AN APPRAISAL OF THE DISPARATE TENURE REGIMES FOR PETROLEUM PROSPECTING LICENCES UNDER THE PETROLEUM INDUSTRY ACT (PIA) 2021*

Abstract

Petroleum licences are never granted in perpetuity. They are usually granted to last for a given duration. This paper critically interrogates the location-specific duration framework of Petroleum Prospecting Licences (PPLs) under Nigeria's Petroleum Industry Act (PIA) 2021—one of the most consequential legislative interventions in the country's hydrocarbon sector. The PIA 2021 introduces a bifurcated tenure regime, granting shorter durations for onshore and shallow water licences (three years, renewable once) and extended terms for deep offshore and frontier basin operations (five years, renewable once). While this stratification is ostensibly justified by operational complexity and investment risk, its normative coherence, regulatory equity, and economic consequences remain underexplored. Anchored in a doctrinal legal methodology, this article conducts a meticulous textual analysis of the PIA's relevant provisions, drawing upon statutory interpretation, comparative practice, and petroleum licensing theory. The findings reveal that the differentiated approach, though rational in principle, may generate perverse incentives, discourage investment in strategic onshore assets, and exacerbate administrative asymmetries. Moreover, the undefined parameters of the force majeure exclusion clause create space for regulatory uncertainty and potential abuse. The article therefore recommends a recalibration of the tenure regime through clearer statutory articulation, performance-linked renewals, and refined interpretive guidance. It concludes that while the location-specific durations may enhance investor confidence in technically challenging terrains, they must be tethered to a transparent, coherent, and enforceable regulatory logic to serve as an effective catalyst for upstream investment and optimal resource development.

Keywords: Petroleum; Prospecting; Licensing; Duration; Nigeria; Renewal.

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1. Introduction

Petroleum exploration and prospecting are inherently daunting and capital-intensive endeavours, with different contract areas, locations or frontiers—such as onshore, shallow water, deepwater, offshore or frontier basins—imposing distinct operational challenges, including geological risks, infrastructural deficits and environmental complexities.[1] The legal and regulatory framework is expected to factor in these different challenges in the Petroleum licensing regimes. Nevertheless, the legal regime under the defunct Petroleum Act[2] 1969 did not provide differential treatments in terms of duration of oil prospecting licence (OPLs) awarded to cover different locations and water depths.[3] This meant that irrespective of the peculiar exploration and drilling challenges of different terrains or water depths, OPLs carried a uniform duration of five years (renewable for another five years.[4]

However, the enactment of the Petroleum Industry Act (PIA) 2021 marks a significant recalibration of Nigeria's hydrocarbon governance regime.[5] After decades of legislative inertia, the PIA consolidates and modernises the legal, fiscal and institutional architecture governing petroleum operations[6]. In the upstream sector, the Act introduces a delineated and ostensibly investor-friendly framework, with the objective of enhancing regulatory certainty, promoting efficiency and attracting capital to an increasingly competitive global energy landscape. Among its most consequential innovations is the restructuring of the licensing framework for petroleum exploration and development.[7]

1 OJ Jacob and others, 'A Review of the Geology and Petroleum Resources of Gulf of Mexico (GOM)' (2024) 10 (11) *International Journal of Advanced Academic Research* 42, 46 and 54.

2 Petroleum Act, Cap P10 LFN 2004 (now repealed, by operation of law).

3 Ibid, Paragraph 6 of the First Schedule thereof, for instance, provides: "The duration of an oil prospecting licence shall be determined by the Minister, but shall not exceed five years (including any periods of renewal)." In other words, a uniform duration was provided for all OPLs.

4 Ibid.

5 Y Omorogbe, 'The Petroleum Industry Act from A Governance Perspective' (2022) 7 (1) *Crescent University Law Journal* 22-40.

6 M Idiong, 'A Critical Appraisal of the Petroleum Industry Act 2021: Challenges and Opportunities' (2023) 6 (1) *African Journal of International Energy and Environmental Law* 178. See also: SA Adebisi and KN Ezebuiro. 'Analysis of the Petroleum Industry Act and its Impact on the Nigerian Oil and Gas Sector' (2023) 6 (3) *Gusau International Journal of Management and Social Sciences* 293.

7 EM Akpambang, 'An Appraisal of Upstream Petroleum Licensing Regime in Nigeria Under the Petroleum Industry Act 2021' (2022) 89 (2) *Curentul Juridic: The Juridical Current, Le Courant Juridique* 30–50.

The PIA 2021, in dismantling the historical Petroleum Act of 1969, abolishes the Oil Prospecting Licence (OPL) regime and replaces it with the Petroleum Prospecting Licence (PPL).[8] This shift is more than nominal; it signals a strategic re-alignment towards performance-based licensing, underpinned by defined obligations, strict timelines, and enhanced regulatory oversight.[9] The PPL now serves as the primary legal instrument conferring rights to undertake petroleum prospecting and drilling activities within a specified acreage, prior to the grant of a Petroleum Mining Lease (PML)[10]. Unlike its predecessor, the PPL is calibrated to reflect the geological and operational variances inherent in Nigeria's diverse sedimentary basins. A notable innovation introduced by the PIA 2021 is the location-specific duration of Petroleum Prospecting Licences[11]. The Act prescribes, thus[12]:

> 77.—(1) A petroleum prospecting licence for onshore and shallow water acreages shall be for a duration of not more than six years, comprising of an initial exploration period of three years and an optional extension period of three years.
>
> (2) A petroleum prospecting licence for deep offshore and frontier acreages shall be for a duration of not more than 10 years, comprising of an initial exploration period of five years and an optional extension period of five years.
>
> (3) The area provided for in a petroleum prospecting licence shall not exceed—
>
> (a) 350 square kilometres for any onshore or shallow water acreages;
>
> (b) 1,000 square kilometres for any deep offshore acreages; and
>
> (c) 1,500 square kilometres for any frontier acreages.

8 Ibid.

9 NP Nweke, 'Innovations, Prospects and Shortfalls of Petroleum Industry Act (PIA) 2021' (2023) 6 (1) *African Journal of International Energy and Environmental Law* 217–228. <https://ajieel.com/index.php/a/article/view/42>accessed 21 September 2025.

10 PIA 2021, s 72 (1).

11 Ibid, s 77.

12 Ibid.

Pursuant to the above provision, the temporal[13] scope of a PPL is contingent upon whether the licensed area is onshore, shallow water, deep offshore, or situated within frontier basins. This stratified approach raises salient legal and policy questions. While ostensibly grounded in considerations of geological complexity and capital exposure, this paper undertakes a measured appraisal of whether the differential tenure structure gives rise to a differentiated regulatory landscape, with attendant implications for investment incentives and operational efficiency. Rather than advancing a purely critical posture, the analysis evaluates the extent to which such a framework coheres with established principles of petroleum licensing design, particularly in relation to optimal resource development, risk allocation, and temporal efficiency.

