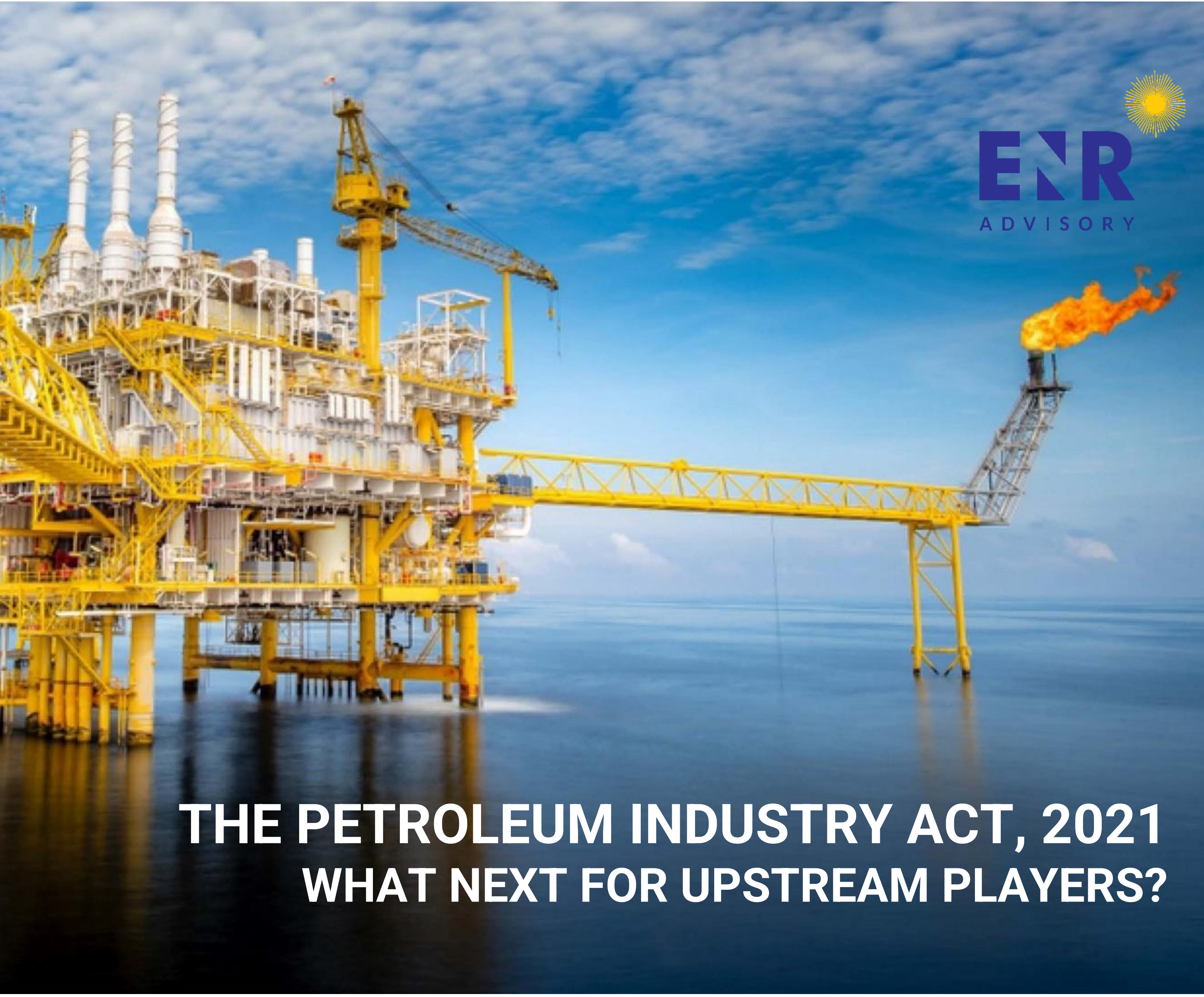

THE PETROLEUM INDUSTRY ACT, 2021
WHAT NEXT FOR UPSTREAM PLAYERS?

