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TASK
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(bachelor, master)

student Moustapha Mbengue **academic group** 185-18-2 IC
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title Technical project for drilling an exploration well in the Diam Niadio field (Senegal)

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Section	Content	Deadline
Technologic	Geological survey of drilling of the wells at the gas-condensate genus. Design of construction of drill wells, method of drilling and drilling equipment.	02/05/2022
Labour and Environment Protection	Analysis of potential problems of the projected about the possibilities of negative on the environment	23/05/2022

Task issued ____________________ O.Pashchenko
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Date of issue 07/02/2022

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Accepted for execution _____________ M.Moustapha
(signature) (name)

ESSAY

Thesis project 83 pages, 21 figures, 8 tables, 47 biblicals.

The object of the study is drilling a well at the Diam Niadio field (Senegal)with the development of measures to improve the quality of drilling fluids.

The purpose of the work is to design a well at the Diam Niadio field (Senegal).

Research tools - literature analysis and theoretical research.

The thesis is compiled in accordance with the requirements of the guidelines. Contains information about the area of drilling, geological structure and characteristics of productive horizons. In the design part, the issues of well construction are resolved: the well structure has been designed, the equipment for the drilling rig, the rock cutting tool, the drilling and cementing technology have been selected. Measures have been developed to improve the quality of drilling fluids during preparation. Safety precautions are given when drilling wells. The issues of subsoil and environmental protection are highlighted. The estimate of well drilling has been substantiated.

PRODUCTION WELL, SKEW WALL, COMPLICATION, DRILLING FLUID PREPARATION.

TABLE OF CONTENTS

INTRODUCTION

The Senegal Province (fig. 1.1), which includes the onshore and offshore (to a water depth of 2,000 m) parts of the Senegal Basin, is situated along the northwestern African coast and includes parts of Western Sahara, Mauritania, Senegal, The Gambia, Guinea-Bissau, and Guinea. The Senegal Basin is classified as an Atlantic-type passive margin or marginal sag basin of Middle Jurassic to Holocene age overlying a Paleozoic basin (Wissmann, 1982). Figure 1.2 is a generalized geologic map of northwest Africa showing the location of Senegal and adjoining provinces. The northern limit of the Senegal Basin is the Precambrian Reguibate Shield in Morocco, and the southern limit is the Bove Basin of Guinea (fig. 3). The eastern edge of the basin is separated from the Taoudeni Basin by Precambrian rocks of the Mauritanide Mountains that were uplifted during the Late Paleozoic Hercynian Orogeny (figs. 1.2 and 1.3).

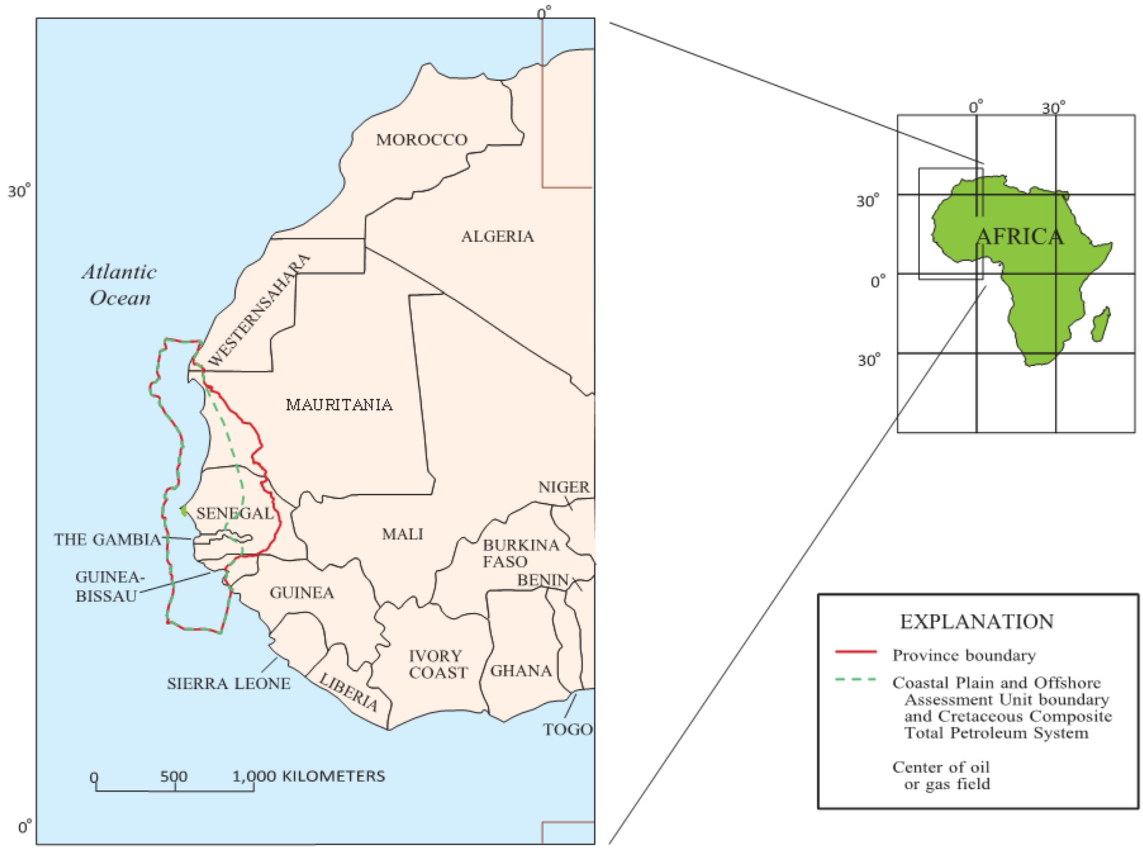


Figure 1.1 Location map showing the Senegal Province (7013) boundary, the Cretaceous-Tertiary Composite Total Petroleum System (701301), the Coastal Plain and Offshore Assessment Unit (70130101), and the center points for oil and gas fields.

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

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

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

SECTION 1 GEOLOGICAL AND TECHNICAL CONDITIONS FOR CONDUCTING DRILLING WORKS

1.1 Senegal Basin Geology

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

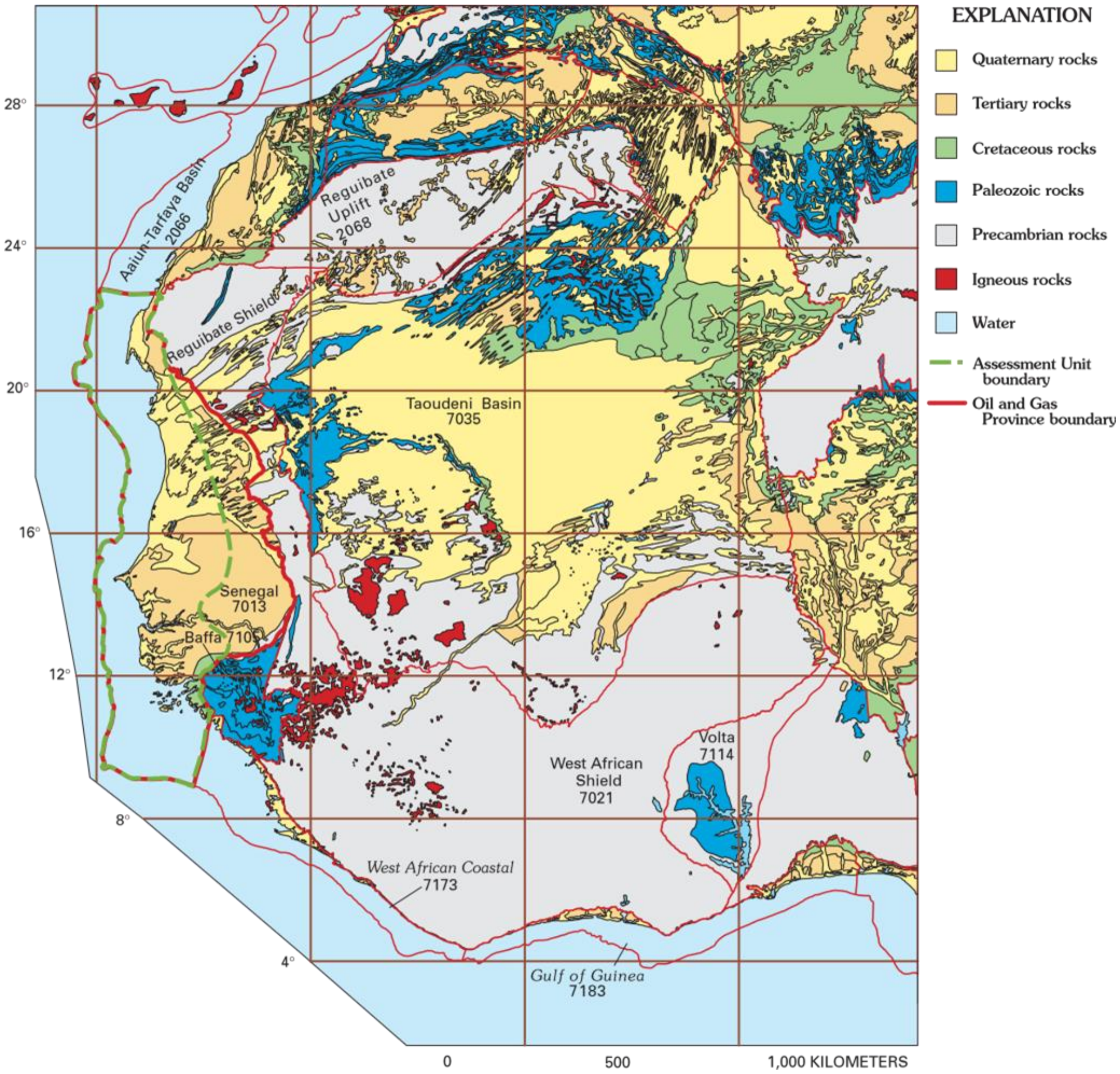


Figure 1.2 - Senegal Basin Geology

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

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

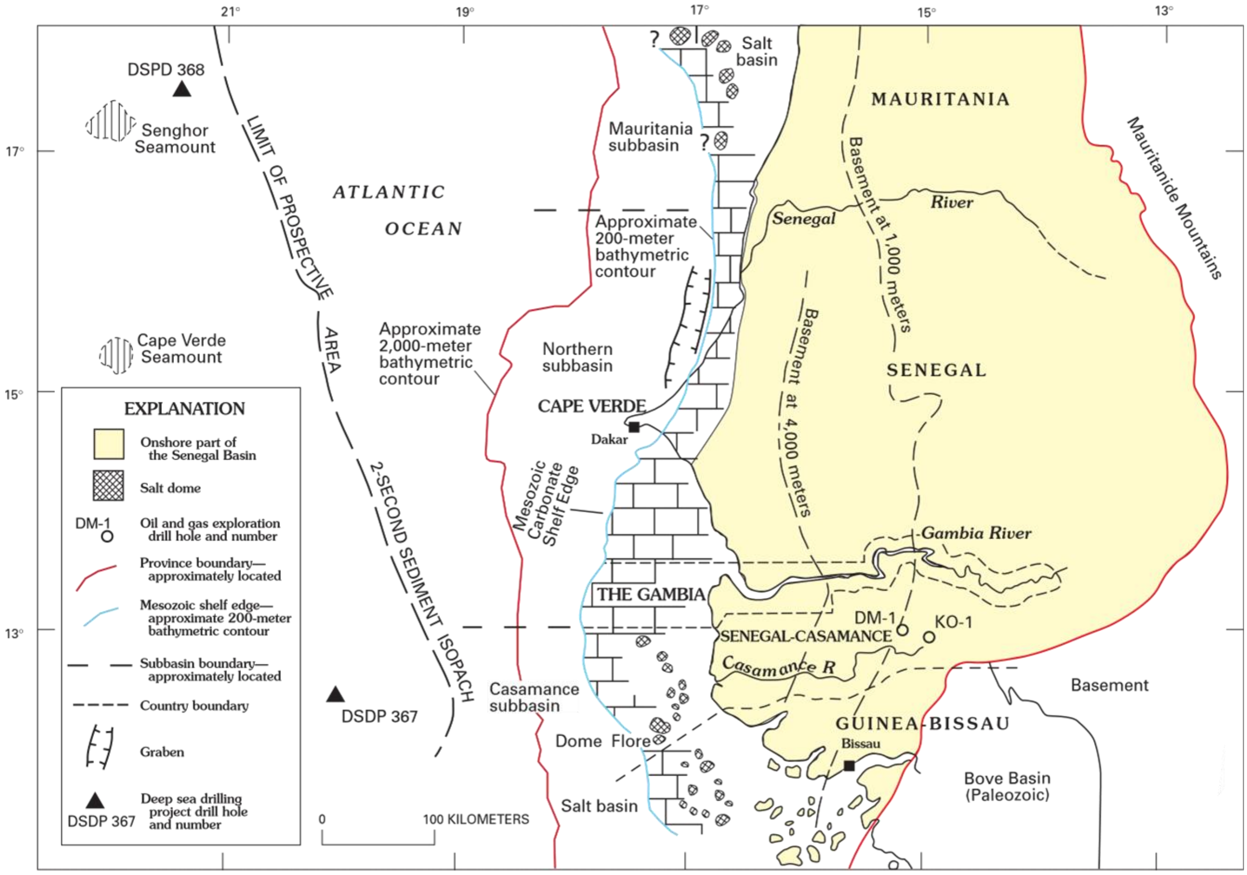


Figure 1.3 - A generalized map of the central and southern parts of the Senegal Basin showing part of the Senegal Province, the Mauritania, Northern, and Casamance subbasins, the Mesozoic shelf edge, the northern and southern salt basins, the Mauritanide Mountains, the Bove Basin, the Deep Sea Drilling Project sites 367 and 368, the 2-second sediment isopach, and the onshore depth to basement isopachs. Also shown are the appropriate locations of the Diana-Malari (DM–1) and Kolda (KO–1) wells that penetrated the Silurian source rocks (Buba Shale). Brick pattern delineates the Mesozoic carbonate rock platform. Modified from Bungener and Hinz (1995).

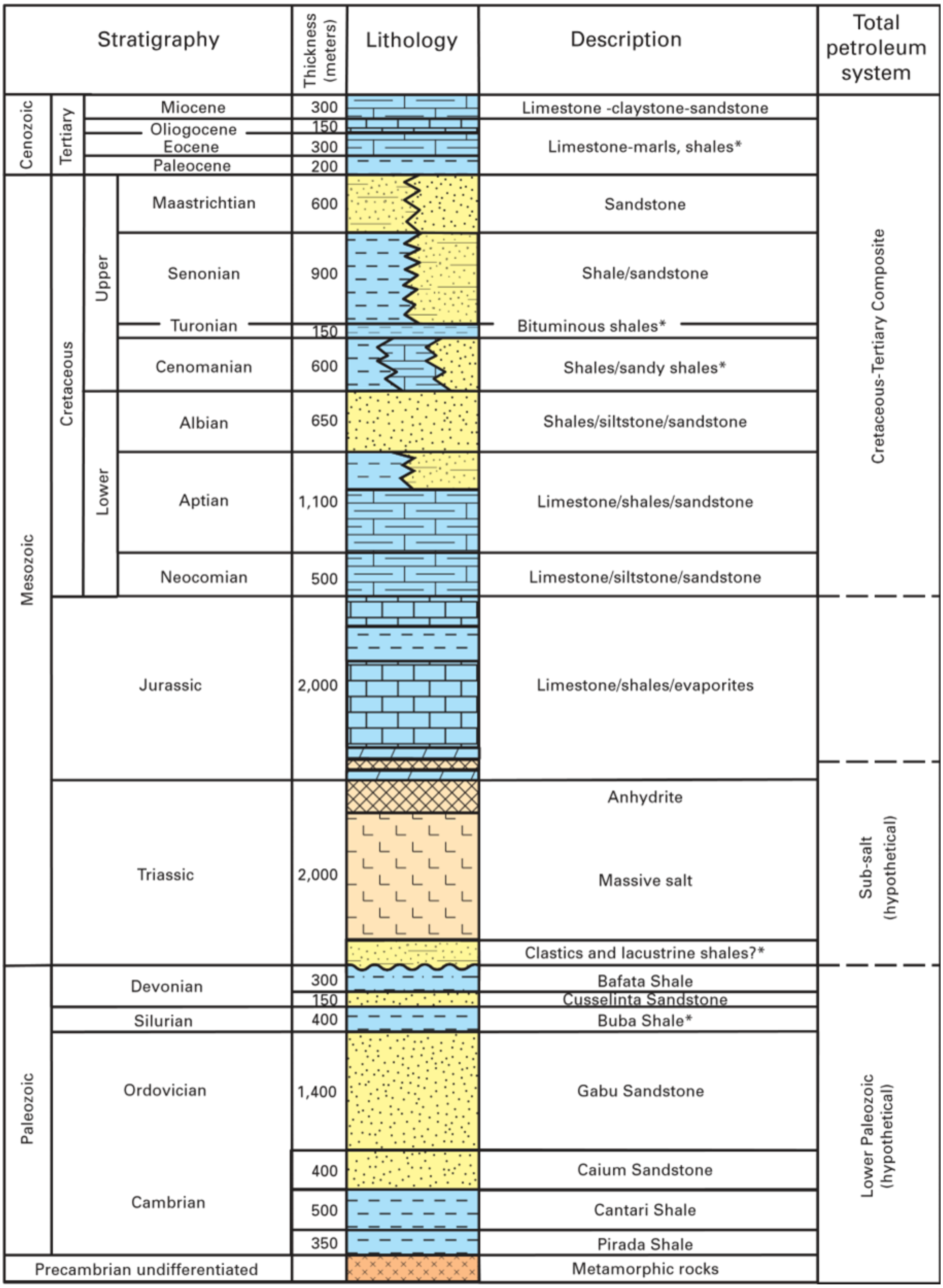


Figure 1.3 - Generalized stratigraphic column showing the three total petroleum systems in the Senegal Basin and the rocks found in the Casamance region of southern Senegal and Guinea-Bissau, includes the Bove Paleozoic Basin, which is an extension of the Taoudeni Basin of Mauritania and Mali. * denotes potential source rocks. Modified from Dumestre and Carvalho (1985).

The opening of the Atlantic was not completed until Albian time. The presence of Triassic evaporites and clastics in the Senegal Basin provides evidence that rift-basin sedimentation occurred during this time, associated with the breakup of northwest Africa and North America. The basal Jurassic and lowermost Cretaceous limestones of the MesozoicTertiary platform (figs. 1.3 and 1.4) are most likely related to the Tethys Sea rather than the South Atlantic because the final opening of the Atlantic did not take place before Albian time.

