J Petrol Explor Prod Technol (2017) 7:379–388
DOI 10.1007/s13202-016-0286-y

ORIGINAL PAPER - EXPLORATION GEOLOGY

Modeling hydrocarbon generation potentials of Eocene source rocks in the Agbada Formation, Northern Delta Depobelt, Niger Delta Basin, Nigeria

Oladotun A. Oluwajana[1] · Olugbenga A. Ehinola[2] · Chukwudike G. Okeugo[3] · Olatunji Adegoke[4]

Received: 23 January 2016 / Accepted: 3 October 2016 / Published online: 15 October 2016

Abstract The Northern Delta depobelt is a significant petroleum province in the Niger Delta Basin. Burial history and maturity levels of the Eocene source rocks in the Northern Delta depobelt have not been extensively discussed. In this study, results of Rock–Eval analysis of forty (40) subsurface samples from selected exploration wells namely Alpha_1, Beta_1 and Zeta_1 within the depobelt were used to characterize the Eocene source rocks of the Agbada Formation and also examine the hydrocarbon generation phases of the source facies. The samples possess mainly Type III/IV organic matter, regarded as gas prone to no petroleum generative potential. The vitrinite reflectance values of the Eocene source intervals range from 0.42 to 1.17 VR_o %, suggesting a thermally immature to mature levels. 1-D basin models of the three wells reveal the generation of liquid hydrocarbon from the Eocene source unit in the Northern Delta depobelt during Paleogene–Neogene times with capability of charging the interbedded reservoir sand bodies. Eocene source rocks could be responsible for oil and condensate discoveries in the Northern Delta depobelt of the Niger Delta Basin.

Keywords Oil generation · Eocene · Niger Delta · Source rock · Northern Delta depobelt

✉ Oladotun A. Oluwajana
oladotun.oluwajana@aaua.edu.ng

1 Department of Earth Sciences, Adekunle Ajasin University, Akungba-Akoko, Nigeria

2 Energy and Environmental Research Group, Department of Geology, University of Ibadan, Ibadan, Nigeria

3 Department of Geology, University of Nigeria, Nsukka, Nigeria

4 Zobeten Petroleum (Nigeria) Limited, Lagos, Nigeria

Introduction

The Niger Delta Basin, located on the western edge of the African continent and southern part of Nigeria, covers an area of 75,000 km^2 and consists of 9000–12,000 m of clastic sediments (Ojo et al. 2012; Aminu and Oloruniwo 2012). The Niger Delta Basin is divided into five depobelts namely: Northern Delta, Greater Ughelli, Central Swamp, Coastal Swamp and Offshore depobelt (Fig. 1). The study area for this paper lies in the Northern Delta depobelt considered the oldest and as one of the productive hydrocarbon depobelt in the Niger Delta Basin. It has substantial hydrocarbon potential as oil and condensate discoveries have been reported (Esedo and Ozumba 2005; Avuru et al. 2011). Published reports on geochemical attributes, burial histories and hydrocarbon generation phases of potential source units in the Northern Delta depobelt have been suggested. The oil and gas accumulated in the late Eocene–Oligocene Agbada Formation, while the source rock intervals are interbedded organic shales within the paralic Agbada Formation.

A better understanding of the hydrocarbon generation is critical in unraveling the potential of the Eocene shaly facies. This study presents the interpretation of Rock–Eval pyrolysis results of forty sidewall samples and 1-D basin modeling study of Alpha_1, Beta_1 and Zeta_1 wells drilled in the Northern Delta depobelt of the Niger Delta Basin using available Shell Petroleum Development Company of Nigeria (SPDC) proprietary dataset with the aim of identifying the potential of the organic source facies, predict periods of thermal maturities and evaluate the hydrocarbon generating potential of the Eocene source facies.

