Hydrocarbon Charge Modeling of the Abakaliki and Anambra Basins of Southeastern Nigeria: A Review

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ABSTRACT

A hydrocarbon charge model is one of the geochemical models applied in oil and gas exploration. This model provides a quantitative approach to the evaluation of oil and gas prospects, thereby, predicting the volumes of oil and gas generated in each source rock domain (as kg per ton of rock) in the basin. In every petroleum system, the principal constraint to the petroleum richness of a province is the adequacy of the charge factor, which must be enough to provide sufficient petroleum charge to the migration – entrapment part of the system. When the total charge for a prospect is predicted, a situation arises whether to continue or stop further exploration. This depends on the volume/quantity of discovered and predicted reserve. However, there are limitations in using this technique. This is mainly from errors in source data in-put, which mainly affect the predicted hydrocarbon reserve. Hydrocarbon charge model integrates other geological/geochemical models (subsidence/burial history, thermal maturation and palaeo-temperature models). In the Abakaliki and Anambra Basins these three models had been done by earlier workers. In addition, a previous work attempted hydrocarbon charge model using two possible source rocks in a portion of this prospect. The aim of this paper is to review all these models and to highlight the challenges in carrying-out the charge model for the entire prospect (Abakaliki and Anambra Basins). Hydrocarbon charge model of the entire prospect is likely to improve oil and gas exploration in these inland basins. It is also necessary even in prolific basins such as the Niger Delta, as it will help to reduce the risks/speculations on the prospects reserve asset. This review work indicates that, the available data for Abakaliki and Anambra basins are insufficient for a reliable geochemical model to be done. This is because errors in data acquisition and input have a large effect on models, especially, on the predicted volume of charge. Hence, for a reliable hydrocarbon charge model to be done in this region, acquisition of 3D-seismic survey data, oil – oil and oil – source rock correlation using biomarker fingerprinting and isotope ratios, and other geochemical/geological information such as time of generation/migration of crude and formation of reservoir/seal lithologies are required.

Keywords: Charge Modelling, Geochemical Models, Source rock, Burial history, Thermal maturation, Palaeo-temperature models, Fingerprinting.

INTRODUCTION

Hydrocarbon charge modeling is one of the petroleum geochemical techniques used in oil and gas exploration. Petroleum geochemistry is the application of chemical principles to the study of the origin, migration, accumulation and alteration of petroleum and the use of this knowledge in the exploration and recovery of hydrocarbons (Hunt, 1995). This technique defines the subsurface zones and areas of possible hydrocarbon generation, migration and accumulation. The application of geochemical data in petroleum exploration is relatively new in the industry as it started at about 30 years ago. The overriding objective of applying this new technique is to reduce risk and cost of exploration.

The inland basins of Nigeria (Abakaliki, Afikpo, Anambra, Middle and Upper Benue Trough, the southeastern sector of the Chad basin, the Bida and Sokoto basins) are difficult areas in terms of oil and gas discovery and have posed serious exploration risks (Obaje *et al.* 2004). Enormous exploration funds have been spent in these basins without economic successes. Some of the basins have no discovered recoverable hydrocarbon reserves, though they contain good source, reservoir and seal rocks.

In the southeastern inland basins of Nigeria, for instance,

The Authors are grateful to Profs. Chukwuemeka Ekweozor, Winifred Ayoma Mode and Celestine O. Okogbue for their guidance and supervision of the work. Also, our thanks go to the staff and management of Getamme Geochem Laboratory for the analysis of samples.

more than 50 exploratory wells and core-holes have been drilled since 1951 for Upper Cretaceous targets, but none of them indicated commercial petroleum accumulations. Only one oil and five gas discoveries resulted from this substantial investment. The step-out wells drilled in the 1980s to appraise the only discovery well (Anambra River-1) did not yield the desired results (Agagu and Ekweozor, 1982).

This paper has two objectives, the first one is to review all the existing geological/geochemical models done in the basins and attempt a charge model for the entire prospect. The second objective is to highlight the challenges in carrying out this model. These will further the understanding of geochemistry of hydrocarbon generation, migration, accumulation and exploration risks. The completed hydrocarbon charge model is likely to improve oil and gas exploration in these inland basins.