1.2 Pre-rift Section

The pre-rift section consists of Precambrian- to Devonianage rocks that outcrop in the Bove Basin of southern Senegal and Guinea, which is an extension of the Taoudeni Basin (figs. 1.2 and 1.3). The most complete pre-rift section was recognized in the Diana-Malari (DM–1) and Kolda (KO–1) wells (fig. 1.3), which penetrated Ordovician, Silurian, and Devonian rocks in southernmost Senegal, also known as the Casamance subbasin. The Cambrian rocks are known only from outcrops in the Bove Basin. The pre-rift section might be as much as 3,500 m thick in the Bove Basin, whereas over 5,000 m of preMesozoic rocks are interpreted from seismic data in the deeper offshore part of the Senegal Basin (Hinz and Martin, 1995). The Precambrian basement consists of metamorphic rocks of unknown thickness (fig. 1.4). The Cambrian sedimentary section is as much as 1,250 m thick and contains three units: the Pirada Shale, the Cantari Shale, and the Caium Sandstone. The Ordovician Gabu Sandstone attains a maximum thickness of 1,400 m. The Silurian section contains the graptolitic Buba Shale source rocks, which are as much as 400 m thick. The Devonian rocks are widespread and are the youngest Paleozoic rocks known in the basin. The Lower Devonian consists of the Cusselinta Sandstone, a 150-m-thick unit, and the Middle and Upper Devonian are represented by the 300-m-thick Bafata Shale. The section is known to occur under much of the southern one-half part of the basin (south of the Mauritanian border).

Two main tectonic regimes have been recognized in the Paleozoic pre-rift part of the Senegal Basin. An extensional system is defined south and east of the Casamance subbasin and south of Cape Verde (fig. 1.3) in which a pre-Hercynian structural style of horsts and grabens and tilted blocks was preserved, and a compressional regime has been defined in the central and northern parts of the basin resulting from the combined effect of Caledonian and Hercynian orogenies (figs. 1.5 a 1.6) .

1.3 Syn-rift Section

The syn-rift section of the southern Senegal Basin consists principally of thick Triassic to Early Jurassic evaporites (Uchupi and others, 1976) overlying inferred Triassic clastic rocks, which may include organic-rich lacustrine rocks (fig. 1.4). The syn-rift evaporite section in the Casamance sub- basin may be as much as 2,000 m thick and consists mostly of salt with an anhydrite cap, whereas the underlying clastic section may be as thick as 1,500 m (fig. 1.7). In the Northern and Mauritania subbasins, the evaporite section might be as thick as 2,000 m (fig. 1.8), whereas the thickness of the under- lying Triassic clastic section is unknown but may have a thickness similar to the Casamance subbasin (fig. 1.7). Except for a few salt structures (Ayme, 1965; Wissmann, 1982) in the Casamance and Mauritania subbasins, the Northern subbasin,

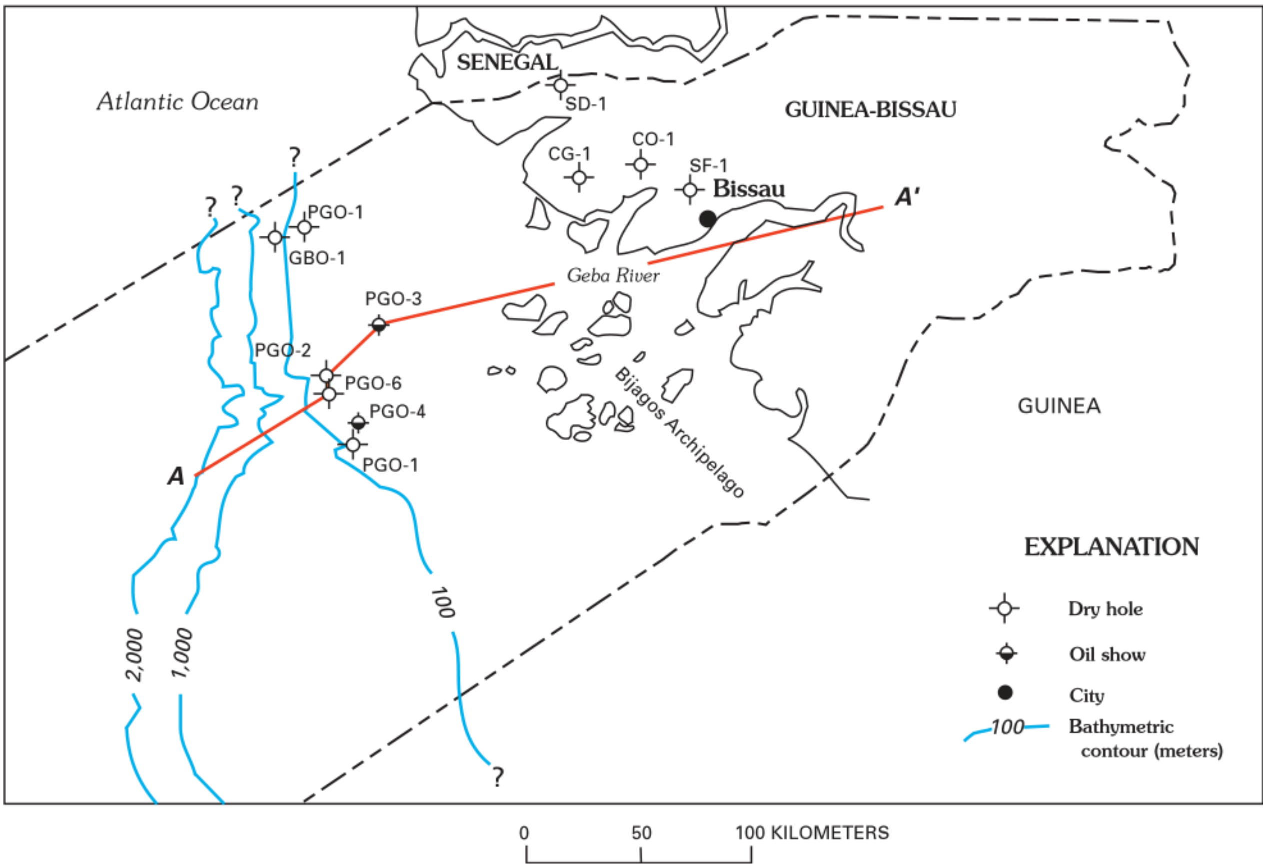


Figure 1.4 - Location map for Guinea-Bissau showing line of section and oil and gas exploration holes, southern Senegal Basin, northwest Africa. Cross section A to A’ is shown in figure 6. Modified from Dumestre and Carvalho (1985).

Senegal Basin Geology

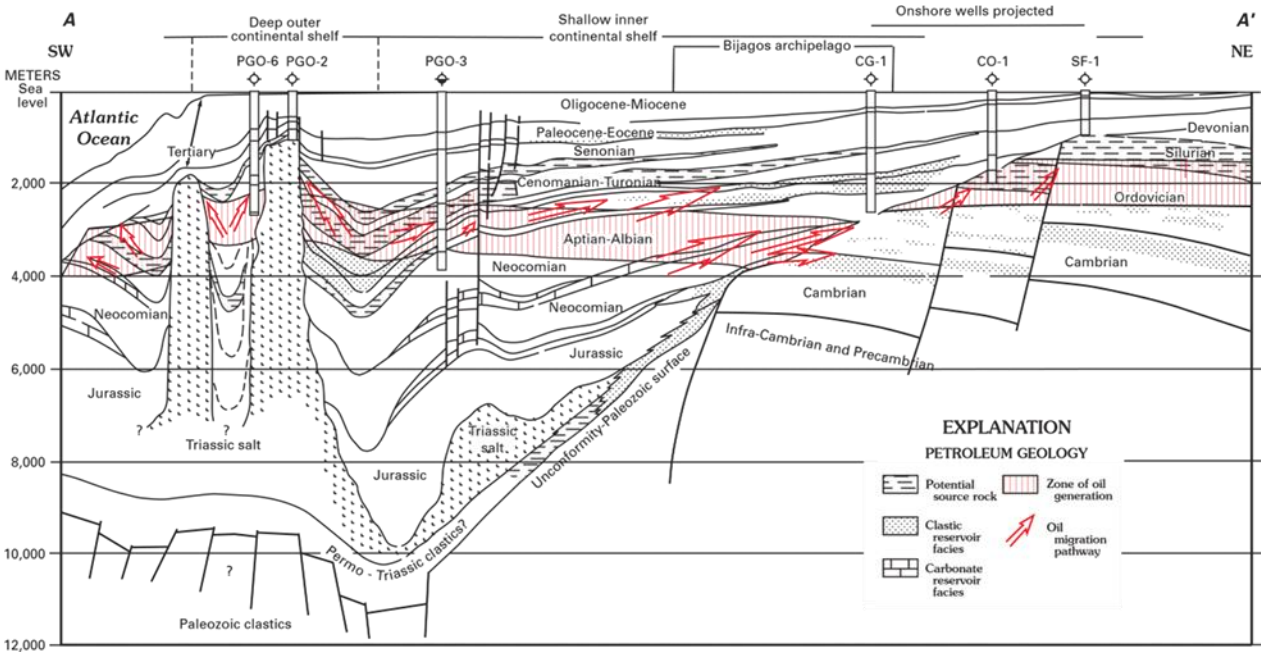


Figure 1.5 - Mouth of Geba River

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

Seismic studies have shown salt diapirs in offshore Mauritania, confirming that this section also is present in the northernmost part of the basin (fig. 3). Salt diapirs have not been recognized in the Northern subbasin (fig. 3). Figure 9 is a schematic east-to-west cross section through The Gambia where the syn-rift section is present but the evaporites exhibit little halokinesis. The onshore part of central Senegal Basin has a thinner syn-rift section consisting of probable Triassic age continental clastics and organic-rich lacustrine shales (fig. 10). The northwest Africa basins have been virtually undisturbed by extension since the Jurassic (Lambiase, 1989).

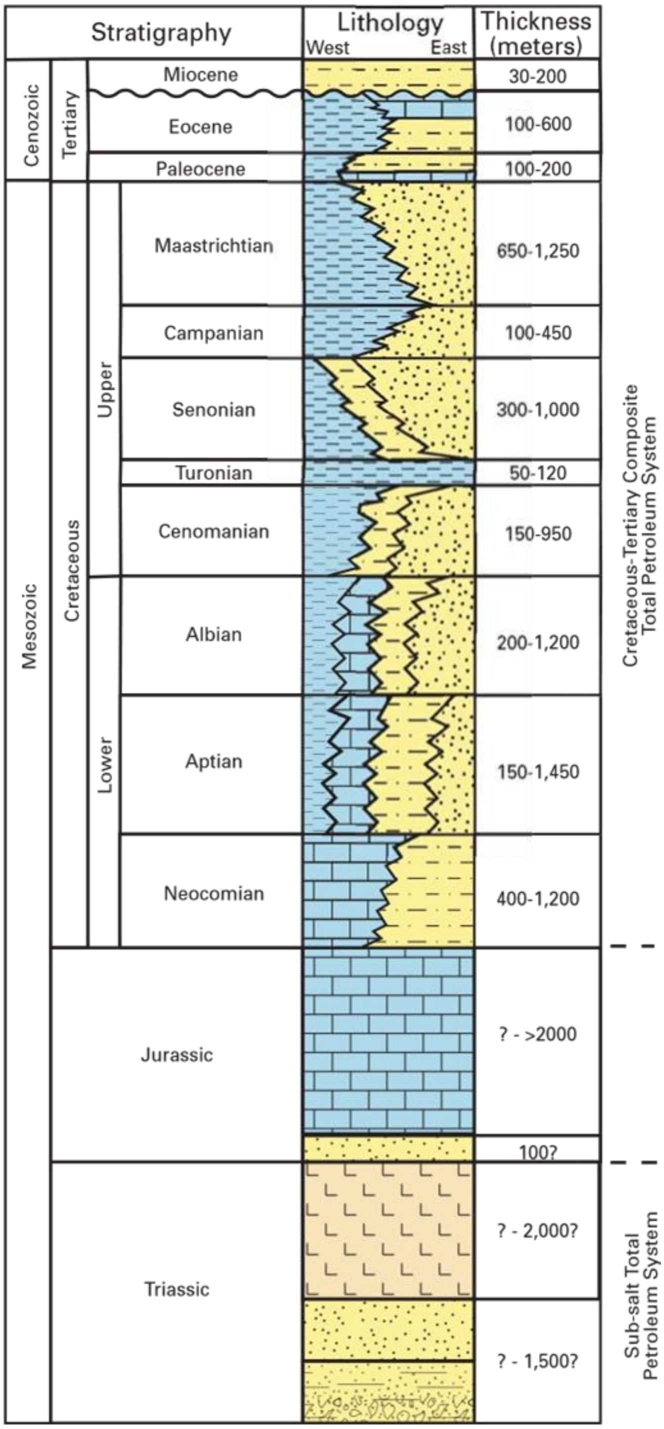


Figure 1.6 - Generalized stratigraphic column of the Casamance offshore sub-basin, south of Cape Verde, Senegal Basin, northwest Africa. In the Casamance sub-basin, the best source rocks are in the Cenomanian and Turonian units. Possible source rocks may exist in the clastic section below the evaporites. Modified from Dumestre (1985).

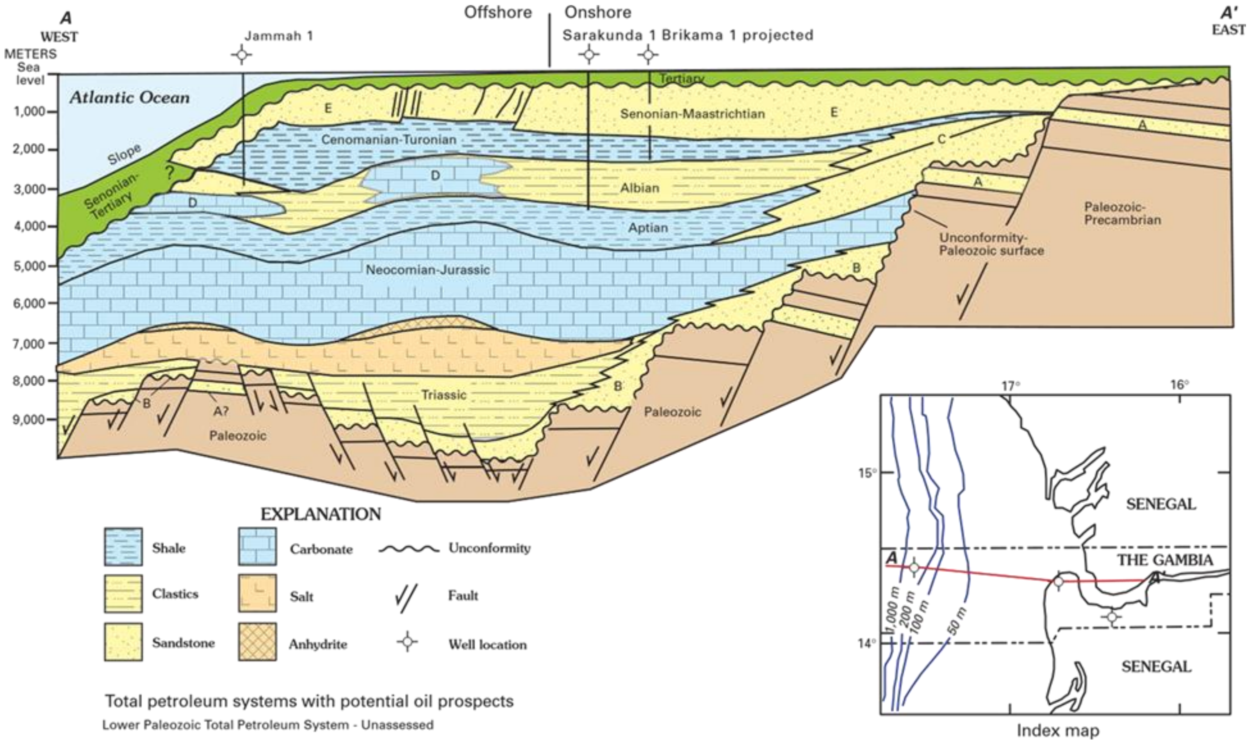


Figure 1.7 - Generalized stratigraphic column for the Northern subbasin and the southern part of the Mauritania subbasins (see fig. 3). Type II and III source rocks are found in the Cenomanian and Turonian units. Modified from Dumestre (1985).

Prospect A - Ordovician-Devonian reservoirs, Silurian source?

Sub-salt Total Petroleum System - Unassessed

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

Cretaceous-Tertiary Composite Total Petroleum System - Assessed

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

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

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

1.4 Post-rift Section

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

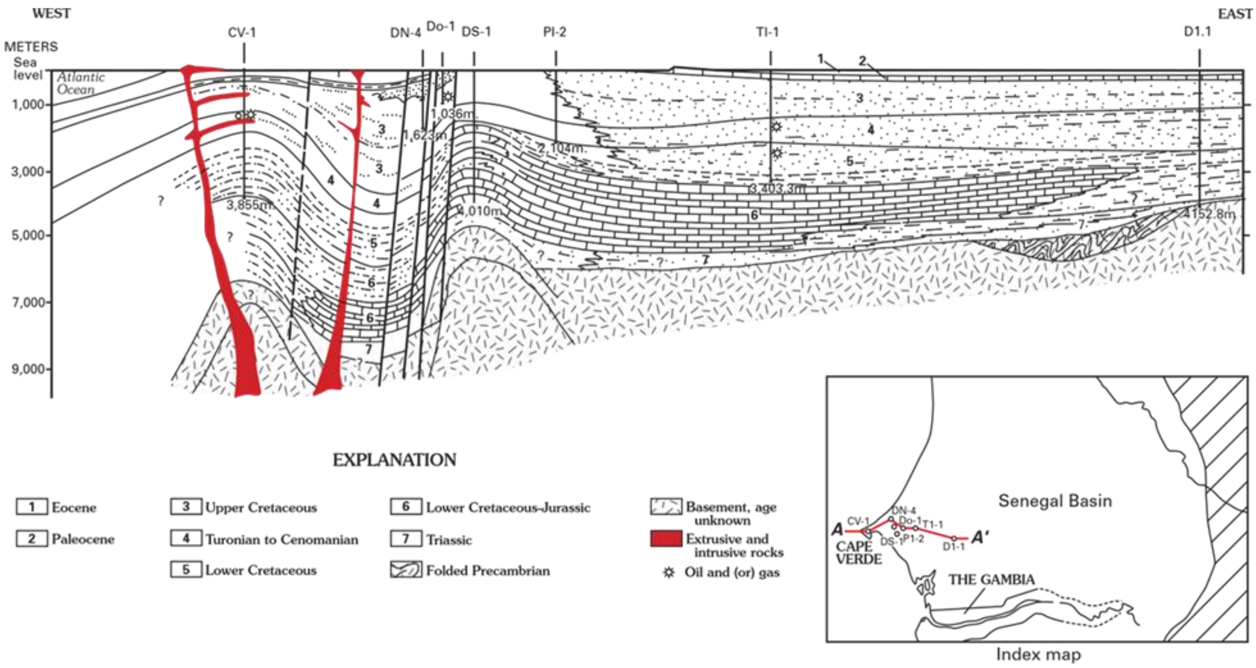


Figure 1.8 - Schematic stratigraphic east-to-west cross section through Cape Verde showing producing zones, Senegal Basin, northwest Africa. Modified from Petroconsultants (1979).

