July 2021

Moneda Special Report

MONEDA

PETROLEUM INDUSTRY BILL

In This Report:

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"Our mission is to trigger unconventional growth in African natural resource value chains - using alternative credit systems and world class execution."

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EXECUTIVE SUMMARY

The oil and gas industry is the backbone of revenue for Nigeria's economy, yet, the oil and gas reserves in Nigeria have remained stagnant for decades, and this stagnancy has cast a dark shadow on the entire industry. Even in stagnancy, the current level of activities being carried out in the industry has grossly failed in retaining value in the country. While attempts have been made, via local content laws, to remedy this situation, our retainment can only go as high (or low) as the investment level goes.

The current level of investment [or lack of it] in the country shows that investors are generally opposed to uncertainties and there is a thick shroud of uncertainty hovering over the fiscal climate in Nigeria's oil and gas industry. The Petroleum Industry Bill crafted with every intention to correct many of the anomalies in the industry and provide a new fiscal regime has been passed by both chambers of the legislature. During its journey through the legislature, the bill endured a series of changes, most of which show an almost desperate need by the legislature to attract investment into the country through reduced taxes and other incentives.

As of the time of writing, the bill is awaiting assent by the President, after which the bill will become law. In anticipation of this, Moneda R&I analyses the provisions of the bill as well as its possible impact on the industry and the country in general.

GOVERNANCE: WHO CONTROLS WHAT AND HOW?

THE GOVERNANCE OF THE NIGERIAN PETROLEUM SECTOR IS THE PIVOTAL GROUND UPON WHICH EVERY OTHER ASPECT OF THE SECTOR RESTS. THE PIB TAKES A BOLD MOVE OF STRIPPING THE DISCRETIONARY POWERS HELD BY THE MINISTER FOR THE PAST FIVE DECADES AND VESTING THEM ON INSTITUTIONS.

The beginning of a better industry obviously comes with the creation of better-structured regulatory bodies.

The Nigerian Upstream Regulatory Commission (the Commission) and the Nigerian Midstream and Downstream Petroleum Regulatory Authority (the Authority) are to be created pursuant to the provisions of Part III and IV of Chapter 1 of the bill. According to the duties of these bodies explicated by the aforementioned sections, these bodies will perform the same functions hitherto performed by the Department of Petroleum Resources (DPR), the Petroleum Pricing and Product Regulatory Agency (PPPRA), and the Petroleum Equalisation Fund. Sections 311 through 315 state guidelines on how this transition is expected to be executed including the transfer of assets, liabilities, and employees.

Both bodies are expected to manage a fund known as the Commission Fund (section 24) and the Authority (section 47) where all monies accrued to the bodies are paid and from which all budgetary obligations, approved by the National Assembly, are met.

This development is very likely to impact he industry positively. Currently, DPR acts as a regulator in

KEY PROVISIONS

Part II, Section 4 (1):

> There is established the Nigerian Upstream Regulatory Commission (the "Commission") which shall be a body corporate with perpetual succession and a common seal.

Part IV, Section 29 (1):

> There is established the Nigerian Midstream and Downstream Petroleum Regulatory Authority (the "Authority"), which shall be a body corporate with perpetual succession and a common seal.

the upstream and downstream. The creation of two separate bodies that are each intended to focus on one sub-sector could lead to the development of expertise in that sub-sector. This specialization could improve its efficiency and effectiveness in interacting with other players as well as laying down forward-thinking strategies.

Where having two separate regulatory bodies breaks down.

The Commission and the Authority are intended to oversee the upstream and midstream & downstream respectively. Section 302 (3) makes it clear that a company looking to play in more than one stream would need to incorporate another company that will operate in that stream. This should make regulation easier since the Commission and the Authority would both be regulating different companies each, right? Well, it is more complicated than that. Cases where these streams overlap are common and the legislature acknowledges this in paragraph 8g where it puts the Commission solely in charge of facilities where there are fully integrated upstream and midstream activities. The question is 'does this not defeat the purpose of having two separate regulatory bodies?'

