Petroleum Industry Bill (PIB) Newsletter Series: New Dawn or False Hope?

No. 1 – Tax Fiscal Highlights & Issues

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Introduction

On 18 July 2012, the Presidency forwarded the 223 page Petroleum Industry Bill (PIB) 2012 to the National Assembly, as an Executive Bill. Despite several assurances especially by the Minister of Petroleum Resources from mid-2010, the National Assembly Class of 2011 was unable to deliver on enactment of the PIB.[1] The process had stalled largely because of the divergence of various 'versions' of the PIB in circulation, and diminished attention from 'the project' as a result of preparation for the April 2011 national elections.

Efforts to 'revive' the PIB picked up after the January 2012 nationwide demonstrations against removal of fuel subsidies by the Federal Government. Government undertook to fastrack deregulation of the downstream sector and see through other proposed industry reforms *vide* the PIB. Subsequently, the Federal Government inaugurated *Special Task Force for the Implementation of the PIB* to produce a 'harmonized' version that will be re-introduced to the National Assembly. Although the Task Force (and its Technical Committee) had an aggressive timeline of February 2012 to produce the revised PIB Bill, they submitted their deliverable to the Minister on 29 June 2012.

This ***Tax Fiscal Highlights Newsletter*** is the ***first in the series*** of our PIB newsletters covering specific areas of interest to operators and potential players in Nigerian oil and gas industry. Subsequent newsletters will respectively focus on: *Commercial Issues*, *Institutional and Regulatory Framework, and Dispute Resolution*. In this issue, (whilst mindful that the PIB may not eventually be enacted in its current form), we discuss key tax and fiscal highlights of the PIB and potential implications for business.

Tax: Upstream Regime

Overview: The PIB intends to repeal the Petroleum Profits Tax Act (PPTA), and incorporates amended provisions of Companies Income Tax Act (CITA) applicable to upstream companies.[2] It also introduces Nigerian Hydrocarbon Tax (NHT) for upstream, removes investment tax credits/ allowances replacing them with general production allowance dependent on location, volume and Dollar value/ price benchmarks. We discuss the NHT first.

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[1] See our February 2010 PIB Newsletter, *Nigeria's Petroleum Industry Bill (PIB) & Stabilization Rights: Keeping an Eye on Emerging Tax & Fiscal Issues.*

[2] Downstream companies are already subject to CITA, we have therefore excluded them from the scope of this Newsletter.

Nigerian Hydrocarbon Tax (NHT):

Sections 299 and ***313*** provides for NHT at: *(a)* 50% for onshore and shallow water areas; and *(b)* 25% for bitumen, frontier acreages and deep water areas, recognizing proportionality where petroleum operations straddle more than one geographical area.

Allowable/Non-Allowable Expenses

The PIB has a strict deductibility test, hence ***the following expenses are not allowed in the computation of NHT***:

- Corporate income tax (CIT) or *"…any income tax, profit tax or similar tax whether charged within Nigeria or elsewhere"* except education tax (***section 306(f***);

- Interest expense on loans by PSC Contractors, albeit such interest was incurred *"wholly, exclusively and necessarily"* for petroleum operations (***section 305(1)(g)***). Will this impact cost oil allocations/cost recovery?;

- Expenditures incurred on gas flaring penalty or fees or breach of domestic supply obligations (***section 306(k)***);

- General, administrative and overhead expenses incurred outside Nigeria exceeding 1% of total annual capital expenditure ***section 306(m)***;

- Unless the local content exceptions apply and regulatory approval is obtained, ***20% of offshore expenses*** (other than *section 306(m) exception*), not deductible; and

- Legal and arbitration costs against the Federal Inland Revenue Service (FIRS) or Federal Government, unless specifically awarded during the legal or arbitration process ***(section 306(o)***.

