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AN EVALUATION OF GHANA'S PETROLEUM FISCAL REGIME

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ABSTRACT

Ghana is poised to be one of the fastest growing economies in Sub-Saharan Africa because of its emerging oil and gas industry. Yet, questions have arisen as to whether Ghana is getting its fair share of the reve-nues from exploiting its hydrocarbon potential. We review Ghana's petroleum fiscal regime as of the year 2010, compare its key features with that of a peer group of oil and gas producing countries, and assess the regime against five key concepts: progressivity, stability, flexibility, neutrality and risk-sharing. The key findings are that Ghana's fiscal regime based on "work-program bidding", has minimum front-loading charges, guarantees minimum State take, rates favourably on flexibility and neutrality, and is progressive in its basic structure. On the surface, when compared with a peer group of countries in Sub-Sahara Africa, Ghana's regime appears reasonably competitive. But the risk of revenue delay is high and the degree of progressivity is weakened somewhat by the absence of cost recovery limits, the weak thin capitalization provisions, and the weak capacity for verification and monitoring of contractors' costs and investments. Several elements of the regime are also open to contractual variation, leaving Ghana's take of resource rents subject to potential ad hoc negotiation. The complexities of the industry notwithstanding, it is useful to standardize the key features of the regime in legislation in a way that defines the scope of discretion in the contracting process. There is scope to improve government take if the expected legislative revisions guard against open ended exemptions, allowances, withholding taxes and cost recovery measures that further compromise the progressivity of the fiscal regime.

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1. INTRODUCTION

Who gains the most from the exploitation of a nation's non-renewable resources when the owner is not the resource developer or producer? The gains come in many forms, but the revenue sharing as defined by the fiscal regime is arguably an important predictor of the distribution of benefits. Petroleum fiscal regimes refer to the fiscal instruments and the contractual framework, which define a host country's share of the wealth accruing from petroleum production through a host of instruments – bonuses, royalties, profit oil, taxes and government participating interest. Several considerations go into the design of the fiscal regime, a key one being the relative development of a country's petroleum industry. Petroleum fiscal regimes for countries that have a mature status as oil producers typically tend to give a higher government take compared with those that have fewer discoveries or those that are still trying to attract investments (Johnston, 2007). Fis-cal regimes are also affected by the geological promise of the area and the type of contractual policy framework that governs petroleum activities (Johnston, 2007, Nakhle, 2010).

There are three broad strategic options that a country can choose from to design its petroleum production policy framework: (a) a 'go-it-alone strategy' in which the State undertakes production by itself through a national oil company, such as in Saudi Arabia; (b) the State grants entire private ownership and the oil companies have full control over the operations (mainly in OECD countries); and (c) a cross between the two in the form of partnership of sorts between the State and the private oil companies to undertake pro-duction- the most popular choice for non-OECD oil producing countries.[1] Ghana's policy framework follows the latter option.

The objectives of this paper are threefold: first, to review Ghana's current upstream fiscal regime; second, to provide a comparative examination of Ghana's fiscal regime against a peer group of petroleum producing countries in Sub-Sahara Africa (SSA); and third, to determine how Ghana's fiscal regime holds up against five key features of importance to government and prospective investors: the degree of progressivity, stability, flexibility, neutrality and how the regime distributes the burden of risk between the resource owner and the oil companies. The rest of the paper is organized as follows. Section 2 outlines the nature of upstream fiscal arrangements and the instruments that make up Ghana's fiscal regime. Section 3 makes comparisons with a sample of regimes, particularly from SSA, focusing on their capture of rents and gov-ernment take, cost containment and cost recovery provisions, avoidance of revenue leakage, income or profit tax provisions and administrative simplicity. Section 4 evaluates Ghana's fiscal regime against the five commonly used concepts. The conclusions follow in section 5.

2. THE UPSTREAM FISCAL ARRANGEMENTS

2.1 World Fiscal Arrangements

As noted earlier, a variety of upstream fiscal arrangements exist in many oil-producing countries. The up-stream arrangement a country chooses has effect on the range of fiscal instruments that can be applied to the petroleum operations. In the instance where the State uses the go-it-alone strategy, the State bears all the risks of exploration and production, profit oil fully accrues to the State and thus renders a fiscal re-gime almost irrelevant as there are no private companies with which the profit oil will be shared. In the case of entire private control, the private operator bears all the risks and the state take comes through a combination of lease sales, income tax, special petroleum taxes and royalties in what is referred to as the Concessionary or Royalty/Tax systems. A blend of the two is the joint venture where the State and International Oil Companies (IOCs) share in varying degrees the risks of exploration, development and production in proportion to their equity share. The instance of State partnership with private oil companies is usually achieved with the State establishing a National Oil Company (NOC) to act on its behalf as a partner with material, capital and technical expertise in the petroleum operation. The latter known as contractual legal regime has been implemented under two families: Production Sharing Contract (PSC) or a Risk Service Contract (RSC). In the PSC, the ownership of the resource remains with the State and the IOC is contracted to develop and extract the resource in return for a share of production. Typically the IOC finances all exploration, and, if oil is found in commercial quantities, part of development and production costs. The government and the IOC each take a share of the profit oil after cost recovery according to an agreed formula. Under RSC the IOC is paid a service fee - in cash or in kind - by the host government to conduct petroleum operations. The service fee can be fixed or linked to profits.[2]

While different families of oil contracts exist, Johnston (2007) remarked that the type of system may matter less than other design elements, including especially the design of the fiscal system. The fiscal regime consists of a variety of tax, non-tax instruments and cost recoverability provisions. Multiple fiscal instruments may be needed to create an identity of interest between the government and the IOCs over the life of the agreement. Production-based instruments, such as royalties can ensure the government receives at least a minimum payment for its mineral resources. Profit-based instruments on the other hand allow the govern-ment to share in the upside of highly profitable projects, but they also increase the government's share in the project's risk inasmuch as the government may receive no revenue if the project turns out to be unpro-fitable (Tordo, 2007). Increasingly, newly prospecting countries tend to favour the PSC because this option obviates the need for host countries to commit scarce funds up front for exploration. This is also a preferred option by the IOCs because it gives them reasonable autonomy in operations.[3]

2.2 Ghana's Fiscal Regime

Ghana has opted for a hybrid system of production sharing and concessionary regime to govern contractual arrangements in the upstream petroleum industry. The fiscal terms are contained in the Petroleum Ex-ploration and Production Law (PNDC Law 88) and the

Box 1: Ghana's Petroleum Fiscal Regime

- Royalty on Gross Production of Crude Oil
  - Percentage varies from block to block, water depth dependent, but not fixed in current law.
  - Ranges from 5% - 12.5% of gross production of crude oil, 3% of gross volume of gas production.

- State Initial or Carried Interest
  - State receives a 10% interest in each contract area. This interest is "carried" during the exploration and devel-opment phases. All the risk of exploration and development is borne by IOC's equity since the latter finances both the exploration and development costs.

- State Additional Interest
  - If a discovery is in commercial quantities, the State is entitled to buy additional interest in each contract area, for which it is responsible for full costs during development and production phases. The allowable percentage of this interest varies for each contract.

- Petroleum Income Tax
  - Petroleum Income Tax Law (PITL) sets default rate at 50%, but can be altered by contract.
  - In Jubilee, the rate has been set at 35%, 10% higher than the corporate profit tax rate.

- Additional Oil Entitlement (AOE)
  - An additional payment to be made to the government if the post tax rate of return for a project exceeds a tar-geted level. Trigger points at RORs of 12.5%, 17.5%, 22.5%, and 27.5%. AOE terms have become more pro-gressive over time.
- Other Taxes and Fees
  - Including surface rental fees and a 5 percent withholding tax on subcontractors.