To complicate matters further, Sections 142 and 146 both deem natural gas-producing, upstream lessees as qualified entities for wholesale and retail gas supply licenses, both of which are within the downstream sector and are granted by the Authority. These companies would now be under the regulation of the Commission and the Authority.

While the perks of two regulatory bodies far outweigh the downsides posed by inevitable overlaps, one thing that was very rarely preached is synergy between both bodies so as to blur out these overlapping areas.

Promoting investment through active participation of the Commission and the Authority.

Some projects are very risky and would likely not have economic appeal to investors yet they need to be explored to ensure the country's energy security. In the upstream, frontier basins pose this risk. Section 9 of the Bill tasks the Commission to promote the exploration of these basins by creating a Frontier Exploration Fund. Subsection 4 of this section stipulates that the fund shall be 10% of rents on petroleum prospecting licenses and petroleum mining leases as well as 30% of NNPC Limited's profit oil and profit gas.

Likewise, the Authority is expected to maintain a Midstream Gas Infrastructure

Fund which will enable the government make equity investments in projects that will improve local consumption of natural gas. The fund will be made up of 2.5% of the wholesale price of petroleum products and natural gas sold in Nigeria. In addition, it will include the fees collected as penalties for gas flaring by the Commission.

Should these funds be properly managed, they could go a long way to make high-risk investments (like gas pipelines and exploration of frontier basins) more appealing to investors. This means all operators with joint ventures with NNPC currently would have to incorporate this JV, if they so wish, after agreeing and executing shareholders' agreement as well as the provisions in the memorandum of association.

Nigerian National Petroleum Company (NNPC) will act less like a regulator and more like a profit-oriented company.

This is to be achieved through the incorporation of the NNPC under the Companies and Allied Matters Act, pursuant to section 53 of the bill, after which NNPC would be transformed to NNPC Limited. As subsection 3 of this section provides, all shares shall be vested in the Nigerian Government which will be held by the Ministry of Finance Incorporated and the Ministry of Petroleum Incorporated in equal proportions. With regard to upstream operations, joint operating agreements between NNPC and operators may be renegotiated (on a voluntary basis) as a joint venture carried out by way of a limited liability company, each referred to as an "incorporated joint venture company" (IJV).

These IJVs would likely improve the efficiency of the JVs as the shareholders would consist of representatives of NNPC Limited (which would make decisions in the best interest of the government) and representatives of the operator (which would be looking to make decisions in their investors' best interests). This could strike a balance and, as we have seen with NPDC's Asset Management Teams, could lead to better-run operations. However, the envisaged increase in efficiency is heavily dependent on the probability that the change in NNPC's structure would cause any positive change with respect to their speed and efficiency in decision-making.

Section 53(8) sheds more light on the legislature's expectation of NNPC Limited. Accordingly, this section provides that where NNPC Limited has a participating interest or 100% interest in a lease or license, it is mandated to pay its share of all fees, rents, royalties, profit oil shares, taxes, and other required payments to the government as any company in Nigeria.

A very interesting cause for concern, though, is in the area of transfer of assets and liabilities between NNPC and NNPC Limited. Section 54 (1) states that the Minister of Petroleum alongside the Minister of Finance would determine the assets, interests, and liabilities that would be transferred. The section and subsequent sections do not make provisions that would guide the decision making leaving it open to more sentiment rather than sound judgement. Subsection 2, however, states that assets and liabilities which are not transferred shall remain with NNPC until they are extinguished or transferred to the government. A recent update to the bill allays fears that the liabilities not transferred to NNPC Limited stand the risk of not being fulfilled. The Minister of Petroleum, Minister of Finance, and the Attorney-General of the Federation are mandated to develop a framework for the payment of all liabilities not transferred to NNPC Limited.

The definition of license/lease areas could be going through constant changes.

Section 69 defines a new national grid system to be adopted by the country in setting boundaries for upstream leases and licenses. This new system is intended to allow for the subdivision and aggregation of parcels into new areas independent of their parent areas. Current leases that do not follow this system are expected to be left unaltered but be apportioned in parcels.

