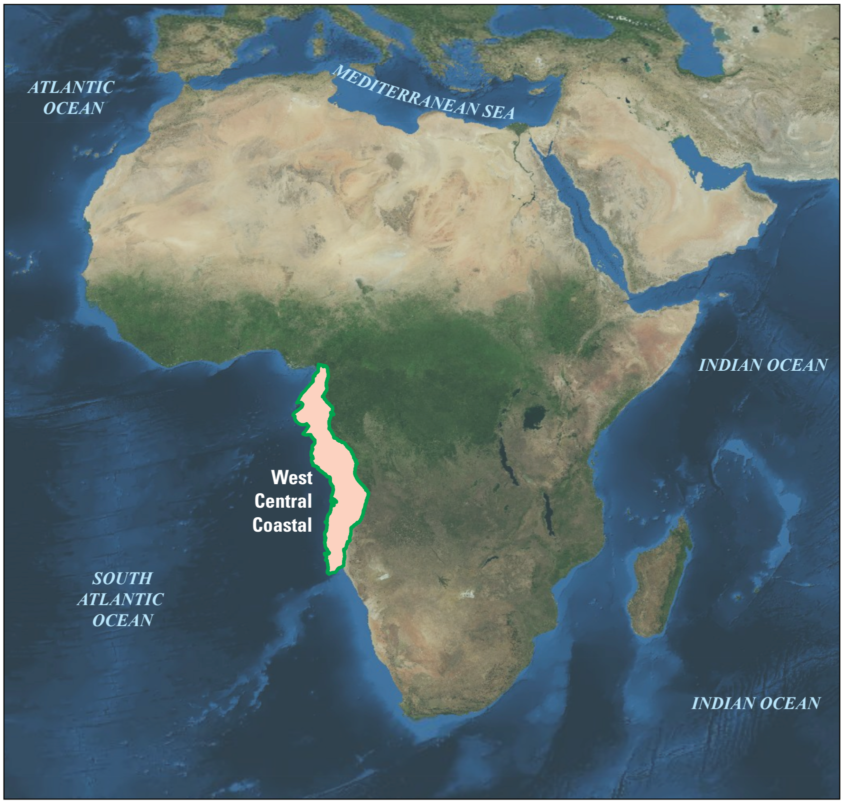
Assessment of Undiscovered Oil and Gas Resources of the West-Central Coastal Province, West Africa

By Michael E. Brownfield



Click here to return to
Volume Title Page

Chapter 7 of

Geologic Assessment of Undiscovered Hydrocarbon Resources of Sub-Saharan Africa

Compiled by Michael E. Brownfield

Digital Data Series 69–GG

U.S. Department of the Interior
U.S. Geological Survey

U.S. Department of the Interior
SALLY JEWELL, Secretary

U.S. Geological Survey
Suzette M. Kimball, Director

U.S. Geological Survey, Reston, Virginia: 2016

For more information on the USGS—the Federal source for science about the Earth, its natural and living resources, natural hazards, and the environment—visit http://www.usgs.gov or call 1–888–ASK–USGS.

For an overview of USGS information products, including maps, imagery, and publications, visit http://www.usgs.gov/pubprod/.

Suggested citation:
Brownfield, M.E., 2016, Assessment of undiscovered oil and gas resources of the West-Central Coastal Province, west Africa, *in* Brownfield, M.E., compiler, Geologic assessment of undiscovered hydrocarbon resources of Sub-Saharan Africa: U.S. Geological Survey Digital Data Series 69–GG, chap. 7, 41 p., http://dx.doi.org/10.3133/ds69GG.

ISSN 2327-638X (online)

Contents

Figures

Table

Abbreviations Used in This Report

AU	Assessment Unit
D	darcy
km	kilometer
m	meter
mD	millidarcies
TOC	total organic carbon
TPS	total petroleum system

Assessment of Undiscovered Oil and Gas Resources of the West-Central Coastal Province, West Africa

By Michael E. Brownfield

Abstract

The main objective of the U.S. Geological Survey's National and Global Petroleum Assessment Project is to assess the potential for undiscovered, technically recoverable oil and natural gas resources of the United States and the world. As part of this project, the U.S. Geological Survey completed an assessment of the West-Central Coastal Province, an area of approximately 838,552 square kilometers that covers parts of the coastal and offshore areas of Cameroon, Equatorial Guinea, Gabon, Democratic Republic of the Congo, Republic of the Congo, Angola (including the Cabinda Province), and Namibia. This assessment was based on data from oil and gas exploration wells, producing fields, and published geologic reports.

The West-Central Coastal Province stretches from the east edge of the Niger Delta south to the offshore Walvis Ridge. The West-Central Coastal Province includes the Douala, Kribi-Campo, Rio Muni, Gabon, Congo, Kwanza, and Benguela Basins, which together form the Aptian salt basin of equatorial west Africa. Since the 2000 USGS World Petroleum Resources Assessment, several giant oil fields have been discovered, especially in the deep-water area of the Congo Basin.

The West-Central Coastal Province in sub-Saharan Africa is a priority province for the World Petroleum Assessment. The assessment was geology based and used the total petroleum system concept. The geologic elements of a total petroleum system consist of hydrocarbon source rocks (source-rock maturation and hydrocarbon generation and migration), reservoir rocks (quality and distribution), and traps for hydrocarbon accumulation. Using these geologic criteria, the U.S. Geological Survey defined four total petroleum systems and five assessment units in the province:

- the Melania-Gamba Total Petroleum System and the Gabon Subsalt Assessment Unit, consisting of Lower Cretaceous source and reservoir rocks;
- the Azile-Senonian Total Petroleum System and the Gabon Suprasalt Assessment Unit consisting of Albian to Turonian source rocks and Cretaceous reservoir rocks;
- the Congo Delta Composite Total Petroleum System and the Central Congo Delta and Carbonate Platform and Central Congo Turbidites Assessment Units consisting of Lower Cretaceous to Tertiary source and reservoir rocks; and
- the Kwanza Composite Total Petroleum System and the Kwanza-Namibe Assessment Unit consisting of Lower Cretaceous to Tertiary source and reservoir rocks.

The province was assessed to a water depth of 4,000 meters.

Large areas of the offshore parts of the Kwanza, Douala, Kribi-Campo, and Rio Muni Basins are underexplored, and current exploration activity suggests that the basins have hydrocarbon potential. Since the 2000 U.S. Geological Survey assessment, the offshore part of the Congo Basin has become a major area for hydrocarbon exploration and new field discoveries, and many deeper water areas in the basin have excellent hydrocarbon potential.

In this 2009 assessment, the U.S. Geological Survey estimated mean volumes of undiscovered, technically recoverable conventional oil and gas resources in the West-Central Coastal Province. The West-Central Coastal Province was divided into the Gabon Subsalt, Gabon Suprasalt, Central Congo Delta and carbonate Platform, Central Congo Turbidites, and Kwanza-Namibe Assessment Units. The estimated mean volumes for these five assessment units are 49,736 million barrels of oil, 75,790 billion cubic feet of gas, and 2,877 million barrels natural gas liquids. This assessment for the province indicates that most of the oil and gas potential is in the offshore.

Introduction

The main objective of the U.S. Geological Survey's (USGS) National and Global Petroleum Assessment Project is to assess the potential undiscovered, technically recoverable oil and natural gas resources of the United States and the world (U.S. Geological Survey World Conventional Resources Assessment Team, 2012). As part of this project, the USGS completed an assessment of the West-Central Coastal Province (fig. 1), an area of about 838,552 square kilometers (km^2) that covers the coastal and offshore parts of Cameroon, Equatorial Guinea, Gabon, Republic of the Congo, Democratic Republic of the Congo, Angola (including the Cabinda Province), and Namibia. This assessment was based on data from oil and gas exploration wells, producing fields (IHS Energy, 2008), and published geologic reports.

This province was assessed previously as part of the USGS World Assessment 2000 (U.S. Geological Survey World Energy Assessment Team, 2000), which estimated mean undiscovered volumes of 29.7 billion barrels of oil, 88.0 trillion cubic feet of gas, and 4.2 billion barrels of natural gas liquids (Brownfield and Charpentier, 2006).

The West-Central Coastal Province was reassessed in 2009 because of increased exploratory activity, recent discoveries, and interest in its future oil and gas potential. The assessment was geology based and used the total petroleum system concept. The geologic elements of a total petroleum system consist of hydrocarbon source rocks (source rock maturation and hydrocarbon generation and migration), reservoir rocks (quality and distribution), and traps for hydrocarbon accumulation. Using these geologic criteria, the USGS defined four total petroleum systems in the West-Central Coastal Province: (1) the Melania-Gamba Total Petroleum System (TPS), (2) the Azile-Senonian TPS, (3) the Congo Delta Composite TPS, and (4) the Kwanza Composite TPS. Five assessment units are defined within these total petroleum systems: (1) the Gabon Subsalt Assessment Unit (AU) of the Melania-Gamba TPS; (2) the Gabon Suprasalt AU of the Azile-Senonian TPS; (3) the Central Congo Delta and Carbonate Platform AU of the Congo Delta Composite TPS; (4) the Central Congo Turbidites AU of the Congo Delta Composite TPS; and (5) the Kwanza-Namibe AU of the Kwanza Composite TPS (figs. 2, 3). The assessment units include the offshore parts of the province to a water depth of 4,000 m. This report documents the assessment of the West-Central Coastal Province and supplements the World Petroleum Assessment 2012 (U.S. Geological Survey World Conventional Resources Assessment Team, 2012) by providing additional geologic detail for the total petroleum systems and assessment units, as well as a more detailed rationale for the quantitative assessment input.

At the time of this 2009 assessment, more than 650 oil and gas fields had been discovered in the West-Central Coastal Province (IHS Energy, 2008) with more than 190 new field discoveries since the 2000 USGS World Petroleum Assessment (U.S. Geological Survey World Energy Assessment Team, 2000).

Geology of West-Central Coastal Africa Province, West Africa

The Aptian salt basin of equatorial west Africa extends from Cameroon in the north to Namibia in the south. The West-Central Coastal Province includes the Douala, Kribi-Campo, Rio Muni, Gabon, Congo, Kwanza, Benguela, and Namibe Basins (fig. 1), which together form the Aptian salt basin (Edwards and Bignell, 1988a). These seven basins share common structural and stratigraphic characteristics and therefore were grouped together in this study as the West-Central Coastal Province. The northern boundary of the province is the southern edge of the Niger Delta Province, and the southern province boundary is the Walvis Ridge of Early Cretaceous to Holocene age (figs. 1, 4). The eastern province boundary is the eastern edge of the sedimentary basins, and the western boundary was set at 4,000 meters water depth.

The Aptian salt basin formed during the breakup of North America, Africa, and South America paleocontinents at the culmination of a Late Jurassic to Early Cretaceous rift system that opened throughout an extensive Paleozoic basin. The complex history of the Aptian salt basin can be divided into three stages of basin development: pre-rift stage (late Proterozoic to Late Jurassic), syn-rift stage (Late Jurassic to Early Cretaceous), and post-rift stage (Late Cretaceous to Holocene). The Aptian salt basin can be further divided into a number of basins aligned in a north-south direction and delimited by an east-west-trending fault system and other structural arches and highs related to syn-rift tectonics (fig. 1).

The initial phase of the post-Hercynian (Carboniferous to Permian) opening of the North Atlantic and the separation of the North American plate from the Eurasia and Africa plates began during Late Permian to Early Triassic time (Uchupi and others, 1976; Lehner and De Ritter, 1977; Ziegler, 1988; Lambiase, 1989). The final breakup of Africa and South America began in the Early Jurassic in the southernmost part of the South Atlantic and extended northward during Neocomian time (Uchupi, 1989; Binks and Fairhead, 1992; Guiraud and Maurin, 1992). The area now occupied by the Gulf of Guinea opened last, forming a continuous anoxic seaway from the Walvis Ridge to North Africa (fig. 5) in the late Albian to Turonian (Tissot and others, 1980). A continuous oxic Atlantic Ocean existed by the end of the Turonian (fig. 5) between Africa and South America. The presence of Aptian evaporite and clastic rocks in the West-Central Coastal Province provides evidence that rift-related sediment was deposited during this time, associated with the breakup of west Africa and South America.

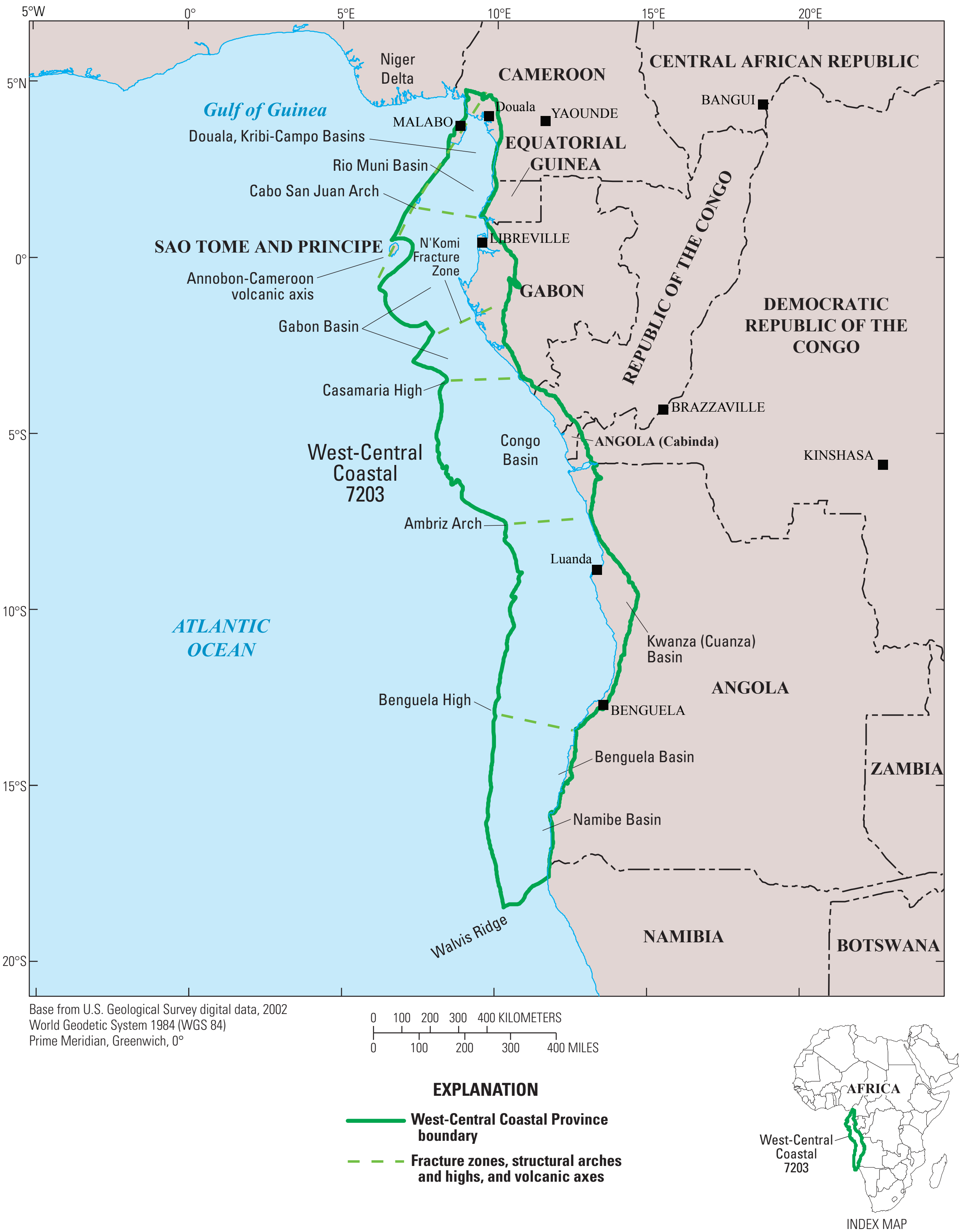


Figure 1. West-Central Coastal Province (7203) and approximate locations of basins within it, from north to south the Douala, Kribi-Campo, Rio Muni, Gabon, Congo, Kwanza (Cuanza), Benguela, and Namibe Basins. The basins' fracture zones, structural arches and highs, and volcanic axes are associated with the Aptian salt basin of equatorial west Africa. The N'Komi fracture zone separates the Gabon Basin into the North Gabon and South Gabon subbasins. The western limit of the province was set at 4,000 meters water depth.

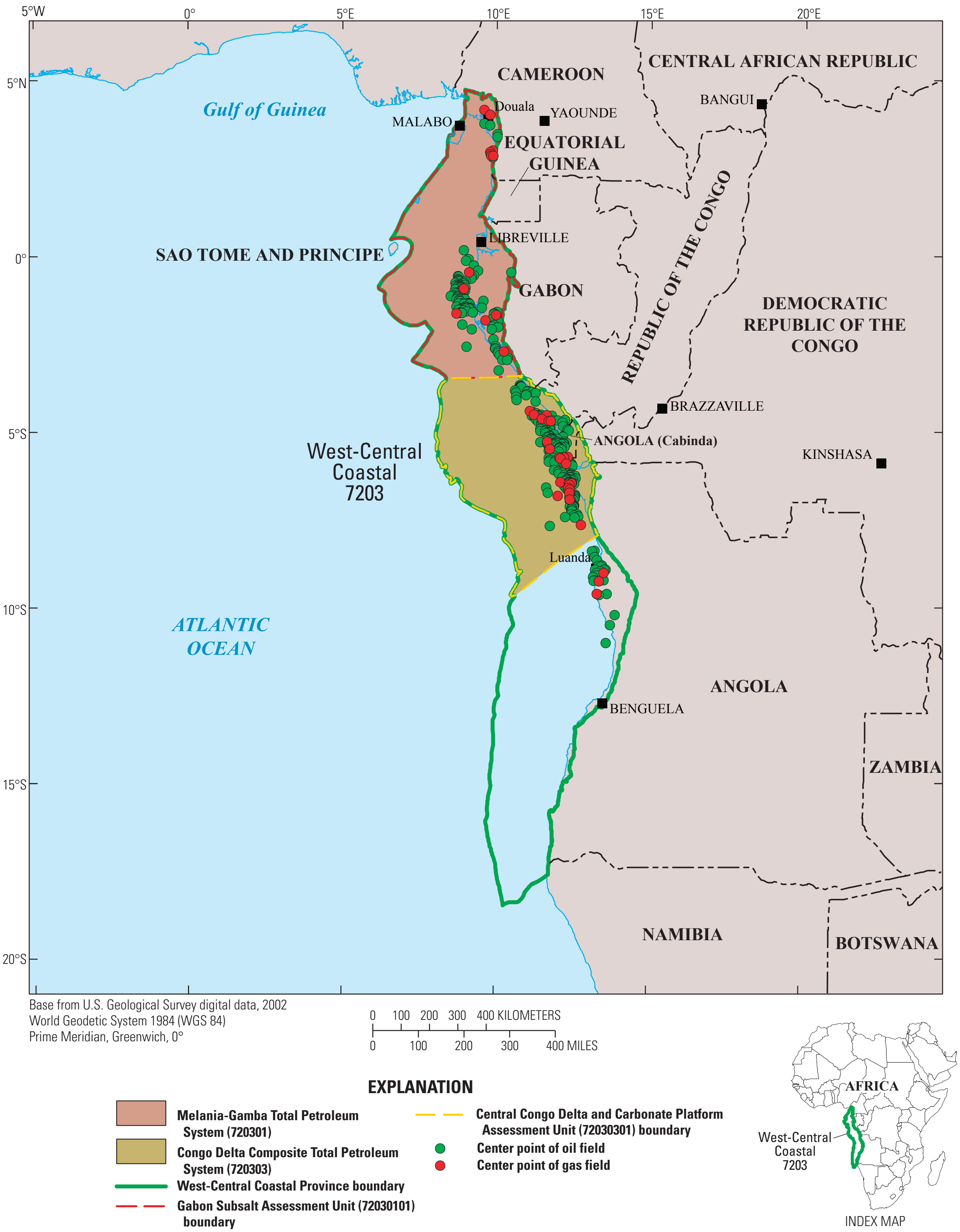


Figure 2. Gabon Subsalt Assessment Unit within the Melania-Gamba Total Petroleum System and the Central Congo Delta and Carbonate Platform Assessment Unit lie within the Congo Delta Composite Total Petroleum System, West-Central Coastal Province, equatorial west Africa. The western limit of the assessment units and the petroleum systems was set at 4,000 meters water depth.

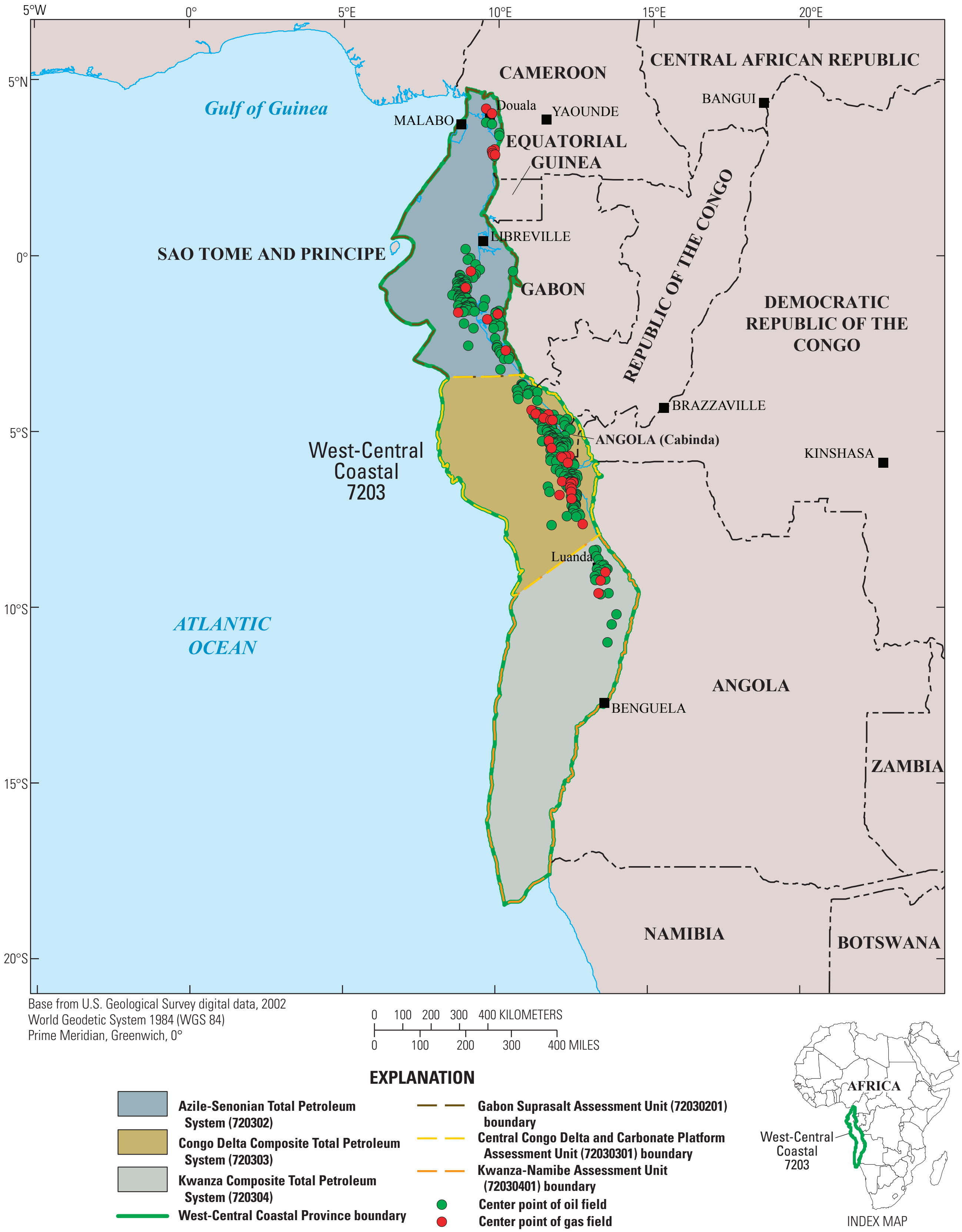


Figure 3. Gabon Suprasalt, Central Congo Turbidites, and Kwanza-Namibe Assessment Units of the Azile-Senonian, the Congo Delta Composite, and the Kwanza Composite Total Petroleum Systems, respectively, in the West-Central Coastal Province, equatorial west Africa. The western limit of the assessment units and the petroleum systems was set at 4,000 meters water depth.

