An Evaluation of Fiscal Regimes for the Nigerian Petroleum Industry Bill

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ABSTRACT

Petroleum has been the mainstay of the Nigerian economy for the past four decades. As a result, government is constantly looking for ways to enhance the contribution of the sector to the national economy without jeopardizing the environment and the communities from which the oil is produced, while taking into consideration the interests of the investor. Thus, there is an ongoing debate in the legislature on a petroleum industry bill which is intended to reform the oil industry in Nigeria. The aspect of the bill that has generated most reactions is the fiscal regime provisions in the bill. The petroleum industry bill sponsored by government, proposes some reforms in the existing fiscal regimes which the international oil companies consider to be detrimental to their interests. This paper identifies the key areas of disagreements on the review of the fiscal regimes. It also examines the strengths and weaknesses of the positions of government and the international oil companies by adopting a discursive approach and using quantitative information from respectable and trusted sources. Some recommendations are then provided for the way forward.

1.0 INTRODUCTION

Nigeria depends heavily on petroleum (oil and gas), with the petroleum industry activities providing about 65% of total government revenue and 95% of export revenues (Thurber et al., 2010). The socio-economic and political development of Nigeria will continue to be largely determined by the future of this industry. As a result, government is constantly looking for ways to enhance the contribution of the sector to the national economy without jeopardizing the environment and the communities from which the oil is produced, while taking into consideration the interests of the investor. Thus, there is an ongoing debate in the legislature on a petroleum industry bill (PIB) which is intended to reform the oil industry in Nigeria.

The PIB proposes fundamental changes in the Nigeria's oil industry anchored on five major goals, namely, creation of new regulatory institutions, transformation of upstream contractual agreements, new fiscal regimes, downstream sector deregulation, government participation in the industry and transparency in contractual agreements. The PIB has drawn different emotions from the stakeholders since it came into the public domain. The aspect of the PIB that has generated most reactions is the fiscal regime provisions in the bill. Fiscal regimes are the provisions for the taxes and fees on the production of oil and gas to secure an income for the government and country.

The controversy surrounding the fiscal regime provisions for the PIB is understandable because the fiscal regime is the government's most important factor the international oil companies (IOCs) consider in determining the profitability of their investments.

Explaining the reasons behind the need to review the fiscal regimes, government through its minister of petroleum noted that “the production sharing contracts (PSCs) that were concluded in 1993 were rather bad deals for Nigeria from an international perspective. The royalties were zero percent (0%). The taxes included a generous tax credit that wiped out much of the tax to be collected. The profit oil shares to government were low compared to most other nations. Therefore, Nigeria collects much less for government under these contracts than other petroleum exporting nations. Therefore the PIB now includes much higher royalties and a new tax framework" (Rilwanu, 2009). This will create a strong basis for renegotiations of the existing unfavourable contracts. The goal is to ensure a fair share of the revenue to Nigeria comparable to other important oil exporting nations. But the IOCs in Nigeria say that government take is already one of the highest in the world (MPPIBD 2009), and that the sanctity of a contract signed close to two decades ago should be respected.

In view of these claims and counterclaims, this paper will attempt to examine the strengths and weaknesses of each side of the argument and assess the fiscal regimes in the PIB in comparison with the international best practices and suggest the way forward. The aim is to contribute to national discuss on the PIB towards the formulation of appropriate policies for the efficient development and growth of the Nigerian petroleum sector. The approach adopted is discursive and tries to expound on the principles and goals of the PIB to promote better understanding of the PIB, its overall objectives and the benefits derivable for the industry, investors and Nigeria in general. It is not intended to form an opinion on any aspect of the bill but to shed light on the fiscal regimes for the PSCs in the bill. After this introductory section, there are five other sections. Section 2 discusses PSC and the fiscal provisions in Nigeria prior to the PIB while Section 3 discusses the fiscal regimes in the PIB. Section 4 examines the arguments for and against the need to review the existing fiscal regimes in the PSCs. Section 5 provides some recommendations for the way forward while the conclusions are presented in Section 6.