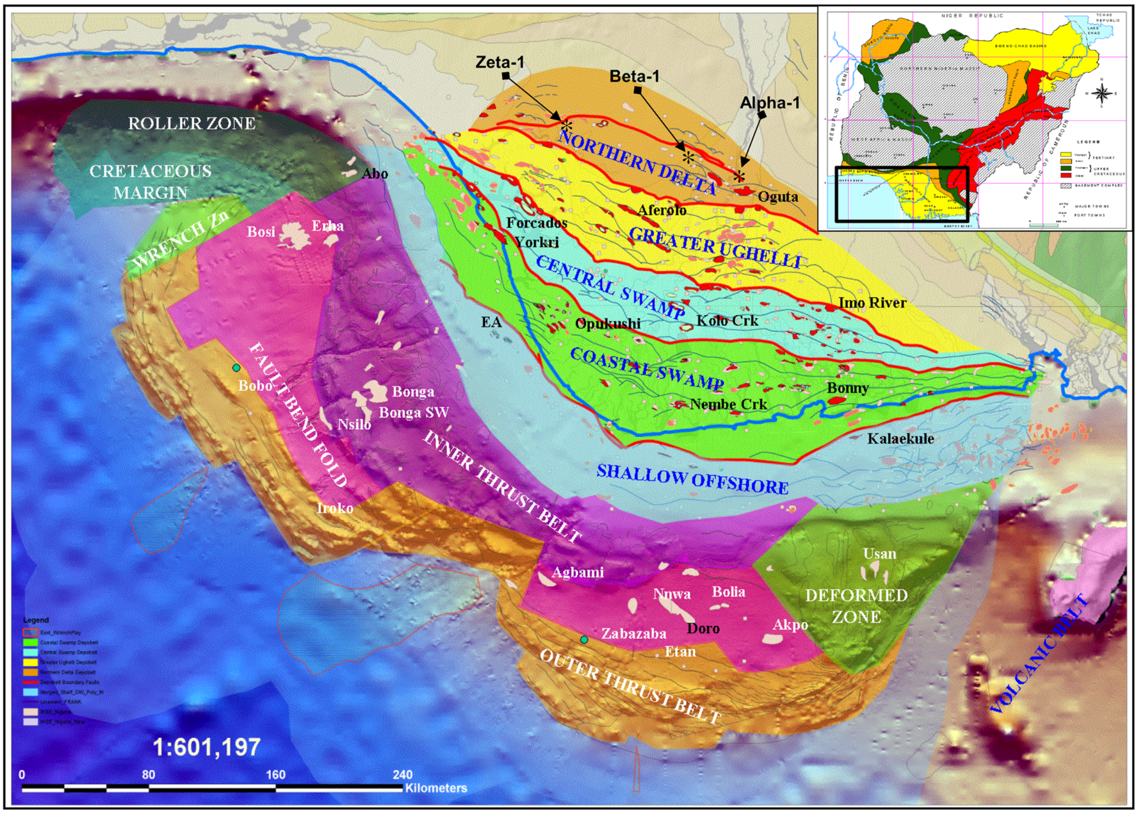

Fig. 1 Diagram showing the location of studied well that penetrated the Oligocene to mid-Miocene succession and the Niger Delta mega-structural framework (modified from Ejedavwe et al. 2002)

Geological settings

The Niger Delta Basin, situated at the apex of the Gulf of Guinea on the west coast of Africa, is one of the most prolific deltaic hydrocarbon provinces in the world (Dim et al. 2014). The regressive Niger Delta comprises of a wedge of clastic sediments of up to 12 km thick formed by a series of offlap cycles (Evamy et al. 1978; Doust and Omatsola 1990). Deposition of sediments in the Niger Delta Basin started in the Eocene, and the maximum thickness of the sediment fill is about 10 km (Lewis et al. 2014). The sedimentary fill of the Niger Delta Basin is divided into three diachronous formations, namely the Akata Formation, Agbada Formation and Benin Formation (Fig. 2).

The Akata Formation is typically undercompacted, overpressured and made up of prodelta shales with occasional turbidite sands. It also provides the detachment horizon for large growth faults that define depobelts (Adeogba et al. 2005). The Agbada Formation consists of paralic, mainly shelf deposits of alternating sands, shales and mudstone. The Benin Formation is predominantly non-marine upper delta plain sandstone. The total sedimentary sequence was deposited in a series of mega-sedimentary belts (depobelts or mega-structures) in a succession temporally and spatially with southward progradation of the Delta (Doust and Omatsola 1990).

Growth faults, rollover anticlines and diapiric structures are the prevailing structural styles in the Niger Delta Basin. Growth faults are the dominant structural features in the Niger Delta (Opara et al. 2008; Magbagbeola and Willis 2007). Most hydrocarbon-bearing structures are along proximal margins of sub basins where growth strata accumulated on blocks downdropped across major syndepositional faults and onlap adjacent anticlinal (rollover) closures (Doust and Omatsola 1990). Source rocks in the Niger Delta might include marine interbedded shale in the Agbada Formation, marine Akata Formation shales and underlying Cretaceous shales (Evamy et al. 1978; Ekweozor and Okoye 1980; Doust and Omatsola 1990). Reservoir intervals in the Agbada Formation have been interpreted to be deposits of highstand and transgressive systems tracts in proximal shallow ramp settings (Evamy et al. 1978). Structural traps formed during syn-sedimentary deformation of the Agbada Formation (Evamy et al. 1978), and stratigraphic traps formed preferentially along the delta flanks, define the most common reservoir locations within the Niger Delta complex (Rowlands 1978).

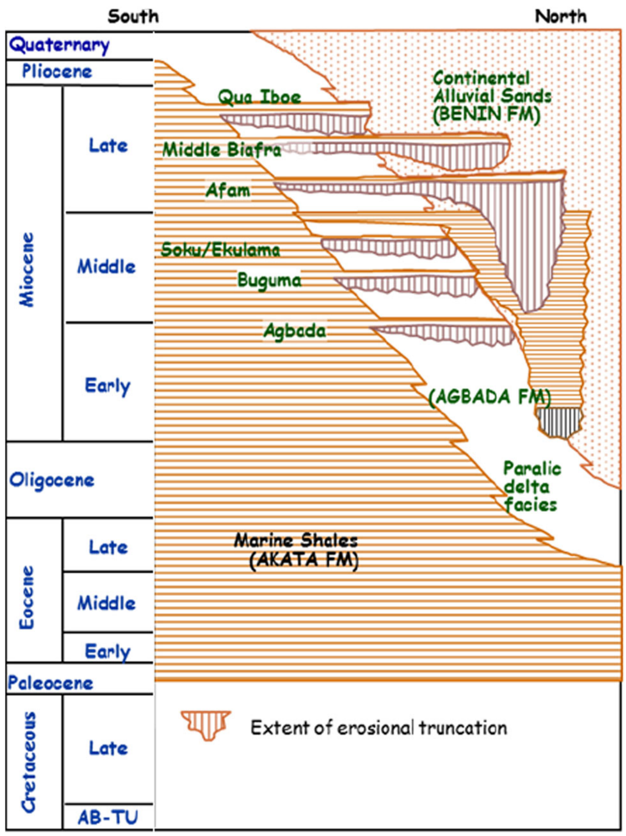

Fig. 2 Regional stratigraphy of the Niger Delta showing different formations (after Ozumba 2013)

The primary seal rocks are interbedded shales within the Agbada Formation. Three types of seals are recognized: clay smears along faults, interbedded sealing units juxtaposed against reservoir sands due to faulting, and vertical seals produced by laterally continuous shale-rich strata (Doust and Omatsola 1990).

Samples and methods

Vitrinite reflectance and Rock–Eval pyrolysis data of forty samples from three wells (Fig. 3) were used to determine the source rock attributes and maturity levels of the Eocene source intervals. The wells for proprietary reason were named as Alpha_1, Beta_1 and Zeta_1. The wells were drilled on the eastern part, toward the central area and the western flank of the depobelt, respectively. The studied well was modeled using PetroMod basin and petroleum system software and used to calculate the levels of thermal maturity and timing of hydrocarbon generation based on calibration of measured vitrinite reflectance (VR_o) against modeled vitrinite reflectance (EASY $\%R_o$, Sweeney and Burnham 1990). The model utilized well stratigraphic ages to reconstruct the burial history through geological time. The input data for the stratigraphic modeling include lithology of different layers, duration of deposition, age and thickness, acquired from the analysis of available well logs and stratigraphic well penetration data.