- Cost recovery, Deduction and Cost Containment
  - Unlimited carry-forward of losses under PITL.
  - 5-year straight-line depreciation of exploration and development costs and other capital expenditures, including buildings, transportation and communication facilities.
  - PITL contains no provisions against transfer pricing, although the Internal Revenue Act (Act 592) contains provisions to deter abusive transfer pricing.
  - PITL provides no limitation on treatment of interest expense and no withholding taxes on interest and dividend payments.
  - PITL levies a withholding tax on payments to subcontractors - both resident and non-residents - but provides a waiver where the subcontractor is an affiliate for contractor whose services are provided at cost.
  - PITL contains no provision for decommissioning costs, but the proposed exploration bill make provisions and such costs shall be deductible expense.
  - Both the PITL and the IRA impose limited ring fencing.
  - Exclusion of taxation of capital gains.

- Stability clauses relate to protection from tax regime changes as provided in petroleum agreements.
- All gas is the property of the State.
- Contractor funds all exploration and funds development and production expenses less the extent of the State's initial carried and additional participating interest.

Table 1: Ghana: Summary of Fiscal Terms in Petroleum Agreements

	Lushann Eternit Saltpond Oil and Gas Field July 2004	Vanco Energy/ Lukoil (Deep) August 2002 (Existing)	Vanco Energy/ Lukoil (Deep) (Draft New Agreement)	Kosmos Energy HC Consortium (Deep) May 2004	Vitol Upstream (Deep Terms) March 2006	Vitol Upstream (Shallow Terms) March 2006	Hess Corporation (Deep) July 2006
ROYALTY	3.0%	5.0%	10.0%	5.0%	7.5%	10.0%	4.0%
INITIAL PARTICIPATION	15.0%	15.0%	15.0%	10.0%	10.0%	10.0%	10.0%
ADDITIONAL PARTICIPATION	0.0%		5.0%	2.5%	5.0%	5.0%	3.0%
ADDITIONAL OIL ENTITLEMENT:	12.5%						
Rate of Return Thresholds					10.0%	10.0%	5.0%
14.0%							
17.5%					12.5%	12.5%	10.0%
18.0%							
19.0%							
20.0%		7.5%	7.5%				
22.5%					16.0%	16.0%	15.0%
23.0%							
25.0%		12.5%	12.5%	7.5%			
27.5%					20.0%	20.0%	20.0%
28.0%							
30.0%		20.0%	20.0%	15.0%			
32.0%							
33.0%							
35.0%		25.0%	25.0%				
38.0%							
40.0%		30.0%	30.0%	25.0%			
SURFACE RENTALS ($/ sq km) per annum							
Initial Exploration Period		20	30	20	30	30	30
First Extension Period		40	75	25	50	50	40
Second Extension Period		75	75	30	75	75	75
Development./Production Period	50	100	100	100	100	100	100

	Tullow Consortium Tano (Deep) 19th July 2006	Tullow Consortium Tano (Shallow) 21st July 2006	Gasop Oil Saltpond 28th July 2006	Vitol Upstream South Cape Three Points (Deep) 30th June 2008	Oranto International/ Stone Saltpond 3rd July 2008	Afren plc./Mitsui Consortium Keta Amendment 2 13th August 2008	Aker ASA/Chemu Power South (Deep) Tano 5th November 2008
ROYALTY	5.0%	5.0%	5.0%	12.5%	12.5%	10.0%	10.0%
INITIAL PARTICIPATION	10.0%	12.5%	10.0%	10.0%	10.0%	10.0%	10.0%
ADDITIONAL PARTICIPATION	5.0%	10.0%	10.0%	10.0%	10.0%	15.0%	15.0%
ADDITIONAL OIL ENTITLEMENT:							
			10.0%	15.0%	15.0%		10.0%
14.0%						12.0%	
17.5%			12.0%	17.5%	17.5%		12.5%
18.0%		10.0%				16.0%	
19.0%	5.0%						
20.0%	10.0%						
22.5%			17.5%	20.0%	20.0%		20.0%
23.0%		15.0%				22.0%	
25.0%	15.0%						
27.5%			22.5%	25.0%	25.0%		30.0%
28.0%		20.0%				28.0%	
30.0%	20.0%						
32.0%						33.0%	
33.0%		25.0%					
40.0%	25.0%						
SURFACE RENTALS ($/ sq km) per annum							
Initial Exploration Period	30	75	30	30	30	40	30
First Extension Period	50	75	40	50	50	40	50
Second Extension Period	75	75	50	75	75	75	75
Development./Production Period	100	100	100	100	100	100	100

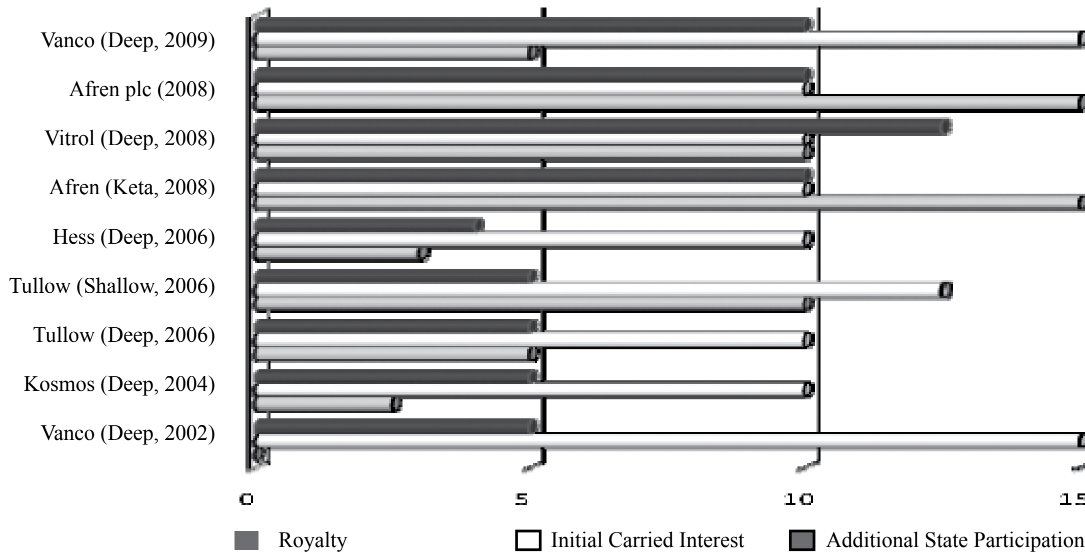
Notes: Corporate income tax is fixed at 35% under all contracts. There is also training allowance set as an annual fee for IOC and varies from $50,000 to $300,000 plus a one-time technology allowance ranging between $200,000 to $500,000 (hardly the equivalent of a signature bonus).

Source: GNPC

Positive Features

The following positive features are noteworthy. First, there are no bonuses or major stock or up-front payments.[5] Ghana's share of revenue therefore accrues from a stream of payments over time and is sensitive to variations in quality and to changes in prices and costs. The training allowance of between $50,000 - $300,000 and the technology allowance hardly amounts to what one might refer to as signature bonus.

Figure 1: Royalty, State Participation (percent): Selected Contracts



Source: GNPC

Second, it provides for the payment of an ad-valorem royalty which guarantees a minimum State take. For the existing con-tracts, this ranges from 5% to 12.5% of gross production, and as seen from Table 1 is water depth dependent, with higher royalties for more recent agreements (Figure 1), reflecting perhaps the greater prospects of Ghana's deepwater exploration.

Third, the State has participating interest in the form of the initial carried interest, under which the State pays only for its proportionate share of production costs, and the additional participating interest, under which the State pays for both devel-opment and production costs. The initial interest has varied in the range 10-15% and, as we see in Figure 1, the additional interest has risen over time from 2.5% to 15%, together bringing State's interest across agreements in the range of 12.5% – 30%. Fourth after the payment of royalties, an allowance for cost recovery deductions by the companies and the sharing of oil in proportion to the equity interest, the oil companies are subject to a corporate income tax of 35%.

Fifth, the fiscal regime provides for additional oil entitlements to the State when the petroleum project achieves a certain level of profitability. This is an important fiscal provision intended to capture a share of resource rents, thus ensuring progres-sivity in the

State's take.[6] By its design, it is a self-adjusting provision that allows the State's share of revenue to rise in the event of high level of profits without modifying the fiscal regime. As we see from Table 1, except for the Jubilee I partners – Kosmos and Tullow - subsequent agreements (for example, Vitrol, Hess Corporation, Oranto, Afren and Aker ASA) have lowered the rate of return accumulation rates and the tax rates have risen, accentuating the progressivity of the fiscal regime (to which we shall return later). State participation through the NOC also increases the level of government take as profit oil is shared between the partners engaged in the production.

