Bull. Chem. Soc. Ethiop. **2008**, 22(1), 67-84.
Printed in Ethiopia
ISSN 1011-3924

FOSSIL FUEL ENERGY RESOURCES OF ETHIOPIA

Wolela Ahmed*

Petroleum Operations Department, Ministry of Mines and Energy, P.O. Box 486, Addis Ababa, Ethiopia

(Received October 4, 2006; revised July 22, 2007)

ABSTRACT. Inter-Trappean coal and oil shale-bearing sediments are widely distributed in the Delbi-Moye, Lalo-Sapo, Yayu, Sola, Chida, Chilga, Mush Valley, Wuchale and Nejo Basins. Coal and oil shale-bearing sediments were deposited in fluvio-lacustrine and paludal depositional environments. The Ethiopian oil shales reach a maximum thickness of 60 m, and contain mixtures of algal, herbaceous and higher plant taxa. Type II and I kerogen dominated the studied oil shales. Pyrolysis data revealed that the Ethiopian oil shales are good to excellent source rocks types up to 34.5 % TOC values and up to 130 HC g/kg S_2. A total of about 653,000,000 - 1,000,000,000 tones of oil shale reserve registered in the country. The coal and coal-bearing sediments attain a maximum thickness of 4 m and 278 m, respectively. Proximate analysis and calorific value data show that the Ethiopian coals fall under the soft coal series (lignite to bituminous coal), and genetically classified under humic, sapropelic and mixed coals. A total of about 297,000,000 tones of coal reserve registered in the country. The Permian Bokh Shale, Oxfordian-Bathonian Hamanlei Limestones, Kimmeridgian Urandab Shale are potential organic-rich source rocks. The Permian Calub sandstone, Triassic-Liassic Adigrat sandstone and Oxfordian-Bathonian Hamanlei carbonates are reservoirs in the Ogaden and Blue Nile Basins. 2.7 TCF (76 x 10^9 m^3) sulfur-free gas and 1817 x 10^6 tons condensate reserves are estimated in the Calub field. About 1.3 TCF gas deposit is also encountered in Hilala field. The Blue Nile Basin is one of the potential basins for hydrocarbon exploration. The presence of mature source rocks and oil seepage in the Blue Nile Basin is clue for the generation of hydrocarbon in the basin. The Gambella Basin is the southern extension of the petroliferous Sudan Interior Basins, and could be one of the potential basins for oil and gas deposits.

KEY WORDS: Coal, Energy, Ethiopia, Fossil fuel, Oil shale, Oil and gas

INTRODUCTION

Energy is one of the basic inputs in economic development and human survival. Energy is needed as an input in industry, agriculture, mining, construction and service-giving organization. The availability of energy at a reasonable cost has always become a condition of industrial growth, economic and social progress. Ethiopia is one of the countries that depend upon imported petroleum products. The yearly import of petroleum products is absorbing more than one third of Ethiopia's annual exporting products. The need of domestic fuel in the country is the major factor for deforestation and soil degradation. To overcome this problem, geological studies were carried to find out a valuable amount of oil shale, coal, oil and gas deposits in country. Coal, oil shale, oil and gas deposits could possibly play an important role in the future energy budgets of Ethiopia.

Inter-Trappean coal and oil shale deposits are distributed on the South-Western and Central Plateau of Ethiopia (Delbi-Moye, Yayu, Lalo-Sapo, Sola and Chida, Chilga, Nejo, Mush Valley Basins) (Figure 1). Coal and oil shale-bearing sediments were deposited in fluviatile, lacustrine and paludal depositional environments. Palynology studies confirmed that the Ethiopian coal and oil shale-bearing sediments range in age from Eocene to Miocene [1, 2]. A total of 297 x 10^6 and 653 x 10^6 to 1 x 10^9 tones of coal and oil shale deposits registered in Ethiopia, respectively.

The intra-cratonic Ogaden Basin (Eastern Ethiopia) and Blue Nile Basin (Central Ethiopia) covers an area of 350,000 km^2 and 120,000 km^2, respectively. The sedimentary successions

*Corresponding author. E-mail: wolela_am@yahoo.com

reach up to 10,000 m and 3000 m in the Ogaden and Blue Nile Basins, respectively. The Permian Bokh Shale, Bathonian-Oxfordian Hamanlei Limestones, Kimmerdigian Urandab Shale are potential organic-rich source rocks. The Permian Calub sandstone, Triassic-Liassic Adigrat sandstone and Hamanlei carbonates are potential reservoirs in the Ogaden and Blue Nile Basins. Oil and gas have been encountered in a number of drilled boreholes in the Ogaden Basin. The gas and condensate deposits in the Calub field are estimated to be 2.7 TCF and 1817 x 10^6 tones, respectively. In Hilala field, the gas and oil deposits are estimated to be about 1.3 TCF and 2.4 x 10^6 barrels oil, respectively.

The Blue Nile Basin is one of the potential basins for hydrocarbon exploration. The Blue Nile Basin is the northern most failed arm of the Karroo rift system. The Blue Nile and Ogaden Basins have similar geological setting, lithological association and structural frameworks. The presence of mature source rocks and oil seepage in the northern part of the Blue Nile Basin are clue for the generation of hydrocarbon in the basin. The Gambella Basin is the southern extension of the Sudan Interior Basins, and could be one of the potential basins for oil and gas deposits.

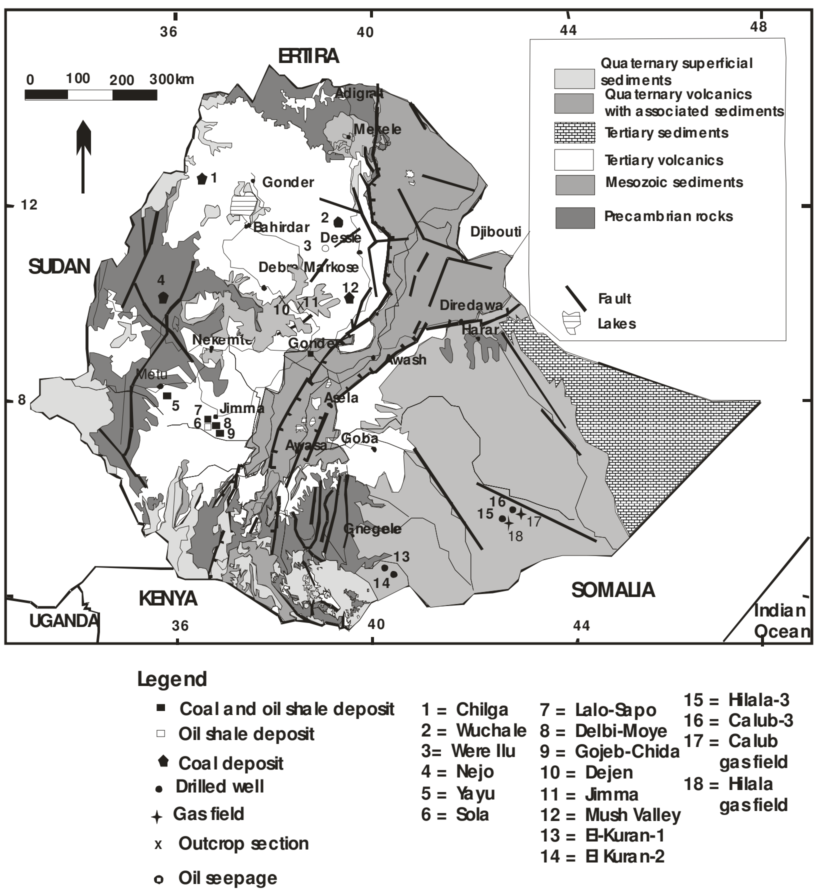

Figure 1. Location map of studied areas.

The main purpose of this study is to highlight Ethiopian coal, oil shale, oil and gas deposits. The paper briefly discusses the geological setting, sedimentation and chemical characteristics of the Ethiopian coal, oil shale, oil and gas deposits. The geology of each deposit is discussed separately. Proximate analysis, Rock Eval (pyrolysis), reflectance microscope and scanning electron microscope studies were carried out to determine the characteristics of the Ethiopian coal, oil shales, oil and gas deposits.