Boundary conditions define the basic energetic conditions for temperature and burial history of the source rock and, consequently, for the maturation of organic matter through time (Ben-Awuah et al. 2013). Paleo-water depth values were used to define the paleogeometry of the basin. Heat flow and sediment–water interface temperature values are the main boundary conditions applied during the modeling. A constant surface temperature of 28 °C is assumed in all the wells. The heat flow history of the basin is proposed by establishing an agreement between a modeled maturity parameters and the equivalent observed maturity parameter (Shalaby et al. 2008). Eocene source rock intervals were defined for evaluation of hydrocarbon potential. The total organic carbon and the hydrogen index for the source rock unit were obtained from the Rock–Eval results. The hydrocarbon generation stages were calculated using reaction kinetics data based on Vandenbroucke et al. (1999). The models were simulated and calibrated before generating 1-D models. The simulation results assist in the model interpretation.

Result and discussion

Lithology

The Eocene sediments are generally overlain by continental (sandy) Oligocene successions. The Zeta_1 well is located on the western flank of the depobelt and penetrated the early- to mid-Eocene succession; Alpha_1 well drilled on the eastern part intercepted the mid- to late-Eocene sediments, while Beta_1 situated west of Alpha_1 penetrated only the late Eocene sediments. The thickness of the Eocene sediments decreases toward the flanks of the depobelt. The late Eocene sediments are completely absent in the Zeta_1 well, suggesting the disappearance of the late Eocene toward the western flank of the depobelt. Eocene source rocks are developed within the Eocene succession of the Agbada Formation in all the wells.

Vitrinite reflectance values (VR_o %)

Vitrinite reflectance ($\%R_o$) is the most widely used method for measuring the thermal maturity of sedimentary strata. The Eocene shale samples from Alpha_1, Beta_1 and Zeta_1 wells have vitrinite reflectance values in the range 0.42–0.70 VR_o %, 0.43–1.17 VR_o %, 0.58 VR_o–0.63 VR_o %, respectively, indicating that they fall within the immature to thermally mature (Table 1). Vitrinite reflectance values for the three wells range between 0.42

Fig. 3 Simplified stratigraphic charts through east–west of the Northern Delta depobelt (Niger Delta Basin)

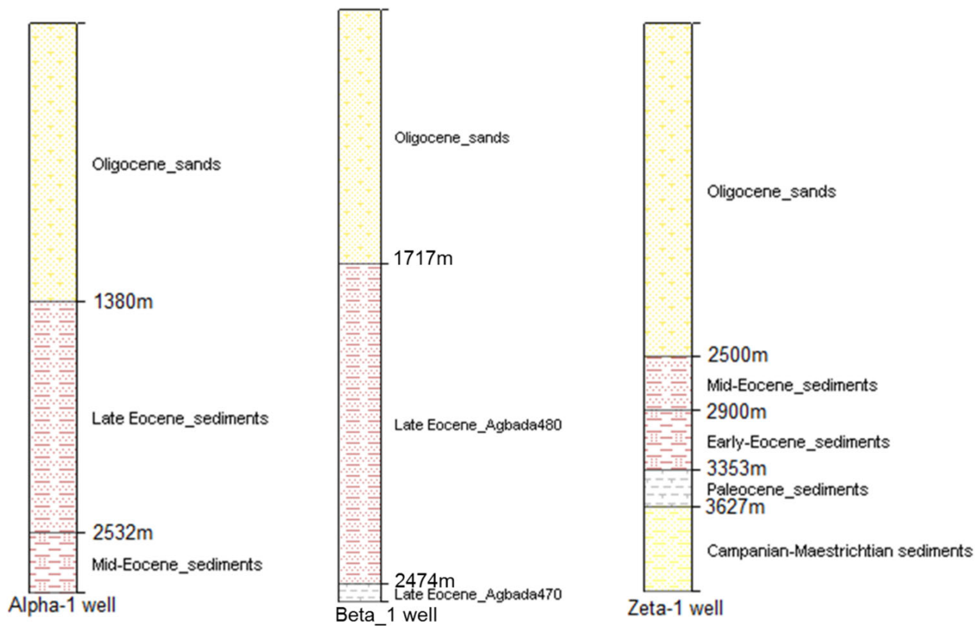

Table 1 Vitrinite reflectance measurements of Eocene stratigraphic levels in the Alpha_1, Beta_1 and Zeta_1 wells

Alpha_1 well	Depth (m)	Measured vitrinite reflectance values
	2764	0.42
	2798	0.7
Beta_1 well	Depth (m)	Measured vitrinite reflectance values
	2495	0.43
	3912	1.17
Zeta_1 well	Depth (m)	Measured vitrinite reflectance values
	2743	0.58
	2773	0.59
	2926	0.62
	3081	0.63
	3231	0.63

and 1.17 VR_o % and thus suggest that samples are within the immature to oil generation window. Vitrinite reflectance value of less than 0.6 $\%R_o$ is considered immature, while values greater than 1.3 $\%R_o$ indicates gas window maturity (Tissot and Welte 1984).

Source rock characteristics

Figure 4 shows the geochemical plots of forty (40) samples from Alpha_1, Beta_1 and Zeta_1 wells (Table 2). The Eocene source beds within the Agbada Formation have been identified as good potential source rock because of total organic carbon (TOC) values (Alpha_1 well; TOC values, 1.21–3.1 wt%); (Beta_1 well; TOC values, 1.04–3.62 wt%); (Zeta_1 well; 1.33–2.12 wt%) which meets the standard as a source rock with good to excellent hydrocarbon-generative potential (Peters and Cassa 1994). The maximum present-day hydrogen index suggests that gas would be expelled at peak maturity. S_2 gives the amount of oil and gas which can be generated from its present stage of thermal maturation to the graphite stage. The TOC content and the pyrolysis S_2 yield values show that the Eocene source rocks are good to very good source rock with poor to fair generative potentials (Fig. 5). The kerogen typically has a low hydrogen index (HI), ranging from 16 mg HC/g TOC to 212 mg HC/g TOC, suggesting Type III and Type III/IV kerogen (Fig. 6).