Some Potentially Negative Features

Much of what we identify as negative features of the fiscal regime are contained in the Petroleum Income Tax Law, 1987 (PNDCL 188) which is intended to deal with the accounting and taxation peculiarities of upstream activities. First, there is no limit on the deductibility of interest expense. The deductibility of interest expense in financing petroleum operations (the so-called thin capitalization provisions) presents a major challenge for many countries. Because interest on money borrowed for the purpose of earning income is generally deductible in determining taxable income, the greater the quantity of debt held relative to the value of equity, the greater the interest deduction is likely to be. The absence of any limitations on debt-equity ratio means that contractors may strip profits by charging excessive interest cost.[7] Thin capitalization provisions provide a way, albeit an imperfect one, of preventing IOCs from avoiding domestic corporate income taxes. The absence of any thin capitalization provisions in Ghana's PITL is a potential setback to government's ability to capture rent. While the Internal Revenue Act (IRA), 2000 (Act 592) contains a thin capitalization provision of 2 to 1 debt to equity ratio, that provision to date is not applicable to petroleum operations, nor is it enforced in the case of mining. Even when the planned repeal of the PITL is carried out and petroleum income tax provisions folded into the IRA, it is unlikely to have any consequential effect because of the fiscal stability provision in existing petroleum agreements.

Second, and closely related to thin capitalization provision, is the fact that the interest expense and dividends are not sub-ject to final withholding tax. What that means is that a contractor with high debt to equity ratio will most likely understate taxable income through the deduction of high interest expense and as a result be able to shift profits to a foreign jurisdiction at the expense of the host country. No less worrisome is the provision that withholding taxes "may be waived …where the subcontractor is an affiliate of the contractor whose services are charged to the contractor at cost" (PITL(1987) Section 27). Surely, this is an invitation for abusive transfer pricing because it is difficult to determine whether a related company is providing services, especially management related expenses, at cost (McPherson et. al., 2009).

Third, and most contentious, is that the withholding tax on employees may be subject to individual contractual variation (PITL (1987) Section 28). Since most industrialized countries tax foreign income but give tax credit for taxes paid to foreign governments, it seems unreasonable that there should be a leeway for exemption from taxes on income earned within a country's borders, if we consider that the percentage of income paid to expatriate employees may be considerable. Anecdotally, even the 183 days residency requirement is routinely breached or not enforced.

Fourth, ring fencing refers to a limitation on consolidation of income and deductions for tax purposes across different activities, or different projects undertaken by the same taxpayer. In the Ghanaian fiscal regime, consolidation of companies under common control is not permitted. However, the regime permits cost recovery deductions from one license area against production from another license area by a single company. The downside of this is that even this limited ringfencing provision can lead to revenue delays for the government because an investor who undertakes a new project will be able to deduct exploration or development expenditures from the new project against the income of existing projects that are generating taxable income. But strict ringfencing may not necessarily be appropriate either. More exploration and development can be stimulated if taxpayers are allowed a deduction against current income, which will generate more government revenue in the long run as the taxable base increases. The choice between opting for modest early revenues as against higher revenues in the longer term depends on the government's fiscal objectives and preference. One safeguard against current revenue losses to government is the use of cost recovery limits, which is noticeably absent in Ghana's regime. The implication here is that, net of royalty as a percentage of production volume, the rest of annual production could be devoted to cost oil, if required, leaving zero profit oil.

Fifth, transfer pricing concerns the act of pricing of goods and services given for use or consumption to a related party (e.g. subsidiary of a company). Governments try to discourage transfer pricing manipulation which occurs when a company fixes the transfer price on a non-market basis resulting in saving the total tax liability of the company by shifting accounting profits from high tax to low tax jurisdictions. Most countries have explicit provisions in their tax laws enabling a price adjustment to be made where under or over-pricing between related companies results in a lowering of taxable profits. There are no such explicit provisions in Ghana's PITL. The Petroleum (Exploration and Production) Law (PNDCL 84) contains a weak provision: "…petroleum operations to be carried out under this Law shall be on the basis of prevailing international competitive prices and such other terms as would be fair and reasonable..."[8] It is the Internal Revenue Act which contains a provision that gives the revenue authority powers to deter abusive transfer pricing (McPherson et. al, 2009). Similar provisions should be echoed in the PITL. The capacity to enforce such provision is however doubtful.

And finally, as seen from Table 1 and as Heller and Heuty also point out in this volume, the regime does not provide for standardization of the fiscal terms. And with no apparent safeguard for contract transparency, this leaves the State's take of the resource rents from petroleum production subject to potentially ad-hoc negotiations with IOCs, vulnerable to corruption, and susceptible to sub-optimal financial outcomes. Most countries no doubt leave some terms up for negotiations on a contract-by-contract basis to facilitate competition among bidders and also to tailor fiscal relationships to the peculiarities of the individual blocks. But it serves the resource owner's interest if the negotiable terms are small and a core is established firmly in law.[9]

The above cataloguing of the shortcomings and the potential profit-stripping avenues call attention to the role of the NOC on the Joint Management Committee (JMC). The JMC is expected to oversee and supervise all petroleum operations, in-cluding budgets that will be implemented by the international contractors.[10] How the JMC operates and the ability to oversee its activities are crucial for cost containment. As we see from the comparative analysis to follow, the absence of cost recovery limits in Ghana's fiscal regime may be justified by how the JMC is expected to operate. Be that as it may, there is concern as to whether the equality of representation on the JMC necessarily amounts to equality of capacities to verify the complex variables of costs and investments. In addition to the imbalance of capacities, the skepticism should come as no surprise because while the ultimate responsibility for cost control may lie in principle in the hands of the JMC, the day-to-day operations and control of costs and expenses remain the responsibility of the contractor.[11] To use the description by Johnston (1994), the bottom line of all this is a financial issue that boils down to the incentives signaling for continued exploration, how costs are recovered and contained, how revenue leakages are safeguarded, profit divided, and rent captured. Of additional interest here is the extent to which Ghana's fiscal system (a) stands against those of other countries in terms of the foregoing considerations and (b) judged on its own, its progressivity, flexibility, neutrality, stability and risk-sharing features.

3. COMPARATIVE ANALYSIS OF FISCAL REGIMES IN SUB-SAHARA AFRICA

Comparison of fiscal systems is always a difficult exercise. Fiscal systems are multi-dimensional, reflecting the diversity in political economy and political risks, in costs and reserves potential, whether offshore or onshore, as well as the time when contracts were negotiated. Features of fiscal regimes for newly-emerging producers are likely to be more investor friendly than fiscal regimes in well-established petroleum producing economies. What the countries selected here have in common is that they are all in Sub-Saharan Africa (SSA) and one will reasonably assume that the political risks that investors face are not too dissimilar, and what investors care most are the political risks and an inefficient rent-collecting fiscal regime. The countries selected are in three categories: (a) oil revenues account for nearly half of all revenues in Nigeria, Angola, Congo, Equatorial Guinea and Cameroon and these are also established producers; (b) Ivory Coast as Ghana's neighbor with potential trans-boundary links to the Ghana's Jubilee field; and (c) Uganda as a newly-emerging producer and likely faces technical and economic challenges similar to Ghana. Table 2 summarizes some of the key fiscal instruments, and they are by no means uniform. Clearly there is no single vector of information that tells whether a country got a better deal than the other. Our goal therefore is simply to look at the features of the range of various instruments.