Petroleum exploration success depends not only on finding a trap but also on determining how high the probability is, that oil has migrated from mature source rock into that trap and has not escaped or been destroyed. Demaison (1984) explained further that successful exploration depends on the simultaneous occurrence of three independence factors of petroleum occurrence: (i) the existence of a trap (structure, reservoir, seal); (ii) the accumulation of a petroleum charge (source, maturation, migration to the trap, timing); and (iii) the preservation of the entrapped petroleum (thermal history, meteoric water invasion, etc). The probability of success is the product of the probabilities of the entire independent factors petroleum occurrence. Therefore, if one factor is absent, a 'dry hole' will be the result, no matter how favourable the other two factors are. The poor exploration results from the inland basins of Nigeria may be attributed to the absence of one or two of the three factors as suggested by Demaison (1984).

The focus of this study is on Abakaliki and Anambra Basins, the locations of the two basins studied is presented in figure 1 showing the geologic map. The geologic map of southeastern Nigeria is shown in figure 2, the generalized stratigraphy of Abakaliki and Anambra Basins is shown in table 1. These two basins are here considered as one domain of petroleum occurrence. The independent factor reviewed in this study is the second factor of Demaison (1984), i.e. the generation, expulsion, migration and accumulation of a hydrocarbon charge in a trap. Generally, the efficiency of a petroleum system and the expulsion efficiency are very low; hence, a hydrocarbon machine must generate enormous volumes of a hydrocarbon charge, so that, after losses through source/migration leakages, thermal alterations, water washing, biodegradation and de-asphalting, a commercial accumulation of petroleum can be found in traps.

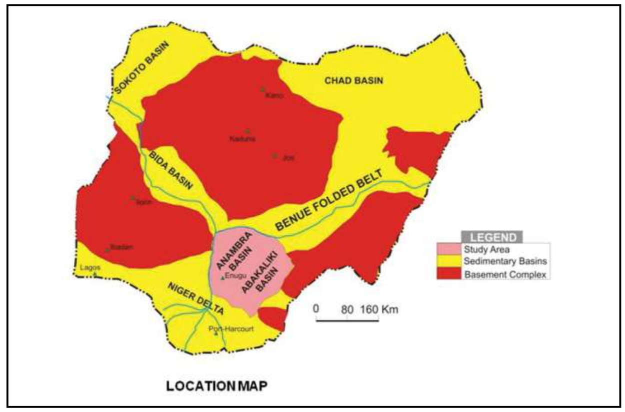


Figure 1: Geologic Map of the Study Area.