EXPERIMENTAL

Representative outcrop and core samples were collected from Delbi-Moye, Lalo-Sapo, Sola, Chida, Yayu, Mush Valley, Nejo, Wuchale, Ogaden and Blue Nile Basins for different analyses. Samples were cleaned in an ultrasonic water bath to avoid recent weathering. The Rock Eval II plus TOC (from Delsi, Inc.) determines total organic content (TOC) by summing the carbon in the pyrolyzate with that obtained by oxidizing the residual organic matter at 600 °C [3]. 4.07 - 107.8 mg of crushed organic-rich samples were placed in a crucible and pyrolyzed at 300 °C for 3 min, followed by programmed pyrolysis at a rate of 25 °C/min to an optimum temperature of 600 °C in helium atmosphere. Simultaneously, the crucible, which had been in the pyrolysis oven was moved to the oxidation oven. Pyrolysis takes place in three stages, at early stage free gaseous (S_1), liquid hydrocarbon, which is released by the thermal breakdown of kerogen appears as liquid hydrocarbon (S_2) peak between 300-550 °C, and carbon dioxide (S_3) held in the organic-rich samples are volatized and detected by means of a flame ionization detector (FID). The temperature at which the maximum amount of S_2 hydrocarbon is generated is called temperature maximum (T_{max}). The hydrogen index (HI) corresponds to the quantity pyrolyzable organic compound or hydrocarbon from S_2 relative to total organic carbon [3]. The oxygen index (OI) corresponds to the quantity of carbon dioxide from S_3 relative to total organic carbon [3].

Polished sections mounted on polystyrene resin were studied under ordinary and fluorescence-mode to determine the degree of maturation. A Nicrphot-Fxa reflectance microscope, attached to Fiber optic light source, light collecting Pi, monochromatic filter, lenses (10x, 20x, 40x, 60x), and oil immersion reflectance index 1.56 were used. Data were processed by a reflectance software developed by the Queen's University of Belfast [4].

Proximate analysis was performed on 1 mg of coal sample using Fisher Model-490 Coal Analyser to determine moisture, volatile, ash and fixed carbon. The gross calorific value of the coal samples was determined according to ASTM method, by burning a 0.5-1.19 mg coal sample in oxygen in a calibrated Parr adiabatic bomb calorimeter. The gross calorific value of the coal was computed from temperature observation made before, during and after combustion.

Gold-coated organic-rich chip samples were used for scanning electron microscope studies. A JEOL 6400 scanning electron microscope equipped with EDX system with an accelerating voltage of 10-15 kV were used to study the composition and distribution of authigenic minerals.

Pyrolysis and reflectance measurement of oil shale deposits in the Delbi-Moye, Chida, Lalo-Sapo and Yayu Basins were done by Chemical Laboratory, Ethiopian Geological Surveys, Geofluid Laboratory, Queen's University of Belfast, UK. Proximate analysis and calorific values of coal deposits in different basins were made by Chemical Laboratory, Ethiopian Geological Surveys, Department of Chemical Engineering Department, Addis Ababa University, Crude Oil Institute of Korea. Pyrolysis of the Ogaden and Blue Nile Basins were done by Chemical and Geofluid Laboratory, Queen's University of Belfast.

Oil shale and coal deposits on the South-Western plateau of Ethiopia

Delbi-Moye Basin

The studied area is situated 7° 21' 49" - 7° 24' 31" N and 36° 50' 21"-36° 52' 54" E latitude and longitude, respectively (Figure 1). Delbi is 390 km west of Addis Ababa, and 48 km south of Jimma. The basin is found between 2060 and 2240 meters above sea level. A total of 25 boreholes were drilled in the Delbi-Moye Basin.

The sediments were deposited in NNW-SSE trending graben. The basin fill consists of the lower basalt, lower sedimentary formation, middle basalt, upper sedimentary formation, upper basalt and acidic to intermediate volcanics [1, 5, 6]. The lower sedimentary formation is deposited unconformably on a basaltic substratum, which is dated to be 31 Ma [7]. The lower sedimentary formation is characterized by five major sedimentary facies (lower mudstone, lower oil shale, upper mudstone, upper oil shale and coal-bearing-sediments), and defining by three major sedimentary cycles. The marginal faults favoured the accumulation of alluvial fan sandy conglomerates and sandstones. The depocenter of the lacustrine sedimentation is dominated by fine-grained clastic and organogenic sediments; whereas the marginal areas of the basin are dominated by coarser-clastic sediments. Fining up trend, high suspension-load/bed-load ratio, well-developed cyclicity and palaeosol features indicates meandering river sedimentation. The channel lag deposits, flat beds, massive beds and parallel laminated heterolithic facies indicate high-flow regime sedimentation; whilst planar cross-beds and trough cross-beds reflect low-flow regime sedimentation. The lacustrine sedimentation in the Delbi-Moye Basin is characterized by offshore lacustrine at the depocenter and shoreline lacustrine deposition at the marginal areas of the basin [1, 2]. Spores and pollen studies confirmed the age of the sediment to be Eocene-Miocene [2].

Oil shale deposit in the Delbi-Moye Basin. Two oil shale horizons are identified in the lower sedimentary formation. The lower oil shale facies is characterized by a dark brown-brownish colour, massive to fissile structure. It reaches a maximum thickness of 60 m at the depocenter of the basin. The lower and upper oil shale horizons are separated by 5-30 m thick mudstone facies.

The upper oil shale facies exhibited well-developed fissility, and reaches a maximum thickness of 20 m in the central part of the basin. The oil shale seams changes to finer clastic sediments towards the western marginal areas of the basin. Subsurface drilling data allow to estimate the presence of about 120,000,000 tones of oil shale deposits in the Delbi-Moye Basin [1, 5, 6].

Coal deposit in the Delbi-Moye Basin. The coal seams and coal-bearing sediments reach a maximum thickness 2.2 m and 278 m, respectively. The coal seams are characterized by brownish to black, compacted to earthy appearance with conchoidal, massive and prismatic fractures. The coal seams in the Moye area are dominated by humic coal (vitrain, clarian and rarely fusian lithotypes), whereas the Delbi coal is dominated by sapropelic coal (boghead and rarely cannel lithotypes). Subsurface drilling data allow to estimate the presence of about 60,000,000 tones of coal deposits in the Delbi-Moye Basin [1, 5, 6].

Yayu Basin

The Yayu Basin is situated 8° 22' 00" - 8° 24' 00" N and 35° 36' 21"-36° 01' 12" E latitude and longitude, respectively (Figure 1). Yayu is 564 km from Addis Ababa along Jimma-Bedle-Gambella road or 500 km along Nekemte-Bedle-Gambella road. The basin is found between 1300 and 1700 m above sea level. A total of 100 boreholes were drilled in the Yayu Basin.

The basin consists of Precambrian basement rocks, lower basalt, sedimentary rocks, upper basalt and quaternary sediments [8-10]. The sedimentary formation in the basin was deposited unconformably either on the Precambrian basement rocks or on the lower basalt. The sediments consist of terrigenous sediments (gravelly sandstone, sandstone, siltstone and mudstone), organogenic sediments (carbonaceous shale, oil shale and coal seams), and volcanogenic sediments. The sedimentation in the basin is characterized by fluviatile and lacustrine depositional environments [10]. Sedimentation in the Yayu Basin commenced with the deposition of the lower sandstone facies in fluviatile depositional environments. Tectonic activities possibly created the development of tectonic lakes. The extensive distribution of the lower oil shale facies indicated the extensive lake development in the basin. The lacustrine depositional environment terminated, possibly by siltation, and a meandering fluviatile environment conditions restored in the basin. The flood plains became good sites for the development of lakes and swamp area, which were favourable conditions for the deposition of coal seams. After meandering sedimentation the lacustrine environment once more was established in the basin for the sedimentation of the upper oil shale facies. The lacustrine depositional environment ceased by siltation, and fluviatile condition restored once more in the basin for the sedimentation of upper sandstone facies. Palynological studies confirmed the age of these sediments to be Oligocene-Miocene.