T_{max} values range from 412 to 430 °C for Alpha_1 well, 416 to 434 °C for Beta_1 well, 406 to 459 °C for Zeta_1 well which are in reasonably good agreement with vitrinite reflectance data, indicating that the Eocene samples have entered the oil window stage. The Eocene source units in the three wells are effective gas-prone source rock that has good generative potential within the Agbada Formation based on TOC content, thermal maturity and widespread distribution.

Heat flow history

The models for the three wells assume that the heat flow values vary from 45 to 75 mW/m^2 (Fig. 7) and the paleo-heat flow values generally decrease to present-day heat flow measurements. The model, using the best match of the measured and modeled vitrinite reflectance data, suggests that the present-day heat flow in the studied wells is

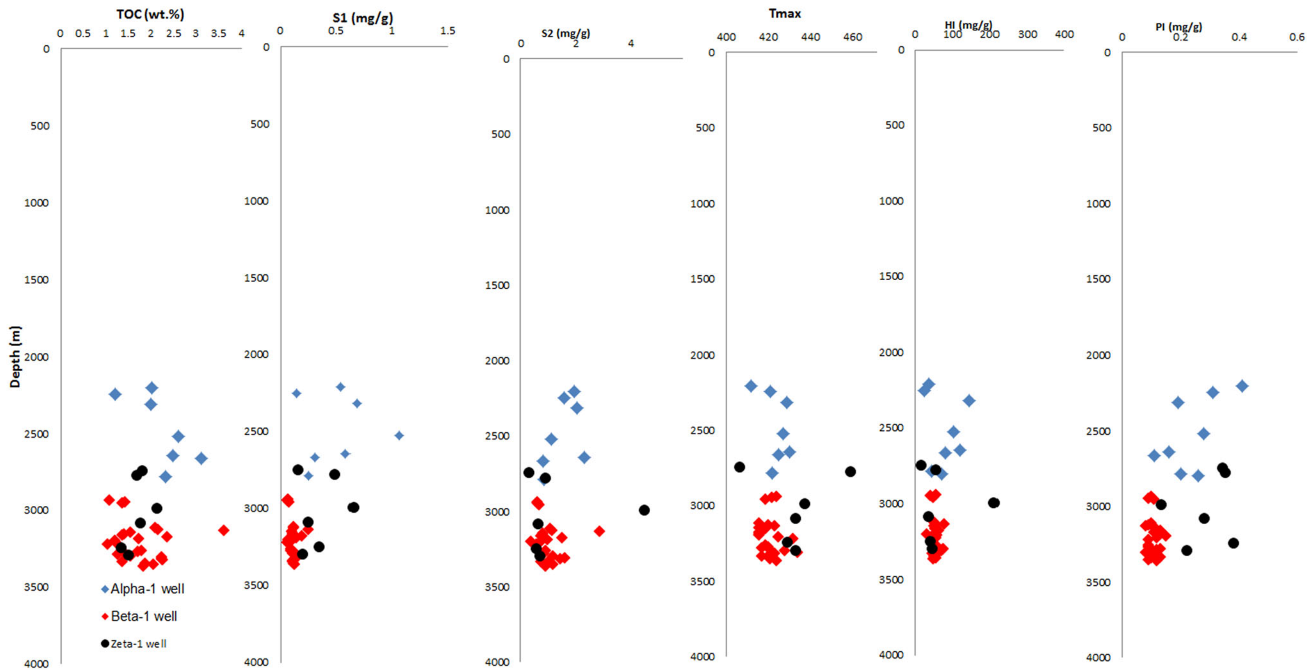

Fig. 4 TOC content and Rock–Eval pyrolysis parameters against depth for the Eocene sediments in wells Alpha_1, Beta_1 and Zeta_1

45 mW/m^2. The values of heat flow in the three wells less than 80 mW/m^2 suggest that the Northern Delta depobelt is not within geothermally active areas. Reduction in the heat flow values might be associated with rapid sedimentation in the Northern Delta depobelt. According to Frielingsdorf et al. 2008, rapid sedimentation may cause reduction in heat flow and thermal maturity.

Hydrocarbon generation phases

The one-dimensional basin modeling of Alpha_1, Beta_1 and Zeta_1 wells was performed using Vandenbroucke et al. (1999) and Sweeney and Burnham (1990) kinetic models to infer hydrocarbon generation potential of Eocene organic-rich shaly interval. A reasonable correlation between measured vitrinite reflectance values and calculated (modeled) vitrinite reflectance values was established.

In Alpha_1 well, the predicted oil-generative window from the mid-Eocene source unit occurred in Oligocene (29.86 Ma) and hydrocarbon generation from the Late Eocene source interval started in the Miocene (11.91 Ma) while liquid hydrocarbon is expected from the Eocene source unit (Fig. 8). Initial oil generation from Late Eocene source interval in Beta_1 well started during Oligocene Epoch (32.84 Ma), and late hydrocarbon generation reached during Miocene (19.63 Ma; Fig. 9). Eocene source rocks have also attained maturity from Miocene to Pliocene times (Odumodu and Mode 2016). In Zeta_1 well, Early Eocene source rocks entered the oil window phase in the Miocene (20.79 Ma) while hydrocarbon generation window from the mid-Eocene source rocks occurred in the Miocene (9.03 Ma). Liquid hydrocarbon is expected from the Eocene source units (Fig. 10). Geological factors responsible for the variation in the hydrocarbon generation time of Eocene source beds in the studied wells are influenced by overburden thickness, lithologic variation of the overburden rock, thermal maturity and the basal heat flow. Petroleum generation within the Niger Delta Basin began in the Eocene and continues today (Tuttle et al. 1999).

