Petroleum Industry Bill (PIB) 2020 - A Game Changer ?

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Preface

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The oil and gas industry has a significant impact on the Nigeria's economy. Though the industry contributes less than 10% to the country's gross domestic product, it contributes about 90% of the foreign exchange earnings and 60% of total income. Consequently, any adverse change in the industry will have a big and long-term impact on government finances. This is the reason why successive governments have remained focused on the sector despite various dis-cus-sions on diversifying the economy.

For the past 20 years, there have been various attempts at reforming the industry. However, none of these efforts has yielded any tangible result until the introduction of the Petroleum Industry Bill (PIB) 2020. Prior to now, there were various iterations of the PIB. The PIB started as an omnibus bill and was later divided into 4 separate bills before emerging in 2020 as a consolidated bill.

It is a fact that previous attempts at passing the PIB in 2009, 2012 and 2018 failed because of factors such as lack of ownership, misalignment of interests between the National Assembly and the Executive, perceived erosion of ministerial powers, stiff opposition by the petroleum host communities and push back by investors on the perceived uncompetitive provisions in those versions of the bill. The PIB 2020 is set to address all the issues to the extent possible. It should be noted that the present administration has demonstrated unparalleled commitment to passing the bill. However, it is important that we do not just pass any law but a law that is competitive, balanced, fair, reasonable and realistic.

The jury is out on whether the PIB will achieve these objectives. One thing is clear – government has tried to strike a balance between immediate revenues demands and the need to attract long-term investment for the industry. This has become extremely crucial when one considers the fact that only 4% of the $70billion investments made in Africa's oil and gas industry between 2015 and 2019 was in respect of Nigeria even though it is the biggest producer and has the largest reserves on the continent. According to the National Bureau of Statistics, only $53.5m or 0.55% of total invest-ment of $9.680billion in Nigeria in 2020 was made in the industry.

If we must achieve our ambition of 40 billion barrels of oil in reserves and 4million barrels of oil per day, we need to attract new investments into the sector. This task has even become more daunting in the light of the various challenges facing the industry, especially with respect to the renewed focus on renewables and energy transition. The oil in the ground is of no use to the country if it cannot monetize it. Therefore, the PIB must lead to a massive transformation of the industry and succeed in attracting the desired investment required to reposition the industry. Otherwise, Nigeria's production will continue to decline significantly.

Hopefully, the provisions of the PIB will be enough to stimulate the desired investment though it has not addressed the issue of energy transition from fossil fuel to clean energy. The key question is whether those investments would pay off or would they be a risky bet?

Contents

Glossary

AG	Associated Gas
ACT	Additional Chargeable Tax
BoT	Board of Trustees
CA	Capital Allowance
CAC	Corporate Affairs Commission
CAMA	Companies and Allied Matters Act
CIT	Companies Income Tax
CITA	Companies Income Tax Act
COVID-19	Coronavirus
CPR	Cost Price Ratio
DOIBPSCA	Deep Offshore and Inland Basin Petroleum Sharing Contracts Act
DPR	Department of Petroleum Resources
ETR	Estimated Tax Return
FID	Final Investment Decision
FDI	Foreign Direct Investment
FG	Federal Government
FIRS	Federal Inland Revenue Service
HT	Hydrocarbon Tax
HCDT	Host Communities' Development Trust
MMBtu	Metric Million British Thermal unit
NAPIMS	National Petroleum Investment Management Services
NDDC	Niger Delta Development Commission

NGLs	Natural Gas Liquids
NNPC	Nigerian National Petroleum Corporation
NUPRC	Nigerian Upstream Regulatory Commission
OML	Oil Mining Lease
OPL	Oil Prospecting Licence
PA	Production Allowance
PIA	Petroleum Investment Allowance
PIB	Petroleum Industry Bill
PIFF	Petroleum Industry Fiscal Framework
PHCD	Petroleum Host Community Development
PML	Petroleum Mining Lease
PPL	Petroleum Prospecting License
PPMC	Pipelines and Product Marketing Company
PPPRA	Petroleum Products Pricing Regulatory Agency
PPTA	Petroleum Profits Tax Act
QCE	Qualifying Capital Expenditure
QDE	Qualifying Drilling Expenditure
TET	Tertiary Education Tax
TP	Transfer Pricing
WREN	Wholly, Reasonably, Exclusively, Necessarily


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Governance

Chapter 1 of the Petroleum Industry Bill, 2020 ('PIB' or 'the Bill') vests the property and ownership of petroleum within Nigeria and its territorial waters, continental shelf and Exclusive Economic Zone in the Federal Government of Nigeria, and outlines the following objectives for the governance and administration of the industry:

- To create efficient and effective governing institutions, with clear and separate roles for the petroleum industry;
- To establish a framework for the creation of a commercially-oriented and profit-driven national petroleum company;
- To promote transparency, good governance, and accountability in the administration of the petroleum resources of Nigeria; and
- To foster a business environment conducive for petroleum operations.

1.1 Governance Arrangements

The PIB proposes to formally segment the Nigerian petroleum industry into upstream sector on one hand, and the midstream and downstream sectors, on the other. The upstream sector is to be overseen by the Nigerian Upstream Regulatory Commission ('the Commission'), while the midstream and downstream sectors would be under the oversight of the Nigerian Midstream and Downstream Petroleum Regulatory Authority (the 'Authority'). General oversight powers over the petroleum industry is vested in the Minister of Petroleum ('the Minister'), whom the Commission and Authority are required to report to.

The three governance organs are discussed below:

1.1.1 The Minister of Petroleum ('the Minister')

Section 3 of the PIB retains the Minister's general oversight and supervisory powers over all facets of the petroleum industry. This remains unchanged from the previous governance regime under the Petroleum Act.

Specifically, the Minister is empowered to formulate, monitor, and administer the Federal Government's policy over the petroleum industry. The Commission and Authority are required to report to the Minister, ensuring his oversight powers over the industry, are total.

However, there have been important deviations from the general powers of the Minister of Petroleum as hitherto granted under the previous regime. A glaring change is that the Minister's former unfettered, sole discretion and power to grant or revoke oil licenses have been curtailed. The Bill specifically requires that the Commission provide recommendations to the Minister before the Minister can exercise such powers. Overall, the Bill limits itself to grant of general powers to the Minister unlike under the Petroleum Act which vested the power to grant specific approvals such as Refinery Licences in the Minister – such specific approvals have been generally vested in the Authority or Commission. The key question, therefore, is whether the Minsiter, who may also be the President, may be bound by the recommendations of the Commission on the award of licences given that the President can remove any member of the Commission. Notwithstanding the bold changes in the PIB, it seems that the Minister will continue to exercise a significant influence in the industry.

1.1.2 *The Nigerian Upstream Regulatory Commission ('the Commission')*

Section 4 of the PIB establishes the Commission to have primary regulatory powers and oversight over the technical, operational, and commercial activities of the upstream petroleum industry.

The Commission will regulate all technical activities in the upstream sector by enforcing, administering, and implementing all laws, regulations, national and international policies, standards, and practices relating to the sector. The Commission is also to enforce compliance with the conditions of all leases, license s, permits and authorisations issued to companies in the sector. Such technical activities include seismic operations, drilling operations and design, construction, and operation of upstream facilities, among others. Given that these powers were exercised by the Department of Petroleum Resources ('DPR'), it is clear that the Commission would replace the DPR in that regard as Section 10 vests the Commission with the power as the successor to the DPR and the Petroleum Inspectorate Division.

The PIB empowers the Commission to oversee commercial activities in the upstream, such as reviewing and approving commercial aspects of field development plans, supervising costs and cost control in upstream petroleum operations, implementing cutback orders by the Minister. It seems safe to surmise that the Commission is to take over some of the commercial regulatory previously undertaken by NNPC's National Petroleum Investment Management Services ('NAPIMS').

Further, with a firm view on encouraging activities in frontier basins, Section 9 specifically outlines the responsibilities of the Commission in that regard. To ensure that the desired promotion activities over frontier basins are undertaken, the PIB proposes a Frontier Exploration Fund, to consist of 10% of rents on petroleum prospecting licences and petroleum mining leases.

The vision to promote exploration activities in frontier basins is commendable, as it will ensure long term sustainability of the industry by boosting the available reserves. However, discretion must be exercised to ensure that current reserves are maximized, and the promotion activities over frontier basins are undertaken in areas that are potentially commercially viable, and not a dissipation of energy.