3.1 Signature Bonuses and Front-Loading Fees

Fiscal regimes in some countries provide for a number of front-end bonuses to be paid to the State at different stages of project development. In our sample in Table 2, there are three main types of bonuses, namely; signature bonuses, produc-tion bonuses and commercial discovery bonuses. The major oil-producing countries - Nigeria, Angola, Congo and Equatorial Guinea levy some form of bonuses. In Nigeria and Angola, signature and production bonuses are water-depth dependent, and in Equatorial Guinea bonuses are linked to some predetermined level of production. From a public finances standpoint, what is good about bonuses is that they serve to bring forward revenue receipts for the State and shift risks to the investor. Less desirable however is that they tend to be regressive especially as in Ivory Coast where signature bonus is not tied to any level of activity. Currently bonuses - be they signature, commercial or production are not part of Ghana's fiscal regime. Competition for blocks is based rather on "work program bidding" – namely, the competitiveness of a plan for profit maximi-zation of a particular block.

3.2 Royalties

Royalty rates vary: they may be negotiable as in Ghana and Cameroon, fixed as in Ivory Coast and Equatorial Guinea, or set between a specified range in other countries based on production capacity (Uganda) or water depth (Nigeria and Ghana). The Ghana Model Petroleum Agreement stipulates a royalty rate of 12.5% of gross production.[12] However, as seen in Table 1, actual agreements signed have levied rates ranging between 3% and 10% depending on the technical risk and the pros-pectivity of the block concerned measured by water depth and the API gravity (or crude sweetness). Rates between 3% and 5% have been applied to Deep Water and marginal blocks, and 10% for Shallow Water operations.[13] Ghana's high end rate of 12.5% matches Uganda's high end for production in excess of 7000 barrels per day. Unlike Ghana's straightforward fraction of production volumes, Uganda relies on progressive sliding royalty between 5 and 12.5% which adjusts upward on the increments when production rises and vice versa. Well productivity acts as proxy for resource quality. Ghana's rate is also lower than Nigeria's 20% for onshore production, 10% for inland basins and depending on water depth from 8% to 18.5% for offshore production.[14] [15]

Table 2: Key Features of Fiscal Regime for Selected Sub-Saharan African Countries

	Nigeria	Angola	Cote D'ivoire	Congo	Cameroon	Equatorial Guinea	Uganda	Ghana	World Average Fiscal Terms
Bonuses	Signature Bonus: Offshore Up to 200ms \$10m Up to 500ms \$20m Up to 800ms \$25m Up to 1000ms and beyond \$20m Production Bonuses: at 50mm bbls 0.2% of price; at 100mm bbls 0.1% of price.	One of three bid items in acreage auction may vary by contract. Signature Bonus: \$10- \$70million. Signature bonuses for 3 ultra deep water blocks in the 1999 licensing round stood at \$300 million each. Production Bonus: Up to \$12 million	Negotiated. However, model contract provides for \$12 million	None	None	Signature bonus: \$0.5mm Commercial Discovery Bonus: \$1mm Production bonuses: \$2mm at 20,000 bpd. \$5mm at 50,000 bpd. Production bonuses recoverable	\$0.5m to meet administrative cost. Amounts may vary	None	
Royalties	Water depth dependent <100ms: 18.5% Up to 200ms: 16.67% Up to 500ms: 12% Up to 800ms : 8%% Up to 1000ms: 4% Deep offshore: 0%	Established by law	None	15%	Royalties are negotiable-a closing item after investors have been guaranteed a minimum share of profit before tax	10%	Daily production dependent (bbls) <2500: 5% 2500<p<5000: 7.5% 5000<p<7000: 10% p>7000: 12.5%	12.5% of gross production of crude oil (a number of existing agreements put this figure at 5%)	World average is about 7%. Most systems have a royalty or effective royalty rate due to the effect of cost recovery limit.
State Participation (the maximum equity share the State can take)	Variable	25%	Up to 20%; 10% initial interest; additional 10% interest carried through exploration and development. Reimbursed from State's share of proceeds, includes interest at LIBOR + 1%	---	State participates in a commercial discovery up to 50% on a carried basis	---	15%on carry forward basis including interest rate at LIBOR from production	Initial State Participation through 10%-15% carried interest through production. Additional participation varies from agreement to agreement and has varied from 2.5% - 15%	Typical average is around 30%. Approximately 50% of countries with option to participate are carried through some stages of petroleum activities.

Table 2: Key Features of Fiscal Regime for Selected Sub-Saharan African Countries

	Nigeria	Angola	Cote D'ivoire	Congo	Cameroon	Equatorial Guinea	Uganda	Ghana	World Average Fiscal Terms
Cost Recovery and other investment incentives	Current expensing of exploration and/or development costs, with provision for tax credits Duty exemption for imports of equipment and capital goods	Normally 50% of production expensed (up to 65%) Includes uplift on CAPEX (20-50%) Depreciation over 4 years. Duty exemption for imports of equipment and capital goods	Negotiable. Indicative cost recovery ceiling may range from 40% of gross production in shallow water to 75% (or even 80%) in deep water. Duty exemption for imports of equipment and capital goods	Current expensing of exploration and/or development costs Cost recovery limit of 70% Duty exemption for imports of equipment and capital goods	Current expensing of exploration and /or development costs No cost recovery limit	Current expensing of exploration and/or development costs No cost recovery limit	Current expensing of exploration and/or development costs. 60% cost recovery limit (CAPEX and OPEX) is allowed. Decom-missioning costs deductible from income. Duty exemption for imports of equipment and capital goods. Excise duty and VAT applicable on all procurements	Current expensing of exploration and development expenses by 5-year straight-line depreciation. No explicit cost recovery limit Decommissioning costs deductible from income. Exemption of customs and other duties on imports of equipment. Foreign national employees of contractor or its affiliates exempted from the payment of taxes and other duties on imports of personal and household effects	Average 65%. PSA's have limits mostly based on gross revenues. Over 20% of countries have no cost recovery limits. World average on depreciation is 5-year straight-line decline for capital costs Most countries (55%) erect ringfence or a modified ring fence (13%) around contract area.
Tax Allowance	50% Credit in Capex for Pre-1998 Contracts. 50% Allowance on Capex for post 1998 Contracts	40% uplift on capital expenditure	N/A	N/A	N/A		N/A		
Income Tax	Petroleum profit tax of 50%, 85%	50%	27%	35%	57.5%/48.65%	25%	30%	Fixed at 35% since 1990s	Average 30-35%
Withhold'g tax	Uganda: 15% applicable on dividend payments, management fees and interest and service delivery. Ghana: 10% withholding tax on amounts due to sub-contractors as specified in the Petroleum Agreement 2010 Budget recommend 15% No comparable data for other countries								

Table 2: Key features of Fiscal Regime for Selected sub-Saharan African Countries

	Nigeria	Angola	Cote D'ivoire	Congo	Cameroon	Equatorial Guinea	Uganda	Ghana	World Average Fiscal Terms
Profit Oil	Profit oil split to government:	Profit oil split to government subject to contract-bycontract variation.	Profit oil split to government:	<20,000bpd at 30%	None	Profit oil split to government:	Profit oil split between State and IOC	Profit oil split between State and IOC based on ROR system (See Additional Oil Entitlement)	Most profit oil splits (about 55-60%) based on production based sliding scale. Others based on ROR system
Additional Oil Entitlement	20% at 350mm bbls 35% at 750mm bbls 45% at 1000mm bbls 50% at 1500mm bbls 60% at 2000mm bbls. Over 2000mm bbls negotiable	<10% ROR at 15% <20% ROR at 30% <30% ROR at 40% <40% ROR at 55% >45% ROR at 80%	<30,000bpd at 40% <50,000 bpd at 44% <100,000 bpd at 46%	<40,000bpd at 50% <40,000bpd negotiable profit oil shares are however biddable		<30% ROR at 0% <40% ROR at 20%-25% <50% ROR at 40%-60% >50% ROR at 60%-80%		See Table 1	
Average Gov't Take	64%-70%	64%	49%	64%	74%-78%		Variable ranges between 43.5% -66%.	Variable: ranges between 38%-50%	
Rentals	**Uganda:** Vary by exploration period: 1st period $2.50 sq km, 2nd period $5 per sq km, 3rd period $7.5 per sq km **Ghana:** Surface Rentals: Initial Exploration Period - US$ 30 per sq km, 1st Extension Period - US$ 50 per sq. km, 2nd Extension Period - US$ 75 per sq km, Devt and production Area - US$ 100 per sq km. Angola's area fees are subject to contract-by-contract variation. No comparable data for other countries								