Capital Allowances

The provisions on capital allowances are set out in the ***4th Schedule***. Key highlights include the following:

- By ***Para 2(3)***, the difference between the original and subsequent acquisition costs of rights to petroleum deposits/purchase of information on the existence or extent of such deposits shall be disregarded for purposes of qualifying petroleum expenditure (QPE) by the subsequent acquirer company. This will put to rest arguments that signature bonuses cannot be regarded as qualifying drilling expenditure pursuant to ***Para 1, 2nd Schedule PPTA***.[3]

- ***Para 5, 5th Schedule PIB*** clarifies that Contractors financing the cost of equipment will be deemed to be the owner of QPE thereon for capital allowance purposes – unlike currently where the capital allowance is shared by PSC parties because chargeable tax is allocated between them in the proportion of their profit oil split. Contractors may also welcome this PIB provision, given (erroneous) arguments in some quarters under current dispensation that as a function of NNPC's ownership of equipment financed by Contractor for PSC petroleum operations, only NNPC is entitled to claim capital allowances thereon.

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[3] *Para 1, 2nd Schedule PPTA* defines qualifying drilling expenditure to include: *"expenditure incurred in connection with acquisition of or rights in or over, petroleum deposits."*

- ***Para (13)*** at page 186 also inserts a ***new Para 7(3)*** to ***2nd Schedule CITA*** as follows: *"where a licensee or lessee has entered into a contract…and such contract for the transfer of assets to such licensee or lessee by the contractor, such transfer shall be valued as equal to the value of cost oil, cost gas or cost condensates paid for such assets ('the deemed income') and* ***capital cost allowances shall be claimed against such deemed income in the hands of the licensee or lessee.*** *The contractor parties shall be entitled to deduct the expenditures for the creation of assets to be owned by a licensee of a petroleum prospecting license or lessee of a petroleum mining lease."*

- The provision of ***Para 6(3), 5th Schedule*** that any asset of which capital allowances has been granted may only be disposed of on the authority of a Certificate of Disposal issued by the Minister of Finance or any person authorized by him, introduces bureaucracy that is reminiscent of the hugely unpopular requirement of obtaining *Certificate of Acceptance on Fixed Assets (CAFA)* by the Industrial Inspectorate Department of the Ministry of Industries for assets exceeding N500,000 in value in order to claim capital allowances thereon under CITA.

- ***Para (11)*** amends ***CITA's 2nd Schedule*** by adding the definition of qualifying upstream petroleum expenditure and setting out initial and annual allowances in respect thereof.

- ***Section 308*** on artificial transactions (replicating current provisions in Nigerian tax laws may be 'modified' in practice by the more comprehensive *Transfer Pricing Regulations* being finalized by the FIRS.

- Since there is no more Petroleum Investment Allowance (PIA), or equivalent in the PIB, it is curious what ***Table 1, 4th Schedule PIB*** setting rates for allowances on QE (based on water depths) relates to, moreso as ***Table II*** clearly relates to annual allowances.

General Production Allowances (GPA)

Section 314 provides for GPA pursuant to ***5th Schedule*** which replaces investment tax credit/allowance (ITC/ITA) for Contractors under current PSCs.

- Unlike ITC/ITA which is a function (50%) of asset cost and applicable only in the year if acquisition, the GPA for PSCs is *"$5 per barrel or 10% of the official selling price, for all production volumes."* Financial modelling will show the exact impact of this on Contractor's take. However, at first glance – since ITC is a more beneficial incentive than ITA, pre-1998 PSCs subject to ITC may be more adversely impacted than post 1998 PSCs that are subject to ITAs.

- Furthermore, the GPA does not apply to companies in joint venture operations with NNPC (notwithstanding that they are currently entitled to PIA under *PPTA*).