While this new system is to allow for a more structured definition of license and lease areas, the exact system to be adopted was not stated in the bill rather the Commission is directed to liaise with the Surveyor-General in the creation of this system. Some guidelines were, however, stated which would give an idea as to the line the new system would toe (subsections 4-5). Existing licenses and leases would be affected since their blocks would be apportioned in parcels and there is a significant probability that these parcels could be awarded to other entities.

On the flip side, there is also a probability that operators could be awarded more parcels. One thing is certain, however, some operators may lose fields while some may gain. Should this apportioning be done in a transparent and fair manner, it could also give room for the bolstering of local capacity as smaller companies could be encouraged with small parcels so they could grow organically.

Different leases, but on the same piece

of land - a recipe for rifts.

Leases in the upstream will not be seen as surface blocks anymore but will be awarded based on subsurface fields. As section 81 (12) confirms, if a lessee discovers a field at a shallower or deeper depth than that it is producing, a separate lease will be granted to the company for that discovery after submitting a field development plan. Paragraph 88 (5b) further complicates the situation. It is now possible for lessees to relinquish the leases to deeper formations and after which they can be granted to other parties. While this aims to discourage idle fields and promote investments, it is bound to cause friction between operators who would have to target different fields ion the same surface. Harmonizing operations would prove extremely difficult.

Licenses/leases would take a new shape, not only on the ground but on paper as well.

The names of licenses and leases were tweaked in section 70. While this name change, perhaps, shows the intention of the government to remain technically and grammatically correct in the accommodation of the exploration and mining of natural gas, the description, bidding, and award processes for these licenses do not significantly differ from what is currently obtainable. As a result, the name change might have very little actual impact. Section 69 (3)'s mandate for a new numbering system in those licenses and leases, perhaps has more impact. The numbering system is intended to also allow for the subdivision and aggregation of parcels of acreages. This reiterates our concern for the potential revocation and re-awarding of parcels that may contain part or full fields. Should this be the case, lease operators would be in a

UPSTREAM LICENSES WILL UNDERGO A NAME CHANGE

OIL EXPLORATION LICENSE	→	PETROLEUM EXPLORATION LICENSE
OIL PROSPECTING LICENSE	→	PETROLEUM PROSPECTING LICENSE
OIL MINING LEASE	→	PETROLEUM MINING LEASE

CONDITIONS FOR LICENSE RELINQUISHMENT

Prior to the expiration of the initial exploration period or of the optional extension period, a licensee shall relinquish every area that is not an appraisal area, retention area or lease area based on parcels or sub-parcels.

A Licensee of a Petroleum Prospecting Licence may voluntarily relinquish parcels and sub-parcels provided he has met all obligations in the contract and the retained shape is approved by the Commission.

After 10 years of the commencement of a Petroleum Mining Lease the applicable Lessee shall relinquish all parcels which do not fall within the boundary of a producing field under this Act and any formation deeper than the deepest producing formation shall be relinquished

guessing game if these stipulations would be in their favor or not.

Relinquishment of blocks will not only come as a whole but it could also come in parts.

The provisions in section 88 show that holders could relinquish significant parcels in their acreages (either willingly or unwillingly) making these parcels available to be awarded to other operators. Based on the conditions set for this relinquishment, operators may attempt to avoid relinquishing parcels through widening appraisal areas. This could translate to more investments and more discoveries.

Marginal fields will be re-awarded as blocks but will anything change?

Discoveries that have been declared as marginal fields and aren't under production at the time the bill is passed would be granted a petroleum prospecting license as described by section 94 which is different from today's laws where marginal fields are still classified under their parent block license. It is unclear as to what difference this will make in terms of impact on operations if any at all since the bill also mandates a farm-out agreement to be executed between the original operator of the lease and the new marginal field operator which is not different from what is obtainable now.

No new marginal fields will be declared.

It is unclear what the rationale for this provision is as none was given but section 94 (9) states that no new marginal field will be declared under this Act.

The bill does not only affect upstream licenses, midstream and downstream ones are also on its radar.