Two major stratigraphic domains delimited by the present shelf edge are recognized within the Senegal Basin. The shelf of northwest Africa is characterized by a 35- to 100-km-wide plain cut by sparse, shallow channels, especially north of Cape

Verde (Egloff, 1972), while south of Cape Verde the shelf is more incised by canyons and affected by recent deltaic deposits. The shelf and western edge of the Jurassic to Lower Cretaceous carbonate-rock platform (fig. 1.3) roughly parallels the 200-m bathymetric contour.

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

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

Petroleum Occurrence in the Senegal Basin

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

Hydrocarbon production in the Senegal Basin has been limited to several small oil and gas fields (fig. 1.10) east of Cape Verde (Brown, 1981; Woodside, 1983). Discovered oil resources in the Senegal Basin are 10 MMBO, with gas resources of 49 BCFG (U.S. Geological Survey World Energy Assessment Team, 2000, disc 4, data file provvol.tab).

1.5 Hydrocarbon Source Rocks in the Senegal Basin

The most effective Cretaceous source rocks related to hydrocarbon discoveries and production in the Senegal Basin are the Cenomanian-Turonian marine shale units (figs. 1.7 and 1.8). Cenomanian to Turonian source rock units developed in two different subbasins (fig. 1.11). The first area is located north of Cape Verde and includes the Mauritania and Northern subbasins (fig. 1.3) where samples from wells located along the shelf boundary have exhibited good source rocks, up to 380 m thick, containing Type II and Type III organic matter (fig. 1.11) with hydrocarbon source potentials between 3 and 21 kg/ton (Reymond and Negroni, 1989). The second area is located south of Dakar in the Casamance subbasin. Reymond and Negroni (1989) state that the richest source rocks here contain Type II organic matter surrounded by a large area containing Type III organic matter (fig. 1.11). These source rocks display source potentials ranging between 5 and 75 kg/ton and range from 330 to 490 m thick. The Turonian interval contains bituminous shales that were probably deposited under anoxic conditions (Kuhnt and Wiedmann, 1995) with thickness up to 150 m (fig. 1.4). Samples analyzed from the Casamance Maritime 10 well (fig. 1.11) contain Type II kerogen with total organic carbon (TOC) values ranging from about 7 to more than 10 percent. Geochemical data obtained from Deep Sea Drilling Project well samples (DSDP 367 and 368, fig. 1.3) identified potential Neocomian to Cenomanian source rocks beyond the 2-second sediment isopach in the Senegal Basin (Tissot and others, 1980; Rullkötter and others, 1982). The source rocks contain mostly Type II kerogen with TOC values ranging from about 3 to more than 10 percent. Minor source rocks within the post-rift section have been identified (Dumestre and Carvalho, 1985; Reymond and Negroni, 1989) including the Senonian and Maastrichtian (2–5 kg/ton, Type II and III), the Paleogene (greater than 5 kg/ton, Type II with detrital Type IV), and the Miocene to Pliocene (2–5 kg/ton, Type II).

A second important source rock has been recognized recently and consists of graptolitic Silurian shale up to 400 m thick (fig. 1.4) in the southern one-half of the Senegal Basin. The Buba Shale may be equivalent to the oil-rich Silurian Tanezzuft Formation of North Africa (fig. 4), which is an important source rock in North Africa and the Middle East. The distribution of marine Silurian rocks, which contain oil-prone black graptolitic shales, is shown in the Silurian paleogeographic map in figure 12. Measurements conducted on samples from the DianaMalari (DM–1) and Kolda (KO–1) wells (figs. 1.3 and 1.11) and outcrop studies in the Bove Basin and the Guinea Paleozoic Basin (Baffa Province, fig. 1.2) show these source rocks contain black amorphous organic matter and have TOC’s ranging from 1 to 5.5 percent (Reymond and Negroni, 1989).

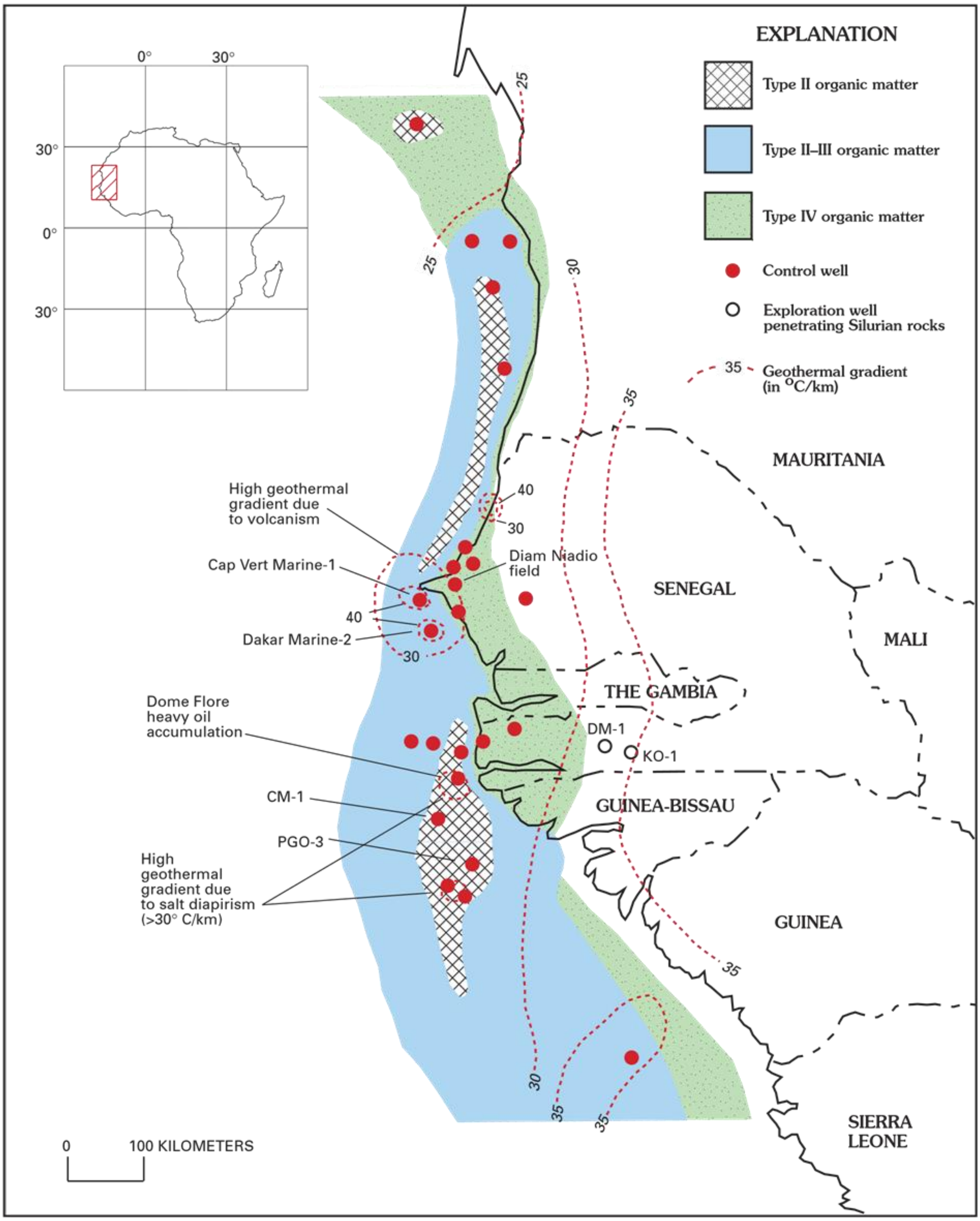


Figure 1.9 - Petroleum Occurrence in the Senegal Basin

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

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

Burial history profiles and maturation studies have been carried out on several wells within the Senegal Basin. Maturation studies were determined from geothermal gradient data and samples analyzed from wells that penetrated the Mesozoic and Paleozoic units, and data extrapolated from outcrops in the Bove Basin for the Paleozoic part of the section. Two periods of oil generation have been determined for the Silurian source rocks (fig. 1.13); the first period began in the Carboniferous (300 Ma) and continued into the Hercynian orogeny (about 250 Ma). Generation paused during the Permian and Triassic, resumed during the Cretaceous, and continues to the present. The zone of oil generation ranges in depth from 1,850 to 4,000 m in the southern part of basin (fig. 1.6). In the eastern part of the Bove Basin, the zone of oil generation is elevated, probably in response to higher heat flow that may be due to intrusions or a local hot spot.

1.6 Hydrocarbon Generation and Migration in the Senegal Basin

Senegal Basin is from the Mesozoic section underlying the Cape Verde Peninsula onshore and the Casamance subbasin offshore. The Cretaceous source rocks display a highly variable maturation history. The Albian source rocks in the Mauritania subbasin started to generate oil in the late Eocene, whereas the Turonian and Senonian source rocks began to generate oil in the Miocene (fig. 1.14, drill hole V–

1). The Upper Cretaceous source rocks began generating oil in the Miocene (fig. 14, drill hole COP–1). The Paleocene source rocks were found to be immature in the Mauritania offshore (fig. 1.14, drill hole COP–1). Two main areas of hydrocarbon generation have been delineated in the Senegal Province (fig. 1.15). The first area is located in the offshore Mauritania and northernmost Northern subbasins (figs. 1.3 and 1.15), whereas the second area is located in the

Casamance subbasin and Guinea-Bissau offshore. North of Cape Verde, the amount of generated hydrocarbons increases seaward due to the combined effect of the thickening and deepening of the Cenomanian to Paleocene source rocks. The quality of source rocks onshore north of Cape Verde is not favorable for the generation of oil. In the Casamance and Mauritania subbasins, the Triassic diapiric salt (fig. 1.3) has induced a modification of maturation gradients because of the good thermal conductivity of the salt. Within the Casamance subbasin at least 2,500 tons of hydrocarbons per square kilometer have been generated (fig. 1.15) mainly from the Cenomanian and Turonian sources (Reymond and Negroni, 1989).

Present depth of the zone of oil generation ranges from less than 1,000 to more than 3,000 m depending upon the local geological and thermal parameters in the Senegal Basin (figs. 1.6 and 1.16). The zone of oil generation in parts of the Casamance and Mauritania subbasins is relatively shallow due to elevated geothermal gradients related to salt diapirism. A shallow zone of oil generation in the vicinity of Cape Verde is related to volcanism and ranges in depth from 900 m (Dakar Marine-2) to 1,200 m (Cap Vert Marine-1). Reymond and Negroni (1989) measured geothermal gradient values of nearly 45 °C/km in these wells (fig. 11). In areas where the average geothermal gradient is about 30 °C/km (fig. 11), the top of the zone of oil generation ranges from 2,285 to 2,680 m. The top of the zone of oil generation is at 2,800 m in the PGO–3 well, where Cenomanian source rocks are immature (figs. 5 and 6). Gas resources may be very significant and accessible in areas where the zone of oil generation is relatively shallow. Migration of hydrocarbons most likely began in the late Miocene and continues to the Holocene.

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

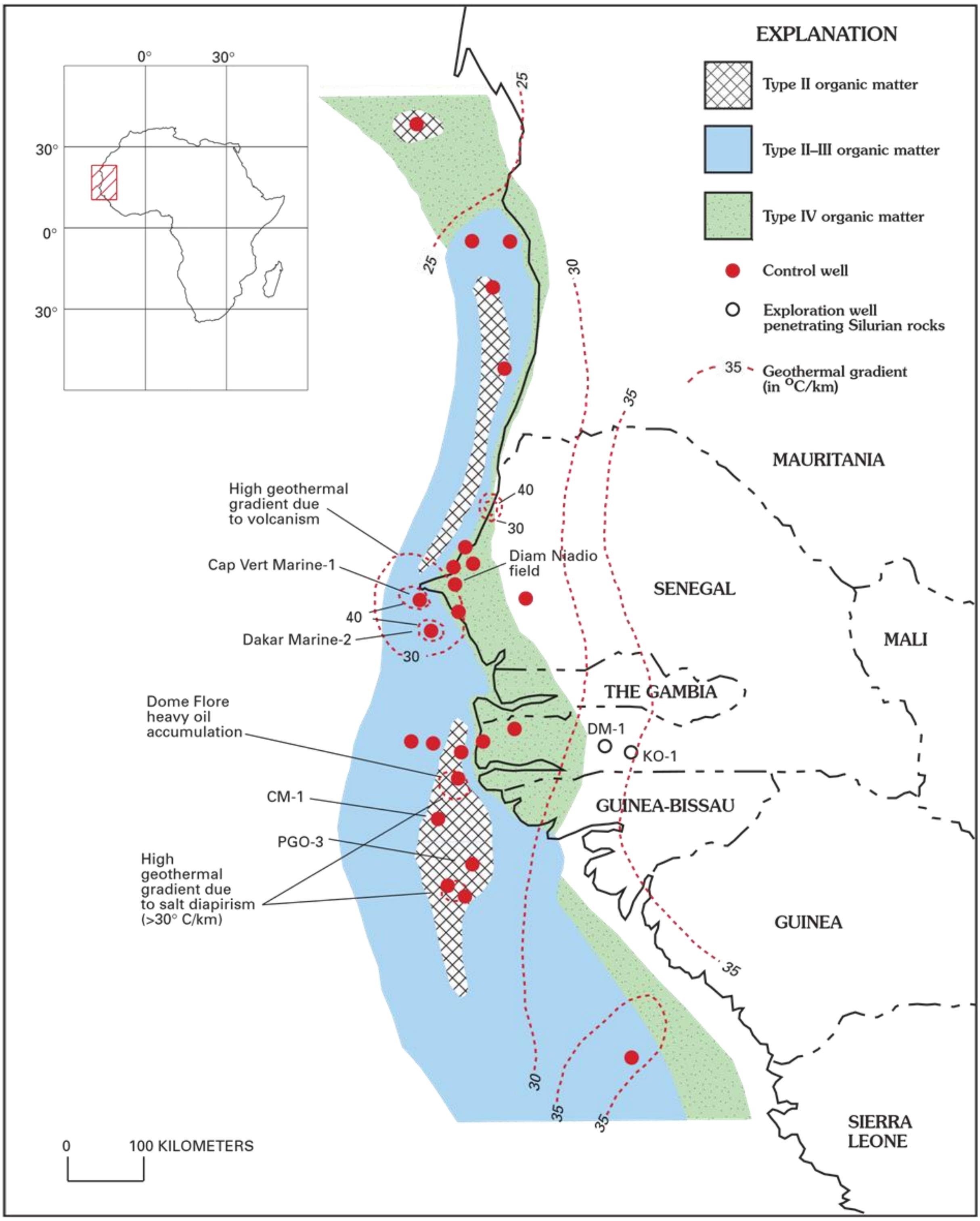


Figure 1.10 - Paleogeographic reconstruction of the Silurian Period showing relative positions of continents and areas of deposition for graptolite-bearing Silurian rocks. Modified from Clifford (1986).

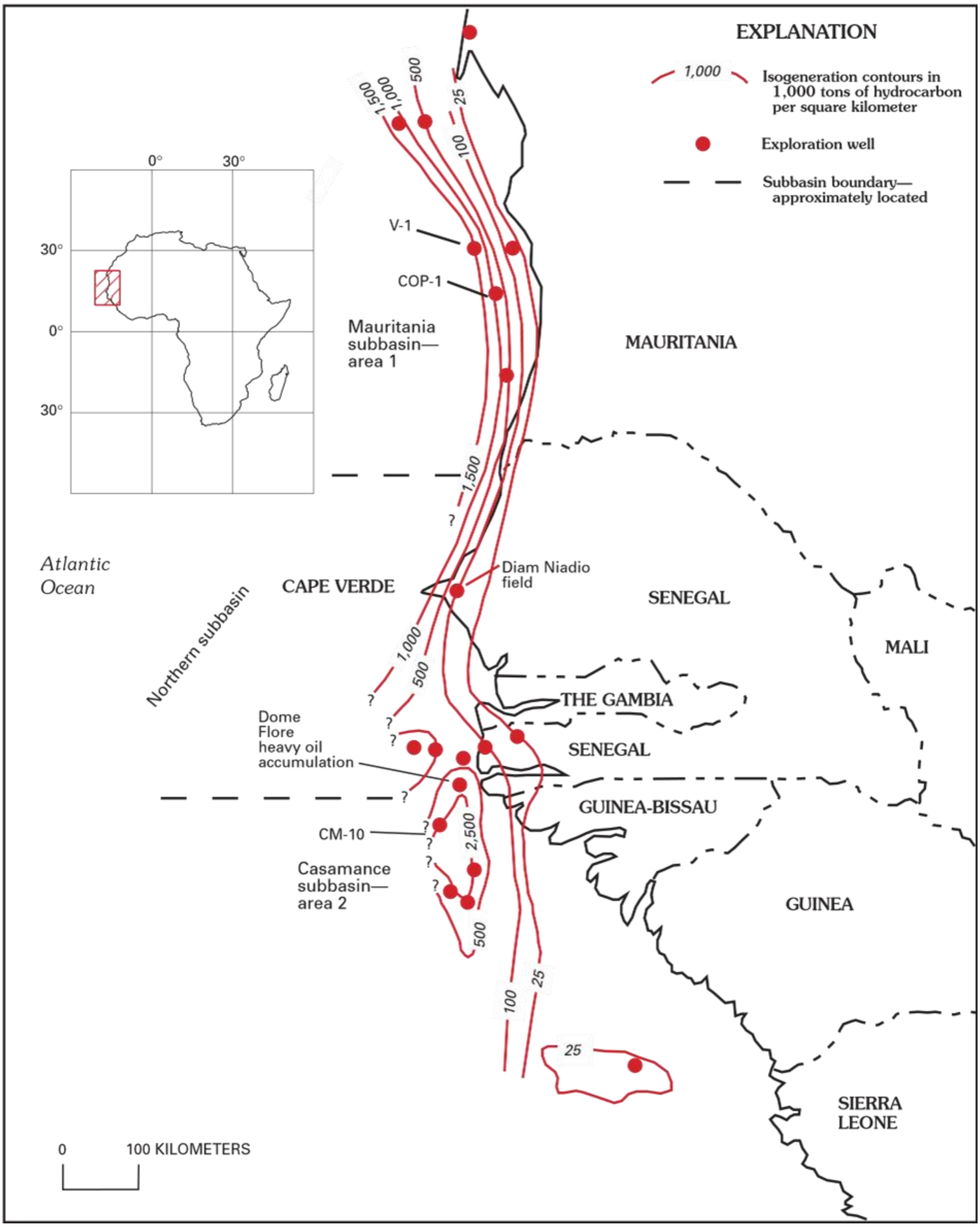


Figure 1.11 - Examples of hydrocarbon maturation evolution in the Senegal Basin involving the Silurian, Jurassic, basal Neocomian, and the Cenomanian to Turonian source rocks. Maturity levels are expressed in percentage of potential hydrocarbons generated. Modified from Reymond and Negroni (1989).