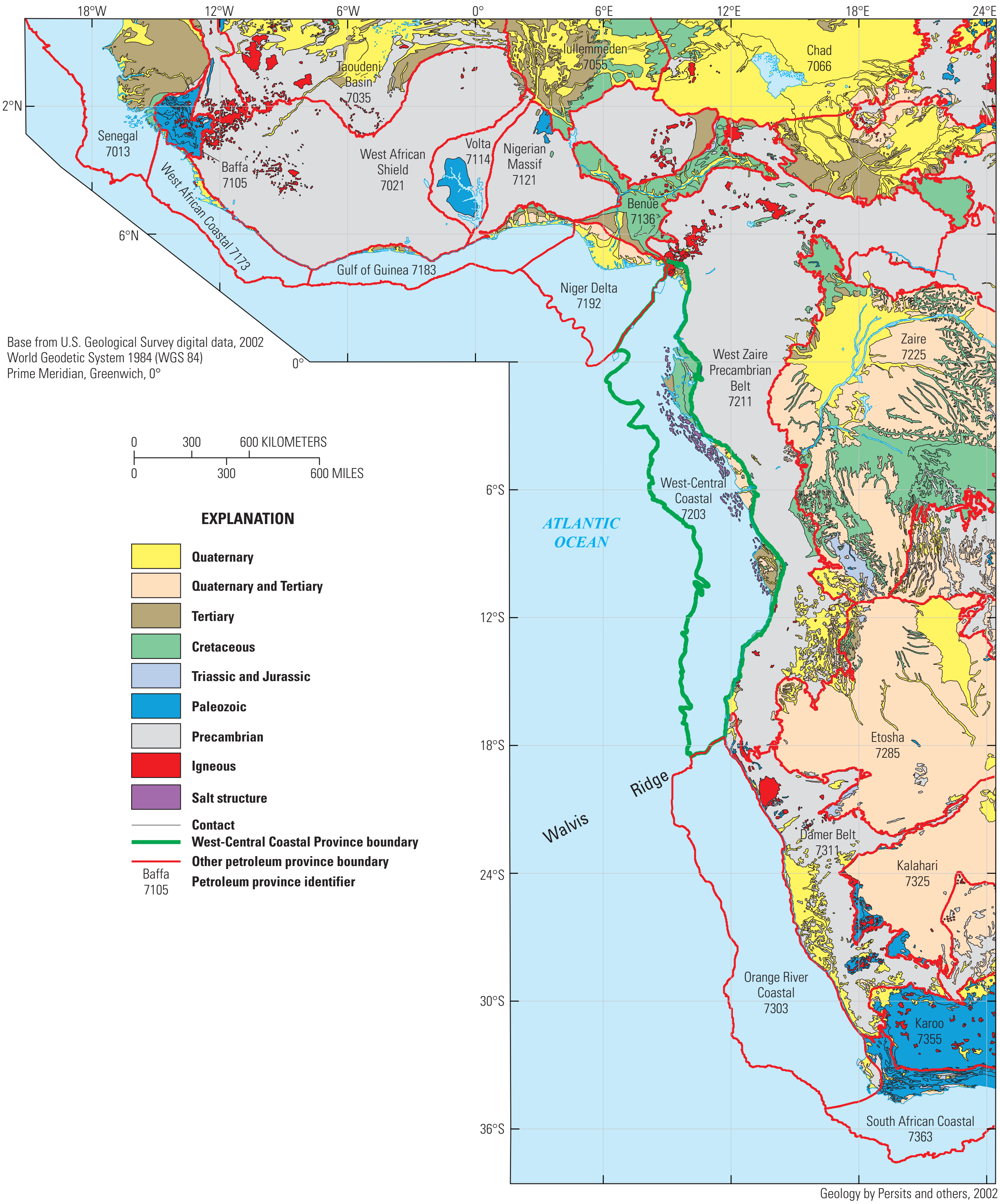


Figure 4. Generalized geology of west Africa (Persits and others, 2002), showing province boundaries and 21 USGS province names and codes as defined in Klett and others (1997).

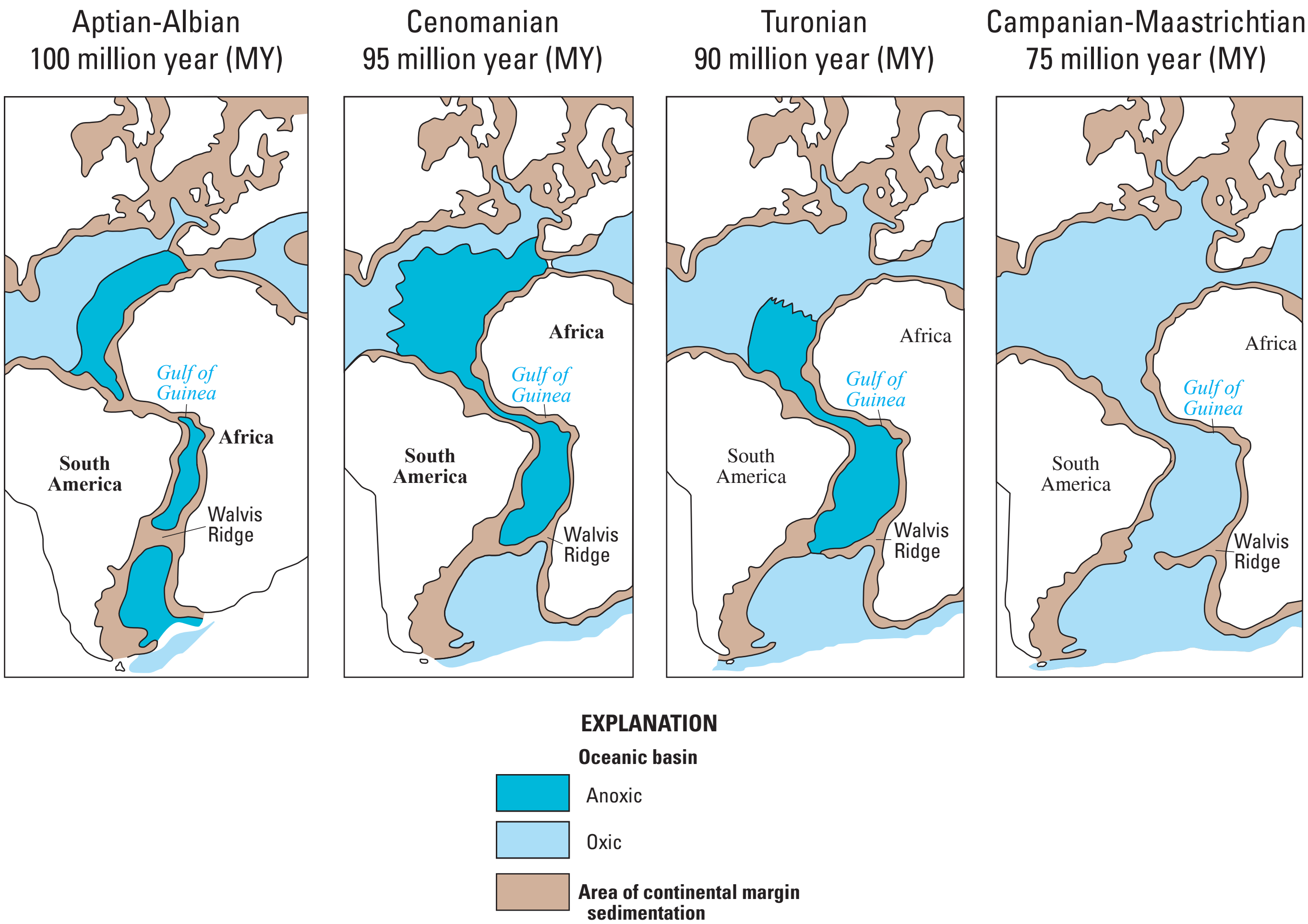


Figure 5. Paleogeography of the Cretaceous breakup of Africa and South America, showing the approximate location of the Gulf of Guinea and the Walvis Ridge. Modified from Tissot and others (1980).

Pre-Rift Stage

The pre-rift section consists of rocks of Precambrian to Jurassic age that crop out in the Interior subbasin of the Gabon Basin (fig. 6) and exist in the subsurface in the eastern part of the Congo Basin. The pre-rift stage lasted through the Late Jurassic and included several phases of intracratonic faulting and downwarping. During these phases as much as 600 m of continental clastic rocks of Carboniferous to Jurassic age (fig. 6) were deposited in the Interior subbasin (Teisserenc and Villemin, 1990). The Interior subbasin is separated from the North Gabon subbasin by the Lambarene horst (fig. 6). These intracratonic basins were depocenters for continental sediments that are now important hydrocarbon-producing reservoirs. Upper Carboniferous rocks contain interbedded tillite and black shale of the Nkhom Formation, whereas the overlying Permian continental rocks (Agoula Formation), from bottom to top, contain conglomerate, bituminous shale, phosphatic rocks, lacustrine dolomite, anhydrite and anhydrite-bearing limestone, shale, and sandstone (Teisserenc and Villemin, 1990). The Triassic to Jurassic fluvial rocks (Movone Formation) consist of sandstone and shale.

Pre-rift rocks have not been penetrated by drilling in the offshore parts of the Benguela or Kwanza Basins (fig. 1), whereas in the Douala, Kribi-Campo, and Rio Muni Basins, the pre-rift section has been penetrated and consists of Precambrian arkosic sandstone and conglomerate (Nguene and others, 1992). The onshore part of the Kwanza Basin (fig. 1) contains possible pre-rift rocks of Jurassic age consisting of the continental Basal Red Beds and Red Basal Series (Burwood, 1999).

Pre-rift rocks in the Congo Basin are limited to the Jurassic(?) Lucula Sandstone, which directly overlies Precambrian basement (Brice and others, 1982; Schoellkopf and Patterson, 2000). This unit, which consists of well-sorted, quartzose, micaceous sandstone, was most likely deposited as alluvial or eolian sand. The total thickness of pre-rift rocks in the Congo Basin is unknown, but more than 1,000 m of clastic rocks have been penetrated in some wells (Brice and others, 1982). The upper boundary of the Lucula Sandstone is commonly defined by the lowest lacustrine shale, marl, or siltstone of the Bucomazi Formation (McHargue, 1990).

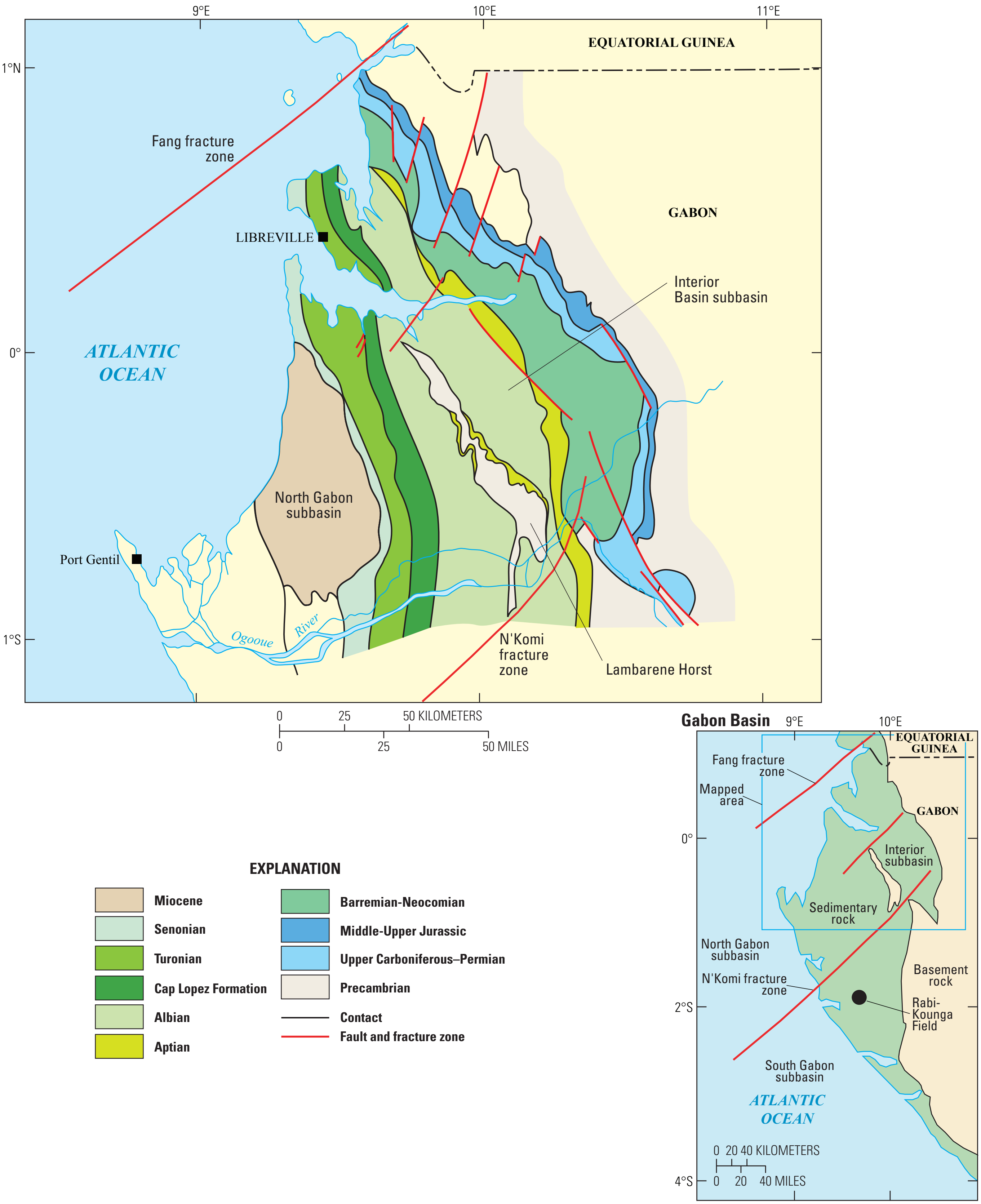


Figure 6. Schematic geology of the Interior and North Gabon subbasins in the Aptian salt basin, equatorial west Africa. The Lambarene horst separates the Interior and North Gabon subbasins. Modified from Teisserenc and Villemin (1990).

Syn-Rift Stage

Initial rifting in the Aptian salt basin formed a series of asymmetrical horst-and-graben basins trending parallel to the present-day coastline. Thick successions of fluvial and lacustrine rocks were deposited in the rift basins. Organic-rich, lacustrine rocks of the syn-rift stage are some of the most important hydrocarbon source rocks in these basins of equatorial west Africa.

Syn-rift rocks are known to exist in the Rio Muni, Douala, and Kribi-Campo Basins of Equatorial Guinea and Cameroon (fig. 1). The syn-rift rocks in the Rio Muni Basin (figs. 7, 8), as much as 4,000 m thick (Ross, 1993; Turner, 1995), consist of Neocomian- to Barremian-age fluvial and lacustrine sandstones and shales deposited in a broad, low-relief basin. Later basinwide normal faulting increased syntectonic lacustrine sedimentation. The oldest syn-rift rocks penetrated in this basin unconformably overlie Precambrian basement in the Douala and Kribi-Campo Basins (fig. 9) and are Barremian(?) to Aptian in age (Nguene and others, 1992). They include continental conglomerate and sandstone with lacustrine shale, limestone, and marlstone. Evaluation of higher resolution seismic data has shown several undrilled syn-rift tilted blocks in the offshore Rio Muni Basin (Ross, 1993).

Syn-rift rocks in Interior Gabon's Interior subbasin (fig. 10) are generally similar to those of the South Gabon subbasin (figs. 6, 11), but some differences exist because the Interior subbasin was much less active tectonically than the South Gabon subbasin. Syn-rift rocks in these subbasins can be divided into two groups separated by a major unconformity. The lower group includes the N'Dombo and Welle Formations (fig. 10) of latest Jurassic to Neocomian age. The 150- to 400-m-thick N'Dombo consists of conglomeratic sandstone, sandstone, and minor shale (Brink, 1974) and is equivalent to the Basal Sandstone in the South Gabon subbasin (fig. 11), whereas the 800- to 900-m-thick Neocomian Welle Formation consists of organic-rich lacustrine shale with pyrobituminous lamina and correlates with the Kissenda Shale in the South Gabon subbasin (Teisserenc and Villemin, 1990). Unconformably overlying the Welle Formation is a second group of rift rocks that include the Fourou Plage Sandstone, the Lobe Shale, and the Bifoun Shale (fig. 10). The organic-rich Lobe and Bifoun shales are lacustrine in origin. Above the organic-rich Bifoun Shale is the 600-m-thick Moundounga Shale, which correlates to the Melania Formation lacustrine shales in the South Gabon subbasin (fig. 11). The Moundounga Shale consists of interbedded sandy shale and bituminous shale of lacustrine origin. The youngest rift rocks deposited in the Interior subbasin are represented by two late Barremian to early Aptian units: the 300- to 400-m-thick continental Benguie Formation (fig. 10), and the N'Toum Formation, which consists of at least 400 m of fluvial sandstone and shale. The N'Toum Formation may include rocks that are equivalent to the Coniquet Sandstone of the North Gabon subbasin (fig. 10).

The syn-rift rocks of the North Gabon subbasin (figs. 6, 10) are not as well known as those in the Interior and South Gabon subbasins (fig. 11) because no wells have been drilled into rocks older than Barremian (fig. 10). The oldest unit penetrated is the N'Toum Formation of late Barremian to Aptian age, which was deposited in a lacustrine environment as fan-delta turbidites. The maximum thickness drilled is 1,500 m, but the total thickness as shown by seismic data is much greater (Teisserenc and Villemin, 1990). The Neocomian Basal Sandstone and other syn-rift units found in the Interior and South Gabon subbasins are most likely present in the North Gabon subbasin. The syn-rift rocks were continuously deposited in the North Gabon subbasin through the early Aptian, whereas deposition was interrupted in the South Gabon subbasin during that time. Overlying the N'Toum Formation in the North Gabon subbasin is the lower Aptian Coniquet Formation of continental and lacustrine origin.

The rocks of the syn-rift stage present in the South Gabon subbasin (fig. 11) are generally fluvial and lacustrine in origin and range in age from Neocomian to early Aptian. Three main structural phases are known (fig. 11): initial basement extensional block faulting and basin formation in the Neocomian, graben and block faulting in the late Neocomian to early Barremian, and draping and growth faulting during the late Barremian and early Aptian (Teisserenc and Villemin, 1990). The Basal Sandstone overlies the basement rocks (figs. 11, 12) and consists of medium- to fine-grained sandstone and conglomerate, with a maximum thickness of 400 m. The Basal Sandstone is considered fluvial in origin and was deposited in a braided-stream environment. Overlying the Basal Sandstone is the Kissenda Shale, which was deposited in a deep lacustrine environment. The Kissenda Shale consists of lacustrine shale, thin carbonate, and minor amounts of siltstone, sandstone, and conglomerate. After the deposition of the Kissenda Shale, the South Gabon subbasin area was subjected to strong tectonic activity that created a second phase of grabens and block faults. The Melania Formation is conformable with the Kissenda Shale (figs. 11, 12), as much as 1,200 m thick, contains many facies that reflect these tectonic events. Abrupt thickness changes are commonly found within the different fault blocks, and the facies can differ from one tectonic block to the next. The lower part of the Melania Formation contains shale and locally well developed fine-grained, argillaceous sandstone units such as the Lucina Member; these units contain abundant plant material (fig. 11). The Lucina Member was deposited as turbidite channels and fans, whereas the middle part of the Melania Formation includes thick fans such as the M'Bya Member. Tectonic activity ceased by mid-Barremian time, and the upper part

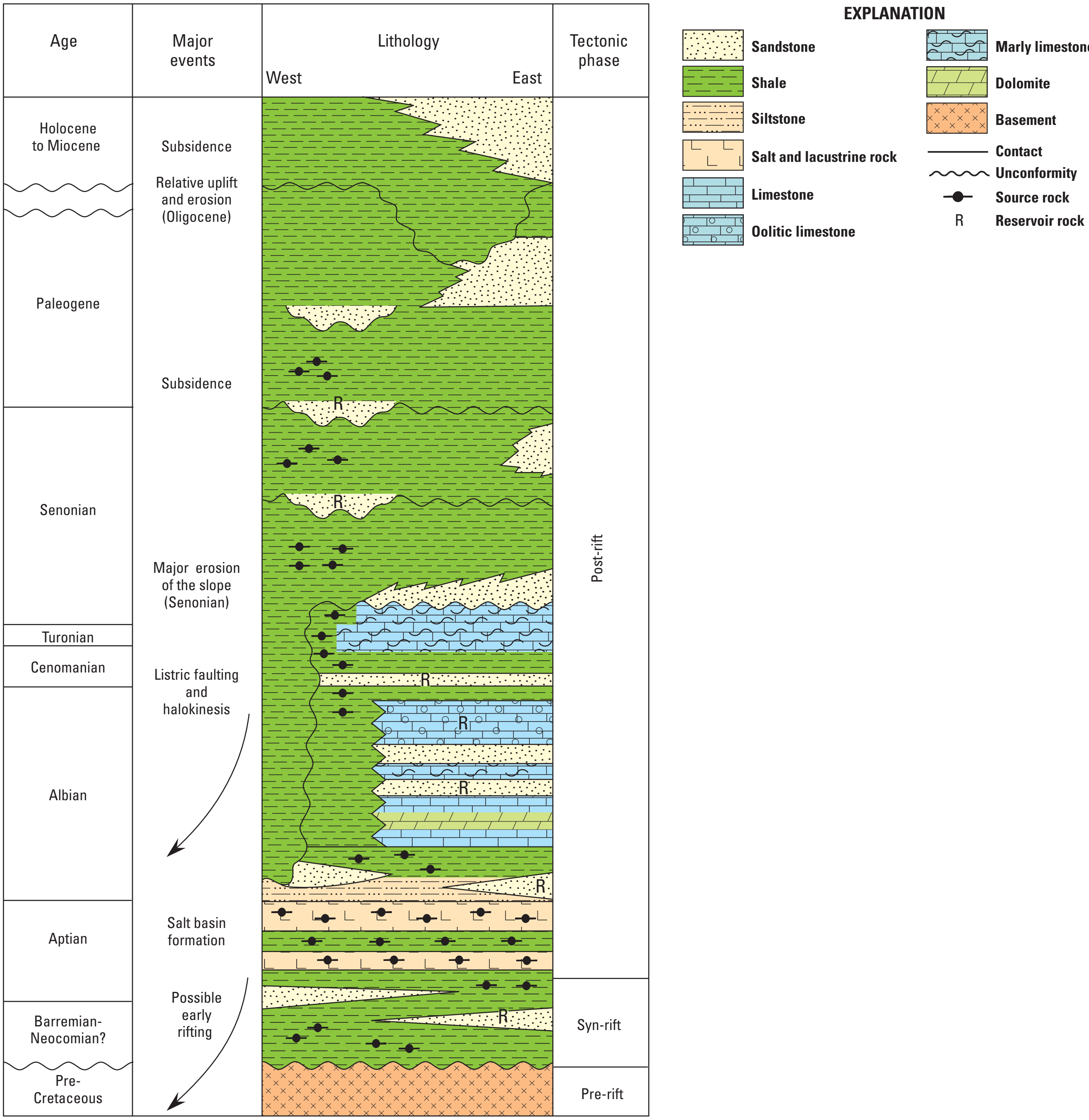


Figure 7. Generalized stratigraphy of the Rio Muni Basin, Equatorial Guinea, west Africa, showing ages of units, major geologic events, lithology, probable source rocks, and tectonic stages. Modified from Ross (1993), Turner (1995), and the Equatorial Guinea Ministry of Mines and Energy (2003).

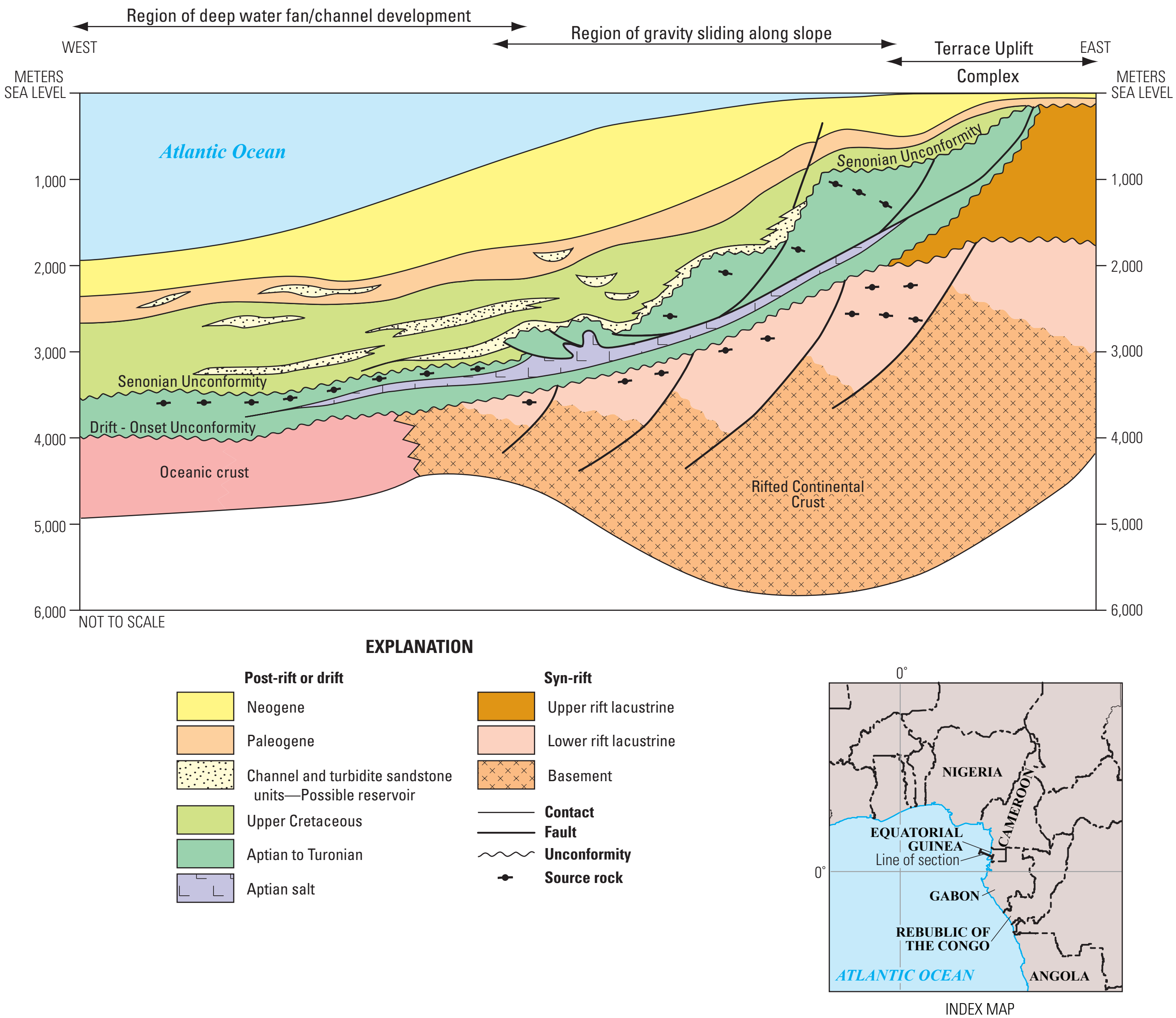


Figure 8. Generalized cross section of the Rio Muni Basin, Equatorial Guinea, west Africa, showing position of probable source rocks. (For formation names and lithology of syn-rift and post-rift units, see fig. 10). Modified from Equatorial Guinea Ministry of Mines and Energy (2003). Horizontal scale generalized.