Notes and Data Sources:
Notations: a) ms means meters of depth, b) m in currency means millions, c) bbls means barrels
Nigeria Signature bonuses and royalties data are taken from Oil and Gas in Africa, Oxford University Press, 2009.
Uganda data taken from Twinamatsiko F. N., Is Uganda's Fiscal Regime Sustainable? An Assessment, University of Dundee
Others: Wood Mackenzie PPT to Petroleum Revenue Management Workshops, Luanda, May 2006 (WB website).
Cote D"Ivoire: Commonwealth Secretariat, Special Advisory Services Division
Nigeria, Congo, Gabon, Cameroon, Equatorial Guinea:
Mineral and Petroleum Taxation: How Attractive are the Fiscal Regimes of the Deepwater Areas Offshore West Africa to Foreign Investment, Odianosen
Data on World Average Fiscal terms taken from Silvana Tordo et. al (2010), Petroleum Exploration and Production Rights, Allocation Strategies and Design Issues, World Bank Working Paper No. 179, 2010, and Johnston (2007)

3.3 State Participation

State participation, or the maximum equity share the State can take, provide options for the host government or the NOC to participate in petroleum activities. This participation usually takes the form of an initial carried and additional participating interest. For Ghana, the Petroleum Exploration and Production Law 1984, gives the State the right to acquire additional percentage interest in the operations of a petroleum project if there is a commercial discovery.

Typically with free carried interest, the resource owner makes no financial contributions towards exploration and development costs. The contractor bears the State's risk and remains responsible for 100% of all costs. However, the State or its agent pays for its proportionate share of production costs on commence-ment of production. This is a way of recovering the State's past expenditures in its exploration and promotion efforts on the block and also reduces Government costs and risks of exploration but increases its share in the rewards of discoveries. Additional participating interest gives the State the right to acquire an additional percentage interest in the project upon commercial discovery.

The majority of countries in SSA have taken steps to ensure some degree of State participation. Known exceptions are Mozambique, Sudan and Egypt.[16] In our sample, with the exception of Congo and Equa-torial Guinea, State participation is a major element of the fiscal regime. The differences clearly reflect the variations in fiscal systems with Nigeria's state equity varying widely among agreements. Ghana's equity share has ranged from 12.5% to 25% compared to, Angola's 25%, Cote d'Ivoire's 20% and Uganda's 15% and only half of Cameroon's ceiling of 50%. Some advantages of government participation are that it increases the sense of country ownership, facilitates transfer of technology and skills and increases the host government's control over field development decisions.

However, government participation through carried interest whereby the investor pays all the costs reduces the investor's cash flow, and from the investor's perspective this may increase the risk profile of the project. The downside with most State participation occurs when the State's interest is paid out of production and therefore the investors have the burden of raising the entire financing for operating and investment costs. For one thing, partners are not bankers and therefore may charge higher interest cost on any carrying arrangements. This is all the more worrisome if there is no limit on deduction of interest expense under thin capitalization provision discussed below. African governments must be proactive in exploring financing options for their equity participation (in place of the traditional "cash call" operations) that best fits the country's overall long-term fiscal and debt management strategy. Cote d'Ivoire caps the interest charges at LIBOR plus one, Uganda at LIBOR to curtail profit stripping.[17]

3.4 Cost Recovery and Cost Containment Provisions

The ability of investors to recover their investments and the ability of the State to control and contain costs are important elements of the fiscal regime. Given the complexity of the industry, African governments are particularly vulnerable to the problems of cost verification, cost overstatement and profit stripping as noted earlier. The challenges range from the monitoring and verification of capital expenditures, loss carryover provisions, transfer pricing mechanisms, ringfencing, and the range and limits of expenses that may be considered deductible for tax purposes.

Some fiscal regimes provide limits on the percentage of crude oil production (after deduction of royalties) that can be used to recover costs. If costs exceed the cost recovery ceiling, the difference is carried forward for recovery in subsequent periods. In our sample, the ceilings range from 40% to 100%. Higher cost recovery limits allow the contractor to achieve payback of its investment faster and therefore serve as incentive for investments. But it also means that the contractor is unlikely to pay corporate tax in the early years of production. This concern may be offset partly by royalty payments which takes effect as soon as production begins.

Uganda provides limitations on cost recovery up to 60% with no uplift on capital expenditures. Cote d'Ivoire's recovery ceiling ranges from 40% of gross production on shallow water to 75-80% in deep water. Congo's recovery ceiling is up to 70%. Angola allows up to 65% of its production to be expensed including a 40% uplift on capital expenditures as tax allowance. It is debatable whether cost recovery limits are necessary in Ghana's case once the competition for blocks has been judged on "work program bidding" which presumably already takes into account the overall profit maximization prospects of a particular block. In which case, what may seem more crucial for Ghana is the "cost stop" elements in the contract– what is allowable cost and what is not. But if Ghana's mining fiscal regime is any indication, the "cost stop" elements in Ghana's petroleum regime, as noted earlier, seem fairly open-ended.

Ghana's PITL allows for; (a) the deduction of capital expenditures, including development costs on a straight-line basis beginning in the year the expenditure is incurred or the year of commencement, whichever is later; (b) losses to be carried forward indefinitely for tax purposes although the Internal Revenue Act allows only a 5-year loss carry forward; (c) deductibility of royalties as expense in determining chargeable income; and (d) exemption of duties and applicable taxes on imports of capital and machinery. The deductibility of royalties in determining chargeable income remains a pernicious provision since "royalty is not paid out of the contractor's share of petroleum".[18] Moreover, there are no sunset clauses in the exemptions regime. In some countries though, these exemptions are limited to the exploration and development phase. There are, however, limitations on ringfencing – that do not permit companies to consolidate income and expenses across activities, but there are no provisions or limitations on transfer pricing, excessive deduction of interest expense or thin capitalization.

3.5 Income Tax

In our sample, this ranges from 25% to 50%. In Ghana's PITL petroleum income tax was fixed at 50% of chargeable income or 'as negotiated in a Petroleum Agreement'. Since the 1990s, a negotiated rate of 35% has been applied in all agreements. The 35% rate is largely in line with that for most of the countries in the sample and, except for Nigeria with tax rate in the range of 50-85%, the 50% fixed in Ghana's old legisla-tion seems to be on the higher side relative to the sample countries. For example Equatorial Guinea, a relatively mature oil producing country, has the lowest income tax rate in our sample at 25% as against the world average of 30-35%. A high corporate tax rate unfortunately diminishes incentives for cost reduction and encourages overstatement of cost to understate profit margin.

3.6 Profit Oil Split

In production sharing contracts, profit oil is the revenue that remains after deduction of royalty and cost recovery. This profit oil is split between Government and the contractor on a pre-determined basis. The alternative to profit-sharing is the gross-production sharing (or Peruvian type PSC) as in Nigeria, Cote d'Ivoire and Congo all of which are on a sliding scale. Tordo (2007) asserts that fiscal systems that use sliding scales based on daily or cumulative production targets are insensitive to changes in prices and costs. Given the price volatility of the oil industry, these systems are more likely to produce a misalignment of interests between host governments and contractors leading to renegotiations. On the other hand, these systems are relatively easy to administer and may prove reasonably efficient in sharing the rent between the contractor and the government when project uncertainty is low.

For PSCs before 2005, profit oil share in Nigeria is based on cumulative production with government share ranging from a minimum 20% to 60%.[19] After 2005, Nigeria's profit oil share is based on ROR factor as in Angola, Equatorial Guinea and Ghana. Angola's structure appears to be more progressive than Ghana's. Angola's minimum profitability threshold is 10% for government take of 15% and a maximum threshold of 45% at a share of 80%. Ghana's minimum threshold for Tullow deep (shallow) is 19% (18%) for government take of 5% (10%). For Kosmos the minimum threshold is 25% for a share of 7.5%. Unlike Angola and Equatorial Guinea, Ghana's maximum profitability threshold for both Tullow and Kosmos is 40% for a share of 25% to the State. ROR based fiscal systems introduce flexibility in the fiscal package to suit the profitability of the particular project. This makes projects under such systems more attractive to contractors and less risky as candidates for project financing. On the down side however, it is relatively more demanding to administer.