The newly enacted Petroleum Industry Act, 2021 (PIA) provides for the overhaul of the institutional, regulatory and fiscal framework for Nigeria's petroleum industry. Amongst the key changes introduced by this reform legislation is the new licensing and fiscal regime for upstream operations. However, Oil Prospecting Licences (OPLs) and Oil Mining Leases (OMLs) granted under the Petroleum Act do not automatically transition into this new regime. The PIA allows holders of OPLs and OMLs granted under the Petroleum Act to opt in to the new regime by converting their respective OPLs and OMLs into an appropriate licence or lease to be issued under the PIA. Key considerations for upstream operators at this time in determining whether to exercise the right to opt in are the fiscal framework and the downsizing of the licence or lease acreages within their portfolio. There are bound to be trade-offs in deciding whether to opt in to the PIA regime and upstream businesses must at this time evaluate the best course of action totake in respect of each licence or lease they currently operate; perhaps based on the inherent peculiarities of the geological formations within those assets and the best value that can be derived from exploiting those assets under the erstwhile or the new fiscal regime offered in the PIA.

This publication highlights for the benefit of upstream players currently holding interests in OPLs, OMLs, Production Sharing Contracts (PSCs) and Marginal Field assets, the fiscal regime ushered in by the PIA and the streamlined asset retention framework, to aid their election on whether to opt in to the PIA regime.

THE NEW UPSTREAM LICENCES AND LEASE REGIME

The PIA renames the existing licences and lease concessions by replacing 'Oil' with 'Petroleum', such that Oil Exploration Licences are now Petroleum Exploration Licences (PEL) while Oil Prospecting Licences are to be known as Petroleum Prospecting Licences (PPL), and Oil Mining Leases are now Petroleum Mining Leases (PML). This change in nomenclature is to better represent the mature status of gas as a standalone resource and an independent target for investors. A new national grid system has also been introduced that breaks down the surface areas for concessions into 1 square kilometre units and 1-hectare subdivisions.

The key difference between the outgoing and the new concessions are the sizes. There is a significant reduction in the overall surface area granted and retained under PPLs and PMLs as against the OPLs and OMLs.

Table 1: Surface Area Granted

	OPL	PPL
Maximum Size	1000 square miles (approx. 2590 square kilometres)	• Onshore and shallow waters - 350 square kilometres • Deep Offshore - 1000 square kilometres • Frontier - 1500 square kilometres
Maximum Duration	5 years	• Onshore and shallow waters: 6 years (3 years initial period; 3 years optional extension) • Deep Offshore and frontier - 10 years (5 years initial period; 5 years optional extension
	OML	**PML**
Maximum Size	500 square miles (approx. 2590 square kilometres)	Limited to the commercial discovery to which the PML relates
Maximum Duration	20 years (renewable for further terms)	20 years (renewable for further terms)

The size of the concessions under the PIA are further reduced by a relinquishment regime that reduces the surface areas retained by a PPL or PML holder.

For a PPL holder, there are a number of instances where it would have to yield back to the government parts of the surface area of the licence:

1. where it makes a discovery, it is required, within 6 months, to indicate if such discovery merits appraisal or if it is not interested, if the latter, then it may be required to relinquish parcels of the acreage that cover such discovery;

2. after completion of the appraisal, if it does not declare a commercial or significant discovery, then it will relinquish parcels of the acreage that cover such discovery;

3. by the end of the term of the PPL, it will relinquish areas that are not appraisal areas, retention areas, or lease areas;

4. by the end of the 10-year retention period, if it has not declared a commercial discovery from the retained significant discovery, then it will relinquish parcels of the retained area; and

5. 2 years after declaring a commercial discovery, if it has not submitted a field development plan and work commitment to the regulator for approval, then it will relinquish parcels of the acreage that cover such commercial discovery.

The PML is granted upon approval of a field development plan in respect of each commercial discovery within a PPL. The PML holder must thereafter commence commercial production within 5 years for onshore acreages and 7 years for shallow water, deep offshore and frontier acreages, failing which the lease would be recommended to the Minister of Petroleum Resources for revocation. Also, within 10 years of commencement of the PML, all parcels of the lease that fall outside the boundary of a producing field will be relinquished.

Bite-size Chunks: In effect, a concessionaire could progress from an initial PPL surface area size of 350 square kilometres to only a few square kilometres under a PML such that PMLs will now ultimately be reduced to cover only the individual commercial fields being produced. It would therefore seem that the objective of the PIA is to deter asset owners from holding on unproductively to huge tracts of lease areas as in the large parcels (1,295 square miles) held under the outgoing regime.