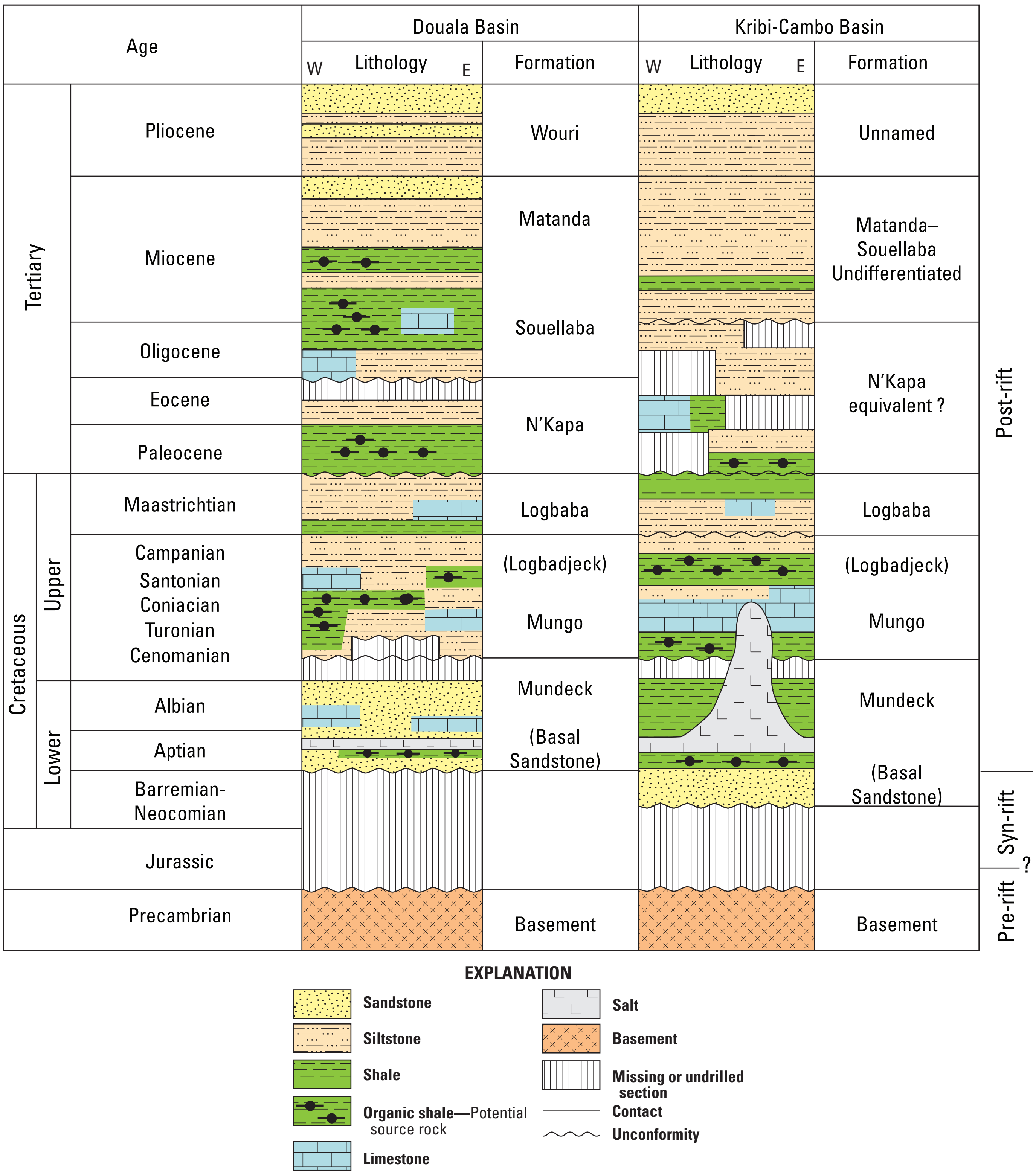


Figure 9. Generalized stratigraphy of the Douala and Kribi-Campo Basins, Aptian salt basin, Cameroon, equatorial west Africa, showing ages, lithology, probable source rocks, formation names, and tectonic stages. Modified from Nguene and others (1992), Tamfu and others (1995), and Oba (2001).

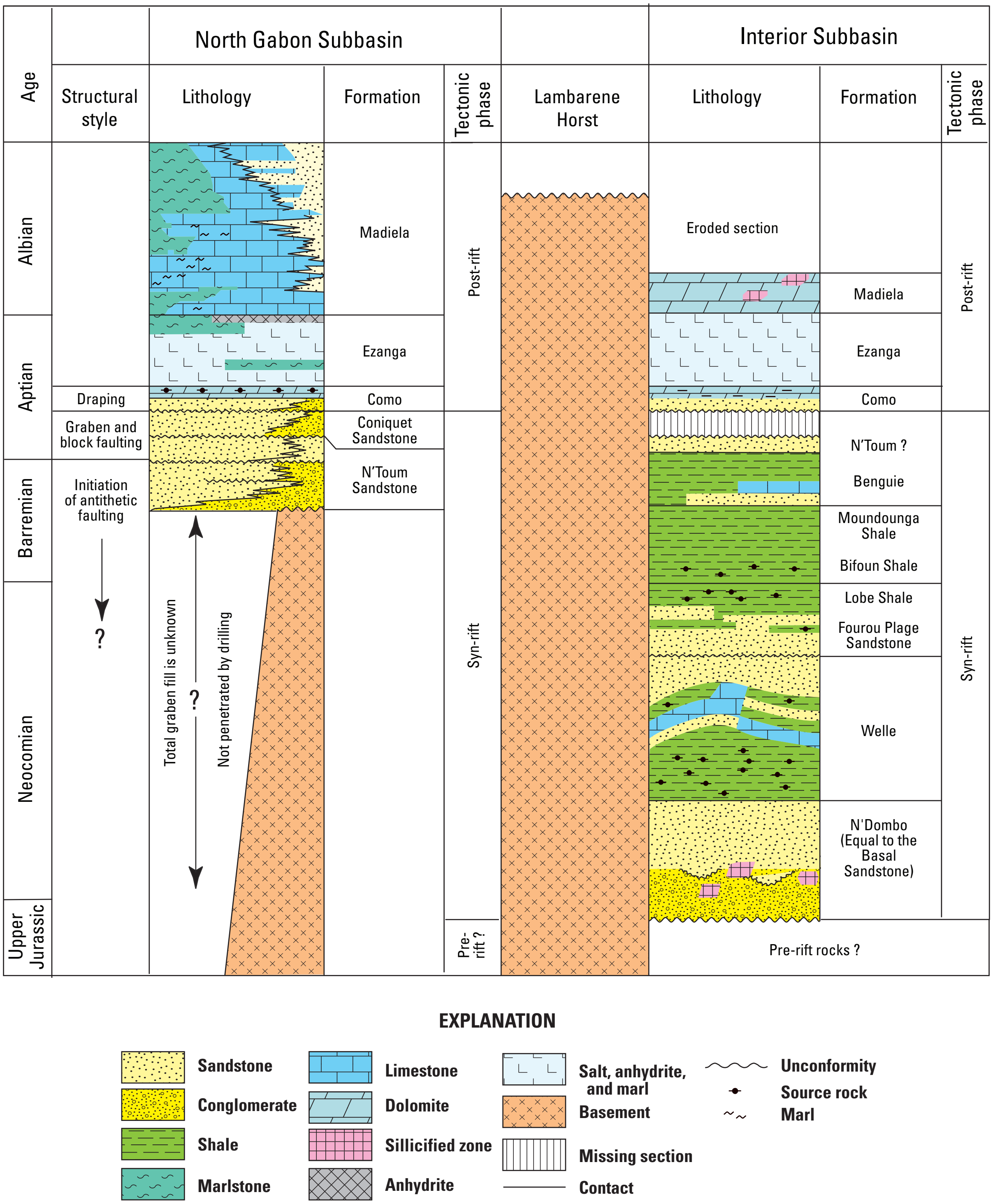


Figure 10. Generalized stratigraphy of the Interior subbasin and onshore part of the North Gabon subbasin, equatorial west Africa, showing ages, structural style, lithology, probable source rocks, formation names, and tectonic stages. Seismic data indicates that the N'Toum Sandstone in the North Gabon subbasin is thicker than in the Interior subbasin and is underlain by other sedimentary units. Modified from Brink (1974) and Teisserenc and Villemin (1990).

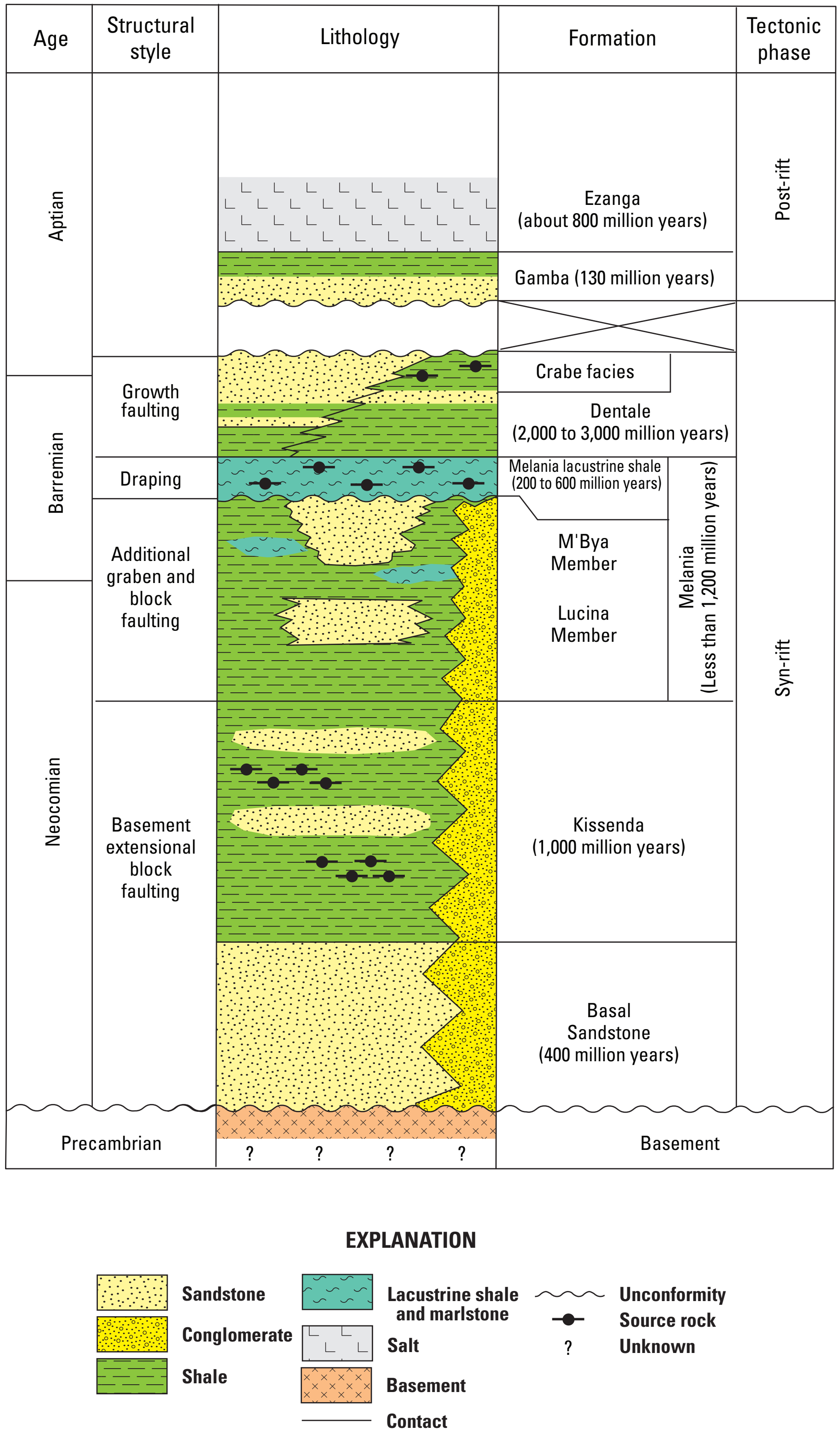


Figure 11. Generalized stratigraphic column of the South Gabon subbasin, Gabon, equatorial west Africa, showing ages, structural styles, lithology and potential source rocks, formation names, and tectonic stages. The Melania Formation lacustrine shale contains as much as 20 weight percent organic matter consisting predominantly of Type I kerogen. Modified from Teisserenc and Villemin (1990).

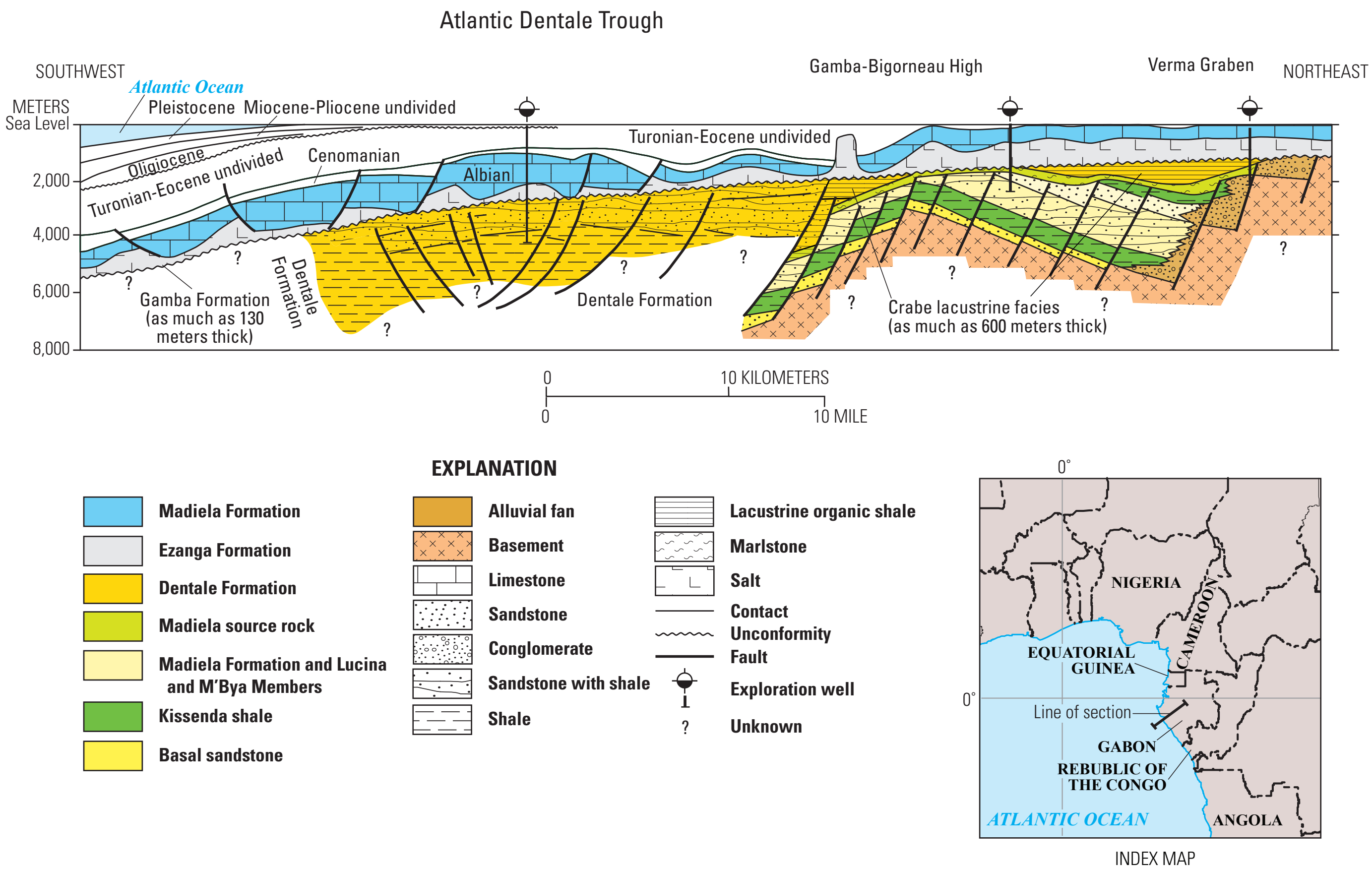


Figure 12. Schematic cross section showing relationships between the Atlantic Dentale Trough, Gamba-Bigorneau High, and the protoplatform, South Gabon subbasin, Gabon, equatorial west Africa. Modified from Teisserenc and Villemin (1990).

of the Melania Formation (the Melania Formation lacustrine shale, fig. 11) is unconformably draped over the underlying units (fig. 11). The Melania Formation lacustrine shale consists of organic-rich shale, siltstone, and calcareous shale and ranges in thickness from 200 to 600 m. The South Gabon subbasin depocenter shifted westward and expanded during the late Barremian because of extensional thinning of the crust. This episode allowed the deposition of the 2,000 to 3,000 m of interbedded lacustrine deltaic sandstone and shale rocks of the Dentale Formation and its organic-rich Crabe facies (figs. 11, 12). The Crabe facies was deposited on a lacustrine deltaic platform (Teisserenc and Villemin, 1990).

Syn-rift offshore rocks of the northern part of the Congo Basin (Republic of the Congo) range in age from Neocomian to Barremian and consist of lacustrine and fluvial rocks (Baudouy and Legorjus, 1991; Harris, 2000). The Neocomian Vandji Sandstone (figs. 13, 14), which overlies the Precambrian basement, consists of coarse sandstone equivalent to the Basal Sandstone of the South Gabon subbasin (fig. 11). The Sialivakou Shale and Djeno Sandstone (fig. 13) are Neocomian to Barremian lacustrine shale and turbidite sandstones equivalent to the lower part of the Bucomazi. The Barremian organic-rich lacustrine shale and marl and dolomitic black shale of the Pointe Noire Marl, as much as 500 m thick, are equivalent to the Melania Formation lacustrine shale in the South Gabon subbasin and the middle part of the Bucomazi Formation of the central and southern (also known as the lower) Congo Basin (figs. 13, 15). The Barremian Pointe Indienne Shale and Toca Formation consist of lacustrine siliciclastic shale and carbonate rocks equivalent to the Melania and Dentale Formations in the South Gabon subbasin (fig. 11).

When active rifting began in the Early Cretaceous, pre-rift rocks in the central and southern parts of the Congo Basin (fig. 1) underwent extensive block faulting and erosion and formed a graben-lacustrine depositional setting. The syn-rift rocks in the Congo Basin (fig. 1) range from Neocomian to early Aptian in age (fig. 15) and consist of lacustrine, alluvial, and fluvial rocks (Brice and others, 1982; McHargue, 1990; Schoellkopf and Patterson, 2000; Da Costa and others, 2001). These include the Lucula Sandstone and Bucomazi Formation in the offshore part of the basin.

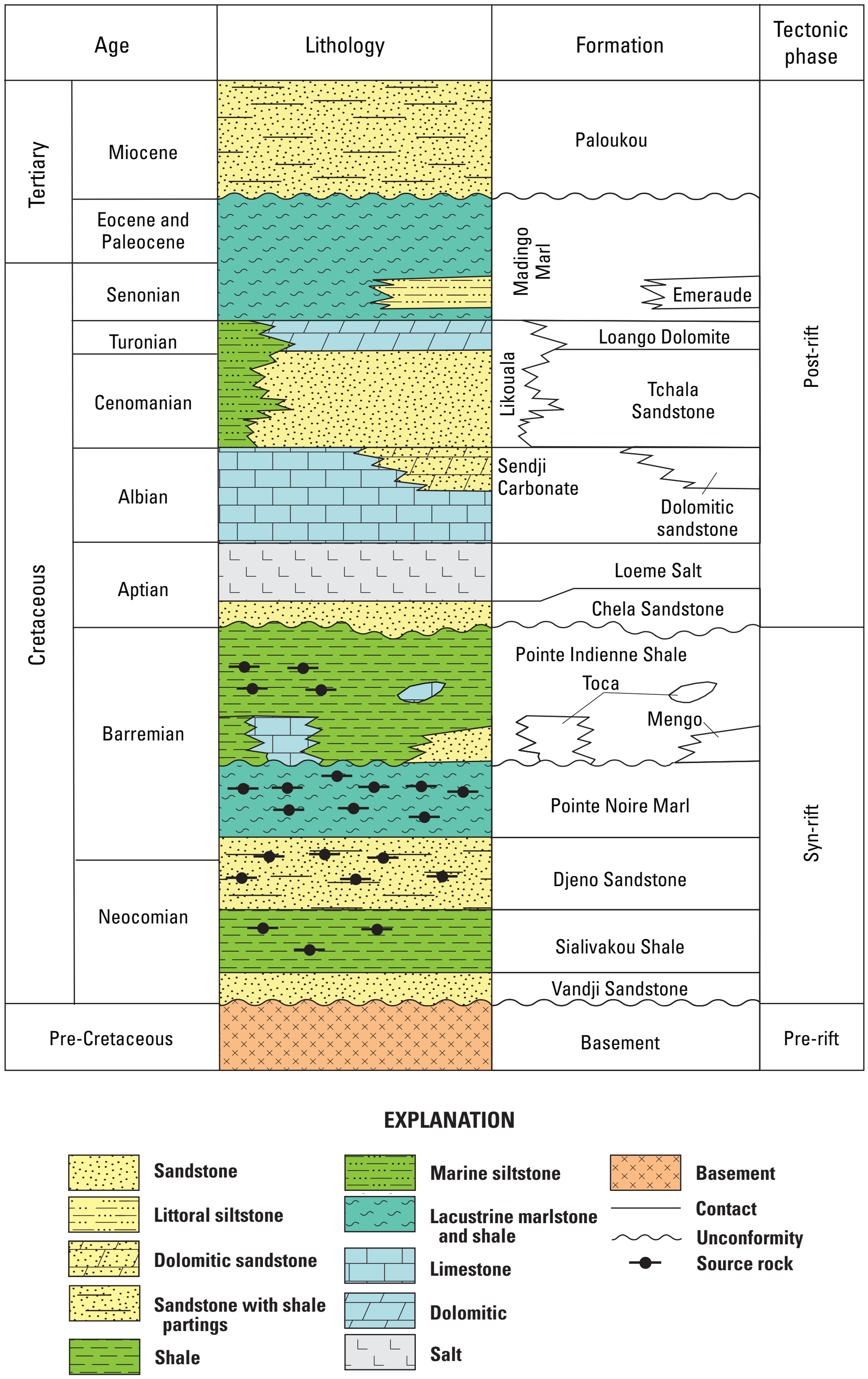


Figure 13. Generalized stratigraphy of the Congo Basin, Democratic Republic of the Congo, equatorial west Africa showing ages, lithology and potential source rocks, formation names, and tectonic stages. Pointe Noire Marl consists of lacustrine marlstone and shale containing total organic carbon of 1 to 5 weight percent, although some units locally reach 20 to 30 weight percent. Modified from Baudouy and Legorjus (1991).