As with the prevailing laws, on the midstream and downstream side, operators are still required to obtain licenses and permits to undertake activities, however, the licenses have now been explicitly defined and delineated to ensure holders have a

SOME NEW MIDSTREAM AND DOWNSTREAM LICENSES

- LICENSE TO ESTABLISH, CONSTRUCT AND OPERATE A TERMINAL OR JETTY FOR THE EXPORT OR IMPORT OF GAS.
- LICENSE TO OPERATE A NATURAL GAS TRANSPORTATION NETWORK
- THE DELINEATION OF A LICENSE FOR WHOLESALE AND RETAIL TRADING OF NATURAL GAS
- LICENSE TO ESTABLISH, CONSTRUCT AND OPERATE A TERMINAL OR JETTY FOR THE EXPORT OR IMPORT OF CRUDE OIL OR PETROLEUM PRODUCTS.

specified function and are well equipped to carry out this function. Any player that wants to play in more than one capacity would be required to show competence in them and to obtain each of the licenses. A few new licenses have also been added. All these initiatives are aimed at improving the competence of operators in the industry or even better, sieving through them ensuring only the competent ones carry out these activities. Some of the licenses (especially gas-related) carry incentives, such as tax breaks, with them. This will encourage more willing participants to show interest in the development of gas infrastructure.

Government, through its regulatory bodies, may interfere with prices..

Section 169 vests the power of price control of midstream and downstream products (gas and liquids) on the Authority where 'it determines that there is a monopoly or undeveloped competition'. The bill is not explicit on what denotes 'undeveloped competition' and leaves the interpretation to the Authority which we consider dangerous Players would stand the risk of fickle profitability should the Authority meddle with the market prices. It is our considered opinion that a better approach is allowing the market develop through market forces and undeveloped competition be combated with regulatory incentives so as to attract new entrants into the industry.

OPERATIONS: HOW PLAYERS ARE EXPECTED TO PLAY

OPERATORS IN THE INDUSTRY ARE EXPECTED TO BE MORE RESPONSIBLE. FROM ENVIRONMENTAL ISSUES TO SUPPLY SECURITY, THE BILL LOOKS TO ENSURE THAT ALL ACTIVITIES ARE CARRIED OUT IN A MANNER THAT IS CONSIDERED TO BE IN THE COUNTRY'S BEST INTEREST.

NNPC and refiners are tasked with making up for the petroleum products shortfall foreseen by the legislature.

In what seems to be the provision that has caused the most uproar, the second paragraph of section 317 (8) mandates the Authority to only grant licenses for importation of shortfalls to companies with active local refining licenses. The import volume to be allocated is dependent on the refining output of the previous quarter.

Despite the incentives to attract investors to the Nigerian refining scene as well as feedstock supply obligations imposed on crude producers, it is somewhat understandable that circumstances beyond control could induce a product shortfall. What is puzzling, however, is restricting the importation to only refiners and even worse, putting a limit to how much can be imported based on refining license that has no bearing on the capacity of the company to effectively carry out this importation.

Attract as many investors as possible through exclusivity and/or non-exclusivity of licenses or leases.

Petroleum Exploration Licenses (PEL) are granted to qualified applicants on a non-exclusive basis. This means

KEY PROVISIONS

Section 102 (1):

A licensee or lessee shall submit for approval an environmental management plan in respect of projects which require environmental impact assessment to the Commission or Authority, as the case may be.

Section 110 (1a):

the Commission shall, by a Regulation or guideline made under this Act, prescribe and allocate the domestic gas delivery obligation on a lessee before 1st March of each year based on the domestic gas demand requirements.

that on the same land, an unlimited number of companies can carry out exploratory (geologic and geophysical) work. Petroleum Prospecting Licenses (PPLs) come with a twist. Licensees can drill exploratory and appraisal wells on the acreages on an exclusive basis but geologic and geophysical work on those acreages are not exclusive.

Any company can bid for and be granted a PEL over those acreages. While the same applies for Petroleum Mining Leases (PMLs), an additional side to the lease is the ability to own and dispose of crude produced on the acreages on an exclusive basis.