Implication for hydrocarbon exploration

The samples from Eocene shaly unit are excellent source rocks capable of generating hydrocarbon. The results of the modeling suggest that hydrocarbon generation from the Eocene source rocks in the Northern Delta depobelt occurred during the Paleogene–Neogene times. Regional maturity distribution and generation of oil from the Eocene source interval in the Northern Delta depobelt seems likely. Hydrocarbon generation started in the eastern and western flanks of the depobelt during Oligocene and Miocene, respectively. Short- to long-distance migration of the hydrocarbon generated from the source unit is expected to have occurred and must have charged the interbedded Eocene sand bodies and younger reservoir units; this fact

Table 2 Results of Rock–Eval pyrolysis and TOC content analyses Eocene sediments in wells Alpha_1, Beta_1 and Zeta_1, Northern Delta depobelt, Niger Delta Basin

Wells	Depth (m)	TOC (wt%)	Rock–Eval pyrolysis					
			S_1 (mg/g)	S_2 (mg/g)	T_{max}	OI (mg/g)	HI (mg/g)	PI (mg/g)
Alpha-1 well	2206	2.01	0.54	1.96	412	38	98	0.41
Alpha-1 well	2248	1.21	0.14	1.6	421	26	132	0.31
Alpha-1 well	2315	1.99	0.68	2.04	429	147	103	0.19
Alpha-1 well	2522	2.61	1.06	1.11	427	104	43	0.28
Alpha-1 well	2644	2.49	0.58	2.32	430	121	93	0.16
Alpha-1 well	2665	3.1	0.31	0.83	425	82	27	0.11
Alpha-1 well	2786	2.32	0.25	0.84	422	44	38	0.2
Alpha-1 well	2801	1.92	0.49	0.78	426	72	41	0.26

Wells	Depth (m)	TOC (wt%)	Rock–Eval pyrolysis					
			S_1 (mg/g)	S_2 (mg/g)	T_{max}	HI (mg/g)	OI (mg/g)	PI (mg/g)
Beta-1 well	2940	1.09	0.07	0.61	424	56	120	0.1
Beta-1 well	2949	1.43	0.06	0.61	422	43	127	0.09
Beta-1 well	2958	1.37	0.08	0.67	419	49	120	0.11
Beta-1 well	3118	2.1	0.12	1.07	416	51	99	0.1
Beta-1 well	3128	2.16	0.12	1.16	420	54	75	0.09
Beta-1 well	3136	3.62	0.25	2.88	423	80	59	0.08
Beta-1 well	3146	1.55	0.1	0.81	416	52	66	0.11
Beta-1 well	3158	1.4	0.11	0.78	419	56	71	0.12
Beta-1 well	3164	1.37	0.11	0.76	418	55	69	0.13
Beta-1 well	3178	2.36	0.19	1.52	416	64	59	0.11
Beta-1 well	3191	1.74	0.14	0.98	416	58	75	0.13
Beta-1 well	3200	1.2	0.07	0.4	416	33	74	0.15
Beta-1 well	3210	1.23	0.1	0.72	425	59	86	0.12
Beta-1 well	3223	1.04	0.06	0.58	432	56	100	0.09
Beta-1 well	3328	2.26	0.13	1.06	421	47	73	0.11
Beta-1 well	3338	1.36	0.11	0.76	417	56	76	0.13
Beta-1 well	3347	1.88	0.11	0.99	421	53	68	0.1
Beta-1 well	3356	2.05	0.12	1.17	421	57	66	0.09
Beta-1 well	3365	1.84	0.13	0.93	424	51	79	0.12
Beta-1 well	3264	1.8	0.09	0.91	419	51	77	0.09
Beta-1 well	3274	1.71	0.09	0.86	420	50	84	0.09
Beta-1 well	3283	1.42	0.13	0.84	417	59	82	0.13
Beta-1 well	3292	1.27	0.11	0.8	421	63	80	0.12
Beta-1 well	3301	1.54	0.15	1.2	428	78	89	0.11
Beta-1 well	3310	2.23	0.14	1.61	434	72	73	0.08
Beta-1 well	3319	2.24	0.14	1.44	423	64	77	0.09
Zeta-1 well	2743	1.8	0.15	0.29	406	16	126	0.34
Zeta-1 well	2774	1.67	0.48	0.9	459	54	297	0.35
Zeta-1 well	2987	2.12	0.65	4.5	437	212	66	0.13
Zeta-1 well	3082	1.75	0.24	0.62	433	35	126	0.28
Zeta-1 well	3243	1.33	0.34	0.55	429	41	98	0.38
Zeta-1 well	3292	1.48	0.19	0.67	433	45	97	0.22

