bargate advisory

New Oil & Gas Fiscal Regime in Nigeria?

Nigeria

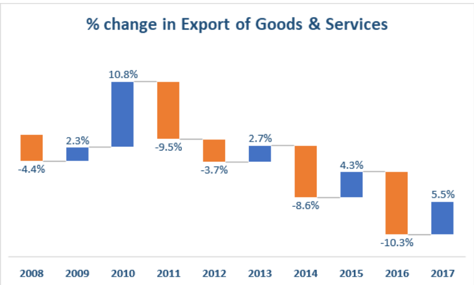
Few initial thoughts on the new draft Nigerian Petroleum Industry Fiscal Bill

May 2018

In this briefing

Nigeria at a glance

Population: 186m (2016 est.)
GDP (2016 est.): US$405.1 bn



Did you know? According to a recent UN report, Nigeria is forecast to add a further 189 million people to its population between 2018 and 2050, or at a rate of about 6 million people a year. Love abounds in the country. Lots.

We'd like to thank the good folk at www.petroleumindustrybill.com an Odujinrin & Adefulu for letting us share our views on their platform

#FiveThings

There is new draft legislation regarding the governance of Nigeria's oil & gas sector. This reform process has gone on for some time now. It's been 10 years since the first of many versions of the Petroleum Industry Bill was drafted, for example. A version of it made its way to the National Assembly (NASS) in 2012 and we looked at the fiscal implications of it back then. It never made it through, though. No, it wasn't because of our analysis.

One of the many problems with that 2012 attempt was that it was a very bulky piece of draft law, even for lawyers. Oh, and there was a minor problem of serious disagreement with certain provisions in it. So, it was decided that the big law would be broken into smaller, more manageable, themed pieces. The Petroleum Industry Governance Bill (PIGB) was the first to make it through the gate. A Petroleum Industry Fiscal Bill (PIFB) was submitted at the end of April. You can imagine our keen interest in having a quick look at it and sharing our initial thoughts in our typical not-so-quick-and-dirty-analysis.

The aim of this PIFB, as stated in its preamble, is to:

> "*establish a progressive fiscal framework that encourages substantial and progressive investment in the petroleum industry balancing rewards with risk and enhancing revenues to the Federal Government of Nigeria; institute a forward looking fiscal framework that is based on core principles of clarity, dynamism, neutrality, open access and fiscal rules of general applications; provide clear distinction between legislative aspects of the fiscal regime and negotiable aspects of contractual obligation; establish a fiscal framework that expands the revenue base for the government while ensuring a fair return for the investors; simplify the administration of petroleum tax; promote equity and transparency in the fiscal system.*"

Ambitious, then. We thought we'd say five things that summarise our first impressions.

#1: The usual suspects are, well, usual

At first glance, the PIFB ticks the right boxes for the things you would normally expect to see in a considered fiscal regime for oil and gas operations, especially for a country like Nigeria who has been in the game for some time. We've highlighted a few examples.

Clever ring-fencing provision

There is a neat little ring-fencing provision which limits treatment of costs to "*operations in each terrain*" (s.4(2)). Companies can consolidate operations within the same terrain except for companies with Production Sharing Contracts (PSCs) and Service Contracts in the naughty corner (i.e. those involving National Asset Management Company; s.4(3)). What this ring-fencing provision does is, among many things, prevent reduction of taxable income by shifting costs/losses from one terrain to another. The provision could do with a bit more detail, though.

Same thing for assessment of profits, adjusted profit, assessable profits & chargeable profits

The provision in s.5 regarding assessment of profits is also not surprising in terms of items to be considered in determining assessable and chargeable profits (such as proceeds of sale and disposal). That said, it is helpful that clarity is provided with regard to treatment of condensates.

Also same for allowable and non-allowable deductions

The provisions for allowable deductions in s.6 have all the usual suspects e.g. drilling costs, royalties, and interest on debt. However, there is a limit on interest deductibility: nothing higher than LIBOR + a market determined rate applicable in the industry will be deductible. This offers some protection to the Government against the dangers of thin capitalisation. But if we wanted to be picky, we would gently warn that an alternative rate to LIBOR be considered, given all the stuff going on with LIBOR's own future.