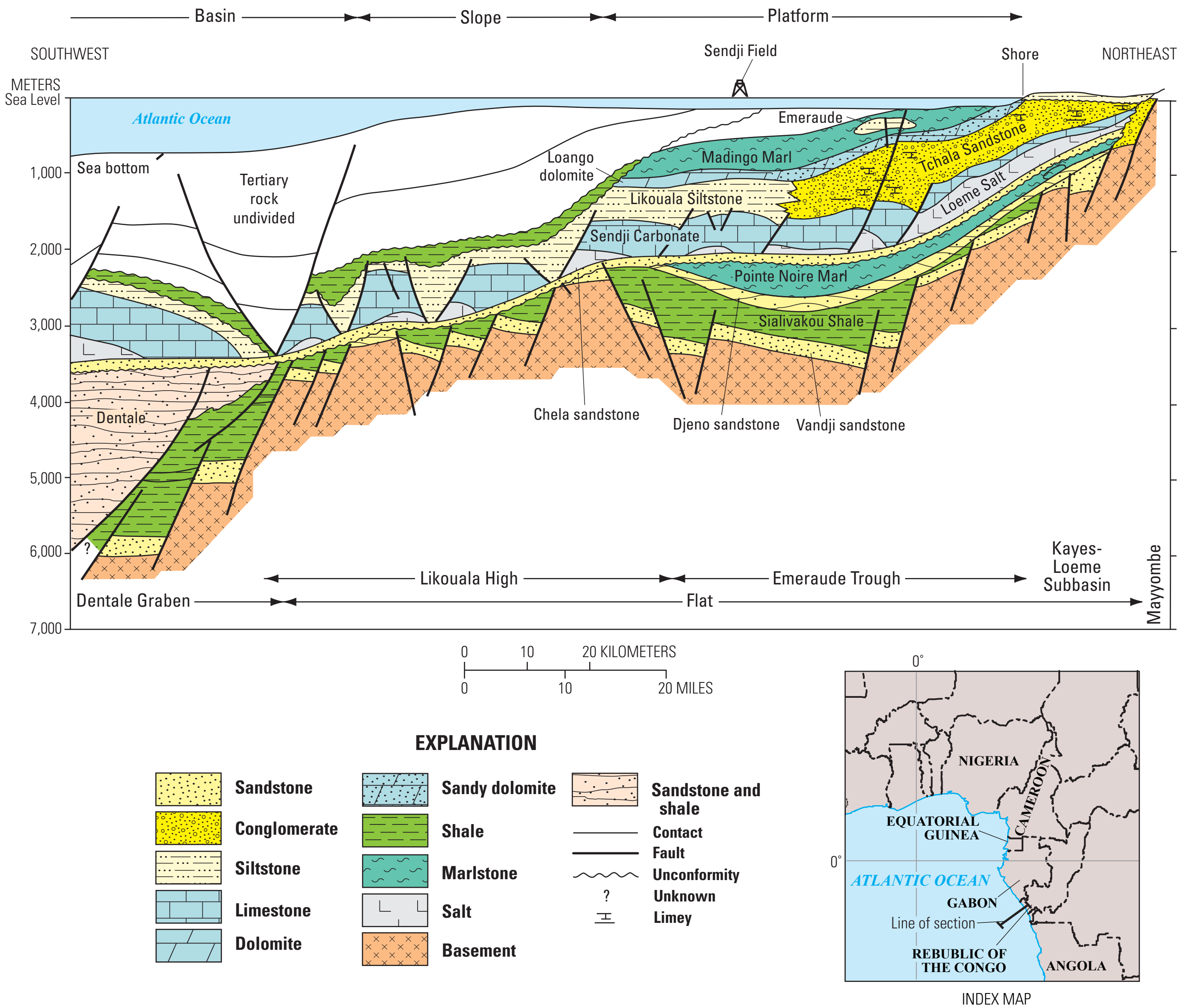


Figure 14. Schematic cross section of the northern part of the Congo Basin showing presalt and postsalt rock units and the approximate location of the Sendji Field, Republic of the Congo, equatorial west Africa. The unconformity beneath the Chela marks the onset of the post-rift tectonic stage. This tectonism removed the Pointe Noire Marl, which is equivalent to the Pointe Indienne Shale and Toca Formation (fig. 13) of the Democratic Republic of the Congo and to the upper unit of the Bucomazi Formation of Angola, including the disputed Cabinda Province (fig. 15). Structural features are approximately located in figure 15 index map. Modified from Baudouy and Legorjus (1991). Location of the cross section in index map.

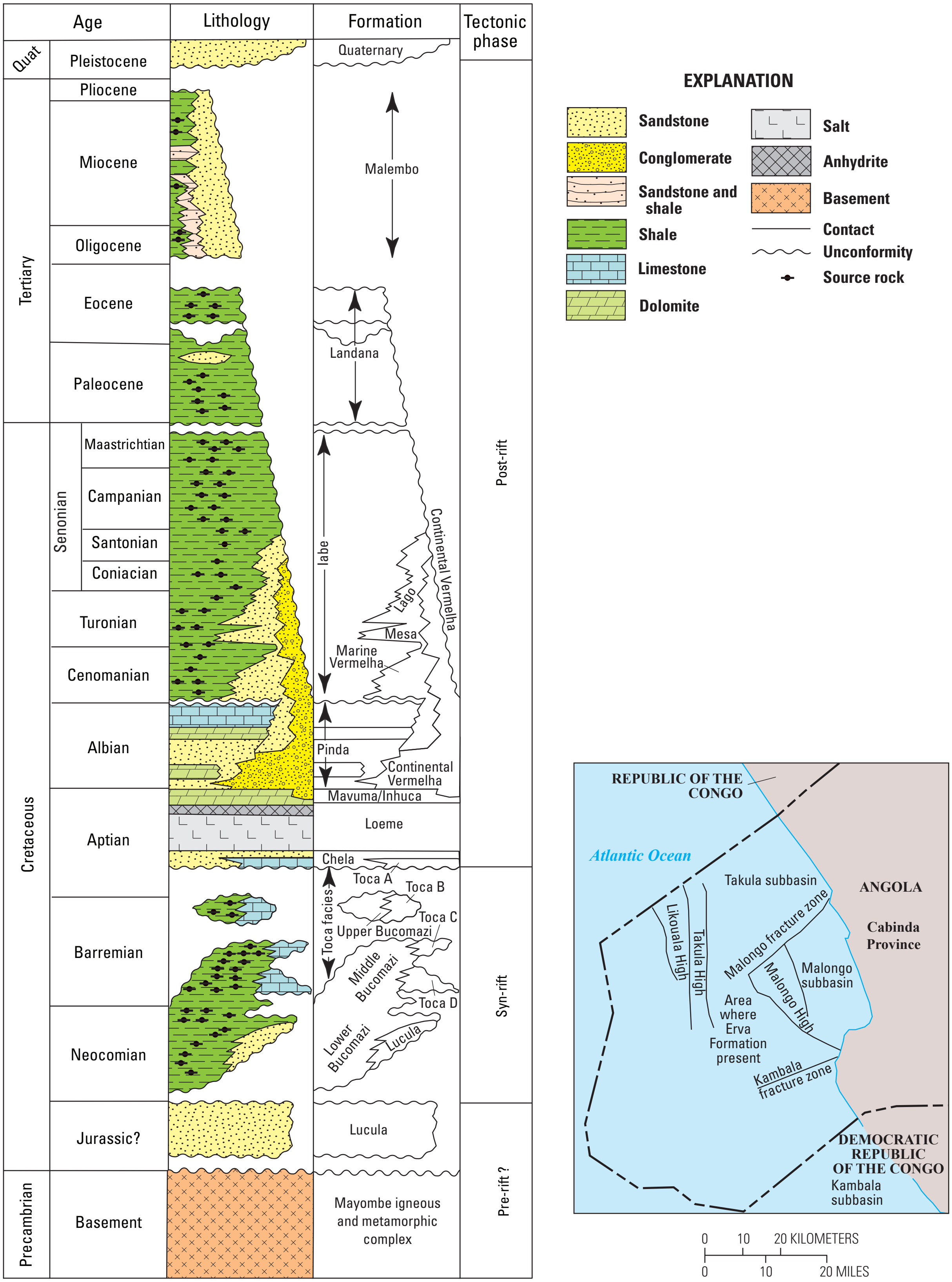


Figure 15. Generalized stratigraphic column of the central and southern (also known as lower) parts of the Congo Basin, showing ages, lithology, potential source rocks, formation names, and tectonic stages of the Republic of the Congo and Angola including the disputed Cabinda Province (fig. 1), equatorial west Africa. Modified from McHargue (1990), Schoellkoph and Patterson (2000), and Da Costa and others (2001). Quat., Quaternary.

The syn-rift Neocomian Lucula Sandstone (fig 15) consists of well-sorted, quartzose, micaceous sandstone and unconformably overlies the pre-rift Jurassic (?) part of the Lucula Sandstone (McHargue, 1990; Schoellkopf and Patterson, 2000). The Lucula Sandstone is thickest along the eastern margin of the Congo Basin (McHargue, 1990) in the Democratic Republic of the Congo and interfingers with the lower part of the Bucomazi (fig. 15), where it is thought to gradually change to shale westward. McHargue (1990) defines two depositional environments for the Lucula: the so-called S-Lucula (straight Lucula) which was derived from nearby Neocomian basement highs and deposited as alluvial fans, and the L-Lucula (lobate Lucula) that intertongues with the green-shale facies of the lower part of the Bucomazi, which is a shoreline facies of the Bucomazi Formation derived from both nearby highlands and the S-Lucula.

The Neocomian to Barremian Bucomazi Formation unconformably overlies or interfingers with the Lucula Sandstone, and is separated by an unconformity from the overlying Chela Sandstone (fig. 15). Toca Formation carbonate rocks overlie the Bucomazi conformably in some places and unconformably in others. The thickness of the Bucomazi Formation ranges to more than 2,100 m but varies considerably across the offshore part of Cabinda and the Congo Basin region (McHargue, 1990). The Bucomazi Formation (fig. 15) is divided into three informal units: the lower, middle, and upper Bucomazi (McHargue, 1990; Schoellkopf and Patterson, 2000). The lower part of the Bucomazi, which exceeds 1,000 m thickness, consists of laminated shale, mudstone, calcareous shale, marlstone, and sandstone. The middle part of the Bucomazi, which may be as thick as the lower Bucomazi, consists of organic-rich shale, carbonate mudstone, and marlstone. The upper part of the Bucomazi, which is as least 400 m thick, consists of green to brown mudstone and gray shale (Schoellkopf and Patterson, 2000). The depositional thickness of the upper Bucomazi is unknown because of erosion prior to the deposition of the post-rift Toca A, part of the Toca Formation and Chela Sandstone (fig. 15). The Bucomazi Formation was deposited in an anoxic lacustrine environment that became increasingly oxic with the deposition of the upper part of the Bucomazi. The middle and upper parts of the Bucomazi Formation are equivalent to the Point Noire Marl and Pointe Indienne Shale of the northern part of the Congo Basin (fig. 13).

In the western offshore part of the Congo Basin, at least 1,200 m of the Erva Formation (McHargue, 1990), a unit equivalent to the Lucula Sandstone and Bucomazi Formations, consists of argillaceous sandstone and interbedded organic-rich shale and well-sorted sandstone. West of the Malongo High, the Erva Formation was deposited as a series of fan-delta deposits and interbedded organic-rich lacustrine shale (index map, fig. 15). The fact that the unit has not been found in the central and eastern parts of the Congo Basin suggests a western source from an intrarift highland or possibly from the western rift margin, now in Brazil.

The Toca Formation represents the uppermost syn-rift rocks in the Congo Basin. The Toca, which is as much as 300 m thick, contains limestone, dolomite, minor shale, and sandy carbonate rocks. The Toca Formation was informally divided into four units (McHargue, 1990); the lower three units (Toca B, C, and D) interfinger with the Bucomazi Formation (fig. 15) and the uppermost unit (Toca A) interfingers with the post-rift Chela Sandstone.

The Kwanza Basin (figs. 1, 16, 17, 18) is separated into inner (onshore) and outer (offshore) basins. These basins in turn are dissected by three major basement structural highs where Aptian salt is thin or absent (Hudec and Jackson, 2002). The structural highs (horsts?) are the Flamingo, Ametista, and Benguela Platforms (fig. 18) and most likely are equivalent to the Cabo Ledo Uplift, Longa Ridge, and Morro Liso Ridge (not shown on fig. 18) of Brognon and Verrier (1966). The inner Kwanza Basin includes the present-day onshore region and some nearshore areas and is an interior salt basin confined by basement highs to the west and Precambrian highlands to the east, whereas the outer Kwanza Basin includes the western offshore part of the basin and developed as a continental-margin basin. The independent development of the inner and outer Kwanza Basins resulted in the deposition of stratigraphically different but time-equivalent units.

The syn-rift rocks of the inner Kwanza Basin of southern Angola are represented by the Infra Cuvo, Maculungo, and Lower (Red) Cuvo Formations (Brognon and Verrier, 1966; Burwood, 1999) and range from latest Jurassic (?) to Barremian in age (fig. 16). The Neocomian Infra Cuvo and Maculungo Formations are lacustrine in origin and consist of tuffaceous rocks, shale, organic-rich shale, and evaporite rocks (Burwood, 1999; Coward and others, 1999). The Barremian Lower Cuvo Formation consists of conglomerate, red sandstone and claystone, and interbedded volcanic ash of continental origin (Brognon and Verrier, 1966).

Syn-rift rocks of the outer Kwanza Basin (fig. 17) are similar to the syn-rift rocks of the southern Congo Basin (fig. 18). The oldest syn-rift rocks in the southern part of the outer Kwanza Basin are Neocomian to early Barremian in age, similar to the Bucomazi Formation of the central and southern Congo Basin (fig. 17). These rocks consist of sandstone, siltstone, shale, organic-rich shale, and minor limestone (Pasley and others, 1998a; Uncini and others, 1998). Carbonate rocks similar to the Barremian Toca Formation (fig. 17) have also been penetrated by offshore drilling and are interpreted to interfinger with the Bucomazi Formation (Da Costa and others, 2001). The outer Kwanza Basin seems to have developed in much the same way as the central and northern parts of the Aptian salt basin and the southern Brazil basins (fig. 17) where the syn-rift rocks are similar in age and lithology (Pasley and others, 1998b).

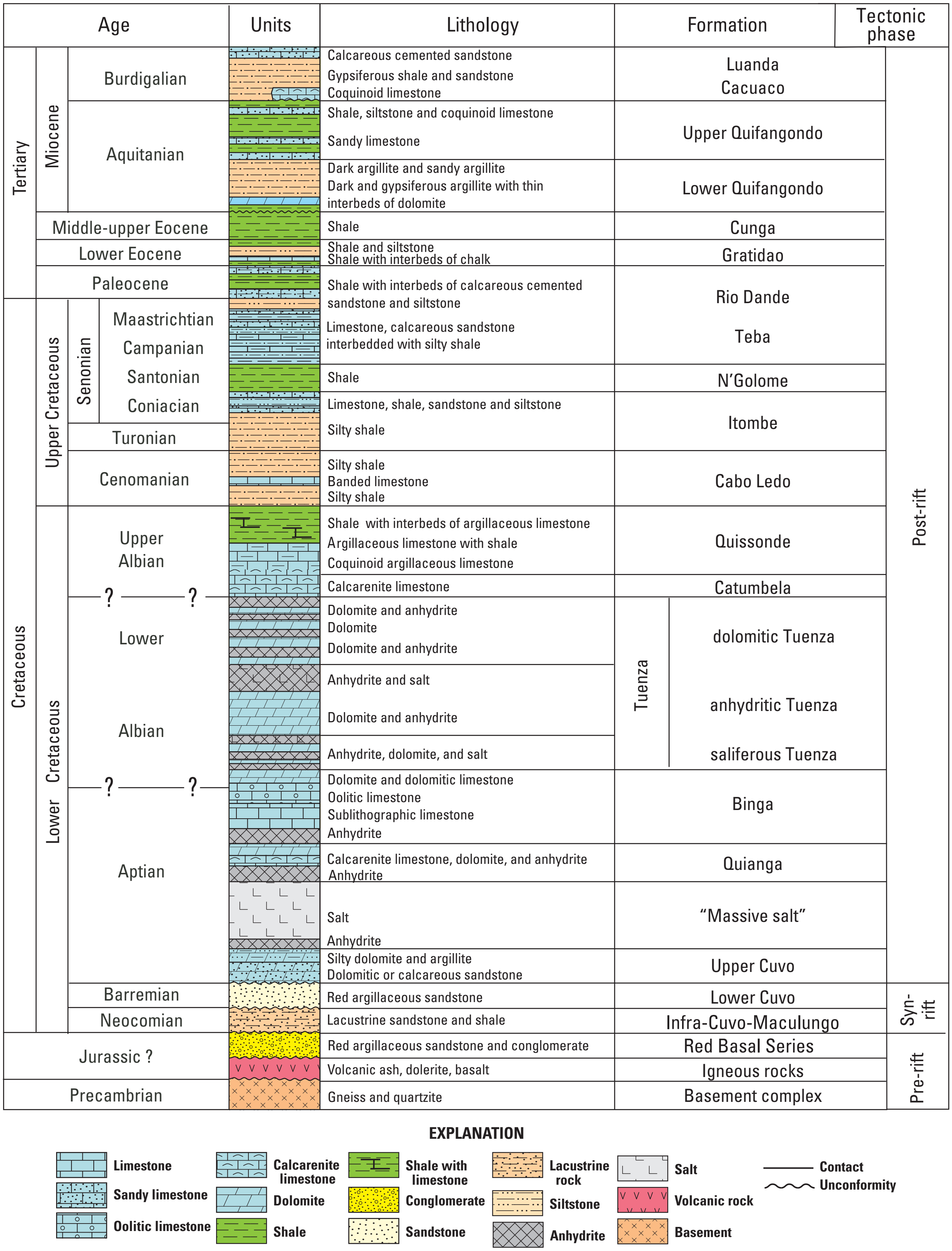


Figure 16. Generalized stratigraphy of the onshore Kwanza Basin (also known as the interior salt basin), Angola, equatorial-west Africa showing ages, lithology and formation names, and tectonic stages. Modified from Brognon and Verrier (1966) and Burwood (1999).

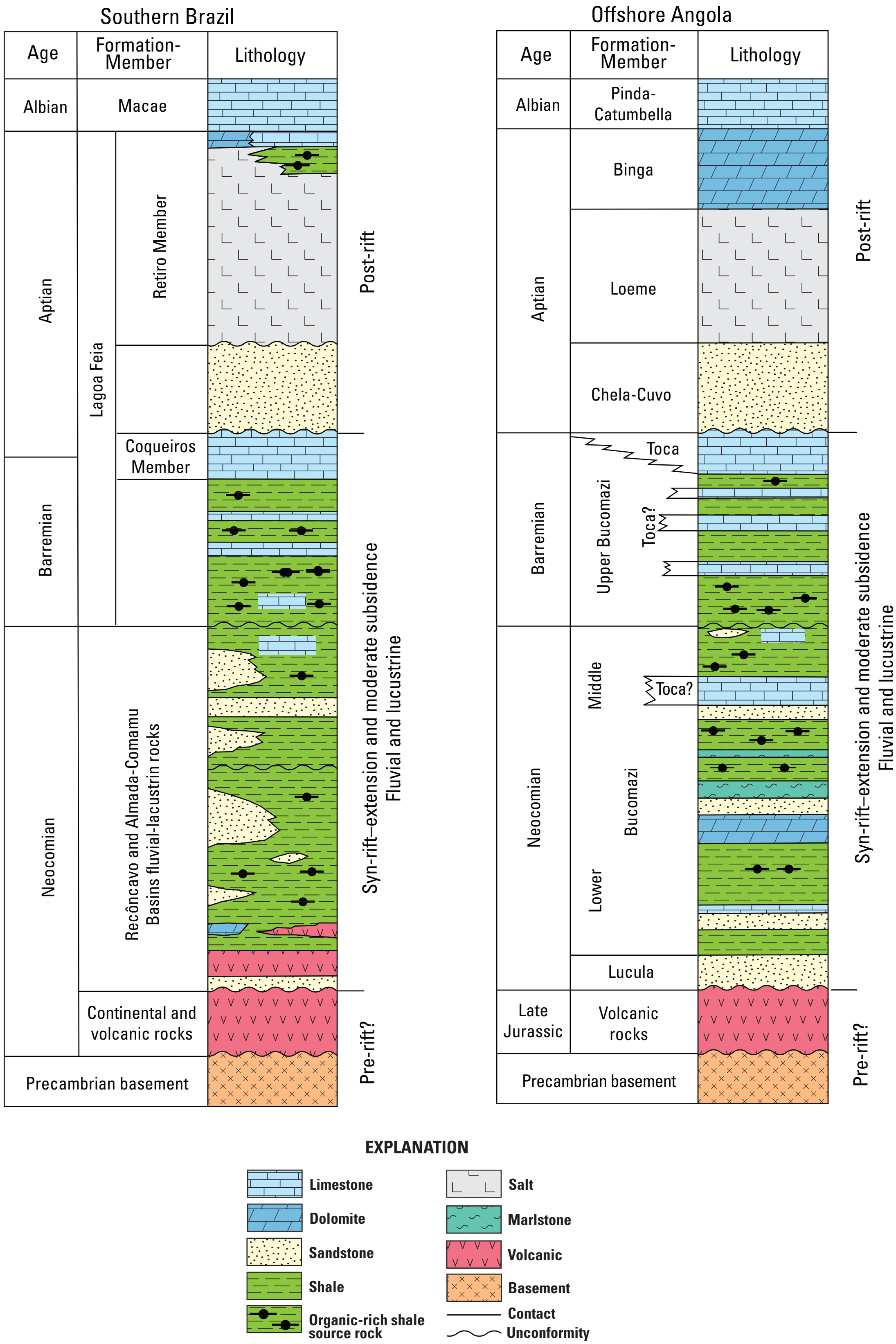


Figure 17. Generalized stratigraphy of the Lower Cretaceous rocks in the offshore marginal (outer) Kwanza Basin and the offshore southern Congo Basin, west Africa, and the Alamda-Camamu and Recôncova Basin, southern Brazil (fig. 22), showing ages, formation and member names, lithology, potential source rocks, and tectonic stages. Modified from Pasley and others (1998b) and Coward and others (1999).

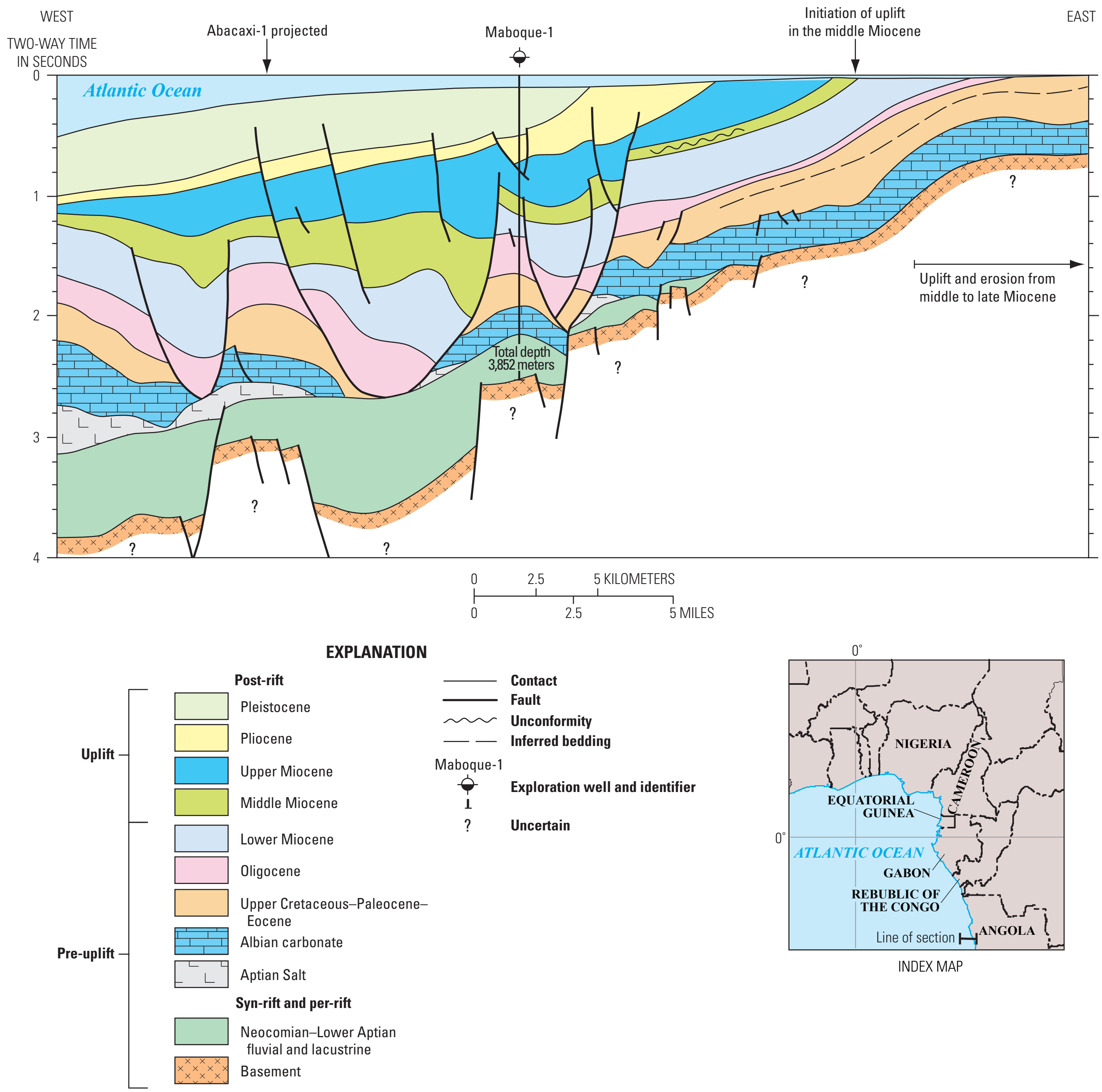


Figure 18. Schematic cross section, based on geologic interpretation of seismic data, of the southern part of the outer Kwanza Basin, Angola, west Africa, showing age of rock units, preuplift and uplift units, and syn-rift and post-rift units. Neocomian to lower Aptian lacustrine and Albian carbonate source rocks were penetrated by Maboque-1 well. Modified from Lunde and others (1992). Location of cross section shown in index map. Abbreviation: TD, total depth; m, meter.

