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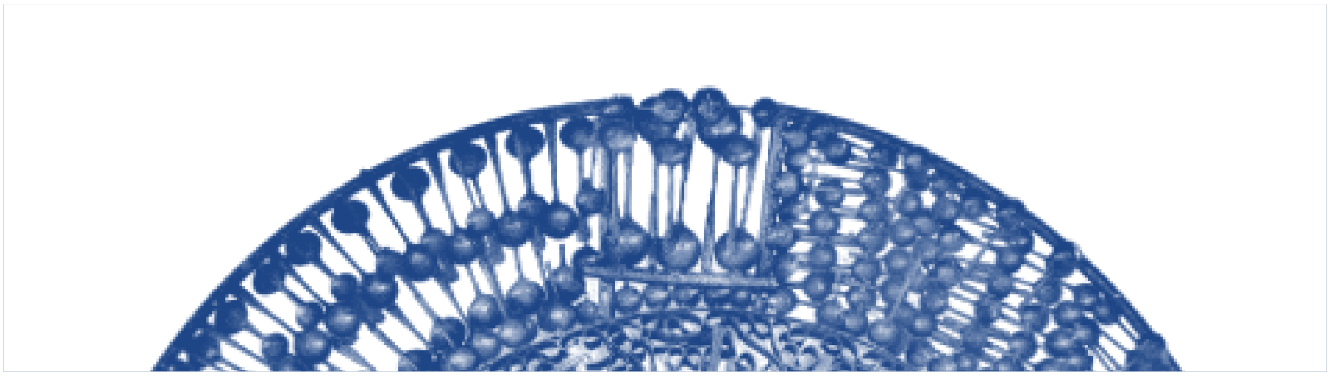
OIL & GAS AND TAX TEAMS UPDATE | 2026

A Ceiling, or a Concession?

The Legal Architecture Behind Nigeria's Deepwater Push

THE STATUTORY BASIS OF THE 6TH AUGUST 2026 EXECUTIVE ORDER, WHAT IT REPLACES, WHAT IT PRESERVES, WHERE DISCRETION STILL SITS, AND WHY IT MATTERS TO INVESTORS, LENDERS, AND PROJECT SPONSORS



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AT A GLANCE

01 On 6th August 2026, President Bola Ahmed Tinubu signed the Deep Offshore Oil and Gas Projects Incentives (Tax Remission) Order, 2026 (the “Order”). The Order was published as S.I. No. 37 of 2026 in Federal Republic of Nigeria Official Gazette No. 150 of 10th August 2026.

02 The Order introduces production tax credits and a conditional profit oil reset for qualifying deep offshore developments. The FGN projects that the framework may unlock up to US$50 billion in new investment, beginning with the approximately US$10 billion Bonga South West project. That projection should be read alongside, but not conflated with, the NUPRC's separate statement that twenty-two major offshore projects are expected between 2026 and 2030 with an estimated investment potential of US$30 billion to US$50 billion. The Order does not identify a closed set of beneficiary projects.

03 The widely reported figures of US$11.50 per barrel and US$8 per barrel of oil equivalent are aggregate ceilings on combined Standard and Supplementary Production Tax Credits (“Tax Credits” or “PTC”), assessed on a case-by-case basis, having regard to the eligibility criteria and the economic profile of the relevant project development. The Tax Credits are not a uniform entitlement available automatically to every project.

04 The Order is expressed to be made pursuant to section 3(1)(e) of the Petroleum Industry Act, 2021 (“PIA”) and section 77(1) of the Nigeria Tax Administration Act, 2025 (“NTAA”), rather than through an amendment to the PIA itself. The two provisions are materially different: section 3(1)(e) is framed as a ministerial function to promote an enabling environment for investment in the petroleum industry, while section 77(1) expressly empowers the President, on the recommendation of the Minister of Finance, to remit tax wholly or in part where the statutory test is met.