NEW FISCAL REGIME: TAXES AND ROYALTIES

New, renewed or converted licences and leases will no longer be subject to 85% Petroleum Profit Tax on petroleum extractive operations. Instead, they will be taxed under the new regime by a combination of the new Hydrocarbon Tax at 30% for PMLs / 15% for PPLs and the general Companies Income Tax at 30% (20% for companies with a turnover of between N25 million to N100 million).

Hydrocarbon Tax

The new Hydrocarbon Tax (HT) is directly levied on income generated from petroleum produced from onshore and shallow water fields and applies specifically to only crude oil, condensates and liquid NGLs produced from upstream oil fields. It does not apply to production of natural gas, NGLs or condensates produced from non-associated gas wells or processing plants, as well as any petroleum production from frontier or deep offshore acreages which are charged under the Companies Income Tax Act (CITA).

The Hydrocarbon Tax regime introduces a reasonability standard for determining deductible expenses in arriving at the adjusted profits of taxable company. The typical expenses that qualify for deduction include royalties, contributions to decommissioning, host community, environmental remediation and NDDC funds etc. The non-deductible items are, however, more stringent than before: gas flare penalties, litigation and arbitration costs, bad debts / interest on borrowings, asset acquisition costs / bonuses / consent fees, etc.

Changes to the Capital Allowances Regime

During the pre-production period, 100% of the expenditure on exploration and the first two appraisal wells would be treated as deductible costs for the first year of production, while additional expenditure on exploration and appraisal on the same field would be amortised and deducted under annual allowances, equally over a 5-year period, with a 1% retention in the final year (19%). The PIA clarifies that the titleholder: licence or leaseholder, is the party that benefits from qualifying expenditure and capitalallowances. Capital allowances are only applicable to compute HT and not regulate cost recovery under PSCs.

New Production Allowances

Production allowances have been introduced to replace investment tax allowances and investment taxcredits, which along with the capital allowances will be deducted from the tax base in determining the chargeable profits.

Table 2: Production Allowances

Renewed and Converted OMLs	New PMLs issued after the PIA
The lower of $2.50 per barrel or 20% of theoil price	**Onshore terrain: lower of –** • $8 per barrel or 20% of oil price up to a cumulative production of 50m barrels • $4 per barrel or 20% of oil price above 100m barrels **Shallow water terrain: lower of –** • $8 per barrel or 20% of oil price up to a cumulative production of 100m barrels • $4 per barrel or 20% of oil price above 100m barrels **Deep water and frontier terrain, the lower of –** • $8 per barrel or 20% of oil price up to a cumulative production of 500m barrels • $4 per barrel or 20% of oil price above 500m barrels

New Cost Price Limit

Under the HT regime the ratio of costs to the gross revenue is capped at 65%, similar to the way PSC cost oil caps currently operate. Thus, the combination of the allowable deductions and allowances in the computation of chargeable profits, must all fall within the 65% cost price ceiling. Costs in excess of thisceiling can be rolled over and recovered in the following year. This ceiling will not apply to deductions forrents, royalties and contributions to certain funds (host community, environmental remediation, NDDC, etc.).

Consolidation of Costs and Taxes

Costs and taxes for upstream petroleum operations related to crude oil can be consolidated across several acreages/terrains for purposes of computing HT, provided that those for PMLs are separated from thosefor PPLs. A PSC contractor under a PSC contract issued under the PIA, is however allowed to consolidate its losses and revenues across PPLs and PMLs.

Companies Income Tax

Companies Income Tax (CIT) now applies to upstream crude oil production operations, and it applies inaddition to HT. Thus, both taxes combined makes up a 60% tax rate on crude oil operations for PMLs and 45% for PPLs. CIT also applies to all other upstream petroleum operations (across all terrains), as well as midstream and downstream petroleum operations. However, separate companies must be used to undertake business in each segment of the value chain, i.e., upstream, midstream and downstream. This is to prevent cross-subsidies and avoid entry barriers for single segment businesses. However, integrated strategic projects traversing all the segments are permitted, and capital investments in the midstream infrastructure can be consolidated with upstream operations for the purposes of the tax, provided that the same capital investments are not used to claim capital allowances in the midstream company and arms-length prices apply to the transfer of hydrocarbons from the upstream to the midstream business.

CIT Deductions and Allowances

The capital allowances for upstream operations are the same for both the HT and CIT, while capital allowances for midstream and downstream operations will align with the regular CIT regime. A company engaged in upstream petroleum operations across different acreages/terrains held under PPLs and PMLs are allowed to consolidate costs for the purpose of computing CIT. Deductions for royalties and contributions to the funds under the PIA will also qualify as deductible costs in the determining adjusted profits for CIT computation. Gas flare penalties, signature and production bonuses, renewal and consent fees are also not deductible in computing CIT.