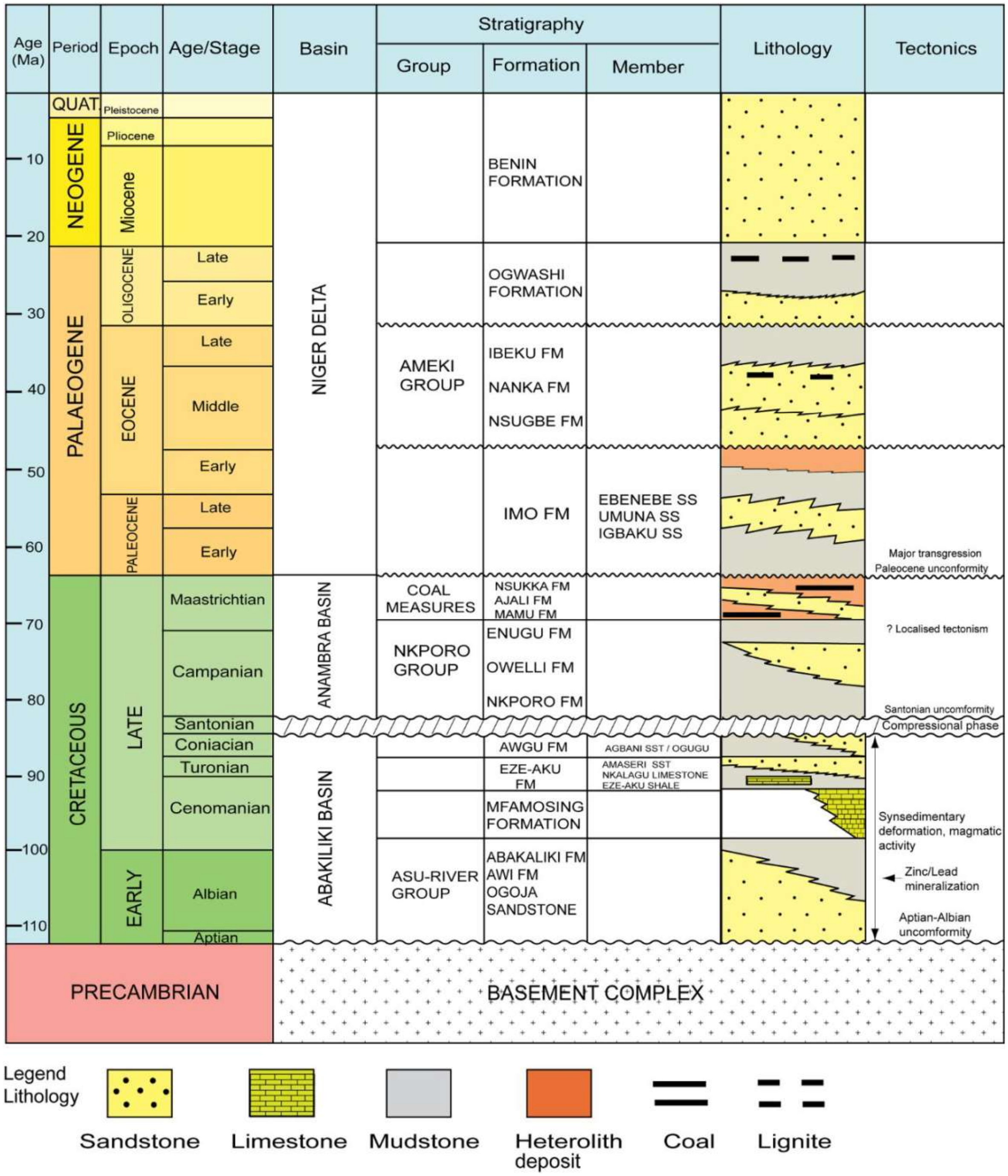
GEOLOGIC SETTING

The Abakaliki and Anambra Basins are located at the Gulf of Guinea re-entrant in the southern Nigeria. The regional topography of southeastern Nigeria shows a prominent cuesta which stretches in a laterally inverted sigmoid form, from Idah, through Enugu, to the bank of Cross River. It forms the structural divide between Cross River and Anambra River drainage basins. Most of the litholofacies of these sedimentary basin fills are exposed on the east-facing scarp-slope of the cuesta. These two basins evolved as a rift (Abakaliki/Benue) and subsequently, as a sag (Anambra), during the same tectonic event that led to the separation of the South American from African plates, with the simultaneous formation of the Benue Trough. The tectono-sedimentological evolution of an aulacogen is typified by the stratigraphic succession of the Benue Trough. The structural setting and litho-stratigraphical framework for Abakaliki and Anambra Basins are well documented in previous works of Petters and Ekweozor (1982), Agagu and Ekweozor 1982), Hoque and Nwajide (1984), Agagu etal. (1985), Benkhel (1989), Ojoh (1990), Nwajide and Reijers (1995), Umeji (2000), Ekweozor (2006) and Nwajide (2006). The first marine transgressive cycles and the early Cenomanian and late Santonian unconformities in the Benue Trough provide a practical basis for the sub-division of sedimentary succession into Albian Asu River Group, a late Cenomanian – early Santonian sequence (Cross River Group), and a post-Santonian deltaic, coal measures and paralic sequence, which is thickest in the Anambra Basin.

REVIEW OF HYDROCARBON CHARGE MODEL

The hydrocarbon charge model is one of the geochemical models applied in search for hydrocarbon. These models provide a quantitative approach to the evaluation of oil and gas prospects. This model can be applied in solving some

Table 1: Stratigraphic succession in the Anambra Basin and outcropping Niger Delta (modified after Nwajide 2013; Ekwenye *et al.* 2016).



exploration problems in difficult basins. Existing literature has shown that geochemical models had been successfully applied to several basins of the world, as reported by Chenet *et al.* (1983), Ungerer etal (1983) and Bishop etal. (1983), the hydrocarbon charge model integrates other geological/geochemical models, particularly, in Abakaliki and Anambra basins, where three other models had been integrated. These are the subsidence/burial history, thermal maturity and palaeo-temperature models. These models showed that the pre-Santonian sediments entered the oil generation window (i.e. oil kitchen) before the peak of Santonian event. This implied that they attained thermal maturity and had generated hydrocarbons which were dissipated by the disruptive. The maturation model range from over mature in Asu River Group to mature in Eze-Aku and Awgu Formations, slightly mature in parts of Nkporo Shales and immature for the other post-Santonian sediments (Whiteman, 1982; Agagu and Ekweozor, 1982; Peters and Ekweozor, 1982; Ekweozor and Gormly, 1983; Onuoha, 1985; Ekinne, 1989; Unomah and Ekweozor, 1993; & 1998; Akaegbobi and Schmitt, 1998; Onuoha and Ekinne, 1999; Onuoha, 2006). In addition, the organic facies in the pre-Santonian sediments were characterized by Ehinola *et al.* (2004). Accordingly, the Albian to middle Cenomanian shales are Type III kerogen, they are overmature and could generate only gas, the late Cenomanian to early Turonian shales are Type I/II kerogens, they are mature and could generate both gas and oil, and the middle Turonian to Coniacian shales are Type III kerogens, they are immature and could generate gas with little oil.