2.0 PRODUCTION SHARING CONTRACTS IN NIGERIA

There are four different types of petroleum arrangements in the Nigerian oil industry. They are Joint Operating Agreement also known as Joint Venture (JV), Production Sharing Contract (PSC), Service Contract (SC), and Memorandum of Understanding (MOU). Each contractual agreement was developed in response to trends in the global oil and gas industry as well as the desire to tackle problems inherent in old arrangements. In 1991, a Memorandum of Understanding (MOU) was signed between the Nigerian National Petroleum Corporation (NNPC) representing the government, and the IOCs – Shell, Mobil, Chevron, Agip, Elf, and pan Ocean - with the aim of attracting more investments into the sector following the price collapse and the subsequent lull in prospectivity in the late 80s. The policy also guaranteed for the IOCs a minimum profit margin of $2.30/bbl after tax and royalties on the equity crude oil. With the shift, the IOCs were encouraged to embark on bullish exploration activities, which enabled Nigeria's crude oil reserves to move from 18.0 billion barrels to 22.0 billion barrels in 1992, barely a year after the policy decision was taken. The MOU contained inherent mechanisms for review in a way that both parties were left satisfied even when the dynamics of the economy such as inflation and exchange rates set in. This is why the MOU is reviewed to reflect prevailing economic realities. Similarly, the PSC was introduced in response to the funding problem faced under the JV as well as the desire to open up the frontier areas such as the inland basins and the deep / ultra deep waters for more foreign participation. There is no doubt that the fiscal regimes in the PSC concluded around that period were based on the experience of the immediate past with low oil prices and a lull in exploration and production and a very limited view of the future which could not anticipate the current high prices of oil. PSCs were first introduced in the Indonesian oil industry in 1966. After independence, nationalistic feelings were running high and foreign companies and their concessions became the target of increasing criticism and hostility. In response to this the government refused to grant new concessions. In order to overcome the subsequent stagnation in oil development, which was a disadvantage to both the country and the foreign firms, new petroleum legislation was brought in. PSCs were regarded as acceptable because government upholds national ownership of the resources. The major oil companies were initially opposed to this new contract form as they were reluctant to invest capital into an enterprise which they were not allowed to own or manage. More importantly, the IOCs did not want to establish a precedent which might then affect their concessions elsewhere. The first PSCs were therefore signed by independent IOCs who showed a greater willingness to compromise and accept terms that had been turned down by the majors. Furthermore, it was argued that the independents saw this as an opportunity to break the dominance of the big oil companies and gain access to high quality crude oil (Barnes 1995). Thus challenged, the major IOCs entered into PSCs and found that in reality the foreign firm usually manages and operates the oilfield directly. From Indonesia, PSCs spread globally to all oil-producing regions with the exception of Western Europe where only Malta offers this type of contract (Kirsten Bindemann, 1999). The petroleum fiscal regime at the inception of the oil industry in Nigeria was characterized by concessionary arrangements between the government and the IOCs, although Ashland Oil Company (now Addax Nigeria) had a PSC arrangement in 1973 with the Nigerian National Oil Company (NNOC). Under a concessionary system, the title to hydrocarbons passes to the investor at the borehole. The state receives royalties and taxes in compensation for the use of the resource by the investor. Title to and ownership of equipment and installation permanently affixed to the ground and/or destined for exploration and production of hydrocarbons generally passes to the state at the expiry, or termination, of the concession whichever is earlier. The investor is typically responsible for abandonment (Silvana, 2007). The establishment of the NNOC, now NNPC in 1971 provided the opportunity for government to participate in oil operations through joint venture (JV) operations with the IOCs. The government is a non-operator and holds 60% (apart from the JV with Shell where it holds 55%) in all its JV arrangements with the IOCs. This arrangement requires the government to provide funds on a yearly basis (cash call payments) for operations with the IOCs. The approach resulted in substantial drain on government resources which could have been channeled to more pressing needs. Moreover, the participation in operations exposed the government to the inherent risks associated with oil and gas exploration. In 1992, the extension of exploration activities into the deep offshore areas marked the introduction of PSCs arrangements between the NNPC and the IOCs. The adoption of PSCs by government was premised on its inability to partner alongside the IOCs based on the fact that deep offshore exploration and production requires significant capital investment and the prospect risks are very high. The PSC was used as a vehicle for achieving deep offshore exploration and production and increasing the country's crude oil reserve. By 2007, Statoil, Shell Nigeria Exploration and Production Company (SNEPCO), Esso, Elf, Nigerian Agip Exploration Limited, Addax, Conoco and Petrobras, Star Deep Water, Chevron, and Oranto Philips were operating the PSC in Nigeria. PSCs seek to attract multinational corporations willing to risk capital and to use their technological expertise to develop a country's reserves. The multinational corporation is conventionally referred to as the operator, and in the event of an unsuccessful discovery, the host government is insulated from the risks associated with the exploration. Although many oil producing countries have adopted PSC, no universal model or standard contract exists as countries over the years developed their own variations of the contract, but there are features common to all types PSCs. These are:

i. The contractor bears all costs of exploration and production without such costs being reimbursable if no find is made in the acreage;
ii. Cost is recoverable with crude oil in the event of commercial find with provisions made for tax oil to offset actual tax, royalty and concession rental due and payable / deductible in full in the year; and cost oil to reimburse

the contractor for capital investments and operating costs.

iii. Profit oil - the balance after deduction of tax oil and cost oil, which is to be shared between the NNPC and the contractor in an agreed proportion.

In Nigeria, government take is classified into two broad categories: pre- production and post – production payments (Omorogbe 2005; Annan, 2010). The pre-production payments are a feature of the PSCs and service contracts and they allow the government to earn some revenue even before any discovery has been made. These include bidding fees, signature bonus, and surface / rental fees. Pre-production payments are dependent on the deposits that the company expects to find and can be substantial. In the early 1990s, the PSCs contractors paid signature bonus of $1million each. In the 1999 PSCs the contractors were subject to $20 million while the signature bonus for the post-2000 PSCs was $30 million each. The largest signature bonus of $210 million was paid by Shell Nigeria Ultra Deep (Omorogbe, 2005).

Post-production payments consist of payments after commercial production and they include value added tax, royalty, rent, production bonus, education tax, Niger Delta Development Commission levy, petroleum profits tax and profit oil (Annan, 2010). Royalties are volume- based, vary with the water depth and the current figures are shown in Table 1. With regard to profit oil split, all payments are expressed in terms of proportions of cumulative or daily oil production and usually, greater proportions are given to the operators during low oil prices. This system is conventionally referred to as production based sliding scale. Alternatively, the profit split could be based on an R-factor (ratio of revenue to expenses) formula or rate of return (RoR) sliding scale. Daniel (2008) observed that a significant difference exists between the production based sliding scale approach and the R-factor / RoR model in that the former has no effect on government take when price increases while government take progresses with increase in oil price in the R-factor / RoR model. For the post-2000 PSCs in Nigeria, the percentages are as shown in Table 2.

Oboarenegbe (2011) viewed host government and investor agreements as a function of country proven reserves and exploration and production costs. In this regard, he posited that where reserves are large with medium exploration costs, countries would opt for PSCs arrangements. Countries in this category include Nigeria, Kazakhstan and Oman. Other West African countries that have embraced PSC models include Angola and Equatorial Guinea. Although PSCs have enjoyed wide appeal by oil producing countries, concessionary systems are still predominant in oil producing industrial countries like the United Kingdom, United States and Norway.

3.0 FISCAL PROVISIONS FOR THE PETROLEUM INDUSTRY BILL

From an historical perspective, the PIB is the idea of the Oil and Gas Implementation Committee (OGIC) inaugurated by the government in April 2000. The draft bill by the OGIC was subsequently subjected to further review and amendments by an Inter-agency Committee comprising the NNPC, Ministries of Petroleum Resources, Finance, Justice, Department of Petroleum Resources (DPR), Federal Inland Revenue Service (FIRS), the Revenue Mobilisation Allocation and Fiscal Commission (RMAFC), and the Nigeria Extractive Industry Transparency Initiative (NEITI). The changes introduced by the inter-agency team proposed a restructuring of the regulatory framework for the oil industry into separate regulators for the upstream, midstream and downstream sectors, introduced fiscal changes for the upstream, provisions for gas utilizations, refining/downstream sector reforms and replaced the joint venture (JV) agreements between the NNPC and the producing companies which cover most of Nigeria's onshore and shallow-water fields with the incorporated joint ventures (IJVs). The IJVs as legal entities will be capable of raising loans commercially and repay them from generated income. As a result, the IJVs will operate independent of government cash call obligations, ensuring an end to the recurrent defaults of NNPC to its cash call commitments. A key benefit for an oil-producing country is the government revenue that is generated. It is therefore critical that the fiscal regime be designed to secure maximum revenue for the government, while still providing investors with sufficient incentive to undertake exploration and development. In seeking to achieve this objective, fiscal regimes for oil tend to differ from those for non-resource sectors due to the presence of resource rents, that is, surplus revenues from an oil field after the payment of all costs, including an investor's risk-adjusted required return on investment. Since rent is pure surplus, it can be taxed without creating distortions. Furthermore, since oil, the source of the rent is an exhaustible natural resource that belongs to all citizens of a country; there is added pressure on the government to secure the rent for the benefit of the country as a whole.