3.7 Government Take

Government take, (defined as the undiscounted revenues that accrue to government from all sources as a percent of total undiscounted gross or net revenues of a project) is often taken as a measure of the fairness or attractiveness of a fiscal regime. On the surface, Ghana's 38-50% government take based on Jubilee Phase I at a price of $65 per barrel may be judged too low compared to the government take of 64-70% for Nigeria, 64% for Angola, and 74-78% for Cameroon. However, as Johnston (2007) points out, government take can be a misleading statistic "because it does not take into account factors such as the timeframe for payouts to government and the level of government participation" (p. 56). For example, fiscal regimes with more front-loaded taxes and charges such as Angola and Equatorial Guinea are likely to yield higher government take than a regime with back-end loaded taxes and relies less on front-end instruments like bonuses and royalties. The attractiveness of a fiscal regime may be multi-dimensional. The comparisons in Figure 2 below put Ghana's fiscal regime into some perspective.

In a comparison of fiscal regimes, the Cambridge Energy Research Associates (CERA) placed Ghana among a peer group of 13 deepwater gas producing environments. Ghana in the sample represented a newly emerging producer that lacks the necessary infrastructure and also faces the challenge of developing export markets in the future. Apart from the separate gas royalty which is currently set at 3%-5%, every aspect of the gas fiscal regime is essentially the same as the fiscal regime for oil. By assessing the full-cycle exploration and development economics and at a range of prices, Figure 2 shows Ghana's fiscal regime ranking on the basis of government take, investors' profit to investment ratio, and full cycle rate of return.

Figure 2: Comparison of Fiscal Regime of Natural Gas

Government Take		Company Profit to Investment Ratio (10% real discount rate)		Full Cycle Rate of Return
Sample Countries	**HIGHEST**	**Sample Countries**	**HIGHEST**	**Sample Countries**
Libya		Italy		Ireland
Norway		Ireland		Australia
Egypt		Australia		Italy
Australia		New Zealand		Egypt
Tunisia		Egypt		New Zealand
United Kingdom		Israel		**Ghana**
Ghana		United States		United States
United States		**Ghana**		Israel
New Zealand		Tunisia		United Kingdom
Italy		United Kingdom		Tunisia
Israel		Canada		Canada
Ireland		Norway		Norway
Canada		Libya		Libya
				Norway
	LOWEST		**LOWEST**	

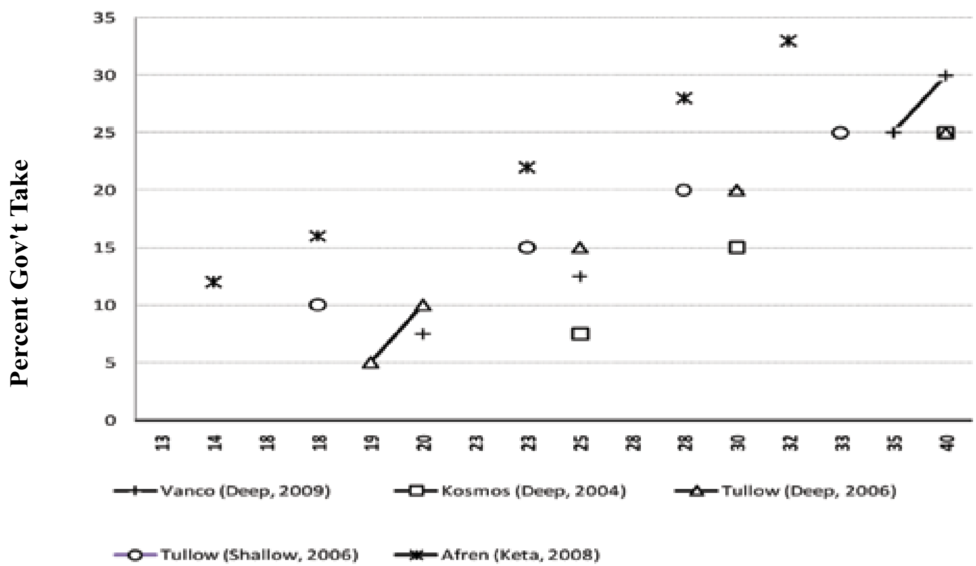
Source: *Adapted from IHS Cambridge Energy Research Associates, published in "A Comparison of Fiscal Regimes: Offshore Natural Gas in Israel" Special Report, 2010*

Based on ranking by government take, Ghana's fiscal regime ranked 7th lowest behind six OECD countries. For the other six countries in the sample, most of them established producers, government take was higher than Ghana. Libya's fiscal regime ranked highest. The last two columns show the ranking based on profit to investment ratio and rate of return, providing a feeling for how quickly investors can get their money back or how long investors can achieve a reasonable return on their investments. Investors' profit to investment ratio ranked highest in Italy and lowest in Libya. Ghana ranked 8th behind OECD countries and, not surprising, as providing more attractive terms than the six other established natural gas producing countries in the sample. As a newcomer with challenges to access to markets, Ghana's fiscal regime appears reasonably competitive and less onerous for investors. It is expected that Ghana's take should increase over time with greater prospectivity, greater clarity about the regulatory environment, and greater predictability of the political environment.[20]

4. EVALUATION

In this section we evaluate the strength of Ghana's fiscal regime on the basis of five key criteria which are important to both the resource owner and contractor; namely, the progressivity, stability, flexibility, neutrality and risk sharing capacity of the fiscal regime. Ideally, a fiscal regime should be sensitive to project profitability, signal greater predictability or minimize policy uncertainties, adequately respond to changes in future market conditions, not distort resource allocation decisions and be equitable in risk sharing between resource owner and contractors. We discuss these in turn.

Figure 3: Additional Oil Entitlement: RoR Thresholds and Percent Gov't Take



Source: GNPC

4.1 Fiscal Regime

A fiscal regime is progressive if the cumulative taxes in the regime are proportional to income and are sensitive to project profitability. Progressivity is important for both contractor and host government. A company will want to pay taxes in proportion to the profitability of its operations or with the level of rents it earns from the operation. Project profitability depends on costs and prices and the government would want to see its take increase as prices improve or as initial costs are recovered making the project more profitable. A progressive regime tends to attract investments for even marginal projects potentially broadening the tax base and eventually resulting in higher government revenues.[21] Progressivity can be attained though a progressive income tax structure, a sliding scale royalty in the case of a concessionary regime, or a progressive government take in the case of production-sharing arrangements. In general, the further downstream the government goes to capture rent, the less regressive the fiscal regime (Tordo, 2010). On that score, additional profit taxes (as in Namibia, Nigeria, and Equatorial Guinea) or contractors' achieved rate of return (as in Angola and Ghana) rank highly under this criterion. Unlike Uganda, the progressivity of Ghana's fiscal regime is captured through the Additional Oil Entitlement (AOE) provision reported in Table 2. Figure 3 shows a sample of the structure of AOE regime in Ghana. Additional payments have to be made to government as soon as the accumulated cash flow becomes positive at the different rate of return thresholds. At which point, investors have already recovered their original investment recoverable in that period. In Figure 3, the lower and the further to the right is the marker, the less progressive is the additional government take in the contract. Progressivity clearly has not been uniform with considerable contractual variation. On that basis alone, the Afren contract for the Keta basin signed in 2008 has a more progressive government take than (a) Tullow contracts of 2006 and 2006, (b) Vanco deepwater contract of 2009, and (c) the Kosmos deepwater contract of 2004 based.

