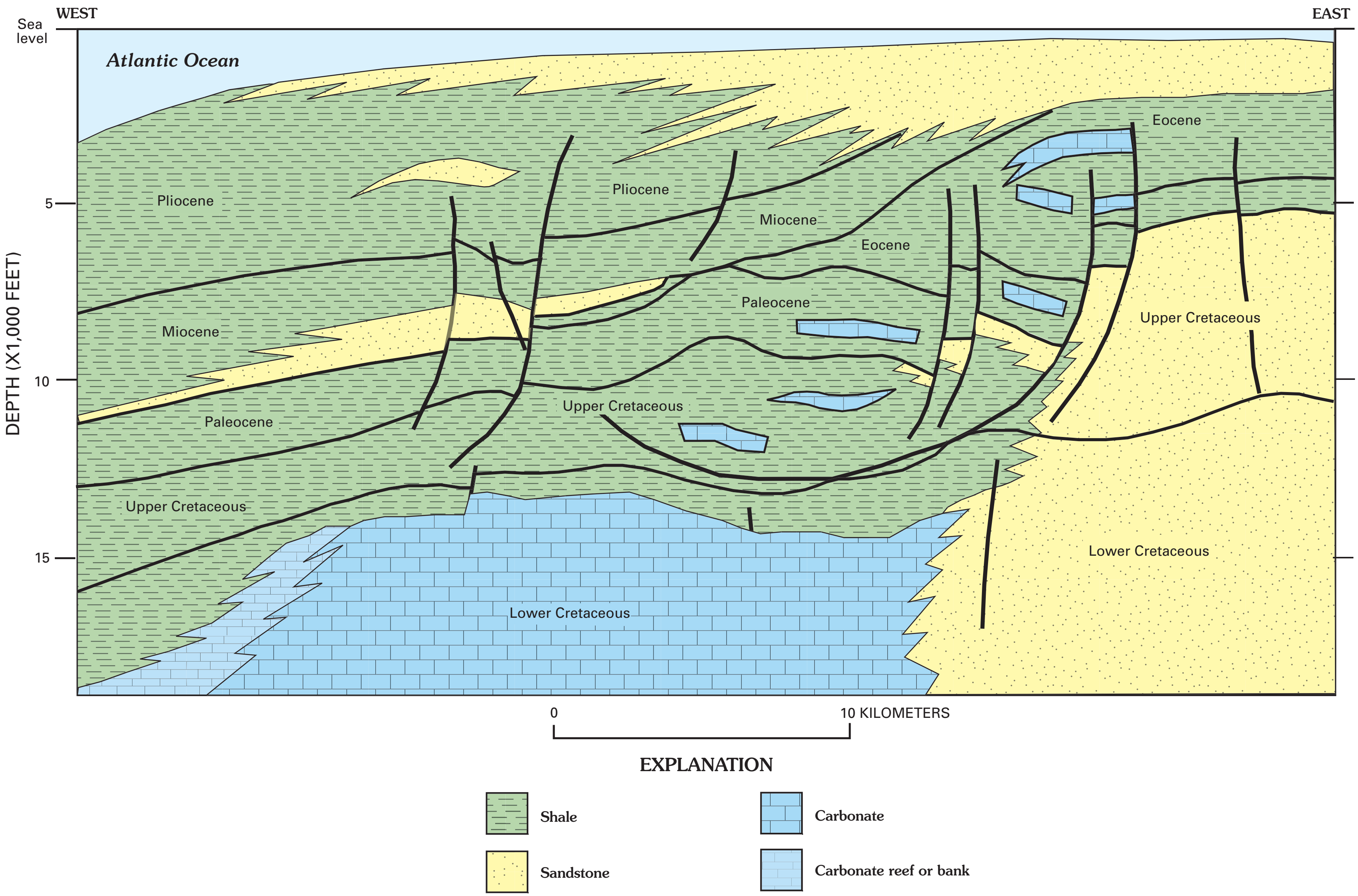


Figure 17. Schematic cross section of the Mauritania offshore, northern Senegal Basin, northwest Africa. Several potential hydrocarbon areas have been identified in the Mauritania offshore, but commercial hydrocarbon accumulations have not been found to date. Oil-prone source rocks (TOC as much as 5 percent) within the Albian-Turonian and potential Upper Cretaceous deltaic reservoir sands with porosities of 17–25 percent have been identified. Lower Cretaceous carbonate rocks are untested in this part of the basin. Miocene turbidite fans also are prospective. Modified from Clifford (1986).