Having a tonne of seismic data of the same basins from different sources will give better subsurface understanding, inform better decisions and increase the probability of hitting hydrocarbon. Apart from the aforementioned, it will also increase government revenue since two or more companies will be required to pay the fees required to obtain these licenses.

The oldest trick in the book - boosting weaker industries through legislation.

Perhaps in hopes of a potential booming refining industry, the bill also addresses the concern of continuous domestic crude oil supply. Section 109 mandates the Commission, in collaboration with the Authority, to impose crude oil supply obligations on operators of mining leases so refiners are never starved of feedstock. While on the gas side, domestic gas supply obligations are currently being imposed as mandated by the prevailing regulations, the new bill states a heavy penalty ($3.5/MBTU of gas not delivered) on defaulters. These provisions would not only increase the consumption of gas in-country, but it would also boost the refining industry and reduce reliance on imported petroleum products.

Saving cashflows of today to offset contingent expenses of tomorrow.

At the end of the life of the project, operators are mandated, pursuant to section 233, to decommission the equipment and facilities in a responsible manner and in accordance with the decommissioning and abandonment plan submitted prior to the award of license (which also formed the basis of the grant of license). While these are not exactly new, what has been added is the creation of a decommissioning fund (subsection 1) which is to be held by a financial institution that is not an affiliate of the operator and operators (or potential operators) are now mandated to state the yearly contribution to the fund in the decommissioning plan.

An interesting strategy for combatting gas flaring.

From strict penalties (which are geared towards the Midstream Fund) to section 105 (2)'s 'threat' that the Commission reserves the right to take natural gas destined for the flare stack free of charge, the bill's stance on gas flaring is clear.

Environmental impact is beginning to take center stage in Nigeria.

Another welcome development is the attempt to reduce the industry's imprint on the environment through the provisions of section 102. The bill mandates operators to provide an environmental management plan to the Commission or the Authority, as the case may be after the license or lease has been granted. Subsection 3 and 4 explicate the rationale for the appropriate regulatory body to approve the submitted plan and subsequently can direct the operator to include certain information to the proposed plan. Also, to achieve this reduced environmental impact, subsection 7 mandates operators to obtain permits before utilizing any chemical in their operations.

Further to these provisions, as expressed by section 103, an environmental remediation fund is to be created by the Commission and the Authority where operators are to pay a prescribed fee periodically aimed at the rehabilitation of negative environmental impacts.

While these provisions come from good intentions and could go a long way to ensure environmentally responsible operations, the bill is mute on the most important thing; execution. Of what use is an approved plan if it is not being followed? What measures are put in place to ensure that the plan is followed to the letter? In the event of an incident is the source of finance for remediation solely from the fund or is the fund just a backup? If the former is the case, can the remediation fund offset every environmental incident that would occur throughout the life of the project? What are the penalties for noncompliance? These are questions that the bill fails to answer which defeats the effort of the aforementioned sections as things are very likely to remain the same if these questions are not addressed.

FISCAL REGIMES: WHAT ACCRUES TO THE GOVERNMENT

IN NIGERIA, WHERE OIL MONEY IS EVERYTHING, A VERY SENSITIVE TOPIC IS GOVERNMENT-TAKE. WHAT MAKES IT EVEN MORE COMPLICATED IS THAT AS THE GOVERNMENT WANTS MORE, SO DO OTHER STAKEHOLDERS. A BALANCE WOULD NEED TO BE FOUND BUT HAS THE PIB HIT THIS BALANCE?

From Petroleum Profit Tax to Hydrocarbon Tax - what is different?

Hydrocarbon Tax would now be chargeable on operators of upstream assets as defined by section 260 of the bill. This tax, which will be accompanied with Company Income Tax subject to the Companies Income Tax Act, would be chargeable on crude oil and condensates from associated gas reservoirs. Natural gas and condensates from non-associated gas reservoirs are exempted and this is different from the Petroleum Profit Tax which does not totally exempt gas revenues but only gives incentives. An even bigger deviation from the PPT Act is the fact that the assessable tax is lower and also dependent on terrain. Deep offshore acreages will be totally exempted from this tax as provided for in subsection 3 of the section.