Oil shale deposit in the Yayu Basin. Two oil shale horizons are identified in the sedimentary successions. The lower and upper oil shale facies are widely distributed through out the basin [8-10]. The thickest oil shales are found in the eastern part of the basin. The lower oil shale facies is characterized by a brown-brown grey colour, a massive to fissile structure. The facies reaches a maximum thickness of 15 m. The lower and upper oil shale facies are separated by 5 - 30 m thick beds of mudstones, siltstones and fine-grained sandstones. The upper oil shale facies is characterized by a dark brown-brownish colour, and a massive to fissile structures. The upper oil shale seam attains a maximum thickness of 30 m. A total of 500, 000,000 to 1,000,000,000 tones of oil shale deposits is estimated in the Yayu Basin.

Coal deposits in the Yayu Basin. Ten humic coal seams are interbedded in the middle sedimentary succession, and laterally traceable through out the basin. The coal seams attain a maximum thickness of 4 m. The middle sedimentary succession contains the main coal seams. The coal seams are encountered in most drilled boreholes. The coal-bearing sediments are deposited during stable tectonic, in the fluvio-lacustrine and paludal depositional environments. A total of 200,000,000 tones of coal deposits estimated in the Yayu Basin.

Coal and oil shale deposits in Lalo-Sapo Basin

The basin is situated 7° 27'-7°30' N and 36° 45'-36° 50' E latitude and longitude, respectively (Figure 1). The area consists of Trap volcanics and sedimentary rocks. The coal and oil shale-bearing sediments un-conformably lie on a basaltic substratum. The sedimentary formation is mainly composed of sandstones, siltstones, mudstones, carbonaceous shales, oil shale and coal seams. The alternating beds of sandstones and siltstones deposited in fluviatile environment, whereas the coal and oil shale-bearing sediments (coal seams, oil shale seams and carbonaceous claystones and carbonaceous shales) were deposited in lacustrine depositional environments [1]. The coal and oil shale sediments are distributed in four tectonic blocks separated by NNW-SSE fault system.

The oil shale-bearing sediments are deposited on the downthrown blocks, and vary in thickness from 40 to 60 m. The oil shale seams reach a maximum thickness of 15 m. Based on pits, trench and deeply cut stream sections, about 15-25,000,000 tones of oil shale reserves are estimated in the Lalo-Sapo Basin.

The coal seams reach a maximum thickness of 2 m. The sapropelic coal seams are characterized by a brownish to black, with massive and prismatic fractures. Based on pits, trench and deeply cut stream sections, about 7,500,000 tones of coal reserve is estimated in the Lalo-Sapo Basin.

Coal and oil shale deposits in Gojeb-Chida Basin

The basin is situated 7° 10'-7°19' N and 36° 45'-36° 53' E latitude and longitude, respectively (Figure 1). The basin is located 80 km south of Jimma City. The development of the Chida Basin is related to the NNW-SSE trending fault system. The basin consists of Trap volcanics and sedimentary rocks. Sedimentation took place on a basaltic substratum, and is overlain by younger volcanics. The sediments are mainly composed of terrigeneous, biogenic and volcanogenic sediments [1, 11, 12]. Sedimentation in the basin is characterized by fluvio-lacustrine depositional environments [1, 11, 12]. The coarser clastics (conglomerates, sandy conglomerate and sandstones were deposited in fluviatile environment, whereas the fine terrigeneous clastics and biogenic deposits were deposited in lacustrine environments. Volcanogenic beds (tuff) intebedded in the lacustrine sediments, indicating contemporaneous volcanic activities during sedimentation.

7 m thick a black-brown, highly fissile oil shale was encountered in the Chida Basin [1, 5, 12]. Pollen and spores studies confirmed the age of the oil shale-bearing sediments to be Eocene-Miocene [1]. Based on pits, trenches and stream sections, about 3-5,000,000 tons oil shale reserve is estimated in the Chida Basin.

The coal-bearing sediments and coal seams attain a maximum thickness of 60 m and 2.5 m, respectively. The coal-bearing sediments cover about 4 km^2. 9,500,000 tones of lignite to sub-bituminous B coal reserve are estimated in the Chida Basin [12].

Oil shale deposit in Sola area

Sola is located 60 km SW of Jimma City (Figure 1). The sedimentary formation in the Sola area is mainly composed of claystones, carbonaceous shales, oil shale seams and tuffaceous sandstones. The sediments are characterized by fluvatile and lacustrine depositional environments [13, 14]. The oil shale seam in the area is exposed at elevation 2290 m, and reaches a thickness of 8 m. Based on pits and deeply cut stream sections, 2,000,000 tones of oil shale reserve is estimated in the Sola area.

Coal deposit in Nejo Basin

The basin is situated 9° 29'-9° 31' N and 35° 20'-35° 29' E latitude and longitude, respectively (Figure 1). Nejo is located 190 km west of the town of Nekemte. The basin is found between 1700 and 1950 m above sea level. The area consists of Precambrian basement rocks, Tertiary sediments and Tertiary volcanics [15, 16]. The coal-bearing sediments were deposited unconformably on Precambrian basement rocks and capped by Trap volcanics. The NW-SE trending fault systems divided the basin into eastern and western blocks. The coal-bearing sediments and coal beds attain a maximum thickness of 15 m and 1.75 m, respectively [15, 16]. The coal-bearing sediments were deposited in lacustrine environments. The depocenter of the lake were dominated by organogenic sediments (coal seams, carbonaceous sediments and carbonaceous shales), whereas the marginal areas of the lake were dominated by fine-grained clastic sediments, indicating fluviatile sedimentation fed by rivers into the lake [1]. Palynological studies revealed the Nejo coal-bearing sediments to Middle Eocene to Oligocene in age [15]. The total reserves coal in the Nejo area is estimated to be 3 million tones [17].

Coal deposits on the North-Western plateau of Ethiopia

Chilga Basin

The basin is situated 12° 25'-12° 38' N and 37° 03'-37° 11'E latitude and longitude, respectively (Figure 1). Chilga is located 52 km southwest of Gonder. The basin is found between 1900 and 2100 m above sea level. 12 boreholes were drilled in the central part of the basin.

The Inter-Trapean coal-bearing sediments were deposited in a small NNE-SSW trending graben, within the main Tana Graben [18]. The area consists of Trap volcanic and sedimentary rocks. The coal-bearing sediments deposited on basaltic substratum dated to be 29-31 Ma [19] and overlain by 8 ± 1.2 Ma dated upper basalt [19, 20].

The coal-bearing sedimentary succession consists of coals, carbonaceous shales, claystones, siltstones, fine to medium-grained sandstones. The coal-bearing sediments were deposited in lacustrine and swampy depositional environments, and reach a maximum thickness of 78 m at the depocenter of the basin [1]. The thickness of the coal seams in the Chilga Basin ranges from 0.2 to 1.25 m. The fine-grained fluviatile sandstones were enclosed by meandering flood-plain fines (siltstones, silty claystones and mudstones), and shows well-developed cyclicity with fining upward trend. The silty clay unit is highly bioturbated, possibly indicating post-depositional modification. The coal seams and carbonaceous sediments are indicator of euxinic deep lacustrine environment. Palynological studies confirmed the age of the coal-bearing sediments to be 27-28.5 Ma [19]. The Chilga coal reserve is estimated to be 19, 700, 000 tones [18].

Coal deposit on the central plateau of Ethiopia

Mush valley

Mush Valley is situated 159 km northeast of Addis Ababa along Addis Ababa-Dessie road. The area is found between 2600-2800 m above sea level. The Inter-Trappean coal-bearing lacustrine sediments predominantly composed of sandstones, siltstones, carbonaceous shales and coal seams. The succession in the Mush Valley lies on the Miocene-Pliocene basaltic substrutum [21]. Two coal seams are interbedded at different levels in the coal-bearing sediments. The lower and upper coal seams attain a thickness of 1.75 m and 1.0 m, respectively. The total reserve is estimated to be 1 million tones.