The PIB requires any government body whose action would impact the upstream industry to notify the Commission, prior to taking such action. This specific inclusion is commendable as it should help to minimize disruption and government agencies seeming to work at cross purposes when the overall objection should be viability of the petroleum industry.

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1.1.2.1 Management of the Commission

The Commission is to be run by a Governing Board, which is responsible for its policy and general administration. The members of the Governing Board, which is to be headed by a non-executive Commissioner, are to be appointed by the President subject to the Senate's confirmation. The Commissioners are to hold office for a term of 5 years, which is renewable for a future 5-year term.

The confirmation of the members of the Governing Board is commendable as it enables the Senate to discharge its constitutional oversight function. However, the President solely has the power to remove the members without deferring to the Senate.

The Commission will have six Executive Commissioners for its operational management although only two of the Executive Commissioners (those for Exploration and Acreage Management, and Finance) are to be members of the Governing Board, along with the Chief Executive Officer.

The PIB requires that the salaries of the Commission's employees be benchmarked against the general standard in the petroleum industry, after consultation with the National Salaries, Incomes and Wages Commission.

One of the sources of funds to the Commission will be from fees earned from services rendered to licensees. This is concerning, given the reputation of Nigeria which is rife with incidences of rent seeking by government officials, and issues of conflict of interest, as well.

1.1.3 The Nigerian Midstream and Downstream Petroleum Regulatory Authority ('the Authority')

Section 29 of the PIB establishes the Authority to have technical and commercial regulation of midstream and downstream petroleum operations in the midstream and downstream segments of the petroleum industry.

The Authority's functions include the regulation of petroleum liquid operations, domestic natural gas operations and export natural gas operation. It is also to determine the appropriate tariff methodology for processing of natural gas, transportation and transmission of natural gas, transportation of crude oil and bulk storage of crude oil. The Authority is empowered to issue regulations in pursuance of its regulatory oversight powers.

Interestingly, the PIB seems to suggest that the sole power to grant, issue, modify, cancel, or terminate all licences, permits and authorisations for midstream and downstream petroleum operations, is vested in the Authority. This is a significant departure from the previous regime whereby such powers were typically vested in the Minister. The powers vested in the Authority seem to indicate that it is taking over the functions of the NNPC (PPMC) and the PPPRA.

1.1.3.1 Management of the Authority

The Authority is also is to be run by a Governing Board, which is responsible for its policy and general administration. The members of the Governing Board, which is to be headed by a non-executive Commissioner, are to be appointed by the President subject to the Senate's confirmation. The Commissioners are to hold office for a term of 5 years, which is renewable for a future 5-year term.

As noted with the Commission, one of the sources of funds to the Authority, is to be from fees earned from services rendered to licenses. As previously noted, this should be revisited as quickly as possible, and eliminated to ensure that the Regulators are put on the proper pedestal.

Also worthy of note is the 1% levy to be imposed on the wholesale price of petroleum products in Nigeria. The stated intention of the PIB is to move away from regulated prices to those determined by market forces. A multiplicity of levies and charges may act to distort that reality.

1.1.3.2 The Midstream Gas Infrastructure Fund

Section 52 of the PIB establishes the Midstream Gas Infrastructure Fund, which is to be a body corporate with its own Governing Council chaired by the Minister of Petroleum.

The stated purpose of the fund is to *"make equity investments of Government owned participating or shareholder interests in infrastructure related to midstream gas operations aimed at – (a) increasing the domestic consumption of Natural Gas in Nigeria in projects which are financed in part by private investment; and (b) encouraging private investment."*

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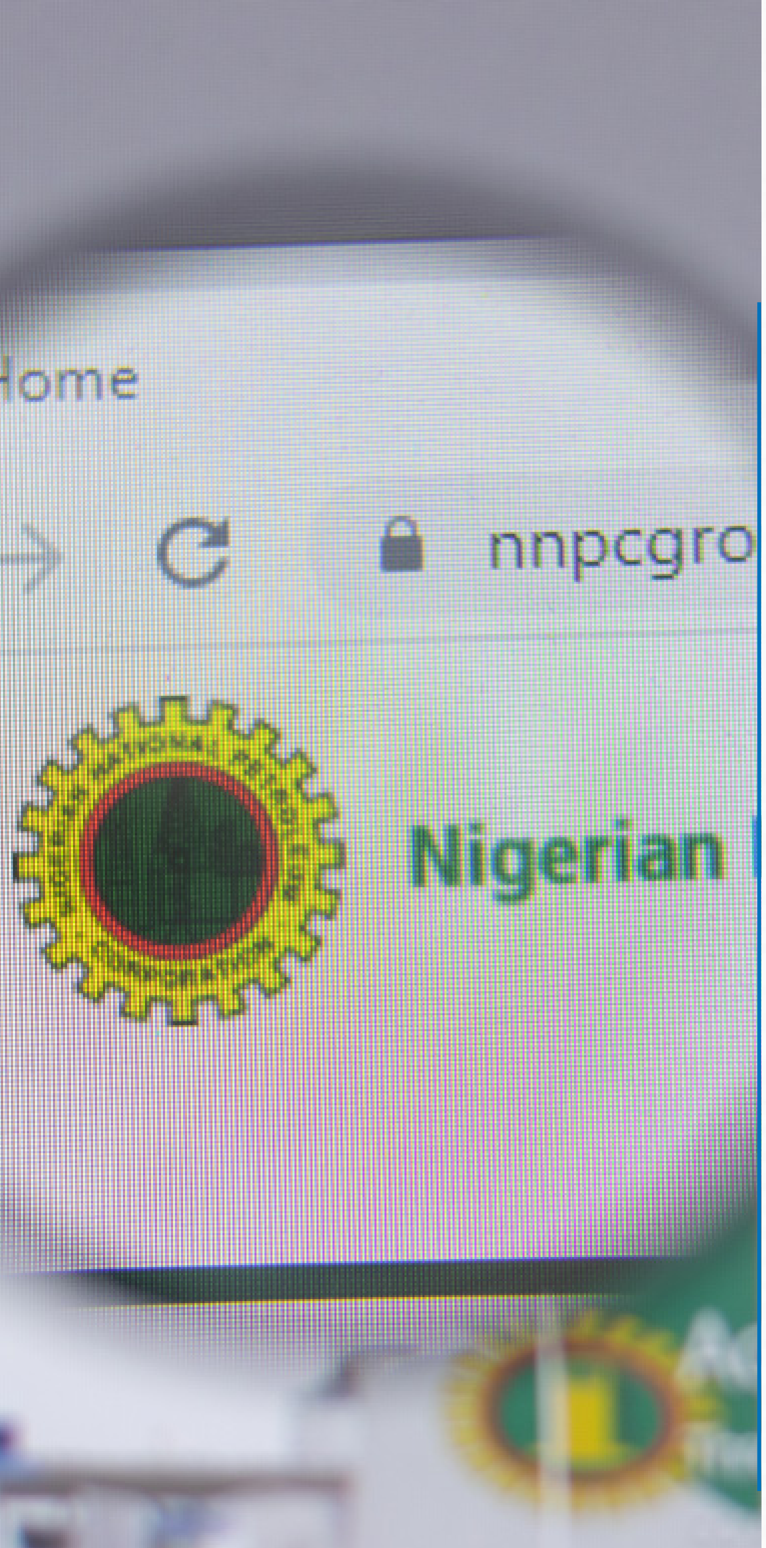

The major source of funding for the Midstream Gas Infrastructure Fund is a 1% levy on the wholesale price of petroleum products sold in Nigeria, and natural gas produced and sold. This levy seems to be the same one to be collected by the Authority with the only distinction that the base is expanded to include "natural gas produced and sold".

Given the oversight of the Authority over this area, it may have been more optimal to make this fund a part of the Authority, rather than seek to have it stand alone as it has been currently set up as this seems as a duplication of governance structures.

1.1.3.3 The Nigerian National Petroleum Company Limited ('NNPC Ltd')

Section 53 directs that the Minister, within six months of the PIB's commencement, incorporate a Nigerian National Petroleum Company Limited at the Corporate Affairs Commission ('CAC'). The shares are to be held by the Ministry of Finance Incorporated on behalf of the Government.

The PIB provides that the Minister of Petroleum and the Minister of Finance are to determine which assets, interests, and liabilities of the current statutory NNPC, are to be transferred to NNPC Ltd. Any other assets, interests and liabilities not transferred to NNPC Ltd would continue to be held by NNPC until they are extinguished or transferred to the Government upon which the NNPC would cease to exist. It should be noted that the PIB empowers the Minister to consult with the Minister of Finance to appoint NNPC Ltd as the liquidation agent of the NNPC.