In comparison with Angola, Madagascar and Namibia, McPherson et. al (2009) remarked that Angola and Namibia's rate structure for sharing petroleum profit had a higher degree of progressivity than Ghana, although Ghana's structure has improved considerably between 2006 and 2008 contracts as evidenced in Figure 3. The income taxes also rate highly here as they target economic rent. It is progressive in the sense that it takes effect at the 'back end' when the company has made its allowable deductions and established the magnitude of its economic rents. The key issues for Ghana are in determining the optimal thresholds, the ROR bands, and the applicable progressive take for each contract. In addition, the absence of cost recovery limit in Ghana's fiscal regime, the absence of thin capitalization provisions and hence limits on interest deductibility, compromise the degree of progressivity that can be attained through the income tax and the AOE because of the scope of 'importing' expenses and limiting the tax base.

4.2 Stability

A "stable" fiscal regime is one that does not change over a certain period of time, or whose changes are predictable (Tordo, 2007). Perceptions of fiscal stability influence investor decisions about undertaking production in a country. Given the long term nature of petroleum projects, the fiscal stability over the life time of the project is an important consideration for potential investors. With high volatility of oil prices, it is undesirable for a host government to continuously adjust fiscal regimes based on short-term price movements. For government, a stable fiscal regime is also desirable since it allows for better planning for expected oil revenues.

Contractors have tried to achieve stability of contract terms by negotiating for stability clauses in their agreements with host governments. Stability clauses are of two types: "freezing clauses" that maintain the fiscal terms unchanged typically for the duration of the contract or for a certain period of time, and "equilibrium clauses" that allow for some adjustment that do not have asymmetric benefit or damage to one party.[22] The most important argument for those who favour freezing clauses is that it eliminates arbitrary changes in the fiscal regime to the detriment of contractors. Stability clauses therefore manage political risks, restrain potential 'legislative mischief' and guarantee that contractual terms will remain constant throughout the life of a project, or that any change would require an agreement between both parties before it may be effected (Amaechi, n.d).[23] Two sections of Ghana's Model Petroleum Agreement bear on stability provisions: Article 12.2 with respect to income tax states:

> "Where a new income tax rate comes into force… Contractor shall have the option of either applying the new income tax rate … or remaining under the Petroleum Income Tax Law."

Article 12.11 also states:

> "Should the fiscal authority involved determine that the Petroleum Income Tax Law does not impose a creditable tax, the parties agree to negotiate in good faith with a view to establishing a credible tax on the precondition that no adverse effect should occur to the economic rights of the State".

The stability provision in Article 12.2 with respect to income tax rates is for all practical purposes a "freezing clause". It puts contractors in a stronger position because compliance in the case of upward revisions is not obligatory. It is also asymmetric because the contractor can exercise its option in the event of downward revision of rates. While Article 12.11 stands as an "equilibrium clause", it is potentially an invitation to interpretation disputes between government and contractors about what is a "credible tax". Resource owners may rightfully regard stability clauses that seek to freeze the terms of the contract, regardless of changes in the external environment, or even that provide for some equilibrium clauses, as a potential loss of sovereignty over their natural resources.

The potential for conflicts of interest may gradually be waning, leading to narrower definitions of stability clauses where both parties agree to a possible renegotiation of fiscal terms if the economic conditions go beyond a certain range of outcomes. Even here the specific terms of conditions and definitions must be pre-defined by both parties. For Ghana, if the experience in mining is any indication of the challenges of obsolescing bargain, it is highly unlikely that government would seek to make retroactive changes to existing fiscal regime arrangements. An industry at the early stage of development should focus on building trust and stability and apply any fiscal changes to new licenses and subsequent block leases.

4.3 Flexibility

Flexibility refers to the responsiveness of fiscal instruments to changes in future market conditions – that is the capacity of fiscal instruments to collect a reasonable share of the resource rent over time under a range of future market outcomes (both better and worse than expected outcomes). In general, flexible fiscal instruments limit the need for renegotiation when market conditions change. Profit-based taxes such as the corporate income tax offer more flexibility. This is because the rate is stable over time (the proportion or percentage of income does not change) as market and project conditions which affect profitability change. With this type of tax, the government take varies with project profitability. The flexibility provision in Ghana's fiscal regime lies in the AOE as explained above. Reviewing the provisions in the relevant legislations that weaken the progressivity of the fiscal regime therefore deserve attention for at least two reasons: to limit the adverse impact of fiscal stability clauses, and to preempt the inevitable pressures to modify the original fiscal regime in the event of sustained price increases.

4.4 Neutrality

A fiscal instrument is neutral if an action or project that is assessed to be financially viable in the absence of the fiscal instrument remains viable after the instrument is applied. In other words, a "neutral" fiscal regime neither encourages over investment nor deters investments that would otherwise occur (Tordo, 2007). The neutrality criterion is useful for determining the extent to which the fiscal instruments may negatively affect exploration, development, production and closure decisions.

In general, signature bonuses that are independent of profitability score poorly under this criterion. Output-based royalties can affect extraction decisions and if investors anticipate their impact on profitability it can also affect their decisions on exploration and development. Profit-based taxes and state equity investments instruments rank more highly under the neutrality criterion. This is because the government take from these instruments varies with project profitability. On the surface, Ghana's fiscal regime, with minimum front-end charges and flexible with the State's take adjusting automatically with profitability, can be said to rate favourably on neutrality. But as Mommer (2001) points out a case can always be constructed where any form of taxes and levies can be a disincentive, deter exploration or, even worse, create perverse incentives.

4.5 Risk Sharing

In the exploration and development phase, the investor bears all the risk and during this phase the State has no direct financial risk but it is obliged to monitor the investor's progress in fulfilling the agreed work programme. The State, however, shares in the project risk by virtue of the fact that at the production phase it grants tax deductions for investor's capital costs. Risk is not limited to the exploration phase and even during production, the project is subject to price risks. Nakhle (2010) identifies price risks as occurring when there are sudden significant changes in petroleum prices. Contractors and the State, by virtue of its equity share, also face cost risks in the production phase. These risks can be catered for with cost recovery mechanisms in the fiscal regime. With these potential risks facing the investor, an attractive fiscal regime is one that provides some assurance that there will be sufficient cost recovery allowances to cater for its costs and risks during the exploration and production phases.

On the part of the government, it faces a risk of revenue delay. Hogan and Goldsworthy (2010) explain revenue delay as a situation in which the government does not start to collect revenue until sometime after the project commences. For instance revenue collection can be delayed due to cost recovery mechanisms that give generous capital allowance to investors. The government can also face a risk of fiscal loss. A fiscal loss occurs when the government receives lower than expected returns due to adverse market outcomes.

Stringent stability clauses therefore do not augur well for minimizing the State's risk. Traditional clauses that effectively eliminate the State's powers to change fiscal terms regardless of changes in the economic environment leads to fiscal losses for the State in the event of unanticipated significant improvements in project profitability. For Ghana, the risk sharing on account of the stability provisions in the Tullow and Kosmos agreements is inequitable, especially since the initial fiscal terms granted by the State, arguably, were highly concessional to reflect the prevailing geological risks and Ghana's entry into petroleum produc-tion.

In general, output-based fiscal instruments help to minimize risks of fiscal loss and/or revenue delays to the government and therefore rank highly under this criterion of risk sharing. Although output-based royalties ensure that government gets some minimum revenue in all the years in which production from the resource is positive as well as in years in which losses may occur, Ghana's fixed royalty of about 5% provides a minimum take below other SSA countries and below the world average of 7% as noted in Table 2. Unlike Nigeria, Angola, Cote d'Iviore and Equatorial Guinea, among others, the absence of signature bonuses to generate early revenues for the State also minimizes risks to the investor. Purely back-end loaded taxes may not be ideal as they transfer too much of the risks to the government, especially since companies may manipulate costs and investments which are complex variables with costly verification and monitoring.