Interesting local content strategy tool alert!

The non-allowable deductions section is also fairly usual, except perhaps for the provision in s.7(1)(g) which doesn't allow 20% of any expense incurred outside Nigeria, "*except where such expenditure relates to the procurement of goods and services which are not available domestically in the required quantity and quality*". This should ~~force~~ encourage companies to think carefully about including Nigerian goods and services in their procurement planning, if they offer value for money.

Transfer pricing rule

The provision in s.9 on "*Artificial Transactions*" is a bit of a transfer pricing rule. It says transactions between persons one of whom has control over the other or ones deemed by the Federal Inland Revenue Service (FIRS) as not at arms' length will be deemed artificial or fictitious and not considered in the determination of deductible stuff. The rule itself is not unusual, but the expression of it is interesting.

Fees and rents are standard, if not a bit vague

The Third Schedule, at paras one and two, makes provisions for fees and rents. We have had fun just stopping there and waiting to see the looks on peoples' faces after actually going to look at the provisions and being told that they shall be published either by the National Petroleum Regulatory Commission (the Commission) guidelines or by regulations pursuant to the act. It is not a big deal, but some clarity and certainty could chip positively away at reputational risk.

#2. There's not a lot of discretionary room, but there is some

Refreshingly reduced discretionary space

One of the issues we had with the Petroleum Industry Bill of 2012 was the rather vast array of discretionary tools at the disposal of the government. We shall not dwell on the risks of wide discretionary powers other than to say that it is typically not a cool thing to have when dealing with high stakes industries using institutions that could be stronger.

So, it was refreshing to note that the PIFB appears to minimise the level of discretionary powers available to the government. A good thing about this is a reduced risk of arbitrary decision making (which is always great for corporate planning). A downside to it is things could get awkward if, say five years down the line, a rigid rule has not quite worked and you then need to go through the parliamentary process to amend stuff.

Discretion alert! Frontier Basin

That said, we spotted a few provisions in there that looked interesting.
For Frontier Basin exploration & development (frontier basin defined in the Bill as "*the inland basins, other basins defined as frontier in a regulation issued by the Commission or a basin where exploration activities have not been carried out*"), the Commission, **subject to the Minister's approval**, may allow consolidation of costs and income from Frontier Basin operations with costs and income from operations in a different terrain. This is to incentivise Frontier Basin exploration (s.4(4)).

The Commission will stipulate the length of this concession and upstream gas operations will get a tax-free period of 5 years commencing from the date of production, provided that the companies being catered to by this provision are not already subject to current laws that will be repealed by these shiny new ones (s.4(5), 75(1) and (2)). This is a useful way to check possible misuse of discretionary powers, **BUT…**

"*…incentives granted under sections 11 and 12 of the Petroleum Profits Tax Act which is repealed by this Act shall continue to apply to projects which have been approved by the NNPC or DPR prior to the commencement of this Act and in respect of which significant investment has been made prior to the commencement of this Act. For the purposes of this section, significant investment means such level of investment as determined by the Commission.*" (s.75(2))

Discretion alert! Carry-forward of losses

The provisions in s.10 on the treatment of losses could perhaps do with some clarification. The first thing to note is that losses can be carried forward indefinitely (s.10(1)). This is not unusual for upstream oil and gas fiscal regimes. The second thing to note is that the FIRS can, subject to a written request from company, allow the company to elect "*in writing that a deduction or any part thereof to be made under this section shall be deferred to and be made in the succeeding accounting period, and may so elect from time to time in any succeeding accounting period.*" (s.10(3)) It seems to allow *carte blanche* shifting of losses during accounting periods. This can be a useful cashflow management tool, but it can also be a headache to track.

#3. There's a lot of royalty rates!

At first count, 32 different royalty categories!

Clever people were allowed too much time alone, it would seem. The Third Schedule, at paras 17 and 18, detail the royalty rates and methodology that would be applicable under this new system.

In terms of methodology, the choice of an average monthly daily production royalty rate is not unusual. It would be interesting, however, to understand why an *ad valorem* royalty rate was not applied, being the simpler to calculate.