In this regard, the article interrogates the normative consistency, functional viability, and investment responsiveness of the tenure regime, situating it within the broader corpus of petroleum licensing jurisprudence and comparative international practice. The appraisal is thus directed not at repudiation, but at a balanced assessment of whether the current approach advances the underlying objectives of regulatory certainty, efficient resource utilisation, and competitive fiscal attractiveness, as articulated in the scholarly literature.

2. Conceptual Framework

In setting out the conceptual framework, this segment examines some key terms and expressions which we consider as central to analysing the disparate tenure regimes for PPLs under the PIA 2021.

2.1 *Petroleum Prospecting Licence (PPL)*

The PPL, as instituted under the PIA 2021, constitutes a core legal instrument within Nigeria's upstream regulatory framework. It is designed to confer upon the licensee the legal authority to conduct petroleum prospecting activities within a defined contract area, serving as an intermediary tenure between reconnaissance and full-scale production operations[14]. What then are the rights

[13] The word, "temporal" simply means relating to time. In legal and academic usage, it often denotes anything connected with duration, timing, or sequence of events. For example, a "temporal limit" refers to a time restriction, while a "temporal horizon" refers to the span of time available for a particular activity.

[14] Ibid, s 70 (1).

conferred by this licence? The PPL, as established under the PIA 2021[15], confers an interesting bundle of rights designed to facilitate the transition from subsurface uncertainty to commercial clarity. Chief among these is the exclusive right to prospect for petroleum, which legally empowers the licensee to conduct petroleum operations within a defined contract area to the exclusion of all others. This exclusivity is practical and operational. It entitles the licensee to drill both exploration and appraisal wells, which are critical for delineating hydrocarbon accumulations. For example, during the development of the Agbami field by Chevron and its partners, multiple appraisal wells were drilled to confirm the extent and structure of the reservoir after initial discovery[16]. These prospecting operations enable the estimation of hydrocarbon volumes in place, reservoir characteristics, and production potential—data fundamental to establishing commerciality and informing field development planning, as mandatorily required under the PIA 2021[17].

Additionally, the PPL authorises the licensee to undertake test production, albeit with prior approval of the Nigerian Upstream Petroleum Regulatory Commission (NUPRC). Test production allows for limited-scale extraction of petroleum over a specified period to evaluate reservoir performance and production viability under real-world conditions. In practice, operators such as Total Energies, during early development stages of the Egina field, conducted extended well testing to calibrate their development models before committing to full-scale investment.

Simultaneously, the PPL grants its holder the legal authority to drill exploration and appraisal wells and do corresponding test production on an exclusive basis[18], and a non-exclusive right to conduct exploration operations[19], including geological mapping, aeromagnetic surveys as well as Two-Dimensional (2D) or Three-dimensional (3D) seismic data acquisition. These activities may occur concurrently with similar non-invasive operations

15 Ibid, ss 70 (1) and 72 (1).

16 CR Harvey, P Matos and D Robinson, 'Petrobras in Nigeria: Valuation of the Agbami Oil Field" (Duke University, Fuqua School of Business, Teaching Case Study, 2010) 5–7. <https://people.duke.edu/~charvey/Teaching/BA499_2010/Petrobras/Petrobras_case.pdf>accessed 21 September 2025.

17 See, for instance, PIA 2021, s 79.

18 Ibid, ss 70 (1) (b) (i) and 72 (1) (a).

19 Ibid.

by other licensees in adjacent or overlapping acreage, particularly where the subsurface structures extend beyond block boundaries. For instance, in one of the sedimentary basins in Nigeria, the Benin Basin, that extends onshore and offshore along the western coast of Nigeria and into the Republic of Benin, multiple operators have conducted regional seismic surveys to refine stratigraphic models before entering exclusive prospecting phases.[20]

The PPL also grants the right to carry away and dispose of crude oil or natural gas won or extracted during the drilling of exploration or appraisal wells as a result of production tests, subject to the fulfilment of obligations imposed by this Act[21]. This duality of rights—exclusive for subsurface penetration and petroleum recovery, non-exclusive for preliminary surface and subsurface data acquisition—underscores the transitional nature of the PPL. It bridges the gap between reconnaissance and development, offering legal certainty for capital investment while preserving regulatory flexibility. Such a structure aligns with international practice: in jurisdictions like Ghana[22] and Brazil[23],exclusive drilling rights are similarly coupled with broader non-exclusive survey rights to encourage basin-wide data acquisition while safeguarding proprietary investment in drilling. Thus, the PPL's architecture under the PIA 2021 seems to reflect a carefully calibrated model that balances sovereign control, investor certainty, and geological intelligence gathering—each essential for advancing Nigeria's upstream exploration agenda.

2.2. *Regulatory Authority: The NUPRC*

Pursuant to the PIA 2021, the regulation of upstream petroleum operations—encompassing, *inter alia*, the oversight and administration of the PPL regime—falls within the statutory mandate of the NUPRC[24], established under Section 4 of the Act. The NUPRC functions as the central regulatory authority mandated to ensure technical, operational, and environmental compliance throughout the lifecycle of upstream petroleum activities[25]. It is vested with

20 MI Odigi and others, 'Tectono-Stratigraphy of Benin Basin, West Africa' (2018) 16 (1) ASRJETS 01-16, 1 and 4.

21 PIA 2021, s 72 (1) (b).

22 Petroleum (Exploration and Production) Act 2016 (Ghana), s 9.

23 <https://iclg.com/practice-areas/oil-and-gas-laws-and-regulations/brazil> accessed 30 December 2025.

24 PIA 2021, ss 5 and 6.

25 Ibid.

the discretion to recommend to the Minister of Petroleum Resources to grant, renew, or revoke licences, subject to the fulfilment of statutory conditions, and plays a pivotal role in performance monitoring and the enforcement of work obligations.

2.3. *Obligations of PPL Holders*

Under the PIA 2021, PPL holders are subjected to a stringent matrix of legal and operational obligations[26], designed to promote timely exploration, accountability and alignment with Nigeria's energy and environmental objectives[27]. These obligations include:

2.3.1 Work Commitment

It is important to emphasise that under the PIA 2021, upstream petroleum licensees and lessees are subject to binding work commitments, expressed as minimum work obligations in their approved work programmes and field development plans. These commitments include specific exploration, appraisal, or development activities (such as seismic acquisition and drilling) that must be performed within stated timelines as a condition for retaining the acreage and progressing to, or maintaining, a petroleum mining lease (PML). Sections 78 and 79 PIA 2021 require licensees and lessees to submit annual work programmes and cost estimates for approval by the NUPRC, with failure to perform approved work commitments potentially leading to relinquishment of acreage or revocation of the licence or lease. This applies to the PPL regime too.