Section 58 indicates that the Board of NNPC Ltd is to be constituted in accordance with the provisions of the Companies and Allied Matters Act ('CAMA') and the company's Articles of Association. Therefore, it seems contradictory that Section 59 indicates that the members of the Board would be appointed by the President, and Section 60 comments on the constitution of Committees for the Board. Indeed, Sections 61-64 highlight matters which are ordinarily determined by the CAMA, Memorandum & Articles of Association and Shareholders' Agreements. The Government has taken a bold step by incorporating NNPC Ltd as a CAMA entity; it should bite the bullet by freeing it up to run the same way that other private companies are run, albeit with interventions as its shareholder.

Interestingly, Section 65 encourages NNPC Ltd and its joint venture partners to explore the use of incorporated joint venture companies, under the principles enumerated under the Second Schedule to the PIB.

Administration

The administration and management of petroleum resources and their derivatives, as provided for in the Petroleum Industry Bill (PIB), apply to activities within or associated with petroleum operations, the petroleum industry and persons involved in such activities. It is aimed at promoting exploration and exploitation of petroleum products for the benefit of the Nigerian people. The PIB is built on the tenets of effectiveness, efficiency, accountability, competitiveness, safety, conducive business environment, among others.

In order to drive the achievement of its main objectives, the PIB has the following major administrative structures and provisions:

2.1 Administration of Upstream Petroleum Operations

The PIB provides that the upstream subsector of the Nigerian Oil and Gas industry shall be regulated by the Nigerian Upstream Regulatory Commission (the "Commission"). The Commission is expected to perform similar technical and commercial regulatory functions previously performed by the Department of Petroleum Resources. The areas of influence of the Commission in the upstream oil and gas sector include:

2.1.1 Recommendation on issuance of licences/lease:

The Commission is empowered to make recommendations to the Minister on granting licences or lease to operating companies incorporated and validly existing in Nigeria under the Companies and Allied Matters Act. The Commission has the responsibility of receiving application for licences and leases and make necessary technical and commercial appraisal that would form the basis of its recommendation to the Minister on the grating of licence/lease to respective applicants. The form of the major licences/lease to be issued for upstream operations are:

- *Petroleum Exploration Licence (equivalent to the current Oil Exploration Licence):* A Petroleum Exploration Licence (PEL) is granted for exploration of petroleum on a speculative and non-exclusive basis and shall be for 3 years and may be renewable for additional period of 3 years.
- *Petroleum Prospecting Licence (equivalent to the current Oil Prospecting Licence):* A Petroleum Prospecting Licence (PPL) is granted for exploration of Petroleum on an exclusive basis. A PPL for onshore and shallow water acreages shall be for a duration of not more than 6 years, comprising an initial exploration period of 3 years and an optional extension period of 3 years. For deep offshore and frontier acreages, it shall be for a duration of not more than 10 years, comprising an initial exploration period of 5 years and an optional extension period of 5 years.
- *Petroleum Mining Lease (equivalent to the current Oil Mining Lease).* A Petroleum Mining Lease (PML) is granted to qualified applicant to search for, win, work, carry away and dispose of crude oil, condensates and natural gas and shall be for a maximum period of 20 years and may be renewable for one or more additional period of not more than 20 years each, subject to meeting specified conditions.

The PIB prescribes that where the Minister does not act upon the recommendation of the Commission for the award of licence within 90 days, the approval shall be deemed as given. However for Ministerial consent, it is 60 days. These provisions will greatly help in enhancing transparency.

2.1.2 Environmental management:

The Commission has a regulatory role of monitoring and ensuring compliance with the PIB with respect to environmental sustainability and environmental degradation that may result from petroleum operations of licensees and lessees. A licensee or lessee, who engages in upstream petroleum operations, is required by the Commission to submit for approval an environmental management plan in respect of projects which require environmental impact assessment within one year of the effective date of the PIB or six months after the grant of the applicable Licence or Lease. The Commission gives its approval of such plan, provided it is in compliance with regulations issued under the Act and the applicant has the capacity or has provided for the capacity to rehabilitate and manage negative impacts on the environment. Furthermore, in order to be sure of the safety of people and the environment, the PIB requires that the applicable permit and approval is granted by the Commission to upstream operators before chemicals can be used for their operations. As a condition for the grant of a licence or lease and prior to the approval of the environmental management plan by the Commission, a licensee or lessee is required to pay a prescribed financial contribution to an Environmental Remediation Fund established by the Commission, for the rehabilitation or management of negative environmental impacts with respect to the licence or lease issued to such licensee or lessee.

This is a notable feature of the PIB that is aimed at engendering a culture of good environmental consideration practice that has been called to question in the sector. It may also help to deal with the perennial issue of oil spillage in the Niger Delta as a result of petroleum operations.

2.1.3 Gas flaring management:

Gas flaring is one of the age-long ills that plague the Nigerian Oil and Gas sector. It has been attributed to unfavourable cost-benefit outcome to the operators in the sector that may choose to harness and monetise associated gas. The cost of processing gas for sale is generally adjudged higher than the benefits that would be derived from commercializing the processed gas. As such, associated gas is preferred to be flared or vented by operators. Considering the environmental impact of gas flaring, the PIB has upheld the prohibition of gas flaring, except for a few circumstance in which there is no other reasonable option than to flare gas.

According to the PIB, a licensee or lessee shall pay a penalty prescribed pursuant to the Flare Gas (Prevention of Waste and Pollution) Regulations 2018. The only recognized few instances where gas flaring may be allowed by the PIB are as follows:

i. in the case of an emergency
ii. pursuant to an exemption granted by the Commission.
iii. as an acceptable safety practice under established regulations.

As part of the efforts to manage the flaring of gas, the Commission requires upstream operators that produce natural gas to submit, within 12 months of the effective date of the PIB, a natural gas flare elimination and monetisation plan to the Commission. This is expected to be prepared in accordance with regulations made by the Commission under the PIB.

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2.1.4 Domestic crude oil supply obligations:

In line with the principles of free market and healthy competition, the PIB provides that the supply of crude oil and condensates for the domestic market shall generally be on a willing supplier and willing buyer basis. However, to manage national exigencies and in the interest of the Nigerian people, the Commission is empowered to issue regulations or guidelines on the mechanism for setting domestic crude oil supply obligation for lessees in the upstream petroleum operations. This power is exercised where, in the opinion of the Commission, the domestic market results in shortages or inadequate supplies of crude oil and condensates for holders of crude oil refining licences. The Commission liaises with the Nigerian Midstream and Downstream Petroleum Regulatory Authority (the "Authority") to ascertain the crude oil requirements of refineries in operation. This is a mediation role of the Commission to ensure that the local market is adequately supplied to the extent possible for the benefit of the Nigerian people, in line with the objectives of the PIB.

2.1.5 Domestic gas delivery obligation:

In order to establish an orderly, fair and competitive commercial environment

within the petroleum industry, the Commission, working hand in hand with the Nigerian Midstream and Downstream Petroleum Regulatory Authority, is responsible for determining, monitoring and ensuring that the volume of natural gas that is expected to be supplied by lessees to strategic sectors and aggregators is achieved. The Commission would manage this through an allocation system among lessees as determined by the Commission upon consultation with the Authority with consideration of supporting infrastructure availability.

Lessees who fail to comply with the domestic gas delivery obligation placed on them by the PIB, shall incur a penalty of US$ 3.50 per MMBtu not delivered, subject to the penalty for failure to deliver as may be stated in any gas purchase and sale agreement between a lessee and a wholesale supplier of the strategic sectors. The penalty amount may be adjusted as the Commission may prescribe in a Regulation made under the PIB. The penalty does not apply in the following circumstances:

i. force majeure

ii. the inability of a purchaser to accept allocated natural gas volumes

iii. the inability to transport the allocated natural gas for reasons beyond the control of the lessee; or

iv. the failure of a purchaser to pay for allocated natural gas volumes

Apart from the penalty for non compliance, the PIB has made compliance with the domestic gas delivery obligation a condition for approval of the supply of natural gas for export projects by lessees. However, it is important that the challenges and bottlenecks that affect the ability of gas producers to meet their domestic gas delivery obligations be addressed.