HT: 30% for onshore and shallow water licenses and leases that are converted pursuant to section 93.

15% for onshore and shallow water acreages that are granted after the commencement of the Act.

Additional tax deductions may or may not get potential investors excited.

KEY PROVISIONS

Section 261:

There shall be levied upon the profits of any company engaged in upstream operations in relation to crude oil a tax to be known as hydrocarbon tax, which shall be charged and assessed upon its profits.

Section 110 (1a):

the Commission shall, by a Regulation or guideline made under this Act, prescribe and allocate the domestic gas delivery obligation on a lessee before 1st March of each year based on the domestic gas demand requirements.

In addition to the stipulations of the Petroleum Profit Tax Act which governs the current fiscal regime in the industry, the Petroleum Industry Bill, through section 263, proposes some additions to the deductions allowed to estimate operators' adjusted profit:

a) an expenditure, tangible or intangible directly incurred in connection with the drilling of the first exploration well and the first two appraisal wells in the same field.

b) any amount contributed to a fund, scheme or arrangement approved by the Commission. These contributions include those to the decommissioning and abandonment fund as well as the host communities development trust.

c) costs of gas reinjection wells, which are re-injecting natural gas that otherwise would be flared

The (a) point is a very interesting deduction that would save operators significant sums and in turn motivate them to pour out investments in the early stages of field development.

Cost deductions are good but putting a limit is better - at least for the government.

Pursuant to section 2 of the sixth schedule of the bill, all costs incurred which are eligible for tax deductions (section 263) must not exceed 65% of the gross revenue determined at the measurement points. However, excess costs which are not deducted in an accounting period may be allowed for deduction in subsequent years provided that those years do not exceed their individual limits. It gets more interesting - where any costs have been carried over at the period of termination of upstream license, they shall be forfeited and not be allowed for hydrocarbon tax deductions.

These stipulations are straightforward and are intended to manage the interests of the government and the country. Also, we do not envisage that it would cause any substantial detrimental impact to the operators.

Even more tax incentives for investors in gas pipeline

Although section 302(5) confers the benefit of gas utilization incentive to midstream and downstream companies, the latter part of that subsection provides an additional tax-free period of 5 years to investors in gas pipelines. Gas pipelines require heavy investment and the payback period is usually slow but they are very necessary infrastructure for the consumption of gas in the country. These provisions could significantly improve the profitability

ROYALTIES

PETROLEUM AMENDMENT REGULATION 2020

ADDITIONAL ROYALTIES WHICH IS BASED ON OIL PRICE

- $0 - $20
  0%
- $20 < X < $60
  2.5%
- $60 < X < $100
  4%
- $100 < X < $150
  8%
- > $150
  10%

ROYALTIES BASED ON TERRAIN

- ONSHORE
  20%
- < 100M WATER DEPTH
  18.5%
- 100M < X < 200M WATER DEPTH
  5%
- >200M WATER DEPTH
  10%
- IN FRONTIER BASINS
  20%

PETROLEUM INDUSTRY BILL

ONSHORE FIELDS

- <= 10,000 BPD
  TRANCHED BASIS:
  FIRST 5,000 BPD - 5%
  NEXT 5,000 BPD - 7.5%
- > 10,000 BPD
  FLAT RATE - 15%

SHALLOW WATER

- <= 10,000 BPD
  TRANCHED BASIS:
  FIRST 5,000 BPD - 5%
  NEXT 5,000 BPD - 7.5%
- > 10,000 BPD
  FLAT RATE - 12.5%

DEEPWATER

- <= 50,000 BPD
  FLAT RATE - 5%
- > 50,000 BPD
  FLAT RATE - 7.5%

IN ADDITION TO PRODUCTION-BASED ROYALTIES, OPERATORS WILL ALSO PAY PRICE-BASED ROYALTIES

- < $50
  0%
- $50 < X < $100
  LINEAR INTERPOLATION BETWEEN 0% & 5%
- AT $100
  5%
- $100 < X < $150
  LINEAR INTERPOLATION BETWEEN 5% & 10%
- > $150
  10%

NATURAL GAS & NGL

- REGARDLESS OF THE TERRAIN
  5%
- SHOULD THE GAS BE MONETIZED IN THE COUNTRY, THE ROYALTY DROPS TO:
  2.5%

and subsequently attract investors.