In other words, work commitment in the PPL context may be contextualised as the statutorily mandated programme of exploration and appraisal activities, backed by minimum financial expenditures and tied to licence duration, which a PPL holder is obliged to perform as a condition for retaining acreage rights and progressing towards commercial production. It embodies a nexus of legal obligation, economic risk assumption, and regulatory discipline, ensuring that petroleum resources are not only speculatively held but actively explored in

26 ibid, s 78.

27 Templars, 'The Anatomy of the Petroleum Prospecting Licence: Our Commentary on the Petroleum Industry Act, 2021' (13 November 2022). <https://www.templars-law.com/app/uploads/2022/11/The-Anatomy-of-the-Petroleum-Prospecting-Licence-Our-Commentary-on-the-Petroleu>.

line with the State's objective of maximising resource recovery. The PIA 2021 stipulates, thus: A petroleum prospecting licence shall contain a requirement that the licensee commit to a work programme and such other terms and conditions as the Commission shall determine.[28]

It is clear from the foregoing provision that the grant of a PPL under the PIA 2021 is expressly conditioned on the licensee's adherence to a minimum work commitment, a requirement designed to incentivise timely and diligent exploration activities and to discourage the speculative warehousing of petroleum acreage. This work obligation is legally anchored in Section 78 of the PIA, as captured above, and further detailed in the licence terms and associated guidelines issued by the NUPRC.

A typical minimum work programme may include, but is not limited to, a sequence of geophysical surveys, interpretation of existing geological data, drilling of a specified number of exploratory and appraisal wells, and submission of periodic technical and financial progress reports. For example, a licensee operating in a frontier basin such as the Chad Basin may be required to acquire and interpret 500 square kilometres of 3D seismic data and drill two exploration wells within the initial three-year term. In contrast, a licensee in a data-rich onshore Niger Delta block may be tasked with reprocessing legacy seismic data and drilling one firm well within a shorter timeframe.

However, it must be stated that the concept of work commitment serves a dual regulatory and policy function. From a regulatory standpoint, it acts as a performance benchmark for evaluating the diligence and seriousness of the licensee. Non-fulfilment or under-performance may trigger administrative sanctions, including revocation or non-renewal of the licence[29] or financial penalties proportionate to the unfulfilled work obligations. From a policy perspective, it ensures that the nation's hydrocarbon resources are not sterilised but are actively explored for the purpose of enhancing reserves and augmenting domestic energy security.

28 PIA 2021, s 78.
29 Ibid, s 238.

Moreover, the work commitment mechanism introduces a degree of accountability into the exploration process. Licensees are expected to post performance guarantees or work programme bonds to demonstrate their financial capacity to execute the committed programme. This is particularly relevant in blocks located in deep offshore zones or ultra-deep terrains, where the capital intensity and technical complexity of exploration warrant stringent regulatory oversight to ensure that only competent and financially robust entities are entrusted with such licences.

A careful comparative analysis demonstrates that the requirement of time-bound and technically defined work commitments is not merely a matter of contractual design, but is firmly grounded in the positive law and licensing architecture of leading petroleum jurisdictions. For instance, in Norway, the statutory basis is found in the Petroleum Act[30], particularly sections 3-8 and 3-9, as complemented by the Petroleum Regulations, which provide that the work obligation—comprising activities such as seismic acquisition and exploration drilling—shall be expressly stipulated in the licence together with defined timelines. The legal consequence of non-performance is equally clear: failure to fulfil the prescribed work programme may result in relinquishment of the licensed area. In Brazil, the Petroleum Law, as operationalised through concession contracts issued by the *Agência Nacional do Petróleo, Gás Natural e Biocombustíveis (*National Agency for Petroleum, Natural Gas and Biofuels) *(ANP)*[31], imposes a binding "Minimum Exploratory Program," requiring concessionaires to execute specified technical operations within phased exploration periods, with default attracting contractual sanctions, including forfeiture. Similarly, in Malaysia, the Petroleum Development Act[32], which vests exclusive ownership and rights in PETRONAS[33], consolidating exploration/production authority and mandating Petroleum Agreements— predominantly Production Sharing Contracts (PSCs) administered by PETRONAS— that bind contractors to phased work programmes (such as geological/geophysical surveys, exploratory drilling)

30 Petroleum Act 1996 (Norway), ss 3-9.

31 ANP, 'Concession Agreement for Exploration and Production of Oil and Gas' (Gov.br, 2020) <https://www.gov.br/anp/pt-br/rodadas-anp/oferta-permanente/opc/arquivos/edital/contrato-blocos-ingles.pdf> accessed 12 Apr 2026.

32 Petroleum Development Act (PDA) 1974 (Malaysia).

33 Ibid, ss 4-6.

within strict timelines (typically 5-10 years exploration phase). In other words, undertaking such delineated exploration activities within stipulated timeframes exists as a condition for the continuation of petroleum rights.

Within this comparative context, the Nigerian framework—particularly under a PPL—reflects a congruent doctrinal orientation. The work commitment requirement embodies the classical principle of "use it or lose it," ensuring that petroleum acreage is not warehoused for speculative purposes but is instead allocated to operators demonstrably capable of converting prospective resources into proven reserves within the licence's prescribed temporal framework[34]. In this sense, work obligations perform both an allocative and regulatory function: they discipline licensee conduct, optimise resource development, and mitigate the risks of acreage hoarding. This alignment with international best practice underscores the broader juridical logic of modern petroleum regimes, wherein the grant of exclusive exploration rights is inextricably conditioned upon measurable, time-bound, and technically defined performance benchmarks.[35]

2.3.2 Submission of Field Development Plan (FDP)

In the course of prospecting for petroleum, if a commercial discovery is made, the PPL holder is legally obligated to make a formal declaration of it[36]. Where a PPL holder declares a commercial discovery under section 78 (8) (a) of the PIA 2021, the licensee shall within two years of the declaration, submit to the NUPRC a field development plan (FDP) with regard to the commercial discovery together with a commitment to carry out the work described in the FDP[37]. In other words, pursuant to Section 79 of the PIA 2021, the submission of a Field Development Plan (FDP) constitutes a central obligation of a PPL holder upon the declaration of a commercial discovery. A "commercial discovery" under the PIA 2021 signifies the establishment of petroleum reserves of sufficient economic value to justify the risks of development and production, having regard to prevailing technical and market conditions. The FDP represents the statutory bridge between prospecting and full-scale

34 PIA 2021, s.71(3)(b).

35 See generally, S Tordo and others, 'Petroleum Exploration and Production Rights: Allocation Strategies and Design Issues' (2010) 123 *World Bank Working Paper* 17.

36 PIA 2021, s 78 (8) (a).

37 Ibid, s 79 (1).

production. It must be submitted to the NUPRC within two years of the declaration of a commercial discovery[38], accompanied by a binding work commitment secured by a bank guarantee, letter of credit, or performance bond acceptable to the NUPRC.