With country's objective of maximizing revenue and the shortcomings of the previous agreements, the PIB introduced higher royalties and increased government take. The proposed royalties which are based on an aggregate of the royalties applied for production rate and oil prices are also differentiated for oil and gas. Productions in onshore fields below 2,000 barrels per day (b/d) attract 5% royalty rate and rising to 25% for production exceeding 5,000 b/d. The shallow water areas attract 5% on up to 5,000 b/d ranging to 25% on production over 50,000 b/d while deepwater attract 5% on production up to 25,000 b/d and above 50,000 b/d attracts 25%. The price-based royalty ranges on an incremental basis from 0% to 25% starting at \$70 bbl with a price cap at \$150. Therefore, in case of deep water fields and high oil prices, the maximum royalty accruing to Nigerian government will be 50%. This is certainly a mechanism for the government to capture windfall profits and increase government take on profitable fields front-end.

Similar changes in government take were introduced for the PSC. The limit for cost recovery is fixed at 80% of gross production and therefore reducing the 100% cost recovery provided under the 1993 PSCs. Also, the PIB terms substitutes the profit oil split on sliding scale basis in contrast to the 1993 PSCs giving the oil companies 80% share of profit oil for the first 350m barrels of production with declining share as cumulative production increases. The same applies to the 2005 PSCs using the R-Factor with the initial company share of 70% profit oil split. The two layers of tax introduced under the PIB, namely the Nigerian Hydrocarbons Tax (NHT) and Companies Income Tax (CIT) are applicable to both JV and PSC operations. NHT replaces the Petroleum Profit Tax (PPT) and is set at 50% for JV, 50% for gas and 30% for PSC while the CIT is introduced for all oil companies at the rate of 30% on net profits. A minimum of 10% withholding tax on dividends and education tax of 2% on revenue existing under the current fiscal regime is retained (Humphrey, 2010).

The PIB terms streamlined the NHT by abolishing the investment tax credits. It proposes to disallow interests expense/financing charges and imposes an 80% limit on expenses incurred outside Nigeria for tax deductibility while introducing benchmarking, verification and approval of all costs for tax deduction purposes. The cost benchmarking would be conducted by the regulatory institutions or the National Oil Company (NOC) and the verification and approval process conducted by the FIRS (Humphrey, 2010).

4.0 ARGUMENTS FOR AND AGAINST RENEGOTIATIONS

The decision to renegotiate petroleum contracts in the deep offshore PSCs is not unique to Nigeria. The unprecedented increase in oil prices in recent times has prompted many oil producing countries to revisit their oil contracts with the IOCs operating in their countries with a view of reflecting current market trends (Oboarenegbe, 2011). The argument by the Nigerian government is based on the fact that majority of these contracts were signed in the early nineties when crude oil price was closer to US$20 per barrel and the cost of exploring in frontier deep offshore was very high. The early deep offshore PSCs in Nigeria were based on a production sliding scale which analysts have argued is not an effective proxy of project profitability, hence the resultant profit split under a production based sliding scale inevitably results in minimum impact of increasing crude oil prices on government take (Oboarenegbe, 2011). Humphrey (2010) also observed that the Nigerian fiscal terms are currently lenient compared to its peers, particularly the countries with the same geological character. For instance, Libya has 93% allowances and the petroleum investment allowance (PIA) uplift on capital expenditures for existing arrangements and replaced them with allowances for small oil fields and new gas finds. Furthermore government take in UAE Abu Dhabi is on an average of 94%. Recent trends in global fiscal terms especially in this era of rising oil prices have built-in mechanisms of increased government share in windfall prices through increased royalty/taxes and linkages of royalty/tax rates to prevailing prices to ensure automatic adjustment of government share to price increases.

Undoubtedly, the tax changes would instigate an increased government take from an average of 73% to a projected 82% under the PIB terms. This calculation is derived on projections of a mid-size deepwater oil field with production of around 50 million barrels a year and oil price of US$75bbl. Therefore, the groundswell of opposition to the PIB is not farfetched since the existing arrangements have put the oil companies in advantage positions of reaping greater share from higher production and current high oil prices.