05 The Order seeks further to reduce reliance on individually negotiated, project-by-project fiscal concessions through published eligibility criteria, but preserves meaningful administrative discretion within that structure, including in: (a) Nigeria Revenue Service's (“NRS”) case-by-case credit assessments, (b) Nigerian Upstream Petroleum Regulatory Commission’s (“NUPRC”) decisions on Final Investment Decision (“FID”) extensions, and (c) Nigerian Content Development and Monitoring Board’s (“NCDMB”) Nigerian content approvals.

A NOTE ON DATES

Information in this article is stated as at 21st August 2026. The implementation guidelines for the Order, including the documentation, valuation methodology, and reporting requirements attaching to the open-book economic model referenced in the Order, had not been published as at that date, and the analysis below should be read subject to that qualification.

1. The outcome, and why its legal form matters

Nigeria has taken a further step in its effort to revive investments in the deep offshore petroleum sector. As we have indicated above, on 6th August 2026, President Tinubu signed the Order, introducing a rules-based package of production tax credits and production sharing incentives for qualifying deep offshore developments. The Presidency's announcement of 11th August 2026 frames the reform as capable of unlocking up to US$50 billion in new investments, and identifies the approximately US$10 billion Bonga South West project as an early intended beneficiary under the Order.

The Federal Government of Nigeria (“FGN”) presents the Order as a move away from years of project-by-project fiscal negotiation towards published eligibility criteria. Its stated ambition extends beyond Bonga South West to create a repeatable investment architecture across categories of qualifying deep offshore developments. Legally, that matters because the reform changes not only the possible amount of fiscal support, but how a project seeks to establish eligibility for, and access to, that support.

The article's core question follows from that shift. The Order does more than offer fiscal relief. The Order seeks to place Nigeria's current deepwater incentive regime within a more structured, rules-based statutory framework, while further reducing reliance on individually negotiated, project-specific concessions. The legal question for investors, lenders and project sponsors is whether the Order’s headline ceilings can be converted into sufficiently certain, durable and contractually implementable fiscal benefits.

A second question follows closely behind the first. The Order was not introduced by amending the PIA. It is instead expressed to be made pursuant to section 3(1)(e) of the PIA and section 77(1) of the NTAA. Those provisions do different legal work. Section 3(1)(e), which sits within Part II of Chapter 1 of the PIA dealing with the Minister of Petroleum, requires the Minister to promote an enabling environment for investment in the Nigerian petroleum industry. Section 77(1) of the NTAA, by contrast, expressly empowers the President, on the recommendation of the Minister of Finance, to remit tax wholly or in part where satisfied that it is just and equitable to do so. That distinction is central to the durability question considered in Section 4: the legal foundation for the fiscal relief depends on the scope of the particular enabling provisions relied upon, and not merely on the Order's own wording.

A third thread runs through both questions and is addressed in Section 5: what the Order replaces, what it preserves, and where discretion still sits. Read narrowly, the Order is a set of published rates and ceilings. Read as a whole, it is better understood as a bounded framework, one that seeks further to reduce reliance on ad hoc, deal-specific negotiation, but that reintroduces discretion of its own within defined administrative parameters and processes, rather than eliminating discretion altogether. That framing recurs across the sections that follow, from the mechanics of the Tax Credit in Section 2 to the FID deadline and Nigerian content conditions in Section 5.

2. What the Order offers: rationale, and the ceiling-versus-concession question

The FGN’s central policy proposition, reflected in public policy statements on the Order, is that greater certainty should attract capital for investments in the targeted sector. The Order should be tested against that proposition rather than treated as proof of it. A published framework may reduce dependence on bespoke fiscal negotiation and allow sponsors of a project to assess its likely fiscal treatment earlier in the investment cycle. That will be so only to the extent that the relevant entitlement is fixed by rules rather than left to case-by-case assessment, administrative judgment or contractual agreement. Rules-based does not mean discretion-free.