1.7 Hydrocarbon Reservoirs, Traps, and Seals in the Senegal Basin

The Mesozoic-Cenozoic section of the Senegal Basin can exceed 10,000 m in thickness and contains several primary reservoirs and seals: (1) Jurassic-Lower

Cretaceous carbonate section sealed by Cenomanian or other Lower Cretaceous shales; (2) Upper Cretaceous sandstone units and overlying shale units; and (3) lower Tertiary clastic and carbonate-rock units and overlying and intercalated shale units (figs. 1.6, 1.9, and 1.10). Cretaceous deltaic sandstone (Clifford, 1986) with porosities ranging from 17 to 25 percent are present in the Mauritania offshore (fig. 1.17). The Jurassic-Lower Cretaceous carbonaterock platform has never been fully penetrated by drilling but does show good porosities ranging from 10 to 23 percent (figs. 1.17 and 1.18). Reef prospects on the shelf edge remain to be explored. Upper Cretaceous sandstone sequences in the eastern part of the basin become interbedded with shale to the western offshore part of the basin. Maastrichtian sandstones up to 30 m thick occur at Dome Flore, with porosities ranging from 20 to 30 percent, and contain light oil (33.6° API). In the Dome Flore area, an excellent Oligocene carbonate-rock reservoir exists and contains up to 1 billion barrels of heavy oil (10° API, 1.6 percent sulfur) in place. About 40 km east of Dakar, several shallow oil and gas discoveries were made in the 1950's. Following a geologic reinterpretation of the area in 1984 (Dumestre, 1985), these wells and two new wells were found to be productive, with rates up to 300 barrels of oil per day (BO/D) and 2.4 million cubic feet of gas per day (MMCFG/D). Currently, only a small amount of gas is being produced from the Diam Niadio field (fig. 1.11).

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

Sandstone reservoirs associated with syn-rift rocks might be present and interbedded with the inferred PermianTriassic source rocks underlying the Triassic salt (fig. 1.9). The thick Triassic salt is the major seal in the syn-rift section in the Senegal Basin.

Potential sandstone reservoirs are abundant in lower Paleozoic rocks based on measured sections in the Bove Basin and analyzed samples from the DM–1 and KO–1 stratigraphic test wells (fig. 1.3). The Ordovician sandstones are intensely fractured and could constitute good secondary reservoirs, whereas the Devonian fine- to coarse-grained sandstone beds have porosities ranging from 15 to 20 percent. In the onshore portion of the Paleozoic basin, regional seismic data have shown that the Paleozoic section has been faulted and could form traps in conjunction with the Paleozoic unconformity (fig. 1.6). Interpretation of seismic data shows that the Paleozoic unconformity is at a depth of about 10,000 m at the PGO–3 (fig. 1.6) exploration hole in the Guinea-Bissau offshore. The Paleozoic reservoirs were not assessed in this study.

1.8 Total Petroleum Systems of the Senegal Province

At least three total petroleum systems (TPS) may be present in the Senegal Province: (1) the hypothetical Lower Paleozoic Total Petroleum System consisting of Silurian source rocks and Ordovician to Devonian and Triassic reservoir rocks; (2) the hypothetical Sub-salt Total Petroleum System consisting of Triassic (?) lacustrine source rocks and clastic reservoirs capped by Triassic salt; and (3) the Cretaceous-Tertiary Composite Total Petroleum System consisting of Cenomanian-

Turonian source rocks and Cretaceous and Tertiary reservoirs. Only limited drilling and seismic information is available for the Lower Paleozoic TSP, whereas there is no drilling and only limited seismic information on the Sub-salt TSP. Only the Cretaceous-Tertiary Composite Total Petroleum System was considered for this assessment because current production and exploration data were almost entirely limited to the Cretaceous. We defined one assessment unit within the TSP—the Coastal Plain and Offshore Assessment Unit.

Lower Paleozoic and Sub-salt Total Petroleum Systems

Events charts (figs. 1.19 and 1.20) for the Lower Paleozoic and Sub-salt Total Petroleum Systems summarize the age of the source, seal, and reservoir rocks and the timing of trap development and generation and migration of hydrocarbons.

The likely source rocks for the Lower Paleozoic Total Petroleum System are oil-prone graptolite-bearing Silurian shale that may be as much as 400 m thick (fig. 4) in the southern one-half of the Senegal Province. Measurements carried out in the Diana-Malari (DM–1) and Kolda (KO–1) wells and outcrop studies in the Bove Basin and the Guinea Paleozoic Basin show these source rocks to contain moderate organic matter and have TOC contents ranging from 1 to 5.5 percent (Reymond and Negroni, 1989). Two periods of oil generation have been determined for the Silurian source rocks and the first period began in the Carboniferous (300 Ma) and continued into the Hercynian orogeny (fig. 1.13). Generation paused during the Permian and Triassic, resumed during the Cretaceous, and continues to the present. Sandstone reservoirs have been shown to be abundant in the lower Paleozoic section based on measured sections in the Bove Basin and analyzed samples from stratigraphic test wells (fig. 1.3). The Ordovician sandstones could be good secondary reservoirs, whereas the Devonian fine- to coarse-grained sandstone beds have porosities ranging from 15 to 20 percent and could comprise a third type of potential reservoirs.

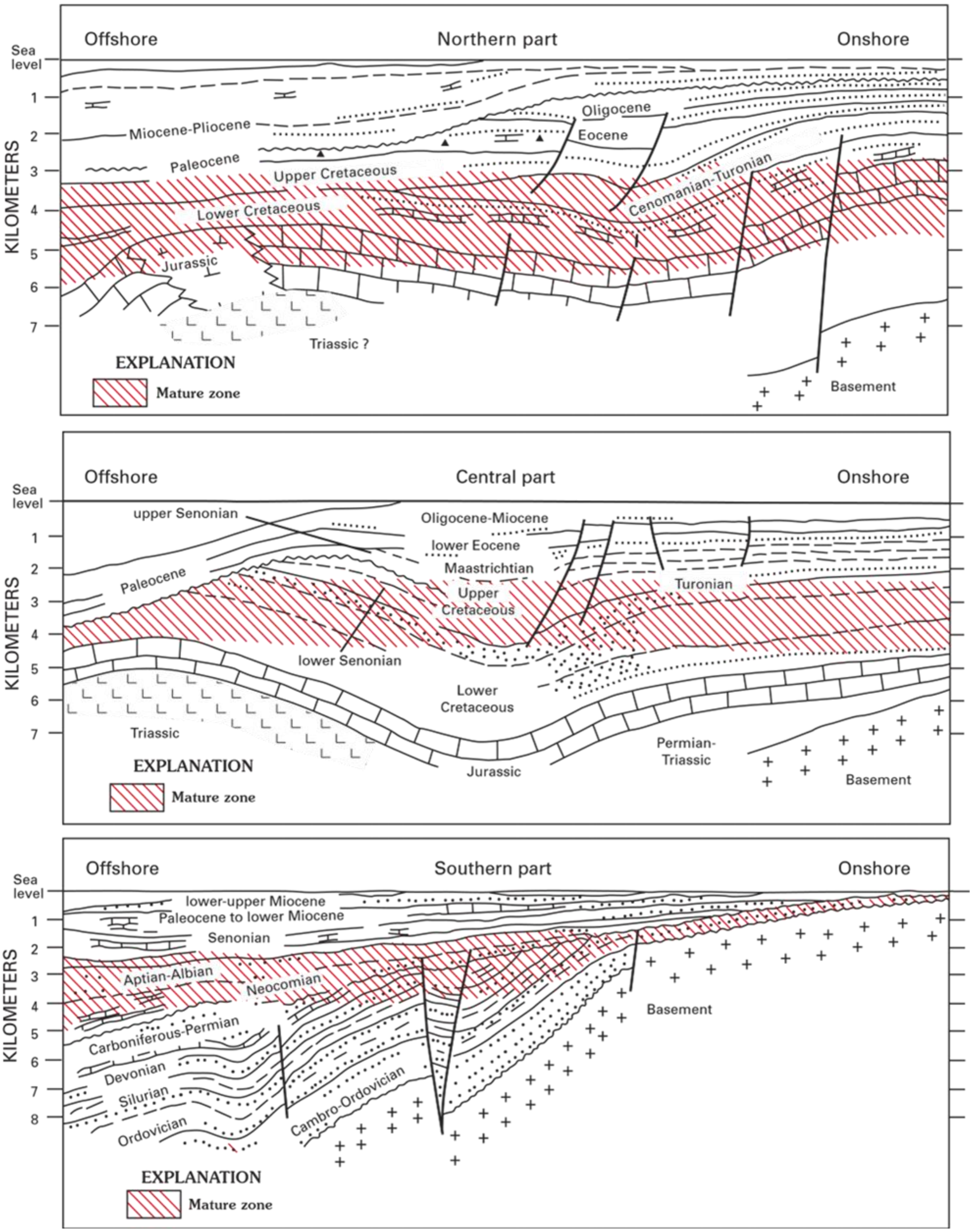


Figure 1.12 - Total Petroleum Systems of the Senegal Province

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

The Sub-salt Total Petroleum System is related to the syn-rift section and has not been tested in the Senegal Province, but seismic data suggest that this TSP may be present and it may be an important future hydrocarbon objective. The potential source rocks are lacustrine rocks below the thick Triassic salt unit. Recent seismic studies have delineated this clastic

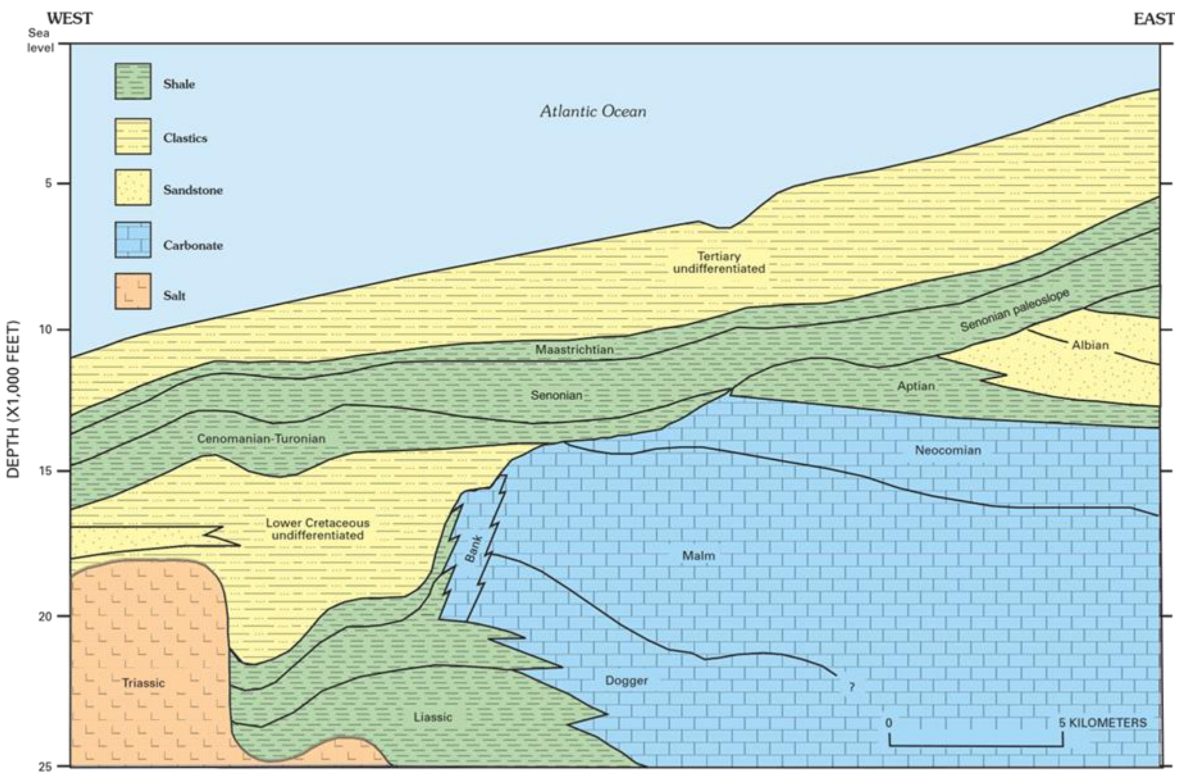


Figure 18. Schematic cross section of offshore Guinea-Bissau, Senegal Basin, northwest Africa. The Albian-Cenomanian Geba delta prograded westward across the carbonate platform providing reservoir-potential sands and source rocks. The carbonate and deltaic rocks subcrop the Senonian paleoslope, offering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

Total Petroleum Systems of the Senegal Province 21

Figure 1.13 - Assessment of the Undiscovered Oil and Gas of Northwest Africa

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

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

Cretaceous-Tertiary Composite Total Petroleum System

The Cretaceous-Tertiary Composite Total Petroleum System (TSP) was defined in the Senegal Province. An events chart (fig. 1.21) summarizes the age of the source, seal, and reservoir rocks and the timing of trap development and generation and migration of hydrocarbons for this TSP.

1.9 The principal source rocks in the Cretaceous-Tertiary

Composite Total Petroleum System are the Cenomanian and Turonian shales (fig. 1.21). The Turonian can be as much as 150 m thick with TOC contents ranging from 3 to 10 percent; it contains Type I, II, and III organic matter. Petroleum generation is presumed to have begun during the Miocene and continues to the present. Migration and charge most likely occurred shortly after generation along faults and porous Cretaceous and Tertiary reservoirs.

Good reservoir rocks are known throughout the section and include Upper Cretaceous sandstones and Tertiary clastics and carbonates, whereas the Lower Cretaceous carbonate-rock platform and Cretaceous reef units have not been explored (figs. 1.6, 1.9, 1.10, 1.16, 1.17, and 1.18). Oligocene carbonate-rock reservoirs exist such as the reservoir at the Dome Flore discovery (up to 1 billion barrels of heavy oil) that was charged with Turoniansourced oil and underwent degradation due to an insufficient seal allowing water washing and(or) biodegradation.

The Upper Cretaceous and Tertiary marine mudstone and shale rocks are the primary seals for the reservoirs in the Cretaceous-Tertiary Composite Total Petroleum System. The Mesozoic-Cenozoic part of the Senegal Province contains diverse trapping mechanisms (figs. 1.6, 1.9, 1.10, 1.16, 1.17, and 1.18) including salt-related structures, structures related to volcanic intrusions, growth-fault-related traps, slope truncations along the present day and paleoshelf edge (Senonian unconformity), Mesozoic and Tertiary pinch-outs along the eastern basin margin, and reef buildups along the shelf edge.

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

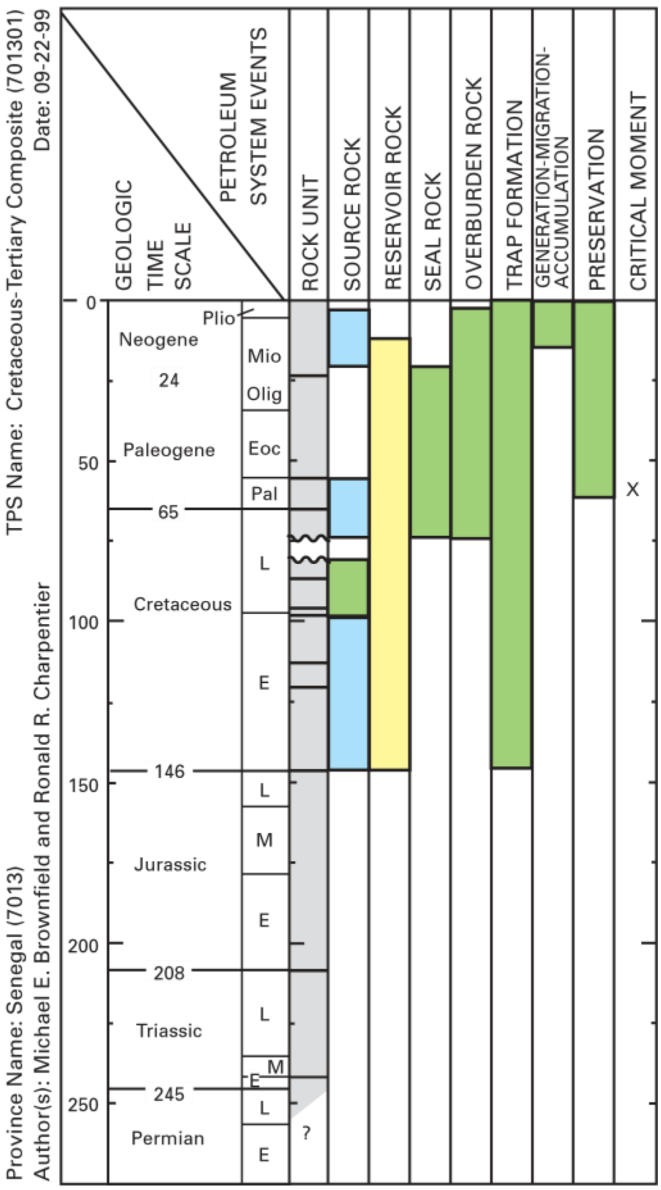


Figure 1.14 - Events chart for the Cretaceous-Tertiary Composite

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

1.10 Coastal Plain and Offshore Assessment Unit

One assessment unit (AU) was defined for the Cretaceous-

Tertiary Composite Total Petroleum System, designated the Coastal Plain and Offshore Assessment Unit (fig. 1.1). The east- ern boundary of the AU was defined as the eastern limit of the Cretaceous rocks within the basin, whereas the western boundary was set at a 2,000-m water depth (figs. 1.2 and 1.3). The AU is

Total Petroleum Systems of the Senegal Province 23 considered a frontier area with only two gas fields and one minor oil field producing east of Dakar and Cape Verde that meet the minimum size criteria for this study. Minimum field sizes of 1 MMBO and 6 BCFG were chosen for this assessment unit.

Discovered oil resources in the Coastal Plain and Offshore Assessment Unit are 10 MMBO, with discovered gas resources at 49 BCFG (Petroconsultants, 1996). Within the past 47 years, fewer than 150 exploration wells have been drilled in the Province, of which 52 are offshore. Most of the wells are concentrated in two areas, in the vicinity of Cape Verde and in the offshore Casamance subbasin (fig. 3). Most of the Senegal Province remains relatively unexplored.

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

The estimated means of the undiscovered conventional petroleum volumes contained in these fields are 157 MMBO, 856 BCFG, and 43 MMBNGL (table 1.2). The mean expected sizes of the largest anticipated undiscovered oil and gas fields are 66 MMBO and 208 BCFG, respectively.

Conclusion by section

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

Two other total petroleum systems were recognized in the Senegal Province: (1) the Lower Paleozoic Total Petroleum System consisting of Silurian source rocks and Ordovician to

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

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

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

SECTION 2 WELL DESIGN.
SELECTION OF DRILLING EQUIPMENT AND TOOLS

2.1 Selection and justification of the drilling method

Table 1.1 - Section along the well № 2

Depth of sole, m	Lithological characteristics of sediments	Category		Pressure gradient, MPa/m		Expected complications
		From hardness	From abrasiveness	Reservoir	Hydraulic fracturing	
50	Fate , clay	II	III	0.0102	0.0140	It collapsed
140	Clay, sand	III	III	0.0102	0.0140	
450	Clay, sandstone	III	VI	0.0102	0.0140	
950	Clay, sandstone, limestone	V	VII	0.0102	0.0164	
1150	Sandstone, argillite	V	VIII	0.0105	0.0164	Narrowing of the trunk
1600	Sandstone, argillite, siltstone	VI	VIII	0.0105	0.0160	
2000	Sandstone, argillite, siltstone	VI	VII	0.0105	0.0160	Shedding of argillites
2600	Argillite, siltstone, sandstone	VI	VIII	0.0110	0.0170	
3200	Sandstone, siltstone, argillite	V	VIII	0.0136	0.0190	Oil-manifestation
3400	Sandstone, argillite, limestone, rock salt	V	VII	0.0136	0.0203	

The diameter of the production casing is 168 mm.