CIT Incentives

The S.39 CITA tax incentives apply to all companies engaged in domestic midstream, petroleum operations, downstream gas operations and large-scale gas utilisation industries. In order to address the dearth of gas infrastructure in the country, gas pipeline companies are entitled to an additional 5- year tax holiday at the end of the 5-year tax holiday granted under the CITA. In effect, a very attractive 10-year tax holiday is offered by the PIA for investment in gas pipelines.

Royalties

The PIA also introduces changes to the royalty rates. These changes are highlighted in Tables below.

Table 3: Changes to the Existing Production and Terrain Based Royalties

OLD PRODUCTION ROYALTIES	NEW PIA PRODUCTION ROYALTIES
Crude Oil and Condensates	
• Onshore - 20% • Offshore 0 – 100m water depth - 18.5% • Offshore 100 – 200m water depth - 16.5% • Offshore above 200m water depth - 10% • Frontier / Inland Basins - 7.5%	• Onshore - 15% • 0 - 200m water depth (Shallow Offshore) - 12.5% • Above 200m water depth (Deep Offshore) - 7.5% • Frontier Basins - 7.5% *Where production in Deep Offshore Fields is ≤ 50,000 bopd – 5% **Where production in Onshore, Shallow Offshore, Frontier and Marginal Fields is ≤ 10,000 bopd ○ 5% for the first 5,000 bopd ○ 7.5% for volumes above 5,00 bopd

Gas and NGLs	
• Onshore - 7% • Offshore - 5%	• Irrespective of the terrain gas is produced - 5% • Where the gas is utilised in-country - 2.5%

Table 4: Changes to Price Based Royalties

Old Price Based Royalties	NEW PIA Price Based Royalties
Crude Oil and Condensates (prices per barrel)	
• $0 to $20 - 0% • $20 to $60 - 2.5% • $60 to $100 - 4% • $100 to $150 - 8% • Above $150 - 10%	Applies to Onshore, Shallow Water and Deep Offshore production but not to production from Frontier terrains • Below $50 - 0% • At $100 - 5% • Above $150 - 10% Where the price is in between $50 to $100 and $100 to $150, the royalty rate shall be derived by linear interpolation

WHAT HAPPENS IF YOU OPT IN?

Relinquishment of Part of the Licence of Lease Area; Possible Downgrade from OML to PPL

OML holders who elect to convert may be required to relinquish up to 60% of the OML area and retain 40% on the conversion date. Such holders will be required to select areas or zones within the OML that fall within these categories:

- Areas, which in the opinion of the holder, merit appraisal and for which the holder is prepared to present an appraisal programme.
- Areas in respect of which the holder is prepared to make a declaration of a commercial discovery and submit a field development plan.
- Areas in respect of which the holder is prepared to make a declaration of a significant gas discovery or significant crude oil discovery and submit an application for approval of a retention area.
- Areas in respect of which field development is underway after having declared a commercial discovery or made a final investment decision to develop the field.
- Areas in respect of which regular commercial production is ongoing.

An OML holder will be awarded PMLs only for areas in respect of which field development is underway or regular commercial production is ongoing; while a PPL will be awarded for areas falling within the other categories listed above. Where the total acreage of the areas or zones designated is less than 40% of the OML area, the holder may select additional areas to make up the 40% to be retained and be awarded a PPL that includes such additional areas. Where the total acreage is more than 40%, the holder will be entitled to keep such larger areas, albeit consisting solely of the selected areas. All other areas or zones within the OML that are not selected by the holder shall be relinquished on the conversion date.

Similarly, an OPL holder who elects to convert would be required to designate zones and areas within the OPL area that fall within the categories listed above. Such OPL holders will be awarded PMLs for areas where field development is underway and in respect of which regular commercial production is ongoing and a PPL for all other appraisal areas, retention areas and any outstanding areas in the OPL. It wouldtherefore appear that there is no mandatory relinquishment requirement for OPL to PPL conversions; however, the unexpired term of the OPL will apply to the converted PPL. The maximum duration of converted PPLs that emerge from an OML would either be 5 years or 10 years depending on the terrain. In either case, mandatory relinquishment applicable to PPLs would apply.