The Standard Production Tax Credit is not itself new to Nigeria's deep-offshore incentive regime. Deep-offshore production tax credits were introduced in 2024 through the Notice of Tax Incentives on Deep Offshore Oil and Gas Production, 2024, issued pursuant to the Oil and Gas Companies (Tax Incentives, Exemption, Remission, Etc.) Order, 2024. The 2026 Order reproduces and recalibrates that standard-credit architecture while adding the supplementary PTC and POR. What follows should therefore be read as a development of an existing incentive mechanism rather than the introduction of a wholly new one.

THE STANDARD PRODUCTION TAX CREDIT

For qualifying crude oil developments, the Order provides for a standard PTC. Projects with producible reserves not exceeding 400 million barrels of oil equivalent may qualify for a credit of US$3.00 per barrel, or 20% of the fiscal oil price if lower, subject to a production ceiling of 150 million barrels. Larger qualifying projects may receive US$4.50 per barrel, or 20% of the fiscal oil price if lower, subject to a production ceiling of 500 million barrels. Qualifying future leases may attract an additional US$1.00 per barrel, subject to the conditions prescribed in the Order.

For crude oil, the applicable standard PTC is reduced by half for any month in which the fiscal oil price falls below US$50 per barrel. Qualifying non-associated gas projects are separately eligible for standard PTCs calculated by reference to the hydrocarbon-liquids content of the field. The crude-oil standard PTC is computed only on crude oil produced and sold from the relevant project development and does not extend to production from another field, lease, project, asset or contract area.

THE SUPPLEMENTARY PRODUCTION TAX CREDIT: A CEILING, NOT AN AUTOMATIC ENTITLEMENT

The Order creates a supplementary PTC for qualifying greenfield developments, layered on top of the standard PTC. This is the source of the widely reported US$11.50 per barrel and US$8 per barrel of oil equivalent figures. It is therefore here that headline reporting can obscure an important distinction: the supplementary PTC is not an automatic entitlement available to every project that meets a threshold.

It is assessed on a case-by-case basis, and the combined value of the standard and supplementary PTCs is capped at US$11.50 per barrel for oil and US$8 per barrel of oil equivalent for gas. The assessment is to have regard to the applicable eligibility criteria and the economic profile of the relevant project development.

That distinction is central to the article. The headline figures represent the maximum potential fiscal support available under the framework, not a floor for every qualifying deep offshore development and not a uniform concession triggered by eligibility alone.

The Order may therefore provide greater certainty about the outer boundary and process of available support without making the precise amount mechanically determinable for every project. A project sponsor who models its economics on the ceiling, rather than on the credit actually available to its specific project profile, risks overstating the fiscal benefit and, in turn, the project's bankability to lenders and partners.

3. The profit oil reset: conditional, not general

A second significant feature of the Order is the Profit Oil Reset ("POR"). Where the relevant conditions are satisfied, the profit oil sliding scale applicable to a new qualifying project may restart at a 70:30 contractor-government allocation, notwithstanding that production elsewhere within the same contract area has already caused the applicable profit oil allocation to move beyond that point under the underlying Production Sharing Contract ("PSC").

The statutory backdrop changed under the 2025 tax reforms. Although the Nigeria Tax Act, 2025 ("NTA") repealed the Deep Offshore and Inland Basin Production Sharing Contracts Act, it substantially consolidated the deep-offshore PSC framework within Chapter Three, Part III of the NTA. Section 110 provides that profit oil is allocated between the parties in accordance with the terms of the relevant PSC. The POR therefore operates within a statutory framework now housed in the NTA, while the applicable profit oil split remains contractually anchored in the PSC.

The measure addresses a particular issue in mature PSC areas: a substantial new development might otherwise inherit fiscal economics shaped by prior production from older projects within the same contract area. Eligibility is therefore narrower than a general 70:30

concession. The POR is available only where the existing profit oil sliding scale in the relevant contract area has already progressed beyond 70:30 through production elsewhere in that contract area.