2.2 General Administration of Midstream and Downstream Petroleum Operations

The Nigerian Midstream and Downstream Petroleum Regulatory Authority (the "Authority") shall be responsible for the management and administration of the midstream and the downstream sector of the Nigerian Oil and Gas Industry. The notable administrative areas of influence by the Authority are as follows:

2.2.1 Licence application:

The Authority is responsible for granting, renewing, modifying and extending licences and permits to operators in the midstream and downstream sector. Where the licence relates to the operation of a refinery, this is issued by the Minister on recommendation by the Authority. In performing this role and making relevant decisions, the Authority is saddled with the responsibility of considering commercial, technical and environmental factors, among others. The Authority is empowered to make and enforce regulations and guidelines that will help it discharge its duties in relation to licensing matters.

2.2.2 Tariff:

The Authority has the power to use Regulations to determine the pricing framework for transportation, distribution and processing of petroleum. The PIB requires that tariffs be determined in US dollars, but may be paid in naira, where the applicable exchange rate shall be based on the Securities and Exchange Commission over-the-counter market rate or any successor rate. The prices should be cost reflective and should allow for reasonable return for the operators.

The Authority, prior to establishing a tariff methodology, is required to initiate and conduct a stakeholders' consultation with applicants, operators, consumers, prospective customers, consumers associations, associations of prospective customers and any other persons with interest in the subject matter of the proposed tariff methodology. Notwithstanding the requirements for stake holders' consultation, the Authority may establish a tariff methodology without conducting a stakeholders' consultation, where it considers it necessary to do so. According to the PIB, such tariff methodology so determined shall be valid for only six months subject to confirmation via due process of stake holders' consultation.

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2.3 Administration of Midstream and Downstream Gas Operations:

The PIB requires a holder of a subsisting lease, licence or permit, who is engaged in activities in midstream or downstream gas operations prior to the effective date of the PIB, to apply to the Authority within 24 months from the effective date of the PIB for the appropriate licence or permit, as applicable. In order to properly administer gas operations in the sector, the PIB provides that the Authority can issue special guidelines and regulations as may be deemed necessary.

The Authority performs the customer-protection function by issuing regulations that require oil and gas product distributors and suppliers to:

i. publish their terms of supply or distribution including tariffs; and

ii. facilitate the establishment of a forum at which customers are able to express their views and raise concerns, among others.

The PIB provides that the Authority shall, prior to the 1st day of March of each calendar year, determine the domestic gas demand requirement and inform the Commission of this requirement.

2.4 Other Matters Related to Downstream, Midstream and Upstream Operations

The Authority exercises regulatory powers in the following areas for the overall objectives of the PIB:

2.4.1 Competition and Market Regulations:

One of the overarching objectives of the PIB is to engender a competitive market devoid of customer exploitation. Subject to the provisions of the Federal Competition and Consumer Protection Act, the Authority is to, among other responsibilities, curb monopoly and restrictive market practices of "powerful" operators, diagnose and forestall all tendencies of barrier to market entry. This would create and encourage an environment conducive for foreign direct investments. Where an operator is engaged in acts that contravene the requirements of the relevant chapters of the PIB, the Authority is empowered to state its intention to issue a "cease and desist" order to curb the unwanted actions of the operator. There is a penalty of a maximum of 10% of the annual turnover of the operator that fails to comply with the provisions of the "cease and desist" order.

2.4.2 Consultation for regulations:

The Commission and Authority are required to consult with stakeholders, such as licencees, permit holders and lessees, prior to finalizing any regulations or amendments to regulations. This may not be the case in instances of exigencies. A regulation made shall be valid for not more than 1 year with effect from its commencement date, except it is confirmed following a stakeholders' consultation.

2.4.3 Abandonment, decommissioning and disposal:

The PIB requires that necessary and adequate provisions be made for the decommissioning and abandonment of onshore and offshore petroleum wells, installations, structures, utilities, plants and pipelines for petroleum operations and shall be conducted in accordance with international best practice and guidelines by the Commission or the Authority. This exercise shall take place with the approval of the Commission or the Authority as applicable.

The PIB requires that each lessee and licensee shall set up and maintain a decommissioning and abandonment fund, which shall be held by a financial institution that is not an affiliate of the lessee or licensee. The fund so set up will be used for abandonment and decommissioning purposes. Where the licencee or the lessee fails to comply with the abandonment plan, the Commission or the Authority will access the fund for this purpose. Operators are required to make periodic payments, as may be determined from time to time, into the fund.

A licensee or lessee is required to inform the Commission or Authority, as the case may be, of the establishment of its decommissioning and abandonment fund not more than three months from the date of commencement of production for upstream petroleum operations or the commissioning of the facilities for midstream petroleum operations; and furnish the Commission or Authority, as the case may be, on an annual basis with statements of accounts with respect to its decommissioning and abandonment fund.

The PIB provides that, from the effective date, contributions to the decommissioning and abandonment fund are eligible for cost recovery and shall be tax deductible, provided that decommissioning and abandonment costs disbursed from the decommissioning and abandonment fund shall not be eligible for cost recovery or deductible for tax purposes. Where there is excess in the decommissioning and abandonment fund after the decommissioning and abandonment has been carried out and approved by the Commission or the Authority, as the case may be, the excess will be available for consideration as income for production sharing or tax purposes and the residual amount left over after the withholding of profit oil and any tax has been deducted shall be returned to the licensee or lessee.

> “The PIB provides that, from the effective date, contributions to the decommissioning and abandonment fund is eligible for cost recovery and shall be tax deductible, provided that decommissioning and abandonment costs disbursed from the decommissioning and abandonment fund shall not be eligible for cost recovery or deductible for tax purposes.”

2.4.4 Conversion and Relinquishment of PPLs & PMLs

All existing OPLs and OMLs would be automatically converted to PPLs and PMLs upon their expiration.

However, the PIB allows holders of OPLs and OMLs under the current regime to voluntarily covert them to PPLs or PMLs, respectively.

The PIB provides some condition precedents which are to be contained in the Conversion Contracts. One such condition is a stipulation that all on-going arbitration and court cases would be terminated. Other conditions are that the fiscal stabilization clauses would not be grandfathered. OML holders will need to designate their acreages into 5 broad classes:

- parcels that merit an appraisal (for exploration);
- parcels to make a declaration of commercial discovery for which a field development plan is to be submitted;
- parcels that have a significant gas discovery;
- parcels which already have development programs underway; and
- parcels in which regular commercial production is occurring.

The PIB prescribes that these 5 parcels should cover 40% of the area of the license granted, and other areas are to be relinquished. The limitation to 40% suggests that if the parcels cover more than 40% of the entire area of the lease area, there would be no relinquishment under such OML. The proposed relinquishment of 60% appears to be onerous and may serve as a disincentive to conversion.

2.5 Comments:

While the provisions and the underlying tenets of the PIB are welcome developments, its effectiveness in transforming the Nigerian oil and gas sector is hinged on the ability of the administrative organs (the Commission and the Authority) to use data to drive operations and decision making. The starting point would be the seamless transfer of industry historical and current data on participants and operations from the current regulator- the Department of Petroleum Resources (DPR)- to the Commission and the Authority. This would aid a quick integration of existing operators into the system under the PIB and the compliance with necessary licence conversion requirements can be monitored.

The administrative organs should leverage technology in interfacing with operators for proper record and decision making. Application for licences, periodic returns and all other information flow should be digitalised. This is a required bedrock for qualitative information that will drive decision making and effective administration of the sector under the PIB.

As part of the kick-off exercise of the administrative organs, there should be awareness/knowledge sharing forum in form of roadshows, webinars, and stakeholders' forum discussions, to sensitize stake holders and also get feedback on opportunities and threats to their set objectives.

There are also concerns as to the cost-benefit analysis of having two regulators for the oil and gas industry. This is with reference to the cost of governance and practices in other comparable jurisdictions Hopefully, the clarity in the role of the regulators will help to promote an efficient, effective and sustainable development of the Nigeria's petroleum industry. It may also help to focus attention on the midstream and downstream rather than the current situation where so much focus is on extraction of petroleum.

Interestingly, the PIB does not define a clear process for dispute resolution between the operators and the Commission/Authority. It is important that there be clarity on how to resolve any ambiguity or dispute that may arise from the implementation of the Act.

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Petroleum Host Communities Development

One of the issues that contributed to the delay in passing the previous versions of the PIB is host community. The host communities, Government and operators could not agree on the best way to address the concerns of the host communities. While the host communities are demanding more to deal with the issue of the environmental effect of oil operations, the government believes that enough is already being done in this area given all the agencies that are involved in the development of the Niger Delta region. It is, therefore, not surprising that the PIB 2020 adopts a novel approach to this issue.