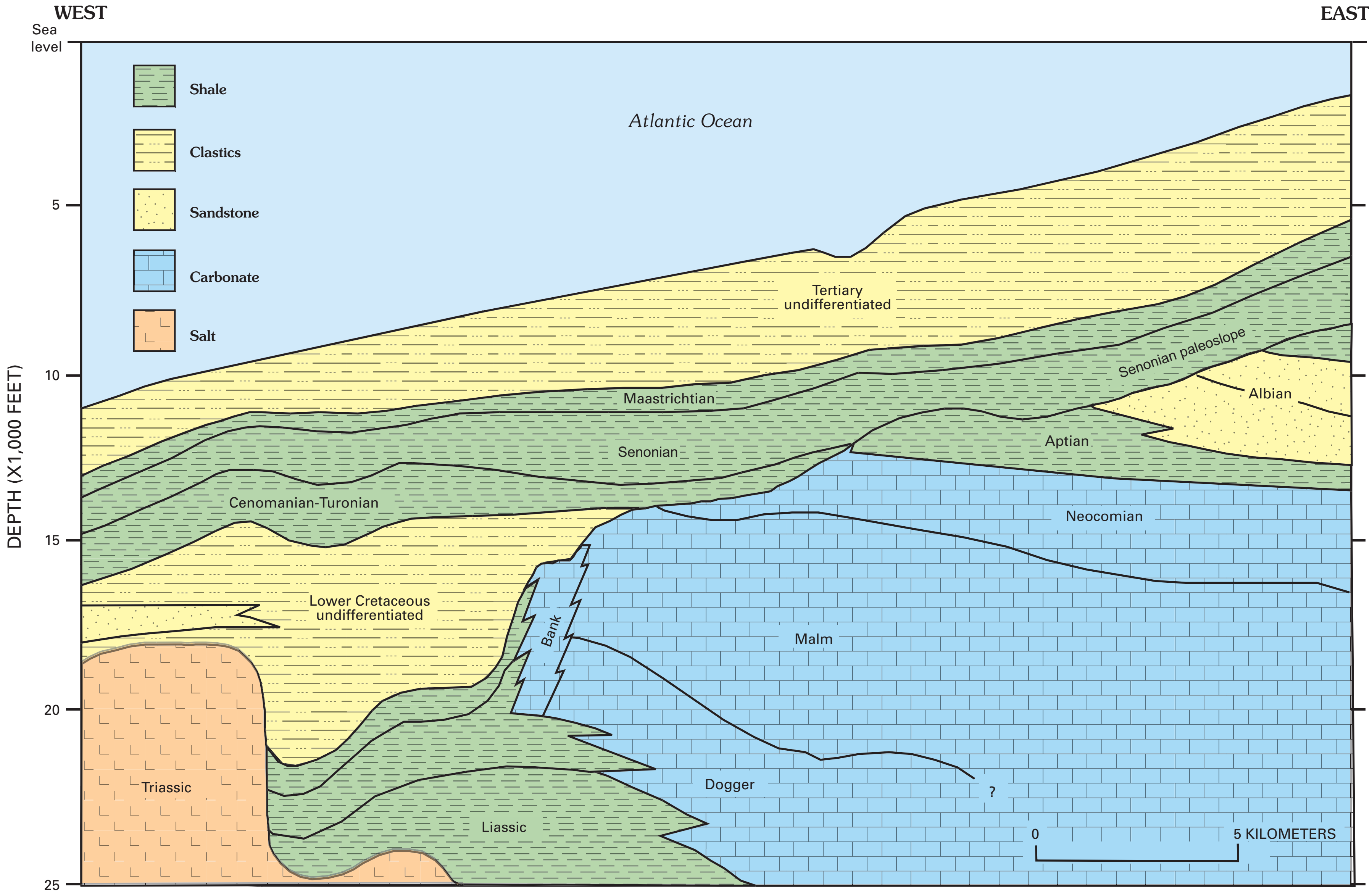


Figure 18. Schematic cross section of offshore Guinea-Bissau, Senegal Basin, northwest Africa. The Albian-Cenomanian Geba delta prograded westward across the carbonate platform providing reservoir-potential sands and source rocks. The carbonate and deltaic rocks subcrop the Senonian paleoslope, offering several areas of potential traps. Modified from Clifford (1986).

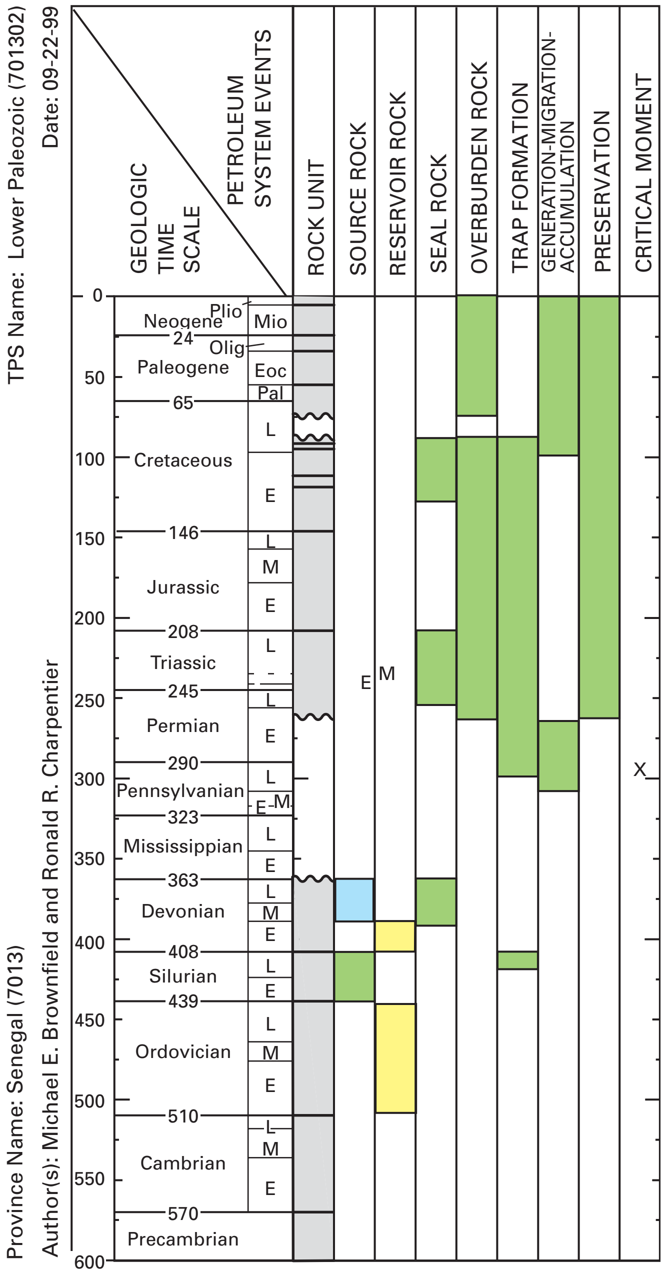


Figure 19. Events chart for the hypothetical Lower Paleozoic Total Petroleum System, Senegal Province, northwest Africa. Light gray shading indicates rock units present. Light blue indicates secondary or possible occurrences of source rocks depending on quality and maturity of the unit. Age ranges of source, seal, reservoir, and overburden rocks and the timing of trap formation and generation, migration, and preservation of hydrocarbons are shown in green and yellow.