Wuchale area

Wuchale is 62 km from Dessie along Addis Ababa-Mekele road. The area is found between 2067 and 3560 m above sea level. The coal-bearing sedimentary succession is deposited on a basaltic substrutum of Ashangi Trap series [22]. The fluvio-lacustrine coal bearing sediments consists of arenaceous, argillaceous, carbonaceous shales, coal and oil shale seams. The coal seams exposed on the southern flanks of Titito River. Two lignite seams are interbedded within 25 m thick coal-bearing sediments. The total reserve is estimated to be 3.3 million tones [17].

Chemical characteristics of Ethiopian oil shales

Scanning electron microscope (SEM) studies revealed the studied oil shales consists of variable mixtures of derital siliciclastic grains, plant remains, algal bodies, crystals of quartz and pyrite, authigenic clay minerals (smectite, kaolinite and chlorite). The Ethiopian oil shales are classified as Type II, I and rarely Type III kerogen. Type-II and I are consistent with the observation of abundant resinite; whereas the oil shales plot as Type-III kerogen indicated low resinite content [23].

The total organic content (TOC) values of the studied oil shales range from 5 to 34.5 % (Table 1), and are excellent source rocks [3, 23, 24]. TOC values within the limit of 0-0.5 % are considered to be poor source rocks, whilst sediments with 0.5-1 % TOC values are classified as marginal in source rock quality, and sediments > 1 % TOC are considered to be good source rock quality [3]. The studied oil shales are rich in organic content, and are immature to early mature stage for hydrocarbon generation.

Table 1. Pyrolysis results, reflectance and reserves of oil shale deposits in Delbi-Moye, Chida, Lalo-Sapo and Yayu Basins.

Basin	Locality	Depth in meter	S_1 in HC kg/t	S_2 in HC kg/t	S_3 in C kg/t	T_{max} in °C	TOC in (%)	HI in mgHC/ g_{org}	OI in mg CO_2/g	Reflect-ance in %	Reserve in tones
Eastern Delbi-Moye	Legamese Stream	Outcrop	2.3	119.9	1.8	444	16	749	11	0.5-1.0	100 x 10^5
	BH-1	101	0.3	15	0.3	438	10	150	2		
		122	1.5	31.8	1.2	438	6.1	530	8		
		155	0.9	18.3	0.8	445	5	369	5		
Western Delbi-Moye	BH-101	43	1	36.6	1.1	441	7.5	488	7		
		58	0.4	20.1	2.6	438	1.7	1187	7		
		28.7	0.3	13.3	1.1	439	4.5	549	8		
Lalo-Sapo	Waro Stream	Outcrop	0.8	20.8	0.8	434	6.0	347	5	0.3-0.6	10-25 x 10^6
	Geta Stream	Outcrop	1.8	47.9	0.5	429	19.2	249	4		
Yayu	Baho Stream	Outcrop	0.19	11.1	0.3	437	5.0	211	6	0.6-0.8	500 x10^6 - 1 x 10^9
			5.93	89.86	2.03	448	34.5	260	6		
	BH-3-2	51	0.45	42.59	2.3	445	24.8	171	9		
		94	0.62	21.64	1.6	436	18.8	115	19		
	BH-4-2	74	2.17	89.49	1.7	442	23.2	386	7		
		102	0.68	42.5	1.29	439	20.9	203	6		
Chida	Didibo Stream	Outcrop	1.6	130	0.4	443	15.5	860	9	0.2-0.5	5 x 10^6
			2.2	118	1.7	447	14.1	812	12		

TOC = total organic carbon, S_1 = free hydrocarbon, S_2 = liquid hydrocarbon, S_3 = carbon dioxide, T_{max} = temperature maximum liquid hydrocarbon generation, HI = hydrogen index, OI = oxygen index.

Temperature maximum (T_{max}) values of the studied oil shales range from 429 to 445 °C (Table 1). T_{max} values less than 435 °C are indicative of rocks that are thermally immature with respect to oil generation; whilst values in the range of 435-460 °C are indicative of rocks at ideal condition for oil generation, and values greater than about 465 °C are indicative of rocks that are beyond the stage of effective petroleum generation [3]. The hydrogen index of studied oil shales range between 115 and 1187 mgHC/g TOC indicating oil and gas prone source rocks (Table 1; Figure 2).

Total hydrocarbon generation potential (free hydrocarbon (S_1) + liquid hydrocarbon (S_2) versus TOC values plot for the Delbi-Moye, Yayu, Chida, Sola and Lalo-Sapo Basins indicated that the upper and lower oil shale samples are good to excellent types of source rocks (Figure 2).

S_2 values of the studied oil shales range from 15-132.8 HCkg/g, which indicate excellent potential source rocks. The Pr/Ph ratio of the upper and lower oil shale in the Delbi-Moye Basin is 3 and 7, whereas the Pr/Ph ratio of oil shale in the Lalo-Sapo Basin is 1.11 [1]. The Pr/Ph ratio >1 indicates a terrestrial source rocks [25].

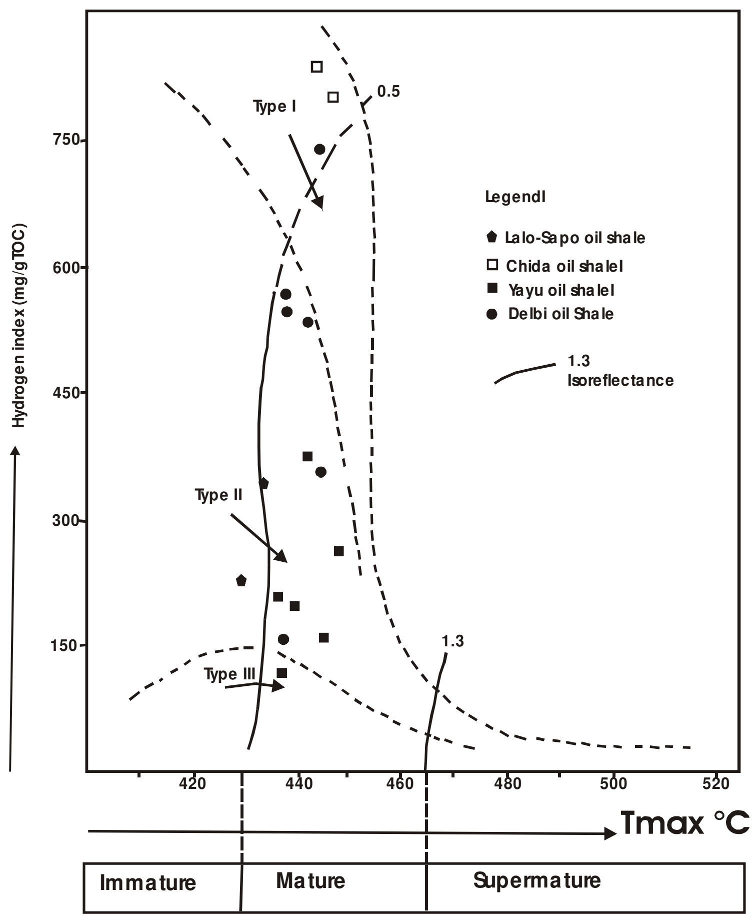

Figure 2. Cross plot of hydrogen index versus T_{max} values, Delbi-Moye, Chida, Lalo-Sapo, Yayu, Chida and Sola Basins.

Chemical characteristics of Ethiopian coal

The Delbi sapropleic coals in the area are characterized by high-medium volatile matter (25.9 - 29.1), medium-low ash content (11.2-25.7 %), low moisture content (3.8-8.58 %) medium to high calorific values (2520-6595 cal/g), and classified as lignite to high-medium volatile bituminous coals with weak coking properties (Table 2). Calorific values and fixed carbon of the Moye humic coals range from 2948-5190 cal/g and 28.1-42.2 %, respectively (Table 2). The Moye coals are characterized by sub-bituminous to high volatile bituminous B coals with strong coking properties. The coal deposit of Moye area is the best type of coking coal deposit in Ethiopia [26].

The humic coals in Yayu, Chilga, Chida, Mush Valley, Nejo and Wuchale Basins range in ash content (16.6-41.6 %), fixed carbon (10.6-45.2 %), volatile matter (18-40.6 %) and calorific values (2824.5-4599.5 cal/g) (Table 2). These coals classified under low-medium ash content, medium volatile matter, moderate calorific values lignite to bituminous coal.