Chapter 3 of the the Bill introduces the Petroleum Host Community Development (PHCD) which has the following objectives:

- To foster sustainable prosperity within host communities;
- To provide direct social and economic benefits from petroleum operations to host communities;
- To enhance peaceful and harmonious co-existence between licensees or lessees and host communities; and
- To create a framework to support the development of host communities.

The PHCD is expected to improve the quality of life of the host communities' population and improve accountability in the management of host communities' development trust (HCDT or "the Trust") fund.

Some of the significant provisions of the framework are as follows:

3.1. Introduction of HCDT

Section 235 of the Bill requires a settlor[1] or a group of settlors under a joint operating agreement to incorporate a HCDT. The Trust is to aid the development of the economic and social infrastructure of the communities within the petroleum-producing area. Where the HCDT is incorporated by a group of settlors under a joint operation, the operator under the agreement will be responsible for the Trust on behalf of the other parties.

The Bill requires the settlor to appoint and authorise a Board of Trustees (BoT), which will be registered with the Corporate Affairs Commission, for the purpose of managing the Trust. The following administrative activities of the BoT are determined by the settlor –

- the selection process, the procedure for meetings, financial regulations and administrative procedures
- the remuneration, discipline, qualification, disqualification, suspension, and removal of members of the BoT; and
- other matters other than the above relating to the operation and activities of the BoT.

Further, Section 251 requires the settlor to conduct a host community needs assessment to determine the needs of each host community and develop a Community Development Plan to address the identified needs.

1 A settlor is defined in the Bill as "*a holder of an interest in a petroleum prospecting licence or petroleum mining lease or a holder of an interest in a licence for midstream petroleum operations, whose area of operations is located in or appurtenant to any community or communities*"

3.2. Timeline for Setting up the Trust

The Bill provides the following timelines for incorporating the Trust:

S/N	Timeline for Incorporation
a.	for existing OMLs, within 12 months from the effective date of the Bill
b.	for existing designated facilities, within 12 months from the effective date of the Bill
c.	for existing new designated facilities under construction on the effective date, within 12 months from the effective date
d.	for existing oil prospecting licences, prior to the application for the field development plan
e.	for petroleum prospecting licences and petroleum mining leases granted under this Bill, prior to the application for the field development plan
f.	for licensees of designated facilities granted under this Bill, prior to commencement of commercial operations

Failure to adhere to the stipulated timeline may result in grounds for revocation of any licence or lease governed by the Bill.

3.3. Other Key Definitions for the Administration of the HCDT

3.3.1. The Management Committee

The Bill requires the BoT to set up a management committee that comprises one representative of each host community as a non-executive member, and other executive members of high integrity and professional qualification. Further, it empowers the management committee to prepare the budget of the fund, manage project awards on behalf of the Trust, supervise project execution, and other functions that may be assigned to it by the BoT.

3.3.2. The Host Community Advisory Committee

The Host Community Advisory Committee ("Advisory Committee") is to be set up by the management committee in accordance with the constitution of the Trust. The Advisory Committee will be responsible for nominating members to represent the host communities on the management committee, communicating community development projects to the management committee, monitoring the progress of community projects, securing project facilities, and advising the management committee on measures to improve security and peace within the community.

"The Bill requires the BoT to set up a management committee that comprises one representative of each host community as a non-executive member, and other executive members of high integrity and professional qualification."

3.4. Objectives of the Trust

The objectives of the Trust include the following:

a) To finance and execute projects for the benefit and sustainable development of the host communities;

b) To undertake infrastructural development of the host communities within the scope of funds available to the BoT for such purposes;

c) To facilitate economic empowerment opportunities in the host communities;

d) To advance and propagate educational development for the benefit of members of the host communities;

e) To support healthcare development for the host communities;

f) To support local initiatives within the host communities, which seek to enhance the protection of the environment;

g) To support local initiatives within the host communities which seek to enhance security;

h) To invest part of the available fund for and on behalf of the host communities; and

i) To assist in any other developmental purpose deemed beneficial to the host communities as may be determined by the Board of Trustees

3.5. Funding for the Trust

3.5.1. Source of Funding

Section 240 of the PIB requires each settlor to contribute 2.5% of its actual operating expenditure in the preceding calendar year to a fund established by the Trust. The HCDT may also be funded by donations, gifts, grants or honoraria (received to achieve its objectives) and interests accruing to the Trust's reserve fund.

Under a joint venture agreement, the responsibility of the settlors with respect to host communities' development falls to the operator appointed under the agreement. Therefore, each settlor under a joint venture contract is required to make an annual contribution to the Trust through the appointed operator.

In line with Sections 256 and 257 of the Bill, the funds of the HCDT are exempted from tax while contributions made by a settlor to the Trust are deductible for hydrocarbon tax and companies income tax purposes, respectively.

3.5.2. Forfeiture of Funds and Basis for Computation

The host community will forfeit its entitlement to any contribution to the extent of the cost to repair damages to the petroleum and designated facilities or disruption to production activities within the host community caused by an act of vandalism, sabotage or civil unrest. Therefore, the amount to contributed by the settlor to the Trust shall exclude the computed cost of such repairs or disruption in petroleum productions.

Though the Bill has not addressed a scenario where the cost of such repairs exceeds the settlor's contribution, it is more likely than not that the excess will be tax deductible in that year.

It is expected that this provision will foster responsibility and accountability amongst the host communities regarding petroleum assets operated in their respective communities.

3.5.3. Allocation of Funds

Section 244 of the PIB prescribes the following allocation ratio for annual contributions to the fund:

a) 75% of the annual contribution shall be used to fund capital projects;

b) a maximum of 5% of the annual contribution shall be utilized solely for administrative costs of running the Trust and special projects; and

c) 20% of the annual contributions shall be retained as a reserve fund. Also, the reserved fund shall be invested for the utilisation of the Trust when contributions from the settlor ceases.

3.6. Comments

Given the introduction of the Petroleum Host Community Fund, the question that has arisen is what is the continued relevance of the contribution to the Niger Delta Development Commission (NDDC) The PIB is not clear on whether the host community fund contribution will be together with the 3% NDDC levy. If this is the case, then the objective of promoting a competitive oil industry will be suspect, given that the industry is already subject to multiple taxes. Of course, there is also the question as to whether the 2.5% of annual operating expenditure will be sufficient to secure the buy-in of the host communities.

“The host community will forfeit its entitlement to any contribution to the extent of the cost to repair damages to the petroleum and designated facilities or disruption to production activities within the host community caused by an act of vandalism, sabotage or civil unrest.”

Fiscal Provisions

Chapter 4 of the Bill introduces the Petroleum Industry Fiscal Framework (PIFF), which has the following objectives: Fiscal Provisions:

- To establish a progressive fiscal framework that encourages investment in the Nigerian petroleum industry, balancing rewards with risk and enhancing revenues to the Federal Government (FG);
- To provide a forward-looking fiscal framework that is based on core principles of clarity, dynamism and fiscal rules of general application;
- To establish a fiscal framework that expands the revenue base of the FG, while ensuring a fair return for investors;
- To simplify the administration of petroleum tax; and
- To promote equity and transparency in the petroleum industry fiscal regime.

The Bill amends and repeals various laws that have implications for the oil and gas industry. *Appendix 1* lists the relevant laws affected in this regard. It provides for the current Petroleum Profits Tax (PPT) to be split into two namely: Hydrocarbon Tax (HT) and Companies Income Tax (CIT). The HT, together with CIT, will apply to companies engaged in upstream petroleum operations.

The fiscal and tax amendments in the PIB will apply upon:

a. conversion of existing Oil Prospecting Licences (OPLs) and Oil Mining Leases (OMLs) to Petroleum Prospecting Licences (PPLs) and Petroleum Mining Licences (PMLs)

b. termination or expiration of unconverted licenses, and

c. renewal of OMLs.

Consequently, holders of OPLs and OMLs that do not convert to PMLs will continue to be taxed under the current PPT Act pending the expiration of their licences.

One of the biggest concerns with the PIB is whether the fiscal provisions are competitive enough in terms of government take in relation to comparable jurisdictions. This will, therefore, make some promising deep water projects attractive. The general sense is that the current fiscal provisions will not help to attract the required investments and unlock value. Furthermore, the PIB has not addressed the issue of multiple taxes, fess and levies. It is hoped that some of the concerns, especially with respect to CPR, HT and Royalty rates, raised by the stakeholders will be fully addressed before the PIB is enacted into law.

Some of the significant fiscal policies introduced by the Bill are discussed on subsequent pages.