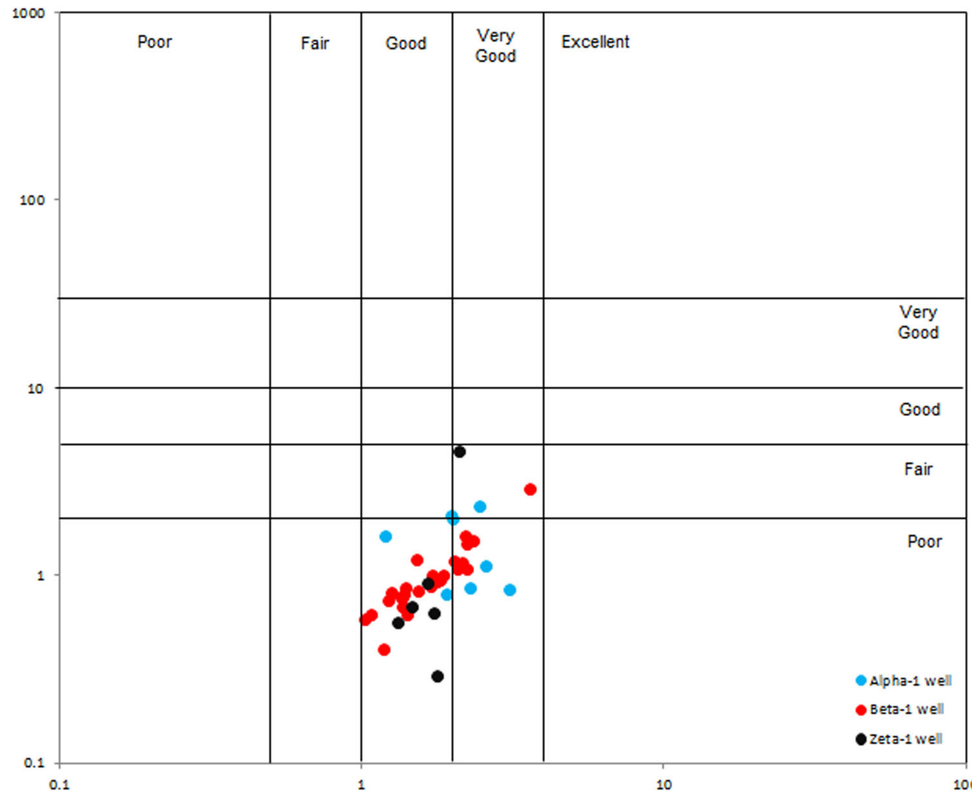

Fig. 5 Rock–Eval pyrolysis S_2 against total organic carbon (TOC), showing generative potential of Eocene source rock samples in wells Alpha_1, Beta_1 and Zeta_1

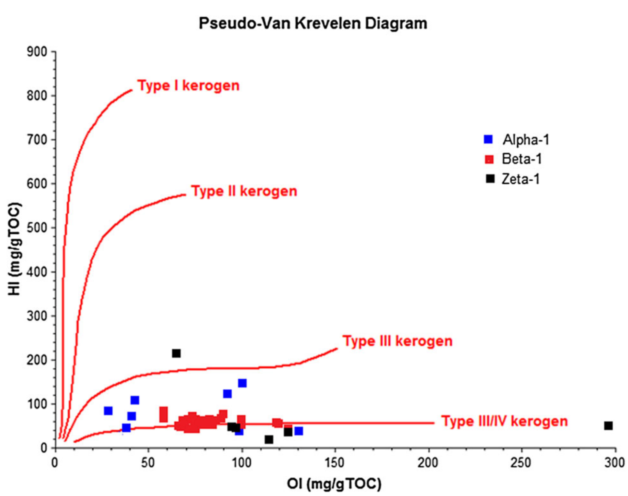

Fig. 6 Rock–Eval hydrogen index (HI) versus T_{max}, showing kerogen quality of the Eocene source rocks in wells Alpha_1, Beta_1 and Zeta_1

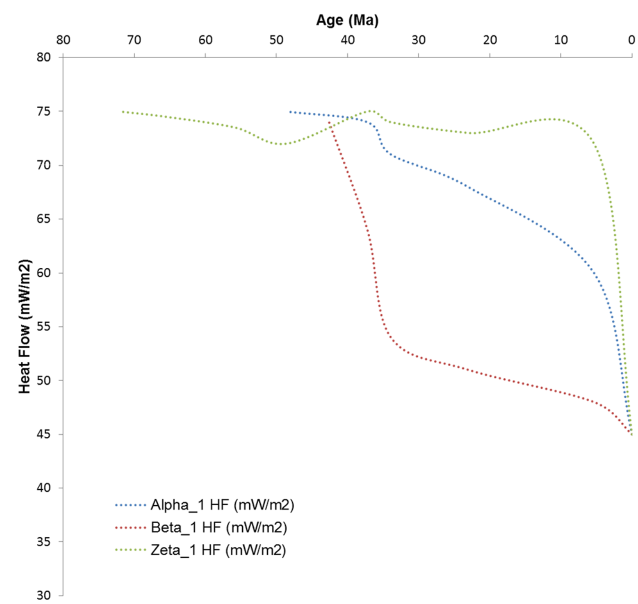

Fig. 7 Heat flow histories in wells Alpha_1, Beta_1 and Zeta_1 were used to model the most probable scenario for hydrocarbon generation in the Northern Delta (Niger Delta Basin) as used in the present study

corroborates production data of the wells, as sub-economical volumes of oil were recovered from the Eocene sand bodies. Possible hydrocarbon migration is expected along fault breakouts and unconformities to adjoining prolific reservoir rocks. The presence of hydrocarbon in the studied well suggests the viability of the Paleogene-sourced play in the Northern Delta depobelt. Hydrocarbon drilling activities in the Northern Delta depobelt should focus on identification of prolific reservoir sand bodies.

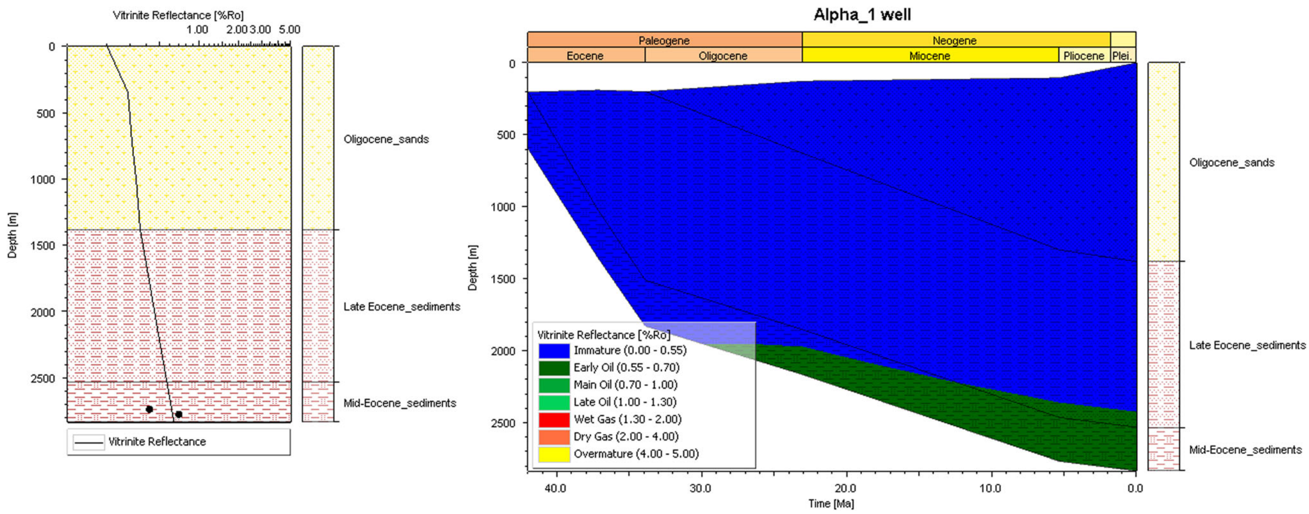

Fig. 8 Correlation of measured and modeled vitrinite reflectance data and burial history (with maturity overlay) of the well Alpha_1