Royalties would not only be based on production but prevailing oil price as well.

The most recent regulation prior to this bill is a 2020 amendment to the Petroleum Regulation 1969. Just like this regulation, additional royalties would also be paid which is a function of the prevailing oil or gas price as the case may be. However, unlike the former, the latter states lower values and also splits the royalties of each terrain based on the level of production.

Overall, it is not difficult to see that the stipulations of the PIB with regards to royalties are more reflective of a sliding scale method which is a fair way of charging operators. Higher production would be charged higher than lower production and more technically challenging terrains would be charged lower. Investors are very likely to encourage this method and favor this over the former method. Some may argue that this would decrease government revenue for the country but it is our considered opinion that this would encourage more investment which would lead to higher production, enough to cover for the shortfall, and more.

New flexibility on the currency of royalties.

The Bill mandates the prioritization of the supply of crude oil to domestic refineries and the provision of paragraph c of 109 (4) suggests that negotiations between oil-producing lessees and refiners could proceed in USD or Naira. Based on this consideration, section 9 (3) of the Seventh Schedule suggests that royalties may be paid in Naira for crude delivered to local refiners. Subsection 4 of the section goes further to suggest that the Commission may remit royalties to the Federation in kind rather than in cash. It is difficult to see how this strange provision would be of any benefit to the country.

Two deductions to NNPC Limited's profits could reduce government revenue.

Of all profit made by NNPC Limited through its operations in accordance with the provisions of the Bill, pursuant to section 53 (7), the entity is mandated to retain 20% as working capital and declare dividends to its shareholders. If handled properly, this could go a long way in ensuring the growth of the company and result in higher profits which would also translate to higher revenue for the government. Another deduction that continues to raise eyebrows, however, is the stipulation of section 9 (4) that mandates the diversion of 30% of NNPC Limited's profit oil and profit gas as in the production sharing, profit sharing, and risk service contracts to the Frontier Exploration Fund. The exploration of frontier acreages is a high-risk venture with a very low probability of yielding success and making NNPC Limited spearhead this exploration rather than private companies who have experience in these high-risk basins makes it all even worse.

Unpaid money government take would accrue interest

Sequel to section 100 (2), royalties, fees, rents, production or profit shares, and other required payments to the Government must be remitted within 30 days after they are due else they would start accruing interest. Perhaps, this is a scheme to motivate companies to make payments on time so as to ensure a steady flow of income to the government purse.

OTHER IMPORTANT PROVISIONS...

Fostering co-operation between the industry and host communities through a trust fund.

Subject to section 240 (2) of the bill, operators of licenses or leases are expected to create a development trust which would be made up of an amount equal to 5% of the actual operating expenditure of upstream operations from the previous calendar year. This trust is aimed at providing finance for the development of host communities including the execution of projects and other empowerment opportunities. An interesting point of view taken by the legislature is the exemption of Midstream and Downstream sectors in the contribution, stating lower profit margins as the basis for this decision.

Section 257 (2) would very likely promote more secure operations in the industry. The section stipulates that damage caused by vandalism would be deducted from the fund, saving operators a significant amount of money. As a result, it is very likely that this will call the communities to order and vandalism could reduce.

CSR spending can be more efficient when it means more.

Sequel to the grant of a lease or license, operators are mandated to carry out a host community needs assessment and as a result create a development plan to be submitted to the Commission or the Authority, as the case may be. This plan, which is pursuant to section 251 of the bill, will be put into consideration during the establishment of the trust. One would be tempted to believe that this would lead to a smoother relationship between host communities and operators but we must consider that most companies already carry out these studies, albeit without statutory obligation, yet no formidable partnership has been formed with the indigenes. Perhaps, would the inclusion of individuals recommended by community stakeholders provide some form of recourse? This question remains to be answered after the bill is enacted.