The applicable royalty for all Frontier Basin is straightforward at 5%. This is where the simplicity ends. The table below shows the various royalty rates applicable for onshore, shallow water and deep water operations for oil, gas and condensates, at various production tranches (and, if you look hard enough, maybe in different colours; such is the detail).

Royalty Rates in the New Fiscal Regime – Lots of 'em

	Onshore		Shallow water		Deep water	
	Production Tranches	Royalty rate	Production Tranches	Royalty rate	Production Tranches	Royalty rate
Oil (kbpd)	First 2.5	2.5%	First 10	5.0%	First 50	5.0%
	Next 7.5	7.5%	Next 10	10.0%	Next 50	7.5%
	Next 10.0	15.0%	Next 10	15.0%	Above 100	10.0%
	Above 20.0	20.0%	Above 30	20.0%		
Gas (MMscf)	First 400	2%	First 600	2%	First 600	2%
	Next 400	4%	Next 400	4%	Next 600	4%
	Above 800	6%	Above 1000	6%	Above 1200	6%
Condensates (kbpd)	First 2.5	2.5%	First 10	5.0%	First 50	5.0%
	Next 7.5	7.5%	Next 10	10.0%	Next 50	7.5%
	Next 10.0	15.0%	Next 10	15.0%	Above 100	10.0%
	Above 20.0	20.0%	Above 30	20.0%		

It's still regressive

It's an awful lot of effort for a fiscal instrument that imposes a front-end burden on pre-tax cashflow, no matter the calibration. Whilst the graduation by larger production volumes can serve to manage the fiscal burden, these royalties are imposed prior to any recovery of costs for the determination of profit. So, no matter the sliding scale, they are still upfront costs.

Opinion alert!

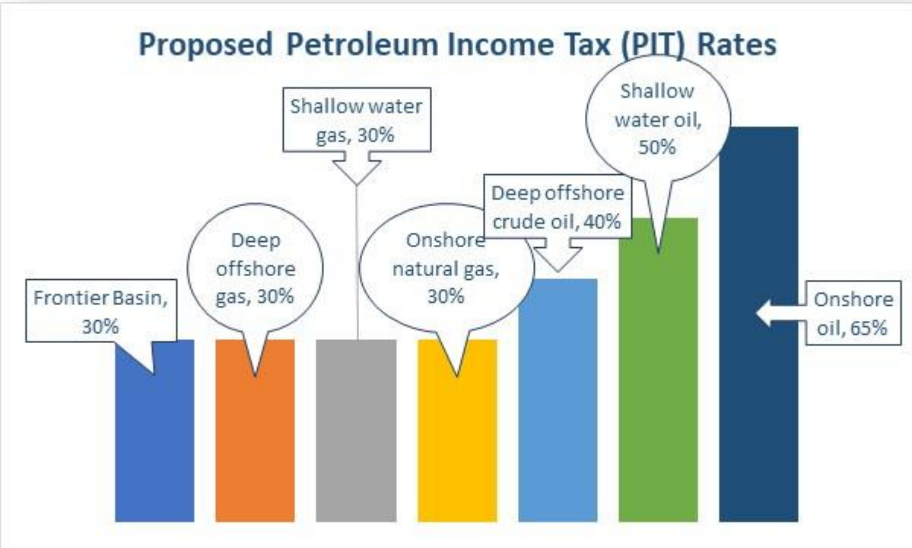
The consideration of different royalty rates in recognition of the cost and terrain differences between onshore, shallow and deep water operations for oil, gas and condensates is very good practice. However, it would be interesting to understand the choice of detailed production-based rates instead of singular value-based rates for each category.

We recognise that it is dangerous to consider petroleum fiscal instruments, such as the royalty, in isolation. However, we also consider that simplicity (where possible in these things) can be fun.

#4. The Petroleum Income Tax (PIT) rates are logical for a mature player

Recognition of different production categories

The PIT rates are straightforward and fit well into the usual suspects category. The lower rate of 30% appears targeted at incentivising Frontier Basin and all gas operations. The higher rates also recognise the comparatively lower but graduating cost profiles for crude oil in deep offshore, shallow water and onshore plays (s13, 58, 62).



Capital allowances are also usual. Hang on, is this the usual suspects section?