Table 2. Proximate analysis and calorific values of coal deposits in different basins.

Basin	Locality	Depth in meter	Thick-ness in meter	Moisture in (%)	Volatile matter in (%)	Fixed carbon in (%)	Ash in (%)	Calorific value in (cal/g)	Reserve in tones
Delbi-Moye (Eastern block)	Legamese Stream	Outcrop	1.0	8.58	29.0	49.1	11.9	6495	20 x 10^6
	BH-1	64	2.0	5.7	25.9	42.8	25.7	6420	
		90.7	1.8	3.8	27.7	58.1	11.2	6350	
	BH-2	50.8	1.4	4.0	26.3	47.1	22.7	2520	
Delbi-Moye (Eastern block)	Yeba Stream	Outcrop	1.3	3.6	22.8	28.3	48.8	2947	40 x 10^6
	Rameta Stream	Outcrop	1.0	1.82	21.8	28.5	49.1	5190	
	BH-18	81	2.0	0.5	20.6	42.2	46.8	4150	
	BH-21	80	2.0	0.3	17.9	42.1	39.6	4880	
Yayu (Wittete Block)	Teble Stream	Outcrop	4.0	18.6	28.3	28.1	24.6	3795	200 x 10^6
	BH-2-1	90.8	1.54	8.1	44.9	14.5	42.1	5605	
	BH-10-1	78	2.1	10.9	46.5	11.3	42.2	5930	
	BH-7-2	119	1.9	20.7	42.0	16.0	41.9	5430	
Chilga	Kirnat	Outcrop	0.7	5.9	21.1	34.4	39.5	3072	19 x 10^6
	Huga	Outcrop	0.6	6.4	24.7	36.4	32.5	3195	
	BH-31	54.8	0.7	10.7	22.6	40.1	26.6	4021	
	BH-27	65.4	0.7	6.6	31.8	45.2	16.6	4560	
	BH-6	35.7	0.6	7.3	22.9	38.2	41.6	4441	
Lalo-Sapo	Bokai Stream	Outcrop	2.0	13.4	32.4	20.9	33.1	4120	7.5 x 10^6
	Waro Stream	Outcrop	1.0	12.0	18.2	58.3	11.5	4015	
	Geta Stream		0.7	9.1	20.5	52.4	18.1	2626	
Chida	Near Gojeb River	Outcrop	1.0	11.2	15.0	51.0	22.8	2492	9 x 10^6
			1.5	18.9	27.6	22.4	33.5	4333	
			0.9	13.5	29.5	19.6	37.3	4088	
Mush Valley	Mush River	Outcrop	1.8	21.3	31.8	27.9	19.0	2824	1 x 10^6
				21.4	40.4	10.6	27.6	3568	
Nejo	Mecakani	Outcrop	0.5	16.0	35.2	28.8	23.1	3400	3 x 10^6
	Gute Sedo		1.0	14.4	30.5	35.5	19.6	3987	
Wuchale	Totito	Outcrop	0.5	10.4	18.0	45.4	35.2	3700	3.3 x 10^6
			0.4	12.3	29.7	22.6	48.7	5445	

Marine and continetal-influenced petroleum potential basins in Ethiopia

The Ogadan and the Blue Nile Basins are the major marine and continental-influenced sedimentary basins in Ethiopia for petroleum exploration. Intra-cratonic rift basins were developed by extensional and transtentional tectonics that initiated during late Palaeozoic. Thick

Permo-Cretaceous continental clastics, marine carbonates, evaporite and marine clastics were deposited in these basins. Types of sediments and depositional environments of these basins are given in Figures 4 and 5. The Permo-Triassic Bokh shale, Oxfordian-Bathonian Hamanlei limestones and Kimmerdgian Urandab shale are organic-rich potential source rocks. The Permian Calub sandstone, Triassic-Liassic Adigrat sandstone and Oxfordian-Bathonian Hamanlei carbonates are potential reservoirs in the Ogaden and Blue Nile Basins. The presence of oil seepage in Derkele (Ogaden Basin) and Were Ilu (Blue Nile Basin) indicated that the generation of hydrocarbons in the basins. The Calub and Hilala gas and condensate fields are also clue for the generation of hydrocarbons in the Ogaden Basin.

Detailed tectonic and sequence stratigraphy of the basin-fills allowed to correlate the Ogadan and the Blue Nile Basins [27-30]. The Ogaden and the Blue Nile Basins have similar geological setting, lithological association and structural frameworks. Sequence stratigraphy of the Ogaden and Blue Nile Basins allow correlation with Saudi Arabia and Yemen sedimentary basins.

Oil and gas deposits in the Ogaden Basin. The intra-cratonic Ogaden Basin covers an area of 350,000 km^2. The sedimentary successions reach up to 10,000 m (Figure 4). The Bokh shale, Transitional Zone (between the Adigrat sandstone formation and Lower Hamanlei limestone formation), Lower Hamanlei limestone formation and the Urandab formation are considered to be potential source rocks in the Ogaden Basin. The TOC values of 450 m thick organic-rich Bokh shale range from 0.5 to 1.5 % (Table 3). The lacustrine Bokh shale is considered to be the source for the Hilala and Claub gas deposits. 50 to 120 m thick Lower Jurassic dark grey organic-rich shales of the Transitional Zone are excellent type of source rocks (Table 3). The condensate deposit in the Calub field is sourced from the Transitional Zone. Up to 120 m thick shelf marine dark laminated shales and marls of the Urandab Formation are the best types of source rock in the Ogaden Basin (Table 3), and is believed to be the source rock for Hilala oil and Genale seepage oil. Cross plot of hydrogen index versus T_{max} values (Figure 3) of the Bokh Shale, Transitional facies and Urandab Shale indicated that excellent types of source rocks.

The Permian to Early Triassic Bokh shale revealed petroleum potential up to 7 kg HC/t, Transitional facies revealed petroleum potential up to 5.3 kgHC/t, and the Urandab formation revealed petroleum potential up to 8.6 kg HC/t [29]. 2.7 TCF (76 x 10^9 m^3) gas and 1817 x 10^6 tones condensate reserves are estimated in the Calub gas-condensate field, whereas the Hilala gas field is estimated to be about 1.3 TCF (40 x 10^9 m^3) gas deposit.

The fluviatile Permian Calub sandstone formation (porosity up to 12 % and permeability up to 19 mD), Triassic-Liassic fluviatile Adigrat sandstone formation (porosity up to 20 % and permeability up to 1000 mD), Bajocian-Bathonian tidal flat sedimentation of the Middle Hamanlei limestone formation and marine shelf sediments-dominated the Callovian Upper Hamanlei limestone formations are also potential reservoirs in the Ogaden Basin. Basement-related tectonics, pinchout of Claub sandstone formation against basement, permeability barrier within the carbonates are the possible stratigrphic and structural traps in the basin. Evaporite, tightly cemented limestones and shales act as sealing materials.

The Bokh shale (source rock)-Calub sandstone formation (reservoir), the Bokh shale (source rock)-Adigrat sandstone formation (reservoir), the Transitioinal Zone (source rock)-Adigrat sandstone formation (reservoir), and the Urandab formation (source rock)-Upper Hamanlei limestone formation (reservoir) petroleum systems are identified in the Ogaden Basin. The chrono, litho-stratigraphic and hydrocarbon plays in the Ogaden Basin is given on Figure 4.

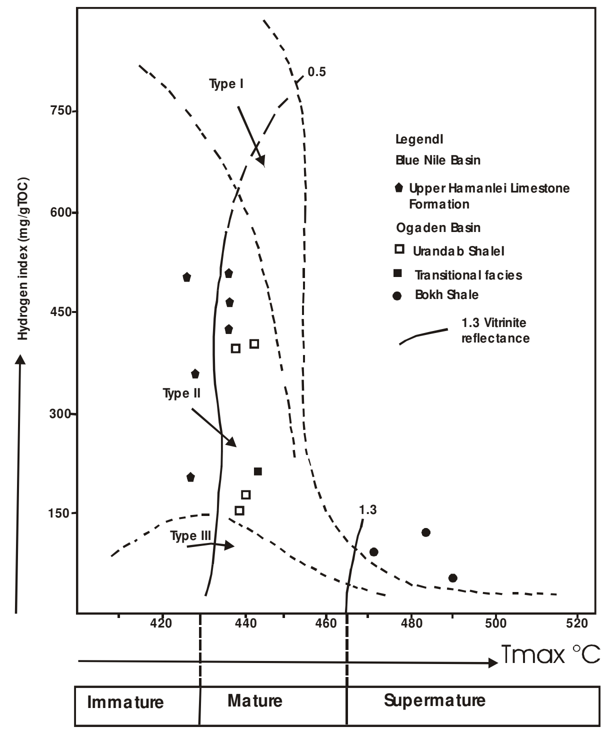

Figure 3. Cross plot of hydrogen index versus T_{max} values, Ogaden and Blue Nile Basins.

