Fiscal Regimes:

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FISCAL REGIMES [*]

INTRODUCTION

Fiscal terms are the most important terms of a natural resource contract as they delimit and define the amounts of profit and economic rent that will accrue to each party throughout the life of the contract. For Nigeria these terms are critically important as the country has remained dependent on the industry for the bulk of its foreign exchange earnings for over thirty years. This paper is written so that participants will have an understanding and a working knowledge of fiscal terms in the Nigerian oil and gas industry in particular. As the industry is international comparative perspectives from other countries are also given.

It must be emphasized that in this area what is being proffered are the opinions of a layperson- a lawyer who has studied and researched on the oil and gas industry for twenty years, who has worked and read several exploration and production contracts, and read and analysed studies on fiscal terms but who remains a layman in terms of petroleum economics and accounting. I can articulate what is being done in other jurisdictions and what should be done but the solutions and the creativity must, at the end of the day emanate from the accountants and the petroleum economists. I stress this because one of the problems of Nigeria is the proliferation of quasi-experts who do not actually merit, but have acquired the appellation because of eloquence, or because of a working knowledge in a subject matter that requires years of study to achieve real expertise. I have no desire to swell this already large category of people who, in the long run, do the nation no service, and who deprive it of its best, offering instead good suggestions, but not the best solutions. I trust that the petroleum economists and accountants (and there are several excellent ones, national and non-nationals alike) will ultimately give us excellent solutions, based on the suggestions gleaned from gatherings such as these, and design for us the exact system that we require, for the ultimate good of Nigeria.

Fiscal terms must be analysed against the background of the needs and policies of the state in question, with ideal terms being those that satisfy these need and are in line with the stated policies. First, what are the policies and needs of Nigeria, and do the existing policies work towards satisfying the needs of the people and the nation? Secondly, what are the fiscal provisions that are in operation in Nigeria? Thirdly, do the existing fiscal terms adequately satisfy the needs of the country?

The Oil and Gas Policy.

It is normal for policies to be articulated and then for the industry in question to be developed in line with these policies. In Nigeria this has often not been the case. Until recently the one clear policy objective was the need to maximise revenues. This is only one of several possible objectives, geared towards development and self-sufficiency. Several main objectives for a developing country are:

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[*] The paper follows the general pattern of a presentation made by me titled 'Fiscal Regimes: Review and Reform,' The Oil and Gas Summit of the Nigerian Economic Summit Group (NESG), Abuja, 12TH- 14TH November, 2003.

- To ensure that exploration is continuously undertaken within the territory.
- To maximize revenues from the industry.
- The acquisition of increased technological skills. This would include increased learning and job opportunities for national entities.
- Having increased control over the national oil industry, an objective that is itself dependent on the acquisition of skills relevant to the running of the industry.

These objectives a lways have a bearing on the clauses contained within contracts entered into between the state and the exploration and production company , to the extent that one can estimate the types of policy objectives of a country from a study E and P contracts. In a sense the realisation of these objectives is in the order written above. First, the poor country is in a desperate and weak bargaining position and therefore has exploration as its main objective. If will often enter into a contract that provides for soft fiscal terms with upfront payments and a high portion of economic rent being retained by the company, particularly if it is desperate, short-sighted and well-aware of the fact that it is competing with many countries for a share of exploration expenditure . If it is a country that thinks long term, it will realises that one objective should not be achieved at the expense of the other. Such a country will be interested in developing its resources as part of a larger development policy, on mutually beneficial terms.

Nigeria has had a main discernible policy aim for practically all its years as a producing nation; the maximization oil revenues. As the maximization of oil revenues is dependent on there being oil in the first place, a corollary policy has been the stimulation of exploration at all times. All other objectives have been secondary. As a result the nation remains dependent on petroleum and the industry is yet to make any discernable impact on the country. Local content levels are said to be in the region of five per cent, and studies show that the present development levels are the same as they were in the 1960s.

Hopefully the nation's focus has changed. There is currently a proposed National Policy on Oil and Gas which was developed by the Oil and Gas Sector Reform Implementation Committee inaugurated by the Vice President of the Federal Republic of Nigeria. According to the Policy the Vision and Mission Statements for the National Oil and Gas Sector are:

To develop an Oil and Gas Sector that will be a model among leading countries in the world in transparency and investor friendliness, with policies and regulations that maximise value to government and the nation on a sustainable basis, giving due regard to Health, Safety, Security and specificallt the Environment as our common heritage.

To maximise the net economic benefit to the nation from Oil and Gas resources and to enhance the social and economic development of the people while meeting the needs fore fuel at a competitive cost, accomplishing all in an environmentally acceptable manner.