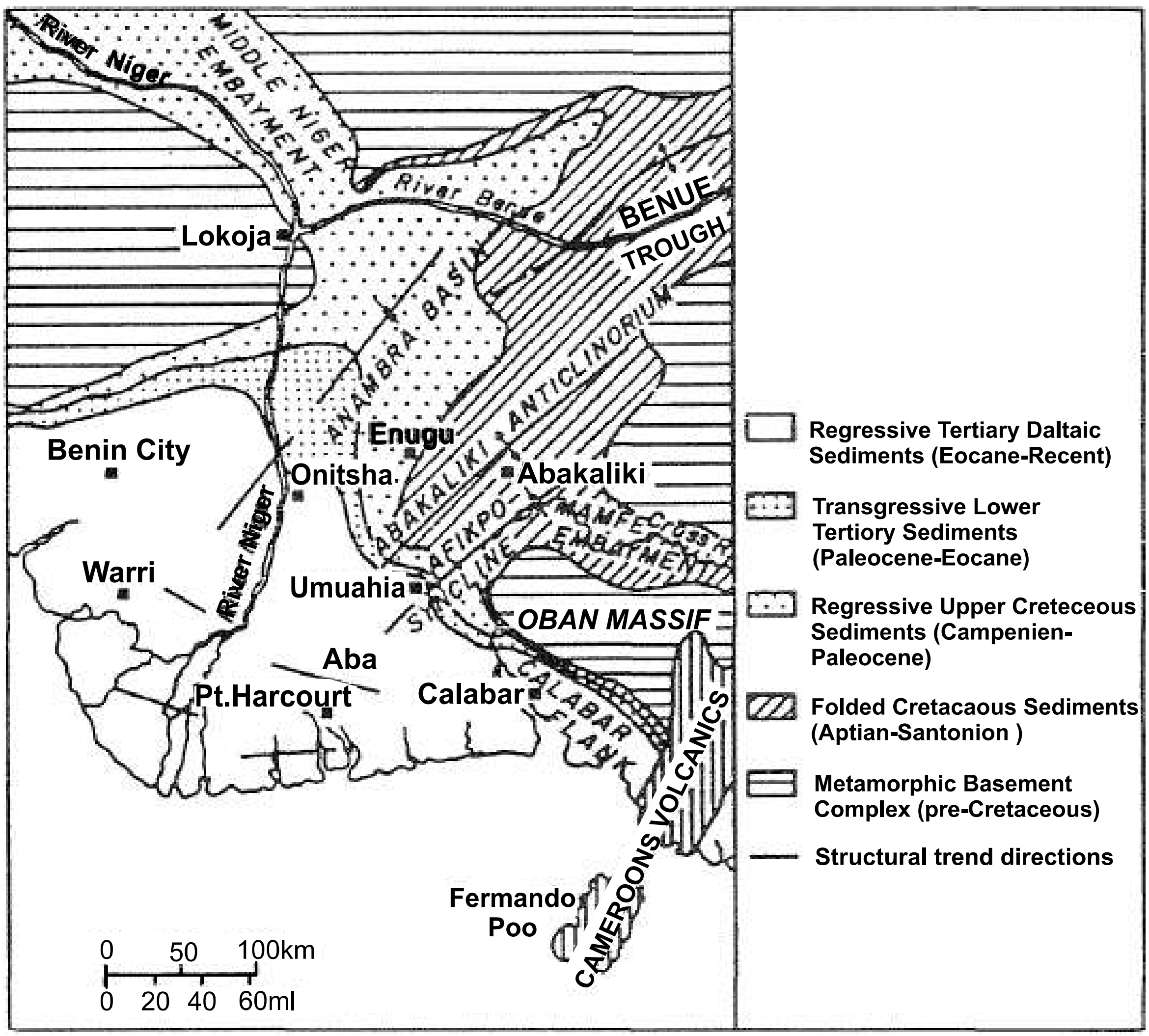


Figure 2: The Geologic Map of SE Nigeria.