Table 3. Pyrolysis results of the Ogaden and Blue Nile Basins.

Basin	Exposure	Format-ion	Depth in meter	TOC in (%)	S_1 in HCkg/t	S_2 in HCkg/t	S_3 in HCkg/t	Tmax in (°C)	OI in mgHC/ gCorg	HI in $mgCO_2$/g
Ogaden	Hilala-3	Bokh	3303	0.4	0.11	0.58	0.02	489	6	161
			4260	0.3	0.14	0.23	0.01	471	3	77
	Calub-3		4400	0.74	0.21	0.34	0.84	428	4	46
	El-Kuran-1	Transitional	2909	1.04	0.13	0.61	0.21	445	19	57
			2921	0.57	0.11	0.62	0.28	442	49	225
	El-Kuran-1	Urandab	1219	3.04	0.28	11.5	0.83	437	27	378
			1220	1.07	0.08	2.20	0.27	443	46	170
	El-Kuran-2		1235	4.15	2.14	16.43	0.74	442	17	395
			1280	0.67	0.02	1.05	0.55	439	82	156
Blue Nile	Dejen	Upper Hamanlei Limestone	Outcrop	1.73	0.06	8.59	0.45	442	16	496
				0.65	0.03	2.10	0.70	429	20	323
				10.93	0.53	42.82	0.81	435	17	392
	Jimma			0.87	0.03	4.27	0.42	425	30	491
				7.22	0.11	15.13	1.20	425	16	210
				1.95	0.07	8.82	0.27	438	18	452

TOC = total organic carbon, S_1 = free hydrocarbon, S_2 = liquid hydrocarbon, S_3 = carbon dioxide, T_{max} = temperature maximum liquid hydrocarbon generation, OI = oxygen index, HI = hydrogen index.

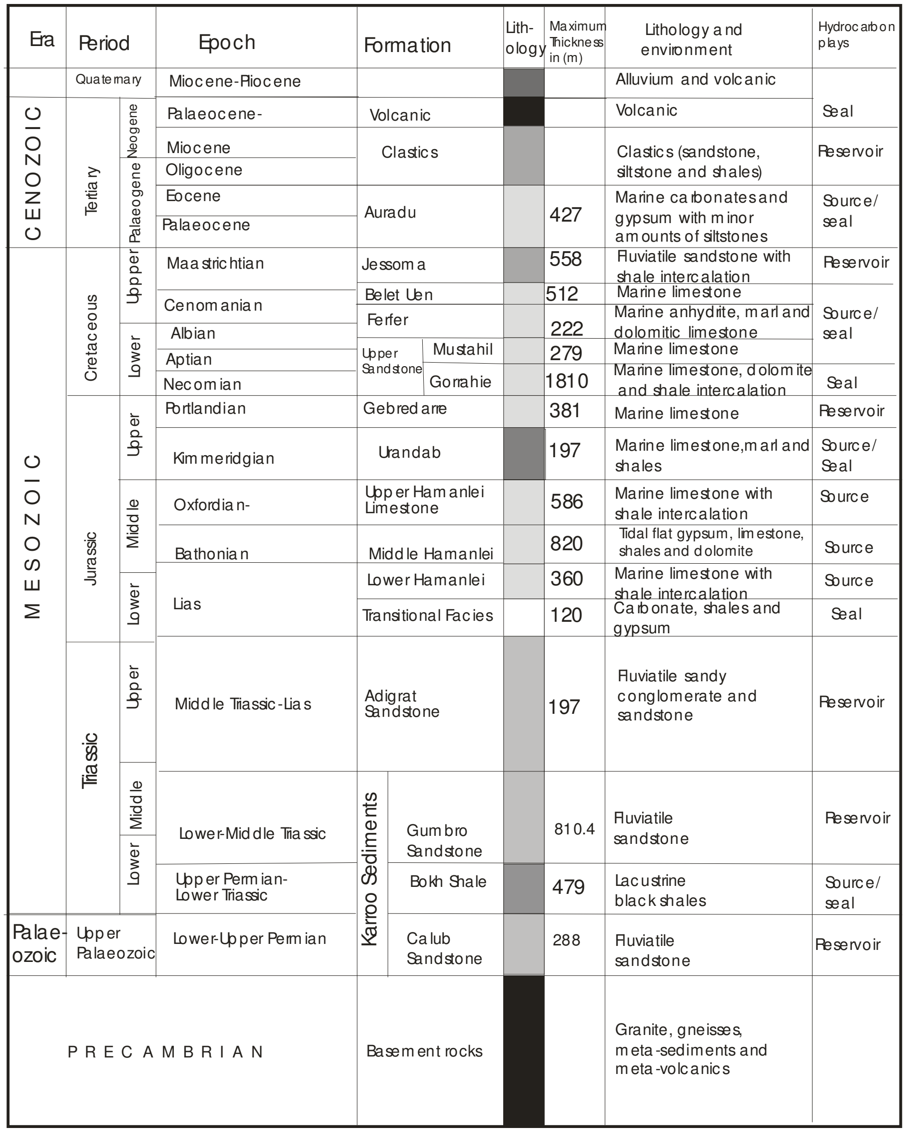

Figure 4. Chrono, litho-stratigraphic and hydrocarbon plays of the Ogaden Basin.

Petroleum potential of the Blue Nile Basin. The Blue Nile Basin is one of the northernmost failed arms of the Karroo Rift system (Figure 6). The basin is one of the major sedimentary basins in Ethiopia for petroleum exploration. The basin contains a thick Late Permian to Cretaceous sediments, carbonate and shale source rocks, carbonate and clastic reservoirs, stratigraphic and structural traps, tightly cemented limestones, evaporites, and shales as sealing materials.