The crux of opposition to the PIB is that the IOCs see government take as already being too high and that it will create a harsh environment that would materially change the economics of the existing and new operations particularly in the deepwater regions. In their assessment of government take in the existing and future planned portfolios of deepwater projects, in comparison with other countries, they gave United Kingdom - 55%, Brazil – 60%, Indonesia – 74%, Norway – 74%, Angola – 76% and Nigeria Inter-agency proposal – 89% (MPPIBD 2009). The IOCs cite the high-cost nature and the complex dynamics of upstream economics, particularly of deep water fields with its high risk frontier explorations as weighted factors in investment decisions for the oil companies. These scenarios are not any different with the Nigerian environment in addition to its peculiar challenges such as the security situation in the Niger Delta, underfunding of JVs and global escalating cost basis. Moreover, the IOCs demand that the sanctity of a contract agreement signed about twenty years ago should be maintained. However, NNPC data shows that government take would increase from the current 42% to 70% whereas the world average is 75% as against the figures provided by the IOCs. Even Ghana that is just starting its petroleum industry has government take of 80% (Okonji, 2011).

5.0 DISCUSSION ON RENEGOTIATION OF CONTRACTUAL TERMS

During the 1980s and 1990s oil companies had difficult time making money exploring for hydrocarbons. At the same time most governments were dissatisfied with the level of exploration and development activity in their countries (Daniel, 2008). Therefore, many oil producing countries crafted incentives to encourage the IOCs to invest in exploration and production of oil and gas in their countries. Hence, much of today's petroleum fiscal systems had their inspiration from the era of low oil price of around US$20 per barrel. The current high oil prices were not anticipated in the design of the fiscal terms. This is why there has been "a great deal of smoke and heat and very little light" (Asiodu, 1993) about the renegotiation of the contracts and fiscal and legislative actions these last few years.

As a matter of fact, the issue of petroleum contract renegotiation has become a recurring concern between host governments and IOCs since quadrupling of oil prices in the early seventies. Although a great many parameters determine the nature of the contracts, such as the maturity of the oil sector, the fiscal regime, import and export dependency, geological aspects, cost and the regulatory framework, the major factor necessitating contract renegotiation has been fiscal terms. Perceived excess profits particularly during periods of high crude oil prices and declining exploration costs are key drivers accentuating contract renegotiations by host governments. The work of Oboarenegbe (2011,) describes this host government / investor relationship as the obsolescing bargain case. In this regard, he noted that "time brings change in perspective to bargaining relations between government and foreign corporations. At the outset of petroleum operations, the contractor could be regarded as the 'protagonist' but once commercial discovery is made, bargaining power shifts to the host government. Securing long term fiscal stability is a key priority to any international investor. This strategy would enable the investor determine the profitability of a particular project *from the onset* with a view of informing its shareholders about likely dividends. Investors would be reluctant to invest in countries with significant high contractual and political risks.

The relationship between host governments and IOCs is governed by contracts most times drafted within the framework of a petroleum law. Kirsten (1999) and Omorogbe (2005) observed that there are instances when these agreements were entered upon at a time when the host country was politically or economically weak, or was badly advised, the consequence being a contract that put the host country at a clear disadvantage. Later, the country, usually under a new political regime, realizes the problem and seeks renegotiations. But some companies (if not all), reject the idea of renegotiation, or complain loudly about its unfairness. Curtis (2010) also noted that there could be features of the oil industry that make contract renegotiations either inevitable or desirable. These are the long-term nature of oil upstream licenses or agreements, the sharp volatility of oil prices, and the vital importance of oil revenues for the exporting countries. And circumstances can change radically at least once if not several times over the contractual periods that usually extend over 20 to 25 years. The sharp volatility of prices is an important change of economic circumstances for the simple reason that conditions agreed upon when oil prices were low become unacceptable when prices move to significantly higher level. Host countries that have taken measures to renegotiate their petroleum contracts in recent time include Algeria, Bolivia, Canada, China, Ecuador, Kazakshstan and Venezuela, all of which imposed new taxes and royalties on production, exports or windfall profits (Curtis, 2010). In the case of Canada, royalty and tax treatment regime extended to all conventional oil, natural gas and oil sands production were reviewed in 2009 in response to rising oil prices (André, 2009). The government of Trinidad and Tobago also noted that oil exploration and development projects are characterized by large capital investments, long lead times, incomplete information, and in most cases significant differences in the abilities of the parties to bear the risks involved in the venture. Thus contracts are potentially unstable and one or both signatories may want to renegotiate at some point in time Trinidad and Tobago (2010). Thus the country started renegotiation of its petroleum contracts in 2010.