Provisions for capital allowances are also what you would normally expect for fiscal regimes of this nature. The table below summarises what is essentially a five-year straight-line depreciation system for capital expenditures.

	1st year	2nd year	3rd year	4th year	5th year
Exploration capex	100%				
2 appraisal wells capex	100%	0%	0%	0%	0%
Intangible well capex	100%	0%	0%	0%	0%
Tangible well capex	20%	20%	20%	20%	19%
Facilities capex	20%	20%	20%	20%	19%
Infrastructure capex	20%	20%	20%	20%	19%

Production allowances are much simpler than what was offered in PIB 2012

The production allowances (PAs) envisaged for Frontier Basin and deep offshore operations are much simpler in design than what was provided in the 2012 PIB. This is a relief, of sorts, because some measure of complexity is added in the form of the Cost Efficiency Factor (CEF). The table below summarises the PAs as proposed.

Production category	Allowance
Onshore	The lower of US$ 3/barrel or 30% of official selling price
Shallow water areas	The lower of US$ 3/barrel or 30% of official selling price
Deep water areas	The lower of US$ 3/barrel or 30% of official selling price
Natural gas fields	The lower of 50% of value of natural gas production or US$1.5 per MMBtu
Dry gas fields	The lower of 100% of value of natural gas production or US$1.5 per MMBtu
Condensate production	The lower of US$ 3/barrel or 30% of official selling price

Cost Efficiency Factor – an incentive to keep costs down?

Companies will be entitled to PA under the above arrangement, which is fairly straightforward. However, their entitlement will only be to the extent of their cost efficiency as determined by this new CEF. The CEF is defined as the ratio of 20% of total revenue to the total operating cost (i.e. 20% revenue/OPEX). So, there's some sort of reward mechanism for keeping costs down, as illustrated in the table below.

Cost Efficiency Factor	PA applicable Factor
If CEF <= 0.5	You claim your PA up to 50%
If 0.5 < CEF < 1.2	You claim your PA from between 50% to 120% (uplift alert!)
If CEF >= 1.2	☺ 120%

There is also provision for additional production allowances, this time based on reserve replacement ratios.

Reserve Replacement Ratio (RRR) Range	Additional production allowance
RRR = 1	50%
1<RRR<1.25	75%
1.25<RRR<1.5	100%
RRR=>1.5	125%

Incentive to drill more wells

The additional RRR-based PAs look a useful incentive for companies to drill more wells especially if opportunity exists to recover more than is stipulated for normal production allowances. This could incentivise more drilling activity than is environmentally sustainable.