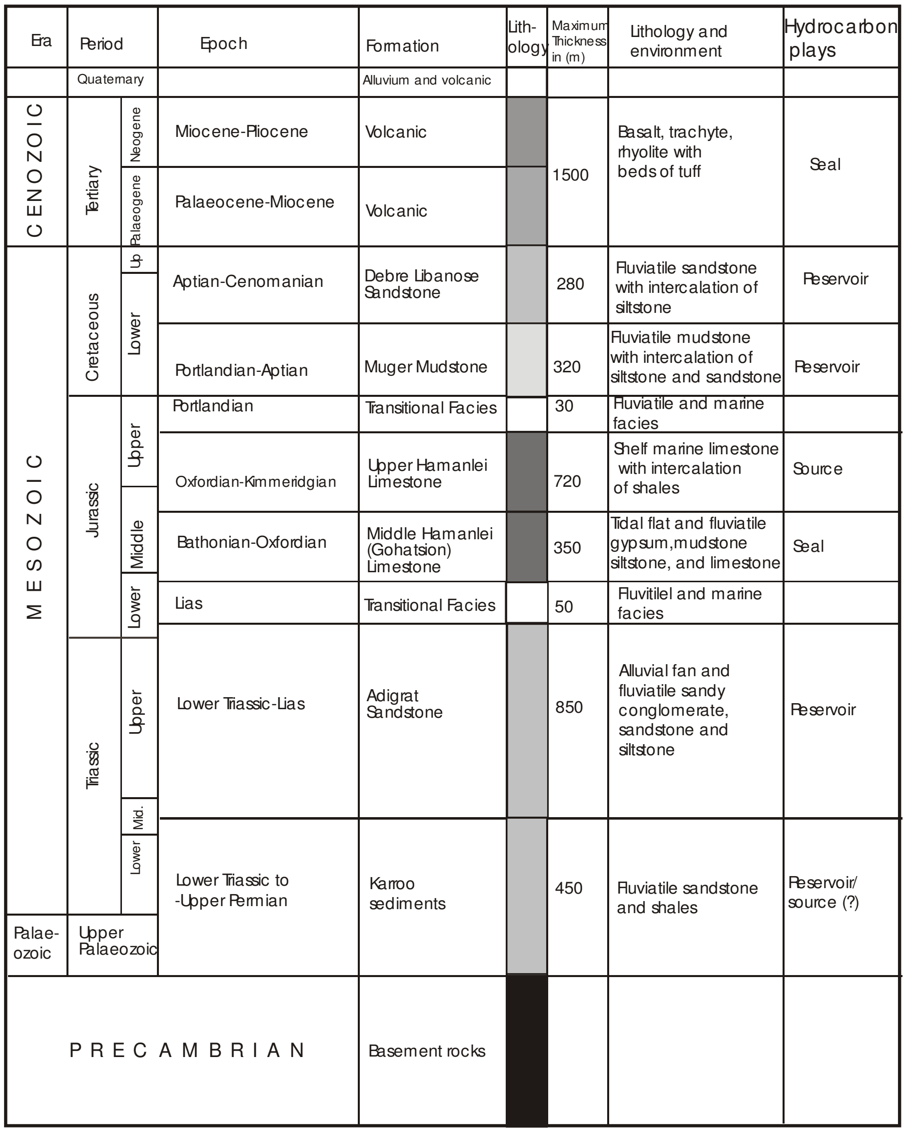

Figure 5. Chrono, litho-stratigraphic and hydrocarbon plays of the Blue Nile Basin.

Source rocks. The Upper Hamanlei limestone formation is largely composed of alternating sequences of limestone and black shales. The TOC values of the black shales range from 1.9 to 10.9 % (Table 3). The Lopatin burial reconstruction in the deeper part of the basin (Were Ilu), the Upper Hamanlei limestone formation entered into the oil window from 10 Ma to the present day [28]. In Were Ilu area, the sediments entered at a depth of nearly 2.5 km. Oil generation starts between 1.2 and 3 km [31]. The virinite reflectance results revealed Ro values between 0.3 to 1.1 %, which indicate excellent type of source rocks. The gas chromatography, carbon isotope and kerogen identification indicated that the possible source for the generation oil seepage in Were Ilu area is marine source rocks with an influx of land-derived organic matter [28]. The Pr/Ph ratio of the studied oil seepage is 0.90 is thought to be derived from a marine shelf source rocks, possibly of a carbonate origin. Cross plot of hydrogen index versus T_{max} values (Figure 3) of the Upper Hamanlei limestone formation indicated that excellent types of source rocks.

Reservoir potential. The Adigrat sandstones formation reaches porosity and permeability maxima of 20.4 % and 710 mD, respectively [28]. The coarse to medium-grained sandstone facies is the most porous and permeable, and a potential reservoir for oil and gas deposit, whilst the fine-grained sandstones and finely-laminated siltstones facies are possible gas reservoirs.

The Debre Libanose sandstone formation attains porosity up to 22.2 %, and permeability up to 809.6 mD [28]. The medium-fine-grained sandstones are high-permeable reservoir rocks for oil and gas deposits, whereas the low-permeability fine-grained sandstones may also have potential for gas reservoir.

Three petroleum systems identified in the Blue Nile Basin. These include: (i) Upper Hamanlei limestone formation (source)-Upper Hamanlei limestone formation (reservoir) petroleum system, (ii) Upper Hamanlei limestone formation (source)-Upper sandstone formation (reservoir) petroleum system, and (iii) black shales in Debre Libanose sandstone formation (source)-Debre Libanose sandstone formation (reservoir) petroleum system. The chrono, litho-stratigraphic and hydrocarbon plays in the Blue Nile Basin is given in Figure 5.

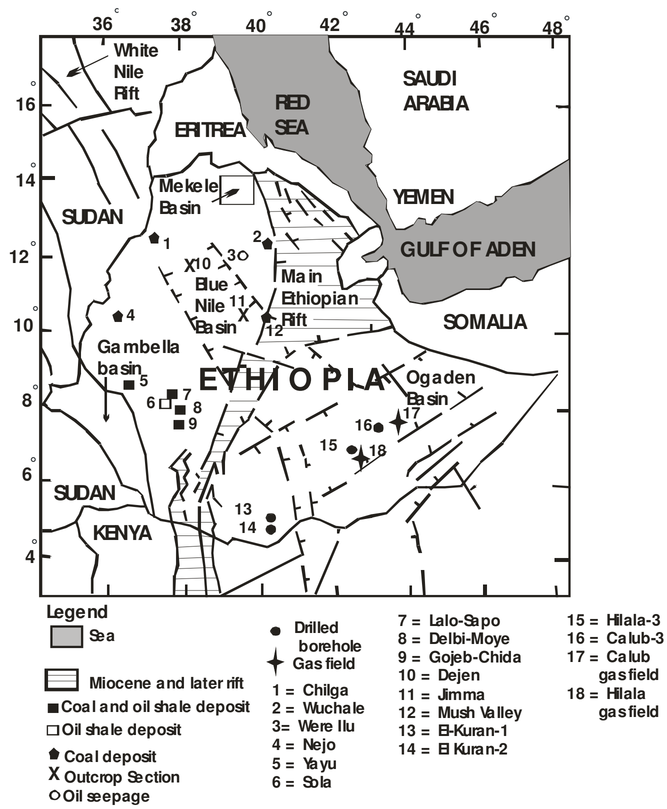

Figure 6. Tectoncic framework of the Ogaden and Blue Nile Basins.

Oil and gas deposit in Fluvio-Lacustrine Basin

Gambella Basin. Opening of the Southern Atlantic was initiated during the Cretaceous and the subsiding East African continental margin initiated to deposit fluvio-lacustrine sediments. A number of intracratonic basins were formed along the Central African Shear Zone [32, 33]. Commercial Mesozoic oil discoveries encountered in the White Nile, Muglad and Abu Gubra Rift Basins of Sudan [32, 34]. The Gambella Basin is the southern extension of the Sudan Interior Basins (Figure 6). The Gambella Basin could be one of the potential basins for oil and gas deposits.

CONCLUSIONS

(1) The Ethiopian coal and oil shale deposits occur between two volcanic flows. The coal and oil shale-bearing sedimentary basins in Ethiopia are one of the striking examples of an Inter-Trappean continental sedimentation. There are strong evidences that the NNW-SSE fault system provided the tectonic configuration for the development of grabens and half-grabens for deposition of coal and oil shale-bearing sediments.
(2) The Ethiopian oil shales are grouped under Type II and I and rarely Type III kerogen. Type II and I kerogen are good source rocks for oil generation. Hydrogen index versus T_{max} values plots indicated that most of the studied oil shale samples fall within immature to early mature stage for hydrocarbon generation. $S_1 + S_2$ ratio versus TOC values indicated that the Ethiopian oil shales are good to excellent potential source rocks. The T_{max} values of the studied oil shales ranges from 410 to 445 °C, which indicate thermally immature-early mature stage for oil generation.
(3) The coal measures of Ethiopia belong to tertiary and minor amounts of mesozoic age. Various geochemical studies were carried out to determine the physico-chemical characteristics of the Ethiopian coal deposits. Genetically, the coal seams are grouped under humic, sapropelic and mixed coal. The humic coal is dominanted by vitrian and clarian lithotype, whilst the sapropelic coal is dominated by boghead with minor amounts of cannel lithotype.
(4) Proxiamte and calorific value analysis results revealed that the Ethiopian coal deposits range from lignite-bitumineous coal. However, the coal seams near the acidic volcanic intrusions metamorphosed to semi-anthracite stage due to high geothermal gradient. The moisture content ranges from 2.7-21.4 %, volatile matter 3.0-46.3 %, ash content 2.4-65 % and calorific value 900-6900 cal/g. Sub-bituminous to high volatile bituminous B coking coal found in the Delbi-Moye Basin. Recent investigation works confirmed the Inter-Trappean coal deposits of Delbi-Moye, Chilga and Yayu Basins are more economical. Test drilling works and detail geological mapping are necessary for that of Mush Valley. The thickness of the coal seams is in the range 1-1.75 m and vicinity of the deposit from the industrial city of Addis Ababa make the Mush Valley coal more attractive. Exploitation of Wuchale and Nejo coals are also economical for local purposes.
(5) The yearly import of petroleum products is absorbing more than one third of Ethiopia's annual exporting products. Oil shale and coal deposits possibly play an important role in the future energy budgets of Ethiopia. The coal and oil shale deposits of Ethiopia can be used for (i) as a substitution firewood, (ii) production of oil and gas, (iii) to relieve the pressure on using wood as fuel for small-scale industries, (iv) gasification of lignite to produce chemical fertilizers, (v) power generation, and (vi) the low-medium volatile bituminous coals of Moye area used to produce coking coals for smelting of iron.
(7) 2.7 TCF (76 x 10^9 m^3) gas and 1817 x 10^6 tons condensate reserves are estimated in the Calub field. About 1.3 TCF (40 x 10^9 m^3) gas deposits are encountered in Hilala field. The Blue Nile Basin is one of the potential basins for hydrocarbon exploration. The presence of mature