4.1 Introduction of HT Regime

The Bill introduces the HT, which will be chargeable on the profits of upstream petroleum companies. The HT will be charged at varying rates depending on the terrain, contract type and whether it is a new or converted acreage as follows:

	Rates		
Contract Type	Onshore	Shallow Waters	Deep Offshore
New Acreages	22.5%	20%	10%
Converted Acreages	42.5%	37.5%	5%

The headline rates for the HT are lower than the current rates of 50% for PSCs and 85% for non-PSCs (65.75% for companies in the first 5 years of commencement) chargeable under the DOIBPSCA and PPTA, respectively. Further, the HT will apply on a company-wide rather than contract area basis. The only exception to this rule would be for the PSCs executed prior to the commencement of the PIB and which have been converted from OPL to PPL or OML to PML.

4.1.1 Application of HT to Petroleum Operations

The HT will only apply to crude oil, condensates and natural gas liquids (NGLs) from associated gas (AG). Condensates and NGLs from non-associated petroleum gas will not be subject to the tax even when subsequently commingled with oil, provided that the related volumes can be determined at the measurement points or at the exit of the gas processing plant. The PIB has effectively resolved the controversy relating to the applicable fiscal legislation for condensates and NGLs that are subsequently commingled with oil. The determination of the applicability of HT will depend on whether the volumes of the condensate or NGLs can be determined at the measurement point or exit of the gas processing plant. The measurement point is defined as the downstream of the flow station.

Further, only the costs that cannot be deemed to be exclusively incurred to produce associated gas will be claimed as tax deductions under the HT. Consequently, costs that are incurred solely on associated gas production will be claimed against the earnings from associated gas production under CIT.

Condensates, whether field or plant, will be treated as oil while NGLs will be treated as gas, for royalty computations. Therefore, price-based royalty will only apply to condensates and not to NGLs.

4.1.2 Ascertainment of crude oil revenue

Section 262 of the PIB provides that the crude oil revenue of a company, in any accounting period, shall be the value of any chargeable oil adjusted to measurement points based on proceeds of all chargeable oil sold and value of chargeable oil disposed. The value of chargeable oil disposed shall be based on the aggregate value of crude oil determined for royalties for all fields. Therefore, extraction, storage and transportation costs will no longer be added back in determining taxable revenue under the HT as is the case under the PPT regime. Further, income incidental to petroleum operations would not be taxable under HT.

“Condensates and NGLs from non-associated petroleum gas will not be subject to the tax even when subsequently commingled with oil, provided that the related volumes can be determined at the measurement points or at the exit of the gas processing plant.”

4.1.3 Submission of returns and penalties for non-compliance

The requirements for submission of tax returns to the FIRS are similar to that in the PPTA.. Based on Section 277 (3) of the PIB, companies yet to commence bulk sales or disposal of chargeable oil are required to submit their tax returns within 18 months from the date of incorporation in the case of a new company, and within 5 months after any period ending on 31st December of the following year, in the case of any other company.

Further, Section 281 of the Bill has significantly increased the general penalty for non-compliance from ₦10,000 and an additional ₦2,000 for each day of continued default to ₦10,000,000 and an additional ₦2,000,000 for each day of continued default. The stiff penalties are to encourage voluntary compliance. However, Section 218 provides for taxpayers that have genuine reasons that may impact their ability to file their tax returns as and when due to proactively engage the FIRS and agree an extension to avoid payment of the penalties.

4.1.4 Interest on revised estimated tax returns

Section 280 (2) requires companies to recompute and file a revised estimated tax return (ETR) whenever there are changes in the price or cost or volumes of condensates. Failure to submit a revised ETR will result in the imposition of interest at LIBOR + 10% on the additional tax that would have been payable if a revised return had been submitted.

Although submission of a revised ETR is not new to the companies operating in the upstream industry especially where the parameters that informed the initial estimate change; however, the imposition of interest for not revising the estimate may be considered harsh given the frequency of volatility in the industry. Interestingly, the Bill is silent on what would happen if a company fails to file a revised ETR which results in a lower tax payable. Therefore, one may assume that the penalty is only effective when the revised ETR results in an additional tax payable rather than a measure to enforce voluntary compliance.

4.1.5 Allowable Deductions

Section 263 of the PIB introduced the following modifications to the list of allowable deductions under the extant PPTA:

a. inclusion of the term "reasonable" as a criterion for the deductibility of expenses for HT purposes

The Bill introduces the concept of reasonableness to the tax deductibility test for HT purposes. However, it fails to define what will qualify a cost as "*reasonable*", thus leaving it to the interpretation of the court in the event of a dispute. This amendment is particularly worrisome given the peculiar complexity of the oil industry and associated significant financial investments required for operations. Therefore, it will be difficult to determine what will not constitute a "*reasonable*" cost in the absence of an adequate provision in the enabling law. The court will definitely have a huge say on this.

b. non-productive rents and bad/ doubtful debts are not allowable

With the twin impact of the global oil price and COVID-19 pandemic on the global economy, especially the oil and gas industry, it is inevitable that companies will incur bad/ doubtful debts. Therefore, the exclusion of bad/doubtful debt and non-productive rents from allowable deduction may result in companies paying taxes on profits that are not recoverable.

Further, there is a potential risk that this provision will affect the cashflow of these companies as they may have to settle their tax liabilities out of capital or monies earmarked for additional investments without any recourse to recover the amounts owed them by the government.

c. *deductibility of interest on loans are now subject to the Commission's approval.*

The PIB requires the The Commission's pre-approval of loan agreements before the interest cost can be claimed as a tax deduction, notwithstanding that the FIRS has oversight on the administration of the HT.

Companies operating in the upstream sector will now contend with the administrative challenges of dealing with the two authorities to review and approve the terms of the same loan in order to claim the interest expense as a tax deduction. Currently, the provision of the PPTA, reiterated by several judiciary pronouncements, requires that the terms of the loan must be consistent with the arm's length principle stipulated in the Transfer Pricing (TP) Regulations for the interest expense to be tax-deductible. Therefore, the additional requirement under the PIB for the The Commission to approve the loan is unnecessary as it may increase the administrative burden on the taxpayers which contradicts the ease of doing business objectives. A more pragmatic approach will be to retain the existing requirement and mandate that all loan agreements must comply with the provisions of the TP Regulations.

Further, the PIB fails to define the procedure for obtaining the approval, including an appeal process where the loan agreement is rejected by the The Commission, thereby leaving the determination of a key sensitive aspect of the oil and gas operations entirely to the discretion of the The Commission. This may also question the free market basis of our economic system given the risk that the The Commission may misuse its power, which can easily tip the industry into troubled waters by stifling the much-needed foreign direct investments (FDIs).

d. contributions for decommissioning and abandonment will be tax-deductible, with any surplus/ residue liable to tax at the end life of the field. However, all funds, schemes or arrangements for this purpose must be approved by the The Commission.

e. royalty incurred in kind and payments made to the Federation Account related to production sharing, profit sharing, risk service contracts, etc. are allowable.

f. amounts contributed to Funds such as the NDDC, NDCF, HCDTF, etc. are tax-deductible.

"Companies operating in the upstream sector will now contend with the administrative challenges of dealing with the two authorities to review and approve the terms of the same loan in order to claim the interest expense as a tax deduction."

4.1.6 *Non-allowable Deductions*

In addition to the usual disallowable expenses, section 264 of the Bill introduces the following as non-deductible expenses:

- Penalties and gas flare fees.
- Financial/ bank charges, bad debts, unapproved interest on loans, arbitration and litigation costs.
- Costs incurred outside Nigeria including head office and affiliate costs.
- Additional costs from tax gross-up clauses.
- Production/ signature bonuses, bonuses/ fees paid for renewing leases and licenses or for assigning rights to other parties.
- Costs that exceed the cost price ratio limit of 65% of gross revenue.

Disallowing bank charges, arbitration and litigation costs, and costs incurred outside Nigeria seem contradictory, as they may satisfy the *WREN* test. Further, this may increase the cost of doing business in the Nigerian oil and gas upstream sector and defeats the objective of the PIFF to "*foster a business environment conducive for petroleum operations*."

4.1.7 *Chargeable Profits and Allowances*

The PIB introduces the following significant modifications to the calculation of chargeable profits and allowance:

i) removal of the restriction on capital allowance (CA).

ii) introduction of Production Allowances to replace the investment tax allowance and investment tax credits.

iii) deletion of petroleum investment allowance.

iv) separation of acquisition costs of petroleum rights into tangible and intangible assets, such that CA claimable on an intangible asset will now be 10% per annum for the purposes of CIT only. Thus, the annual allowance on the intangible portion is not claimable under HT.