In line with the PIA Act 2021[39], the Field Development Plan (FDP) is not conceived as a mere technical submission; rather, it operates as an integrated regulatory instrument through which the licensee must evince conformity with a dense matrix of technical prudence, economic rationality, and statutory compliance. The provision, read purposively, underscores the legislature's intention to ensure that petroleum development is neither speculative nor extractively myopic, but anchored in principles of optimal resource recovery, fiscal discipline, and sustainable operations.

At the technical core of the FDP lies the reservoir development strategy. Here, the licensee is required to articulate a coherent plan for achieving maximum economic recovery, grounded in sound reservoir engineering. This entails, inter alia, judicious well placement, the deployment of pressure maintenance mechanisms, and the adoption of efficient production techniques calibrated to the geological peculiarities of the field. The regulatory expectation is clear: petroleum resources, constitutionally vested in the State, must be exploited in a manner that minimises waste and maximises long-term value.

Complementing this is the obligation to present detailed surface and midstream infrastructure plans. The FDP must delineate the architecture of processing facilities, evacuation pipelines, and associated infrastructure, while also demonstrating integration with existing or proposed midstream operations. This requirement reflects a systemic approach to petroleum development, recognising that upstream efficiency is inextricably linked to midstream adequacy and logistical coherence. Equally central are the economic and fiscal projections embedded within the FDP. The licensee must provide robust cost estimates, realistic production profiles, and a demonstrable commitment to cost efficiency, particularly the avoidance of inflated capital or operating expenditures. In this respect, the FDP functions as a safeguard

38 Ibid.
39 Ibid, s 79(2).

against value erosion, ensuring that project economics remain aligned with both investor expectations and the State's revenue interests—a concern extensively interrogated in the petroleum economics literature.[40]

Beyond technical and economic considerations, the FDP must internalise Nigeria's local content imperatives. In accordance with the Nigerian Oil and Gas Industry Content Development Act 2010, the plan is expected to incorporate a structured programme for the recruitment, training, and advancement of Nigerian personnel, alongside scholarship schemes and broader capacity-building initiatives. This dimension reflects the developmental ethos of the Act, seeking to transform petroleum exploitation from a purely extractive enterprise into a catalyst for domestic industrial and human capital development.

Furthermore, the FDP must be undergirded by rigorous environmental and social safeguards. It is required to include an environmental management plan compliant with Section 102 of the PIA, a comprehensive decommissioning and abandonment framework pursuant to Sections 232–233, and credible strategies for the elimination of routine gas flaring. In addition, the plan must demonstrate adherence to host community obligations under Chapter 3 of the Act, thereby embedding principles of environmental stewardship and social licence within the project lifecycle. This aligns with the broader trajectory of international petroleum regulation, which increasingly integrates environmental, social, and governance (ESG) considerations into upstream approval processes.

However, approval of the FDP is not automatic: the NUPRC is mandated to assess the submission against these criteria and must render a decision within 180 days[41]. Significantly, where no decision is communicated within this statutory period, the FDP is deemed approved by operation of law. Furthermore, failure to submit an FDP within the prescribed two-year window results in the relinquishment of the discovery area, underscoring the PIA's emphasis on accountability and disciplined resource development. Historical

40 S Tordo, D Johnston and D Johnston, 'Petroleum Exploration and Production Rights: Allocation Strategies and Design Issues' (World Bank Working Paper No 179, World Bank 2010) 97.

41 Ibid, s 79 (10).

practice in Nigeria underscores the critical role of robust FDPs in advancing deepwater projects. For instance, the Bonga field, Nigeria's pioneering deep offshore development, located in OML 118, progressed only after Shell Nigeria Exploration and Production Company (SNEPCo) submitted a pioneering FDP centred on the deployment of a Floating Production, Storage and Offloading (FPSO) unit[42]—a technological innovation at the time. Similarly, the Egina field, operated by TotalEnergies, was underpinned by an FDP that combined advanced reservoir simulation with environmental safeguards and a subsea-to-FPSO configuration capable of producing 200,000 barrels per day.[43] In both cases, the approved FDPs provided the legal and technical foundation for the issuance of Petroleum Mining Leases (PMLs), converting exploratory rights into production rights under a stable fiscal regime.

By codifying FDP submission as a statutory requirement for lease conversion, the PIA aligns Nigeria's petroleum governance with international best practice. Comparable regimes in Norway, Brazil, and the United Kingdom similarly condition production authorisation on the prior approval of FDPs, thereby ensuring that petroleum resources are developed in a manner that is economically efficient, technically sound, and environmentally sustainable.

2.3.3 Social and Environmental Obligations

In line with global Environmental, Social and Governance (ESG) imperatives, the PPL framework incorporates obligations pertaining to environmental protection, community engagement, and social investment. Licensees are bound by the provisions of the Host Communities Development Trust[44], as well as applicable environmental regulations promulgated by the NUPRC and the Nigerian Midstream and Downstream Petroleum Regulatory Authority (NMDPRA)[45].

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42 Offshore Technology, 'Bonga Deep-water Project, Niger Delta, Nigeria' <https://www.offshore-technology.com/projects/bonga/?utm>accessed 27 December 2025.

43 This Day, 'Will Shell's Divestment of Assets Brightens Future of Nigeria's Deepwater Projects?' <https://www.thisdaylive.com/2021/08/15/will-shells-divestment-of-assets-brightens-future-of-nigerias-deepwater-projects/> accessed April 22 2026.

44 PIA 2021, Part III, Chapter 3.

45 Templars (n27) 4.

In essence, the PPL regime under the PIA 2021 reflects a deliberate shift towards a more disciplined, accountable, and performance-oriented upstream licensing architecture, with an express emphasis on commercial responsiveness, environmental stewardship, and regulatory rigour.

3. The Location-Specific Duration of PPLs

Under the PIA regime, there is no uniform duration for all categories of PPLs. The duration for each PPL is dependent on the terrain or location of the contract area[46], which could be onshore and shallow waters or deep offshore and frontier acreages.

3.1. *Onshore and Shallow Water Acreages*

The PIA 2021 introduces a structured, location-sensitive approach to the duration of PPLs. For acreages situated onshore and in shallow water—defined in accordance with the limits established by the NUPRC—the PPL is granted for an initial term of three (3) years[47]. This tenure is renewable once for a further period of three (3) years, subject to the licensee's compliance with minimum work obligations and other regulatory benchmarks. Accordingly, the maximum cumulative duration for a PPL in these terrains is six (6) years.