Implementation also has a contractual dimension. Where a POR is approved, the relevant PSC is to be amended by an addendum between the contractor and the concessionaire within thirty days of approval. Sponsors should therefore plan the necessary internal, co-venturer and financing approvals before making the application, rather than after approval has been obtained.

The FGN's policy description places the Nigeria National Petroleum Company Limited ("NNPCL"), as the Government's nominated PSC counterparty, within the implementation architecture for the necessary PSC amendments. That commercial and contractual role should be distinguished from the regulatory approvals and licensing functions of the NUPRC.

4. Why the statutory basis -and the 2024/2026 transition- matter

The FGN has not amended the PIA to introduce the regime contained in the Order. The Order is instead expressed to be made pursuant to section 3(1)(e) of the PIA and section 77(1) of the NTAA. Those provisions do not, however, perform the same legal function.

SECTION 3(1)(E) PIA	SECTION 77(1) NTAA
Section 3 sits within the part of the PIA dealing with the Minister of Petroleum, and section 3(1)(e) forms part of the functions the Minister is required to discharge: promoting an enabling environment for investment in the Nigerian petroleum industry. It is not framed as an express power to remit tax or to make subsidiary legislation.	Section 77(1) of the NTAA is different. It expressly empowers the President, on the recommendation of the Minister of Finance, to remit wholly or in part tax payable by a taxable person where the President is satisfied that it is just and equitable to do so.

The statutory setting has also changed since the preceding deep-offshore incentive regime. In 2024, the Oil and Gas Companies (Tax Incentives, Exemption, Remission, Etc.) Order, 2024 was made under, among other provisions, sections 23(2) and 89 of the Companies Income Tax Act ("CITA"). The 2025 tax reforms subsequently repealed CITA and expressly revoked that Order. The 2026 Order therefore operates within a materially different statutory framework, relying for its tax-remission mechanism on section 77(1) of the NTAA rather than the CITA provisions relied upon in 2024.

That legislative transition sharpens, rather than resolves, the question of legal form. Section 77(1) provides an express presidential tax-remission power. Section 3(1)(e) provides an important petroleum-policy and investment-promotion context, but is materially different in character because it is framed as a ministerial function. The relevant legal question is therefore whether the particular tax-credit mechanisms established by the Order fall within the scope of the enabling provisions on which it relies, and how those mechanisms interact with the fiscal provisions of the NTA and the PIA.

For investors, lenders and project sponsors, the question is consequently not simply whether an executive instrument is inherently less durable than primary legislation. It is more specific: what is fixed by legislation; what depends on the scope and continued operation of the enabling powers under which the Order was made; and what remains dependent on administrative determination, implementation guidance or contractual amendment. The fact that the Order has been gazetted distinguishes it from a policy announcement or informal administrative concession, but does not remove the need to consider the statutory limits within which it operates.

That last point has immediate practical significance. The Order contemplates applications to the NRS supported by detailed project economics, including an open-book economic model, and further contemplates implementation guidelines addressing documentation, valuation and reporting requirements. As at the date of this article, those guidelines had not been published. The Order therefore establishes the statutory framework for the new incentives, but the practical administration of that framework may be just as important to a project's economics and bankability as its headline terms.

5. What the Order replaces, what it preserves, and where discretion still sits

Read as a whole, the Order changes the framework through which deep-offshore fiscal support is accessed rather than replacing the wider legal regime. The FGN presents the new structure as a move away from project-by-project fiscal negotiation towards published project categories, rates, ceilings and procedures and a sustainable, repeatable investment architecture for qualifying deep offshore projects.

What the Order does not replace is equally important. It preserves the PIA institutional architecture, the post-2025 tax framework, PSC contractual arrangements, NUPRC approvals, Nigerian content requirements, project-specific implementation steps and administrative judgment where the Order expressly leaves a matter to the relevant authority. It narrows the field of negotiation regarding incentives rather than eliminating it.