4.1.8 *Additional Chargeable Tax*

Where the chargeable tax calculated by a company for any period is less than the chargeable tax for crude oil for the same period, the company will pay the difference between the two amounts as additional chargeable tax (ACT). The chargeable tax for crude oil is determined as the number of barrels of crude oil at the measurement point multiplied by the fiscal oil price per barrel as advised by the Commission.

There may be concerns about whether the The Commission will be transparent in determining the fiscal oil price given the Government's desire to increase revenue. It is expected that the desire to increase government take will not be the driver for determining the fiscal oil price.

4.1.9 *Cost Price Ratio (CPR) Limit*

All deductible costs under the HT will be subject to a cost price ratio limit of 65% of gross revenues determined at the measurement points. Any excess costs not deducted due to the restriction may be deducted in subsequent years of assessment provided that:

i) the total costs to be deducted shall not exceed the actual costs incurred, and

ii) in carrying costs forward, CA shall be carried forward with priority over operating costs, and

iii) the total costs to be allowed as deduction in those subsequent years shall be such an amount that, if added to the sum of the total deductible costs, shall not exceed the specified cost price ratio limit of 65%; and

Any unrecovered costs (i.e., costs that exceed the cost price ratio limit) upon the termination of petroleum operations will not be deductible for HT purposes.

Most of the costs incurred by businesses operating in Nigeria are as a result of bureaucracy and consequently outside their control . This, therefore, makes the cost of doing business in Nigeria to be very high relative to comparable countries. With the CPR of 65%, some of these costs will not be recoverable, thereby adding to the cost of operations. The Federal Government is aware of this issue and has, therefore, launched an initiative to reduce costs in the industry. The expectation should be that such CPR limit should be suspended until those initiatives have been implemented. Otherwise, this will make the Nigerian oil industry uncompetitive and unattractive.

“Most of the costs incurred by businesses operating in Nigeria are as a result of bureaucracy and consequently outside their control. This, therefore, makes the cost of doing business in Nigeria to be very high relative to comparable countries.”

4.2 Application of CIT to Petroleum Operations

4.2.1 Consolidation of Taxes

Companies engaged in upstream petroleum operations will also be taxed under CIT and are required to settle their CIT liability on an actual year basis, using a similar estimate mechanism to that provided for HT. However, HT will not be deductible for CT purposes. CIT will be applied as an entity-based tax, thereby allowing for consolidation of results across terrains. This means that there are no field-by-field restrictions.

However, companies that acquire loss making companies in other to take advantage of the above incentive, would not be allowed to claim the losses of the acquired company.

4.2.2 General Requirements for Companies to pay CIT

a) Companies, concessionaires, licensees, lessees, contractors or subcontractors involved in upstream, midstream and downstream petroleum operations will be liable to CIT.

b) `Allowable deductions are modified to include:

- rents and royalties incurred with respect to commercial sale, delivery or disposal of crude oil, condensates and natural gas and payments to the Federation Account related to production sharing, profit sharing, risk service contracts or other contractual features
- any amount contributed to any fund, scheme or arrangement for abandonment and decommission, petroleum host communities' development trust, provided that the fund/ scheme/ arrangement is approved by the Commission or Authority and any surplus or residue of such funds shall be subject to tax under CIT
- other deductions as may be prescribed by the Minister of Finance by Order published in the Gazette.

c) Non-allowable deductions are revised to include:

- expenditure for the purchase of information on the existence and extent of petroleum deposits
- any penalty incurred, including natural gas flare fee or charges
- production bonuses, signature bonuses paid for acquisition of rights on petroleum deposits, signature bonuses or fees paid for renewing PML or PPL or fees paid for the assignment of rights to other parties including for marginal field
- additional costs from tax gross-up clauses.

d) Late payment of tax due from companies involved in upstream operations shall carry interest at NIBOR plus 10% from the due date until paid for naira remittance, and LIBOR or succession rate plus 10% from the due date until paid for foreign currency remittance.

4.3 Capital and Production Allowances

4.3.1 Capital Allowance

The PIB prescribes the following in the Fifth Schedule:

i. Qualifying expenditure must relate to expenditure incurred directly for upstream petroleum operations applicable to crude oil for PML or PPL.

ii. For a qualifying drilling expenditure (QDE) to qualify for CA, the cost of that QDE must not have benefited from CA prior to the acquisition of the asset by another entity.

iii. Any loss suffered on assets disposed of before the beginning of a company's first accounting period would be disallowed upon commencement of the accounting period. Also, any profit realized upon disposal would be liable to capital gains tax.

iv. The treatment of pre-production expenditure would depend on its nature. Where the expenditure would have been treated as a qualifying capital expenditure (QCE) if it was incurred in the first accounting year, then it would be classified as such, and CA claimed thereon. However, where the expenditure would have been treated as a tax-deductible expense, it should be amortized over a period of five (5) years with a 1% retention value.

v. Where the owner of the relevant interest does not have statutory title to the asset, (i.e., it is not the licensee or lessee to the asset), the QCE and the accruing CA shall be to the benefit of the holder of the license or lease.

vi. Capital expenditure will not be eligible for the claim of CA under HT, where the building, structure or works was previously used before the interest was acquired.

While the section is silent on whether the CA can be claimed under CIT, it may be pragmatic to assume that since CIT was not expressly stated, the building would qualify as QCE under the CIT.

vii. Expenditure incurred on exploration and the first two (2) appraisal wells in the same field is to be treated as 100% deductible costs in the year incurred. However, additional exploration and appraisal expenditures in the same field relating to the pre-production period are to be amortized and deducted upon commencement of the company's accounting period at an annual allowance of 20% for the first four (4) years and 19% in the fifth year with a 1% retention value.

viii. Other changes include the deletion of PIA, definition of "*in use*" and exclusion of certain expenditure.

"Any loss suffered on assets disposed of before the beginning of a company's first accounting period would be disallowed upon commencement of the accounting period. Also, any profit realized upon disposal would be liable to capital gains tax."

4.3.2 Production Allowance (PA)

In the sixth schedule, the PIB introduced the following provisions:

i. PA for crude oil production by converted OMLs which will be the lower of US$2.50 per barrel and 20% of the fiscal oil price.

ii. PA shall be applied on leases granted post-commencement of the PIB as follows:

- *for onshore areas* – the lower of US$ 8.00 per Barrel and 20% of the fiscal oil price per barrel up to a cumulative maximum production of 50 million Barrels from the commencement of production and the lower of US$4.00 per barrel and 20% of the fiscal oil price thereafter;
- *for shallow water areas* – the lower of US$8.00 per barrel and 20% of the fiscal oil price, up to a cumulative maximum production of 100 million barrels from the commencement of production and the lower of $4.00 per barrel and 20% of the fiscal oil price thereafter;
- *for deep offshore areas and frontier basins* – the lower of US$ 8.00 per barrel and 20% of the fiscal oil price, up to a cumulative maximum production of 500 million barrels from the commencement of production and the lower of US $4.00 per barrel and 20% of the fiscal oil price thereafter.

4.4 Other Key Fiscal Provisions

4.4.1 Minister to request Petroleum Products or take-over works, plants or premises

The PIB empowers the Minster to request license/ lease holders to provide petroleum products to the FG or crude oil to third parties who own licenses to operate refineries. The price of the petroleum shall be at a "*reasonable value at the point of delivery less discount to be agreed by both parties*" or where no agreement was entered into before the Minister exercised the right of pre-exemption, a mutually agreed fair price at the port of delivery. Any arbitration may only take place after the petroleum or petroleum products have been delivered. Further, the Minister may take control of the licensee's or lessee's works, plants or premises in exchange for a "*reasonable compensation*".

It is hoped that this provision will only be invoked in an emergency and not exercised arbitrarily.

4.4.2 Companies to separate upstream and midstream operations

Companies engaged in the end-to-end value chain will have to segregate their upstream from their midstream operations. This may have a negative impact on the profitability of those midstream projects as the final investment decision (FID) was predicated on the consolidation of both operations. This may also trigger significant issues for existing operators especially with respect to current pipelines, transfer of assets/ liabilities, transfer of staff and related obligations, compliance costs, transfer pricing issues. This provision, therefore, needs to be revisited. To address these issues, there may be a need to grandfather existing projects or those that have already taken FID from this rule.