3.2. *Deep Offshore and Frontier Acreages*

In Nigerian Petroleum jurisprudence, deep offshore means any area within the territorial waters, continental shelf or exclusive economic zone offshore of Nigeria having a water depth in excess of 200 meters[48], while frontier acreage or basin refers to any or all acreages in an area on land in Nigeria defined as a frontier in a regulation issued by the NUPRC[49]. However, in contrast to onshore and shallow water acreages, for acreages located in the deep offshore or frontier basins, the PIA 2021 prescribes an initial term of five (5) years, renewable once for an additional five (5) years[50]. This extended term—a total of ten (10) years—reflects a deliberate legislative recognition of the heightened geological, technical, and financial challenges associated with

46 Ibid, 3.
47 PIA 2021, s.71(1)(a).
48 Ibid, s 318.
49 Ibid.
50 Ibid, s.71(1)(b).

operations in such terrains. These include ultra-deep formations, harsh marine conditions, and the limited availability of pre-existing infrastructure.

3.3. *Comparison with Previous Petroleum Act Regime*

Under the now-defunct Petroleum Act 1969,[51] the Oil Prospecting Licence (OPL), the predecessor to the current Petroleum Prospecting Licence (PPL), was granted for an initial period of five (5) years, subject to discretionary renewal.[52] The regime did not systematically distinguish licence durations based on location or terrain.[53] In other words, under the earlier Petroleum Act 1969 as well as under the Deep Offshore and Inland Basin Production Sharing Contracts Act 1999 (DOIBPSCA), the Nigerian State remained the sovereign owner of petroleum resources,[54] but the legal architecture governing tenure and location-specific duration has shifted from an implicit, policy-driven patchwork under the Petroleum Act and the DOIBPSCA to a more explicit, statute-codified regime under the PIA 2021.

The DOIBPSCA-anchored framework left the basic Oil Prospecting Licence/Oil Mining Lease (OPL/OML) structure in the Petroleum Act 1969 largely intact; however, it did not clearly differentiate statutory tenure by geographic location, but relied on ministerial discretion and fiscal-contractual incentives to produce practical differences between deep-offshore/frontier and onshore-area treatment.[55] By contrast, the PIA 2021 deliberately restructures this arrangement by consolidating licensing typology, tenure-brackets, and fiscal-incentives into a single, hierarchically coherent statute, thereby foregrounding location as a statutory-jurisdictional determinant rather than an interpretive policy marker.

The PIA achieves this by replacing OPL and OML with the PPL and Petroleum Mining Lease (PML), and then expressly tying permissible tenure to the physical and hydrogeographic characteristics of the acreage. Onshore

51 Cap P10, LFN 2004.

52 T Adebayo, 'Oil Licensing Regime Under the Petroleum Industry Act 2021 (Part 2): Petroleum Prospecting Licence' (2024) <https://topeadebayolp.com/oil-licensing-regime-under-the-petroleum-industry-act-2021-part-2-petroleum-prospecting-licence/ confirming OPL>

53 Cap P10 (n51), First Schedule, Para 6.

54 JS Olayande, 'An Evaluation of Fiscal Regimes for the Nigerian Petroleum Industry Bill' (2011) 1 (1) *Journal of Energy Policy, Research and Development* 122-133.

55 Ibid.

and shallow-water PPLs are capped at six years (three-year initial term plus a three-year extension), while deep-offshore and frontier PPLs are allowed up to ten years (five-year initial term plus a five-year extension), with similar logic extended to PMLs through a 20-year base term and renewable 20-year blocks keyed to the commercial life expectation of the field.[8] This sharp codification embeds DOIBPSCA-style location-based risk calibration into the statute itself, so that the difference between frontier and non-frontier tenure is no longer a matter of ad hoc fiscal-incentive schemes or uncodified renewal practice but a statutory allocation reflected in the shape and duration of the licences themselves.

In terms of regulatory institutionalisation, the old regime dispersed location-specific tenure decisions across the Ministry of Petroleum Resources, the Nigerian National Petroleum Corporation (NNPC) (as it were), and sector-specific administrative units, making discretion and policy-driven outcomes dominant features of the system.[56] The PIA 2021 centralises this within the Nigerian Upstream Petroleum Regulatory Commission (NUPRC), which now administers the location-differentiated tenure framework with greater transparency, procedural formality, and appeal-based accountability. At the same time, the PIA's integrated fiscal-regulatory design aligns location-based incentives (such as frontier-area fiscal provisions and investment-linked allowances) with the explicit tenure categories, so that differences in effective economic life between deep-offshore and onshore projects are now legally traceable to a single, coherent statutory-regulatory architecture rather than a fragmented, extra-statutory policy overlay.

Though the terrain-based tenure system is a crucial aspect of the PPL regime, this researcher is not aware of any caselaw on it. However, by way of illustration, imagine, under the Petroleum Act 1969 as informed by the DOIBPSCA,[57] the Nigerian petroleum regime as an untidy, ad hoc map of licences drawn by hand rather than by statute. On this map, the State still owns all the oil beneath the ground, but the rules for how long a company can hold a OPL, as it were, over a given block were not written in clear, uniform ink; instead, they emerge from the overlapping scripts of different actors—

56 Ibid.
57 DOIBPSCA, ss 2-4.

Ministerial circulars, internal departmental practice, and production-sharing contracts stamped "deep offshore" or "inland basin." So, on paper, an OPL in the Niger Delta creeks and another in the deep-offshore frontier might look alike, both initially three years with possible renewals, but in practice their life-spans diverge because the Minister quietly treats the deep-offshore licence as a longer, higher-risk project, and the DOIBPSCA-driven Production Sharing Contracts (PSCs) grant it softer fiscal terms and gentler renewal expectations.[58] The differentiation is real, but it is woven into policy-documents and unwritten norms, not into a transparent, location-labelled timetable in the statute book itself.

In that pre-PIA landscape, two companies—one holding an OPL on swampy onshore land, the other over a deep-offshore block—could end up with radically different effective tenure purely because of where the block sits. The deep-offshore licence might be allowed to roll forward in three-year tranches for years, accompanied by tax allowances and investment-incentive structures that make the project viable over a long horizon, while the onshore licence is pushed more aggressively toward prompt appraisal and production, with less room for extension. The law on the face of the Petroleum Act 1969 does not say "onshore: six years, deep-offshore: ten years"; it simply gives the Minister broad discretion, and the deep-offshore/frontier status becomes a bureaucratic-policy signal rather than a statutory category. Thus, the architectonic drawing of the tenure-regime is a patchwork: the same labelled licence-type covers both areas, but the invisible lines—drawn by DOIBPSCA incentives and Ministerial practice—carve out a de facto geography-based tenure code that is felt in the field but not neatly inscribed in the statute.