Post-Rift Stage

Post-rift rocks in the West-Central Coastal Province range from Aptian to Holocene in age and represent the opening of the Atlantic Ocean in equatorial west Africa. The oldest post-rift rocks are of early to mid-Aptian age and consist of continental, fluvial, and lagoonal rocks that were deposited as rifting ceased in the province. Extensive deposition of evaporite units, mainly salt, followed. Younger post-rift rocks were deposited in two distinct regimes: as transgressive units consisting of shelf clastic and carbonate rocks followed by progradational units along the continental margin, and as open-ocean, deep-water units.

In the Douala, Kribi-Campo, and Rio Muni Basins (fig. 1), the oldest post-rift rocks are represented by mid-Aptian organic-rich shale, marlstone, and sandstone (Ross, 1993), probably of lacustrine origin (figs. 7, 8, 9).

In the Interior and North Gabon subbasins (fig. 6) the initial post-rift rocks (fig. 10) are represented by the mid-Aptian Como Formation (Teisserenc and Villemin, 1990), as much as 500 m thick, consisting of sandstone, dolomite, shale, and organic-rich shale. The Como Formation is equivalent to the Gamba Formation of the South Gabon subbasin (figs. 11, 12, 19). The Gamba Formation, which is as much as 130 m thick, is a transgressive unit consisting of fluvial sandstone with lagoonal rocks at the top. A complete Gamba section consists of the following units: basal conglomerate, poorly sorted sandstone, sandy shale, clean sandstone and, at the top, shale interbedded with sandstone, dolomite, or anhydrite or all three.

In the offshore section of the Republic of the Congo (that is, the northern Congo Basin) the oldest post-rift rocks (figs. 13, 14) are the lower Aptian Chela Sandstone that consists of sandstone and shales deposited in a variety of environments including marine, lacustrine, and fluvial (Harris, 2000). The oldest post-rift rocks in the central and southern parts of the Congo Basin (also known as the lower) are represented by the coarse-grained clastic rocks of the lower Aptian Chela Sandstone (figs. 13, 14, 15) and the lacustrine carbonate, sandstone, and shale that make up the Toca A unit of the Toca Formation (Brice and others, 1982; McHargue, 1990).

The basal post-rift rocks in the onshore part of the inner Kwanza Basin include the lower Aptian Upper Cuvo Formation (fig. 16) and consist of sandstone, dolomite, and limestone with minor coals (Brognon and Verrier, 1966; Burwood, 1999). The Upper Cuvo, as much as 300 m thick, is equivalent to the Chela Sandstone of the Congo Basin (figs. 13, 15). In the outer Kwanza Basin, the youngest post-rift rocks are represented by the thick Upper Cuvo Formation (Pasley and others, 1998a, b; Uncini and others, 1998) consisting of sandstone, siltstone, shale, and minor limestone of fluvial and lacustrine origin (fig. 17). The Upper Cuvo Formation in this area is equivalent to the Chela Sandstone of the Congo Basin and intertongues with dolomite and anhydrite of the Upper Cuvo Formation to the east.

Salt Deposition

Salt was deposited during the late Aptian throughout the equatorial west Africa basins within the West-Central Coastal Province. Brownfield and Charpentier (2006) provide a detailed discussion of the salt deposition in the province. The migrating Tristan da Cunha hotspot, also known as the Walvis Ridge (fig. 4), formed a barrier at the southern end of the province that restricted circulation from the open-marine ocean to the south. The Annobon-Cameroon volcanic axis (also called the Cameroon fracture zone) formed during the Early Cretaceous (fig. 1) and defined the northern extent of the Aptian salt basin.

Evaporite units as thick as 800 m are present in the Rio Muni Basin (figs. 7, 8); they consist of interbedded evaporite rocks (beds are as much as 10 m thick) and organic-rich shale (Turner, 1995) deposited in a deep lacustrine basin starved of coarser siliciclastic sediment. The evaporites and interbedded lacustrine shale thin northward and have not been penetrated by drilling in the northernmost part of the Douala Basin. However, diapiric evaporites were penetrated in the Kribi Marine-1 well in offshore Cameroon (Pauken, 1992) in the Kribi-Campo Basin (fig. 9).

In the offshore parts of Angola and the Congo Basin, massive salt deposits such as the Aptian Loeme Salt (figs. 13, 14, 15) can be at least 1,000 m thick. Clastic units are commonly found near the top of the main evaporite section. The salt grades upward into a regionally extensive 50-m-thick dolomite unit representing a basinwide freshening in the Congo Basin and the end of the Loeme evaporite cycle. The thick salt in the basin acts as a décollement zone for many of the post-salt growth-fault structures in the Congo Basin.

The Aptian to Albian evaporite units in the inner Kwanza Basin (fig. 16) were deposited as a succession of evaporite cycles beginning with the Massive Salt (Brognon and Verrier, 1966). The Massive Salt, as much as 600 m thick, is overlain by eight sabkha-like evaporite cycles with a total thickness as much as 1,400 m. The evaporite unit in the outer Kwanza Basin (fig. 17) contains massive halite and interbedded anhydrite, similar to the Loeme Salt of the Congo Basin and the Retiro Member of the Lagoa Feia Formation of Brazil (Pasley and others, 1998a, b; Uncini and others, 1998).

Salt-Related Deformation and Progradational Sedimentation

Thick ramp units of shelf carbonate rocks were deposited from south to north in the Aptian salt basin of west Africa during Albian to Turonian time. Beneath these units, the salt began to flow due to differential loading and gravity sliding. High-energy shoal settings developed over the salt diapirs and swells, and clastic sediments with future reservoir potential were deposited along the continental margin. Brownfield and Charpentier (2006) provide a discussion of the carbonate-platform units in the province.

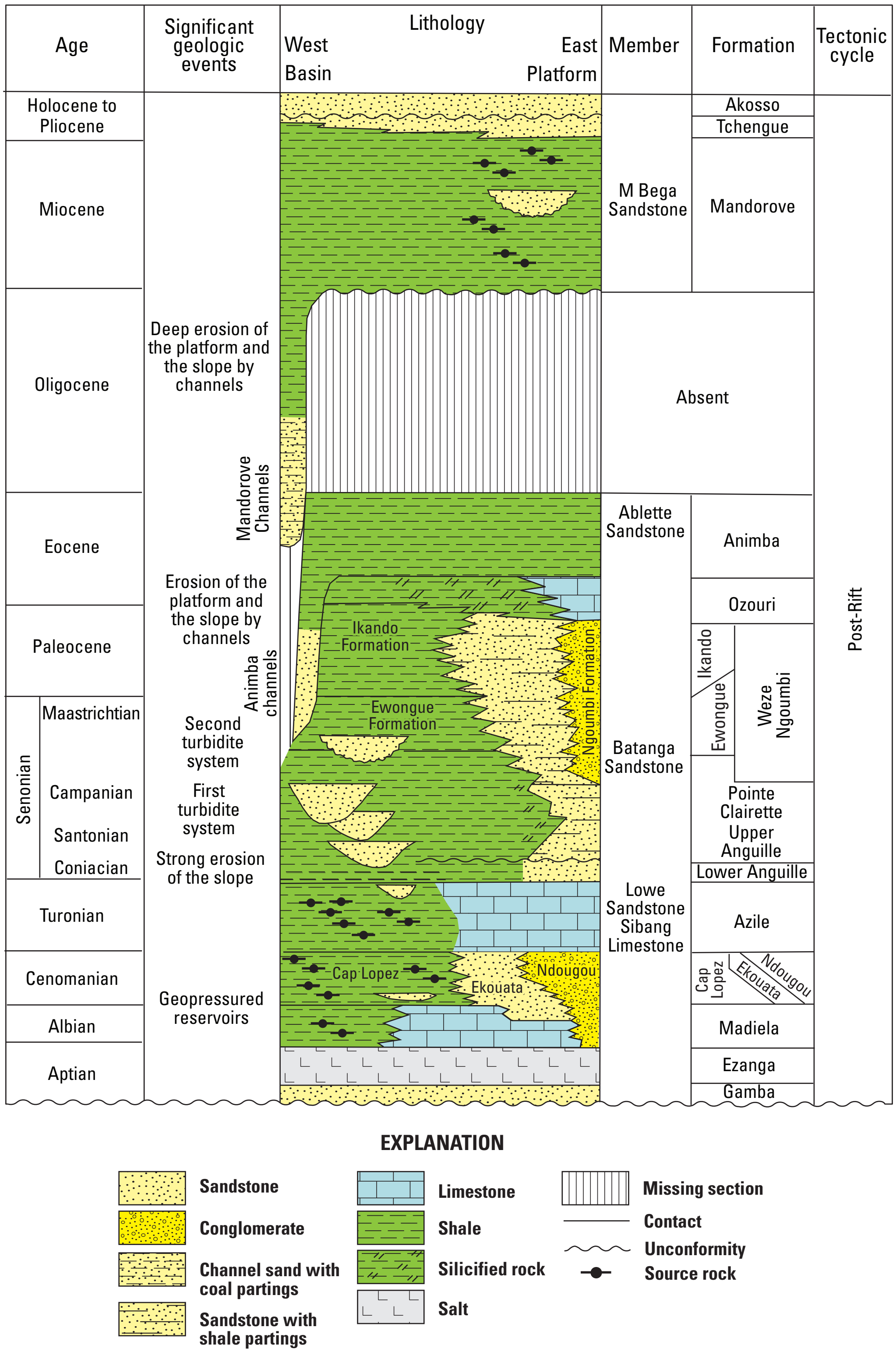


Figure 19. Generalized stratigraphy of the offshore part of North Gabon and South Gabon subbasins, equatorial west Africa showing ages, significant geologic events, lithology, potential source rocks, formation and member names, and tectonic stage. Modified from Teisserenc and Villemin (1990).

The upper Albian Catumbela Formation, found in the southern offshore and marginal part of the Kwanza Basin (fig. 17), is the oldest shelf-carbonate unit in the basins of west Africa. The Catumbela consists of oolitic limestone and is the lateral equivalent of rock units in two other locations: the dolomitic Tuenza Formation (Danforth and others, 1997) and the Catumbela Formation (calcarenite) of the inner Kwanza Basin (figs. 16, 17), and the late Albian Pinda Formation of the southern Congo Basin (fig. 15). The Pinda Formation, as much as 1,200 m thick, consists of cyclic carbonate and siliciclastic units deposited in a sabkha to shallow-marine environment. The lowermost shelf carbonate in the outer Kwanza Basin is the Binga Formation (fig. 16), a transitional unit between the massive Aptian salt and the shelf carbonates. In the inner Kwanza Basin, the Binga is the second of eight evaporative cycles above the Massive Salt (Brognon and Verrier, 1996).

In the northern part of the Congo Basin, shelf-carbonate rocks are represented by the Albian Sendji Carbonate consisting of high-energy dolomitic, oolitic limestone, and interbedded sandstone units deposited in tidal channels in the lower part and as offshore bars and shoreface units in the upper part (fig. 13).

In the North Gabon (fig. 10) and the offshore part of the South Gabon (fig. 19) subbasins, shelf-carbonate rocks are represented by the Albian to lower Cenomanian Madiela Formation, ranging from 90 to 1,500 m in thickness, and the Turonian Sibang Limestone Member (Teisserenc and Villemin, 1990). Deformation of the underlying Ezanga Formation evaporites during the deposition of the shelf-carbonate Madiela Formation resulted in its variable thickness.

The shelf-carbonate rocks in the Rio Muni Basin consist of middle Albian to Cenomanian cyclic, shallowing-upward units of oolitic limestone and calcarenite ranging from 5 to 15 m thick (Turner, 1995). Shelf carbonate rocks in the Cameroon Kribi-Campo Basin are similar to the Rio Muni carbonate rocks and are represented by the Mungo Formation (fig. 9), whereas in the Douala Basin of northern-most Cameroon, the Mungo Formation lacks massive shelf-carbonate rocks.

Widespread organic-rich marine mudstone and marlstone developed lateral to and above the shelf carbonate rocks in the Aptian salt basin during the early post-rift stage in Albian to Maastrichtian time (figs. 7, 9, 13, 15, 19). These marine rocks include the Madingo Marl (fig. 13, 14) and the Logbadjeck (fig. 9), Mungo, Cap Lopez (fig. 19), Azile (fig. 19), and Iabe (fig. 15) Formations. The regional extent and organic richness of these marine rocks suggest that marine circulation between the North and South Atlantic Oceans was still partially restricted in the Gulf of Guinea during their deposition (figs. 1, 5). A regional erosional event began during the early Senonian and continued into the Paleogene, forming a widespread unconformity.

Cenozoic sedimentation was dominated by progradational marine sedimentation that included the development of several Tertiary deltas, especially those of the Niger and Congo Rivers in the Niger Delta and West-Central Coastal Provinces, respectively. This progradational phase resulted in the deposition of turbidite sandstone and siltstone and deep-marine shale units during the Paleocene and Eocene. Continued drifting during the Neogene caused westward tilting and subsidence of the west African marginal basins, which accentuated the erosion of the continental slope and formed a regional Miocene unconformity (Da Costa and others, 2001). The Miocene unconformity represents an important event for the accumulation of hydrocarbons because in some basins the erosion cut into the Albian to Cenomanian reservoir rocks and may have formed hydrocarbon traps and reservoir by depositing shale seals (Edwards and Bignell, 1988a). The post-Miocene rocks in the Aptian salt basin consist of poorly sorted marine rocks with localized channel-fill and turbidite sandstone.

Petroleum Occurrence in West-Central Coastal Province, West Africa

Hydrocarbons have been found both onshore and offshore in several formations in the West-Central Coastal Province; they are discussed in detail by Brownfield and Charpentier (2006). The best-understood hydrocarbon accumulations in the province are in Cretaceous and Tertiary reservoirs in the Douala, Kribi-Campo, Rio Muni, Gabon, Congo, and Kwanza Basins (fig. 1).

Source Rocks

Cretaceous Source Rocks

Syn-rift Neocomian to Aptian organic-rich shale and marlstone appear to be the source rocks responsible for most hydrocarbon accumulations in the West-Central Coastal Province. A series of graben and half-graben basins along the Early Cretaceous rifted margins of western Africa and Brazil formed depocenters for organic-rich lacustrine rocks. In the offshore Lower Congo and outer Kwanza Basins of Angola this syn-rift event produced the lacustrine source rocks of the Bucomazi Formation (figs. 15, 17), which is as much as 1,500 m thick (McHargue, 1990). Time-equivalent organic-rich lacustrine rocks include the Pointe Noire Marl of the northern Congo Basin (figs. 13, 14) and the Kissenda and Melania Formations of the offshore South Gabon subbasin (fig. 11), and the Brazilian Lagoa Feia (Campos Basin), Guaratiba (Santos Basin), Mariricu (Espirito Santos Basin), and Itaípe (Alamda-Camamu Basin) Formations (Coward and others, 1999; Schiefelbein and others, 1999) (fig. 17).

The source rocks in the middle units of the Bucomazi Formation contain Type I kerogen. Total organic carbon (TOC) percentages have a wide range, but generally average more than 5 weight percent, although some analyses show TOC contents as high as 20 weight percent. The source rocks of the lower and upper units of the Bucomazi contain Type I and Type II kerogen and average 2–3 weight percent TOC, although some organic-rich claystone locally contains more than 10 percent TOC (Brice and others, 1982; Schoellkopf and Patterson, 2000).

Hydrocarbon source rocks within the early syn-rift section of the outer Kwanza Basin contain thick, organic-rich, lacustrine shale with abundant Type I kerogen (Pasley and others, 1998b). These source rocks are limited in regional extent because they were deposited within grabens. The upper part of the syn-rift section contains source rocks that are more widespread. These source rocks were deposited during a regional sag phase; they contain shale rich in Type I and Type II kerogen. Analyses from Bucomazi time-equivalent source rocks in the southern outer Kwanza Basin contain Type I kerogen (Pasley and others, 1998b) and have an average TOC content of 3.1 weight percent. Some analyzed samples had TOC contents greater than 20 weight percent (Geochemical and Environmental Research Group, 2003).

Potential source rocks are numerous in the Neocomian to Barremian syn-rift rocks of the northern part of the Congo Basin. The lacustrine Pointe Noire Marl (figs. 13, 14) contains Type I and Type II saprolitic kerogen averaging from 1 to 5 weight percent TOC; some source rocks contain more than 20 weight percent TOC (Baudouy and Legorjus, 1991). The Sialivakou Shale and lower part of the Djeno Sandstone contain Type II and Type III organic matter and have TOC contents averaging 1 weight percent. The upper part of the Djeno Sandstone contains Type I and Type II saprolitic organic matter and generally has a TOC content of 1 to 5 weight percent, but some source rocks contain as much as 20 weight percent TOC (Baudouy and Legorjus, 1991).

In the South Gabon subbasin, the most important source rock is the uppermost part of the Barremian Melania Formation (figs. 11, 20). This organic-rich source rock, which was deposited in a low-energy lacustrine environment, consists of varved, pyritic shales with an average TOC content of 6.1 weight percent; some analyses were as much as 20 weight percent TOC (Teisserenc and Villemin, 1990). Although the Melania Formation has not been penetrated by drilling in the North Gabon subbasin, either onshore or offshore, it should be considered a potential hydrocarbon source. Less is known about the Neocomian Kissenda Shale source rocks because they are encountered in only a few onshore wells. The Kissenda Shale consists of organic shale with interbeds of siltstone and carbonaceous shale deposited in a lacustrine environment. Kissenda source rocks contain mostly Type III or Type II/III kerogen and have an average TOC content of 1.5 to 2 weight percent, suggesting at least in part, a terrestrial source. The Kissenda Shale in the South Gabon subbasin is similar to the lower unit of the Congo Basin's Bucomazi Formation (fig. 15; McHargue, 1990).

In the Rio Muni Basin (fig. 8), the lacustrine source rocks of Barremian to Aptian age are found underlying and interbedded with the Aptian evaporite rocks and are equivalent to the Kissenda Shale (Turner, 1995). These lacustrine rocks make up the Rio Muni Basin's primary source rock; its hydrocarbon consists chiefly of algal kerogen with TOC contents of as much as 6 weight percent. In the Kribi-Campo Basin of Cameroon (fig. 9), similar rocks were penetrated in the Kribi Marine-1 offshore well (Pauken, 1992). Aptian evaporate rocks have also been identified in the Douala Basin (Coward and others, 1999; Oba, 2001), and analyses of oil seeps in the Douala Basin suggest that there may be lacustrine source rocks (fig. 9) interbedded with these thin evaporite beds towards the center of the basin (Tamfu and others, 1995).

Cenomanian to Maastrichtian marine marl source rocks were deposited during the early post-rift stage in the Aptian salt basin, from the Douala Basin in the north to the Kwanza Basin in the south (figs. 9, 15, 18). The outer Kwanza Basin (fig. 18) may contain Cenomanian to Maastrichtian marine source rocks that resulted from deep-water sedimentation in graben basins; those basins developed over a detachment surface in the salt (Duval and others, 1992; Lundin, 1992) along the regionally subsiding Late Cretaceous shelf edge. These rocks are equivalent to the Iabe Formation in the Congo Basin (fig. 15).

Analyses of marine source rocks (marlstone and shale) from the Cenomanian to Maastrichtian Iabe Formation in the central and southern Congo Basin generally contain TOC contents greater than 2 weight percent; some intervals have TOC contents as high as 3 to 5 weight percent (Schoellkopf and Patterson, 2000). The organic matter in these samples consists mostly of Type II kerogens, but some Type I kerogens are found in organic-rich intervals (Schoellkopf and Patterson, 2000). The Madingo Marl (Senonian to Eocene) of the Democratic Republic of the Congo part of the Congo Basin (fig. 13) consists of marine marlstone (Baudouy and Legorjus, 1991) and may be equivalent, in part, to the Iabe Formation (fig. 15).

Analyses of the upper Albian to Cenomanian Madiela and Cap Lopez Formations in the North and South Gabon subbasins (figs. 19, 20) have shown excellent source-rock potential, but data from these units are scarce. Deep Sea Drilling Project data (Leg 40, Site 364; Tissot and others, 1980) indicate that these units contain TOC contents as high as 10 weight percent. The Turonian Azile Formation is probably the most important source rock in offshore fields south of Port Gentil (fig. 6). The source rocks of the Azile Formation contain mostly marine-algae-derived, Type II/III kerogen and have an average TOC content of 3 to 5 weight percent (Teisserenc and Villemin, 1990). These mixed kerogens have compositions between Type II and Type III and intermediate hydrogen indexes (HI, 200–300 milligrams hydrocarbon per gram TOC (mg HC/g TOC). Potential source rocks showing characteristics similar to those of the Azile Formation have been found in the Anguille and Pointe Clairette Formations (fig. 19) but lack regional distribution.

The Rio Muni Basin (fig. 7) contains Cenomanian to Turonian source rocks (Equatorial Guinea Ministry of Mines and Energy, 2003) for which chemical data suggest deposition in similar marine settings. These source rock-bearing units may be equivalent to the Cap Lopez and Azile Formations in the Gabon Basin (fig. 19). Geochemical analyses of hydrocarbon samples

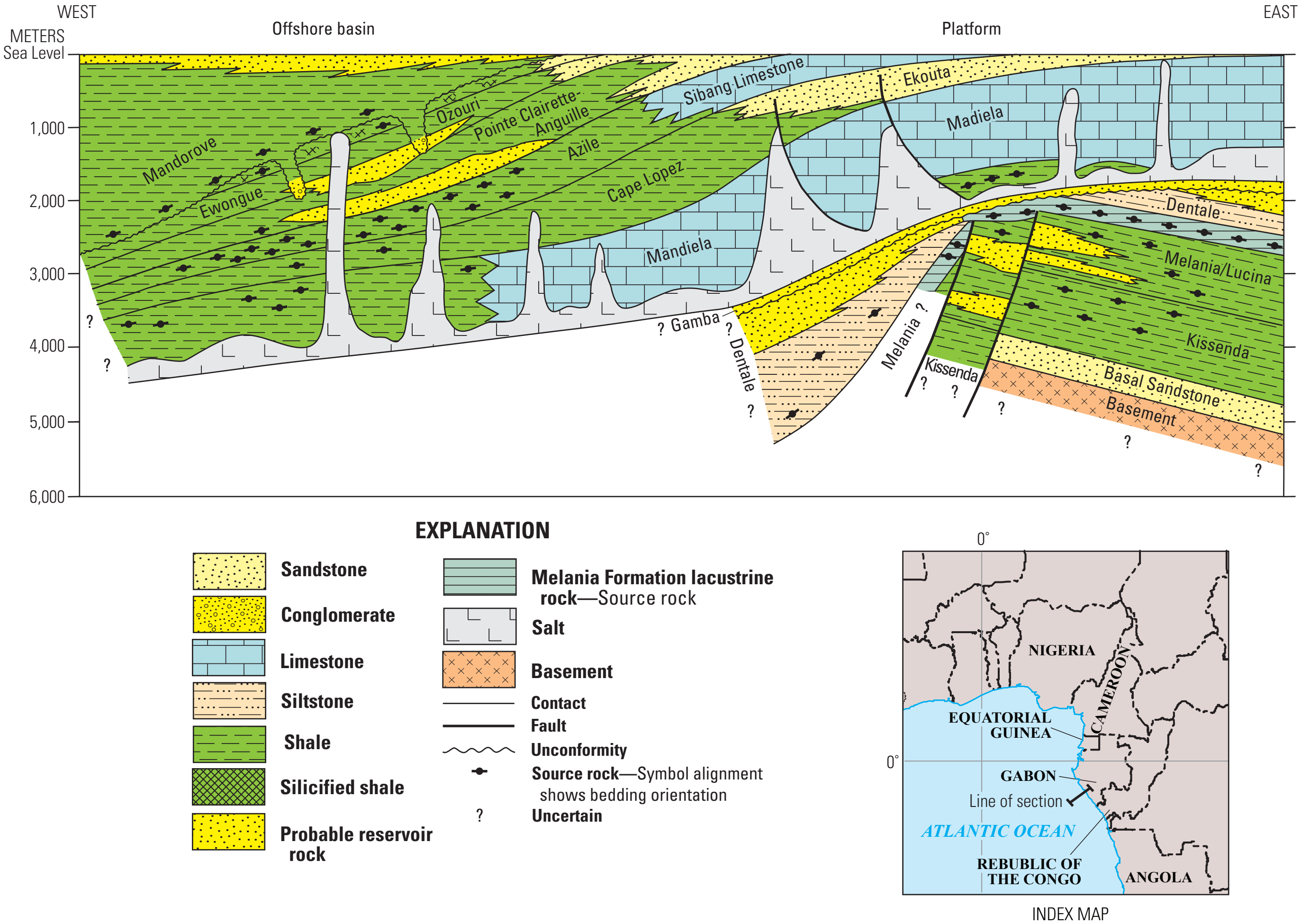


Figure 20. Schematic cross section of the southern part of the Gabon Basin, Gabon, equatorial west Africa, showing lithology, formation name, known source rocks, and probable reservoir rocks. Modified from Teisserenc and Villemin (1990). Not to scale.

suggest that oil-prone source rocks probably exist in the Upper Cretaceous Logbadjeck and Mungo Formations in the Douala and Kribi-Campo Basins (fig. 9). Paleoenvironmental data also suggest that these source rocks were deposited in marine settings (Ackerman and others, 1993). In corroboration with the source-rock studies, geochemical studies of oil-seep samples suggest that the oils could have been derived from rocks deposited in a hypersaline marine environment.