- Other GPA prescriptions are as follows:

  (a) ***for onshore*** – the lower of $30 per barrel or 30% of the official selling price (OSP) up to cumulative maximum of 10 million barrels, and thereafter the lower of $10 per barrel or 30% of the OSP up to cumulative maximum of 75 million barrels;

(b) ***for shallow water areas*** - the lower of $30 per barrel or 30% of the OSP up to cumulative maximum of 20 million barrels, and thereafter the lower of $10 per barrel or 30% of the OSP up to cumulative maximum of 150 million barrels; and

(c) ***for bitumen deposits, frontier acreage and deep water areas***[4] - the lower of $15 per barrel or 30% of the OSP up to cumulative maximum of 250 million barrels per PML, and thereafter the lower of $5 per barrel or 10% of the OSP.

With the exception of (c), i.e. *bitumen, frontier acreage and deep water*, once the latter cumulative maximum threshold has been reached, the GPA will lapse; whereas currently, PIA (for JVs) or ITC/ITA (for PSCs) applies during the producing life of the asset.

The question may arise whether cumulating for the relevant threshold starts counting from the time the PIB is enacted or from historic production? For reasons of equity and fairness, the former would be the better/preferable approach. *Quaere*: is there any indicative import in ***Para (11)*** provision that *"marginal field operators shall be entitled to claim the allowances…on the incremental production from the Effective Date up to the cumulative amounts provided for in these paragraphs"*?

With regard to gas production, where (potentially more favourable) incentives for utilisation of associated and non-associated gas currently apply,[5] the PIB's GPA make detailed respective prescriptions for onshore, shallow offshore and bitumen/frontier acreage and deepwater respectively as follows:

[4] *"Frontier acreages"* is defined as licenses or leases located in an area defined as frontier in a regulation issued by the Minister pursuant to the Act; "deepwater" retains its definition ("deep offshore") as offshore areas with water depths in excess of 200 metres.

[5] For example, ability to charge gas related upstream expenditure against PPT (with higher tax rate), whilst gas income is taxed under CITA (with lower tax rate), and only expenses exclusively incurred in the utilisation of gas are regarded as gas expenses under CITA (*sections 11 and 12 PPTA*).

Location	*>5 Bbls condensate per Mcf*[6]	*<5 Bbls per mcf*	*Condensate production from gas fields: $20/bbl or 30% OSP or:*
Onshore	Lower of $1.0/ MMBtu or 50% value of natural gas up to cumulative 1Bcf per PML; subsequently, lower of $0.50 per MMBtu or 30% of OSP.	Lower of $1.0/ MMBtu or 100% of natural gas value up to cumulative max 1Bcf per PML; subsequently, lower of $0.50 per MMBtu or 50% of OSP.	Lower of $10/bbl or 20% of OSP cumulative max 100m bbls; subsequently, lower of $3 per bbl or 10% of OSP.
Shallow Water	$1.0/ MMBtu or 50% value of natural gas up to cumulative 2Bcf per PML; subsequently, lower of $0.50 per MMBtu or 30% of OSP.	$1.0/ MMBtu or 100% of natural gas value up to cumulative 2Bcf per PML; subsequently, lower of $0.50 per MMBtu or 50% of OSP.	Lower of $10/bbl or 20% of OSP cumulative max 200m bbls; subsequently, lower of $3 per bbl or 10% of OSP.
Bitumen, Frontier & Deepwater	$1.0/ MMBtu or 50% of natural gas up to 3Bcf per PML; subsequently, lower of $0.50 per MMBtu or 30% of OSP.	$1.0/ MMBtu or 100% of natural gas value up to cumulative 3Bcf per PML; subsequently, lower of $0.50 per MMBtu or 50% of OSP.	Lower of $10/bbl or 20% of OSP cumulative max 300m bbls; subsequently, lower of $5 per bbl or 10% of OSP.
Current PSCs/JV Operations	$0.50 per MMBtu or 30% of value of natural gas per PML *regardless of liquid yield, for all production volumes*.	$0.50 per MMBtu or 30% of value of natural gas per PML *regardless of liquid yield, for all production volumes*.	Lower of $5/bbl or 10% of OSP for *all production volumes*. (PSCs only).[7]

[6] ***Para (6), 5th Schedule*** states that the GPA under this head shall only be applicable to gas production that is subject to royalties and where such gas is not utilized for purposes of reinjection.