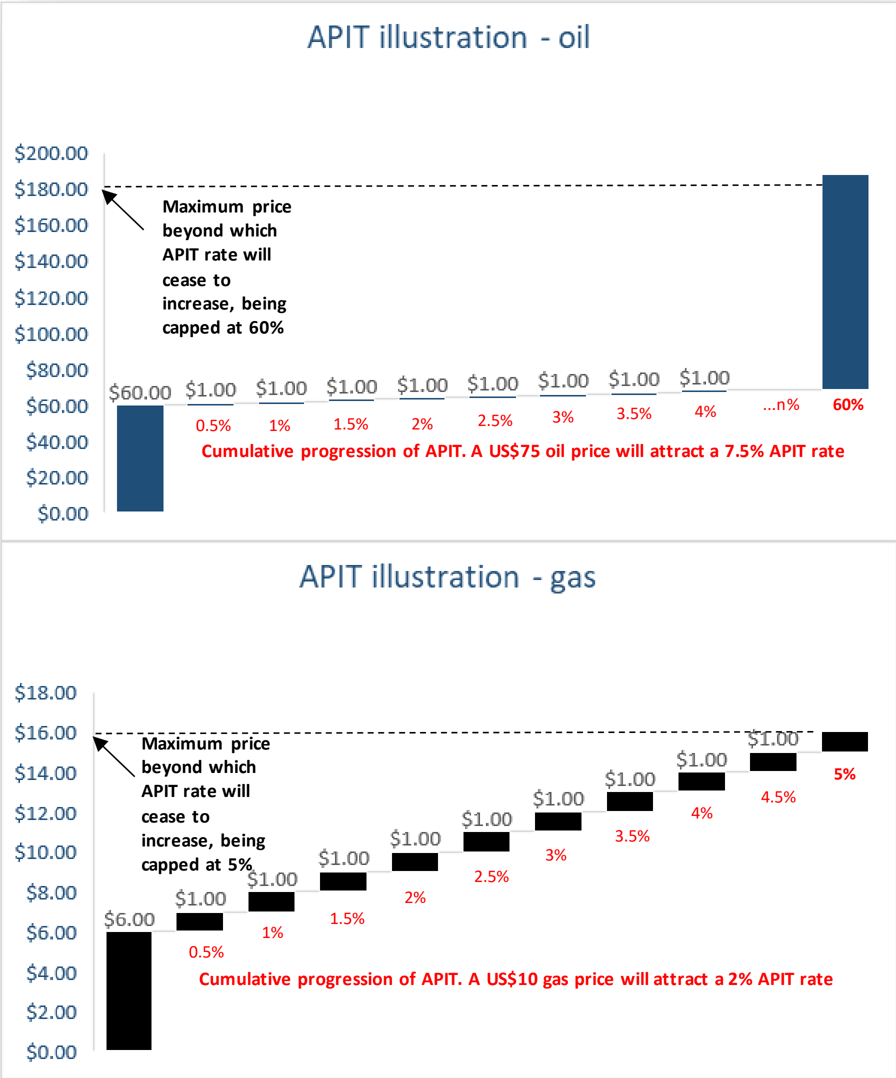
In all, though, complex much. The system seems to take from companies and want to give lots back. We make a point about the incentives for keeping costs down when considering the Additional Petroleum Income Tax in the next section of this briefing note.

#5. Finally, a progressive fiscal regime is attempted…

… but it's not quite there. A new feature of the proposed petroleum fiscal regime is the addition of a *progressive* instrument that seeks to increase the overall level of fiscal burden as the project becomes more profitable. The Nigerian fiscal system for petroleum operations has always been regressive, so this is an interesting attempt at capturing more economic rent from the upside when the upside comes.

Price-based formula

The PIFB proposes, at s.16, an additional PIT (APIT) of 0.5% for every US$1 increase above the threshold price of US$60 per barrel for crude oil, and the same for every US$1 increase of the threshold price of US$6 per MMBtu for natural gas. This additional tax can escalate up to a maximum of 60% for crude oil, and up to 5% for natural gas.



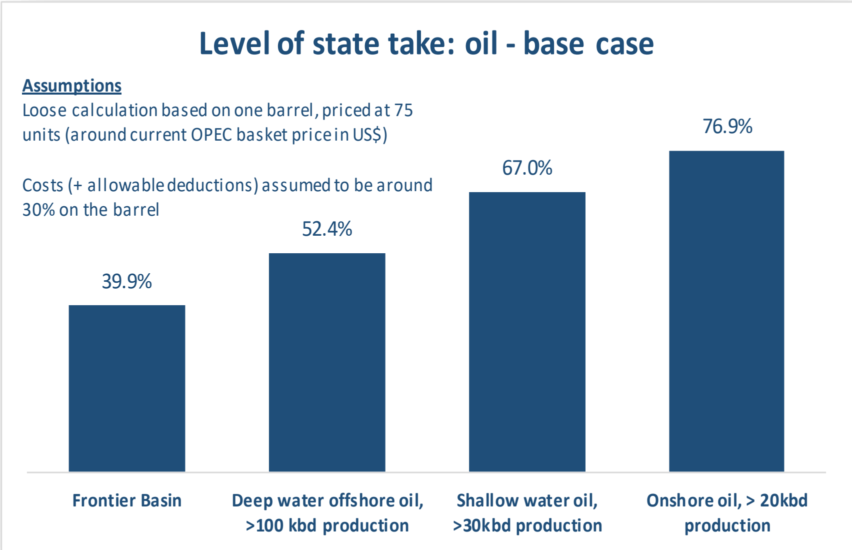
New Oil & Gas Fiscal Regime in Nigeria?