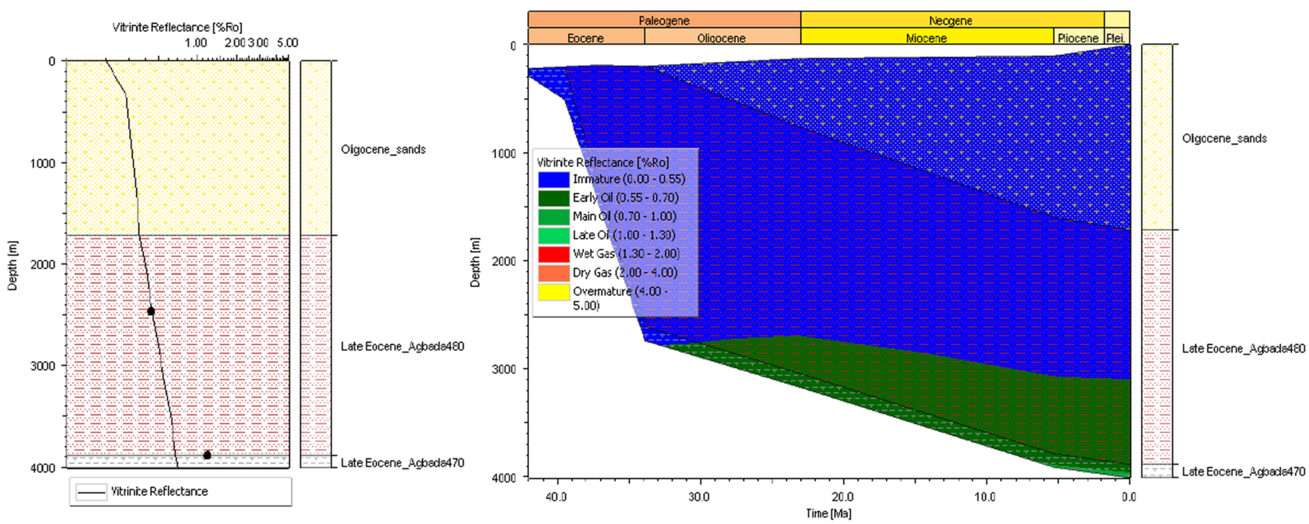

Fig. 9 Correlation of measured and modeled vitrinite reflectance data and burial history (with maturity overlay) of the well Beta_1

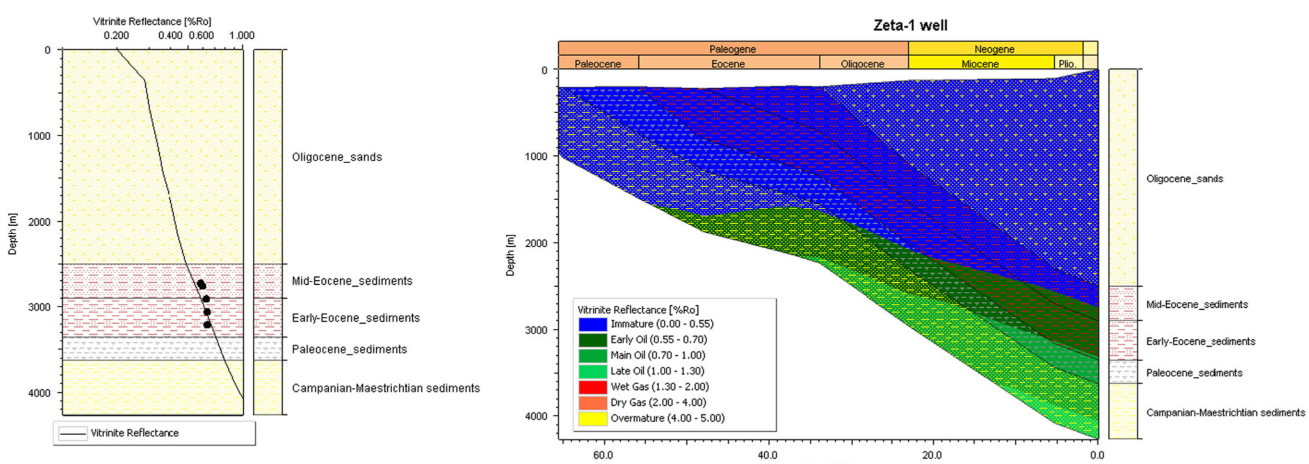

Fig. 10 Correlation of measured and modeled vitrinite reflectance data and burial history (with maturity overlay) of the well Zeta_1

Conclusion

This study has established the importance of source rock evaluation studies and basin modeling in determining the hydrocarbon generation potentials of Northern Delta depobelt of Niger Delta Basin. Investigation of Eocene Formation indicates that most shale of the Agbada Formation as observed in the wells Alpha_1, Beta_1 and Zeta_1 are good to excellent source rocks in the Northern Delta depobelt of the Niger Delta Basin. The maximum present-day hydrogen index suggests that gas would be expelled at peak maturity. Kerogen type and total organic carbon data from Rock–Eval pyrolysis indicate that most shale units of the Eocene Formation contain mainly Type III/IV kerogen with low hydrogen index values (65–200 mg HC/g TOC). Numerical modeling of three wells in the Northern Delta depobelt indicates that the Eocene source rocks entered the oil window stage for significant hydrocarbon generation during Paleogene–Neogene times and are capable of charging the interbedded Eocene reservoir bodies. The Eocene sediments are effective source rocks for oil in the Northern depobelt of the Niger Delta Basin. This study presents information that improves our understanding of the Paleogene-sourced facies. Because of more favorable maturity, the Eocene source rock is expected to have been responsible for oil and condensate discoveries in the Northern Delta depobelt of the Niger Delta Basin.