The Fiscal Regime

The Policy states that the fiscal regime for the upstream shall ensure that maximum revenue accrues to Government from Oil and Gas activities while also guaranteeing a reasonable return on investment.[1]

It also recommends some incentives for marginal field operators including that farmees should be allowed to benefit from the revised Memorandum of Understanding and that taxes for them should be at the corporate tax rate in the country 'but in any case, not mare than 50%.' The Policy believes that marginal field operators (and all indigenous operators) should be granted pioneer status for the first 5 years

For gas, the Policy recommends that present incentives for national gas should not apply to non-associated gas. It also recommends that tax consolidation currently enjoyed by upstream producers should be discontinued so as to encourage new entrants.

Fiscal Provisions

Fiscal provisions consist of two broad categories; pre-production and post-production payments. Both should serve the following government objectives:[2]

1. To achieve 'high' overall levels of take consistent with encouragement of exploration and development of fields which are viable on pre-tax basis.
2. To avoid distorting behaviour such as premature abandonment, overinvestment or 'gold-plating.'
3. To receive at least part of the take comparatively early in field life.
4. To establish an appropriate degree of project risk-sharing throughout the life of the contract.

Pre-production payments serve the purpose of allowing the host country to earn some revenue right from the inception of the industry, even before any discovery has been made. However the amounts that can be collected upfront are dependent on the deposits that the company expects to find and can be quite substantial. Where there are no such expectations and high amounts are stipulated these amounts can be disincentives. These amounts consist mainly of:

- Bidding fees,
- Signature bonuses; and
- Surface or rental fees.

[1] The Proposed National Policy on Oil and Gas 2004, Vol.2, Chap 6 at p.55.
[2] Alexander Kemp, 'Designing Economic Terms for Production Sharing Contracts' presented at a Conference on *How to Manage the Evolving Relationship Between NOCs and IOCs through Effective Production Sharing Agreements* 'organised by IQPC, January 29th-30th 2004, London, England.

Post-production payments consist of all other payments after commercial production. These amounts are geared towards ensuring that the state collects as much of the economic rent as possible without interfering with continued exploration and development.

> "Economic rents from petroleum exploitation are the returns accruing to investors over and above those necessary to sustain(1) ongoing production from existing fields, (2) the development of new but discovered fields, and (3) new exploration."[3]

To be able to measure the rent requires knowledge of the necessary costs, production profiles, oil prices and investors discount rates. Without this knowledge it is difficult to design an ideal system of rent collection that collects a higher share of the rent when they increase either as a result of higher oil prices or lower costs. Where the rent is left to the companies under a period of high prices then the company is said to earn windfall profits and is not in the country's favour. When too much rent is collected, so that ongoing production or new field development are impaired as a result, then the system is said to be regressive. Post-production payments consist mainly of:

- Production bonuses
- Taxes
- Royalties
- Profit oil shares; and
- Participation interest percentages from joint venture arrangements.

Fiscal terms are regulated by legislation and the contracts entered into between the government/NNPC and the companies. The main law is the Petroleum Profits Tax Act and its amendments. The contracts are:

- The Oil Mining Lease, the Participation Agreement and the Joint Operating Agreement, all of which make up the Joint Ventures,
- The Production Sharing Contract
- The Service Contract.

In addition, the fiscal terms are regulated by the Memorandum of Understanding. This is a contract between the government/NNPC and the companies that are in joint venture relationships with it and it is solely for the regulation of fiscal terms.

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[3] Alexander Kemp, Petroleum Rent Collection around the World, The Institute for Research on Public Policy, Nove Scotia, Canada, 1987, at xxxvii.

Bonuses

Nigerian bonus payments are a main pre-production payment, and are a feature of the production sharing and service contracts. The amounts are steadily increasing. In the early 1990s the PSCs contractors paid signature bonuses of $1 million each. In 1999 the PSCs given by the Abubakar regime and cancelled by President Obasanjo were subject to a $20 million signature bonus. The signature bonuses for the post-2000 PSCs were $30 million. For Nigeria – Sao Tome e Principe Joint Development Zone the deepwater blocks offered in 2003, signature bonuses were a bid item as those for the just concluded Nigerian bidding round. For the JDZ the highest signature bonus bid was US$123, in respect of Block 1.[4] The largest signature bonus paid in Nigeria to my knowledge is $210 million, by Shell Nigeria Ultra Deep, in respect of a deepwater block.

Royalties

Royalty payments are amounts paid to the owner of a resource as compensation for the exploitation of a non-renewable and irreplaceable resource. Traditionally they are based on volume and not on profitability. The level of production is the only parameter in volume based royalty schemes; the costs of production and prevailing oil prices play no part. Thus, royalty payments for a high cost field will be the same as for a low cost one of the production levels are the same. Therefore in a conventional royalty scheme the percentage paid as royalty goes up when prices are low. When prices are high the percentage is reduced and the economic rents accrue to the company.