Tertiary Source Rocks

Paleocene to Miocene marine source rocks exist in the West-Central Coastal Province. Oil-prone, deep-water source rocks contain Type II, Type II/III, and Type III kerogens, whereas gas-prone source rocks are associated with Tertiary deltas and contain mostly Type III kerogen (Lunde and others, 1992; Pauken, 1992; Ross, 1993; Raposo and Inkollu, 1998; Equatorial Guinea Ministry of Mines and Energy, 2003). However, the Tertiary delta source rocks are generally thermally immature.

The Paleocene N'Kapa and the Oligocene Souellaba Formations in the Douala and Kribi-Campo Basins of Cameroon contain marine source rocks (fig. 9). Miocene deep-marine, oil-prone source rocks with mixed Type II and Type III kerogens are found in the northern part of the Douala Basin of Cameroon (Equatorial Guinea Ministry of Mines and Energy, 2003). These rocks have a TOC content of 1 to 2 weight percent and may be locally mature owing to elevated heat flow from the Annobon-Cameroon volcanic axis (fig. 1). Gas-prone Miocene source rocks containing Type III kerogen with TOC contents of 1 to 2 weight percent are found associated with the Sanaga Sud gas field in the southern part of the Douala Basin; oil-prone source rocks are rare (Pauken, 1992). Farther south, Paleocene source rocks (fig. 7) have been reported in the Rio Muni Basin (Ross, 1993).

The Miocene Mandorove Formation (figs. 19, 20), of the South Gabon subbasin contains coaly source rocks with an average TOC content of 4 to 5 weight percent (Teisserenc and Villemin, 1990). Some higher values have also been reported, but the formation is thermally immature throughout the basin.

In the central and southern Congo Basin, the Paleocene to Eocene source rocks of the Landana Formation consists primarily of deep-water marine shale. They generally have TOC contents as high as 3 to 5 percent, similar to those of the Iabe Formation (fig. 15) (Schoellkoph and Patterson, 2000).

The mid-Oligocene to Miocene Malembo Formation (fig. 15) generally has TOC contents of 1 to 2 weight percent; the lower and upper parts of the formation contain from 2 to 5 weight percent Type II and Type II/III kerogens (Schoellkoph and Patterson, 2000).

The offshore section of the southern part of the Kwanza Basin contains deep-marine source rocks in fault-controlled troughs (fig. 18) (Lunde and others, 1992). These source rocks should be similar to the Paleocene to Oligocene source rocks in the central part of the province. Miocene uplift of the inner Kwanza Basin resulted in the deposition of 3,000 m of sediment in the outer Kwanza Basin (fig. 18). Analyses show that marine source rocks with Type II and Type II/III kerogen contain 2 to 10 weight percent TOC (Raposo and Inkollu, 1998), and the oil composition in discoveries in the outer Kwanza Basin also suggests a marine source.

Generation and Migration

Hydrocarbon generation has been active in the Aptian salt basin from the Late Cretaceous to the present (Schoellkopf and Patterson, 2000), even as the sedimentary depocenters, sites of hydrocarbon generation, and migration or charging systems have shifted westward through time as the western African continental margin prograded westward.

Timing of oil generation from syn-rift source rocks in the Douala, Kribi-Campo, and Rio Muni Basins is not well understood, but most of the hydrocarbons were likely generated during the Late Cretaceous to the present (Pauken, 1992). Upper Cretaceous and Tertiary source rocks in the post-rift (post-salt) section may be locally mature and may have been generating hydrocarbons from mid-Tertiary time (figs. 7, 8, 9). Mature Cretaceous and Tertiary source rocks have not been penetrated in the Douala and Rio Muni Basins, but chemical analyses of oil samples from seeps and wells indicate that generation and migration have occurred from lacustrine, shallow-marine, and lagoonal source rocks located in the deeper parts of the basins (Tamfu and others, 1995).

In the North and South Gabon subbasins, oil generation has been active from the Late Cretaceous to the present (Edwards and Bignell, 1988a). Lacustrine shale in the Melania Formation (fig. 11) is widespread in the onshore and offshore parts of the South Gabon subbasin and is the major source of hydrocarbons in the basin (Teisserenc and Villemin, 1990). Thermal maturity gradients observed in the onshore and offshore syn-rift section in the South Gabon subbasin are higher than gradients calculated from models (Teisserenc and Villemin, 1990). This thermal maturity anomaly has two causes: higher heat flow associated with the earliest phase of rifting, and erosion of overburden rocks from uplifted blocks during rifting. Burial-history curves of post-rift source rocks in the Madiela, Cap Lopez, and Azile Formations in the North and South Gabon subbasins indicate that the rocks did not mature until the Miocene (Teisserenc and Villemin, 1990). The zone of oil generation in the South Gabon subbasin that corresponds to vitrinite reflectance values of 0.5 to 1.0 (fig. 21) lies at depths ranging from 1,000 to nearly 2,000 m.

The timing of oil generation from hydrocarbon sources in the Congo Basin's Bucomazi Formation (fig. 15)—and stratigraphically equivalent source rocks such as the Melania Formation lacustrine shale and Pointe Noire Marl (figs. 11, 13)—varies slightly from the south to north in the basins; this variance reflects variations in Tertiary sediment downloading (Orsolini and others, 1998). Most of the oil was generated during Cenomanian to Paleocene time, but generation continues to the present (Schoellkopf and Patterson, 2000). Geochemical modeling also suggests that oil generation and migration started in the Upper Cretaceous and is still active today (Orsolini and others, 1998). The Iabe and Landana Formations (fig. 15) and their stratigraphically equivalent source rocks began generating oil in the middle Miocene and continue into the present. In the eastern parts of the basin, the rate of oil generation slowed after the Cretaceous owing to the lack of further deposition of Tertiary overburden rocks (Schoellkopf and Patterson, 2000). This slowing is quite evident in the Democratic Republic of the Congo part of the Congo Basin (figs. 13, 14), where the post-salt source rock (Madingo Marl) is immature, and in the Congo Basin and South Gabon subbasin, where the Miocene Malembo and Mandorove Formations (figs. 15 and 19, respectively), are mostly immature. Exceptions are seen where deep troughs are filled with Tertiary rocks because of rafting of the underlying marine section on the Aptian salt (Schoellkopf and Patterson, 2000).

Miocene erosion of overburden in the inner Kwanza Basin, had a direct effect on the regional maturation of post-salt units in the outer Kwanza Basin. As much as 2,000 m of sedimentary rocks were eroded and the detritus was redeposited in the outer Kwanza Basin, where offshore troughs contain as much as 3,000 m of Miocene rocks (Lunde and others, 1992). Maturation levels sufficient to generate oil are much shallower in the inner Kwanza Basin compared with the outer Kwanza Basin. Offshore well data show the onset of oil generation ($Ro = 0.5$ percent) at a depth of 4,000 m, whereas onshore well data show this maturity level at depths ranging from 2,000 to 3,000 m. Most of the oil in the inner Kwanza Basin was probably generated in the Miocene, but outer Kwanza Basin post-rift source rocks were still immature at that time. The offshore syn-rift source rocks most likely reached maturity during early Tertiary time (Danforth and others, 1997) but, as in the Congo Basin, may have reached maturity as early as the Late Cretaceous (Schoellkopf and Patterson, 2000).

Migration pathways are predominantly fault related and generally nearly vertical in the West-Central Coastal Province. Salt windows provide the major migration pathways for syn-rift oils into the post-salt reservoirs. Considerable lateral migration of syn-rift oil has taken place along clastic units directly underlying the regional salt in the Aptian salt basin, such as the Chela Sandstone in the Congo Basin (figs. 13, 14, 15). Stratigraphically equivalent subsalt units—the Como (fig. 10), Gamba (figs. 11, 12, 19, 20), and Upper Cuvo (fig. 17) Formations in the North Gabon subbasin, South Gabon subbasin, and offshore part of the outer Kwanza Basin, respectively—also act as lateral oil-migration pathways.

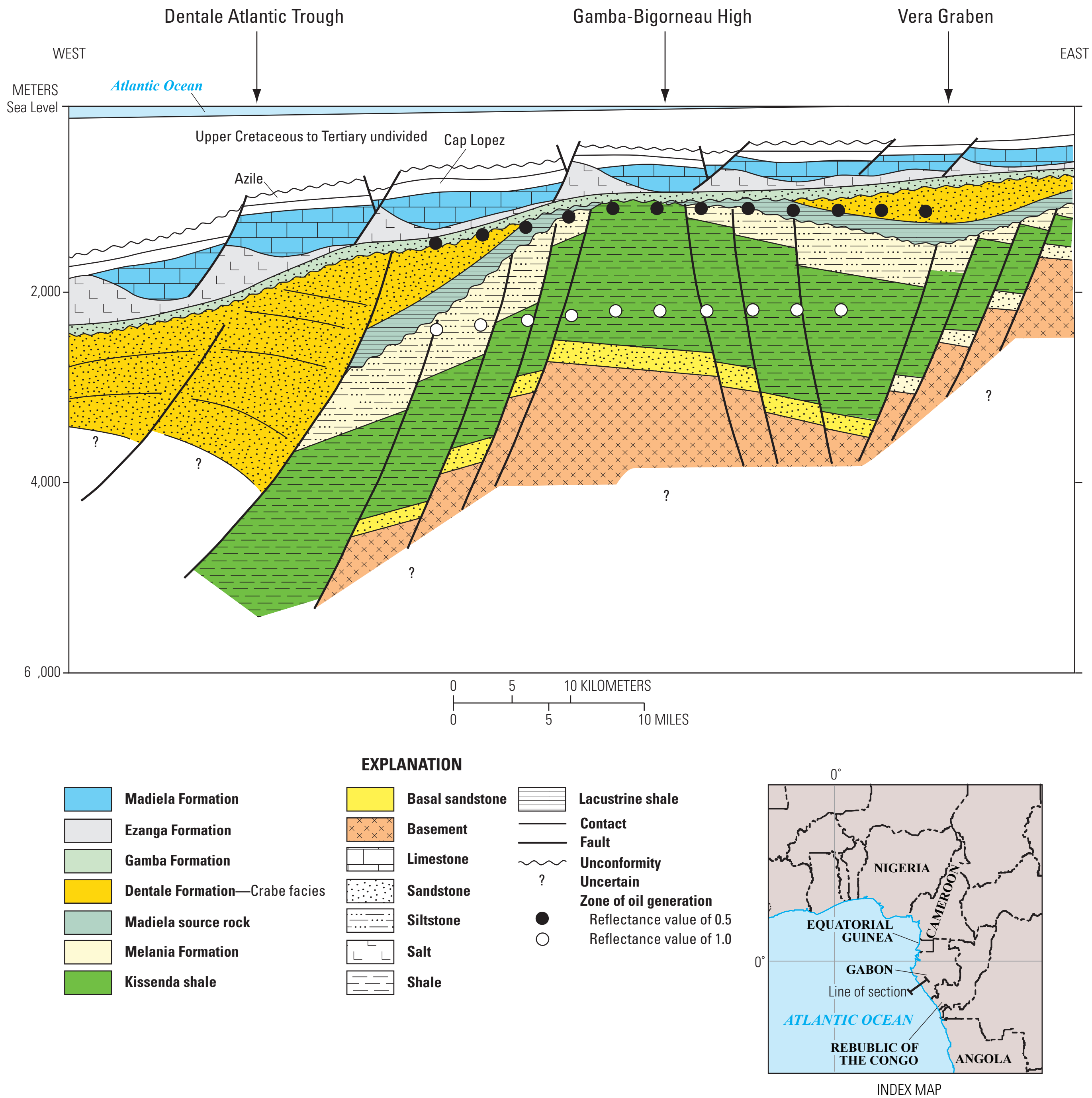


Figure 21. Schematic cross section through the Gamba-Bigorneau High, South Gabon subbasin, equatorial west Africa, showing formations, lithology, and the zone of oil generation. Modified from Teisserenc and Villemin (1990).

Reservoir Rocks, Traps, and Seals

A limited number of core studies in the offshore Douala Basin (fig. 1) have shown that the Lower Cretaceous submarine fan and fan-delta sandstone reservoir rocks are as thick as 100 m, have porosities ranging from 20 to 25 percent, and have an average permeability of 142 millidarcies (mD) (Pauken, 1992). Upper-fan or turbidite-channel deposits are less well sorted and therefore have lower porosities. Interpretations of higher-resolution seismic data indicate a variety of potential syn-rift reservoir rocks, including Aptian to Albian deep-water sandstone units deposited as submarine fans, fan-deltas, and turbidites with their associated channel sediments (Pauken and others, 1991).

Syn-rift reservoir rocks in the Rio Muni Basin consist of lacustrine and fluvial sandstone, whereas post-rift reservoir rocks consist of both sandstone and carbonate rocks (Turner, 1995; Equatorial Guinea Ministry of Mines and Energy, 2003). Potential traps include fault blocks, rollovers, and salt structures with Cenomanian to Senonian shale acting as reservoir seals. Interpretations of higher-resolution seismic data indicate that Turonian to Paleocene deep-water turbidite rocks may be potential hydrocarbon reservoirs; hydrocarbon traps may be stratigraphic pinchouts, shale-channel truncations, or thickened sandstone units related to growth faults. Miocene submarine-fan units are also potential reservoir rocks in the Rio Muni Basin (Equatorial Guinea Ministry of Mines and Energy, 2003).

The Interior, North, and South Gabon subbasins (figs. 10, 11) contain many potential Lower Cretaceous reservoir units in the N'Dombo Formation and Basal Sandstones, the Lucina and M'Bya Members of the Melania Formation and the Dentale and Gamba Formations (Teisserenc and Villemin, 1990). The N'Dombo and Basal Sandstones are present throughout most of the Interior and South Gabon subbasins, but only a few wells have penetrated them. The N'Dombo and Basal Sandstones have the best reservoir properties (Brink, 1974): porosity ranges to 25 percent and permeabilities are as high as 100 mD (Teisserenc and Villemin, 1990). Near the eastern margin of the Interior and South subbasins, other wells have tested the Basal Sandstone closer to the source, where it consists of clay-rich conglomerate with poor reservoir properties. The Basal Sandstone has not been penetrated by drilling in the North Gabon subbasin but seismic data suggest it should be present. The Lucina Member sandstones have porosities ranging from 15 to 25 percent and permeabilities from 10 mD to 100 mD; the M'Bya Member most likely has similar reservoir characteristics. In the upper part of the Dentale Formation, reservoir sandstones have porosities as high as 29 percent and permeabilities as great as 1 darcy (D) (Teisserenc and Villemin, 1990), whereas in the Rabi-Kounga field the Dentale Formation sandstones have porosities of nearly 30 percent and permeabilities of several darcies (Boeuf and others, 1992). The Gamba Formation sandstone reservoirs have porosities ranging from 20 to 30 percent and permeabilities ranging from 100 to 5 D (Teisserenc and Villemin, 1990; Boeuf and others, 1992).

The offshore sedimentary section of the Congo Basin includes many potential reservoirs and traps. The syn-rift reservoir rocks include the pre-rift Jurassic(?) Lucula Sandstone and the syn-rift Neocomian Lucula Sandstone and Toca Formation carbonate rocks (fig. 15) that were deposited in eolian, alluvial, and lacustrine environments (Schoelkopf and Patterson, 2000), respectively. The Toca Formation carbonate rocks have porosities ranging from 16 to 20 percent (Dale and others, 1992) and locally have permeabilities as high as 600 mD. Hydrocarbon traps in the Lucula Sandstone and Toca Formations formed in faulted basement blocks, and reservoirs are sealed by Bucomazi Formation shales and the Loeme Salt (fig. 15). Cretaceous post-salt reservoirs in the Congo Basin include the Mavuma, Pinda, Vermelha, and Iabe Formations (fig. 15) that were deposited as lagoonal, strand-plain, and nearshore sandstones and carbonate rocks, respectively (Dale and others, 1992; Schoelkopf and Patterson, 2000). The Aptian Mavuma Formation produces oil in the Kungulo field, where the reservoir properties range from poor to fair. Reservoirs in the Vermelha Formation have formed in strand-plain and nearshore sandstones with porosities of 25 percent and permeabilities as high as 1,000 mD. In contrast, reservoirs in the Pinda Formation sandstone have average porosities of 22 percent (porosities of some units are as high as 35 percent) and permeabilities of only 150 mD (Dale and others, 1992). Traps associated with the Vermelha and Pinda Formations are rollover anticlines in which marine shales act as reservoir seals. The Turonian to Coniacian Mesa and Lago Members of the Iabe Formation (fig. 15) contain sandstone reservoir rocks with interbedded limestone and dolomite; these reservoir units display variable porosity and permeability (Schoelkopf and Patterson, 2000). Traps associated with the Iabe Formation are primarily rollover structures and thickened turbidite strata. Transgressive shale units form reservoir seals. Tertiary reservoir rocks include turbidite channel and stacked turbidite sands and delta, prodelta, and basin-floor-fan sands. Reservoir rocks in the Oligocene to Miocene Malembo Formation have high porosity and permeability, consist of stacked turbidite channel deposits; claystone units form the reservoir seals. The reservoir sandstone units have porosities ranging from 20 to 40 percent and permeabilities of 1 to 5 D (Raposo and Inkollu, 1998). Eocene to Miocene turbidite channel deposits are the producing reservoirs in many of the post-1994 offshore discoveries; cumulative drill-stem tests range from 10,000 to 15,000 barrels of oil per day (Raposo and Inkollu, 1998).

Potential fluvial and lacustrine sandstone and carbonate reservoir rocks in the outer Kwanza Basin are equivalent to the Neocomian to Barremian Toca Formation (Uncini and others, 1998) of the southern Congo Basin (fig. 17). Fluvial and lacustrine sandstone reservoir rocks may also be present in equivalent rocks of the Bucomazi Formation (Schoellkopf and Patterson, 2000). The Aptian Upper Cuvo Formation is of fluvial and lacustrine origin, a potential reservoir unit and is equivalent to the Chela Sandstone of the Congo Basin (Pasley, 1998a). Oil accumulations are present in the Albian Catumbela Formation (fig. 17). Other potential reservoir rocks are associated with a Late Cretaceous divergent-margin phase related to regional subsidence that allowed the deposition of progradational clastic units, equivalent to the Iabe Formation of the Congo Basin.

The outer Kwanza Basin was influenced by a major Neogene uplift that removed as much as 2 kilometers (km) of Cretaceous and Paleogene rocks from the inner Kwanza Basin. As a result, Miocene sediment (fig. 18) was deposited in the offshore forming a section currently at least 3,000 m thick (Lunde and others, 1992; Raposo and Inkollu, 1998) in Tertiary troughs that were probably formed along growth faults resulting from extension along a detachment surface within the salt (Duval and others, 1992; Lundin, 1992). These troughs or grabens developed primarily during the middle Tertiary, but some deformation appears to have started in the late Cenomanian to early Turonian (Duval and others, 1992; Lundin, 1992). Filled grabens as long as 70 km and as wide as 15 km contain both structural and stratigraphic traps. Tertiary sandstone reservoir rocks in the outer Kwanza Basin are similar to units found in the southern Congo Basin. The outer Kwanza Basin Tertiary sandstones have porosities ranging from 20 to 40 percent and permeabilities of 1 to 5 darcies. These rocks represent deposition in amalgamated or stacked turbidite channels and sandstone units in delta, prodelta, and basin-floor-fan settings and have interbedded marine shale that acts as reservoir seals (Raposo and Inkollu, 1998).

Total Petroleum Systems of West-Central Coastal Province, West Africa

Comparison of subbasin geology permitted definition of three region areas from which to build an understanding of the total petroleum systems present in the West-Central Coastal Province. These regions are the offshore and onshore area north of the Congo Basin including the Gabon, Rio Muni, Douala, and Kribi-Campo Basins (fig. 1); the Congo Basin including the large Tertiary Congo Delta (fig. 2); and the offshore and onshore area south of the Congo Basin including the Kwanza and Benguela Basins (fig. 1). Four major total petroleum systems are defined in the West-Central Coastal Province. The West-Central Coastal Province north of the Congo Basin contains two total petroleum systems (fig. 2): the Melania-Gamba TPS consisting of Lower Cretaceous source and reservoir rocks, and the Azile-Senonian TPS consisting of Albian to Turonian source rocks and Cretaceous reservoir rocks (fig. 3). The Congo Basin contains the Congo Delta Composite TPS (figs. 2, 3) consisting of Lower Cretaceous to Tertiary source and reservoir rocks, whereas the area south of the Congo Basin contains the Kwanza Composite TPS consisting of Lower Cretaceous to Tertiary source and reservoir rocks.

Five assessment units are defined in the West-Central Coastal Province: (1) the Gabon Subsalt AU of the Melania-Gamba TPS, (2) the Gabon Suprasalt AU of the Azile-Senonian TPS (figs. 2, 3), (3) the Central Congo Delta and Carbonate Platform AU of the Congo Delta Composite TPS; (4) the Central Congo Turbidites AU of the Congo Delta Composite TPS, and (5) the Kwanza-Namibe AU of the Kwanza Composite TPS. These assessment units were first used in the 2009 assessment. Brownfield and Charpentier (2006) provide a detailed discussion of the petroleum systems and assessment units.

Melania-Gamba Total Petroleum System (720301)

The Melania-Gamba TPS was defined north of the Congo Basin (fig. 2). An events chart (fig. 22) for the Melania-Gamba TPS summarizes the ages of the source, seal, and reservoir rocks as well as the timing of trap development, generation, and migration of hydrocarbons.

The primary source rocks of the Melania-Gamba TPS, which are found in the syn-rift section north of the Congo Delta, are Neocomian and Aptian continental and lacustrine rocks (figs. 7, 8, 9, 10, 11). The lacustrine shale is highly organic, especially the upper part of the Melania Formation (fig. 11) in the Gabon Basin where the total organic carbon (TOC) content averages 6.1 weight percent and reaches as high as 20 percent (Teisserenc and Villemin, 1990). The organic-rich black shale section is 200 to 600 m thick and contains both Type I and Type II kerogen. Source rocks of secondary importance include the lacustrine shale found in the Neocomian Kissenda Formation (fig. 11). The Kissenda contains source rocks averaging 1.5 to 2 weight percent TOC in Type II/III kerogens. Oils generated are paraffinic. Maturation and migration probably began in the Late Cretaceous (fig. 22) and continue to the present. In the Rio Muni Basin, similar lacustrine source rocks of Barremian to Aptian age (figs. 7, 8) contain as much as 6 weight percent TOC (Turner, 1995), and geochemical evidence suggests that lacustrine source rocks may exist in the Douala Basin.