[7] There seems to be an inadvertent omission of JV operations under the GPA for condensate production from gas fields' subhead. **Note** also that ***Para 10(b)*** [incorrectly written as (c) – page 222] provides that all existing crude oil, condensate and gas production from PSCs in existence prior to the effective date shall be eligible for GPA of $5/bbl of oil equivalent.

Generally, where allowances cannot be fully deducted due to nil or insufficient assessable profits in an accounting period, these may be carried forward to subsequent accounting period. Also, where a field development produces a combination of crude oil, condensate and natural gas, the related GPA shall be taken separately. Where a field is covered by two or more PMLs, the allowances for each PML shall be determined based on the total unitized production.

Where a lessee is producing crude oil with associated gas at the Effective Date and is flaring substantial volumes of gas, it could propose a development plan to significantly eliminate routine flaring. If same is approved by the National Petroleum Inspectorate, the lessee shall be entitled to claim applicable GPA in the above table (herein) regarding natural gas and condensate attributable to such development plan.

Furthermore, all GPA thresholds are to be fixed on the total production per PML aggregated at company level subject to the following exceptions:

(a) claims by Contractors in deepwater PSCs shall be ring-fenced per PML;

(b) supplier of gas destined solely for the domestic market shall be entitled to claim production allowance per PML; and

(c) where a shareholder holds 10% stake (directly or indirectly) in several companies, the companies shall be treated as one for the purposes of computing the GPA.

NHT Returns and Dispute Resolution Process

Companies are to file estimated returns to the FIRS within two months of commencement of their accounting period (***section 325***) and pursuant to ***section 327*** are to file self assessment. ***Section 330*** details the objection procedure; presumably these will be supplemented to the extent necessary by ***section 59*** and ***5th Schedule FIRS Act 2007*** which also provides for tax objection and appeal procedure.

However, ***section 333*** provides that taxpayers may seek redress against assessments which the FIRS refuse to amend/review pursuant to their objection, to the Federal High Court (FHC), instead to the Tax Appeal Tribunal (TAT) as envisaged by the FIRS Act.

The implication of this is that the TAT will no more have jurisdiction over upstream (NHT) tax disputes; it may also be reflective of recognition that the TAT currently has jurisdiction over all tax appeals, despite postulations to the contrary by parties relying on ***section 251(1) 1999 Constitution*** that confers exclusive jurisdiction on the FHC to the *"exclusion of any other court"* on matters of companies' taxation and revenue of the Government of the Federation.

Section 334 goes on to state that any person aggrieved with any action of the FIRS may seek relief at the FHC, whether against FIRS, *any other taxable person* or government agency. Has this expanded the definition of 'tax disputes' such that a contractual dispute between two upstream taxpayers with tax dimensions would be expected to be filed at the FHC?

We will discuss in greater detail, the ramifications of this and related provisions in our forthcoming ***PIB Disputes Resolution Newsletter***.

Other NHT Compliance Provisions

The provision of ***section 333(2)***[8] that where an assessment has become final and conclusive, any tax overpaid shall be repaid is in sync with the refund provisions of *section 23 FIRS Act.* Whether in such case rigorous audit that is meant to be part of the refund process will be conducted may be a question of FIRS discretion depending on the circumstances (for example if such audit had preceded the assessment that became final and conclusive).

Provisions such as ***sections 344*** and ***345*** (on penalties for failure to deduct and remit tax and on deduction of tax at source respectively) are unnecessary because they replicate extant provisions in the *FIRS Act*. Also ***section 353*** and ***3rd Schedule PIB*** on functions and powers of the FIRS are unnecessary because subsisting FIRS Act provisions, sufficiently covers the ground in that regard.