The Sub-salt Total Petroleum System is related to the syn-rift section and has not been tested in the Senegal Province, but seismic data suggest that this TSP may be present and it may be an important future hydrocarbon objective. The potential source rocks are lacustrine rocks below the thick Triassic salt unit. Recent seismic studies have delineated this clastic section in the Casamance region of southern Senegal (figs. 6 and 9). The Newark (New Jersey, USA) and Congo-Cabinda (Congo and southern Gabon, Africa) analog rift basins contain lacustrine source rocks with Type I and Type II organic matter. Hydrocarbon generation is inferred to have started in the early Cretaceous to middle Cretaceous. Reservoir rocks are inferred to be Triassic clastic units along the margins of the rift valleys and clastic rocks along the landward margins of Jurassic to Neocomian limestones (figs. 6 and 9).

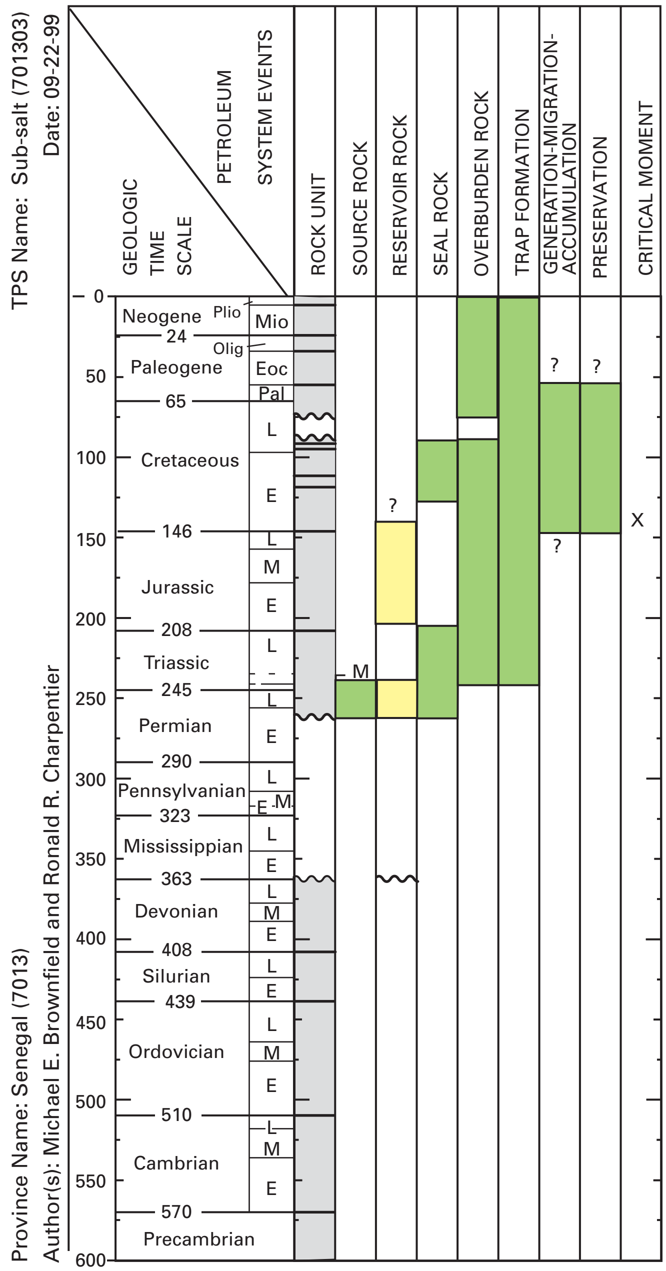


Figure 20. Events chart for the hypothetical Sub-salt Total Petroleum System in the Senegal Basin, northwest Africa. Light gray shading indicates rock units present. Age ranges of source, seal, reservoir, and overburden rocks and the timing of trap formation and generation, migration, and preservation of hydrocarbons are shown in green and yellow.

The hypothetical Lower Paleozoic and Sub-salt Total Petroleum Systems were not assessed in this study because current production and exploration data in the Senegal Province was almost entirely limited to the Cretaceous and Tertiary units. These two total petroleum systems may have the potential to be significant hydrocarbon objectives in the future.