Reservoir rocks in the syn-rift section are primarily fluvial and shoreface sandstones of the Gamba Formation. Porosities range from 25 to 30 percent and permeabilities range from 100 to as much as 5,000 mD (Teisserenc and Villemin, 1990; Boeuf and others, 1992). Some lacustrine-deltaic sandstones of the Dentale Formation have porosities as high as 29 percent and permeabilities as high as several darcies (Teisserenc and Villemin, 1990; Boeuf and others, 1992). Lacustrine-turbidite sandstones of the Melania Formation have porosities as high as 25 percent and permeabilities as high as 100 mD (Teisserenc and Villemin, 1990). Reservoir rocks in the Douala Basin consist of Lower Cretaceous submarine fans and fan-delta sandstones with porosities ranging from 20 to 25 percent and permeabilities as high as 142 mD. Trap formation began in the Late Cretaceous; traps are mostly broad anticlines in the Gamba Formation (fig. 11), but some traps are formed by rift structures (Teisserenc and Villemin, 1990; Boeuf and others, 1992). The Ezanga Formation salt forms a regional reservoir seal, although some hydrocarbons may have migrated through faults that have penetrated the Ezanga and equivalent rocks

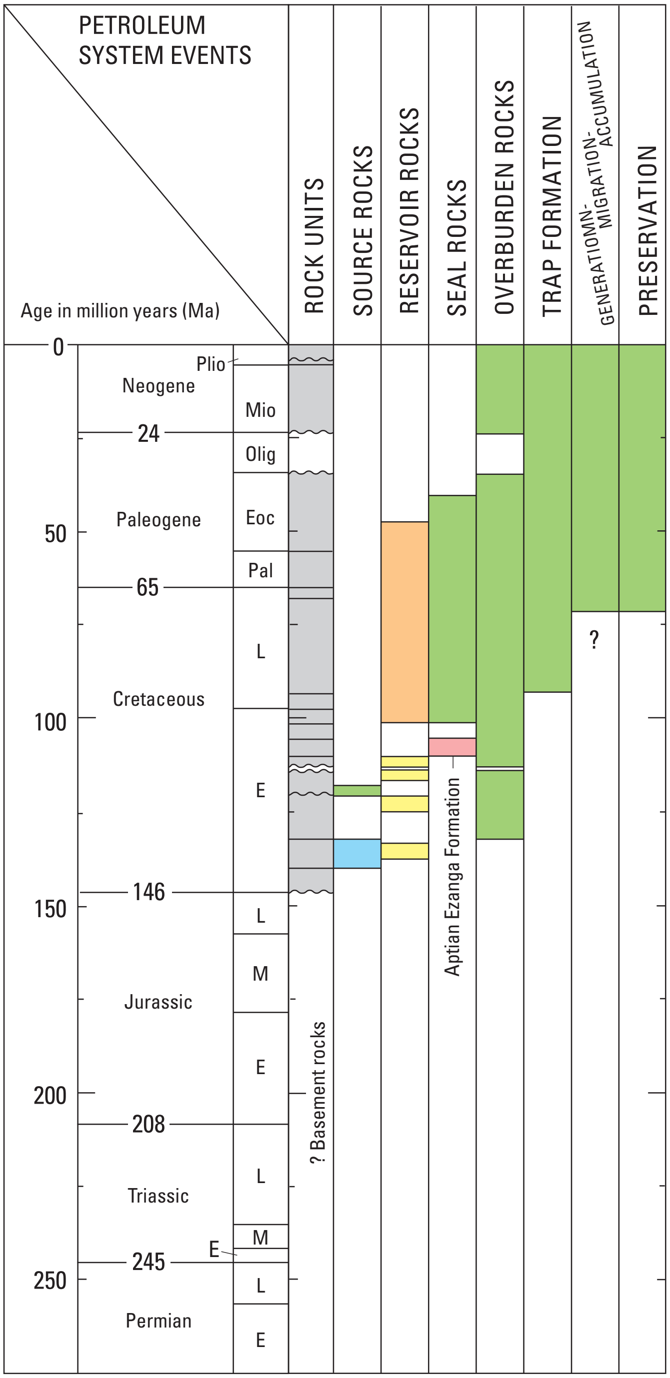


Figure 22. Events chart for the Melania-Gamba Total Petroleum System (720301) and the Gabon Subsalt Assessment Unit (72030101). Gray, rock units present (see figs. 7, 11, 19); blue, secondary or possible source rocks depending on quality and maturity of the unit; orange, probable reservoir rocks containing lacustrine oil in the Douala and Rio Muni Basins (figs. 8, 9); yellow, reservoir rocks; pink, Aptian Ezanga Formation (regional evaporate unit); green, source and overburden rocks, timing of trap formation, and generation, migration, and preservation of hydrocarbons; wavy line, unconformity. Divisions of geologic time conform to dates in U.S. Geological Survey Geologic Names Committee (2010). Ma, thousands of years ago; Plio, Pliocene; Mio, Miocene; Olig, Oligocene; Eoc, Eocene; Pal, Paleocene; L, Late; M, Middle; E, Early.

(Brownfield and Charpentier, 2006). Other hydrocarbon traps are stratigraphic and include fluvial and lacustrine sandstone units in the Dentale and Melania Formations (fig. 11). Interbedded shales are the reservoir seals.

Gabon Subsalt Assessment Unit (72030101)

The Gabon Subsalt AU of the Melania-Gamba TPS includes syn-rift source rocks and reservoir rocks north of the Congo Basin (fig. 1). The eastern boundary of the assessment unit was defined as the eastern limit of the Cretaceous rocks, whereas the western boundary was set at 4,000-m water depth (fig. 2). Most discoveries that have been made since 1970 and most of the discovered fields have been small or moderate in size. One giant field, Rabi-Kounga (fig. 6 index map; 1,400 million barrels), was discovered in 1985 (Boeuf and others, 1992).

Geologic Model

The geologic model developed for the assessment of conventional oil and gas in the Gabon Subsalt AU is as follows:

1. Oil and gas were generated from the Lower Cretaceous Melania lacustrine shale. The organic-rich Melania averages 6.1 weight percent TOC and reaches as high as 20 weight percent (fig. 11). The Kissenda Formation contains Type II/III kerogen, averaging 1.5 to 2 weight percent. Maturation and migration probably began in the Late Cretaceous (fig. 22) and have continued to the present.
2. Once generated, hydrocarbons migrated into Lower Cretaceous reservoirs.
3. Traps are mostly broad anticlines in the Gamba Formation (fig. 11), but some traps were formed by rift structures. Other traps are stratigraphic and include fluvial and lacustrine sandstone units in the Dentale and Melania Formations. Trap formation began in the Cretaceous.
4. The Ezanga Formation salt forms a regional reservoir seal. Other seals are interbedded shale in the Dentale and Melania Formations.

Assessment Results

The USGS assessed mean undiscovered volumes of 7,589 million barrels of oil (MMBO), 18,754 billion cubic feet of gas (BCFG), and 867 million barrels of natural gas liquids (MMBNGL) (table 1). The expected sizes of the largest undiscovered oil and gas fields are 2,559 MMBO and 7,384 BCFG, respectively.

Table 1. West-Central Coastal Province assessment results for undiscovered, technically recoverable oil, gas, and natural gas liquids.

[Largest expected mean field size in million barrels of oil and billion cubic feet of gas; MMBO, million barrels of oil. BCFG, billion cubic feet of gas. MMBNGL, million barrels of natural gas liquids. Results shown are fully risked estimates. For gas accumulations, all liquids are included as natural gas liquids (NGL). Undiscovered gas resources are the sum of nonassociated and associated gas. F95 represents a 95-percent chance of at least the amount tabulated; other fractiles are defined similarly. Fractiles are additive under assumption of perfect positive correlation. Fractiles are additive under assumption of perfect positive correlation. AU, assessment unit; AU probability is the chance of at least one accumulation of minimum size within the assessment unit. TPS, total petroleum system. Gray shading indicates not applicable]

Total Petroleum Systems (TPS) and Assessment Units (AU)	Field type	Largest expected mean field size	Total undiscovered resources											
			Oil (MMBO)				Gas (BCFG)				NGL (MMBNGL)			
			F95	F50	F5	Mean	F95	F50	F5	Mean	F95	F50	F5	Mean
West-Central Coastal Province—Melania–Gambia TPS														
Gabon Subsalt AU	***Oil***	2,559	2,042	6,492	16,805	7,589	1,134	3,783	12,115	4,863	57	191	617	247
	Gas	7,384					1,883	9,196	43,246	13,891	83	410	1,934	620
West-Central Coastal Province—Cretaceous–Tertiary Composite TPS														
Gabon Suprasalt AU	***Oil***	2,550	2,047	6,445	16,710	7,548	941	3,250	11,378	4,385	24	83	302	115
	Gas	6,583					1,241	7,356	39,177	11,822	38	227	1,224	370
West-Central Coastal Province—Congo Delta Composite TPS														
Central Congo Delta and Carbonate Platform AU	***Oil***	1,249	1,111	3,379	8,514	3,917	841	2,758	8,541	3,492	42	139	431	176
	Gas	3,305					645	4,009	20,577	6,307	33	208	1,091	334
Central Congo Turbidites AU	***Oil***	2,148	3,186	8,133	17,597	8,957	1,850	4,885	11,557	5,567	94	247	589	282
	Gas	2,014					215	1,304	10,437	2,814	9	58	466	126
West-Central Coastal Province—Kwanza Composite TPS														
Kwanza-Namibe AU	***Oil***	5,093	6,417	19,200	45,677	21,715	2,789	8,406	20,537	9,613	74	224	566	260
	Gas	7,729					1,306	7,640	44,892	13,036	34	199	1,198	347
Total Conventional Resources			**14,803**	**43,650**	**105,303**	**49,736**	**12,845**	**52,547**	**222,467**	**75,790**	**488**	**1,946**	**8,418**	**2,877**

Azile-Senonian Total Petroleum System (720302)

The Azile-Senonian TPS was also defined (fig. 3) north of the Congo Delta (it is colocated geographically with Melania-Gamba TPS, 720301). An events chart (fig. 23) summarizes the ages of the source, seal, and reservoir rocks and the timing of trap development and generation and migration of hydrocarbons.

The primary source rocks for the Azile-Senonian TPS in the Gabon Basin are marine shale and marlstone of the Turonian Azile Formation (fig. 19) above the Ezanga Formation salt. Shale contains mainly Type II/III kerogen, averaging from 3 to 5 weight percent TOC; some samples contain as much as 10 weight percent TOC (Tissot and others, 1980). Other possible sources include shale in the Cap Lopez and Madiela Formations. Oil generated in the Azile-Senonian TPS are paraffinic. Maturation and migration began later, during the Miocene, than for the post-rift source rocks (Teisserenc and Villemin, 1990), and continue to the present (fig. 23).

Upper Albian to Maastrichtian source rocks in the Douala and Rio Muni Basins (figs. 7, 9) consist of marine marlstone that may be equivalent to the Cap Lopez and Azile Formations. Secondary Paleocene, Oligocene, and Miocene source rocks have also been identified in these basins.

In the North Gabon subbasin, known reservoir rocks are mainly turbidite sandstones of the Senonian Anguille and Pointe Clairette Formations and Batanga Sandstone Member of the Ewongue Formation (fig. 19). Porosities average 23 percent and permeabilities average 1,500 mD. Trap formation began in the Late Cretaceous. Most traps are salt-related, primarily nonpiercement domes. Reservoirs are sealed by shale. Some stratigraphic traps may exist that are related to turbidite units.

In the deep-water parts of the Douala and Rio Muni Basins, higher-resolution seismic data indicate that Upper Cretaceous and Tertiary reservoir rocks in the deep water are turbidite strata. Possible Miocene turbidite reservoirs may also exist in the deeper water offshore. Most Miocene traps are stratigraphic and include turbidite units sealed by shales.

Gabon Suprasalt Assessment Unit (72030201)

The Gabon Suprasalt AU of the Azile-Senonian TPS includes suprasalt source rocks and reservoirs north of the Congo Basin (fig. 3). The eastern boundary of the assessment unit was defined as the eastern limit of the Cretaceous rocks, whereas the western boundary was set at a water depth of 4,000 m. Since the 1950s, about 75 fields have been discovered, mostly small or moderate-sized oil fields. Most fields are in the Ogooue River delta area of Gabon (fig. 6). The Douala and Rio Muni Basins of Cameroon and Equatorial Guinea (fig. 1), to the north of Gabon, are also included with this assessment unit.

Most of the exploration has taken place onshore or in shallow water. Significant potential exists for the deep-water part of the Ogooue River delta and the Douala and Rio Muni Basins, including potential for large undiscovered oil and gas fields. Oil exploration is considered moderately mature, whereas gas exploration is immature.

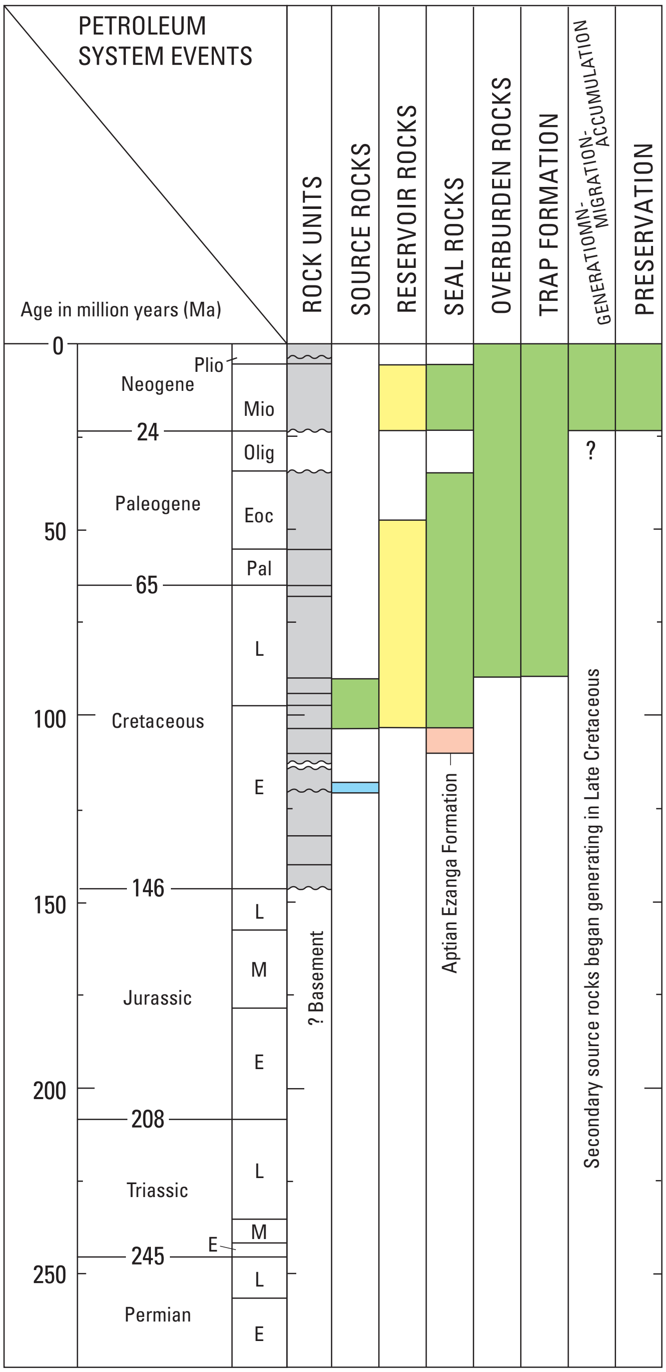


Figure 23. Events chart for the Azile-Senonian Total Petroleum System (720302) and the Gabon Suprasalt Assessment Unit (72030201). Gray, rock units present (see figs. 7, 11, 19); blue, secondary or possible source rocks depending on quality and maturity of the unit; yellow, reservoir rocks (reservoir rocks containing lacustrine oil are found in the Douala and Rio Muni Basins (figs. 8, 9)); pink, Aptian Ezanga Formation (regional evaporate unit); green, source and overburden rocks, timing of trap formation, and generation, migration, and preservation of hydrocarbons; wavy line, unconformity. Divisions of geologic time conform to dates in U.S. Geological Survey Geologic Names Committee (2010). Ma, thousands of years ago; Plio, Pliocene; Mio, Miocene; Olig, Oligocene; Eoc, Eocene; Pal, Paleocene; L, Late; M, Middle; E, Early; ?, uncertain.

Geologic Model

The geologic model developed for the assessment of conventional oil and gas in the Gabon Suprasalt Assessment Unit is as follows:

1. Oil and gas were generated from marine shale and marlstone of the Turonian Azile Formation. These shales average 3 to 5 weight percent TOC; some samples contain as much as 10 weight percent TOC. Upper Albian to Maastrichtian source rocks have been identified in the assessment unit. Lacustrine shales in the Melania Formation may have also been the source hydrocarbons. Maturation of Melania source rocks began in the Early Cretaceous, whereas the maturation of the Turonian source rocks began later during the Miocene and has continued to the present (fig. 23).
2. Once generated, hydrocarbons migrated into Upper Cretaceous and Miocene sandstone reservoirs during the Early Cretaceous. Beginning in the Miocene, Turonian oils migrated into Tertiary turbidite reservoirs.
3. Hydrocarbon traps are salt-related, nonpiercement domes or are stratigraphic and related to turbidite units.
4. Reservoir seals are mostly Upper Cretaceous and Miocene shales.

Assessment Results

The USGS assessed mean undiscovered volumes of 7,548 MMBO, 16,207 BCFG, and 485 MMBNGL (table 1). The expected sizes of the largest undiscovered oil and gas fields are 2,550 MMBO and 6,583 BCFG, respectively.

Congo Delta Composite Total Petroleum System (720303)

The Congo Delta Composite TPS was defined in the West-Central Coastal Province of equatorial west Africa (fig. 2). An events chart for the Congo Delta Composite TPS summarizes the age of the source, seal, and reservoir rocks and the timing of trap development and generation and migration of hydrocarbons (fig. 24).

The primary source rock for the Congo Delta Composite TPS is the syn-rift lacustrine shale of the Lower Cretaceous Bucomazi Formation (figs. 15, 24). Source rocks in the middle unit of the Bucomazi Formation contain Type I kerogen and average 5 weight percent and as much as 20 weight percent TOC. The lower and upper units of the Bucomazi Formation average only 2 to 3 weight percent TOC. Additional marine source rocks in the post-rift section are marine shale and marlstone of the Upper Cretaceous Iabe Formation, the Paleocene-Eocene Landana Formation, and the Oligocene to Miocene Malembo Formation (figs. 15, 24).

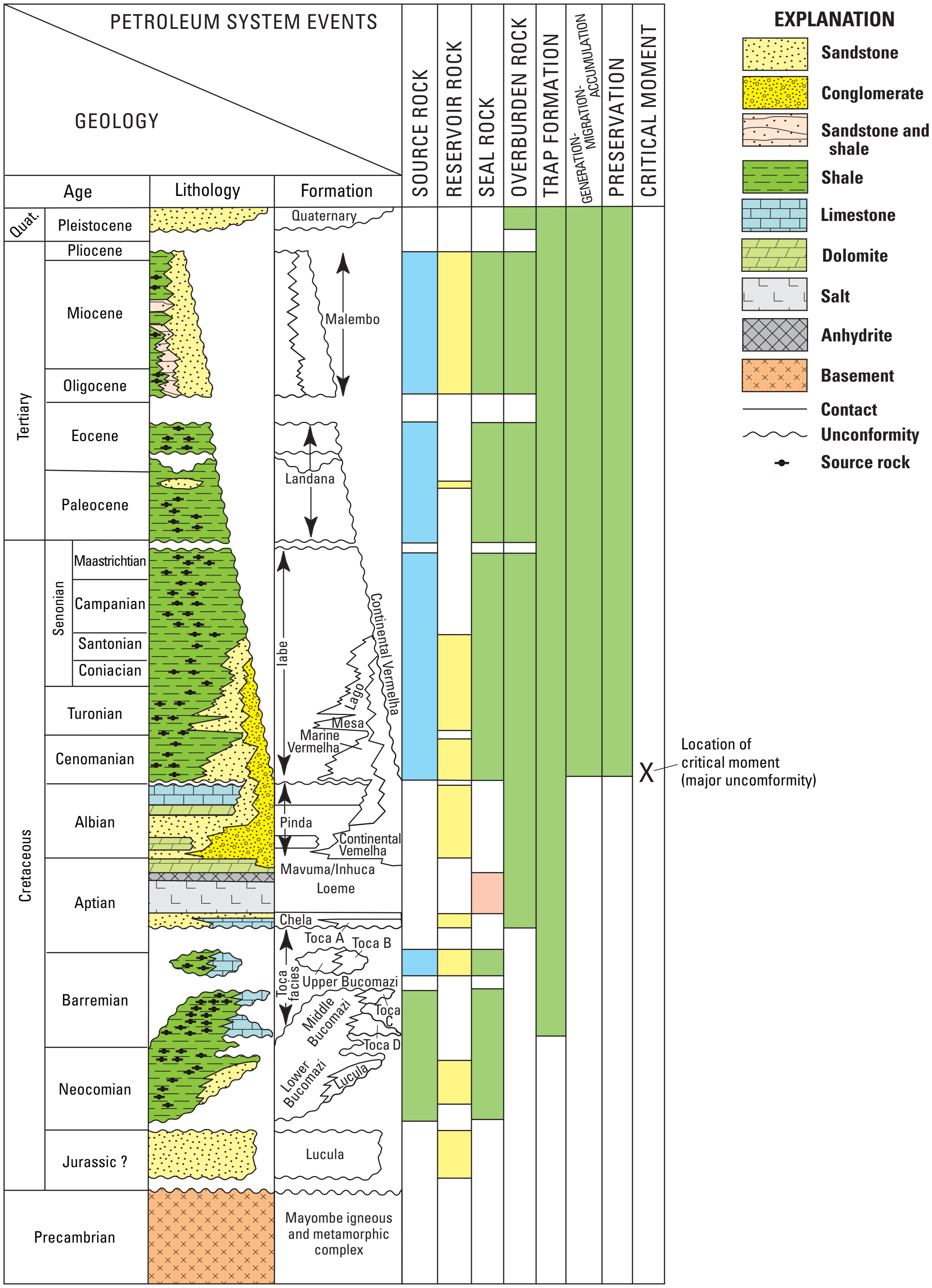


Figure 24. Events chart for the Congo Delta Composite Total Petroleum System (720303) and the Central Congo Delta and Carbonate Platform and the Central Congo Turbidites Assessment Units (72030301 and 72030302, respectively). Blue, secondary source rocks depending on quality and maturity of the unit; yellow, reservoir rocks; pink, Aptian Ezanga Formation (regional evaporate unit); green, source and overburden rocks, timing of trap formation, and generation, migration, and preservation of hydrocarbons. Divisions of geologic time conform to dates in U.S. Geological Survey Geologic Names Committee (2010). Age, formation, and lithology modified from McHargue (1990), Schoellkopf and Patterson (2000), and Da Costa and others (2001). Quat., Quaternary.

Lacustrine oils generated from the Bucomazi are paraffinic. Oil generation began in the Late Cretaceous (Schoellkopf and Patterson, 2000) and continues to the present (fig. 24). Migration pathways are mostly along faults, but some lateral migration has occurred below the Loeme Salt within the Chela Sandstone. Lacustrine oils charged many of the Upper Cretaceous and Tertiary turbidite units in the Congo Basin (Schoellkopf and Patterson, 2000).

In the shallow-water areas of the Congo Basin, the majority of reservoir rocks are sandstones of both syn-rift and post-rift origin (fig. 15). A large number of reservoirs consist of carbonate rocks (about 50 percent each limestone and dolomite), mainly those found in the Albian Pinda Formation (fig. 15). Overall, porosities average about 21 percent, and permeabilities average 450 mD. In the deeper-water prospects, reservoir rocks are expected to be primarily Oligocene and Miocene turbidite channels and basin-floor fans and mounds.

Trap formation most likely began in the late Neocomian to Barremian (Edwards and Bignell, 1988b; Teisserenc and Villemin, 1990) when a second phase of rifting and subsidence developed in the central part of the Aptian salt basin. The thick regional evaporite sequence deposited in Aptian time and subsequent salt deformation strongly influenced both structure and facies distribution related to trap development (Edwards and Bignell, 1988b). In the shallow-water areas, traps are mostly anticlinal and related to rollovers. Other traps are related to fault blocks or paleotopography. Reservoir seals are Cretaceous to Tertiary lacustrine and marine shale. In deeper water, traps are both stratigraphic and structural and include turbidite channels and sandstones and ponded or thickened, growth-fault-related sandstone sealed by shale.

Central Congo Delta and Carbonate Platform Assessment Unit (72030301)

The Central Congo Delta and Carbonate Platform AU of the Congo Delta Composite TPS (fig. 2) contain both syn-rift and post-rift source rocks and reservoirs of Mesozoic through Miocene age in the area of the Congo Basin (fig. 1). The eastern boundary of the assessment unit was defined as the eastern limit of the Cretaceous rocks, and the western boundary was set at a 4,000-m water depth. Although the nonturbidite reservoirs included in this assessment unit could extend into the westernmost parts of the assessment unit, most of the expected prospective activity is to be in the eastern, shallow-water part.

Most of the exploration in this assessment unit has taken place since the middle 1960s. Sizes of discovered oil fields have not shown much decrease with time, suggesting that the exploration is not mature.

Geologic Model

The geologic model developed for the assessment of conventional oil and gas in the Central Congo Delta and Carbonate Platform Assessment Unit is as follows:

1. Oil and gas were generated primarily from the organic-rich lacustrine shale of the Lower Cretaceous Bucomazi Formation. The source rocks contain Type I kerogen and an average of 5 weight percent but as much as 20 weight percent TOC. Additional marine source rocks are found in Upper Cretaceous strata. Oil generation began in the Late Cretaceous and has continued to the present.
2. Once generated, the hydrocarbons migrated along faults into Cretaceous and Tertiary reservoirs. Some lateral migration has occurred in the Chela Sandstone below the Loeme Salt (fig. 24). The primary reservoir rock is carbonate, including the Pinda Formation (fig. 22). Upper Cretaceous and Tertiary sandstones are also reservoirs in the eastern part of the assessment unit.
3. In the eastern part of the assessment unit, hydrocarbon traps are mostly structural and include fault blocks and anticlines related to rollovers. In the western part of the assessment unit, traps are both stratigraphic and structural and include turbidite units and ponded or thickened, growth-fault-related sandstone.
4. Reservoir seals are Cretaceous and Tertiary shale.

Assessment Results

The USGS assessed mean undiscovered volumes of 3,917 MMBO, a mean of 9,799 BCFG, and a mean of 510 MMBNG (table 1). The expected sizes of the largest undiscovered oil and gas fields are 1,249 MMBO and 3,305 BCFG, respectively.

Central Congo Turbidites Assessment Unit (72030302)

The Central Congo Turbidites AU of the Congo Delta Composite TPS (fig. 3) contains both subsalt and suprasalt source rocks and Oligocene to Miocene turbidite reservoirs in the area of the Congo Basin (fig. 1). The eastern boundary of the assessment unit is defined at 200-m water depth, and the western boundary was set at 4,000-m water depth. The assessment unit lies primarily in deep water.

The large size of discovered fields (some more than 500 MMBO) suggested a high potential for large remaining fields. The deeper-water turbidite areas are underexplored, and geologic considerations suggest that they may be basin-floor fans equivalent in prospective resources to the recent discoveries of slope-channel turbidites. The geologic setting presents the possibility that large fields will be found in the underexplored deep-water part of the Central Congo Turbidites AU, given appropriate fluid generation and migration paths.