We did some very quick analysis

We have done a quick analysis of the overall level of fiscal burden (or state take) imposed on companies by the combination of royalties, PIT and APIT on project cashflows. As this is an initial look-in, we have done it back-of-the-envelope-ish and simplified all lifecycle costs and production profiles into one barrel (we're only looking at oil for this briefing).

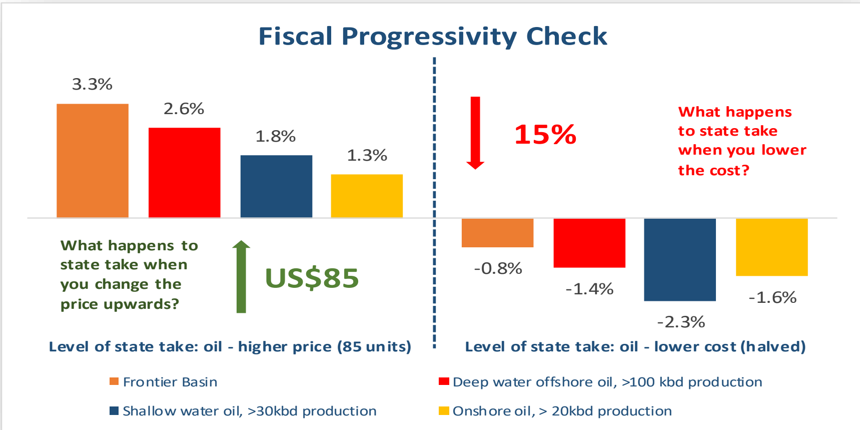
Higher levels of fiscal burden for less difficult operations seem logical

We randomly selected four categories of operations based on type and production volumes, and applied the respective royalty, PIT and APIT rates as envisaged by the PIFB to determine state take (overall percentage government share of gross profits). We also assumed the current oil prices to be around US$75, which is not far from the prevailing OPEC basket. The self-explanatory chart below summarises our findings



It's progressive when prices go up, but not when costs come down

We then tested the degree of progressiveness by raising the oil price arbitrarily to US$85 and tested also by halving assumed costs while holding everything else constant. For consistency, we ran these scenarios for the four categories of operations.



The envisaged system works well when prices go up. However, we consider that the other source of increase in profitability, i.e. cost efficiency, is not captured by this formula.

Policy risk

This could well be a policy choice to reward companies for keeping costs down (company take increases at the expense of state take when costs come down), but specific incentives have been designed for this purpose in the CEF. This raises a possible flag (maybe not red, but reddish) in the implementation of this provision. In our experience, the probability of some regulator picking up on this matter later on and ~~forcing~~ encouraging renegotiations is a policy or regulatory risk worth keeping an eye on.

Misplaced complexity?

The provisions of the PIFB are, in terms of detail, a statement of recognition that the implementation of these things can be complex. We even noticed a sly message in s.2 of the Bill to the FIRS and the Petroleum Regulatory Commission clearly stating who will calculate and administer what. Administrative complexity therefore, in our initial view, does not factor as a big deal.

That said, depending on the policy thinking, some of this complexity could be shifted around in order to perhaps strike a more sustainable balance between investment attractiveness and value extraction. The APIT is an opportunity for this.

Rate of return systems that track the relationship between revenues and costs, similar in calculation principle to the CEF, would definitely result in an APIT that yields a higher government take no matter the source of profitability. This approach will reduce the need, for example, to revisit the provisions in seven years as envisaged in s.73.

All in all, seems a decent attempt

As the key provisions currently stand, it is refreshing to see that there is not a lot of discretionary space. It is also pretty cool to have a clear delineation of responsibilities for the administration of the money stuff. The incentives on offer are much simpler than what was envisaged in the 2012 PIB, and what currently obtains.

But some clarification will be useful

The choice of production-based royalties and the number of categories seems to raise things on the complexity scale, in the unnecessary category. The choice of a price-based APIT seems to reduce the level of government take if the source of profitability is cost efficiency, thereby making the system look a little generous. We are not saying this is a bad thing. It could well be strategy to increase the inflow of risk capital for development projects, especially for Frontier Basin and deep water offshore projects. But given that incentives for keeping costs down have already been addressed by the CEF, we got a little curious and look forward to finding out more.

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