One of the world's best known renegotiations of the last few years involved the world's largest PSC, the one covering the Kashagan field in Kazakhstan. There the heart of the problem was the concept of cost recovery, under which a large percentage of production, known as cost oil is allocated off the top to the contractors to recover their costs. In the case of Kazakshstan, that percentage was 80 percent. After allocation of that 80%, the remaining production, known as profit oil, was allocated initially 90% to the contractor and 10% to the State, a ratio that was eventually supposed to change in favour of the State based on a set of complicated triggers set forth in the agreement. Until then, the contractor would continue to receive 80% of the cost oil and 90% of the profit oil, or 98% of the total production.

Despite what many feel is a typical alignment of interests in a contract including such cost recovery provisions, experience shows that this structure is a recipe for disaster, and that is exactly what happened in Kazakshstan. Overall costs of the project increased by more than 100 billion dollars, and production, originally scheduled to start in 2005 or 2006 is now scheduled for 2012. The net result was that in the world's largest discovery in recent times, which is expected to produce 1.5 million barrels per day, the state would have received a grand total of 2% of the oil produced for at least the first decade of production, not including the relatively small participation of a subsidiary of the national oil company in the contractor consortium. The government of Kazakshstan it an unacceptable situation, which most people with knowledge of the facts fully recognized. In the renegotiation, the national oil company's subsidiary doubled its stake in the project, a new priority share was allotted to government off the top, and new cost and schedule control mechanisms were introduced to help guard against future cost increases and delays (Curtis, 2010).

Crafting agreements with the right combination of stability and progressivity is one of the industry's important challenges (Daniel, 2008). While the host government may exercise the right to renegotiate its contractual terms, the oil rich developing countries in need of foreign investments stand the risk of losing development of their oil reserves as a result of frequent contract renegotiations. The oil companies are in business to make money and hence are constantly in search of where their returns will be highest. In this regard, Shell's Director of Projects and Technology has this to say: "in the upstream, we have shifted our portfolio more to Organization for Economic Cooperation and Development (OECD) countries to balance the risk in the overall portfolio. We have clearly seen that over the past few years as oil prices rose, returns in the non-OECD countries deteriorated compared with those in the OECD. Our upstream strategy is underpinned by a very active and aggressive exploration approach" (Matthias, 2011). Alfred (*Alfred, 2004) compared profitability from a number of oil producing countries to underscore the importance of fiscal regimes in the upstream project economics. The result summarized in Fig. 1, shows that* a 25 million barrels field in Ireland gives the same profit after tax for the oil company as a 104 million barrels field in Nigeria and the IOCs have access to such analysis. Hence, there is no doubt that investments in the sector by overseas companies will be reduced.

An independent assessment based on the deterministic and probabilistic modelling of the impact of the fiscal provisions in the PIB on offshore exploration and production economics and system measures shows that the government take is 89% in the deterministic case and for the stochastic case at 50 per cent confidence, government take ranges from 87% to 90% with the most likely being 88% (Iledare, 2010).

6.0 CONCLUSION

Petroleum has a major impact on every aspect of our socio-economic life. It plays a vital role in the economic, social and political development of the nation. Thus the current debate on the PIB deserves extensive analysis by all in order to arrive at positions that will be most agreeable to stakeholders in balancing government objective of maximizing revenue and IOCs objective of maximizing present value of their income from the exploration and production activities.

The PIB came about in order to improve on the general efficiency of the petroleum sector. The present legislations and especially the fiscal regimes are no longer in tune with the current realities of Nigeria and international best practices in the oil and gas industry. The agreements were negotiated when oil prices were very low compared with current oil prices. Given that petroleum business is an international subject, experts in the field are of the opinion that petroleum contracts could indeed be renegotiated. Therefore, the IOCs need to cooperate with government to find a lasting solution to the problem.