From 0 to 50 m there are fate and clay. They have II category from hardness and III category from abrasiveness. Reservoir pressure gradient is 0.0102 MPa/m and hydraulic fracturing pressure gradient is 0.0140. In this depth is possible collapse.

From 50 to 140 m there are clay, sand. They have III category from hardness and III category from abrasiveness. Reservoir pressure gradient is 0.0102 MPa/m and hydraulic fracturing pressure gradient is 0.0140. In this depth is possible collapse.

From 140 to 450 m there are clay, sandstone. They have III category from hardness and VI category from abrasiveness. Reservoir pressure gradient is 0.0102 MPa/m and hydraulic fracturing pressure gradient is 0.0140. In this depth is possible collapse.

950 they are clay,sandstone,limestone.They have V category from hardness and VII category from abrasiveness.Reservoir pressure gradient is 0,0102 Mpa/m and hydraulic fracturing pressure gradient is 0,0164.In this deph is possible collapse.

1150 There are sandstone,argillite.They have V category from hardness and VIII category from abrasiveness.Revervoir pressure gradient is 0,0105 Mpa/m and hydraulic fracturing gradient is 0,0164.In this deph is possible collapse.

1600 they are sandstone,argillite,sitstone.They have VI category from hardness and VIII category from abrasiveness.Reservoir pressure gradient is 0,0105 Mpa/m and hydraulic fracturing gradient is 0,0160.In this deph is possible collapse.

2000 they are sandstone,argillite,siltstone.they have VI category from hardness and VII category from abrasiveness.Reservoir pressure gradient is 0,0105 Mpa/m and hydraulic fracturing gradient is 0,0160.In this deph is possible collapse.

2600 there are argillite,siltstone,sandstone.They have VI category from hardness and VIII category from abrasiveness.Reservoir pressure gradient is 0,0110 Mpa/m and hydraulic fracturing gradient is 0,0170.In this deph is possible collapse.

3200 they are sandstone,siltstone,argillite.They have V category from hardness and VIII category from abravesiveness.Reservoir pressure gradient is 0,0136 Mpa/m and hydraulic fracturing gradient is 0,0190.In this deph is possible collapse.

3400 there are sandstone,argillite,limestone,rock salt.They have V category from hardness and VII category from abrasiveness.Reservoir pressure gradient is 0,0136 Mpa/m and hydraulic fracturing gradient is 0,0203.In this deph is possible collapse.

2.2 Selection and justification of the well design

Conductor casing:

A conductor casing is the first and largest in diameter pipe installed in the bore. It extends 80-150 feet below the Earth's surface and is cemented throughout its full length. A conductor casing has two primary purposes. The first is to prevent unconsolidated sediments from entering the bore and the second is to prevent shallow groundwater, such as rainwater-based infiltration, from entering and contaminating the bore or interfering with the services or facilities placed within the bore.

2.3 Surface casing:

A Surface Casing is a pipe string with a large diameter that is the first one to be set in a well. It is a low-pressure pipe which is cemented first in the well to act as a protective shield to preserve the water aquifers in the region.

Intermediate casing:

Intermediate Casing is the casing which is generally set in place before production casing and after surface casing to provide protection against the abnormally pressured or weak formations. The casing enables the use of drilling fluids with different density crucial for controlling the lower formations.

2.4 Production casing:

Production casing is the final casing run and is hung from a casing hanger on the surface. In conventional wells the production casing is generally set below the target zone, but it can stop above the target zone if it is desirable to change drilling fluid for penetrating the target zone. Production casing must be able to withstand full wellhead shut-in pressure, full bottom-hole pressure, and any mud or workover kill-fluid weight. It is common to flow reservoir fluids up the casing (or casing/tubing annulus) so the production casing must be compatible with expected reservoir fluids. Production casing is cemented to surface.

2.5 Liner casing:

A liners Casing used in drilling and completion is one of the Types of Casing or tubing string of varying length which is set with its top below the surface of the well. Liners can be cemented in place, and may include perforated pipe or well screen. We think that you might be interested in Casing Liner Hanger Setting & Cementing Procedures.

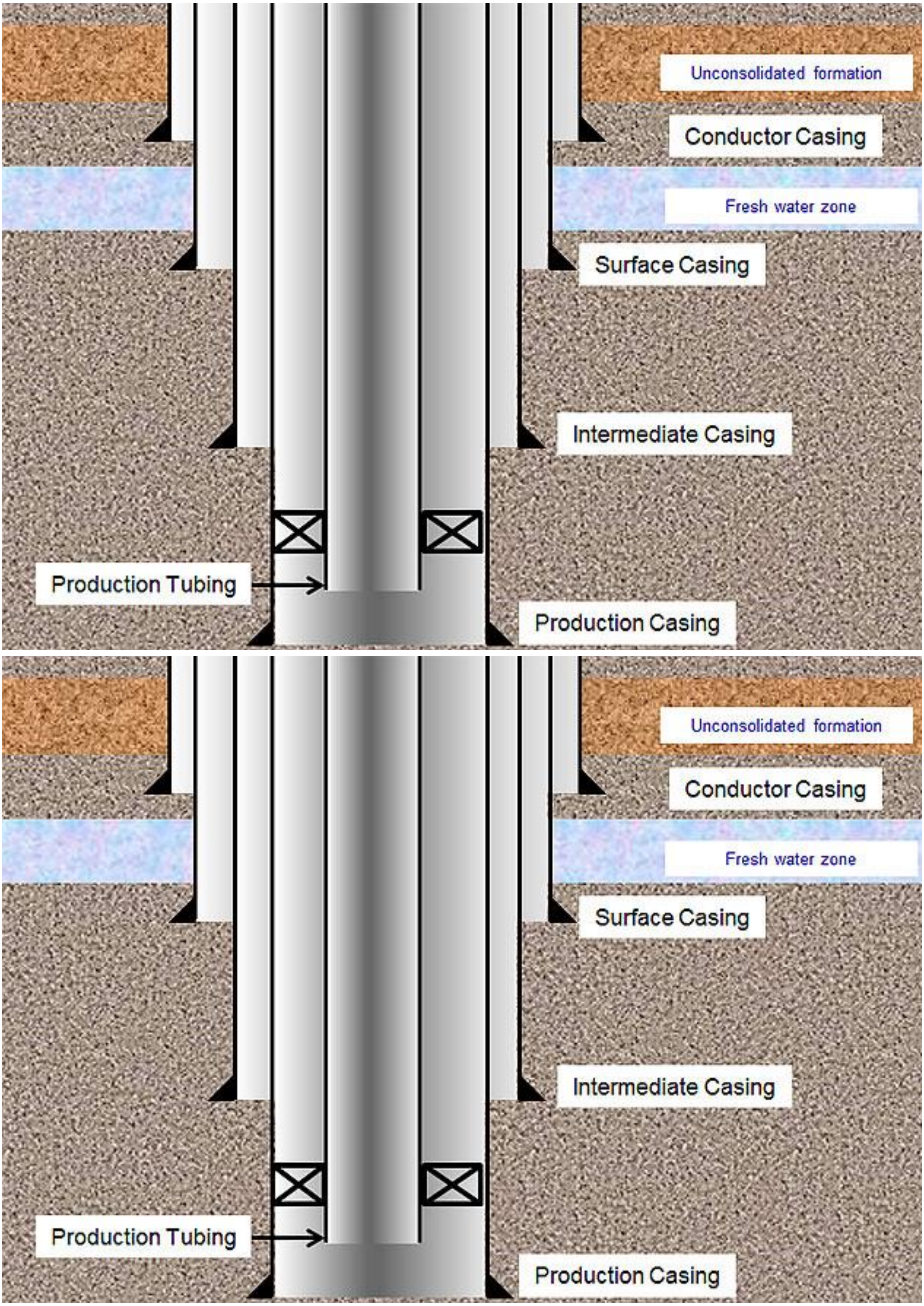
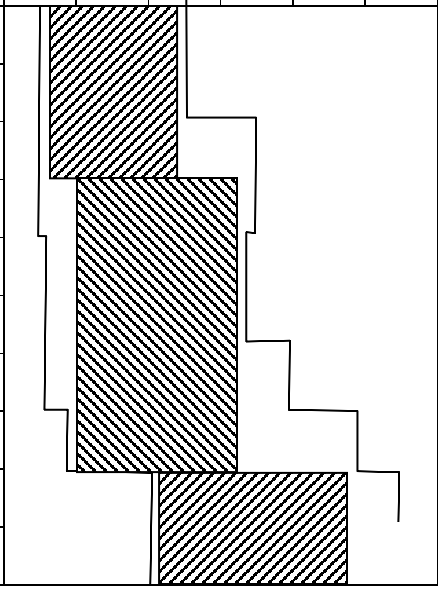
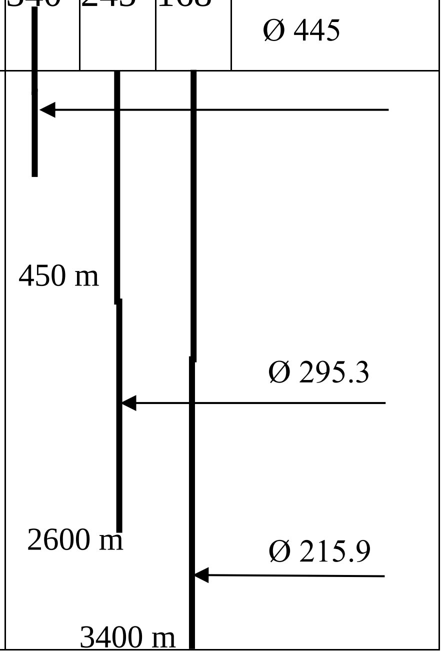


Figure 2.1 - Combined pressure schedule and well design

Table 1.2 - Combined card of pressure

Occurrence interval, m	Pressure gradient, MPa / m		Combined card of pressure						Well design			
	Reservoir	Hydro-rupture	0.0100	0.0120	0.0140	0.0160	0.0180	0.0200	340	245	168	Ø 445
50	0.0102	0.0140										
140	0.0102	0.0140										
450	0.0102	0.0140										
950	0.0102	0.0164										
1150	0.0105	0.0164										
1600	0.0105	0.0160										
2000	0.0105	0.0160										
2600	0.0110	0.0170										
3200	0.0136	0.0190										
3400	0.0136	0.0203										





The diameter of the production casing is 168 mm.

1. The diameter of bore bit under a production casing is delineated after equation

$$Д_{д}^{э} = Д_{м} + 2\delta$$

$Д_{д}^{э} = 187,7 + 2 * 10 = 207,7$ mm

Standard bit

$Д_{д}^{э} = 215.9$ mm

2. Delineate the bore diameter of the previous boring casing, coming from that a difference between the bore diameter of previous column and bit diameter must be a 6-8 mm, so

$Д_{в} = Д_{д} + (6 \div 8)$

$Д_{в} = 215.9 + 7 = 222.9$ mm

3. Standard casing

$d_{н}^{пр} = 245$ мм; $d_{вн}^{пр} = 228.7$ мм; $d_{м}^{пр} = 269.9$ мм.

4. Drill bit for intermediate casing

$$Д_{д} = Д_{м} + 2\delta$$

$Д_{д} = 269.9 + 2 * 10$=289.9 mm

5. Standard bit

$Д_{д}^{э}$ =295.3 mm

6. Surface casing

$Д_{в} = Д_{д} + (6 \div 8)$

$Д_{в} = 295.3 + 7 = 302.3$ mm

7. Standard surface casing diameter

$d_{н}^{к} = 340$ мм; $d_{вн}^{к} = 322.9$ мм; $d_{м}^{к} = 365.1$ мм.

8. Drill bit for surface casing

$$Д_{д}^{э} = Д_{м} + 2\delta$$

$Д_{д}^{э} = 365.1 + 2 * 20$=405.1 mm

9. Standard bit

1-describe different drilling methods.

2.6 Rotary drilling

Based on the design of the well, the geological and technical conditions of drilling and the final diameter, we accept rotary drilling.

a.Cable tool drilling

The original percussion drilling apparatus consisted of a spring pole anchored into the ground at an angle, with the bit suspended from the free end by a rope. To impart the necessary reciprocating action to the bit, the Chinese employed a number of men who alternately jumped on and off the spring pole beam from a ramp. Many early brine wells in the United States were drilled in the same manner, except that the spring pole was equipped with stirrups where two or three men stood and literally kicked the well down.

Figure 2.2 - Rotary drilling

b. Rotary drilling

rotary drilling The process of cutting a borehole in which ground is cut or crushed by a rotating drill system, using a drill bit turned by means of a kelly. Engineering and shallow studies usually involve either a mast or an A-frame. Deep drilling is usually from a derrick. See also CABLE DRILLING.

Figure 2.3 - Rotary drilling

C.Downhole motors

The Down Hole Motor is driven via fluid pumped into the motor, which then turns it into a mechanical rotary motion through the form of a rotor. This rotary motion is applied to a Drill Bit (either PCD, impregnated diamond) and attached to the end of the motor to cut into the formation being drilled.

Figure 2.4 - Top drive

d.Top drive

A top drive is a mechanical device on a drilling rig that provides clockwise torque to the drill string to drill a borehole. It is an alternative to the rotary table and kelly drive. It is located at the swivel's place below the traveling block and moves vertically up and down the derrick.

Figure 2.5 - Top drive

Determinations Of Drill Bits

Table 1.2 - Determinations Of Drill Bits

Depth	Bits
0-450	Д445С-ЦВ
450-2600	Ш295,3К-ЦВ
2600-3400	Ш215,9К-ГНУ

1-Describe different type of drilling bits.

a. ROLLER CON BITS

The bits are sub divided into different categories depending on the drilling process, including the type of formation being drilled and the operating conditions anticipated. There are two main categories: roller-cone bits and fixed-cutter bits. Roller-Cone bits are composed of rotating disks called cones. Rock hardness is one of the determining factors taken into account when selecting an appropriate drill bit. The cutting structure of the bits varies according to the rock formation. Softer formations are drilled with a roller-cone bit with widely spaced, long protruding teeth. Whereas harder formations are drilled with closer-spaced and shorter-toothed bits. Roller-Cone bits are versatile and can cut through many formation types.

Figure 2.5 - ROLLER CON BITS

b.PDC

PDC is extremely important to drilling, because it aggregates tiny, inexpensive, manmade diamonds into relatively large, intergrown masses of randomly oriented crystals that can be formed into useful shapes called diamond tables. Diamond tables are the part of a cutter that contacts a formation.

Figure 2.6 - PDC BITS

2.7 The drill string

The different type of drill string.

Drill string components serves several purposes and functions which includes the following:

The drill string Provides a fluid conduit from the drilling rig to the Drilling Bits.

Also drill string had another function which is to impart rotary motion to the Drilling Bits.

Because of the existence of drill collars in the drill string, it will provide Weight On Bit (WOB) necessary to drill the hole.

Lower and raise the Drilling Bits in the well.

Drill String functions is a lot more but it depends about what do you need to do like it can allow formation evaluation and testing but this will be done by special tools for such application.

Drill string components

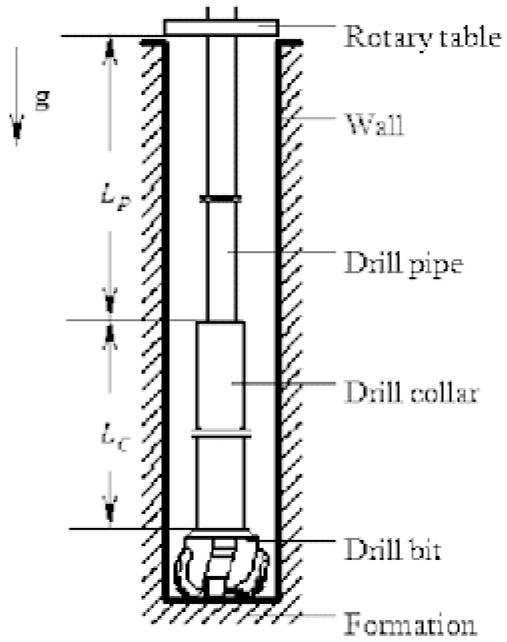


Figure 2.7 - Drill string components

At determination of diameters of collars and pipe drills take into account the recommended ratio by the diameters of bits, collars and pipe drills (table. 4)

Except for it, choose the diameters of borings and collars drills so that such correlations were maintained

$\frac{d_{ОБТ}}{D_{д}} = 0,75 - 0,85$ at $D_{д}$<295,3 mm;

$d_{ОБТ} = (0,75 - 0,85)D_{д} = 0.8 * 215,9$= 172.72

Standard

$d_{ОБТ}$ =178 mm

Drill string

$\frac{d_{бт}}{d_{ОБТ}} = 0,75 - 0,80,$

$d_{бт} = (0,75 - 0,80)d_{ОБТ},$

$d_{бт} = 0,77 * 178$ =137.06 mm

Standard

$d_{бт}$ =139.7 mm

ТБН139,7

$$l_{ОБТ} = \frac{KС_{д}}{q_{ОБТ}\left(1-\frac{\rho_{пр}}{\rho_{м}}\right)},$$

where К is a coefficient of reserve, К=1,20-1,25; Сд is abutment, Н; $\rho_{п}$р is flushing liquid, kg/$м^3$ density; (a m is density of metal, kg/of $м^3$; $q_{ОБТ}$ is weight a 1 m of collars, N/m, for 178 mm of collars $q_{ОБТ}$ =1631 N/m; G is weight of bottomhole motor, Н.

The got length of collars is broken in a greater flank to the extent, what multiple to length of candle. If arrangement of collars must be stepped, then a bottom (first) degree is done long ((=a 0,7-0,8). Diameter of the second degree of collars is chosen on one or two diameters less first.

$$l_{ОБТ} = \frac{1{,}25*250000}{1631*\left(1-\frac{1550}{7850}\right)} = 239 \text{ m.}$$

$$l_{ОБТ} = 250 \text{ m}$$

The weight of the drill collar is

$G_{УБТ} = l_{УБТ} \cdot q_{УБТ} = 250 \cdot 1631 = 407750$ Н.

Above collars it is recommended to place the overbite batch of pipe drills. For this purpose mainly choose pipe from steel of bank of endurance capability of "Д" with the most depth of wall and long a 300 m. For ТБН139,7×11Д is q_1 = 35 kg/m = 350 N/m.

Then the weight of the HWDP

$G_{УБТ} = l_{УБТ} \cdot q_{УБТ} = 300 \cdot 350 = 105000$ Н.

2.8 Drill string design

1. First section 139.7×8Д

q_1 = 26 kg/m = 260 N/m.