Geologic Model

The geologic model developed for the assessment of conventional oil and gas in the Central Congo Turbidites Assessment Unit is as follows:

1. Oil and gas were generated primarily from subsalt lacustrine shale. Other possible source rocks include suprasalt marine shale. The primary lacustrine source rocks contain Type I kerogen; they average 5 weight percent TOC and may contain as much as 20 weight percent TOC.
2. Once generated, the hydrocarbons migrated into Oligocene and Miocene turbidite reservoirs. Migration pathways are fault related. Reservoirs are turbidite sandstone and ponded or thickened, growth-fault-related sandstones. Possible deep-water fans may also exist.
3. Hydrocarbon traps are mostly stratigraphic and include turbidite units and with some structural ponded or thickened, growth-fault-related sandstones.
4. Reservoir seals are Tertiary shale.

Assessment Results

The USGS assessed mean undiscovered volumes of 8,967 MMBO, 8,381 BCFG, and 408 MMBNGL (table 1). The expected sizes of the largest undiscovered oil and gas fields are 2,148 MMBO and 2,014 BCFG, respectively.

Kwanza Composite Total Petroleum System (720304)

The Kwanza Composite TPS was defined south of the Congo Basin (figs. 1, 3). An events chart (fig. 25) summarizes the age of the source, seal, and reservoir rocks, and the timing of trap development and generation and migration of hydrocarbons.

Primary source rocks in the Kwanza Composite TPS are syn-rift lacustrine shale (figs. 16, 17) and post-rift marine shale and marlstone (fig. 15). Syn-rift source rocks in the southern offshore part of the outer Kwanza Basin consist of thick, organic-rich, lacustrine shale and marine shales that contain Type I and Type II kerogens (Pasley and others, 1998b). The source rocks have an average of 3.1 weight percent and as much as 20 weight percent TOC (Geochemical and Environmental Research Group, 2003). The oils generated in this petroleum system are paraffinic. The syn-rift sources may have matured in the Late Cretaceous. The post-rift marine source rocks probably matured in the early to mid-Tertiary (Danforth and others, 1997). Migration pathways are mostly fault related, but some lateral migration in the Cuvo or equivalent Chela Sandstone is apparent (fig. 17).

Cretaceous onshore and nearshore reservoirs include both carbonate and clastic types that are similar to reservoirs in the Pinda Formation of the southern Congo Basin (fig. 15) and the Tuemza Formation of the onshore Kwanza Basin (fig. 16) (Danforth and others, 1997). Traps in the onshore and nearshore discovered fields are primarily anticlinal. Analogous to the deep-water discoveries in the Congo Basin, Oligocene to Miocene turbidite reservoirs are present in deeper water of the outer Kwanza Basin. These reservoir rocks are located in grabens related to Tertiary extension along the detachment surface in the salt (Duval and others, 1992; Lundin, 1992). Tertiary reservoir rocks are similar to reservoir rocks found in the southern Congo Basin. Porosities and permeabilities range from 20 to 40 percent and from 1 to 5 Darcy, respectively (Raposo and Inkollu, 1998). The Tertiary turbidite sandstone units may contain both stratigraphic and structural traps with shale seals.

Kwanza-Namibe Assessment Unit (72030401)

The Kwanza-Namibe AU of the Kwanza TPS System includes source rocks and reservoirs in the Mesozoic and Cenozoic rocks of the Kwanza Basin of Angola, south to the Walvis Ridge (figs. 1, 3). The eastern boundary of the assessment unit was defined as the eastern limit of the Cretaceous rocks, whereas the western boundary was set at a 4,000-m water depth (fig. 3). Exploration since the 1950s has focused on the onshore and nearshore parts of the Kwanza Basin. Only a few small- to moderate-sized oil fields have been discovered.

The immaturity of exploration, especially in deeper waters, could allow for some large undiscovered fields. Prospective areas would be greatest in the northern part of the assessment unit, where the stratigraphic section is thickest. To the south, the section is thinner and lacks large sources of sediment such as the Congo Delta. These factors suggest that there may be fewer suitable sandstone reservoirs and that the source rocks may not be buried sufficiently for peak generation of hydrocarbons.

Geologic Model

The geologic model developed for the assessment of conventional oil and gas in the Kwanza-Namibe Assessment Unit is as follows:

1. Oil and gas were generated from both lacustrine shale and marine shale and marlstone. Source rocks average 3.1 weight percent TOC; some samples have TOC contents greater than 20 weight percent TOC. Hydrocarbon generation by Lower Cretaceous lacustrine sources began in the Late Cretaceous, and Late Cretaceous marine sources matured in the early to mid-Tertiary. Generation most likely continues to the present.
2. Once generated, the hydrocarbons migrated along faults into Cretaceous and Tertiary reservoirs (fig. 22). Some lateral migration is apparent in the Cuvo or equivalent Chela Sandstone (fig. 17).
3. Cretaceous hydrocarbon reservoirs include both carbonate and clastic types. Oligocene and Miocene turbidite sandstone units are important reservoirs.
4. Reservoir seals are Cretaceous and Tertiary shale.

Assessment Results

The USGS assessed mean undiscovered volumes of 21,715 MMBO, 22,649 BCFG, and 607 MMBNGL (table 1). The expected sizes of the largest undiscovered oil and gas fields are 5,093 MMBO and 7,729 BCFG, respectively.

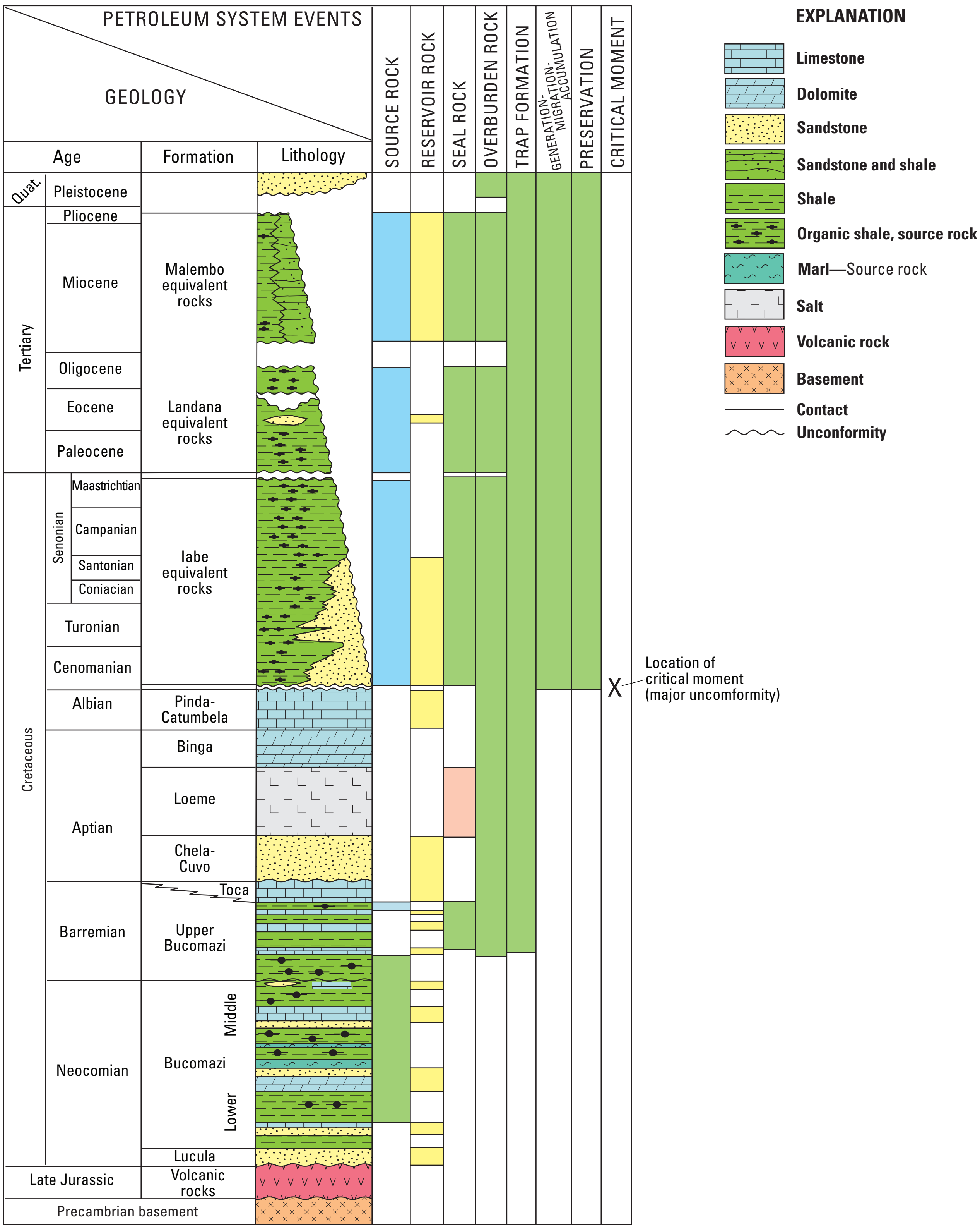


Figure 25. Events chart for the Kwanza Composite Total Petroleum System (720304) and the Kwanza-Namibe Assessment Unit (72030401). Blue, secondary or possible source rocks depending on quality and maturity of the unit; yellow, reservoir rocks; pink, Aptian Ezanga Formation (regional evaporate unit); green, source and overburden rocks, timing of trap formation, and generation, migration, and preservation of hydrocarbons. Divisions of geologic time conform to dates in U.S. Geological Survey Geologic Names Committee (2010). Age, formation, and lithology modified from McHargue (1990), Lunde and others (1992), Pasley and others (1998b), Coward and others (1999), Schoellkopf and Patterson (2000), and Da Costa and others (2001). Quat., Quaternary.

Exploration

More than 650 oil and gas fields have been discovered in the West-Central Coastal Province (IHS Energy Group, 2008), and more than 190 fields have been discovered since the 2000 USGS World Petroleum Assessment (U.S. Geological Survey World Energy Assessment Team, 2000). Much of the province is now considered a deep-water hydrocarbon province, because many new discoveries are being found in water depths greater than 200 m in turbidite-related reservoirs.

Resource Summary

The West-Central Coastal Province was divided into the Gabon Subsalt, Gabon Suprasalt, Central Congo Delta and Carbonate Platform, Central Congo Turbidites, and Kwanza-Namibe Assessment Units. The estimated mean volumes for these five assessment units are 49,736 million barrels of oil, 75,790 billion cubic feet of gas, and 2,877 million barrels natural gas liquids (table 1).

The cumulative known oil volume has increased steadily in the province since the 2000 World Assessment (U.S. Geological Survey Assessment Team, 2000), when the western part of equatorial Africa became a deep-water hydrocarbon province. New field discoveries and higher-resolution and three-dimensional seismic studies since the original USGS assessment of the province have encouraged an increase in exploration in all the subbasins in the West-Central Coastal Province. Large offshore parts of the Kwanza, Douala, and Rio Muni Basins are underexplored and contain many potential prospects. The province has hydrocarbon potential in both onshore and offshore parts, but the greatest potential is in the deep-water parts of the province. Gas resources may be substantial and accessible in areas where the zone of oil generation is relatively shallow.

For Additional Information

Assessment results are available at the USGS Central Energy Resources Science Center website: http://energy.cr.usgs.gov/oilgas/ or contact Michael E. Brownfield, the assessing geologist (*mbrownfield@usgs.gov*).

Acknowledgments

The author wishes to thank Mary-Margaret Coates, Jennifer Eoff, Christopher Schenk, and David Scott for their suggestions, comments, and editorial reviews, which greatly improved the manuscript. The author thanks Wayne Husband for his numerous hours drafting many of the figures used in this manuscript, and Chris Anderson, who supplied the Geographic Information System files for this assessment.

References

Ackerman, W.C., Boatwright, D.C., Burwood, B.M., Van Lerberche, D., Bondjo, E., Tamfu, S.F., and Ovono, D., 1993, Geochemical analysis of selected hydrocarbon samples in the Douala Basin, Cameroon—Implications for an oil-prone source rock [abs.]: American Association of Petroleum Geologists Bulletin, v. 77, no. 9, p. 1604.

Baudouy, S., and Legorjus, C., 1991, Sendji field—People’s Republic of Congo, Congo Basin, *in* Foster, N.H., and Beaumont, E.A., eds., Treatise of petroleum geology Atlas of oil and gas fields—Structural traps V: American Association of Petroleum Geologists, p. 121–149.

Binks, R.M., and Fairhead, J.D., 1992, A plate tectonic setting for Mesozoic rifts of west and central Africa: Tectonophysics, v. 213, p. 141–151.

Boeuf, M.A.G., Cliff, W.J., and Hombroek, J.A.R., 1992, Discovery and development of the Rabi-Kounga field—A giant oil field in a rift basin onshore Gabon, *in* World Petroleum Congress, 13th, Buenos Aires, 1991: New York, John Wiley, v. 2, p. 33–46.

Brice, S.E., Cochran, M.D., Pardo, Georges, and Edwards, A.D., 1982, Tectonics and sedimentation of the South Atlantic rift sequence, Cabinda, Angola, *in* Watkins, J.S., and Drake, C.L., eds., Studies in continental margin geology: American Association of Petroleum Geologists Memoir 34, p. 5–18.

Brink, A.H., 1974, Petroleum geology of Gabon basin: American Association of Petroleum Geologists Bulletin, v. 58, no. 2, p. 216–235.

Brognon, G.P., and Verrier, G.R., 1966, Oil and geology in Cuanza basin of Angola: American Association of Petroleum Geologists Bulletin, v. 50, no. 1, p. 108–158.

Brownfield, M.E., and Charpentier, R.R., 2006, Geology and total petroleum systems of the West-Central Coastal Province (7203), west Africa: U.S. Geological Survey Bulletin 2207–B, 52 p.

Burwood, R., 1999, Angola—Source rock control for Lower Congo Coastal and Kwanza Basin petroleum systems, *in* Cameron, N.R., Bate, R.H., and Clure, V.S., eds., The oil and gas habitats of the South Atlantic, The Geological Society, London, Special Publication 153, p. 181–194.

Coward, M.P., Purdy, E.G., Ries, A.C., and Smith, D.G., 1999, The distribution of petroleum reserves in basins of the South Atlantic margins, *in* Cameron, N.R., Bate, R.H., and Clure, V.S., eds., The oil and gas habitats of the South Atlantic: The Geological Society, London, Special Publication 153, p. 101–131.

Da Costa, J.L., Schirmer, T.W., and Laws, B.R., 2001, Lower Congo Basin, deep-water exploration province, offshore west Africa: American Association of Petroleum Geologists Memoir 74, p. 517–530.

Dale, C.T., Lopes, J.R., and Abilio, S., 1992, Takula oil field and the greater Takula area, Cabinda, Angola, *in* Halbouty, M.T., ed., Giant oil and gas fields of the decade 1978–1988: American Association of Petroleum Geologists Memoir 54, p. 197–215.

Danforth, Al, Koning, Tako, and De Deus, Odette, 1997, Petroleum systems of the coastal Kwanza and Benguela Basins, Angola, *in* Mello, M.R., and Katz, B., eds., Hedberg Research Symposium Extended Abstracts, November, 16–19, 1997, Rio de Janeiro, Brazil, 4 p.

Duval, Bernard, Cramez, Carlos, and Jackson, M.P.A., 1992, Raft tectonics in the Kwanza Basin, Angola: Marine and Petroleum Geology, v. 9, no. 4, p. 389–404.

Edwards, Alan, and Bignell, Roger, 1988a, Hydrocarbon potential of W. African salt basin: Oil and Gas Journal, v. 86, no. 50, p. 71–74.

Edwards, Alan, and Bignell, Roger, 1988b, Nine major play types recognized in salt basin: Oil and Gas Journal, v. 86, no. 51, p. 55–58.

Equatorial Guinea Ministry of Mines and Energy, 2003, Petroleum—Technical review: 8 p. Available at http://www.equatorialoil.com. Last accessed September 23, 2003.

Guiraud, Rene, and Maurin, Jean-Christophe, 1992, Early Cretaceous rifts of western and central Africa—An overview: Tectonophysics, v. 213, p. 153–168.

Harris, N.B., 2000, Toca carbonate, Congo Basin—Response to an evolving rift lake, *in* Mello, M.R., and Katz, B.J., eds., Petroleum systems of South Atlantic margin, American Association of Petroleum Geologists Memoir 73, p. 341–360.

Hudec, M.R., and Jackson, M.P.A., 2002, Structural segmentation, inversion, and salt tectonics on a passive margin—Evolution of the inter Kwanza Basin, Angola: Geological Society of America Bulletin, v. 114, p. 1222–1244.

IHS Energy Group, 2008 [includes data current as of December, 2009], International petroleum exploration and production database: IHS Energy Group; database available from IHS Energy Group, 15 Inverness Way East, Englewood, Colorado 80112 USA.

Klett, T.R., Ahlbrandt, T.A., Schmoker, J.W., and Dolton, G.L., 1997, Ranking of the world's oil and gas provinces by known petroleum volumes: U.S. Geological Survey Open-File Report 97–463, one CD–ROM.

Lambiase, J.J., 1989, The framework of African rifting during the Phanerozoic: Journal of African Earth Science, v. 8, no. 2/3/4, p. 183–190.

Lehner, P., and De Ritter, P.A.C., 1977, Structural history of Atlantic margin of Africa: American Association of Petroleum Geologists Bulletin, v. 61, no. 7, p. 961–981.

Lunde, Geir, Aubert, Kristin, Lauritzen, Ornulf, and Lorange, Erik, 1992, Tertiary uplift of the Kwanza basin in Angola, *in* Curnelle, R., ed., Géologie Africaine, 1 er Colloque de Stratigraphie et de Paléogéographie des Bassins Sédimentaires Ouest-Africains, 2 e Colloque Africain de Micropaléontologie, Libreville, Gabon, 1991, Recueil des Communications: Boussens, Elf Aquitaine, p. 99–117.

Lundin, E.R., 1992, Thin-skinned extensional tectonics on a salt detachment, northern Kwanza Basin, Angola: Marine and Petroleum Geology, v. 9, no. 4, p. 405–411.

McHargue, T.R., 1990, Stratigraphic development of proto-south Atlantic rifting in Cabinda, Angola–A petroliferous lake basin, *in* Katz, B.J., ed., Lacustrine basin exploration case studies and modern analogs: American Association of Petroleum Geologists Memoir 50, p. 307–326.

Nguene, François-Roger, Tamfu, Simon, Loule, Jean-Pierre, and Ngassa, Célestin, 1992, Paleoenvironments of the Douala and Kribi/Campo subbasins, *in* Cameroon, west Africa, *in* Curnelle, Robert, ed., Géologie Africaine, 1er Colloque de Stratigraphie et de Paléogéographie des Bassins Sédimentaires Ouest-Africains, 2 e Colloque Africain de Micropaléontologie, Libreville, Gabon, 1991, Recueil des Communications: Boussens, Elf Aquitaine, p.129–139.

Oba, A.O., 2001, Stratigraphy of the Sergipe-Alagoas (Brazil), Douala, Rio Muni, and Gabon (west Africa) sedimentary basins: http://rainier.seis.sc.edu/alfredo/OvonoOba.htm, Department of Geological Sciences, University of South Carolina, 16 p.

Orsolini, P., Scheevel, J.R., Jeronimo, P., and Barletta, V., 1998, Regional evaluation of the pre-salt system of Cabinda, Angola [abs.], *in* Mello, M.R., and Yilmaz, P.O., eds., Rio '98 Petroleum Geology in a Changing World Extended Abstracts, November 8–11, 1998, Rio de Janeiro, Brazil, p. 358.

Pasley, M.A., Wilson, E.N., Abreu, V.A., Brandão, M.G.P., and Telles, A.S., 1998a, Lower Cretaceous stratigraphy and source rock distribution in pre-salt basins of the South Atlantic—Comparison of Angola and southern Brazil [abs.]: American Association of Petroleum Geologists Bulletin, v. 82, no. 10, p. 1949.

Pasley, M.A., Wilson, E.N., Abreu, V.A., Brandão, M.G.P., and Telles, A.S., 1998b, Lower Cretaceous stratigraphy and source rock distribution in pre-salt basins of the South Atlantic—Comparison of Angola and southern Brazil [abs.], *in* Mello, M.R., and Yilmaz, P.O., eds., Rio '98 Petroleum Geology in a Changing World Extended Abstracts, November 8–11, 1998, Rio de Janeiro, Brazil, p. 822–823.

Pauken, R.J., 1992, Sanaga Sud field, offshore Cameroon, west Africa, *in* Halbouty, M.T., ed., Giant oil and gas fields of the decade 1978–1988, American Association of Petroleum Geologists Memoir 54, p. 217–230.

Pauken, R.J., Thompson, J.M., Schuman, J.R., and Cooke, J.C., 1991, Geology of the Douala Basin, offshore Cameroon: American Association of Petroleum Geologists Bulletin, v. 75, no. 3, p. 651–652.

Persits, F.M., Ahlbrandt, T.S., Tuttle, M.L., Charpentier, R.R., Brownfield, M.E., and Takahashi, K.I., 2002, Map showing geology, oil and gas fields, and geologic provinces of Africa: U.S. Geological Survey Open-File Report 97–470A, Version 2.0, CD–ROM.

Raposo, António, and Inkollu, Murthy, 1998, Tertiary reservoirs in Congo-Kwanza-Namibe Basins, *in* Mello, M.R., and Yilmaz, P.O., eds., Rio '98 Petroleum Geology in a Changing World Extended Abstracts, November 8–11, 1998, Rio de Janeiro, Brazil, p. 668–669.

Ross, Don, and Hempstead, Norman, 1993, Geology and hydrocarbon potential of Rio Muni area, Equatorial Guinea: Oil and Gas Journal, v. 91, August 23, 1993, p. 96–100.

Schiefelbein, C.F., Zumberge, J.E., Cameron, N.R., and Brown, S.W., 2000, Geochemical comparison of crude oil along the South Atlantic margin, *in* Mello, M.R., and Katz, B.J., eds., Petroleum systems of South Atlantic margins: American Association of Petroleum Geologists Memoir 73, p. 15–26.

Schoellkopf, N.B., and Patterson, B.A., 2000, Petroleum systems of offshore Cabinda, Angola, *in* Mello, M.R., and Katz, B.J., eds., Petroleum systems of South Atlantic margins: American Association of Petroleum Geologists Memoir 73, p. 361–376.

Tamfu, S.F., Batupe, M., Pauken, R.J., and Boatwright, D.C., 1995, Geological setting, stratigraphy and hydrocarbon habitat of the Douala Basin, Cameroon [abs.]: American Association of Petroleum Geologists Bulletin, v. 79, no. 13, p. 95.

Teisserenc, P., and Villemin, J., 1990, Sedimentary basin of Gabon—Geology and oil systems, *in* Edwards, J.D., and Santogrossi, P.A., eds., Divergent/passive margin basins: American Association of Petroleum Geologists Memoir 48, p. 117–199.

Texas A&M University Geochemical and Environmental Research Group, 2003, Geochemistry of Angolan oils and rocks: College Station, Texas, Texas A&M University. Available at http://www.gerg.tamu.edu/menu_RGD/rs_regional/Geochemistry.htm.

Tissot, B., Demaison, G., Masson, P., Delteil, J.R., and Combaz, A., 1980, Paleoenvironment and petroleum potential of middle Cretaceous black shales in Atlantic basins: American Association of Petroleum Geologists Bulletin, v. 64, no. 12, p. 2051–2063.

Turner, J.P., 1995, Gravity-driven structures and rift basin evolution—Rio Muni Basin, offshore west Africa, American Association of Petroleum Geologists Bulletin, v. 79, no. 8, p. 1138–1158.

Uchupi, Elezar, 1989, The tectonic style of the Atlantic Mesozoic rift system: Journal of African Earth Sciences, v. 8, no. 2/3/4, p. 143–164.

Uchupi, Elezar, Emery, K.O., Bowin, C.O., and Phillips, J.D., 1976, Continental margin off western Africa—Senegal to Portugal: American Association of Petroleum Geologists Bulletin, v. 60, p. 809–879.

Uncini, Giuseppe, Brandão, Mario, and Giovannelli, Antonio, 1998, Neocomian–upper Aptian pre-salt sequence of southern Kwanza Basin—A regional view [abs.]: American Association of Petroleum Geologists Bulletin, v. 82, no. 10, p. 1894–1895.

U.S. Geological Survey Geologic Names Committee, 2010, Divisions of geologic time: U.S. Geological Survey Fact Sheet 2010–3059, 2 p. Available at http://pubs.usgs.gov/fs/2010/3059/.

U.S. Geological Survey World Conventional Resources Assessment Team, 2012, An estimate of undiscovered conventional oil and gas resources of the world, 2012: U.S. Geological Survey Fact Sheet 2012–3042, 6 p. Available at http://pubs.usgs.gov/fs/2012/3042/.

U.S. Geological Survey World Energy Assessment Team, 2000, U.S. Geological Survey World Petroleum Assessment 2000—Description and results: U.S. Geological Survey Digital Data Series DDS–60, 4 CD–ROMs.

Ziegler, D.G., 1988, Early Mesozoic plate reorganization, *in* Ziegler, D.G., ed., Evolution of the Arctic-North Atlantic and the western Tethys: American Association of Petroleum Geologists Memoir 43, p. 43–61.

Click here to return to
Volume Title Page