For investment analysis, a sponsor should therefore ask not only what fiscal support the Order makes available, but what additional benefit it produces relative to the economics that would otherwise apply to the project. It is that incremental benefit, rather than the headline ceiling viewed in isolation, that represents the Order's effect on the investment case.

The Order preserves administrative discretion within that structure. The supplementary PTC remains a case-by-case assessment by the NRS, not a formula applied mechanically once eligibility is shown to have been met. The POR depends on a factual determination of whether the sliding scale in a given contract area has already progressed beyond 70:30, which may itself require project-specific verification.

Missing the 31st December 2029 FID deadline does not automatically forfeit the standard PTC: a lessee may apply to the NUPRC for a force majeure extension, and NUPRC's decision on that application is itself a discretionary act. Access to the supplementary PTC and the POR further depends on compliance with Nigerian content requirements, broadly, that project activities be performed in Nigeria, subject to exceptions for critical path items and for activities that would cost more than a prescribed margin to execute locally, and those exceptions themselves require an NCDMB-approved Nigerian Content Plan.

The Nigerian content conditions are not merely collateral compliance obligations. They are better understood as forming part of the policy bargain underlying the enhanced project economics. The FGN has linked the framework with maximising Nigerian execution where feasible, including engineering, fabrication, marine logistics, project management capability and deeper domestic supply chains. For transaction planning, Nigerian content should therefore be treated as part of the economics and eligibility analysis, rather than as a separate post-approval compliance workstream.

The practical conclusion is that the Order is better understood as a bounded framework than as either a blanket concession or a rigid formula. It fixes the outer limit of available fiscal support and channels discretion into identifiable administrative processes, including the NRS' case-by-case assessment, NUPRC's extension decisions, NCDMB's content approvals and the factual and contractual questions relevant to any POR. That channelled discretion is central to assessing whether the Order will deliver the investment certainty it is designed to promote.

6. Institutional context: the Order, NNPCL, and the NUPRC

A separate August development is relevant to the institutional setting in which the Order will operate. Nigeria's 2025 Licensing Round, results for which were announced by the NUPRC on 21st July 2026, recorded 200 bids from 143 companies for 37 of the 50 blocks originally offered, with 31 companies emerging as winning bidders and 13 blocks receiving no bids.

NNPCL's statement of 8th August 2026 addressed the allocation of functions under the PIA. In relation to the Licensing Round, the statement referred to NUPRC's statutory mandate for licensing rounds and petroleum block allocations, and described NNPCL's post-incorporation role by reference to its commercial and contractual participation in the upstream sector.

That allocation of functions is relevant to implementation of the Order. The Order concerns fiscal incentives and the commercial mechanics for implementing them in eligible projects, while NNPCL's statement helps locate upstream licensing within NUPRC's statutory remit. Where implementation requires PSC documentation involving NNPCL, that contractual role should be understood alongside, but separately from, the regulatory approvals and licensing functions of the NUPRC.

7. Reading the two August developments together:

fiscal incentives and institutional context

Taken individually, the Order and NNPCL's statement on the Licensing Round address different aspects of the post-PIA framework. The Order concerns fiscal predictability, by seeking further to reduce reliance on bespoke negotiation through published parameters for qualifying deep offshore projects. NNPCL's statement provides institutional context on the respective regulatory and commercial roles relevant to upstream activity. For deepwater projects, both points matter: competitive economics must be supported by a framework in which regulatory approvals and contractual implementation can be identified and planned for with sufficient confidence.

Improved fiscal terms can raise a project's internal rate of return, but capital allocation over the life of a deep offshore project, typically a decade or more, also depends on how the relevant approvals, contractual steps and implementation processes operate in practice. A generous ceiling on tax credits will be of limited practical value if the process for accessing the benefit is uncertain. Conversely, a clear institutional framework will not by itself make a marginal deepwater project bankable if the available fiscal terms remain uncompetitive.