Under the PIA 2021, this picture is redrawn in bolder, cleaner lines. The PIA does not abolish the State's ownership, but it re-traces the architecture of tenure and location-specific duration so that the map is now engraved in statute, not just interpreted through policy. The schematic is no longer a blur of overlapping OPLs and OMLs overlaid by DOIBPSCA-stamped PSCs; instead, the Act plainly sets out that onshore and shallow-water PPLs are built on a six-year frame, while deep-offshore and frontier PPLs are designed for a ten-year cycle, with the PML system likewise calibrated—at 20-year blocks—

58 Ibid.

to reflect the higher risk and longer development schedules of frontier areas. In this vivid shift, what was once an implicit, policy-driven patchwork—where location-based difference lived in the margins of documents and in the habits of the Ministry—becomes a central, explicit, and codified statutory-regime, in which the acreage's geographic identity directly shapes the shape and duration of the licence.

The PIA's innovation lies in formalising this distinction, thereby codifying what had previously been a matter of regulatory discretion. While the legacy framework enabled a degree of uniformity, it arguably failed to account for the differential risks and investment profiles inherent in various geophysical settings. The PIA thus institutionalises a bifurcated tenure regime, signalling a shift towards greater regulatory precision and terrain-sensitive incentivisation. Nevertheless, this codification invites a deeper interrogation of its policy coherence, especially regarding whether the duration differentials optimally balance state interests in expeditious resource development with investor needs for commercial certainty.

4. An Appraisal of the Location-Specific Duration

4.1. *Rationale for Differentiated Durations*

While the PIA 2021 does not expressly articulate the rationale for prescribing differential durations for PPLs, the logic underpinning this bifurcation is reasonably inferred from the geological and commercial realities of Nigeria's sedimentary basins.

i. Complexity and Capital Intensity

Studies have shown that deep offshore and frontier basin explorations are characterised by profound operational complexity and formidable capital outlays, distinguishing them from conventional onshore or shallow water operations[59]. These challenges arise primarily from the technical demands of operating in ultra-deep marine environments, often exceeding depths of 1,500 metres, where the seabed is inaccessible by conventional drilling rigs[60]. In such cases, specially designed dynamically positioned drillships or semi-submersible rigs, costing hundreds of millions of dollars, must be deployed.

59 M Nguyen and others, 'Deepwater Drilling: Challenges, Evolutions of Drilling Practice, Well Design and Lessons for Vietnam' (2024) 6 (SI7) *VNUHCM Journal of Engineering and Technology* 180.

60 Ibid.

Additionally, the extraction of hydrocarbon resources at such depths requires the installation of sub-sea wellheads, remote-operated vehicles (ROVs) for maintenance, and floating production, storage, and offloading (FPSO) vessels, which function as self-contained offshore processing units. These technologies are not only expensive but also highly sensitive to harsh marine conditions, including deep ocean currents, high pressure, and temperature gradients, necessitating meticulous engineering and prolonged development schedules. For instance, Shell's Bonga field—Nigeria's first deep offshore project—required an investment exceeding $3.6 billion and took approximately eight years from discovery to first oil. Similarly, TotalEnergies' Egina field involved capex in excess of $16 billion, underpinned by over 200 subsea components deployed across vast underwater terrain[61]. Frontier basins, such as the Chad or Benue troughs, while not offshore, present analogous risks due to their limited geological data, remoteness, and lack of infrastructure, further compounding project timelines. In this context, the extended tenure—an initial five years renewable for five more—under the PIA 2021[62] is a legislative recognition of the high-cost, high-risk profile inherent in these terrains. It aligns the duration of legal rights with the technical and financial realities of such ventures, offering regulatory certainty critical for attracting capital and sustaining exploration momentum.

ii. Higher Risks and Extended Timelines

Deep offshore and frontier basin exploration is not merely more capital-intensive; it is also inherently risk-laden and temporally uncertain, owing to a confluence of geographical, geophysical, and infrastructural constraints[63]. The physical remoteness of deep offshore fields, often located over 100 nautical miles from the coastline, imposes significant logistical challenges. Mobilising drilling equipment, support vessels, and personnel entails complex marine coordination and high susceptibility to weather disruptions. For instance, operations in the Gulf of Guinea during the monsoon season face extended downtimes due to heavy swells and unpredictable wave regimes[64].

61 Offshore Technology, 'Egina Oil Field, Nigeria' <https://www.offshore-technology.com/projects/egina-field/> accessed 27 December 2025.

62 PIA 2021, s 71(1)(b).

63 Nguyen (n59) 180.

64 <https://www.nuprc.gov.ng/13-billion-barrels-reserve-of-oil-in-nigerias-deepwater-dpr/> See also, JK Mark and GP Allan, 'The Impact of Weather and Ocean Forecasting on Hydrocarbon Production and Pollution Management in the Gulf of Mexico' (2007) 35 (2) *Energy Policy* 966; <https://doi.org/10.1016/j.enpol. 2006.01.026. (https://www.sciencedirect.com/science/article/pii/S0301421506000711)> accessed 27 December 2025.

Studies have also demonstrated that limited subsurface data further compounds exploration risk[65]. Unlike onshore and shallow water acreages, which have benefitted from decades of seismic mapping and legacy well data, deep offshore and frontier regions remain geologically underexplored. In Nigeria's frontier inland basins such as the Sokoto or Bida basins, for example, exploration is often based on sparse 2D seismic grids, rendering hydrocarbon prospectivity uncertain. Consequently, companies must invest heavily in high-resolution 3D seismic surveys before drilling can even be contemplated—activities that may take two to three years before yielding actionable insights. Adverse environmental and security conditions further elongate project timelines. Deepwater operations must navigate ecological sensitivities such as marine biodiversity conservation and risks of oil spills in fragile ecosystems.[66] In frontier onshore areas like the Lake Chad Basin, insecurity due to insurgency adds another layer of delay and financial risk, requiring heightened operational precautions and even military support in extreme cases.

In stark contrast, onshore and shallow water blocks, particularly in the Niger Delta, are relatively well-mapped and infrastructure-adjacent, often lying within proximity of existing pipeline networks, export terminals, and service hubs[67]. This proximity enables faster mobilisation, reduced drilling uncertainty, and shorter appraisal-to-development timelines. The PIA 2021's differentiated tenure regime—granting six years for onshore/shallow water PPLs and ten years for deep offshore/frontier PPLs—thus mirrors these asymmetries in operational risk and temporal requirement. It acknowledges that while geological luck plays its part, regulatory timeframes must align with geological reality if Nigeria is to remain a competitive jurisdiction for high-risk petroleum investment.

65 B Kilhams and others, 'Challenges and Opportunities for Hydrocarbon Exploration Within the Mesozoic Sub-Basalt Plays of the Norwegian Atlantic Margin' (2022) 28 (4) *Petroleum Geoscience* 22.

66 EE Cordes and others 'Environmental Impacts of the Deep-Water Oil and Gas Industry: A Review to Guide Management Strategies' (2016) 4 *Frontiers in Environmental Science* 58.