Acknowledgments This study was carried out during the first and third authors' PhD research attachment with Onshore and Coastal Swamp Exploration Department of Shell Petroleum Development Company (SPDC); Port Harcourt. Schlumberger is acknowledged for providing the PetroMod Modeling software for Department of Geology, University of Ibadan. Special thanks to an anonymous reviewer for his worthwhile comments that has improved this research article.

References

Adeogba AA, McHargue TR, Graham SA (2005) Transient fan architectureand depositional controlsfrom near-surface 3-Dseismic data, Niger Delta continental slope. Am Assoc Pet Geol Bull 89(5):627–643

Aminu MB, Oloruniwo MO (2012) Seismic paleo-geomorphic system of the extensional province of the Niger Delta: an example of the Okari field. InTech Open Access Publisher, Chapter, p 4

Avuru A, Adeleke V, Gbadamosi T (2011) Unraveling the structural complexity of a marginal field—The Asuokpu/Umutu study. Niger Assoc Pet Explor 23(1):1–4

Ben-Awuah JGW, Adda AM, Andriamihaja S, Siddiqui NA (2013) 2D basin modeling and petroleum system analysis of the Triassic play in the Hammerfest basin of the Norwegian Barents Sea Research. J Appl Sci Eng Technol 6(17):3137–3150

Dim CIP, Mode AW, Ozumba BM, Osterloff PI (2014) Regional Stratigraphic configuration and structural styles: an outcome of sequence stratigraphic framework of sigma-merge blocks eastern coastal swamp depobelt Niger Delta Nigeria. Niger Assoc Pet Explor 26(1/II):11–26

Doust H, Omatsola E (1990) Niger Delta. In: Edwards JD, Santogrossi PA (eds) Divergent/passive margin basins, vol 48. American Association of Petroleum Geologists Bulletin Memoir, Tulsa, pp 239–248

Ejedavwe J, Fatumbi A, Ladipo K, Stone K (2002) Pan—Nigeria exploration well look—back (Post-Drill Well Analysis). Shell Petroleum Development Company of Nigeria Exploration Report 2002

Ekweozor CM, Okoye NV (1980) Petroleum source-bed evaluation of Tertiary Niger Delta. Am Assoc Pet Geol Bull 64:1251–1259

Esedo R, Ozumba B (2005) New Opportunity identification in a mature basin: the Oguta North prospect in OML 20, Niger Delta. Niger Assoc Pet Explor 19(1):16–24

Evamy BD, Haremboure J, Kamerling P, Knaap WA, Molloy FA, Rowlands PH (1978) Hydrocarbon habitat of Tertiary Niger Delta. Assoc Pet Geol Bull 62:1–3

Frielingsdorf J, Aminul Islam S, Martin Block Md, Mizanur Rahman Md, Rabbani Golam (2008) Tectonic subsidence modeling and Gondwana source rock hydrocarbon potential, Northwest Bangladesh modelling of Kuchma, Singra Hazipur wells. Mar Pet Geol 25(6):553–564

Lewis G, Gurch M, Adegbaju A, Akinwotu K, Alalade B, Ananyi D, Dewberry S, Frowe R, Lory R (2014) Adapting Salt workflows to fault shadow problems on the eastern Niger Delta shelf. Niger Assoc Pet Explor 26(1):81–86

Magbagbeola OA, Willis BJ (2007) Sequence stratigraphy and syndepositional deformation of the Agbada Formation, Robertkiri field, Niger Delta, Nigeria. Am Assoc Pet Geol Bull 91(7):945–958

Odumodu CFR, Mode AW (2016) Hydrocarbon maturation modeling of Paleocene to Lower Miocene source rocks in the Niger Delta Basin: implications for hydrocarbon generation. Arab J Geosci 9:411. doi:10.1007/s12517-016-2427-5

Ojo OJ, Akpabio I, Frielingdorf J (2012) Burial and thermal history modeling and petroleum system analysis of the Northwest Niger Delta. Comunicações Geológicas 99:53–59

Opara AI, Onuoha KM, Anowai C, Mbah RO, Onu NN (2008) Overpressure and trap integrity studies in parts of the Niger Delta Basin: implication for hydrocarbon prospectivity. Niger Assoc Pet Explor 20(1):24–30

Ozumba, B., 2013. Geology of the Niger Delta: An Overview for Geophysics Processors. An SPDC presentation for geologists in Nigeria

Peters KE, Cassa MR (1994) Applied source rock geochemistry; the petroleum system-from source to trap magoon. Am Assoc Pet Geol Bull 60:93–117

Rowlands PH (1978) Hydrocarbon habitat of Tertiary Niger Delta. Am Assoc Pet Geol Bull 62(1):1–39

Shalaby MR, Abdullah WH, Abu Shady AN (2008) Burial history, basin modeling and organic geochemistry in the Western Desert, Egypt, Geological Society of Malaysia Bulletin (54):103–113

Sweeney JJ, Burnham AK (1990) Evaluation of a simple model of vitrinite reflectance based on chemical kinetics. Assoc Am Pet Geol Bull 74:1559–1570

Tissot GP, Welte DH (1984) Petroleum Formation and occurrence, 2nd edn. Springer, p 702

Tuttle MLW, Charpentier RR, Brownfield ME (1999) The Niger Delta petroleum system: Niger Delta province, Nigeria, Cameroon, and Equatorial Guinea, Africa. United States Geological Survey Open-File Report 99-50-H

Vandenbroucke M, Behar F, Rudkiewicz JL (1999) Kinetic modelling of petroleum formation and cracking: implications from the high pressure/high temperature Elgin Field (UK, North Sea). Org Geochem 30:1105–1125