In Nigeria royalties are paid based on volume and decrease as the water depth increases. They are presently as follows:

Onshore		20%
Offshore	-0-100 metres	18.5%
	-100-200 metres	16.67%
	-210-500 metres	12.00%
	-501-800 metres	8.00%
	-801-1000 metres	4.00%
	> 1000 metres	0%

[4] Carlos Gomes "Evolution of the Nigeria – Sao Tome e Principe Joint Development Zone Production Sharing Contract presented at *How to manage the Evolving Relationship between NOC'S AND IOC's through Effective Production Sharing Agreements* organised by IQPC, held at London 29th – 30th January 2005

There are several other devices for the payment of royalties, used in other countries. These include royalty rates that are based on value of production, or on a combination of well production volumes, the oil price and the time of discovery. Interestingly Norway also has a royalty system based on volume that is the opposite of Nigeria's. The percentages payable increase as production increases. Royalty rate under the JDZ will be a maximum of 5%, with lower rates for smaller fields and those in decline. Thus, it is more responsive to economic and technical conditions. For the 2005 Nigerian bidding rounds a graduation royalty system that is dependent on production will be introduced.

Taxes

Taxes are one of the most important means of revenue and rent collection in Nigeria Petroleum profit tax is payable under the joint ventures and production sharing contracts. In many other jurisdictions PSC contractors pay company income tax as they are seen as conducting petroleum operations on behalf of the state oil company, which holds the concession area. Taxation is affected by the incentives given to the companies by the MOU and the contractual arrangements. The 50% tax rate was a contractual term which was enacted as an amendment to the PPTA after several years of operation. Nigerian tax rates are listed in the accompanying slide presentation. Worldwide, various types of taxes are levied on proceeds from petroleum. There is normal company income tax, normally paid by service and PSC contractors in other jurisdictions. There are special profit-related taxes, which are not conventional income taxes and are often levied on a field-by-field basis. There are special excise taxes, specifically for the purpose of being inefficient collectors of rent, but they remain in use in various jurisdictions. Resource rent tax is an alternative that meets with acceptance by the specialists. This tax allows the investor to achieve a specified and discounted rate of return on a project before tax becomes payable. The threshold rate of interest is used to compound forward the investor's cash flows, commencing with initial exploration. The accumulated total becomes a larger and larger negative number until production commences, and the accumulation continues until the figure becomes positive. The resource rent tax is then levied and continues to be levied on positive cash flows. This tax regime there fore has the government sharing risks with the company as no tax is paid until a threshold rate of return is attained. It is an interesting tax regime, mentioned here but not advocated unless there is adequate capacity on the existing regulatory institutions.

Profit Sharing

Profit sharing occurs under production sharing contracts. They were first used in Indonesia in the early 1960's and have grown increasingly popular. They are to be found all over the world. The distinguishing feature of a PSC is the profit split. Under this contract all payments are expressed in terms of percentages of production. In a typical PSC the contract area is held by the state through the national oil company who then engages the services of an oil company as a contractor. The contractor company bears the risks and costs of exploration which it loses if there is no discovery. If there is a discovery it recoups its costs from an agreed percentage of the production, normally 40-50%. The balance of the production is shared between the contractor and the national oil company in accordance with agreed percentages that normally give a greater portion to the company when production is low. Higher volumes of production give corresponding larger shares to the NOC for the post 2000 Nigerian PSCs the percentages are typically as follows:

PROFIT OIL PERCENTAGES

Cumulative Production (MMB) from Contract Area	Contractor	Corporation
0-350	70	30
351-750	65	35
751-1000	52.5	47.5
1001-1500	45	55
1501-2000	35	65
Greater than 2000	Negotiable	

Nigerian PSCs have Cost Oil, Royalty Oil, Tax Oil, and Profit Oil. Crude oil is allocated in the following order:

Royalty Oil

Cost Oil

Tax Oil

Profit Oil

Under the deepwater PSCs there are no limits to the cost oil that is recoverable in a given year. This means that it is possible for the host country to earn nothing for initial years. How this provision came about is anyone's guess but will not be unconnected with the fact that Nigeria has one of the world's highest risk ratings and is therefore not a place that readily attracts investment capital. It is certainly a VERY rare provision worldwide. Happily PSCs that are awarded under the 2005 bidding rounds are to include a cost recovery ceiling of 80%. Even this is a high ceiling. One would expect that the absence of a cost recovery ceiling would entitle the host country to a larger share of profit oil when production levels are low, but the profit oil percentages for Nigerian PSCs are average, from an international and comparative perspective. PSCs can be the most lucrative types of contracts for the company, although they also carry the most risks. Therefore they are extremely popular and many variants exist worldwide, with the host country being more involved in the running of operations. Regulatory institutions need to be well trained, experienced and equipped to monitor costs satisfactorily, for the nation to derive the best.