In A Nutshell...

Huge changes, significant impact?

The overriding goal of the Petroleum Industry Bill is to bring lasting change to the Nigerian oil and gas industry. In order to attract the much-needed investment and ensure transparency in the industry, the bill seeks to take steps to reform the governance, administrative, regulatory, and fiscal framework of the industry.

The current version of the bill, which is the result of the review done by a committee set up by the Senate, includes a steep downward revision of not just taxes but royalties as well and this shows an almost desperate need by the country to attract investors. Many analysts believe the bill is coming a little too late. While they make very valid points, perhaps, it is better late than never. It is very difficult to predict the future and even more difficult to quantitatively estimate the impact of the provisions of the bill. However, educated and well-calculated guesses could be made with respect to the general reaction of the industry should this bill come into force.

From the perspective of the producers.

The risk appetite of Big Oil (including Shell, Total, ExxonMobil and Chevron) is on a steady decline and these companies are moving towards low risk and low production cost areas like Guyana. The recent announcement by Shell to abandon all onshore fields is clear proof of the state of mind of the decision-makers in Big Oil. Despite the removal of Hydrocarbon Tax in deep offshore fields and significantly reduced royalty rates, we do not foresee any major oil company snapping up new acreages. International independents (including Tullow, FAR, Woodside Petroleum, etc.) have a higher risk appetite and as a result of the enticing incentives, we expect an influx of these companies into Nigeria.

This also presents a good opportunity for Nigerian independents to snap up more fields, increase their portfolio,

and potentially, their revenue. We expect that this would happen. We may begin to see more Nigerian independents literally testing the waters and dabbling into offshore acreages.

In NNPC Limited's case, perhaps, the roll of dice is easier to predict. Only time will tell if the provisions of the bill (particularly the incorporation of NNPC) would solve the company's inefficiency with respect to oil production.

From the perspective of the contractors.

It is not hard to see that contractors would be the biggest winners in all of this. Regardless of who is making investments in the industry, they would need equipment, infrastructure, and services that would be provided by contractors. Apart from the increase in revenue that contractors will see in the upstream, there is the benefit of diversification of revenue as well as widening expertise which will come from the unlocking of the refining sector. In periods of low crude oil prices, the refining sector booms, and contractors can now make up for the shortfall in revenue with contracts from refineries. Contractors who strategically position themselves would see their exposure to the industry volatility greatly reduce.

One downside that may not be immediately evident is how this PIB would increase contractors' exposure to FX risk. The bill is littered with provisions that make operators of upstream, midstream, and downstream licenses or leases exchange products for cash in local currency (Naira). While these provisions come from a good place, we foresee that these operators would greatly increase the frequency of Naira payments to contractors, however, their costs will still be in dollars since the required equipment will still be sourced abroad.

From the perspective of banks and other financial institutions.

A very obvious direct impact of increased activity in the oil and gas industry is the consequent increase in the demand for finance (through loans) to execute these operations. While It is very difficult to quantitatively estimate just how much increment will occur, various scenarios explored point to a significant increase in demand for finance. The question of the capability of banks and other financial institutions to meet this demand will continue to be asked but there is more. The expectation that more investment will find their way into high-risk, high-capital ventures in the industry particularly in gas infrastructure and frontier basin exploration complicates things. These are areas that are not only high risk but are new and strange to the traditional financial institutions and as such, they are very likely to shy away from them even if they have the capital base to execute.

To make matters worse, PIB cripples their access to foreign currency by forcing producers to supply local refiners with crude oil and allowing this purchase to proceed in Naira. Nigeria's largest supplier of foreign exchange will now have more local currency in circulation than it should. On the other hand, until the industry grows to a point of self-sufficiency, in terms of technical expertise, equipment, and machinery, input to the industry will be sourced abroad. As a result, in the near term, while there will be an increase in the demand for foreign currency-denominated loans, the ability to meet this demand will be lower, thus, further widening the funding gap in the industry.

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