Finally, we have discussed how Ghana's fiscal regime rates on these features that are important to both government and contractors as a check list. But, in practice, it makes more sense to think of them as a Venn diagram of varying overlapping circles and mutually reinforcing features. It is a challenging feat to design a fiscal regime that satisfies all of these features satisfactorily and in equal measure. A fiscal regime that is highly progressive may be less neutral and less equitable in risk sharing. In a rapidly changing environment, enhancing flexibility may also mean making it possible to make periodic adjustments to some areas as needed. In fact, it is quite possible that policy-makers do not consciously develop their fiscal re-gime with the view to addressing all these issues in equal measure. Sufficient to achieve a certain measure of intersection, the degree and desirability of which are likely to change over time. To borrow a caution from Brennan and Buchanan (1977), actual fiscal design especially in this context may look more reasonable when the institutional and political realities are considered than they do from an optimal tax perspective. The fiscal regime's adequacy therefore depends on the fine balance which policy-makers put on these features and on what they consider to be the priorities.

5. CONCLUSIONS

Ghana emerged as a new oil-producing country in 2010.The question we have tried to help answer, at least partially, is whether Ghana is getting a fair share of the revenues from petroleum exploitation. Of course, it is not just the revenue shares that constitute benefits. The employment opportunities for Ghanaians during development and production, the profits that accrue to local businesses, the technology transfer skills and know-how matter as well. In this paper we have focused on the fiscal regime, made comparisons of some of its key features with those of a sample of Sub-Saharan African countries, and assessed the strengths of the regime on the basis of progressivity, stability, flexibility, neutrality and its risk-sharing features.

With minimum front-end charges, Ghana's fiscal regime guarantees minimum State take, rates favourably on neutrality and flexibility. While it appears to be competitive against a peer group of SSA, its risk of revenue delay is high. On the surface, Ghana's 38-50% government take based on $65 per barrel may be judged too low compared to the 64-70% of Nigeria, 64% for Angola and 74-78% for Cameroon. But a comprehensive review suggests that the current share is neither the largest nor the smallest, that the percentage take alone is not sufficient to judge the fairness of value sharing. One thing is certain, government share should increase with greater prospectivity, greater clarity about the regulatory environment as Ghana seeks to build political stability at home and trust in the industry. While Ghana's regime by all standards is progressive, it is not the most progressive with competing jurisdictions in SSA. For sure, in the current regime, progressivity is undermined by the weak thin capitalization, the absence of cost recovery limits and weak capacity for monitoring of contractors' costs and investments.

There is a world of choice open to the design of a petroleum fiscal regime. Decisions over the type of fiscal regime, the State's needs for revenue for the extraction of its resources, the incentives system, the monitoring and cost verifications, and equitable risk-sharing are important considerations within the context of the geological uncertainties in petroleum activities. The reality is that both oil and gas contractors and governments, to quote one industry expert, "want to maximize rewards and shift as much risk as possible to the other party".

The balancing of interest should begin with defining the fiscal regime in legislation in a way that is not rigid yet does not leave too much discretion in the contracting process. The current regime does not provide for standardization of the terms governing contracting. As impressive as the additional oil entitlement provision is, too many elements of the regime are open to contractual variation, leaving Ghana's share of the resource rent subject to potential ad-hoc negotiations.

Second, we have not fully reviewed the Petroleum Income Tax Law (PNDCL 188) promulgated in 1987. But it does contain some fundamental flaws. The revisions to the law should reflect current industry best practices with the view to guarding against open-ended exemptions, allowances, withholding taxes, transfer pricing and cost containment. A superficial revision that does not respond adequately to these concerns betrays the trust of citizens in the State's capacity to realize the full benefit of resource extraction for the public good. Indeed a better option might be to repeal the PITL and incorporate all its essential features into the Internal Revenue Act to ensure consistency of the treatment of chargeable income and with greater clarity on "cost stop" elements for all extractive industries, mining included. Third, the revisions to the PITL or its incorporation into the Internal Revenue Act, ought to keep in mind that stability does not mean no change, but the conditions for change should not be asymmetric with the contractors holding the stronger discretionary position.

Finally, while fiscal design elements are important, so are the means by which blocks are allocated. Ghana's "work program bidding" by which blocks are awarded on the basis of competitive bids, has a major shortcoming of lack of transparency on what is judged to be "competitive". In the end what could become a competitive bid is in fact a negotiated package on several items.

ENDNOTES

[1]See Johnston (1994) and Nakhle (2010) for a taxonomy of legal framework governing hydrocarbon activities.

[2]Service contracts can be a pure service contract, in which a contractor is engaged to undertake specific upstream activity and is paid for its service, or a "risk service contract" whereby a company undertakes all the exploration and is paid for its services at a fixed rate of return if there is a positive find (Johnston, 1994). See also Tordo (2007) for a rendition on the key features of the legal arrangements. For the classification of petroleum fiscal regimes and "who" has title, see Johnston (2007).

[3]Oil and Gas in Africa, AfDB and AU (2009).

[4]It should be noted here that the legal framework that embodies the fiscal regime was at the time of writing the subject of debate on two fronts: first, whether the PITL should be repealed and rolled into the Internal Revenue Act, 2000 (Act 592) to ensure consistency of tax and cost containment provisions, and second, whether a new exploration and production and legislation should be promulgated to repeal PNDC Law 88.

[5]"Overview of Ghana's Fiscal Issues", presentation by Ghana National Petroleum Corporation, 3rd February 2010, Accra.

[6]McPherson, Goldsworthy and Sunley (2009).

[7]Ibid

[8]Clause 25, PNDCL 84.

[9]Heller and Heuty, "Accountability Mechanisms in Ghana's 2010 Proposed Oil Legislation", in this volume.

[10]Joint Management Committee (JMC) is a committee of Ghana National Oil Corporation and International Oil Company. (Model Petroleum Agreement, Article 6) The JVC consists of 2 representatives of GNPC and 2 representatives of the Contractor. However, much of the work of JMC - the accounting for the complex costs and investments expenses, and the preparation of the agenda for meetings and supporting documents - remains the responsibility of the contractor. Clause ix) of Article 6 states that costs and expenses incurred by GNPC in its participation in JMC meetings shall be borne by contractor.

[11]Duval et. al (2009), Production Sharing Agreements.
[12]Royalty rates are traditionally set at a level close to 12.5% (1/8th rule) of production as was customary for many operations in North America. This was increased to 1/6th in the 1970s then to 1/5th in the 1980s (Mommer, 2001).
[13]Commonwealth Secretariat (2003).
[14]Nazeer Bello, Presentation to IMF's Conference on Petroleum taxation in Sub-Saharan Africa, Kampala, June 29, 2010.
[15]From the investor's perspective royalties can be regressive as they are frontloaded. It is not profit based and the contractor has to make this payment before considerations of cost deductions are made. To mitigate the negative effects of royalties some countries apply sliding scale royalties based on production levels or sales values, well depths or R-factors (Kazakhstan, Mali and Peru). On the other hand, royalties are attractive to governments because they ensure an upfront revenue stream as soon as production starts.
[16]Oil and Gas in Africa, Oxford University Press, 2009.
[17]LIBOR is the London Intertbank Offered Rate. This is the average interest rate at which banks can borrow funds, in marketable size, from other banks in the London interbank market.
[18]McPherson et.al (2009) p. 22.
[19]Nazeer Bello, Kampala, 2010.
[20]In countries where the probability of discovering large reserves remain high as in Angola, Libya and Nigeria, IOC's strongly compete against each other to gain access to such acreage, offering favourable terms in competitive tenders and biddable terms (Duval et. Al, 2009).
[21]Tordo (2007), McPherson et. Al. (2009)
[22]Tordo (2007) and the reference to footnote 19 p. 15.
[23]The need for such stabilization clauses have been occasioned by past experience with expropriations and nationalizations that took place in some oil Producing countries, resulting in a number of IOCs losing their investments in these countries. Although most IOCs are currently less likely to be wary of outright expropriations due to the possibility of international arbitrations, they still see the need for protection against any changes to the fiscal and regulatory provisions that govern their agreements with the host country. The relevance or legitimacy of this need rests in the logic that petroleum projects are costly and IOCs more often than not need to take on debt to finance the initial project costs, which generally take a long period to recover for the IOCs to earn a reasonable return. As such any later attempts by the host country to alter the fiscal or regulatory terms of a contract may lead to a disruption in the profitability of the petroleum project and affect the ability of the IOC to service its debt obligations.

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