When determining the design of the drill string, we assume that the drill string has a single-stage design. For the first section, we accept drill pipes of strength group "K" with a minimum wall thickness (7 mm). The length of the first section is determined from the condition of permissible tensile stresses by the formula

$$l_1 = \frac{Q_{p1} - K_т(G_{УБТ} + G_{нк})\left(1 - \frac{\rho_{пр}}{\rho_м}\right) - Р_п F_п}{K q_1\left(1 - \frac{\rho_{пр}}{\rho_м}\right)};$$

$$Q_{p1} = \frac{Q_т}{K_1 n},$$

Where Q_{p1} – permissible tensile load for pipes of the first section, Н;

$К_т$ – coefficient of friction ($К_т$=1,15);

$G_{УБТ}$ – collar weight, Н;

$G_{нк}$ – weight of the above-bit set, Н;

$Р_п$ – bit pressure loss, Па;

$F_п$ – drill pipe flow area, $м^2$;

q_1 – weight of 1 m of drill pipes of the first section, q_1 = 142 Н/м;

$Q_т$ – tensile load limit determined from the yield point of the pipe material $\sigma_т$, Н for steel grades "К" $\sigma_т$ = 380 MPa;

$Q_т = \sigma_т \cdot F_{тр}$.

$F_{тр}$ – cross-sectional area of the drill pipe body, $м^2$;

n – safety factor (since rotary drilling n=1,4);

$К_1$ – coefficient that takes into account the effect of torque and bending moment (for rotary drilling K1 = 1.04).

ID = OD – 2T = 139,7-2*8= 123.7 mm

Then

$$Q_{p1} = \frac{380 \cdot 10^6 \cdot 0{,}785(0{,}1397^2 - 0{,}1237^2)}{1{,}04 \cdot 1{,}4} = 863431 \text{ Н}$$

Then the length of the first section $l_1 = \frac{863431 - 1{,}15 \cdot (4077500 + 105000)\left(1 - \frac{1550}{7850}\right) - 12 \cdot 10^6 \cdot 0{,}785 \cdot 0{,}1237^2}{1{,}15 \cdot 260 \cdot \left(1 - \frac{1550}{7850}\right)} = 1025.4$ m

l_1 = 1025 m

2. Second section 139.7×9Д, for this pipe q_2 = 290 N/m

$$l_2 = \frac{Q_{p2} - Q_{p1}}{kq_2\left(1 - \frac{\rho_{пр}}{\rho_м}\right)}.$$

Where

$$Q_{p2} = \frac{380 \cdot 10^6 \cdot 0{,}785(0{,}1397^2 - 0{,}1217^2)}{1{,}04 \cdot 1{,}4} = 963984 \text{ Н}$$

Then the length of the second section

$$l_2 = \frac{963984 - 863431}{1{,}15 \cdot 290 \cdot \left(1 - \frac{1550}{7850}\right)} = 375.9 \text{ м.}$$

In accordance with the length of the candle, we take l_2 = 375 m.

3. Third section 139.7×10Д, for this pipe q_2 = 320 N/m

$$l_2 = \frac{Q_{p2} - Q_{p1}}{kq_2\left(1 - \frac{\rho_{пр}}{\rho_м}\right)}.$$

Where

$$Q_{p3} = \frac{380 \cdot 10^6 \cdot 0{,}785(0{,}1397^2 - 0{,}1197^2)}{1{,}04 \cdot 1{,}4} = 1062899 \text{ Н}$$

Then the length of the second section

$$l_2 = \frac{1062899 - 963984}{1{,}15 \cdot 320 \cdot \left(1 - \frac{1550}{7850}\right)} = 334 \text{ м.}$$

In accordance with the length of the candle, we take l_3 = 325 m.

4. Forth section 139.7×11K, for this pipe q_2 = 350 N/m

$$l_2 = \frac{Q_{p2} - Q_{p1}}{kq_2\left(1 - \frac{\rho_{пр}}{\rho_м}\right)}.$$

Where

$$Q_{p4} = \frac{380 \cdot 10^6 \cdot 0{,}785(0{,}1397^2 - 0{,}1177^2)}{1{,}04 \cdot 1{,}4} = 1526545 \text{ Н}$$

Then the length of this section

$$l_4 = \frac{1526545 - 1062899}{1{,}15 \cdot 350 \cdot \left(1 - \frac{1550}{7850}\right)} = 1435 \text{ м.}$$

Since while the total length of the sections, drill collars and BHAs exceeds the design depth of the well, the length of the third section will be

$l_4 = L_{скв} – l_{УБТ} – l_{нк} – l_1 – l_2 – l_3$ = 3400 – 250 – 300 – 1025 – 375 – 325 = 1125 м.

Table 1.3 - The drill string design is given in the summary table.

Indicators	Section number					
	Collars	HWDP	1	2	3	4
Outside diameter of pipes, mm	178	139.7	139.7	139.7	139.7	139.7
Wall thickness, mm		11	8	9	10	11
Strength group of pipe material	Д	Д	Д	Д	Д	К
Section length, m	250	300	1025	378	325	1125
Weight 1m, N / m	1631	350	260	290	320	350
Section weight, Н	407750	105000	266500	109620	104000	393750
Total weight, Н	1386620					

2.9 Determination of boring behavior

Д445С-ЦВ

1. Weight on the bit $C_д$.

Duty on a bit it is possible to define two methods, going out volumetric rock destruction

a) after a specific duty

$C_д = c_п D_д,$

$C_д = 7 * 10^5 * 0.445$= 311500 N

б) after hardness of breeds and by an area interference

$С_д = k_п р_ш F_к,$

Table 1.4 - The drill string design.

Category from hardness	I	II	III	IV	V	VI	VII	VIII	IX	X	XI	XII
$p_ш$, MPa	<100	100-250	250-500	500-1000	1000-1500	1500-2000	2000-3000	3000-4000	4000-5000	5000-6000	6000-7000	>7000

$k_п = 1$

$p_ш = 300$ MPa

$F_k = 480$ mm^2

$C_д = 1 * 300 * 10^6 * 480 * 10^{-6} =$144000 N

$$C_д \le [C_д]$$

$$311500 < 500000$$

Final

$C_д = 312000$ N

2. Frequency of rotation of bit.

For roller-cone bits frequency of rotation is delineated after equation

$n_д = \frac{d_ш}{t_{д_{min}}}$,

$t_{min} = 8 \cdot 10^{-3}$ second, Z = 31, $d_ш = 240$ mm

$n_д = \frac{240}{0.008*445*31}$ = 2.17 s^{-1}= 130 min^{-1}

3. Expense of circulating fluid.

Flushing expense fluid is chosen on two terms

a) from the clause of the bottomhole cleaning from the drilled rock

$Q_1 = q_0 F_{виб}$,

where Q1 is an expense of circulating fluid, м3/с; q0 is a specific expense of circulating fluid, m^3/c on 1 m^2 of bottomhole (q_0=0,35-0,5 – at a rotor and electrical bottomhole drilling; q_0=0,5-0,7 – at boring fluid bottomhole drives); $F_{виб}$ is an area of bottom hole, m^2;

q_0=0,35-0,5

$F_{виб} = \frac{3.14}{4} D^2 = \frac{3.14}{4} 0.445^2$=0.155 m^2

$Q_1 = 0.4 * 0.0155$=0.062 m^3/s= 62 l/s

б) from the clause of hauling of the core boring in circular space

$Q_2 = V\text{кп}_{min}$

where V_{min} – minimum possible rate of movement of circulating fluid in circular space (in rocky breeds V_{min}= 0,7-1,0 m/s; in soft V_{min}=1,0-1,4 m/s; at boring of large-break bits V_{min}=0,3-0,5 m/s).

V_{min}= 0.4 m/s

$F_{кп} = \frac{3.14}{4}(D^2 - d_{бт}^2) = \frac{3.14}{4}(0.445^2 - 0.178^2)$ =0.131 m^2

$Q_2 = 0{,}4 * 0.131$=0.052 m^3/s = 52 l/s

Final

Q = 62 l/s

III295,3К-ЦВ

1. Weight on the bit $C_д$.

Duty on a bit it is possible to define two methods, going out volumetric rock destruction

a) after a specific duty

$C_д = c_п D_д$,

$C_д = 17 * 10^5 * 0.2953$= 502010 N

б) after hardness of breeds and by an area interference

$C_д = k_п p_ш F_к,$

Table 1.5 - The drill string design

Category from hardness	I	II	III	IV	V	VI	VII	VIII	IX	X	XI	XII
$p_ш$, MPa	<100	100-250	250-500	500-1000	1000-1500	1500-2000	2000-3000	3000-4000	4000-5000	5000-6000	6000-7000	>7000

$k_п = 1$

$p_ш = 1500$ MPa

$F_k = 190$ mm^2

$C_д = 1 * 1500 * 10^6 * 190 * 10^{-6}$ =285000 N

$$C_д \leq [C_д]$$

$$502010 > 400000$$

Final

$C_д = 400000$ N

2. Frequency of rotation of bit.

For roller-cone bits frequency of rotation is delineated after equation

$n_д = \frac{d_ш}{t_{д_{min}}},$

$t_{min} = 8 \cdot 10^{-3}$ second, Z = 24, $d_ш = 160$ mm

$n_д = \frac{160}{0.008*295{,}3*24}$ = 2.82 s^{-1}= 170 min^{-1}

2.10 Expense of circulating fluid.

Flushing expense fluid is chosen on two terms

a) from the clause of the bottomhole cleaning from the drilled rock

$Q_1 = q_0 F_{виб}$,

where Q1 is an expense of circulating fluid, м3/c; q0 is a specific expense of circulating fluid, m^3/c on 1 m^2 of bottomhole (q_0=0,35-0,5 – at a rotor and electrical bottomhole drilling; q_0=0,5-0,7 – at boring fluid bottomhole drives); $F_{виб}$ is an area of bottom hole, m^2;

q_0=0,35-0,5

$F_{виб} = \frac{3.14}{4} D^2 = \frac{3.14}{4} 0.2953^2$=0.068 m^2

$Q_1 = 0.4 * 0.068$=0.027 m^3/s= 27 l/s

б) from the clause of hauling of the core boring in circular space

$Q_2 = V\text{кп}_{min}$

where V_{min} – minimum possible rate of movement of circulating fluid in circular space (in rocky breeds V_{min}= 0,7-1,0 m/s; in soft V_{min}=1,0-1,4 m/s; at boring of large-break bits V_{min}=0,3-0,5 m/s).

V_{min}= 1 m/s

$F_{кп} = \frac{3.14}{4}(D^2 - d_{бт}^2) = \frac{3.14}{4}(0.2953^2 - 0.178^2)$ =0.043 m^2

$Q_2 = 1 * 0.043$=0.043 m^3/s = 43 l/s

Final

Q = 43 l/s

III295,3К-ЦВ

<u>1. Weight on the bit $C_д$.</u>

Duty on a bit it is possible to define two methods, going out volumetric rock destruction

a) after a specific duty

$C_д = c_п D_д$,

$C_д = 17 * 10^5 * 0.2953$= 502010 N

б) after hardness of breeds and by an area interference

$С_д = k_п р_ш F_к$,

Table 1.6 - The drill string design

Category from hardness	I	II	III	IV	V	VI	VII	VIII	IX	X	XI	XII
$р_ш$, MPa	<100	100-250	250-500	500-1000	1000-1500	1500-2000	2000-3000	3000-4000	4000-5000	5000-6000	6000-7000	>7000

$k_п = 1$

$р_ш = 1200$ MPa

$F_k = 153$

$С_д = 1 * 1200 * 10^6 * 153 * 10^{-6}$ =183600 N

$$С_д \le [С_д]$$

$$323850 > 250000$$

Final

$С_д = 250000$ N

<u>2. Frequency of rotation of bit.</u>

For roller-cone bits frequency of rotation is delineated after equation

$n_д = \frac{d_ш}{tд_{min}}$,

$t_{min} = 8 \cdot 10^{-3}$ second, Z = 19, $d_ш = 120$ mm

$n_д = \frac{120}{0.008 * 215,9 * 19}$ = 3.65 s^{-1}= 220 min^{-1}

<u>3. Expense of circulating fluid.</u>

Flushing expense fluid is chosen on two terms

a) from the clause of the bottomhole cleaning from the drilled rock

$Q_1 = q_0 F_{виб}$,

where Q1 is an expense of circulating fluid, м3/с; q0 is a specific expense of circulating fluid, m^3/c on 1 m^2 of bottomhole (q_0=0,35-0,5 – at a rotor and electrical bottomhole drilling; q_0=0,5-0,7 – at boring fluid bottomhole drives); $F_{виб}$ is an area of bottom hole, m^2;

q_0=0,35-0,5

$F_{виб} = \frac{3.14}{4} D^2 = \frac{3.14}{4} 0.2159^2$=0.037 m^2

$Q_1 = 0.4 * 0.015$=0.015 m^3/s= 15 l/s

б) from the clause of hauling of the core boring in circular space

$Q_2 = V\text{кп}_{min}$

where V_{min} – minimum possible rate of movement of circulating fluid in circular space (in rocky breeds V_{min}= 0,7-1,0 m/s; in soft V_{min}=1,0-1,4 m/s; at boring of large-break bits V_{min}=0,3-0,5 m/s).

V_{min}= 1 m/s

$F_{кп} = \frac{3.14}{4}(D^2 - d_{бт}^2) = \frac{3.14}{4}(0.2159^2 - 0.178^2)$ =0.0117 m^2

$Q_2 = 1 * 0.0117$=0.0117 m^3/s = 11.7 l/s

Final

Q = 15 l/s

Table 1.7 - The drill string design

Depth	Bits	Parameters		
		WOB, N	Frequency, min^{-1}	Flow, l/s
0-450	Д445С-ЦВ	312000	130	62
450-2600	Ш295,3К-ЦВ	400000	170	43
2600-3400	Ш215,9К-ГНУ	250000	220	15

2.11 Flushing The Well

1-Additional information about drilling rigs for oil and gas drilling.
It is widely known that the drilling fluid´s primary function is to keep well control and prevent an influx of formation fluid to the well causing a blowout. The mud also prevents loss to the formation by keeping the hydrostatical pressure. Not a big issue in the top sections of the well. As we approach the reservoir, however, the consequences of a loss to the formation is critical. The permeability is reduced, and the danger of emulsion is lurking in the dark.

Figure 2.7 - Flushing The Well

Justification of the density of the flushing fluid

We select the density of the drilling fluid according to the combined pressure graph and refine it for each interval of compatible drilling conditions using the formula

$$\rho_{пр} = \frac{\alpha P_{пл}}{gH};$$

Where $P_{пл}$ – reservoir pressure in the well interval for which is determined $\rho_{пр}$;

g – free fall acceleration, м/с^2;

H – hole top depth, м;

α – normative coefficient, which, in accordance with the requirements of the rules for conducting drilling operations, determines the pressure reserve in the borehole above the reservoir.

1. 0-450 m

Density in the range of 0-460 m (because H<1200 then we accept α = 1,12).

$\rho_{пр} = \frac{1,12 \cdot 450 \cdot 0,0102 \cdot 10^6}{9,81 \cdot 450} = 1164$ кг/м^3.

We accept $\rho_{пр} = 1160$ кг/м^3.

2. 450-2600 m

Density in the range of 450-2600 m (because H>1200 then we accept α = 1,05).

$\rho_{пр} = \frac{1,05 \cdot 2600 \cdot 0,0110 \cdot 10^6}{9,81 \cdot 2600} = 1256$ кг/м^3.

We accept $\rho_{пр} = 1260$ кг/м^3.

3. 2600-3400 m

Density in the range of 2600-3400 m (because H>1200 then we accept α = 1.05).

$\rho_{пр} = \frac{1,05 \cdot 3400 \cdot 0,0136 \cdot 10^6}{9,81 \cdot 3400} = 1553$ кг/м^3.

We accept $\rho_{пр} = 1550$ кг/м^3.

2.12 Selection Of The Drilling Rig

1. Additional information about drilling rigs for oil and gas drilling (classification, main components, etc).

a.Classification

Rotary drilling rigs can be classified as land rigs and marine rigs. The main features of land rigs are portability and maximum operating depth. Land rigs are built so that the derrick can be moved easily and reused for drilling new holes. The various rigs components are skid-mounted so that the rig can be moved in units and connected easily.

b.Main component

The rig is basically comprised of a derrick, the drawworks with its drilling line, crown block and traveling block, and a drilling fluid circulation system including the standpipe, rotary hose, drilling fluid pits and pumps. These components work together to accomplish the three main functions of all rotary rigs.

We select the drilling rig according to the rated lifting capacity in accordance with the largest weight of the drill or casing string in the air.

To determine the greatest weight of the string, we will compile a comparative table of the weight of the drill and casing strings.

Table 1.9 - Indicators

Indicators	Drill string	Intermediate casing	Production casing
Column length	3400	2600	3400
Weight 1 m, H		462	290
Column weight, H	1386620	1201200	986000

The type of drilling rig is БУ-3200/200 ЭУК-3МА.
Load on the hook 2000 kN.

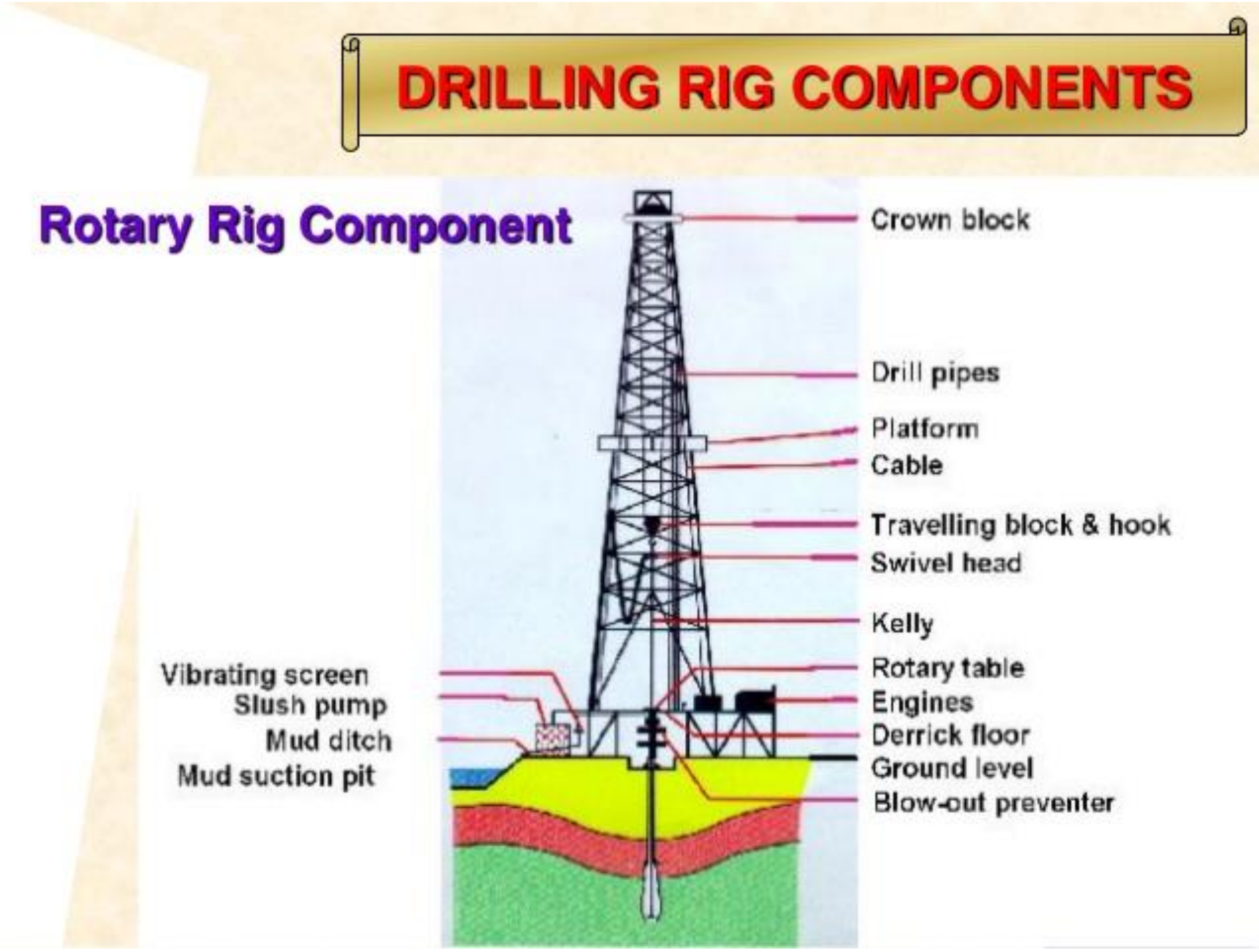


Figure 2.8 - The type of drilling rig is БУ-3200/200 ЭУК-3МА.