Cretaceous-Tertiary Composite Total Petroleum System

The Cretaceous-Tertiary Composite Total Petroleum System (TSP) was defined in the Senegal Province. An events chart (fig. 21) summarizes the age of the source, seal, and reservoir rocks and the timing of trap development and generation and migration of hydrocarbons for this TSP.

The principal source rocks in the Cretaceous-Tertiary Composite Total Petroleum System are the Cenomanian and Turonian shales (fig. 21). The Turonian can be as much as 150 m thick with TOC contents ranging from 3 to 10 percent; it contains Type I, II, and III organic matter. Petroleum generation is presumed to have begun during the Miocene and continues to the present. Migration and charge most likely occurred shortly after generation along faults and porous Cretaceous and Tertiary reservoirs.

Good reservoir rocks are known throughout the section and include Upper Cretaceous sandstones and Tertiary clastics and carbonates, whereas the Lower Cretaceous carbonate-rock platform and Cretaceous reef units have not been explored (figs. 6, 9, 10, 16, 17, and 18). Oligocene carbonate-rock reservoirs exist such as the reservoir at the Dome Flore discovery (up to 1 billion barrels of heavy oil) that was charged with Turonian-sourced oil and underwent degradation due to an insufficient seal allowing water washing and(or) biodegradation.

The Upper Cretaceous and Tertiary marine mudstone and shale rocks are the primary seals for the reservoirs in the Cretaceous-Tertiary Composite Total Petroleum System. The Mesozoic-Cenozoic part of the Senegal Province contains diverse trapping mechanisms (figs. 6, 9, 10, 16, 17, and 18) including salt-related structures, structures related to volcanic intrusions, growth-fault-related traps, slope truncations along the present day and paleoshelf edge (Senonian unconformity), Mesozoic and Tertiary pinch-outs along the eastern basin margin, and reef buildups along the shelf edge.

The lack of hydrocarbon production possibly is due to poor timing of hydrocarbon migration and the lack of effective seals. However, many of the early exploration wells were drilled on structures based on interpretations of poor seismic data. Currently, many of the seismic lines are being reinterpreted and new lines have been run. The Senegal Province is underexplored considering its large size, and that it has hydrocarbon potential in both the offshore and onshore in all three total petroleum systems.