67 JT Ekanem and IE Udoh, 'Impacts of Oil Exploration (Oil and Gas Conflicts; Niger Delta as a Case Study' (2023) 11 (3) *Open Journal of Social Sciences* 1-15.

4.2. *Arguments For and Against the Differentiated Approach*

Globally, the petroleum industry is capital-intensive and fraught with a lot of risks.[68] Thus, one possible key argument for the differentiated approach is the need for mitigating capital Intensity and exploration risks.

Fundamentally, the regime embodies a pragmatic recognition of the disproportionate capital intensity and elevated risk profiles inherent in frontier and deepwater exploration. Onshore operations typically involve lower upfront costs—estimated at $5–10 million per well—due to established infrastructure and seismic data availability, allowing quicker amortisation within shorter tenures. In contrast, deepwater drilling demands $100–200 million per well, compounded by extreme pressures, subsea complexities, and sparse geological datasets, where success rates hover below 20%.[69] By granting a decade-long horizon, the policy enables investors to spread these expenditures, conduct phased seismic surveys, and drill multiple appraisal wells without premature relinquishment pressures. A pertinent example is Shell's Bonga deepwater field (OPL 212), where extended timelines under pre-PIA regimes facilitated discovery in 1996 and first oil by 2005, yielding over 1 billion barrels to date. This mirrors Brazil's ANP regime, where 12-year exploration phases for ultra-deepwater blocks (for example, pre-salt Libra field) have unlocked 15 billion barrels in reserves since 2010.[70]

Therefore, the differentiated tenure (otherwise referred to as terrain-based or location-based) regime for PPLs enshrined in the PIA 2021 represents a consciously calibrated policy instrument. We contend that it is meticulously tailored to address the heterogeneous geological, commercial, and operational risks across the nation's petroleum provinces—ranging from mature onshore basins like the Niger Delta to high-risk frontier areas such as the Benue Trough and deepwater blocks in the Gulf of Guinea. This regime differentiates initial exploration periods: six years for onshore and shallow water licences

68 N Khan, S Mejri and S Hammoudeh, 'How Do Global Commodities React to Increasing Geopolitical Risks? New Insights into the Russia-Ukraine and Palestine-Israel Conflicts' (2024) 138 *Energy Economics* 107812. See also, C Wilson, G Shrimali and B Caldecott, 'Investment in New Oil and Gas Assets: The Effect of Energy-Related Uncertainty and Climate Policy' (2025) 151 *Energy Economics* 107443.

69 US Energy Information Administration, *International Energy Outlook 2025* (EIA, 2025) Table A-12 <https://www.eia.gov/outlooks/ieo/> accessed 23 April 2026.

70 ANP Brazil, ''Resolution 11/2013: 12-Year Exploration Phases for Ultra-Deepwater/Pre-Salt; Libra field (2010) Unlocked 15Bbbl Reserves' <https://www.gov.br/anp/pt-br> accessed April 20 2026.

(with optional two-year extensions), versus ten years for deepwater and frontier licences, reflecting a nuanced risk-adjusted framework under the PIA.

However, the differentiated tenure structure is best understood not merely as a technical calibration of licence duration, but as a deliberate instrument of regulatory economics. That is to say, one that seeks to reconcile geological reality with investment behaviour. Its normative appeal lies in its responsiveness to risk: by extending the temporal horizon for exploration in frontier or deepwater acreages, the regime acknowledges the capital intensity, technological complexity, and probabilistic uncertainty that define such ventures. In this respect, longer tenures function as a form of regulatory risk mitigation, enabling investors to amortise substantial upfront costs and to sequence exploration activities in a commercially rational manner.

This approach finds resonance in comparative petroleum regimes. Jurisdictions such as Brazil and Angola have, over time, adopted similarly elastic tenure frameworks for deep offshore operations, recognising that rigid licensing timelines may prematurely truncate viable exploration cycles. As Tordo, Johnston and Johnston persuasively argued in their work on petroleum fiscal systems, the design of licensing regimes must internalise geological risk if it is to attract capital in a competitive global environment.[71] Within the contemporary context—marked by capital discipline among international oil companies and the gradual reallocation of investment toward low-carbon assets—the provision of extended tenures may thus enhance Nigeria's attractiveness to technically sophisticated, capital-intensive operators.

Yet, this differentiated approach is not without its doctrinal and policy tensions. Its asymmetrical structure introduces the possibility of distorted investment signals across the upstream sector. Onshore and shallow water assets, though comparatively less risky, play an indispensable role in sustaining domestic production levels, fostering indigenous participation, and underpinning energy security. A regime that appears to privilege deepwater investment—by affording it greater temporal flexibility—may inadvertently render these assets less attractive, particularly where fiscal terms do not sufficiently compensate for the shorter tenure cycles.

71 Tordo (n35) 96.

Moreover, the administrative implications of such differentiation are far from trivial. A licensing system characterised by variable durations inevitably demands a more sophisticated regulatory apparatus—one capable of monitoring compliance across divergent work programmes, timelines, and performance benchmarks. In the absence of rigorous oversight, the extended tenure granted to higher-risk acreages may degenerate into regulatory laxity. There is a palpable risk that operators, shielded by longer licence periods, may engage in strategic delay, under-investment, or speculative holding of acreage, thereby frustrating the overarching objective of timely resource development.

From a law-and-economics perspective, the critical issue is whether the incentive structure embedded in the differentiated regime is sufficiently counterbalanced by robust performance obligations and enforcement mechanisms. Without periodic licence reviews, enforceable work commitments, and credible sanctions for non-performance, the policy risks entrenching inefficiency rather than alleviating it. In such a scenario, what is conceived as a facilitative instrument of investment may instead operate as a conduit for delayed monetisation and suboptimal resource governance. The differentiated approach, therefore, sits at the intersection of prudence and peril: it embodies a sophisticated appreciation of geological risk, yet simultaneously exposes the regulatory system to the dangers of asymmetry, complexity, and moral hazard. Its ultimate efficacy will depend less on its conceptual elegance than on the institutional capacity deployed in its implementation.