Section Conclusions

The well will be drilled by a drilling rig Uralmash-3D-76 in four drilling intervals: direction - 426 mm in diameter, conductor - 324 mm in diameter, intermediate string - 245 mm in diameter and for production casing 168/146 mm in diameter, using mud. The drilling process is monitored by the GTI station. Cementing of the well will be carried out using cement mixing machines 2SMN-20, cementing units and a blending tank. Control of the process will be provided by the SKTs-2M cementing control station.

SECTION 3 LABOR PROTECTION

3.1 Introduction

The oil and gas sector is potentially one of the most dangerous industries, so it must have one of the most advanced safety programs. The combination of powerful and high-tech equipment, flammable chemicals and high-pressure processes can lead to dangerous and even fatal consequences for any personnel error and equipment failure. This is why it is so important that health and safety engineers and plant managers determine recommended safety measures prior to each work shift, and also provide training on potential hazards in a specific workplace. Despite the implementation of a set of measures to ensure industrial and fire safety of tank farms, the level of protection of fire hazardous facilities is at risk. This fact indicates that the problem of fire protection of these facilities requires special attention and further improvement. The purpose of this article is to analyze the state of fire safety at the facilities for storing and transporting petroleum products using the example of oil depot, identifying existing problems and finding their solutions. Based on this, the relevance of the proposed topic aimed at ensuring safety in the oil and gas industry is beyond doubt.

3.2. Problem statement

Activities related to the life cycle of production and maintenance of oil and gas fields, transportation and processing of products and their storage include many different types of equipment and materials [5], which are potential sources of various hazards. Recognizing and controlling threats is critical to prevent possible injury and death. There are the following risk factors that threaten the safety of workers in oil and gas complexes and service enterprises. Road traffic accidents. Workers and equipment must be transported to and from the wells. Deposits are usually located in remote areas and require long distances to reach them. Road traffic accidents arethe main cause of death of oil production, gas production and storage workers. Approximately 4 out of every 10 workers who die in production in this industry are victims of a road traffic accident. [4]

Mechanical stress. Three out of five accidents in the oil and gas industry are the result of dangerous mechanical impact on humans. Workers can be exposed to a variety of mechanical hazards such as moving vehicles, equipment in operation, falling equipment, and high pressure accidents [7].

Falls. While working, workers may need access to platforms and equipment located high above the ground. To do this, they need fall protection and fall prevention from a tower, drilling platform, tanks and other equipment located high above the earth's surface [7].

High pressure lines and equipment. Workers can be exposed to hazards from compressed gases or high pressure pipelines. Internal line erosion can lead to leaks or line breaks, exposing workers to high pressures from compressed gases or high pressure lines. If the connections that secure the high pressure lines fail, there may be a risk of injury [6].

Electrical and other hazards associated with energy equipment. Workers can be exposed to uncontrolled electrical, mechanical, hydraulic, or other hazardous energy sources if equipment is not properly designed, installed and maintained. In addition, to ensure safe operation, it is necessary to develop and implement administrative control measures, such as procedures for checking such devices [5].

Explosions and Fires. Oil and gas workers face the risk of fire and explosion due to the ignition of flammable vapors or gases. Combustible gases such as vapors and hydrogen sulfide can be released from wells, vehicles, manufacturing equipment, or ground equipment such as tanks or shale shakers.

In turn, sources of ignition can be static, electrical energy sources, open flames, lightning, cigarettes, cutting and welding tools, and hot surfaces [6].

Based on the foregoing, it can be concluded that workers in the oil and gas industry continue to be one of the groups with the highest risk of injury and death at work in comparison with all other industries.

3.3 Equipment Operation and Maintenance

All well-producing equipment should be kept neat, clean, painted and in good working order. Equipment should be painted to blend into the surroundings, if required or appropriate, and kept clean to present an acceptable appearance. Selected moving equipment may be painted different colors to enhance visibility.

Safety guards necessary to protect humans, livestock, wildlife, and promote public safety should be maintained around equipment. Refer to API 11ER for information on guarding of pumping units. Equipment lockout/tagout procedures should also be developed and implemented.

Drip pans should be provided under equipment and storage containers potentially subject to minor leaks. These drip pans should be monitored on a routine basis to recover and recycle or dispose of accumulated oil and other liquids.

Bulk storage, recyclable, and reusable containers should be considered in order to reduce the number of containers that must be maintained and disposed. All reusable containers should be well marked to denote contents and the fact that they are to be reused.

The installation or use of double stuffing boxes, leak detectors, and shutdown devices should be considered in areas of particular environmental sensitivity.

Well cellars should be kept clean, dry, and guarded to prevent accidental falls. Well cellars should be filled if they may fill with sour gas and present a safety hazard to people.

3.4 Metallurgy and Corrosion

All equipment should be manufactured from materials which are suitable for the environment in which they are to operate. NACE MR 0175 and NACE RP 0475 should be consulted for more information.

Equipment operating in known corrosive conditions should be inspected on a routine basis for signs of corrosion, with corrective action taken, as needed, to assure the equipment continues to operate in an environmentally acceptable manner.

If well production or injection conditions change in terms of hydrogen sulfide or carbon dioxide content, pressure, water cut, or any other parameter, the metallurgy of the well equipment should be reassessed to assure its suitability for the new conditions.

3.5 Leak Detection

All equipment should be inspected on a routine basis for signs of leakage, with corrective action taken, as needed, to assure the equipment continues to operate in a safe and environmentally acceptable manner.

All injection and disposal wells equipped with tubing and packed should periodically monitor the tubing casing annulus pressure to test the integrity of the tubing and packer. If a well is not completed with a packer, then other methods should be used, such as tracer logs or temperature logs to ensure the fluids injected are properly controlled and are going into the proper injection/disposal formation. Frequency of testing is dependent on the operating conditions. For example, if an area has a high number of corrosion failures, testing for the mechanical integrity of the well should be frequent.

3.6 Inspection and Certification

Equipment should be manufactured, refurbished, inspected, and installed according to manufacturer, API or other industry standards, and legal requirements.

3.7 Well Testing

Venting and Flaring

Venting and flaring should be restricted to a safe location. Where possible, the flare or vent should be located downwind considering the prevailing wind direction at the well location. When possible, all gas resources of value should be captured and used. If not possible, then this gas should be flared.

Flare Pits

Flare pits, sometimes called blowdown or emergency pits, should not be used for storage or disposal. The primary purpose of a flare pit is to catch any incidental fluid that might be associated with the gas stream that does not burn. Fluids in a flare pit should be removed daily, or as quickly as practical.

Siting and construction of flare pits should minimize the risk of surface and groundwater contamination. The size of the flare pit should be proportionate to the volume of liquid effluent that might be expelled from the gas flare. Use of a knockout vessel should be considered.

Control of Noise and Other Nuisances

Flares may need to be provided with noise abatement measures to maintain noise levels compatible with the local environment. The noise intensity, duration, location relative to public areas and natural resources, as well as the flare/vent exit design should be considered, where applicable.

Other nuisances, such as light emittance from a lighted flare, odors, and dust, should be controlled as considered appropriate for the location.

SECTION4: SUBOIL AND ENVIRONMENTAL PROTECTION

The minister of petroleum and energy and the state-owned company Petrosen are the administration officials in charge of the mining operations sector regulate the oil and gas industry.

According to Decree 2017-1574, the minister has the power to promote, explore and manage prospective hydrocarbon areas with the prime minister's approval.

Further, according to Article 36 of Decree 98-810, administration officials have administrative, technical and safety supervision rights in relation to oil operations.

Under the 2019 Petroleum Code, the minister of petroleum and energy's powers remain the same.

Further, under the Article 4 of 2019 code, only Petrosen can act on behalf of the state in order to:

promote the sedimentary basin;

undertake oil operations (on behalf of the state and on the state's request); and

hold the state's shares in hydrocarbon deposits and the capital of companies that hold oil contracts.

Finally, administration officials are responsible for the implementation of the new provisions.

4.1 Exploration and production

Rights

Who holds the rights to oil and gas reserves in your jurisdiction?

Article 5 of the new Petroleum Code (Law 2019-03) provides that:

All deposits or natural accumulations of hydrocarbons on the territory of the Republic of Senegal are the property of the Senegalese people. The State shall ensure its management and valuation under the conditions provided for in this Code.

Article 6 provides as follows:

The State exercise across the territory of the Republic of Senegal, sovereign rights for the purpose of prospecting, exploration, and exploitation, liquefaction of natural gas, storage and transportation of hydrocarbons.

No natural or legal person, including landowners, may undertake oil operations unless they have first been authorized by the State

In short, the state holds sovereign rights to oil and gas reserves.

Is there a distinction between surface and subsurface rights?

Article 2 of the to-be repealed 1998 Petroleum Code (Law 98-05) reads as follows:

the territory of the Republic of Senegal refers to the land part of the Republic of Senegal as well as the Senegalese maritime areas which include the territorial sea and the continental shelf as defined by national law in accordance with the United Nations Convention on the Law of the Sea, ratified by Senegal.

Article 4 of the 1998 code states that the “state exercises sovereign rights throughout the territory of the Republic of Senegal for the purpose of prospecting, research, exploitation and transport of hydrocarbons”.

From these two articles, it is obvious that there is no distinction between surface and subsurface rights. The Senegalese state owns all rights.

The 2019 code confirms this principle.

What rules and procedures govern the grant of rights for exploration and production purposes (eg, through licences, leases, concessions, service contracts, production sharing agreements)?

1998 Petroleum Code (Law 98-05)RulesArticle 5 of the repealed 1998 code provides that the Senegalese state can allow natural or legal persons to undertake oil operations through:

prospection authorisations;

hydrocarbon exploration permits;

provisional operating permits; and

hydrocarbon operating concessions.

The state and the mining title holder will enter into an agreement in order to settle the rights, obligations and commitments attached to the mining title.

Notably, under Article 2 of the 1998 code, a mining title is considered an exploration licence or a hydrocarbon operating concession granted by the state, excluding any licence or concession granted for non-oil operations. Therefore, agreements are concluded only where:

a natural or legal person has a hydrocarbon operating permit; or

a natural or legal person has an exploration licence.

Agreements will take the form of service contracts or production sharing agreements.

Under the new legal framework (Law 01-2019), the state permits only legal persons to undertake oil operations through prospection authorisations, exploration authorisations, exclusive operating licences and provisional operating licences. Exclusive operating licences and provisional operating licences are only issued to Senegalese legal persons. The Senegalese state and the mining title holder will conclude an agreement in order to settle the rights, obligations and commitments attached to the mining title.

Procedures Article 25 of the 1998 code provides that hydrocarbon exploitation concessions are granted by decree. It confers on holders, within the limits of its scope, exclusive rights to carry out all oil operations in accordance with the applicable agreements. These oil operations include production operations.

Article 22 of Decree 98-810 provides that research permit holders can apply to the minister of petroleum and oil for a hydrocarbon exploitation concession if they discover commercially exploitable hydrocarbon deposits. The applicant must apply for a concession within the timeframe agreed by the relevant service agreement or convention.

Article 23 concerns the information that must be provided in an application for a hydrocarbon exploitation concession, including:

a development and commissioning plan for the deposit(s) concerned;

the coordinates and surface area of the requested concession or operating perimeter;

a geographical map at a 1:20,000th or 1:50,000th scale; and

a memorandum justifying the delimitation of the requested concession or operating perimeter.

According to Article 2 of the 1998 code, a services agreement is a risky hydrocarbon exploration and exploitation contract by which the state or a state-owned company grants a qualified person (who assumes the financing risks) exclusive hydrocarbon exploration and exploitation rights within a defined perimeter.

Article 7 of Decree 98-810 provides that applicants of prospection authorisations, hydrocarbon exploration permits or services agreements must provide three copies of their application to the minister of petroleum and energy. The minister will register the application and acknowledge receipt.

Article 8 provides that all applications for prospection authorisations, hydrocarbon exploration permits or services agreements must include at least 14 pieces of information, including the company’s name, its legal form and its articles of association.

Finally, according to Article 9, the minister will inform the applicant about the admissibility of the application. To be admissible, the application must meet all relevant conditions and must relate to areas available for hydrocarbon exploration and exploitation.

2019 Petroleum Code (Law 2019-03)RulesArticle 7 of the 2019 code provides that one or several legal persons can be authorised to undertake oil operations through:

prospection authorisations;

exploration authorisations;

temporary exploitation authorisations; or

exclusive exploitation authorisations.

Article 7 specifies that the last two authorisations are reserved for companies incorporated under Senegalese law.

An oil contract must be drawn up in order to establish the rights and obligations attached to hydrocarbon mining titles.

Finally, oil contract holders must pay a signature bonus to the state.

ProceduresThe decree implementing the 2019 code has not yet been published. As such, limited information is available regarding applicable procedures. That said, the following information is clear:

The minister of petroleum and energy will grant by order prospection authorisations for a two-year period.

Exploration authorisations will be granted by decree for an initial four-year period. Exploration authorisations can be renewed two times for up to three years each time through a decree.

Exploitation authorisations are divided as follows:

Temporary authorisation – Article 27 provides that exploration authorisation holders can apply to temporarily operate producing wells (for up to six months).

Exclusive authorisation – Article 29 provides that if an exploration authorisation holder discovers commercially viable hydrocarbon, they will be granted an exclusive exploitation permit for the discovery area, provided that they apply for the permit before their authorisation expires.

What criteria are considered in awarding exploration and production rights (eg, are there any restrictions on the participation of foreign investors/companies)?

1998 Petroleum Code (Law 98-05)Under the repealed 1998 code, the criteria to award exploration and production rights are “to demonstrate technical and financial capacity”. A legal person or a natural person can hold a mining title or service agreement. This is also true for foreign companies and persons.

2019 Petroleum Code (Law 2019-03)Under the 2019 code, to be awarded exploration and production rights, an applicant must be a legal person (ie, a company) which can demonstrate its technical and financial capacity.

Therefore, under this new code, natural persons cannot undertake oil operations. Further, Article 7 of the code provides that both types of exploitation authorisation (temporary or exclusive) can be granted only to legal persons incorporated under Senegalese law.

4.2 Joint ventures

Are there any special legal provisions applicable to joint ventures?

Laws 98-05 and 2019-03 both contain provisions relating to the contracting group, particularly where a participating interest is transferred (see below). In short, joint ventures are regulated under the laws, but the organisation and commitments of each party are not regulated. As such, parties are free to form and organise a contracting group as they see fit.

4.3 Third parties

Can exploration and production rights be transferred to third parties?

1998 Petroleum Code (Law 98-05)Under the repealed 1998 code, hydrocarbons mining titles, conventions and services agreements can be transferred to legal persons that can demonstrate their technical and financial capacities, provided that the holder of such authorisations has prior authorisation to do so.

2019 Petroleum Code (Law 2019-03)Article 61 provides that hydrocarbon mining titles can be transferred to legal persons (ie, companies) that can demonstrate their technical and financial capacities to undertake oil operations.

Deeds of transfer for mining titles must be sent to the minister in charge of hydrocarbons for approval.

In order to transfer a participating interest from one member of a contracting group to an affiliated company, the minister of hydrocarbons must be provided with a declaration to this effect.

Prospection authorisations cannot be transferred.

4.4 Fracking

Is hydraulic fracturing (‘fracking’) permitted in your jurisdiction?

There is no known legal or statutory provision which forbids this operation. The Oil Code contains no provisions in this regard.

4.5 Transport and storage

What is the general legal framework governing the transportation and storage of oil and gas resources in your jurisdiction?

1998 Petroleum Code (Law 98-05)Under the repealed 1998 code, the parties that transport and store oil and gas must be licenced to do so. Moreover, the 1998 code provides that while a concession or services agreement is valid, the holder of a hydrocarbon deposit has the right to transport the hydrocarbons to storage, processing, loading and mass consumption sites.

2019 Petroleum Code (Law 2019-03)Chapter 5, Articles 35 to 39 of the 2019 code relate to the transport and storage of hydrocarbons.

Article 35 states that while an exclusive operating permit is valid, the contractor has an exclusive right to transport the resources that result from its operating activities. The minister of hydrocarbons will grant authorisation orders only to legal persons incorporated under Senegalese law that can demonstrate their technical and financial abilities.

A hydrocarbon transport authorisation order allows its holder to construct and operate hydrocarbon transport infrastructures. The minister of hydrocarbons will set the duration of the authorisation.

4.6 Transportation

How is cross-border transportation of oil and gas resources regulated?

The cross-border transport of oil and gas resources is considered an export. Neither the 1998 code nor the 2019 code contain provisions regarding exports. However, Article 5 of the Customs Code states: “For exports, there is only one tariff, consisting of export tax duties.” Article 188 of this code further specifies that hydrocarbon resources are exempted from duties and taxes collected for the state’s benefit.

Are there specific provisions governing marine and ground transportation of oil and gas resources?

1998 Petroleum Code (Law 98-05)Article 37 of the repealed 1998 code provides that during the valid period of a services or concession agreement, the contracting party has an exclusive right to transport the results of its operating activities. To do so, the contracting party must obtain the minister of hydrocarbons’ authorisation. The minister’s order will set the duration of the applicant’s right and allow it to construct canalisations and transport hydrocarbon resources.

Under Article 33 of Decree 98-810, to receive authorisation from the minister of hydrocarbons, the contracting party must submit a report on the canalisation construction project which includes:

all of the technical and economic elements justifying construction of the pipeline;

the routes and characteristics of the pipeline;

an environmental impact assessment;

a cost estimation of the construction and exploitation of the pipeline;

an economic and financial assessment of the pipeline’s exploitation;

rates for third-party use of the pipeline, if applicable; and

conditions for third-party compensation, if applicable.