Companies Income Tax (CIT)

Upstream CIT Overview:

Part B of the tax provisions of the PIB is titled *"Companies Income Tax Applicable to Upstream Petroleum Operations."*[9] In summary it makes all companies in upstream petroleum operations (concessionaires, licensees, lessees, contractors and subcontractors) subject to CITA. Previously companies regarded as conducting petroleum operations for their own account pursuant to *section 2 PPTA* were not subject to CITA, except in respect of other income not arising from, or incidental to their petroleum operations.

Pertinent provisions[10] (and their headline implications) include the following:

- ❖ Companies involved in both upstream and downstream petroleum operations are to determine their CIT separately;
- ❖ NHT is not deductible for CIT purposes (and *vice versa*);
- ❖ Recognition and application of Transfer Pricing Rules (to be issued by the FIRS) through PIB's explicit amendment of current *section* ***22(1) CITA*** in dealing with dispositions and transfers;
- ❖ Amendment of ***section 24 CITA*** (on allowable deductions) to include *"rents and royalties payable on Upstream Petroleum Operations";*

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[8] There are numbering errors on page 174 *et seq.* of the PIB. The section 333 referred to here should actually be section 335 because there are earlier sections 333 and 334 on p. 174 before the second 333. This means that subsequent sections (right to the end of the PIB) would need to be renumbered.

[9] **Section 362** defines "Upstream Petroleum Operations" as *"the winning or obtaining and transportation of petroleum, chargeable oil or chargeable natural gas chargeable condensate or bitumen in Nigeria by or on behalf of a company for its own account including production sharing contractors, by any drilling, mining, extracting or other like operations or process, not including refining…in the course of a business carried on by the company engaged in such operations, and all operations incidental thereto and any sale of or any disposal of chargeable oil or chargeable natural gas or chargeable condensate or bitumen by or behalf of the company."*

[10] They appear after ***section 353*** (from page 184) but are numbered (1) to (13), with *section 354* (Repeals) appearing thereafter.

- The attempt to remove the erstwhile four year loss limitation rule through ***Para (7)*** is unnecessary because the ***CITA (Amendment) Act 2007*** has already removed such limitation;

- The "gas utilisation incentives" in ***section 39 CITA*** have been curtailed such that only companies engaged in LNG projects, downstream gas distribution, operators of gas extraction facilities, refineries and downstream crude oil processing facilities will be eligible.

- On the upstream side, *"upstream gas operations shall be entitled to **only** the tax holiday" "provided the gas supply destination is solely to the domestic market."* This means that the alternative and post tax holiday incentives under ***section 39 CITA*** for upstream gas (35% additional investment allowance which does not reduce the value of the asset and accelerated capital allowances after the tax relief period respectively), is slated for removal. Nonetheless, the incentive under PIB is clearly to incentivize domestic gas supply, given for example, the *"gas to power"* requirements of the Power Sector Roadmap.

- According to ***Para (10)*** *"for the purposes of computation, assessment and payment of CIT, companies engaged in upstream petroleum operations shall apply the NHT accounting periods on an actual year basis and the procedures for paying tax estimates on a monthly basis in anticipation of paying the balance of the full tax due at the end of the accounting period."* This is a departure from current CIT requirement (***section 77(5) CITA***) whereby companies filing on self assessment basis may pay the tax within two months of due date of filing in lump sum or in maximum of six monthly instalments. This does not mean loss of time value of money for upstream companies because they had always been paying PPT on a monthly basis.

Petroleum Host Community Fund (PHC Fund):

The PHC Fund is to be established and *"utilized for the development of the economic and social infrastructure of the communities within the petroleum producing area."* Every upstream producer shall remit on a monthly basis 10% of its net profit (defined as adjusted profit less royalty, allowable deductions and allowances, NHT and CIT), to the Fund. Remittances to PHC Fund in respect of deepwater operations are to be applied for the benefit of petroleum producing littoral States; this would seem to be in addition to the 13% derivation currently enjoyed by such States in line with constitutional provisions.