Memorandum of Understanding

The Memorandum of Understanding is a contract between the Nigerian government and the joint venture companies, which first came into force in 1986. It is an arrangement under which the Nigerian government guarantees a certain level of profits to the oil company irrespective of fluctuating market prices, in return for continuing exploration and work by the companies. The first MOU was entered into in 1986, as earlier stated. It was reviewed and a new one came into force in 1991. Some incentives of the 1986/1991 MOU are:[5]

1. A guaranteed minimum profit margin which was $2.00 per barrel (after tax and royalty) under the 1986 MOU. Under the 1991 MOU this was increased to between $2.30 and $2.50 (after tax and royalty). The higher margin was guaranteed where the capital investment of an operator did not exceed $1.50 per barrel.

2. Any company that increased its reserves by more than its actual production was guaranteed a bonus by way of an offset against the company's petroleum profit tax and was called the Reserves Additional Bonus (RAB).

3. Certain tax reliefs were introduced for each year that the company increased its investments beyond a certain level.

In return the companies were to work out a five year programme aimed at achieving Nigeria's objectives, and to lift agreed volumes of NNPCs crude oil upon receipt of 15 days notice of the company's inability to lift its equity crude up to a monthly maximum of 920.000 barrels.

A new MOU came into force from 1st January 2000 and contains the following incentives, amongst others:

1. This new agreement allows for a minimum guaranteed notional margin of $2.50, after tax and equity, to the company on its equity crude. For NNPC crude a minimum of $1.25 is guaranteed, also after tax and royalty. This is all premised on the fact that the technical cost of operations does not exceed the notional fiscal technical cost which, at present, is $4.00 per barrel.

2. When in any one calendar year the company's actual capital investment costs exceed $2.00 per barrel on average then the minimum guaranteed notional margin shall be $2.70 and $1.35 per barrel, for company's and NNPCs equity crude respectively.

3. To encourage investments and maintain cost efficiency a tax inversion rate of 35% shall be applied.

[5] See Sola Adepetun, "African Petroleum Contracts, Joint Ventures and Negotiations", presented at the African Petroleum Management Institute-Management Leadership Programme, Wits Business School, Johannesburg, 17th – 23rd – September 2000.

4. In any calendar year all taxes, levies and other impositions by the federal state or local governments, including Central Bank commissions, apart from royalty and petroleum profits tax, shall be set-off against the company's tax liability for that year under the Education Tax Decree 1993. The amount remaining is deductible under sec. 10 of the Petroleum Profits Tax Act.

The MOU has proved quite popular and has achieved its aim of stimulating upstream activity. Its provisions appear to be quite generous to the companies. However it is an extremely complex contract that is said to be understood by very few people, including many persons in the Federal Bureau of Internal Revenue. The question arises as to whether the incentives are actually applied on condition that the companies' costs are within the agreed cost levels. What these costs are is not quite clear. The company and NAPIMS figures are quite low, that is, less than four dollars. However independent studies have stated that these costs are quite high, ranging between $4.50 - $12.50 per barrel.

There are several contractual means through which companies can be encouraged to continually explore and produce, even within an existing E&P contract. To give one example, in Malaysia, since 1997 a 'revenue over cost' concept has been utilized to encourage additional investment in the country's upstream oil industry.[6] The contractor's profitability at any time is measured by the R/C Index, which is the rate of the contractor's cumulated revenue (cost oil + profit oil) over the contractor's cumulative costs. The PSCs with this clause, known as R/C PSCs, allow the contractors to accelerate cost recovery if they perform within certain cost targets and when profitability is low. When profitability improves, i.e., when the R/C Index is greater than 1.4 the corresponding share to PETRONAS is gradually increased.

The MOU is a very important part of the Nigerian fiscal regime. However the view here is that it shouldn't be there at all. First of all it is a contract containing terms that affect or even amend existing fiscal terms contained in legislation. Secondly contracts are private instruments and belong in the public domain only if the parties so desire (unless there is a law compelling disclosure of contractual terms, as does a new law in Sao Tome and Principe.) A fiscal regime should be open to the public, as laws in statutes are. If Nigeria chooses to continue with the MOU, at the very least, it should be published and made available to any interested parties. Its existence is not in line with the present trend towards good governance, transparency and accountability.

Conclusion

This workshop is a landmark, for the nation and certainly for me. It is the first time that I have been asked to talk to the general public about the oil industry, even though for more than four decades Nigeria has been dependent on its revenues. This trend, which started at international levels, will happily become a national trend with the most important stakeholders-the people- knowing about and participating in decision-making in respect of this vital resource.

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[6] "Production Sharing Contracts" www.petronas.com.my/internet/business.nsf/dbcf3db8a4c05acbc825671c0017634c/..