As an alternative, the government may consider a Ring Fence Corporation Tax similar to that of the UK.

4.4.3 PSC Fiscal Stability Clause

Fiscal stability clauses, which serve as a guarantee or a sort of protection to investors against change in government policies or legislation, provided by the NNPC in any PSC or any contract of similar nature, in respect of OPLs and OMLs to be converted will now be null and void.

The discharge of these clauses will create a level playing field between old and new investors and address potential distortions that may have been created as a result of perceived discrimination. However, it is important that tax rates be not changed indiscriminately in a way that will affect the viability of projects started prior to the change.

4.4.4 Artificial Transactions

The PIB has made provisions of the Income Tax (Transfer Pricing) Regulations, 2018 the basis for determining artificial transactions. However, it is uncertain why deductibility of interest on loan is subject to the FIRS and Commission's approval and costs incurred outside Nigeria, head office costs, affiliate costs are included as non-deductible expenses, rather than both costs being subject to TP Regulations as obtained under the extant PPTA.

"The price of the petroleum shall be at a "reasonable value at the point of delivery less discount to be agreed by both parties" or where no agreement was entered into before the Minister exercised the right of pre-exemption, a mutually agreed fair price at the port of delivery."

4.4.5 *Trade or Business Sold or Transferred*

The provisions for businesses sold or transferred are similar to that of the PPTA, except for the following modification

- the first accounting period will be from the date of acquisition/ transfer of the business till 31st December of that year.
- any concession enjoyed in terms of CA will be rescinded where the acquirer disposes of the assets within 3 years of acquisition.
- acquisition cost relating to business transfer/ sale between non-related parties will enjoy a 10% annual CA under the CITA but none under HT.

These modifications would ensure consistency in the accounting periods and discourage tax avoidance and profit shifting schemes.

4.4.6 *Conversion of OPLs and OMLs.*

The PIB would not apply to holders of OPLs or OML who have not converted their licences to PPLs or PMLs until such OPLs or OMLs are terminated. However, any renewal of an OML will be based on the PIB.

Consequently, the provisions of PPTA will continue to apply to unconverted OMLs and OPLs.

4.4.7 *Set off of payments made in error*

Where a company makes tax payment in error, the PIB provides for setting off "*the credit against the liabilities of a similar tax payable to the Service*." Though the Bill does not clarify the applicable taxes under this provision, it is assumed that it will extend to CIT and TET as they are all taxes on income

4.4.8 *Calculation of Royalties*

i. Production Royalty

Production royalty will be calculated on a field basis and is chargeable on the volume of crude oil and condensates produced from the field area in the relevant month on a terrain basis as follows:

a. onshore areas with monthly production less than 10,000 bpd – 5% for the first 5,000 bpd and 7.5% for the balance
b. onshore areas with monthly production above 10,000 bpd – 18%
c. shallow water (up to 200m water depth) – 16%
d. deep offshore (greater than 200m water depth) with monthly production less than 15,000 bpd – 7.5%
e. deep offshore (greater than 200m water depth) with monthly production above 15,000 bpd – 10%
f. frontier basins - 7.5%

Where a single field covers two or more PMLs, the royalty shall be determined based on the total production from the field.

The major concern with the royalty rates is that they are not competitive and may therefore not lead to new investments. There is also the issue of non-adherence to the principle of sanctity of contracts. In the Production Sharing Contracts executed by those operating above 10,000m, royalty rate is set as zero.

ii. Gas Royalty

For natural gas and natural gas liquids, royalty will be on the chargeable volume in the relevant area on a terrain basis as follows:

a. onshore areas - 7.5%

b. deep offshore areas – 5%

c. shallow water and frontier basins – 5%

The royalty rate for natural gas produced and utilized in-country shall be 5% of the chargeable volume.

Further, Regulations will be issued to cover the calculation of weighted average royalty in instances where a field is located partially in onshore and in shallow water or partially in shallow water and deep offshore areas.

iii. Price Royalty

In addition to production royalty, companies would be liable to additional royalty when crude oil, and condensate, prices exceed specified benchmark prices and are payable to the Nigerian Sovereign Investment Authority.

For fields in onshore, shallow water and deep offshore areas, the royalty rates will apply as follows:

a. Below US$50 per barrel – 0%

b. At US$100 per barrel – 5%

c. Above US$150 per barrel – 10%

Prices between ranges will be determined by *"linear interpolation"* (For example, if the price is US$75/bbl, the price royalty rate shall be 2.5%). Further, the above rates are only valid for 2020, therefore they will be increased annually by 2% over prior year rates.

Price royalty do not apply to gas or production from Frontier acreages.

4.4.9 Stiffer Penalties

The Bill introduced stiffer penalties to encourage voluntary compliance, curb default and entrench integrity. Taxpayers should therefore ensure strict compliance with the provisions of the Bill to avoid unnecessary fines or penalties as they will be disallowed for tax purposes.

> "The major concern with the royalty rates is that they are not competitive and may therefore not lead to new investments. There is also the issue of non-adherence to the principle of sanctity of contracts."

4.5 Other Key Fiscal Provisions – Gas

4.5.1 Domestic Gas Supply Obligation

PIB prescribes that supply of gas to midstream gas export operations will not be allowed until the domestic supply obligations have been met. This provision may undermine contractual obligations already entered by the gas supplier before the commencement of the Act.

This provision needs to be reviewed accordingly.

4.5.2 Gas Pricing Framework

The gas price for gas-based industries shall be determined as follows:

$$CP = NRP * (1 + EPF) <= EPP$$

Where:

CP is the applicable gas price in $/MMbtu

NRP is the National Reference Price of $1.00/MMbtu

EPF is th*e End Product Factor which is (CMPP – PRP)/PRP*

CMPP is the Average Current Month End Product Price in $/MT

PRP = Product Reference Price in $/MT which varies depending on the industry

For ammonia, urea, methanol, polypropylene (LDPPE/HDPPE), the PRP (US$/MT) is 250; while for low sulphur diesel (GTL), the PRP is 325.

However, the PIB does not provide the basis for determining the CMPP, whether it will be issued monthly by the Commission or be based on each company's average?

4.5.3 Domestic Base Price and Pricing Framework

The Third Schedule to the Bill provides that the floor price for gas-based industries shall be $ 0.90 per MMBtu, while the domestic base price (i.e., ceiling price) as of 1 January 2021 will be $3.20 per MMBtu. This base price will increase by $0.05 per MMBtu every year until 2037 when a price of $4.00 per MMBtu will apply going forward.

The Schedule further provides that the Authority may issue regulations changing the domestic base price and the yearly increase to reflect changing market conditions and supply frameworks.

Given the consistent calls for the deregulation of the gas sector and the prescription of a ceiling price, the PIB does not appear to have been geared towards the effective deregulation of the gas industry.

Appendices

Appendix 1

The Bill will amend the provisions of the Pre-Shipment Inspection of Oil Export Act, 1996 and Petroleum Equalisation Fund, and effectively repeal the following Acts:

i. Associated Gas Reinjection Act, 1979 CAP A25 Laws of the Federation (LFN) 2004, and its amendments;

ii. Hydrocarbon Oil Refineries Act No. 17 of 1965, CAP H5 LFN 2004;

iii. Motor Spirits (Returns) Act, CAP M20 LFN 2004;

iv. Nigerian National Petroleum Corporation (Projects) Act No. 94 of 1993, CAP N124 LFN 2004;

v. Nigerian National Petroleum Corporation Act (NNPC) 1977 No, 33 CAP N123 LFN as amended, when NNPC ceases to exist pursuant to section 54(3) of this Act;

vi. Petroleum Products Pricing Regulatory Agency (Establishment) Act 2003;

vii. Petroleum Equalisation Fund (Management Board etc.) Act No. 9 of 1975, CAP P11 LFN 2004;

viii. Petroleum Equalisation Fund (Management Board, etc.) Act, 1975;

ix. Petroleum Profit Tax Act Cap P13 LFN 2004, (PPTA); and

x. Deep Offshore and Inland Basin Production Sharing Contract Act (DOIBPSCA), 1993 CAP D3, LFN 2004 and its 2019 amendment.

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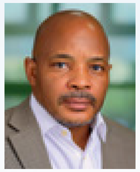

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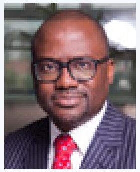

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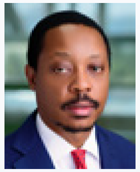

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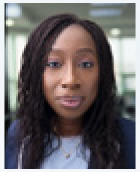

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