The impact of the 10% remittance could be deemed ameliorated by ***section 118(4)*** that "*the contributions made by each upstream petroleum company ... will constitute an immediate credit to its total fiscal rent obligation as defined in this Act."*[11] Effectively, the 10% net profit remittance is a deductible expense, albeit it may contribute to negatively impacting upstream company's take.

Fees, Royalties and Rentals:

[11] '*Total fiscal rent obligation'* is not defined, but "fiscal rent' is defined in ***section 362*** as the aggregation of royalty, NHT, and CIT obligations arising from upstream petroleum operations, whilst "rent" *"includes any annual or other periodic charge made in respect of a license granted under this Act."*

Remarkably (and unlike some earlier versions), these are not set out in the PIB. ***Section 197*** merely provides that *"there shall be in respect of licences, leases and permits under this Act such royalties, fees and rentals as may be contained in this Act and in any regulations made by the Minister pursuant to this Act."* The provision might have been inserted to give the Minister additional time within which to take considered action on rentals and royalty rates. Pending the issuance of Regulations, the royalty rates enshrined in the *Petroleum Drilling and Production Regulations (PDPR)* made pursuant to the Petroleum Act, will continue to apply.

Such view is reinforced by ***section 354(3) PIB*** that *"any subsidiary legislation made pursuant to any of the enactments repealed in subsection(1) of this section shall, where it is not inconsistent with the provisions of this Act, remain in operation until it is revoked or replaced by subsidiary legislation made under this Act, and shall be deemed for all purposes to have been made under this Act."*

It is also noteworthy that *"royalty percentage in addition to the relevant subsisting royalty percentage"* is part of bid parameters in the open transparent and competitive bidding process for acreages under ***section 190 PIB***.

Gas Flaring Penalties:

The PIB also fails prescribe penalties for gas flaring. ***Section 201(1)*** provides that *"the lessee may pay such gas flaring penalties as the Minister may determine from time to time."* At least one previous version had stated that the penalty would be equivalent to the value of gas flared.

No Preferential Fiscal Regime for Indigenous Companies

The PIB (unlike earlier versions) has not toed the line of creating preferential fiscal regime for *"indigenous petroleum companies"*, defined as one in which 51% or more of its shares are beneficially owned directly or indirectly by Nigerian citizens or associations of Nigerian citizens. Will a 51% company owned by another "Nigerian" company in which Nigerians hold 49% stake not qualify an indigenous petroleum company?

Also, any *"company listing on any stock exchange in Nigeria <u>with a majority of Nigerian directors</u> shall be deemed to qualify as an indigenous petroleum company in Nigeria."*

At the moment, it seems that only indigenous companies producing less than 25,000 barrels per day enjoy preferential treatment: exemption from operation of *"back-in rights"* by Government and entitlement to produce up to the technical allowable output set for the license or lease (***sections 285 and 286***).

Conclusion:

Whilst everyone awaits deliberations by the National Assembly on the PIB, (upon resumption from their recess in September 2012), we have taken a ladle into the headline tax fiscal provisions and their potential impact on operators.

In subsequent series of our PIB Newsletters to be circulated instalmentally next week, we will analyse other dimensions of the PIB – *Commercial Issues*, *Institutional /Regulatory Framework* and *Dispute Resolution* (especially impact of PIB provisions on vested rights and subsisting contracts). We intend to thereby appraise clients, stakeholders and analysts of issues of interest which could inform their strategy responses, participation during the PIB public hearing sessions, or other actions.

President Goodluck Jonathan has avowed his commitment to enacting the PIB as part of his “transformation agenda”, further reinforced by similar reiterations post resolution of the January 2012 fuel subsidy crisis. Given widely acknowledged public yearning for overdue reforms to the Nigerian petroleum industry, there is a high likelihood that this time, the efforts to enact the Bill will succeed. Accordingly, it is prescient that stakeholders (especially current players and prospective investors) pay close attention to the PIB, and take requisite response actions to meet their business goals within (enacted PIB’s) regulatory and compliance framework.

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