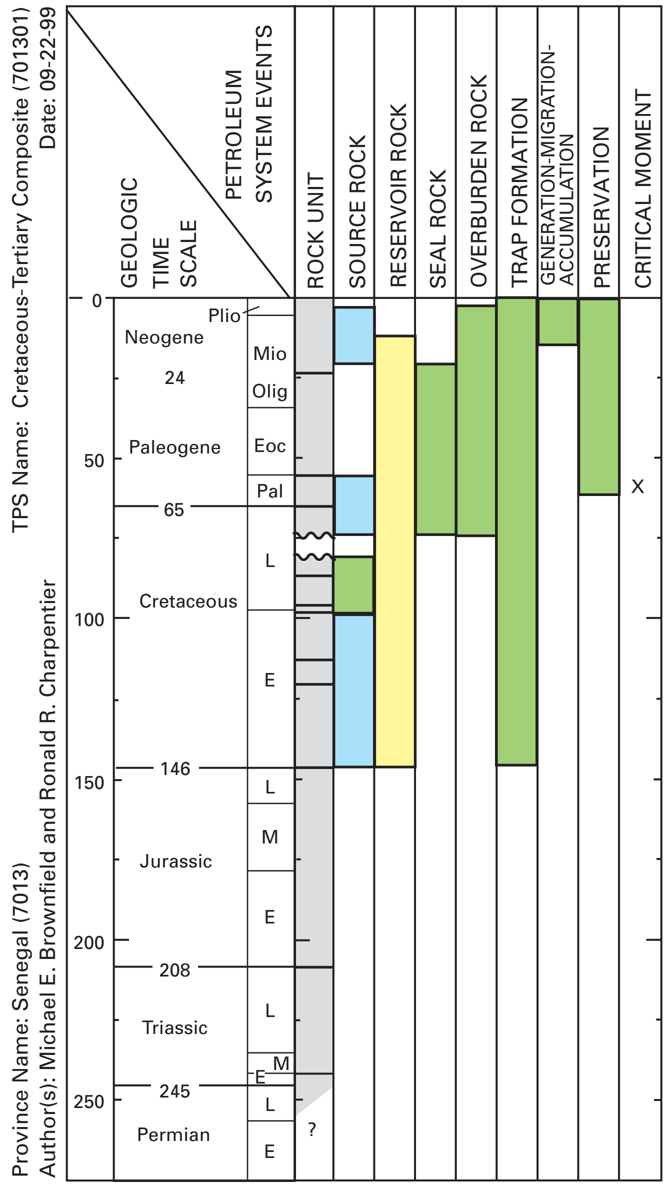


Figure 21. Events chart for the Cretaceous-Tertiary Composite Total Petroleum System (701301) and the Coastal Plain and Offshore Assessment Unit (70130101). Light gray shading indicates rock units present. Light blue indicates secondary or possible occurrences of source rocks depending on quality and maturity of the unit. Age ranges of source, seal, reservoir, and overburden rocks and the timing of trap formation and generation, migration, and preservation of hydrocarbons are shown in green and yellow.

Coastal Plain and Offshore Assessment Unit

One assessment unit (AU) was defined for the Cretaceous-Tertiary Composite Total Petroleum System, designated the Coastal Plain and Offshore Assessment Unit (fig. 1). The eastern boundary of the AU was defined as the eastern limit of the Cretaceous rocks within the basin, whereas the western boundary was set at a 2,000-m water depth (figs. 2 and 3). The AU is considered a frontier area with only two gas fields and one minor oil field producing east of Dakar and Cape Verde that meet the minimum size criteria for this study. Minimum field sizes of 1 MMBO and 6 BCFG were chosen for this assessment unit. Discovered oil resources in the Coastal Plain and Offshore Assessment Unit are 10 MMBO, with discovered gas resources at 49 BCFG (Petroconsultants, 1996). Within the past 47 years, fewer than 150 exploration wells have been drilled in the Province, of which 52 are offshore. Most of the wells are concentrated in two areas, in the vicinity of Cape Verde and in the offshore Casamance subbasin (fig. 3). Most of the Senegal Province remains relatively unexplored.

This study estimates that 10 percent (three fields) of the total number of fields (discovered and undiscovered) of at least the minimum size has been discovered. The estimated mean size and number of undiscovered oil fields are 12 MMBO and 13 fields, and the mean size and number of undiscovered gas fields are 44 BCFG and 11 fields. The estimated ranges in size and number and estimated coproduct ratio for these undiscovered fields are given in the U.S. Geological Survey World Petroleum Assessment 2000—Description and Results CD–ROM (U.S. Geological Survey World Energy Assessment Team, 2000) and are summarized in table 1.

The estimated means of the undiscovered conventional petroleum volumes contained in these fields are 157 MMBO, 856 BCFG, and 43 MMBNGL (table 2). The mean expected sizes of the largest anticipated undiscovered oil and gas fields are 66 MMBO and 208 BCFG, respectively.

Summary

The Cretaceous-Tertiary Composite Total Petroleum System consists of Cenomanian-Turonian marine source rocks containing Type I, II, and III organic matter and Cretaceous and Tertiary carbonate-rock and sandstone reservoirs. Upper Cretaceous and Tertiary marine mudstone and shale rocks are the primary seals. Petroleum generation began in the Miocene and continues to the present. Migration and charge most likely occurred shortly after generation and continues to the present. The Coastal Plain and Offshore Assessment Unit was defined and assessed for the Cretaceous-Tertiary Composite Total Petroleum System.

Two other total petroleum systems were recognized in the Senegal Province: (1) the Lower Paleozoic Total Petroleum System consisting of Silurian source rocks and Ordovician to Devonian and Triassic reservoir rocks; and (2) the Pre-salt Total Petroleum System consisting of Permian-Triassic (?) lacustrine source rocks and clastic reservoirs capped by Triassic salt. Although they have the potential to be significant hydrocarbon objectives in the future, these total petroleum systems were not assessed because current production and exploration data were almost entirely limited to the overlying Cretaceous-Tertiary Composite Total Petroleum System.