However, in renegotiation, government should also bear in mind that ventures in the petroleum sector are of a high risk nature in the physical, commercial and political sense as it is difficult to determine in advance the existence, extent and quality of the reserves as well as production costs and the future price in the world market. Profitability is not assured even though the IOCs are in business to make profit. Hence care should be taken so the review of the fiscal regimes does not become counterproductive by reducing investment inflows into the sector and subsequently jeopardize the socio-economic development aspirations of the country. The challenge of an efficient fiscal system is to induce maximum effort from the oil companies while ensuring that the government is adequately compensated.

Table 1: Royalties Payment in Nigeria

S/No.	Location	Water Depth, metres	Rate, %
1.	Onshore	0	20
2.	Offshore	0 - 100	18.5
3.	Offshore	100 - 200	16.67
4.	Offshore	201 - 500	12
5.	Offshore	501 - 800	8
6.	Offshore	801 - 1000	4
7.	Offshore	> 1000	0%

Sources: FGN (1999), Omorogbe (2005)

Table 2: Profit Oil Percentages

S/No.	Cumulative Production (million barrels) from	Contractor	Government
1.	0 - 350	70	30
2.	351 - 750	65	35
3.	751 - 1000	52.5	47.5
4.	1001 - 1500	45	55
5.	1501 - 2000	35	65
6.	> 2000	Negotiable	Negotiable

Source: Omorogbe (2005)

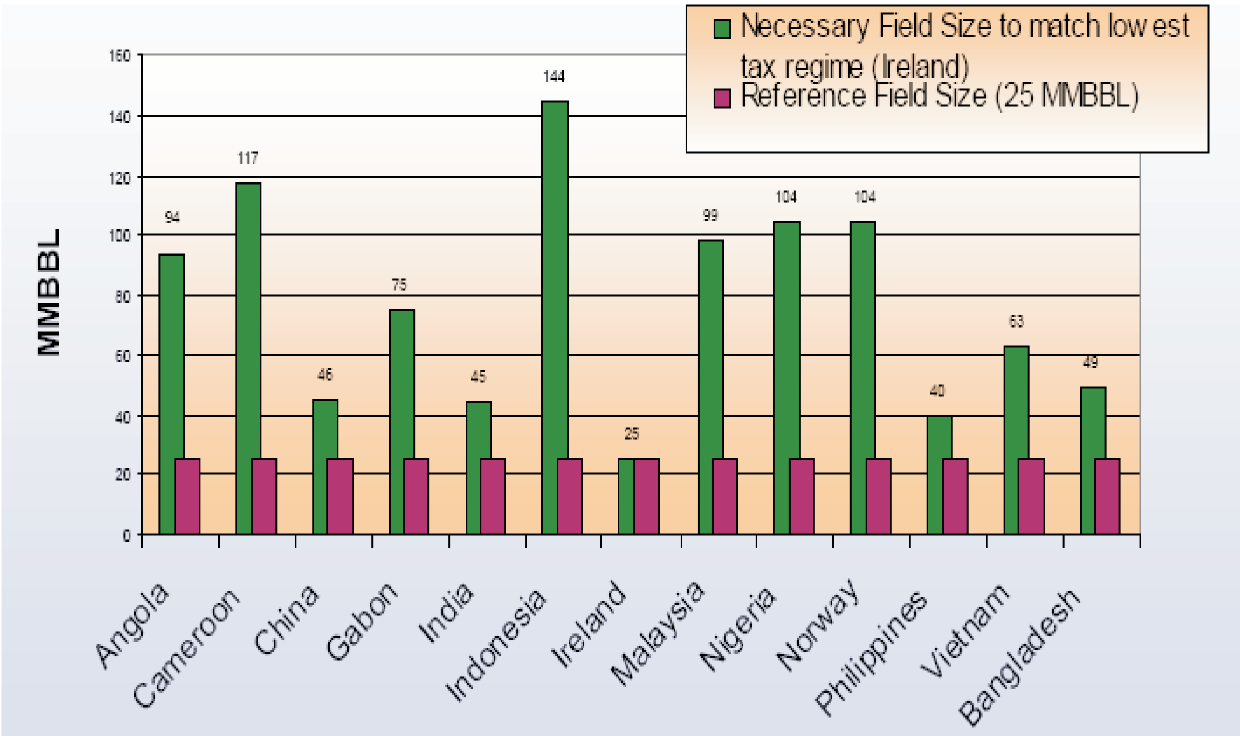

Fig. 1: Value of Discovery after Tax
Source: Alfred Kjemperud, 2004

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