Other Implications of Opting In

While the PIA does not provide details as to the form or structure of a conversion contract, it provides that the contract will contain provisions which require the holder of the OML or OPL to discontinue all outstanding arbitration or court cases related to the OPL or OML. It further provides that stabilisation provisions and guarantees provided by the Nigerian National Petroleum Corporation (NNPC) in respect of the OPL and OML shall become null and void and that the incentives provided in sections 11 and 12 of thePetroleum Profits Tax Act shall no longer apply.

How Do You Opt In?

OPL and OML holders who intend to opt in must enter into a 'voluntary conversion contract' (presumably with the Federal Government). Section 92(2) of the PIA provides that a licensee of lessee under a conversion contract shall benefit from the PIA fiscal regime where such licensee or lessee complies with the provisions of the Act. There is a defined window within which the right to opt in may be exercised. Section 92(4) requires voluntary conversion contracts to conclude by the “conversion date”, which is described as the earlier of 18 months from the commencement of the Act or date of expiration of the OML or conversion of conversionofthe OPL to an OML.

WHAT HAPPENS IF YOU DO NOT OPT IN?

OPLs/OMLs

The provisions of the PIA, including the fiscal regime discussed above will not apply to holders of OPLs and OMLs who elect to not enter into a conversion contract. In that event, the Petroleum Act, Petroleum Profits Tax Act, Oil Pipelines Act (and any subsidiary legislation in so far as it is consistent with the Act), Deep Offshore and Inland Basin Production Sharing Contract Act (as amended) and any other law or regulation as a consistent with section 92(6) will continue to apply to such OPLs and OMLs. However, renewals of such OPLs and OMLs shall be based on the PIA.

Sole Risk Concessionaires

An exception however applies to OPLs and OMLs awarded to indigenous Nigerian companies on a solerisk basis under the Petroleum Act in respect of which the Government has successfully exercised its back-in rights prior to the commencement of the PIA. Such sole risk concessionaires will benefit from a royalty rate of 0% per field for a period of 5 years from the date of commencement of field production including all relevant accounting periods prior to the commencement of the PIA. Following this 5-year period, the new production and price-based royalty rates stipulated in the PIA shall apply.

Production Sharing Contracts

Unexpired PSCs

Subsisting PSCs and their underlying OMLs or OPLs will be unaffected by the passage into law of the PIA, until they come up for renewal/conversion, whereupon all the fiscal terms of the PIA will apply to them.

PSCs Under Renegotiations

For PSCs that are currently being renegotiated with NNPC (Renegotiated PSCs), such PSCs must be signed within one year of the commencement of the PIA otherwise they will be deemed to fully conform to the new regime introduced by the PIA. These Renegotiated PSCs will not feature any investment tax credits (unless carried over as part of the renegotiation) but will feature a cost oil limit of not more than 60% of total oil production and at least a 55% haircut on any existing disputed amounts. Furthermore, the cumulative production for the purpose of determining profit oil shall be based on the rationalised production areas stipulated under the new acreage management system. If signed with the one-year limit, the old regime will apply to the new term of these Renegotiated PSCs, except that the new acreage management system under the PIA will apply to the underlying lease.

Marginal Fields

Marginal Fields Producing Petroleum

The outgoing royalty rates and farmout agreement structure will apply to marginal fields that have attained commercial production, for another 18 months before they would be required to convert to a PML under the PIA regime. The fiscal terms for these converted fields will be HT at 15% and CIT at 30%.

Marginal Fields Not Yet Producing Petroleum

Non – producing fields located within OMLs that have already been declared by the government to be Marginal Fields before January 1, 2021, and have been handed over to the government would be converted to PPLs and benefit from the new PIA fiscal regime. This would be the case for the current marginal fields being awarded under the 2020 Marginal Field Bid Rounds.

For undeclared marginal fields, i.e., fields undeveloped for 7 years after discovery that have not been transferred back to the government, the holder of any OML where they are located have 3 more years to do any of the following:

1. present appropriate field development plans and proceed to achieve commercial production from the field;
2. carve out and farmout these fields to third parties on terms approved by the Commission; or
3. relinquish the field to the government.

The PIA brings an end to the marginal field regime and transforms these fields into substantive PMLs or PPLs within the next 18 months, except for new marginal fields that are farmed out privately by the OML holders that elect not convert.

Disclaimer: This publication is not a legal opinion and is not designed to provide legal advice. Should you require legal advice on how the PIA directly impacts your business, do not hesitate to contact us.

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