4.3. *Force Majeure Clause and its Impact on Duration Extensions*

It is customary to insert a Force Majeure Clause in petroleum contracts, at least, to account for unforeseen events. According to Piper Hampton,[72] force majeure represents a situation in which a contracting party is unable to perform its obligations due to an impediment that lies beyond its control. Such an impediment must ordinarily be one that could neither have been reasonably anticipated nor averted. Upon the occurrence of a qualifying event, the affected party may be excused, wholly or in part, from the performance of its contractual duties. Although the doctrine finds its origins within the common

[72] P Hampton, 'Finding Our New Normal: Reevaluating Force Majeure Within Oil Finding Our New Normal: Reevaluating Force Majeure Within Oil and Gas Contracts in the Wake of COVID-19 and Gas Contracts in the Wake of COVID-19' (2021) 7 (1) *Oil and Gas, Natural Resources, and Energy Journal* 152-153.

law tradition, the specific events that trigger its operation are seldom exhaustively defined in abstract terms. Rather, the determination of what constitutes a force majeure event is primarily contingent upon the express stipulations of the contract and the extent to which the relevant circumstances were within the contemplation of the parties at the time of contracting.[73]

In Nigeria, the PIA 2021 stipulates that where a holder of a petroleum PPL fails to fulfil any term or condition of the licence, it shall not, except as provided in the licence, give the Minister a right of claim against the licensee or be deemed a breach of the licence, if the failure arises from force majeure[74]. This provision, we submit, presupposes that any period during which operations are suspended due to force majeure shall be excluded from the computation of the licence duration. While this provision reflects standard contractual practice in international petroleum regimes, its scope and interpretive clarity are critical.

Under the PIA 2021[75], a force majeure includes delays or inability to perform any obligations under this Act (other than a payment obligation), due to any event beyond the reasonable control of a person, and the event may be, but is not limited to, any act, event, happening, or occurrence due to natural causes, and acts or perils of navigation, fire, hostilities, war (declared or undeclared), blockade, labour disturbances, strikes, riots, insurrection, civil commotion, quarantine restrictions, epidemics, storms, floods, earthquakes, accidents, blowouts or lightning and an event of force majeure shall not include changes in the laws of Nigeria or any political subdivision thereof or any acts or orders of Government, any minister, ministry, department, subdivision, agency, authority, council, committee, or other constituent element thereof, or any corporation owned or controlled by any of the foregoing, where operations are delayed, curtailed or prevented by force majeure, then the time for carrying out the obligation and duties thereby affected, and rights and obligations hereunder, shall be extended for a period equal to the period thus involved provided that such period shall not exceed three years in total after which each party can terminate the respective licence or lease. The PIA 2921 does not

73 Ibid.
74 PIA 2021, s 72 (3).
75 Ibid, s 318.

define "force majeure" in operational terms, thereby leaving room for divergent interpretations. Unless carefully circumscribed through subsidiary legislation or model licence terms, operators may invoke the clause opportunistically to prolong tenures beyond their intended limits. In contexts of regulatory laxity, this may further distort the duration framework and undermine the efficiency rationale of the location-based tenure model.

From the foregoing discourse, it is safe to conclusively posit that while the differentiated duration regime reflects a rational alignment with geological and commercial variances, it raises non-trivial concerns regarding policy coherence, administrative equity, and investment neutrality. A balanced reform would necessitate clearer statutory guidance, harmonised enforcement, and periodic review of the efficacy of duration differentials in promoting optimal resource development.

5. Conclusion and Recommendations

The Petroleum Industry Act (PIA) 2021 introduces a location-contingent framework for PPLs, distinguishing between onshore/shallow water and deep offshore/frontier basins. The former are limited to an initial term of three years, renewable once for an additional three years, while the latter enjoy an extended initial term of five years, with a further five-year renewal option. This bifurcation is a marked departure from the uniform tenure structure of the repealed Petroleum Act 1969 and signals a shift towards differentiated regulation aligned with geospatial and technical realities.

While the rationale for differential tenures—rooted in geological complexity, financial exposure, and longer exploration timelines—is intelligible, it is not without challenge. The current framework risks creating investment imbalances, with onshore assets potentially rendered less attractive despite their strategic importance. Moreover, ambiguous provisions, such as the undefined contours of the *force majeure* exception, could open the door to regulatory arbitrage. Without robust oversight, the model may inadvertently entrench inefficiencies and delay commercialisation.

In order to secure regulatory coherence and preserve the principle of investment neutrality within Nigeria’s petroleum licensing architecture, a number of interrelated reforms call for deliberate and methodical

consideration. Foremost among these is the imperative of normative clarity. The extant framework under the PIA 2021 would benefit from a more explicit articulation—whether through targeted statutory amendment or carefully crafted subsidiary legislation—of the underlying rationale for the observed duration differentials in PPLs. Such codification is not merely cosmetic; it serves a foundational rule-of-law function by enhancing transparency, fostering investor confidence, and mitigating interpretive uncertainty. As has been persuasively argued in the literature, regulatory opacity in resource governance regimes often engenders rent-seeking behaviour and undermines the credibility of licensing systems. Closely allied to this is the need to recalibrate the renewal regime in a manner that is firmly anchored in performance accountability. Renewals of PPLs should not assume an automatic or discretionary character; rather, they ought to be strictly contingent upon verifiable compliance with prescribed work commitments and demonstrable progress against clearly defined technical and operational benchmarks.[76] This approach resonates with the widely endorsed "use it or lose it" principle, which underpins efficient acreage management in leading petroleum jurisdictions such as Norway and Brazil. By conditioning tenure extension on performance, the regulatory framework not only discourages speculative licence holding but also incentivises timely resource development, thereby aligning private operator conduct with national resource optimisation objectives.

Equally critical is the refinement of the force majeure regime as it applies within the PPL context. While the inclusion of force majeure clauses in petroleum instruments is both customary and necessary, their current formulation often suffers from indeterminacy and susceptibility to opportunistic invocation. There is, therefore, a compelling case for the introduction of clearer definitional parameters, coupled with robust procedural safeguards governing notification, verification, and duration of relief. Such reforms would ensure that the doctrine operates as a shield against genuinely unforeseeable and uncontrollable disruptions, rather than as a convenient mechanism for regulatory evasion. Comparative experience underscores this necessity; jurisdictions such as the United Kingdom and Malaysia have

[76] See generally, the Acreage Management and Petroleum (Drilling and Production) Regulations, 2024,

progressively moved towards more tightly circumscribed force majeure provisions in upstream contracts.

Furthermore, the intellectual and policy foundations of the location-based differentiation in PPL duration would be considerably strengthened by sustained empirical interrogation. There remains a notable paucity of data-driven analysis assessing whether licences in frontier, deepwater, and onshore terrains—subject to differing temporal regimes—actually exhibit divergent performance outcomes in terms of exploration success, reserve maturation, and investment inflows. Future research, ideally situated at the intersection of petroleum economics and regulatory law, should therefore undertake a rigorous comparative evaluation of these variables. Such an inquiry would not only illuminate the efficacy of the differentiated tenure model but also provide an evidentiary basis for iterative policy refinement. Ultimately, while the adoption of a location-sensitive duration framework for PPLs represents a commendable and sophisticated regulatory innovation within the PIA, its enduring effectiveness will depend on the precision of its legal design, the consistency and integrity of its administrative implementation, and its capacity to adapt to the evolving exigencies of the global petroleum industry. In this regard, reform must be conceived not as a discrete intervention, but as part of a continuous process of regulatory calibration, informed by both doctrinal insight and empirical reality.