Moreover, under Articles 25 and 26 of Decree 98-338, to obtain authorisation, the contracting party must have a fleet of tank trucks with a minimum capacity of 100m3. All of these trucks must comply with the technical standards in force.

Further, the contracting party must provide precise information on the condition of its fleet – in particular, each vehicle's capacity and technical characteristics.

There is no distinction between marine and ground transport of oil and gas.

2019 Petroleum Code (Law 2019-03)Concerning ground transportation of oil and gas resources, Article 35 of the new Petroleum Code provides that during the valid period of an exclusive operating authorisation, the contracting party obtains an exclusive right to transport the production resulting from the operating activities. To do so, the contracting party must receive the minister of hydrocarbons' authorisation. This authorisation will be granted to companies incorporated under Senegalese law that have the technical and financial abilities essential to undertake the activities. Such authorisation will allow the contracting party to construct canalisations and transport hydrocarbon resources.

Under Article 33 of Decree 98-810, to obtain authorisation from the minister of hydrocarbons, the contracting party must submit an application and a report on the canalisation construction project which includes:

all of the technical and economic elements justifying construction of the pipeline;

the routes and characteristics of the pipeline;

an environmental impact assessment;

a cost estimation of the construction and exploitation of the pipeline;

an economic and financial assessment of the pipeline's exploitation;

rates for third-party use of the pipeline, if applicable; and

conditions for third-party compensation, if applicable.

Moreover, under Articles 25 and 26 of Decree 98-338, to obtain authorisation, the contracting party must have a fleet of tank trucks with a minimum capacity of $100m^3$. All of the tank trucks must comply with the technical standards in force. Further, the contracting party must provide precise information on the condition of its fleet – in particular, each vehicle's capacity and technical characteristics.

In relation to marine transport, Article 35 of the 2019 code provides that the ministers of hydrocarbons and marine affairs will grant authorisations.

Construction and infrastructure

How are the construction and operation of pipelines, storage facilities and related infrastructure regulated?

1998 Petroleum Code (Law 98-05)Under the repealed 1998 code, the minister of hydrocarbons' approval must be obtained before constructing pipelines. To obtain approval, the applicant must submit the following information in its application and pipeline report:

all of the technical and economic elements justifying construction of the pipeline;

the routes and characteristics of the pipeline;

an environmental impact assessment;

a cost estimation of the construction and exploitation of the pipeline;

an economical and financial assessment of the pipeline exploitation;

if applicable, rates for third-party use of the pipeline; and

if applicable, conditions for third-party compensation.

Further, Article 8 of Law 98-31 of 14 April 1998 requires storage facility owners to meet certain product quality, installation safety and environmental protection standards. In addition, any petroleum product storage facility owners (excluding refinery storage facilities) must ensure that their facilities can be accessed freely by any natural or legal person authorised to import or distribute petroleum products – regardless of the product's label, brand or emblem – as long as said person meets the required technical standards.

2019 Petroleum Code (Law 2019-03)The construction and operation of pipelines, storage facilities and related infrastructure are regulated by the 2019 Petroleum Code. The latter provides that all pipeline construction projects are subject to the minister of hydrocarbons' approval. A hydrocarbon operator or the beneficiary of a transport authorisation transfer can apply for approval.

What rules govern third-party access to pipelines and related infrastructure?

1998 Petroleum Code (Law 98-05)Article 38 of the repealed code provides that hydrocarbon transport rights can be transmitted to third parties individually or jointly. The beneficiaries of such a transfer must respect the terms of the agreement that relate to the construction and operation of the facilities and pipelines concerned, as well as with the specific conditions laid down in the service agreement or contract. As such, the beneficiary of such rights must apply for the minister of hydrocarbons' approval to construct transportation facilities.

2019 Petroleum Code (Law 2019-03)Article 36 provides that hydrocarbon transport rights can be transmitted to third parties individually or jointly by the holder of the exclusive operating rights under the conditions defined by the oil contract. The beneficiaries must respect the terms of the agreement that relate to the construction and exploitation of installations. The deed of transfer must be notified to the minister in charge of hydrocarbons for approval.

4.7 Trading and distribution

Regulation

How are oil and gas resources traded in your jurisdiction and what (if any) regulations and procedures apply to oil and gas sales, distribution and marketing activities, both nationally and internationally?

Article 14 of Law 98-31 of 14 April 1998 provides that all companies considering hydrocarbon commercialisation activities must obtain a licence from the minister of hydrocarbons. Such licences will be valid for a 10-year period.

Senegal has no standard regarding the international trade of oil and gas.

Is oil and gas pricing regulated in your jurisdiction?

Refined hydrocarbon pricing is regulated by Decree 2006-952 of 26 September 2006. According to Article 7, the "cap prices of refined hydrocarbons are fixed by order of the Minister for Hydrocarbons". The minister's last order set the import parity price of regular gasoline at CFA franc 361,835.

Occupational health and safety and labour issues

Health and safety

What health and safety regulations and procedures apply to oil and gas operations (upstream, midstream and downstream)?

1998 Petroleum Code (Law 98-05) The 1998 Petroleum Code and its implementing decree (Decree 98-810 of 6 October 1998) contain provisions regarding health and safety.

In accordance with Article 28 of the code, the development plan attached to the application for a hydrocarbon exploitation concession "must contain measures to ensure the safety and health of employees and third parties".

Further, Article 39 of the 1998 code states that:

The route and characteristics of the pipelines must be established in such a way as to ensure the collection, transport and disposal of the production of hydrocarbon deposits under the best technical, economic and environmental conditions.

According to Article 36 of Decree 98-810:

In order to exercise the rights of administrative and technical supervision and safety control of petroleum operations, the officials of the Administration in charge of the petroleum operations sector are authorized and sworn in.

Finally, Article 38 of Decree 98-810 states that the "minister and the officers under his direction shall supervise the exploration, research, development, exploitation and transport of hydrocarbons".

The purpose of this monitoring is to:

conserve all deposits;

ensure that transport, public and occupational health and safety conditions are met;

conserve buildings, dwellings and roads;

protect the use of springs and bodies of water; and

protect the environment.

The Hygiene Code also contains health and safety provisions.

2019 Petroleum Code (Law 2019-03)This law contains specific provisions concerning health and safety. It further requires oil operations to be conducted in accordance with the Environmental Code and other national and international texts regarding:

hygiene;

the health and safety of workers and the public; and

environmental protection.

Labour law

Are there any labour law provisions with specific relevance to the oil and gas industry (eg, with regard to use of native and foreign personnel)?

Article 58 of the 2019 Petroleum Code states that:

Holders of oil contracts and companies working on their behalf must employ Senegalese personnel with equal qualifications, as a matter of priority, to carry out oil operations on the territory of the Republic of Senegal.

What is the state of collective bargaining/organised labour in your jurisdiction's oil and gas industry?

There is currently no collective bargaining in the oil and gas industry. The only protective provisions are provided in the Collective Bargaining Agreement for the Extractive Industries and Mineral Exploration of the Federation Of Mali.

In addition, a national union of oil and gas workers actively defends workers' rights in this sector. In 2016 the union's president stated that it had succeeded in increasing wages for workers in the hydrocarbons sector by 37%.

4.8 Environmental protection

What preliminary environmental authorisations are required before commencing oil and gas-related activities?

Articles L48 to L54 of the Environmental Code regulate environmental authorisations.

Further, Article 21 of Decree 98-810 states that any development project or activity (including policies, plans, programmes and regional and sectoral studies) likely to affect the environment must undergo a prior environmental assessment.

Article 13 of the Environmental Code states that the Ministry of the Environment will issue operating permits for first-class installations.

Article R5 of Decree 2001-282 implementing the Environmental Code and Article 62 of the Environmental Code provide for authorisations for the discharge, dumping and incineration at sea of substances not included in the list provided for in Article L61, provided that such operations do not affect the marine environment or its uses.

These authorisations have been maintained in the 2019 Petroleum Code.

Requirements

What environmental protection requirements apply to the operation of oil and gas facilities?

1998 Petroleum Code (Law 98-05) Under the to-be repealed 1998 code, oil operations must be undertaken in a way which preserves national resources and protects the environment. Therefore, companies must use proven techniques and take appropriate steps to prevent and control pollution. Hydrocarbon title holders bear the costs of environmental protection measures in accordance with the convention and applicable service agreement.

Moreover, Article 6 of Law 98-31 of 14 April 1998 provides that oil and gas importers must meet product quality, installation safety and environmental protection standards.

Under Decree 2009-1335 of 30 November 2009, emergency plans must make it possible to deal with serious environmental pollution events.

Article 8 of Decree 98-810 of 6 October 1998 requires the issuance of an environmental impact notice. This notice must sets out the conditions under which the general work programme satisfies applicable environmental protection standards.

Article 28 of the 1998 code sets out the requirements for development plans, which must contain measures to guarantee the health and safety of employees and third parties, as well as the ecological balance of the environment. Further, title holders must have an abandonment plan to protect the environment.

Article 13 of the Environmental Code and Article 16 of Decree 2001-282 set out a reporting obligation for second-class installations.

2019 Petroleum Code (Law 2019-03)The Petroleum Code contains all of the environmental protection requirements which apply to the operation of oil and gas facilities.

The Environmental Code also requires that companies:

take appropriate measures to prevent and control pollution;

use proven techniques for waste treatment;

use proven techniques to preserve flora and fauna; and

use proven techniques to preserve soil and subsoil water.

Consequences

What are the consequences of failure to adhere to the relevant environmental regulations and to what extent can operators be held liable for environmental damage?

1998 Petroleum Code (Law 98-05) Under the repealed 1998 code, if a company fails to observe the relevant environmental regulations, it and its directors may be held responsible. Persons held liable may be subject to financial and criminal penalties, such as imprisonment.

2019 Petroleum Code (Law 2019-03)The risks remain the same under the 2019 code.

4.9 Taxes and royalties

What taxes (direct and indirect) and/or royalties apply to oil and gas activities in your jurisdiction (including upstream, midstream and downstream activities)?

The 2019 Petroleum Code (Law 2019-03) largely sets out the applicable tax and customs requirements. However, some relevant taxes are set out under the General Tax Code (Law 2012-31 of 31 December 2012, as amended).

Any oil agreements (eg, production sharing contracts) signed between a company and the state also contain tax and customs provisions which, in principle, apply by derogation.

Tax treaties signed between Senegal and the other party's country of residence may also provide for exemptions from certain taxes and fixed rates.

Thus, the taxes, royalties and rates set out below are subject to any exemptions set out in the relevant agreements and tax treaties.

TaxesThere is a 30% corporate tax on realised profits.

Further, the General Tax Code sets out other taxes, including:

a minimum flat tax on companies – oil exploration licence holders are exempt from this tax while they hold a valid title (including during renewal periods and the development and investment phase). This exemption is valid for three years from the first production (Article 39);

a 10% income tax on securities (Article 173);

a 16% income tax on receivables, deposits and guarantees (Article 173);

a 25% tax on non-commercial profits, with a deduction of 20%, thus an effective rate of 20% (Article 202);

a 0% to 40% withholding tax on wages, depending on the worker's gross salary and marital status (Article 167 and following);

a 5% withholding tax on amounts paid to third parties (Article 200);

a representative tax between CFA franc900 and CFA franc36,000 per year, to be paid monthly or quarterly (Article 275);

a 3% lump-sum contribution by the employer – this tax does not apply during the research phase (Articles 263 and 264);

a land converted property contribution – there is an exemption for oil exploration permit holders while they hold a valid title (including during renewal and the development and investment phase). This exemption is also valid for three years from first production (Article 286);

a land contribution of unwrought properties – there is an exemption for oil exploration permit holders while they hold a valid title (including during renewal and the development and investment phase). This exemption is also valid for three years from first production (Article 299);

a local economic contribution (Article 320 and following) – during the research and development phase, petroleum exploration licence holders are exempt from this contribution while they hold a valid title (including during renewal). This exemption is valid for three years from the first production (Article 323). During the operating phase, unless there are relevant exemptions, this contribution applies at a rate of 1% of the added value generated during the year. A cap of 70% of the turnover applies to the company’s added value contribution. For leased premises, the applicable rate is 15%. For owned premises, lands and facilities recorded on the assets side of the balance sheet, the applicable rate is 20%.

an 18% value added tax (VAT) – during the research phase, the supply of goods and services rendered to a research permit holder and its subcontractors is exempt from VAT while the permit is valid, provided that the operations are included in the research programme (Article 361.25). During the operating phase, VAT will apply, unless a relevant convention provides otherwise. However, imports under a suspensive customs procedure and exports are exempt from VAT (see the customs section);

a 10% tax on passenger vehicles (Article 439);

a CFA franc50,000 to CFA franc200,000 tax per private vehicle for legal entities, depending on their tax power (Article 549); and

a tax on real estate gains at a rate of 5% on the share of the capital gain that does not come from the owner (Article 156).

RoyaltiesThe 2019 Petroleum Code provides for a levy on the value of hydrocarbons produced by a provisional operating licence holder or an exclusive authorisation for a hydrocarbon exploitation holder. The following rates apply:

liquid hydrocarbons operated onshore – 10%;

liquid hydrocarbons operated offshore shallow – 9%;

liquid hydrocarbons operated deep offshore – 8%;

ultra-deep offshore liquid hydrocarbons – 7%; and gaseous hydrocarbons operated onshore, shallow offshore, deep offshore and ultra-deep offshore – 6%.

Superficial rentSuperficial rent is planned for the exploration period and ranges between $30 per km2 and $75 per km2.

Imports and exports

What taxes and duties apply to oil and gas imports and exports?

Under Article 49 of the 2019 Petroleum Code (Law 2019-03), during exploration, evaluation and development, the following community levies apply:

statistical fee – 1% of the cost, insurance and freight (CIF) value;

community solidarity levy – 1% of the CIF value; and

Economic Community of West African States (ECOWAS) levy – 0.5% of the CIF value.

Despite these levies, oil contract holders are exempt from all customs duties and taxes, including the Senegalese Council of Shippers' levy.

This exemption applies to a number of materials and assets essential for the completion of exploration programmes and fuels, lubricants fuelling fixed installations, drilling equipment, machinery, commercial vehicles, machinery and other equipment for oil operations. It also applies to subcontractors. It is subject to the minister of finance's visa formalities.

However, during periods of operation, unless otherwise specified, the following taxes are due on the import of materials, equipment, supplies, machinery, spare parts, products and consumables:

customs duties – 0% to 20%, depending on the category;

VAT – 18%;

statistical fee – 1% of the CIF value;

community solidarity levy – 1% of the CIF value; and

ECOWAS levy – 0.5% of the CIF value (Article 51 of Law 2019-03).

Notably, under Article 59 of the 2019 code – which relates to the obligation to supply the local market – exclusive exploitation permit holders may, after satisfying the domestic needs of the country, freely export their production share on payment of a customs duty fixed at 1% of the value of production. This tax must, in principle, exclude the customs duties abovementioned.

4.10 Decommissioning

Regulation

How is the decommissioning of oil and gas facilities regulated?

Article 33 of the 1998 Petroleum Code (Law 98-05) and Article 25 of the 2019 Petroleum Code (Law 2019-03) state that, in the event of partial or total decommissioning, the concession holder must carry out the decommissioning work and take all necessary measures to protect the environment.

4.11 Dispute resolution

Disputes

How are oil and gas disputes typically resolved in your jurisdiction?

1998 Petroleum Code (Law 98-05)Article 66 of the repealed code provides that all offences will be heard by the courts and tribunals of Senegal. The article also specifies that it is possible to revert a dispute to arbitration where it relates to the interpretation or application of a services agreement or convention (if allowed by law).

2019 Petroleum Code (Law 2019-03)Article 71 provides that all offences will be heard by the Senegalese courts. Any disputes arising out of the interpretation or application of an oil agreement can be settled by dispute resolution methods, such as mediation, conciliation, arbitration or any jurisdictional or non-agreed mechanism.

4.12 Anti-corruption measures

Dishonest practices

What regulations and procedures are in place to combat bribery, fraud, collusion and other dishonest practices in the oil and gas sector in your jurisdiction?

1998 Petroleum Code (Law 98-05)Under the repealed code, officials under the minister of oil and energy's authority supervise oil operations. Therefore, hydrocarbon mining title holders and services agreement holders must give officials access to temporary or permanent installations, constructions and constructions sites. They must also provide officials with all required information, data and documents. If an authorised and sworn official finds that an infringement has occurred, the guilty party may be fined between $5 million and $10 million. In case of recidivism, this amount will be doubled (Articles 63, 64, 65 and 66).

2019 Petroleum Code (Law 2019-03)In 2012 Senegal became a party to the Extractive Industries Transparency Initiative, a global standard for the good governance of oil, gas and mineral resources.

Once a state has acceded to the initiative, it must transfer information regarding its oil and gas sector. This information is processed by an all-party commission, comprising government officials, companies and investors. The commission will make recommendations based on the provided information to help governments enact reforms.

This is why the new oil code includes provisions regarding transparency. In particular, the code requires hydrocarbon mining title holders to participate in transparency payment mechanisms as part of their oil operations. Moreover, all income from oil operations that is due to and collected by the Senegalese state is releasable and will be disclosed. Article 63 governs external financial relationships. The code also specifies that administrative supervision will take place.

Authorised and sworn officials are responsible for notifying any infringements of the new code. The code sets out eight offences (eg, diverting or facilitating the diversion of oil or gas substances), which are punishable by fines between $1 million and $20 million.

Under Article 1 of Decree 2017-1574 of 13 September 2017 the minister of petroleum and energy has the initiative and responsibility to combat fraud.

Law stated date

This information is correct as of 2 April 2019. The 2019 Petroleum Code (Law 2019-03) has been in effect since 1 February 2019; however, decrees and other implementing regulations have not yet been issued.

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Section Conclusions

Measures to prevent accidents and complications, protection of mineral resources and the environment.

CONCLUSIONS

In this work, drilling and casing of a production well with oil and gas field with the development of measures to prevent violations of the integrity of the walls of the well.

In the general part, the following is given: the geographical location, an overview of previously conducted geological and geophysical studies and the geological characteristics of the area of work. Described: stratigraphy, tectonics andphysicochemical properties of formation fluids in a given area.

The well will be drilled by a drilling rig in four drilling intervals: direction - 426 mm in diameter, conductor - 324 mm in diameter, intermediate string - 245 mm in diameter and for production casing 168/146 mm in diameter, using mud. The drilling process is monitored by the GTI station. Cementing of the well will be carried out using cement mixing machines, cementing units and a blending tank. Control of the process will be provided by the cementing control station.

The work provides all the necessary life safety measures, Considered measures to prevent accidents and complications, protection of mineral resources and the environment.

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APPENDIX A

The type of materials in the quality of works

No.	Format	Designation	Names	Number of pages	Note
1					
2			Documentation		
3					
4	A4	OGEB.22.02.EN	Explanatory note	83	
5					
6			Demonstration material	14	
7					
8					