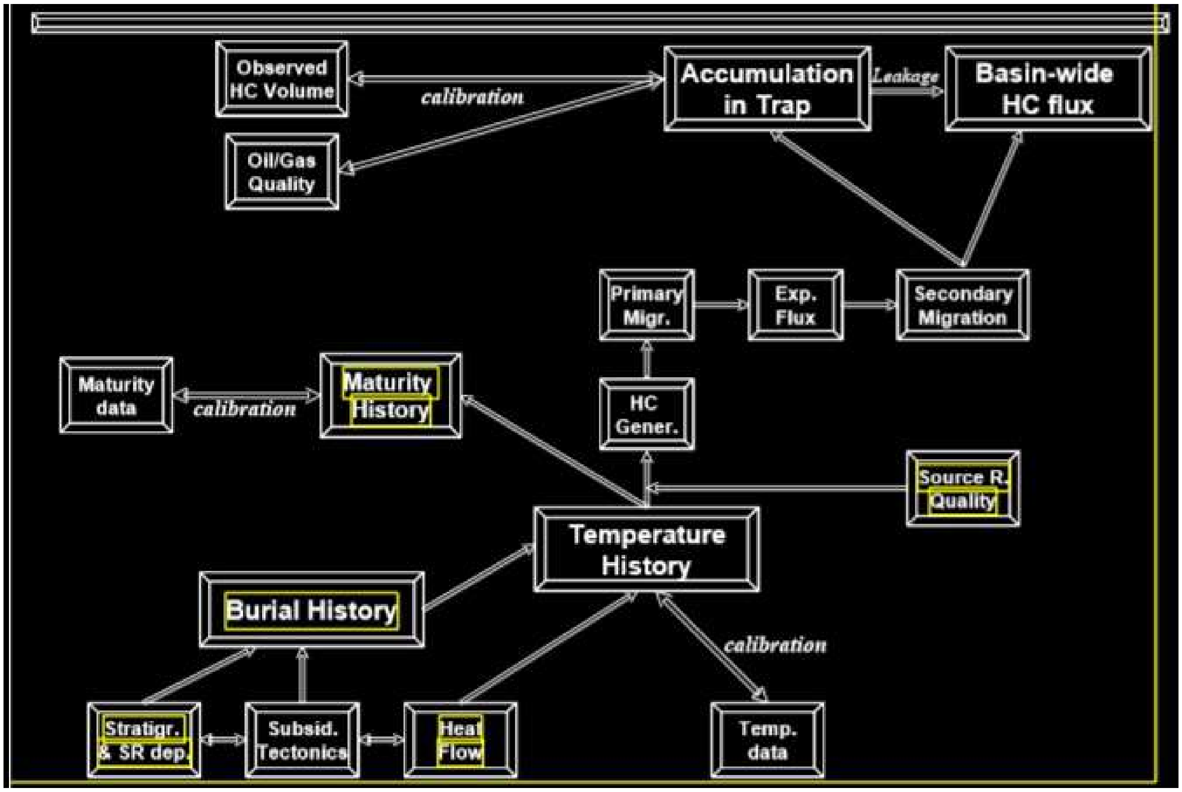


Figure 3: The Generalised Proceedure/workflow for Hydrocarbon Charge Model

The first attempt to model hydrocarbon generation in Anambra was made by Akaegbobi, *et al.* (2000). they calculated oil and gas volumes generated from shaie and coal source rocks of Nkporo and Mamu Formations respectively. They reported low source potential index for the source rocks, indicating an under – charged system and hence, low exploration potential. However, the existing literature show that about 74 oil stains, smells and seeps occur in this area (Agagu, 1978; Agagu and Ekweozor, 1982; Ekweozor, 1982; Peters and Ekwezor, 1982). According to Agagu, (1978), the stratigraphic distribution of the hydrocarbon-indicators for the surface and subsurface sections show that, the highest frequency is in Eze-Aku Formation (50) followed by Awgu/Nkporo Formation (21), Mamu Formation (3), the Asu RiverGroup was not penetrated by any of the wells. The seepage of heavy oil from Owelli Sandstone (Nkporo Formation) has been correlated to the basal shale member (Lokpanta Shales) of Eze-Aku Formation Ekweozor, (2006). According to this author, this shale member has been mapped for over a 1000km2 territory via two major traverses. The organic carbon content (TOC) of surface outcrops range between 2.0 and 10.0 wt% corresponding to Hydrogen Index (HI) values greater than 600mg Hc/mg TOC. This value agrees with the Type-II sedimentary organic matter (anoxic/marine organo-facies). The estimated Fischer Assay Yield varies from 30 – 80 liters/ton which is significant considering that the cut-off yield for authentic oil shale is generally put at 42 liters/ton. It has been estimated that in the Lokpanta area alone, more than 500 million barrels of oil may have been generated by only a 30m thick oil shale column occurring in an area of approximately 60km2. This charge factor is likely to be powerful enough to provide sufficient petroleum charge to the migration – entrapment part of this petroleum system, based on the petroleum system of Magoon and Doe, (1994). In addition, this carbonaceous basal unit of Eze-Aku Formation (Ekweozor, 2006) might have produced enormous volumes of petroleum into reservoirs, which were disrupted by the Santonian event. The crude oil accumulations appear to have been subsequently dissipated by this tectonism, hence, the numerous oil seepages that occur in this area. He further stated that, the continuous oil seepages in the area, such as the one at Ugwueme Hills indicate that, the oil pool associated with this super source rock system is yet to be found. The first step in generalized procedure/workflow for hydrocarbon charge model is identify the effective source rock(s) in the prospect and determine their lateral extents, areas and thicknesses using 3D – seismic survey and well data. This is followed by the development of subsidence/burial history, palaeo – temperature and hydrocarbon maturation models. The correlative studies are done for oil – source rock (source rock evaluation) and oil – oil (migration pathway and reservoir characterization) using the biomarker fingerprinting technology and isotope ratios. The total charge is calculated, which is the predicted reserve. Finally, the generalized procedure/workflow for hydrocarbon charge model is illustrated in figure 3.