source rocks and oil seepage in the Blue Nile Basin is clue for the generation of hydrocarbon in the basin. The Gambella Basin is the southern extension of the petroliferous Sudan Interior Basins, and could be one of the potential basins for oil and gas deposits. Oil and gas deposits possibly plays major role in the future energy budget of Ethiopia.

AKNOWLEDGEMENTS

The author acknowledges the Petroleum Operations Department and Ethiopian Geological Surveys, Ministry of Mines and Energy for their support and helps to carry out this research work. Thanks extended to Dr. Parnell for pyrolysis analysis of the Blue Nile and Ogaden Basins. The Coal Phosphate Complex Project acknowledged for kind permission to access their core samples and providing the chemical analyses results of the Yayu Basin. Most of the laboratory studies were carried out at the Chemical Laboratory, Ethiopian Geological Surveys; Chemical Engineering Department, Addis Ababa University, Geochemical Laboratory, Geofluid and Electron Microscopy Unit, the Queen's University of Belfast, Northern Ireland. The staffs of these institutions are acknowledged for their support and help.

REFERENCES

1. Wolela, A. *Coal and oil shale occurrences and their geological setting in Ethiopia*, Report, Ministry of Mines and Energy: Addis Ababa; **1991**; 205p.
2. Wolela, A. *SINET: Ethiop. J. Sci.* **2004**, 27, 45.
3. Peters, K.E. *Am. Assoc. Petroleum Geologists Bull.* **1986**, 70, 318.
4. MONSON, B. *Reflectance measurement manual*, Department of Geology, Queen' University of Belfast: Belfast; **1995**; pp 1-5.
5. Bae, G.Y.; Minye, B.; Getahun, B.; Wolela, A.; Asmamaw, T. *Report on geology and sub-surface exploration for coal and oil shale occurrence of Delbi and surrounding areas*, Kaffa Administrative Region, Ministry of Mines and Energy: Addis Ababa; **1989**; 80p.
6. Getahun, B.; Yirga, T.; Minye, B. *Detail geological mapping, subsurface exploration, geochemical studies and reserve evaluation of coal and oil shale resources at Delbi-Moye Basin*, Technical Report, Ehiopian Institute of Geological Surveys: Addis Ababa; **1993**; 119p.
7. Zanettin, B.; Justin-Visentin, E. *Memorie del Instituto di Geologia e Mineraloga dell Universita di Padova* **1974**, 31, 1.
8. Kibre, T.; Gashaw Beza, M. *Preliminary geological report of Geba Basin (Yayu area), Western Ethiopia*, Ethiopian Institute of Geological Surveys: Addis Ababa; **1997**.
9. Kibre, T. *M.Sc. Thesis*, Addis Ababa University, Ethiopia, **2000**.
10. Wolela, A.; Alula, H.G.; Belay, W. *Sedimentology, depositional environments and hydrocarbon potential of the Yayu Basin*, Report, Petroleum Operations Department, Ministry of Mines: Addis Ababa; **2002**; 45p.
11. Heeman, W.; Minye, B.; Wolela, A. *Occurences of coal and carbonaceous shale in Keffa near Chida and Waka*, Report, Ministry of Mines and Energy: Addis Ababa; **1985**.
12. Yirga, T.; Zewdeneh, T. *Subsurface geological report on coal and oil shale deposit of the Gojeb-Chida area*, Report, Ethiopian Geological Surveys, Ministry of Mines and Energy: Addis Ababa; **1995**; 31p.
13. Assefa, A.; Minye, B.; Wolela, A.; Getahun B.; Asmamaw, T. *Geological report on coal occurrences of Meteso-Soyoma areas*, Ministry of Mines and Energy: Addis Ababa; **1987**; 40p.

14. Alula, H.G.; Gasaw Beza, M.; Kibre, T.; Tessfaye, D. *The geology of Sola area*, Report, Ministry of Mines and Energy: Addis Ababa; **1992**; 20p.
15. Reinhardt, P.; Sisay, D. *Evaluation of lignite occurrences in Ethiopia*, Report, Ministry of Mines and Energy: Addis Ababa; **1981**.
16. Heeman, W.; Minye, B. *Report on lignite prospection west of Nejo*, Ministry of Mines and Energy: Addis Ababa; **1986**.
17. Getaneh, A.; Saxena, G.N. *Energy Exploration and Exploitation*, **1984**, 3, 36.
18. Belachew, T.; Heeman, W. *Report on the lignite of Chilga area*, Report, Ministry of Mines and Energy: Addis Ababa; **1984**.
19. Mulugeta, F. *Ph.D. Thesis*, The University of Texas at Austin, USA, **2002**.
20. Kedamawit, Y.; Bonnefille, R.; Faure, H. *Nature* **1985**, 318, 653.
21. Babu, S.K.; Getaneh, A. *Geophytology* **1981**, 11, 204.
22. Assefa, A.; Getahun, B. *Preliminary geological report on coal occurrences of Wuchale and Dessie areas*, Ministry of Mines and Energy: Addis Ababa; **1987**; 18p.
23. Tissot, B.P.; Welete, D.H. *Petroleum Formation and Occurrence*, Springer Verlag: Berlin; **1984**.
24. Peters, K.E.; Cassa, M.R. *Applied source rocks geochemistry*, Magoon, L.B.; Dow, W.G. (Eds.), AAPG Mem. 60, American Association of Petroleum Geologists: Tulsa, Oklahoma, USA; **1994**.
25. Clayton J.L.; Swetland, P.J. *Am. Assoc. Petroleum Geologists Bull.* **1980**, 64, 1613.
26. Tessfaye, L.; Wolela, A.; Cheru, G. *Bull. Chem. Soc. Ethiop.* **1992**, 6, 59.
27. Raaben, V.P.; Komenyev, S.P.; Lissin, V.N.; Kitachew, W.T. *Preliminary report on the evaluation of petroleum prospects of the Ogaden Basin, Ethiopia*, Ethiopian Institute of Geological Surveys: Addis Ababa; **1979**; Note No. 112.
28. Wolela, A. *Ph.D. Thesis*, The Queen's University of Belfast, UK, **1997**.
29. Hunegnaw, A.; Sage, L.; Gonnard, R. *J. Petrol. Geol.* **1998**, 21, 401.
30. Shimelis, H., *PhD Thesis*, Technical University, Berlin, Germany, **1998**.
31. Tissot, B.; Durand, B.; Espitalie, J.; Ombaz, A. *Am. Assoc. Petroleum Geologists Bull.* **1974**, 58, 499.
32. Schull, T.J. *Am. Assoc. Petroleum Geologists Bull.* **1988**, 72, 1128.
33. Bosworth, W.A. *Tectonophysics* **1992**, 20, 115.
34. Petroconsultants Foreign Scourting Service *Ethiopia, Kenya, Somalia, Sudan and Yemen countries*, International Energy Service: Geneva, Swizerland; **1997**.