The FGN's proposition is that greater certainty should attract capital. Implementation will determine how far that proposition is borne out in practice: whether published fiscal parameters are administered predictably, whether the relevant regulatory and contractual roles operate clearly, and whether the commercial documents needed to implement approved incentives can be completed on terms on which financiers and sponsors can rely.

8. Implications for operators, financiers, and investors: transaction planning, execution, and diligence points to watch

For operators, financiers and investors, the significance of the Order lies not only in the level of fiscal support potentially available, but in how that support is accessed, quantified and implemented for a particular project. The framework still leaves important matters to case-by-case assessment, regulatory judgment, and contractual implementation. The following points should therefore be addressed early in transaction planning, project structuring and diligence:

i **Test whether the promised shift from negotiation to rules is achieved in practice:** Distinguish matters objectively determined under the Order from matters still requiring case-by-case assessment, regulatory judgment or contractual agreement. Where material project economics remain dependent on discretionary implementation, reflect that uncertainty in conditions precedent, economic sensitivities, financing assumptions, longstop dates and investment committee materials.

ii **Model the minimum credit actually available, not the ceiling:** Establish precisely which tier of the standard PTC a project qualifies for by reference to its reserves, and whether the project is likely to be assessed favourably for the supplementary PTC, rather than building base-case economics on the headline supplementary PTC figures of US$11.50 per barrel or US$8 per barrel of oil equivalent. Establish separately whether the project is held under an existing lease or a future lease, since the additional US$1.00 per barrel applicable to qualifying future leases is a discrete component of the standard PTC. That distinction may be material to acreage awarded in recent and forthcoming licensing rounds.

iii **Track the FID deadline and its consequences:** The 31st December 2029 deadline for FID affects both the supplementary PTC and POR and, in a reduced form, the standard PTC. Development schedules, financing timetables, and any planned reliance on a force majeure extension should therefore be tested against that date now, not close to it.

iv **Address PSC amendment mechanics and the thirty-day execution window for any POR:** Where a project depends on a reset, confirm the process for the PSC addendum, NNPCL's role as counterparty, and how the thirty-day execution period following approval interacts with financing conditions precedent, co-venturer approval requirements and longstop dates. Internal authorities, board approvals and signatory arrangements should be in place before an application is submitted.

v **Build Nigerian content compliance into the project from FID:** Access to the supplementary PTC and the POR depends on a NCDMB-approved Nigerian Content Plan and on satisfying the stated exceptions for critical path and cost differential activities. This should be structured into procurement and execution planning from the outset, not addressed retrospectively.

vi **Treat regulatory approvals and contractual implementation as related workstreams:** For implementation of the Order, diligence, correspondence with the relevant FGN entity, and internal investment papers should clearly identify NUPRC approvals and NNPCL's commercial or contractual involvement in PSC amendments or related project documentation.

vii **Monitor the outstanding implementation guidelines:** The NRS' documentation, valuation and reporting requirements for the open-book economic model had not been published as at 21st August 2026. Those guidelines, once issued, will determine how the supplementary PTC will be administered in practice and should be reviewed as soon as available.

9. Conclusion: Capped support, not automatic relief

The Order is better understood as a framework for capped fiscal support for eligible projects than as an automatic concession. It seeks further to reduce reliance on ad hoc negotiation for individual projects, but it does not replace the underlying need for careful, project-specific analysis.

The FGN's stated objective of greater investment certainty should ultimately be measured by whether a project can identify in advance what is fixed by rule, what remains subject to administrative judgment, what requires contractual implementation, and what remains dependent on guidance not yet published.

For operators, financiers, and investors, the Order narrows the range of negotiation; it does not remove it. Its practical significance will be determined by implementation guidance not yet published, and by whether the relevant regulatory and contractual roles operate clearly in practice. A project's bankability will depend not only on the level of fiscal support available, but also on the predictability of the approvals, documentation and implementation steps required to access it.

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