Current hydrocarbon production is limited to gas and minor amounts of oil in several small fields east of Dakar. Production is from Upper Cretaceous sandstone reservoirs bounded by normal faults. The traps are a combination of structural closures and stratigraphic pinch-outs. No other commercial accumulations have been found to date.

Many of the early exploration wells were drilled on structures based on interpretations of older, two-dimensional seismic data. Currently, many of the seismic lines are being reprocessed and reinterpreted, and many new three-dimensional lines have been run. Recent exploration drilling by Woodside Petroleum in the Mauritania offshore has delineated a light oil (47° API) accumulation. The Senegal Province is underexplored for its large size and does have possibilities in both the offshore and onshore potential prospects in all three total petroleum systems. Gas resources may be very significant and accessible in areas where the zone of oil generation is relatively shallow.

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Table 1. Estimated sizes, number, and coproduct ratios of undiscovered oil and gas fields for the Coastal Plain and Offshore Assessment Unit in the Cretaceous-Tertiary Composite Total Petroleum System of the Senegal Province, northwest Africa

[MMBO, million barrels of oil; BCFG, billion cubic feet of gas; CFG/BO, cubic feet of gas per barrel oil, not calculated for gas fields; BNGL/MMCFG or BL/MMCFG, barrels of natural gas liquids per million cubic feet of gas or barrels of total liquids per million cubic feet of gas. BNGL/MMCF was calculated for USGS-defined oil fields, whereas BL/MMCFG was calculated for USGS-defined gas fields. The mean size of the accumulation are within a lognormal distribution of field sizes for which the origin is the selected minimum field size. Shading indicates not applicable]

	Size of fields				Number of fields					Gas–to–oil ratio (CFG/BO)					NGL–to–gas ratio (BNGL/MMCFG or BL/MMCFG)				
Field type	Minimum	Median	Maximum	Mean	Minimum	Median	Maximum	Mean	Mode	Minimum	Median	Maximum	Mean	Mode	Minimum	Median	Maximum	Mean	Mode
Oil fields	1	4	500	13	1	12	35	13	4	1,100	2,200	3,300	2,198	2,200	30	60	90	60	60
Gas Fields	6	20	1,500	50	1	10	25	11	6						22	44	66	44	44

Table 2. Estimated undiscovered volumes of conventional oil, gas, and natural gas liquids for oil and gas fields for the Coastal Plain and Offshore Assessment Unit in the Cretaceous-Tertiary Composite Total Petroleum System of the Senegal Province, northwest Africa

[MMBO, million barrels of oil; BCFG, billion cubic feet of gas; NGL, natural gas liquids; MMBNGL, million barrels of natural gas liquids. MFS, minimum field size assessed (MMBO for oil fields or BCFG for gas fields). Volumes of undiscovered NGL were calculated for oil fields, whereas volumes of total liquids (oil plus NGL) were calculated for USGS-defined gas fields. Largest anticipated undiscovered field is in units of MMBO for oil fields and BCFG for gas fields. Results shown are estimates that are fully risked with respect to geology and accessability. Undiscovered volumes in fields smaller than the selected minimum field size are excluded from the assessment. Means can be summed, but fractiles (F95, F50, and F5) can be summed only if a correlation coefficient of +1.0 is assumed. Shading indicates not applicable]

Field type	MFS	Probability (0–1)	Undiscovered conventional resources Oil (MMBO)				Gas (BCFG)				NGL (MMBNGL)				Largest undiscovered field (MMBO or BCFG)			
			F95	F50	F5	Mean	F95	F50	F5	Mean	F95	F50	F5	Mean	F95	F50	F5	Mean
Oil fields	1	1.00	15	120	430	157	33	255	968	345	2	15	59	21	7	41	217	66
Gas fields	6	1.00					83	414	1,276	510	3	18	58	22	31	137	648	208
Total			15	120	430	157	116	669	2,244	856	5	33	118	43				