LIMITATIONS OF HYDROCARBON CHARGE MODEL

The greatest error in this model comes from data input from source rock. The 3D-seismic mapping gives information on the thickness variation of the source rock and not on its organic facies/quality variation. The thickness and quality of source rock increases towards the basin centre and the land plant contribution usually increases towards the basin margin. Many source rock sequences are alterations of laminae that are organic rich and organic poor. These non-uniform properties of source rocks impact severely on the model results, especially, on the predicted volume of the generated hydrocarbon. Generally, geochemical modeling tools are mainly probabilistic rather than a deterministic method and are mainly used to rank prospects. However, some previous workers reported that, the forecasting efficiency of Shell International, using both geology and geochemistry to rank prospects rose to 65%, compared to only 18%, when prospects were ranked by geology (trap size) alone.

SUMMARY AND CONCLUSION

The Abakaliki and Anambra basins present a good natural setting for petroleum formation in terms of availability of source rocks, reservoir rocks and seal lithologies. The temperatures and tectonics are very important in assessing source rocks naturally in frontier basins Pigott, (1985). The highly bituminous petroleum source rocks in this prospect were deposited during the occurrence of Cretaceous anoxic event, Arthur and Schlanger (1979); Demaison and Moore, (1980). This enabled the preservation of enormous quantity of organic matter in sediments. In addition, the Cretaceous source rocks of Albian, Cenomanian and Turonian are responsible for the major oil fields on both sides of the Atlantic. In Dahomey Basin, an indigenous oil company discovered mature crude oil in Cenomanian – Turonian sands and the recent oil discovery in Ghana is thought to be from the Cretaceous reservoir. And, biomarkers of Cretaceous origin found in Niger Delta oil Sonibare and Ekweozor, (2000) indicates that this oil accumulation should be somewhere in Nigeria and the super excellent source of Eze-Aze Formation is a suspect. In the prospect under review, the available geological/geological data are insufficient for an efficient geochemical model to be Tissot and Welte, (1978). Errors and insufficient data input in the model have a large effect on the predicted volume of charge. Hence, for a reliable hydrocarbon charge model to be done to be in this region, a 3D – seismic survey must be done to calculate the thickness to the effective source rock. More work is required on the oil – oil and oil – source rock correlation based on biomarker finger-printing and isotope ratios to complete the other elements and processes of the petroleum system already Identified in the basins and other geological/geochemical data from the region. This is very necessary for a reliable predicted volume of charge and an accurate reserve estimate for this prospect. This geochemical technique in exploration will ultimately reduce risks and cost of exploration.

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